INFORMATION SHEET

PRESIDING: Chair Mitchell; Commissioners Brown-Bland, Gray and Clodfelter
PLACE: Raleigh, NC
DATE: Tuesday, September 24, 2019
TIME: 1:30 p.m. – 5:27 p.m.
DOCKET NO.: E-22, Sub 562 and E-22, Sub 566
COMPANY: Virginia Electric and Power Company, d/b/a Dominion Energy North Carolina
DESCRIPTION: Application of for an Adjustment of Rates and Charges Applicable to Service in North Carolina and Petition for an Accounting Order to Defer Certain Capital and Operating Costs Associated with Greensville County Combined Cycle Addition.
VOLUME: 6

APPEARANCES

FOR VIRGINA ELECTRIC and POWER COMPANY, d/b/a DOMINION ENERGY NORTH CAROLINA:
- Robert W. Kaylor, Esq.
- Mary Lynne Grigg, Esq.
- Andrea Kells, Esq.
- Horace P. Payne, Esq.

FOR CAROLINA INDUSTRIAL GROUP FOR FAIR UTILITY RATES I:
- Warren K. Hicks, Esq.

FOR NUCOR STEEL-HERTFORD:
- Joseph W. Eason, Esq.
- Damon E. Xenopoulos, Esq.

FOR THE USING AND CONSUMING PUBLIC, THE STATE AND ITS CITIZENS:
- Jennifer Harrod, Esq.
- Margaret A. Force, Esq.
- Theresa Townsend, Esq.

FOR THE USING AND CONSUMING PUBLIC:
- David Drooz, Esq.
- Dianna Downey, Esq.
- Lucy Edmondson, Esq.
- Heather Fennell, Esq.
- Layla Cummings, Esq.
- Gina Holt, Esq.

WITNESSES

See Attached

EXHIBITS

See Attached

I/A

Supporting Schedules

DOMININON ENERGY NORTH CAROLINA
Docket No. E-22, Sub 562
North Carolina Retail Operations
SUPPORT FOR RECONCILIATION SCHEDULE
For the Test Year Ended December 31, 2018
(in Thousands)

Johnson Exhibit 1
Schedule 1(a)

Line No.	Item	Rate Base Impact 1/ (a)	Income Statement Impact 2/ (b)	Total Revenue Impact 3/ (c)
1	Remove Mt Storm Impairment costs	($83)	($998)	($1,081)
2	Remove Skiffes Creek mitigation costs	(264)	(119)	(383)
3	Remove Chesterfield Units 3 & 4 wet-to-dry conversion costs	(75)	(49)	(124)
4	Adjust CCR costs	(903)	(6,181)	(7,084)

1/ Johnson Exhibit 1, Schedule 2-1, Line 11.
2/ Johnson Exhibit 1, Schedule 3-1, Line 20.
3/ Column (a) plus Column (b).

I/A

DOMININON ENERGY NORTH CAROLINA
Docket No. E-22, Sub 562
North Carolina Retail Operations
REVENUE IMPACT OF SETTLED AND UNRESOLVED ADJUSTMENTS
For the Test Year Ended December 31, 2018
(In Thousands)

Johnson Settlement Exhibit 1
Schedule 1

Line No.	Item	Per Public Staff (a)	Per Company (b)	Difference 9/ (c)
1	Non-fuel revenue requirement increase per Company application	$ 26,958 1/	$ 26,958	$ -
2	Revenue impact of Company update in first supplemental filing	(2,079) 2/	(2,079)	-
3	**Non-fuel revenue requirement increase per Company after updates**	24,879	24,879	$ -
4	Revenue impact of Public Staff adjustments: 3/			
5	**Settled Issues:**			
6	Change in equity ratio from 53.65% to 52.00% equity	(1,903)	(1,903)	-
7	Change in debt cost rate from 4.442% to 4.442%	-	-	-
8	Change in return on equity from 10.75% to 9.75%	(8,064)	(8,064)	-
9	Change in retention factor - uncollectibles	(17)	(17)	-
10	Adjust uncollectibles	(238)	(238)	-
11	Adjust allocation of state accumulated deferred income taxes	-	-	-
12	Remove Mt Storm impairment costs	(470)	(470)	-
13	Adjust NUG Contract Termination Expense - Regulatory Asset	(36)	(36)	-
14	Adjust outside services	(177)	(177)	-
15	Eliminate certain ADIT balances	-	-	-
16	Remove Skiffes Creek mitigation costs	(153)	(153)	-
17	Remove executive compensation costs	(92)	(92)	-
18	Remove Chesterfield Units 3 & 4 wet-to-dry conversion costs	-	-	-
19	Adjustment to remove federal unprotected EDIT treatment as a rider	(287)	(287)	-
20	Adjust lobbying expense	(42)	(42)	-
21	Adjust storm costs	(81)	(81)	-
22	Remove employee severance program costs	(304)	(304)	-
23	Remove advertising costs	(12)	(12)	-
24	Adjust annual incentive plan costs	(358)	(358)	-
25	Adjust employee VRP Backfill costs	-	-	-
26	Adjust expenses for customer growth, usage, and weather normalization	(90)	(90)	-
27	Adjust variable non-fuel O&M expenses for displacement	(142)	(142)	-
28	Adjust inflation adjustment	(9)	(9)	-
29	Adjust uncollectibles for decrease in base fuel rate	(7)	(7)	-
30	Adjust cash working capital under present rates	(83) 8/	(83) 8/	-
31	Adjust cash working capital under proposed rates	(282) 8/	(282) 8/	-
32	Adjustment to reflect kWh change in revenue annualization	49	49	-
33	Adjustment for New Office Building	(720)	(720)	-
34	Rounding	1	1	-
35	**Total Settled Issues**	(13,517)	(13,517)	-
36	**Unsettled Issues:**			
37	Adjust coal combustion residual (CCR) costs	(7,096) 7/	(2,750) 7/	(4,346)
38	Adjust cash working capital for CCR adjustment	(74) 8/	(29) 8/	(45)
39	**Total Unsettled Issues**	(7,170)	(2,779)	(4,391)
40	**Recommended increase in non-fuel revenue requirement**	$ 4,192 4/	$ 8,583	$ (4,391)
41	**Public Staff recommended decrease in base fuel revenue requirement**	$ (2,155) 5/	$ (2,155)	$ -
42	**Annual EDIT Rider recommended by Public Staff for 5 year period**	$ 649 6/	$ 649	$ -

1/ Company Exhibit PMM-1, Page 1, Line 6, Column (6).
2/ Company Supplemental Exhibit PMM-1, Page 10.
3/ Calculated based on Johnson Settlement Exhibit 1, Schedules 2, 3, 4, 5, and backup schedules.
4/ Johnson Settlement Exhibit 1, Schedule 5, Line 7.
5/ Johnson Settlement Exhibit 1, Schedule 5, Line 6.
6/ Johnson Settlement Exhibit 2, Schedule 1, Line 14.
7/ DENC and the Public Staff have agreed on a small portion of this issue involving compounding of financing costs.
8/ Calculated based on including and excluding Public Staff and Company CCR adjustments in spreadsheet calculation.
9/ Column (a) - Column (b).

AGO Johnson Cross Exhibit 1
I/A

OFFICIAL COPY

Sep 18 2019

DOMININON ENERGY NORTH CAROLINA
Docket No. E-22, Sub 562
North Carolina Retail Operations
REVENUE IMPACT OF SETTLED AND UNRESOLVED ADJUSTMENTS
For the Test Year Ended December 31, 2018
(In Thousands)

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11	Adjust allocation of state ~~accumulated~~ deferred income taxes	-	-	-
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13	Adjust NUG Contract Termination Expense - Regulatory Asset	(36)	(36)	-
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28	Adjust inflation adjustment	(9)	(9)	-
29	Adjust uncollectibles for decrease in base fuel rate	(7)	(7)	-
30	Adjust cash working capital under present rates	(63) 8/	(63) 8/	-
31	Adjust cash working capital under proposed rates	(282) 8/	(282) 8/	-
32	Adjustment to reflect kWh change in revenue annualization	49	49	-
33	Adjustment for New Office Building	(720)	(720)	-
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40	**Recommended increase in non-fuel revenue requirement**	$ 4,192 4/	$ 8,583	$ (4,391)
41	**Public Staff recommended decrease in base fuel revenue requirement**	$ (2,155) 5/	$ (2,155)	$ -
42	**Annual EDIT Rider recommended by Public Staff for 2 year period**	$ 649 6/	$ 649	$ -

1/ Company Exhibit PMM-1, Page 1, Line 6, Column (6).
2/ Company Supplemental Exhibit PMM-1, Page 10.
3/ Calculated based on Johnson Settlement Exhibit 1, Schedules 2, 3, 4, 5, and backup schedules.
4/ Johnson Settlement Exhibit 1, Schedule 5, Line 7.
5/ Johnson Settlement Exhibit 1, Schedule 5, Line 8.
6/ Johnson Settlement Exhibit 2, Schedule 1, Line 14.
7/ DENC and the Public Staff have agreed on a small portion of this issue involving compounding of financing costs.
8/ Calculated based on including and excluding Public Staff and Company CCR adjustments in spreadsheet calculation.
9/ Column (a) - Column (b).

I/A

Public Staff
Floyd Exhibit No. 1
Docket No. E-22, Sub 562

Impact of NUG Adjustment on Allocation Factor 1 (Production Plant) and Factor 2 (Transmission).

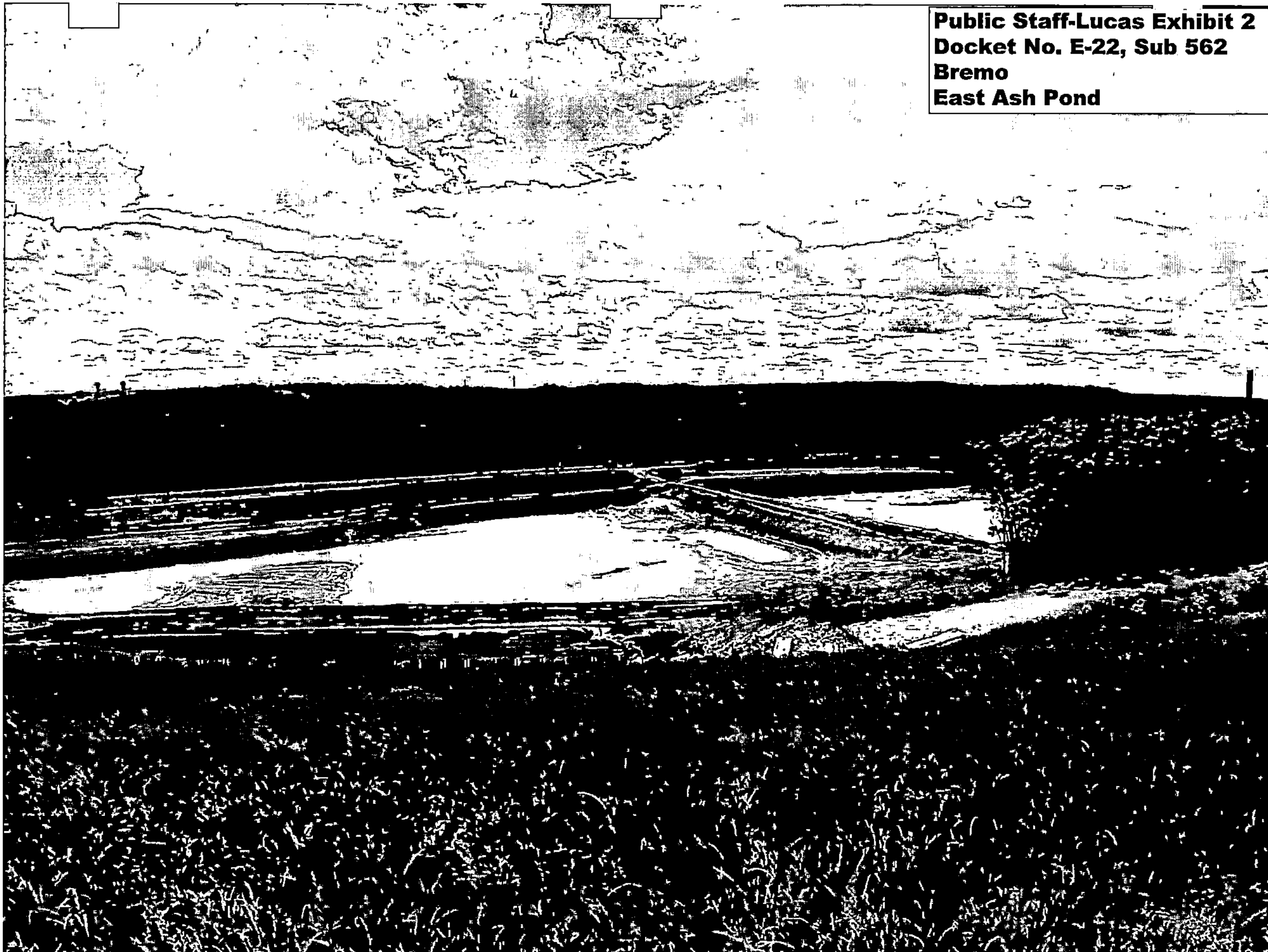
Factor 1	Including NUG Adjustment[1]	Excluding NUG Adjustment[2]
NC Retail	4.9507%	4.9503%
Res.	49.3792%	49.0445%
SGS	18.6501%	18.6042%
LGS	12.6175%	12.7442%
6VP	4.9392%	4.9926%
NS	14.0774%	14.2721%
Outdoor Ltg.	0.3264%	0.3321%
Traffic	0.0102%	0.0103%

Factor 2	Including NUG Adjustment[1]	Excluding NUG Adjustment[2]
NC Retail	4.2009%	4.1993%
Res.	49.5576%	49.2724%
SGS	18.6429%	18.5937%
LGS	12.5772%	12.6939%
6VP	4.9190%	4.9672%
NS	13.9706%	14.1355%
Outdoor Ltg.	0.3225%	0.3271%
Traffic	0.0102%	0.0102%

[1] From Supplemental Filing, E-1, Item 45A.
[2] From Company Response to Staff Data Request 97-19.

I/A

Public Staff-Lucas Exhibit 2
Docket No. E-22, Sub 562
Bremo
East Ash Pond



I, A

Public Staff - Lucas Exhibit 3
Docket No. E-22, Sub 562

COMMONWEALTH of VIRGINIA

STATE WATER CONTROL BOARD
2111 Hamilton Street

Richard N. Burton
Executive Director

Post Office Box 11143
Richmond, Virginia 23230-1143
(804) 257-0056

STATE WATER CONTROL BOARD ENFORCEMENT ACTION

A SPECIAL ORDER ISSUED TO

VIRGINIA POWER

POSSUM POINT POWER STATION 4/14/87

This is a Special Order issued by the State Water Control Board (referred to hereafter as "the Board") under the authority of Section 62.1-44.15(8) of the Code of Virginia to Virginia Electric and Power Company (referred to hereafter as "Virginia Power").

Virginia Power owns and operates Possum Point Power Station located in Dumfries, Virginia. This facility is authorized to discharge wastewater to Quantico Creek and the Potomac River. Virginia Power's discharge of wastewater is the subject of NPDES Permit No. VA0002071 that was issued to Virginia Power by the Board effective April 26, 1985, and will expire April 26, 1990.

At the Possum Point site, Virginia Power uses 2 ponds (Ash Ponds D and E) to dispose of its fly ash waste. Virginia Power has conducted groundwater monitoring in the vicinity of Ash Pond D and Ash Pond E. The initial groundwater monitoring data indicate violations of groundwater standards. Because of these data, the Board believes that groundwater in the vicinity of the two ponds should be studied further.

The Board orders and Virginia Power agrees to study the groundwater in order to define the extent and nature of the contamination and to evaluate the remediation alternatives. The study shall be conducted in accordance with Appendix A to this Order which is attached hereto and incorporated herein by reference.

Virginia Power waives its rights to a hearing on, to judicial review of, and to service of this Order. Virginia Power waives its right to written findings of fact and conclusion of law to support this Order. Notwithstanding the foregoing, Virginia Power shall not be deemed to have waived in any future administrative or judicial proceedings its right to contest the factual basis upon which any allegation of violation, or noncompliance with, this Order rests. Virginia Power further agrees that the Board may cancel this Order in

I/A

Public Staff - Lucas Exhibit 4
Docket No. E-22, Sub 562

COMMONWEALTH of VIRGINIA

STATE WATER CONTROL BOARD
2111 Hamilton Street

MAY 14 1991

Richard N. Burton
Executive Director

Post Office Box 11143
Richmond, Virginia 23230-1143
(804) 367-0056

CERTIFIED MAIL
RETURN RECEIPT REQUESTED
P 620 918 395

VEPCO
Innsbrook Technical Center
5000 Dominion Boulevard
Glen Allen, Virginia 23060

Attention: Environmental Compliance Unit

Re: Cancellation of Consent Special Order - Possum Point Plant

Dear Sir or Madam:

Based on a review of regional and enforcement files in the above referenced matter, it appears that the requirements of the above referenced consent special order (hereinafter the "Order"), issued on September 12, 1989 have either been substantially fulfilled, or, if not fulfilled, incorporated into the newly reissued VPDES permit for the Possum Point facility. Accordingly, I am prepared to recommend to the State Water Control Board, at its next quarterly meeting on June 24, 1991, that the Order be cancelled, and hereby give you the notice of cancellation required by the Order. Should you have any questions or concerns regarding the cancellation proceeding, please do not hesitate to contact me at (804) 367-6811.

Sincerely,

Kathleen F. O'Connell

Kathleen F. O'Connell

cc: Jan Pickerel, SWCB, NRO
Steve Hetrick, SWCB, VRO

I/A

Dominion Energy North Carolina
2019 NC Base Case – Docket No. E-22, Sub 562
Public Staff
Data Request No. 161

The following responses to Questions No. 1 of Public Staff Data Request No. 161, dated August 7, 2019 has been prepared under my supervision.

Jason Williams

Jason E. Williams
Director, Learning Development &
Communications
Dominion Energy Services, Inc.

Question No. 1:

In DR 61-2, the Public Staff asked for Company's organizational charts for its environmental management divisions, including all organizational units responsible for disposal, regulatory compliance, and other management of Coal Combustion Residuals, for each year from 1980 to the present. We received the present organizational chart and comparable charts from 1995, 1997, and 2001. We also received a spreadsheet identifying individuals in management positions from 2005 through 2019. From 1995 (and possibly prior) through 2001 we have identified A.W. Howard as the manager for coal ash related environmental compliance. From 2001 through 2015, we have identified Pamela Faggert as the manager for coal ash related environmental compliance. For 2015 through the present, we have identified Jason Williams as the manager of coal ash related environmental compliance.

a. Please confirm we have correctly identified the people primarily responsible for CCR management and disposal for time periods noted in the organization charts.
b. Are the positions held by Mr. Howard and Ms. Faggert identical in function and duties to the position currently held by Jason Williams? If not, please provide a detailed statement on any ways in which the positions differ.
c. When did Jason Williams start his current position? Was he with the Company prior to being in this position? If so, what was his former position(s) and who did he report to?

Response:

a. The timeline is correct, but the person in the Company's Environmental Services organization primarily responsible (at a Director level) for coal ash environmental compliance between 2002 and 2015 was Cathy Taylor, not Pamela Faggert. Ms. Faggert was the Vice President over the entire Environmental Services organization, and Mr. Hadder before that. Prior to Ms. Taylor assuming her role, Judson White held the position (either at a Director or Manager level).

I/A

Public Staff - Lucas Exhibit 8
Docket No. E-22, Sub 562

1. **<u>Data Request 3-1 (sent March 29, 2019—due April 8, 2019)</u>:**

For all current and former coal generating stations, please list all locations (e.g. lay of land areas, cinder piles, ponds, impoundments, and landfills) where the Company has disposed of CCR, including both original locations and, where applicable, new or relocation sites if CCR has been moved from its original location. For each location, please provide:

a. The physical address.
b. The nomenclature used to identify each CCR storage area at each location.
c. Year(s) during which each CCR storage area was in operation (receiving or storing CCR).
d. Amount of CCR disposed (columns for cubic yards and tonnage) during each year identified in 1.c. (if available), and cumulatively.
e. A description of the engineering features and construction details of the storage areas including, the storage volume.
f. A site plan for each location, and, if available, an aerial photograph with key features marked.
g. Whether the Company plans to excavate or otherwise close or take corrective action at the area.
h. The timeframe for closure plans or other corrective action. Please also provide any draft closure or corrective action plans.
i. If the area is being excavated or other corrective action is being taken, whether it being done to meet regulatory requirements and which regulatory requirements.
j. If the area is being excavated and there is not a regulatory requirement or other environmental compliance reason, please provide the management reason for the excavation or other corrective action being taken.

<u>Response to Data Request 3-1 (received April 18, 2019)</u>:

The response for a, b, c, d, g, h, i, and j are provided in a table included in Attachment Public Staff Set 3-1b (JW). The response for "e" is provided in Attachment Public Staff Set 3-1a (JW) which includes applicable engineering, design, and construction information. The site plans requested in "f" can be found in the groundwater monitoring plans included in Attachment Public Staff Set 3-11b (JW).

I/A

Public Staff - Lucas Exhibit 9
Docket No. E-22, Sub 562

The Public Staff has requested that the Company provide groundwater monitoring data in spreadsheet format for each coal-fired generating facility showing exceedances, by constituent, of applicable groundwater quality standards from the date that groundwater monitoring first began (obligated or voluntary) at each facility to the present.

In response to the Public Staff's requests, the Company searched for and produced voluminous groundwater monitoring data dating back as far as 30 years for some facilities and groundwater monitoring reports dating back as far as 20 years for some facilities. The Company, however, is unable to create a spreadsheet or table that represents whether or not the Company exceeded groundwater standards during the operation of the coal ash impoundments up to the time of CCR Rule monitoring.

The Company represents that, based on the records currently in the Company's possession, developing the summary spreadsheets is practically infeasible and could mischaracterize the data. For example, because the Company's spreadsheets containing historic groundwater monitoring data contain only raw data, it would be inappropriate—without the critical additional information on applicable background levels and other contextual information (such as groundwater monitoring plans, permits, and well maps for each sample period)—to characterize the data as representing an exceedance (or not) of a standard in effect at the time. There may or may not have been additional groundwater exceedances caused by coal ash over the life of the impoundments that the Company cannot determine because it is not feasible to reconstruct a complete history of exceedances from Dominion's existing records.

Specifically, the Company represents that it has produced all documented, reported, and/or verified exceedances of applicable groundwater standards that it was able to locate. The Company has provided these in the form of groundwater reports. The Company further represents that, to the best of its knowledge, the groundwater reports produced in discovery reflect the Company's available records of scientifically verified and analyzed groundwater data, including exceedances, at its CCR storage facilities. The Company acknowledges, however, that it has not been able to locate some historical VPDES permits and related documents for its CCR sites in Virginia and West Virginia.

I/A

Public Staff - Lucas Exhibit 9
Docket No. E-22, Sub 562

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Public Staff - Lucas Exhibit 11
Docket No. E-22, Sub 562

Dominion Energy North Carolina
2019 NC Base Case – Docket No. E-22, Sub 562
Public Staff
Data Request No. 3

The following response to Question No. 15 of Public Staff Data Request No. 3, dated March 29, 2019 has been prepared under my supervision.

Jason E. Williams
Director-Environmental Services
Dominion Energy Services, Inc.

Question No. 15:

Please identify, by plant and basin location, which seeps are authorized in NPDES permits, and which are not.

a. For the seeps not authorized by NPDES permits (including those for which permit applications are pending), please explain whether VEPCO contends they were or were not violations of NPDES permit requirements, or violations of Virginia's § 62.1-44.15 or West Virginia's § 22-11-6, and why.
b. Please include whether the seep is an engineered seep or not.
c. Please provide the date the seep was first identified and, if applicable, the year the seep was eliminated.

Response:

There are no NPDES permitted or unpermitted seeps associated with VEPCO's CCR impoundments. VEPCO understands the term "seep" to mean a channelized flow of water emanating from the berm of an impoundment that does or has the potential to reach surface waters.

I, A

Public Staff - Lucas Exhibit 12
Docket No. E-22, Sub 562

Chesapeake - Industrial Landfill

No. of Virginia SWMR Groundwater Monitoring Exceedances by Constituent

Parameters	Annual Report		Exceedances Total
	2017	2018	
Antimony	-	2	2
Arsenic	14	14	28
Barium	-	-	-
Beryllium	-	-	-
Cadmium	-	-	-
Chromium	-	-	-
Cobalt	1	-	1
Copper	-	-	-
Lead	-	-	-
Mercury	-	-	-
Nickel	-	-	-
Selenium	-	-	-
Silver	-	-	-
Thallium	-	-	-
Tin	-	-	-
Vanadium	-	-	-
Zinc	-	-	-
Carbon disulfide	-	-	
Acenaphthene	-	-	
Anthracene	-	-	
Dibenzofuran	-	-	-
Di-n-butyl	-	-	-
Fluorene	-	-	-
Cyanide	-	-	-
Sulfide	12	15	27
Exceedances Total	27	31	58

Notes:

*Data compiled from Domminion responses to Public Staff Data Request 3-11, dated April 18, 2019.

*The annual data is from two or semi-annual sampling events and was collected from ten (10) downgradient wells.

*The inactive bottom ash pond was intended to be closed in place per the CCR Rule prior to April 17, 2018 and therefore be exempt from the detection and assessment monitoring requirements. However, there is no longer an exemption for inactive CCR surface impoundments and a 547-day extension was granted by the USEPA.

I/A

No. of CCR Rule Groundwater Monitoring Exceedances by Generating Station and Constituent

Parameters	Generating Station								Exceedances Total
	Bremo	Chesapeake	Chesterfield	Clover	Mt. Storm	Possum Pt.	VCHEC	Yorktown	
Appendix III Constituents									
Boron	10	N/A	37	7	5	9	3	5	76
Calcium	4	N/A	18	18	-	15	9	7	71
Chloride	-	N/A	14	15	5	18	-	2	54
Fluoride	2	N/A	9	-	6	-	3	3	23
pH	-	N/A	8	2	11	-	5	-	26
Sulfate	2	N/A	36	23	3	18	9	10	101
Total Dissolved Solids	2	N/A	19	14	-	18	6	9	68
Appendix IV Constituents									
Antimony	-	N/A	-	-	-	-	-	-	-
Arsenic	-	N/A	8	-	2	-	-	-	10
Barium	-	N/A	-	-	-	-	-	-	-
Beryllium	-	N/A	-	-	-	-	-	-	-
Cadmium	-	N/A	-	-	-	-	-	-	-
Chromium	-	N/A	-	-	-	-	-	-	-
Cobalt	-	N/A	33	-	1	1	-	-	35
Fluoride	-	N/A	-	-	1	-	-	-	1
Lead	-	N/A	-	-	-	-	-	-	-
Lithium	2	N/A	11	-	-	-	3	-	16
Mercury	-	N/A	-	-	-	-	-	-	-
Molybdenum	-	N/A	-	-	1	-	-	-	1
Selenium	-	N/A	-	-	-	-	-	-	-
Thallium	-	N/A	-	-	-	-	-	-	-
Total Radium	-	N/A	8	-	-	-	-	-	8
Exceedances Total	22	-	201	79	35	79	38	36	490

Notes:
*Parentheses (Virginia GWPS Exeedance)

*Data compiled from Domminion responses to Public Staff Data Request 3-11, dated April 18, 2019.

*1. For constituents for which a Maximum Contaminant Level (MCL) has been established, the MCL was used.
2. For constituents for which a health-based GWPS has been adopted under the August 29, 2018 Phase 1,

I/A

Public Staff - Lucas Exhibit 15
Docket No. E-22, Sub 562
Public Version

Dominion Energy North Carolina
2019 NC Base Case – Docket No. E-22, Sub 562
Public Staff
Data Request No. 157

The following responses to Questions No. 1-5 of Public Staff Data Request No. 157, dated August 6, 2019 have been prepared under my supervision.

Gregg Crenshaw
Director, Corporate Risk Management
Dominion Energy Services, Inc.

BEGIN CONFIDENTIAL

Question No. 1:

Please provide a list of all insurance carriers that may be liable for environmental damages for each site with a CCR unit, including general liability, environmental, or property liability insurance. For each policy, please provide a description of the coverage, when the coverage was purchased, the time period of the coverage, and any other relevant information.

[redacted]

[redacted]

[redacted]

Public Staff - Lucas Exhibit 16
Docket No. E-22, Sub 562

I/A

DOMINION ENERGY NORTH CAROLINA
Docket No. E-22, Sub 562
Twelve Months ended December 31, 2018
(000's)

Annualize Depreciation Expense
Page 1 of 7

Line No.	Description		Amount	
	To Annualize Depreciation Expense based on Plant in Service at June 30, 2019.			
1	Gross Plant Projected @ June 30, 2019 (see page 3)	$	42,957,794	
2	Depreciation Rate		2.94%	
3	Annualized Depreciation Expense at June 30, 2019 (Line 1 x Line 2)	$	1,262,959	
4	Test Year Depreciation Expense [Note 1], line 17	$	1,117,830	
5	Increase in Depreciation Expense (Line 3 - Line 4)	$	145,129	
6	North Carolina Jurisdictional Factor [Note 2], line 22		5.0457%	
7	**North Carolina Adjustment for Depreciation Expense**	**$**	**7,323**	**NC-37**
8	**Adjustment to Accumulated Depreciation for Annualization of Depreciation Expense (Line 7)**	**$**	**7,323**	**NC-75**
9	Transactional Income Tax Rate		25.623%	
10	**Adjustment to Accumulated Deferred Income Taxes for Annualization of Depreciation Expense (- Line 7 x Line 9)**	**$**	**(1,876)**	**NC-82**
11	**[Note 1]**			
12	Test Year Depreciation Expense - System (COS Sch 4, line 144) (see page 6)	$	1,142,010	
13	Less Test Year Depreciation Expense for:			
14	Ringfenced Projects (COS Sch 4, line 144) (see page 6)		5,352	
15	Distribution Strategic Underground Program (VA Only Activity) (see page 6) (COS Sch 4, Lines 81, 83, 85, 87, 89, 91, 93, and 104)		9,975	
16	ARO other than Ringfenced Projects (COS Sch 4, Lines 36, 61-62, 105-106, and 130-131) (see page 6)		8,852	
17	Adjusted Total System Depreciation Expense (line 12 less lines 14-16)	$	1 117 830	
18	**[Note 2]**			
19	NC Jurisdiction Depreciation Expense (COS Sch 4, line 144) (see page 6)		56,838	
20	Less: NC ARO (COS Sch 4, Lines 36, 61-62, 105-106, and 130-131) (see page 6)		436	
21	NC Jurisdiction Depreciation Expense less ARO (line 19 - line 20)		56,403	
22	NC as a % of System Excluding Ringfenced, Rider U and ARO (line 21 / line 17)		5.0457%	

Public Staff - Lucas Exhibit 16
Docket No. E-22, Sub 562

I/A

DOMINION ENERGY NORTH CAROLINA
Docket No. E-22, Sub 562
Twelve Months ended December 31, 2018
(000's)

Annualize Depreciation Expense
Page 1 of 7

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5	Increase in Depreciation Expense (Line 3 - Line 4)	$	145,129	
6	North Carolina Jurisdictional Factor [Note 2], line 22		5.0457%	
7	**North Carolina Adjustment for Depreciation Expense**	**$**	**7,323**	**NC-37**
8	**Adjustment to Accumulated Depreciation for Annualization of Depreciation Expense (Line 7)**	**$**	**7,323**	**NC-75**
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Public Staff - Lucas Exhibit 17
Docket No. E-22, Sub 562

I, A

Dominion Energy North Carolina
Docket No. E-22, Sub 562
Twelve Months ended December 31, 2018
(000's)

Annualize Depreciation Expense

Line No.	Description		Amount	
	To Annualize Depreciation Expense based on Plant In Service at June 30, 2019.			
1	Total North Carolina Jurisdiction Depreciation Expense, June 30, 2019 (Page 3, Line 7)	$	59,572	
2	Total North Carolina Jurisdiction Test Year Depreciation Expense (Page 7, Line 31)		56,400	
3	**North Carolina Jurisdiction Depreciation Adjustment (line 1 - line 2)**	**$**	**3,173**	**NC-37**
4	**Adjustment to Accumulated Depreciation for Annualization of Depreciation Expense (Line 3)**	**$**	**3,173**	**NC-75**
5	Transactional Income Tax Rate		25.623%	
6	**Adjustment to Accumulated Deferred Income Taxes for Annualization of Depreciation Expense (- Line 4 x Line 5)**	**$**	**(813)**	**NC-82**

I/A

DOMINION ENERGY NORTH CAROLINA
Docket No. E-22, Sub 562
North Carolina Retail Operations
AMORTIZATION SCHEDULE FOR DEFERRED CCR COSTS
For the Test Year Ended December 31, 2018
(in Thousands)

Maness Exhibit I
Schedule 1-1

		DENC Coal Ash Spend			DENC N.C. Retail Coal Ash Deferral							
Line No.	Month	System Spend per Company 1/	Public Staff Prudence Adjustments 2/	System Spend per Public Staff 3/	% to NC for Spend 4/	Beginning Balance 5/	NC Spend 6/	Ending Balance 7/	Deferred Cost of Debt 8/	Deferred Cost of Equity 9/	Total Return 10/	Ending Balance 11/
		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)
1	Jun-16							$ -				
2	Jul-16	$ 8,385	$ -	$ 8,385	5.0924%	$ -	$ 427	427	$ 0	$ 1	$ 1	$ 428
3	Aug-16	8,504	-	8,504	5.0924%	427	433	860	1	3	4	865
4	Sep-16	15,634	-	15,634	5.0924%	860	796	1,656	2	5	7	1,668
5	Oct-16	10,413	-	10,413	5.0924%	1,656	530	2,186	3	8	11	2,209
6	Nov-16	9,958	-	9,958	5.0924%	2,186	507	2,694	3	10	14	2,730
7	Dec-16	34,895	-	34,895	5.0924%	2,694	1,777	4,471	5	15	20	4,527
8	Jan-17	(342)	-	(342)	5.0924%	4,471	(17)	4,453	6	19	25	4,535
9	Feb-17	7,055	-	7,055	5.0924%	4,453	359	4,812	6	20	26	4,921
10	Mar-17	11,081	-	11,081	5.0924%	4,812	564	5,377	7	22	29	5,514
11	Apr-17	16,106	-	16,106	5.0924%	5,377	820	6,197	8	25	33	6,367
12	May-17	5,783	-	5,783	5.0924%	6,197	295	6,491	9	27	36	6,697
13	Jun-17	13,484	-	13,484	5.0924%	6,491	687	7,178	10	29	39	7,423
14	Jul-17	5,304	-	5,304	5.0924%	$\boxed{7,423}$	270	7,693	11	32	43	7,735
15	Aug-17	19,983	-	19,983	5.0924%	7,693	1,018	8,710	11	35	46	8,799
16	Sep-17	11,814	-	11,814	5.0924%	8,710	602	9,312	13	38	51	9,452
17	Oct-17	13,689	-	13,669	5.0924%	9,312	697	10,009	13	41	55	10,204
18	Nov-17	6,321	-	6,321	5.0924%	10,009	322	10,331	14	43	58	10,583
19	Dec-17	20,347	-	20,347	5.0924%	10,331	1,036	11,367	15	46	61	11,681
20	Jan-18	6,396	-	6,396	5.0924%	11,367	326	11,693	16	49	65	12,072
21	Feb-18	9,058	-	9,058	5.0924%	11,693	461	12,154	17	51	67	12,601
22	Mar-18	10,001	-	10,001	5.0924%	12,154	509	12,663	17	53	70	13,180
23	Apr-18	8,899	-	8,899	5.0924%	12,663	453	13,117	18	55	73	13,706
24	May-18	8,945	-	8,945	5.0924%	13,117	456	13,572	19	57	76	14,237
25	Jun-18	6,001	-	6,001	5.0924%	13,572	306	13,878	19	59	78	14,621
26	Jul-18	9,256	-	9,256	5.0924%	$\boxed{14,621}$	471	15,092	21	63	84	15,176
27	Aug-18	8,805	-	8,805	5.0924%	15,092	448	15,540	21	65	87	15,711
28	Sep-18	7,889	-	7,889	5.0924%	15,540	402	15,942	22	67	89	16,202
29	Oct-18	12,255	-	12,255	5.0924%	15,942	624	16,566	23	69	92	16,918
30	Nov-18	7,088	-	7,088	5.0924%	16,566	361	16,927	23	71	95	17,374
31	Dec-18	21,667	-	21,667	5.0924%	16,927	1,103	18,031	24	75	99	18,576
32	Jan-19	3,464	-	3,464	5.0924%	18,031	176	18,207	25	77	103	18,855
33	Feb-19	5,173	-	5,173	5.0924%	18,207	263	18,470	26	78	104	19,222
34	Mar-19	7,223	-	7,223	5.0924%	18,470	368	18,838	26	80	106	19,696
35	Apr-19	6,973	-	6,973	5.0924%	18,838	355	19,193	26	81	108	20,158
36	May-19	6,457	-	6,457	5.0924%	19,193	329	19,522	27	83	110	20,597
37	Jun-19	12,729	-	12,729	5.0924%	19,522	648	20,170	28	85	112	21,357
38	Jul-19	-	-	-	5.0924%	$\boxed{21,357}$	-	21,357	30	91	121	21,478
39	Aug-19	-	-	-	5.0924%	21,357	-	21,357	30	91	121	21,599
40	Sep-19	-	-	-	5.0924%	21,357	-	21,357	30	91	121	21,720
41	Oct-19	-	-	-	5.0924%	21,357	-	21,357	30	91	121	21,841
42	Total	$ 376,693	$ -	$ 376,693			$ 19,183		$ 653	$ 2,005	$ 2,658	

1/ NCUC Form E-1, Supplemental Item 10, Page 174 of 350, Column (1).
2/ There are no Public Staff recommended prudence disallowances to the deferred CCR costs.
3/ Column (a) plus Column (b).
4/ NCUC Form E-1, Supplemental Item 10, Page 174 of 350, Column (2).
5/ Amount in Column (g) of previous line, plus return for prior 12 months in July of each year.
6/ Column (c) times Column (d).
7/ Column (e) plus Column (f).
8/ Column (e) plus Column (g), divided by 2, times after tax cost of debt per NCUC Form E-1, Supplemental Item 10, Page 179 of 350, divided by 12.
9/ Column (e) plus Column (g), divided by 2, times after tax cost of equity per NCUC Form E-1, Supplemental Item 10, Page 179 of 350, divided by 12.
10/ Column (h) plus Column (i).
11/ Column (g) plus total return for year to date from Column (j).

DENC Lucas Cross Exhibit 1

I/A

STATE OF NORTH CAROLINA
UTILITIES COMMISSION
RALEIGH

DOCKET NO. E-2, SUB 1142

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of	)
	)
	)
Application of Duke Energy Progress, LLC for Adjustment of Rates and Charges Applicable to Electric Utility Service in North Carolina	)

Video Deposition of JAY LUCAS

(Taken by Duke Energy Progress, LLC)

Raleigh, North Carolina

Thursday, November 2, 2017

Reported by: Marisa Munoz-Vourakis - RMR, CRR and Notary Public

DENC Lucas Cross Exhibit 2

I/A

NORTH CAROLINA
PUBLIC STAFF
UTILITIES COMMISSION

May 24, 2019

Ms. M. Lynn Jarvis, Chief Clerk
North Carolina Utilities Commission
4325 Mail Service Center
Raleigh, North Carolina 27699-4300

Re: Docket No. EMP-103, Sub 0 – Application for CPCN to Construct an 80-MW Electric Merchant Plant in Roper, Washington County, North Carolina

Dear Ms. Jarvis:

In connection with the above-referenced docket, I transmit herewith for filing on behalf of the Public Staff the testimony of Evan D. Lawrence, Utilities Engineer, Electric Division.

By copy of this letter, we are forwarding copies to all parties of record.

Sincerely,

/s/ Megan Jost
Staff Attorney
megan.jost@psncuc.nc.gov

OFFICIAL COPY

DEWC Lucas Cross Exhibit 3
I / A

FILED
DEC 1 1 2017
Clerk's Office
N.C. Utilities Commission

PLACE: Dobbs Building

Raleigh, North Carolina

DATE: Wednesday, December 6, 2017

TIME: 9:30 a.m. - 12:30 p.m.

DOCKET NO: E-2, Sub 1142

ORIGINAL

BEFORE: Chairman Edward S. Finley, Jr., Presiding

Commissioner Bryan E. Beatty

Commissioner ToNola D. Brown-Bland

Commissioner Jerry C. Dockham

Commissioner James G. Patterson

Commissioner Daniel G. Clodfelter

IN THE MATTER OF:

DUKE ENERGY PROGRESS, LLC

Application for Adjustment of Rates and Charges

Applicable to Electric Utility Service

in North Carolina.

VOLUME: 19

Noteworthy
Reporting Services, LLC

I / A

DOMINION ENERGY NORTH CAROLINA
DOCKET NO. E-22, SUB 562
ENERGY AND FUEL EXPENSES

Normalized and Adjusted Energy and Fuel Expense based on Actual 12-Months Ended June 2018
(Company Ownership Only)

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)
	12-Months Ended June 2018							June 2018			
	Expense ($)	Generation (MWh)	Rate ($/MWh)	Supply (%)	Ratio of Coal Oil, CT & CC NUG & Other MWH To Total Sum	Coal, Oil, CT & CC, NUG, Other, Nuclear Adj. and Growth MWh	Adjusted Generation (MWh)	Expense ($)	Generation (MWh)	Rate ($/MWh)	Normalized & Adjusted Fuel Expense at Applicable Rate (8) x (11)
Coal (1)	471,290,374	14,918,376	31.59	16.7	0.2402	61,149,808	14,686,411	39,177,455	1,186,626	31.59 (5)	463,943,723
Nuclear											
Surry	92,861,852	14,166,909	6.55	15.8			14,089,231	7,679,153	1,216,094		
North Anna	89,900,546	13,484,033	6.67	15.1			13,489,188	7,827,546	1,214,887		
Total Nuclear	182,762,398 (4)	27,650,942	6.61	30.9			27,578,419	15,506,699	2,430,980	6.61 (5)	182,293,353
Heavy Oil	21,254,912	357,813	59.40	0.4	0.0058	61,149,808	352,223	6,716,689	138,525	59.40 (5)	20,922,046
CC & CT (2)	1,004,343,099	29,436,131	34.12	32.9	0.4739	61,149,808	28,978,466	69,750,846	2,912,060	28.97 (5)	839,541,311
Hydro	0	3,337,366		3.7			3,337,366	0	378,644		0
Solar		100,404		0.1			100,404		7,585		
Power Transactions											
NUG Fuel (6)	45,053,070	4,145,060	10.87	4.6	0.0667	61,149,808	4,080,649	7,998,059	367,450	10.87 (5)	44,352,767
NUG Statute Adjustment											29,426,701
Greensville Adjustment											(90,736,791)
PJM Purchases	381,349,975	13,258,175	28.76	14.8	0.2134	61,149,808	13,052,060	21,462,163	223,702	28.76 (7)	375,421,410
Adjustments											
Sales for Resale	(41,128,862)	(249,427)		-0.3			(249,427)	0	(33,308)		(41,128,862) (3)
Net	385,274,183	17,153,828	22.46	19.1			16,883,282	29,460,222	557,844		317,335,224
Pumping	0	(3,370,203)		-3.8			(3,370,203)	0	(383,829)		0
Energy Supply	2,064,924,966	89,584,657	23.05	100.0			88,445,965	160,611,912	7,228,434	20.62	1,824,035,658

NOTE: ALL VALUES REFLECT COMPANY'S OWNERSHIP OF NORTH ANNA, CLOVER AND BATH COUNTY

(1) Coal includes wood and natural gas steam generation
(2) CC & CT includes jet oil, light oil and natural gas generation
(3) Fuel expense is equal to 12 months ended June 2018
(4) Nuclear expense excludes interim storage
(5) Fuel expense rate based on weather normalized fuel expense
(6) NUG fuel includes expenses related to dispatchable NUGs at 78% for those units subject to the marketer percentage
(7) Purchases include 78% of the fuel expense and the impact of the FTRs

I/A

Dominion Energy North Carolina
Docket No. E-22, Sub 562

	2011								2012												
	1	2	3	4	5	6	7		8	9	10	11	12	13	14	15	16	17	18	19	
kWh (Net) in North Carolina	June	July	Aug	Sept.	Oct.	Nov.	Dec.	Total	Jan.	Feb.	March	April	May	June	July	Aug	Sept.	Oct.	Nov.	Dec.	Total
Residential Lighting - kWh /year Savings (Deemed with assumed realization and net-to-gross rates from May 1, 2019 EMV Report)	7,385	109,757	128,564	169,847	150,313	261,235	200,924	1,028,025	-	-	-	-	-	-	-	-	-	-	-	-	1,028,025
Monthly - Adjusted kWh (Net)								Total Months													Total Months
Jun, 2011	615	615	615	615	615	615	615	7	615	615	615	615	615	615	615	615	615	615	615	615	19
Jul		9,146	9,146	9,146	9,146	9,146	9,146	6	9,146	9,146	9,146	9,146	9,146	9,146	9,146	9,146	9,146	9,146	9,146	9,146	18
Aug			10,714	10,714	10,714	10,714	10,714	5	10,714	10,714	10,714	10,714	10,714	10,714	10,714	10,714	10,714	10,714	10,714	10,714	17
Sep				14,154	14,154	14,154	14,154	4	14,154	14,154	14,154	14,154	14,154	14,154	14,154	14,154	14,154	14,154	14,154	14,154	16
Oct					12,526	12,526	12,526	3	12,526	12,526	12,526	12,526	12,526	12,526	12,526	12,526	12,526	12,526	12,526	12,526	15
Nov						21,770	21,770	2	21,770	21,770	21,770	21,770	21,770	21,770	21,770	21,770	21,770	21,770	21,770	21,770	14
Dec							16,744	1	16,744	16,744	16,744	16,744	16,744	16,744	16,744	16,744	16,744	16,744	16,744	16,744	13
Jan, 2012									-	-	-	-	-	-	-	-	-	-	-	-	12
Feb										-	-	-	-	-	-	-	-	-	-	-	11
Mar											-	-	-	-	-	-	-	-	-	-	10
Apr												-	-	-	-	-	-	-	-	-	9
May													-	-	-	-	-	-	-	-	8
Jun														-	-	-	-	-	-	-	7
Jul															-	-	-	-	-	-	6
Aug																-	-	-	-	-	5
Sep																	-	-	-	-	4
Oct																		-	-	-	3
Nov																			-	-	2
Dec																				-	1
Total (Cumulative by Month) - Adjusted kWh (Net):	615	9,762	20,476	34,629	47,156	68,925	85,669	0	85,669	85,669	85,669	85,669	85,669	85,669	85,669	85,669	85,669	85,669	85,669	85,669	

Actual kWh (Jun. - Dec., 2011): 257,232

Actual kWh (Jan. - Dec., 2012): 1,028,025

Planned:	Bulbs	18,282	18,282	18,282	18,282	18,282	18,282	18,282	127,976	0	0	0	0	0	0	0	0	0	0	0	0	0
Actual:	Bulbs	276	3,966	4,495	6,027	5,419	9,315	7,622	37,120	0	0	0	0	0	0	0	0	0	0	0	0	0
									29%													0%

I/A

Docket No. E-22, Sub 562
Nucor Exhibit PJW-1

OFFICIAL COPY

Aug 23 2019

GDS Associates, Inc
ENGINEERS & CONSULTANTS

Paul J. Wielgus - Managing Director

EDUCATION

JD, 1996, licensed in Texas, South Texas College of Law, Houston, Texas

MBA, 1985, graduated with Honors, thesis on electric utility marketing, Lamar University, Beaumont, Texas

MS, College of Mineral and Energy Resources, 1979, awarded Federal Mining Fellowship, thesis on fuel transportation pricing and contracting, West Virginia University, Morgantown, West Virginia

BS, ECONOMICS, 1977, energy economics concentration, West Virginia University, Morgantown, West Virginia

EXECUTIVE PROFILE

As a Senior Executive in the energy industry was engaged in the development and implementation of commercial business plans. Initiatives undertaken included long-term energy sales and marketing arrangements, energy procurement, development projects, asset expansions, asset management, mergers and acquisitions, and regulatory activities. Currently providing energy advisory services to clients involving the above matters and perform other energy related work assignments on the behalf of clients including expert testimony.

PROFESSIONAL EXPERIENCE

GDS ASSOCIATES, INC., Atlanta, GA Managing Director	2008-Present
NRG Energy, New Roads, LA Vice President – Development	2006-2008
GDS ASSOCIATES, INC., Atlanta, GA Managing Director	2002-2006
ENTERGY WHOLESALE OPERATIONS, Houston, TX Senior Vice President - Business Development	1999-2002
AMERICAN ELECTRIC POWER (AEP), Columbus, OH, Houston, TX Vice President - Project Development	1997-1999
ENRON CAPITAL AND TRADE, Houston, TX Director	1991-1997
PEPSICO (FRITO-LAY), Plano, TX Energy Manager	1987-1991
Prior professional energy experience	1979-1987

I, A

ELECTRIC UTILITY COST ALLOCATION MANUAL

January, 1992

NATIONAL ASSOCIATION OF REGULATORY UTILITY COMMISSIONERS

1101 Vermont Avenue NW
Washington, D.C. 20005
USA
Tel: (202) 898-2200
Fax: (202) 898-2213
www.naruc.org

$25.00

I / A

Docket No. E-22, Sub 562
Nucor Exhibit JMT-1

OFFICIAL COPY

Aug 23 2019

GDS Associates, Inc
ENGINEERS & CONSULTANTS

Jacob M. Thomas, P.E. - Principal

EDUCATION

MBA, 2006, concentration in Finance, Auburn University

BS, INDUSTRIAL ENGINEERING, 2000, Georgia Institute of Technology

EXECUTIVE PROFILE

Mr. Thomas has over twenty years of experience, all with GDS Associates, consulting in the areas of finance and data analytics. Mr. Thomas specializes in cost of service modeling, retail and wholesale rate design, economic analysis, evaluation of demand response, load forecasting, load research, and impact evaluation. Jacob has developed cost of service models and managed rate studies for municipal and cooperative clients throughout the United States and has worked as an expert witness evaluating cost of service models and building cost of service scenarios in multiple rate cases involving models developed by Investor Owned Utilities.

PUBLICATIONS

- ◊ "Distributed Energy Generation Compensation and Cost Recovery Guide." NRECA, 2017. Co-author.
- ◊ "Residential Behavioral Program Persistence Effects in Pennsylvania." ACEE Summer Study on Energy Efficiency in Buildings, 2016. Lead author.
- ◊ "AMP Focus Forward Member Toolkit: Preparing for a Distributed Energy Future." American Municipal Power, 2016. Co-author.

REGULATORY EXPERIENCE

Mr. Thomas has filed testimony in the following:

- ◊ Indiana Utility Regulatory Commission – Cause No. 44967
- ◊ Michigan Public Service Commission – Case No. U-15701
- ◊ North Carolina Utilities Commission – Docket No. E-22, Sub 532
- ◊ North Dakota Public Service Commission – Case No. PU-16-666
- ◊ Utah Public Service Commission – Docket No. 16-035-36
- ◊ Vermont Public Service Board – Docket No. 7440; Case No. 18-0974-TF

I / A

DOMINION ENERGY NORTH CAROLINA
Docket No. E-22, Sub 562
CALCULATION OF LEVELIZED FEDERAL
UNPROTECTED EDIT RIDER CREDIT
For the Test Year Ended December 31, 2018

Boswell Exhibit I
Schedule 1

Line No.	Item	Year 1 Revenue Requirement (a)	Year 2 Revenue Requirement (b)	Year 3 Revenue Requirement (c)	Year 4 Revenue Requirement (d)	Year 5 Revenue Requirement (e)	Total Revenue Requirement (f)
	Annuity Factor						
1	Number of years	5 1/					
2	Payment per period	1					
3	After tax rate of return	6.150% 2/					
4	Present value of 1 dollar over number of years with						
5	with 1 payment per year	4.1952					
6	1 plus (interest rate divided by two)	1.0308					
7	Annuity factor (L4 x L5)	4.3244					
8	Total NC retail regulatory liability to be amortized	($5,928,660) 3/	($5,928,660) 3/	($5,928,660) 3/	($5,928,660) 3/	($5,928,660) 3/	
9	Annuity factor (L7)	4.3244	4.3244	4.3244	4.3244	4.3244	
10	Levelized rider federal EDIT regulatory liability (L8 / L9)	(1,370,979)	(1,370,979)	(1,370,979)	(1,370,979)	(1,370,979)	(6,854,895) 6/
11	One minus composite income tax rate	74.38% 4/	74.38% 4/	74.38% 4/	74 38% 4/	74 38% 4/	74 38% 4/
12	Net operating income effect (L10 x L11)	(1,019,696)	(1,019,696)	(1,019,696)	(1,019,696)	(1,019,696)	(5,098,479)
13	Retention factor	0.739861 5/	0.739861 5/	0.739861 5/	0.739861 5/	0.739861 5/	0.739861 5/
14	Levelized rider federal EDIT credit (L5 / L6)	($1,378,226)	($1,378,226)	($1,378,226)	($1,378,226)	($1,378,226)	($6,891,131)

1/ Rider period recommended by Public Staff.
2/ Boswell Exhibit 1, Schedule 2(a), Line 3.
3/ Company Supplemental Exhibit PMM-2, Schedule 1, page 3, lines 86 plus 87.
4/ One minus the composite income tax rate of 25.6228%.
5/ Johnson Exhibit 1, Schedule 1-2, Column (d), Line 14.
6/ Sum of Columns (a) through Column (e).

Public Staff - D. Williamson Exhibit #3
Docket No. E-22, Sub 563

I, A

190230230

Virginia State Corporation Commission
eFiling CASE Document Cover Sheet

Case Number (if already assigned)	PUE-2012-00029
Case Name (if known)	Application of Virginia Electric and Power Company for Approval and Certification of Electric Facilities: Surry-Skiffes Creek 500 kV Transmission Line, Skiffes Creek-Whealton 230 kV Transmission
Document Type	OTHR
Document Description Summary	Update on Status of Certificated Project (February 27, 2019)

Total Number of Pages	52
Submission ID	16229
eFiling Date Stamp	2/27/2019 3:15:03PM

**MEMORANDUM OF AGREEMENT
AMONG
VIRGINIA ELECTRIC AND POWER COMPANY,
THE VIRGINIA STATE HISTORIC PRESERVATION OFFICE,
U.S. ARMY CORPS OF ENGINEERS NORFOLK DISTRICT, AND
THE ADVISORY COUNCIL ON HISTORIC PRESERVATION**

SUBJECT: ISSUANCE OF U.S. ARMY CORPS OF ENGINEERS' PERMITS FOR THE PROPOSED SURRY-SKIFFES CREEK-WHEALTON TRANSMISSION LINE PROJECT, SURRY COUNTY, JAMES CITY COUNTY, YORK COUNTY, CITIES OF NEWPORT NEWS AND HAMPTON, VIRGINIA

APRIL 24, 2017

WHEREAS, pursuant to 36 CFR Part 800, regulations implementing Section 106 of the National Historic Preservation Act of 1966 (NHPA), as amended, 54 U.S.C. § 306108, and 33 CFR Part 325, Appendix C, Processing of Department of the Army Permits: Procedures for Protection of Historic Places, the US Army Corps of Engineers Norfolk District (Corps) is required to take into account the effects of federally permitted undertakings on properties included in or eligible for inclusion in the National Register of Historic Places (NRHP) prior to the issuance of permits for the undertaking and to consult with the Virginia State Historic Preservation Office (SHPO); and with the Advisory Council on Historic Preservation (ACHP) where historic properties are adversely affected; and

WHEREAS, Virginia Electric and Power Company (Dominion), proposes to construct new electrical transmission line infrastructure in the Hampton Roads area of Virginia. The project is intended to provide sufficient and reliable electricity to residents, businesses, and government agencies located on the Virginia Peninsula, and to meet mandatory federal North American Electric Reliability Corporation Reliability Standards. The project is collectively known as the Surry – Skiffes Creek – Whealton project, located in Surry, James City, and York Counties and the Cities of Newport News and Hampton, Virginia (the Project); and

WHEREAS, the Project involves construction of a new high voltage aerial electrical transmission line that consists of three components; (1) Surry – Skiffes Creek 500 kilovolt (kV) aerial transmission line, (2) Skiffes Creek 500 kV – 230 kV – 115 kV Switching Station, and (3) Skiffes Creek – Whealton 230 kV aerial transmission line. The proposed project will permanently impact 2,712 square feet (0.06 acres) of subaqueous river bottom and 281 square feet (0.01 acres) of non-tidal wetlands, and convert 0.56 acres of palustrine forested wetlands to scrub shrub non-tidal wetlands. The transmission lines will cross portions of the James River, Woods Creek, and Skiffes Creek. In addition to structures being built within the James River, structural discharges are proposed in non-tidal wetlands. The proposed activities will require a Corps permit pursuant to Section 10 of the Rivers and Harbors Act and Section 404 of the Clean Water Act; and

I/A

Exhibit JRW-1

Dominion Energy North Carolina
Recommended Cost of Capital

Panel A - Primary Cost of Capital Recommendation

Capital Source	Capitalization Ratios*	Cost Rate	Weighted Cost Rate
Long-Term Debt	50.00%	4.44%	2.22%
Common Equity	50.00%	9.00%	4.50%
Total Capitalization	100.00%		6.72%

* Capital Structure Ratios are developed in Exhibit JRW-3.

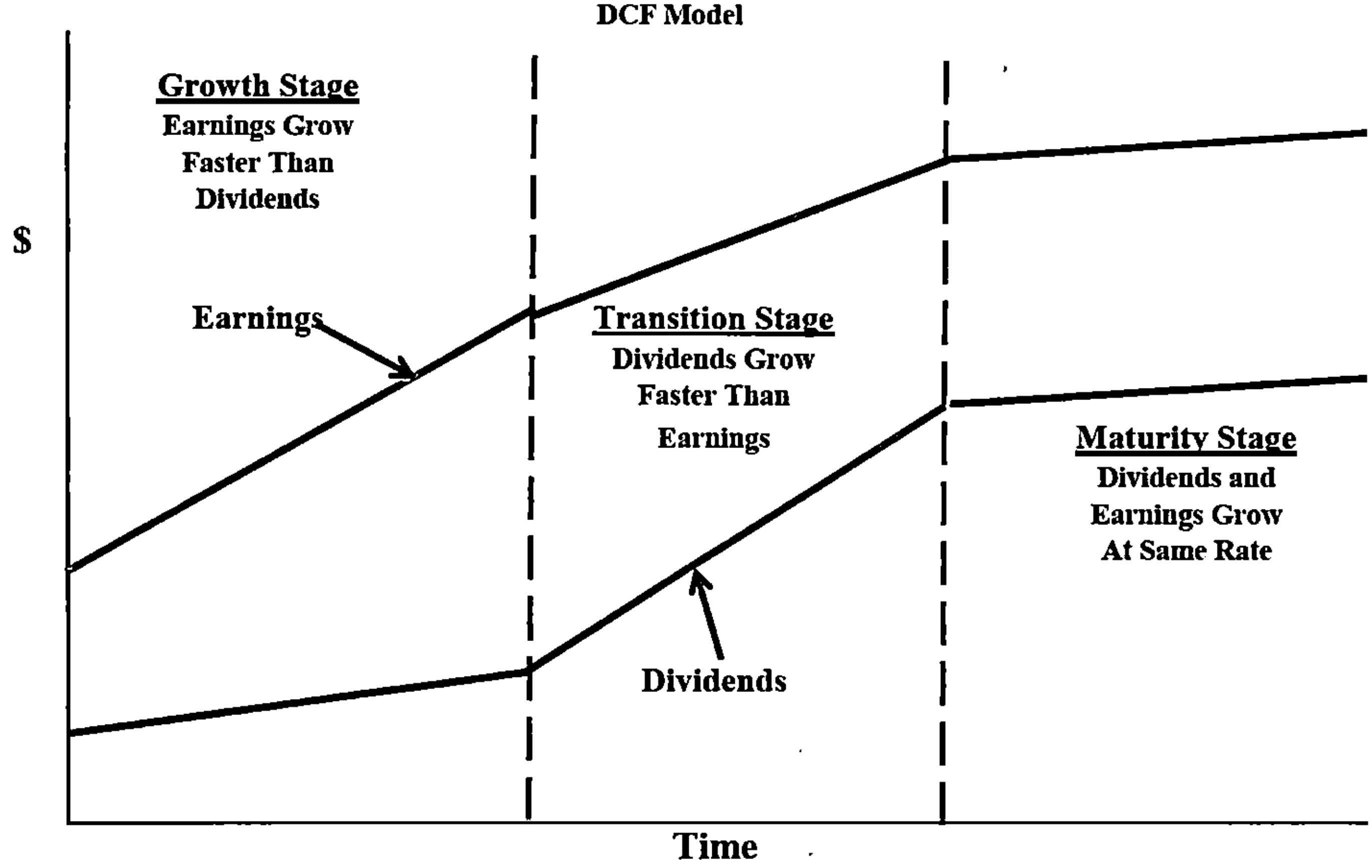
Panel B - Alternative Cost of Capital Recommendation

Capital Source	Capitalization Ratios*	Cost Rate	Weighted Cost Rate
Long-Term Debt	46.35%	4.44%	2.06%
Common Equity	53.65%	8.75%	4.69%
Total Capitalization	100.00%		6.75%

* Capital Structure Ratios are developed in Exhibit JRW-3.

I/A

Exhibit JRW-6
DCF Model



I/A

Exhibit JRW-7

Dominion Energy North Carolina
Discounted Cash Flow Analysis

Panel A
Electric Proxy Group

Dividend Yield*	3.10%
Adjustment Factor	1.02675
Adjusted Dividend Yield	3.18%
Growth Rate**	5.35%
Equity Cost Rate	8.55%

* Page 2 of Exhibit JRW-7
** Based on data provided on pages 3, 4, 5, and 6 of Exhibit JRW-7

Panel B
Hevert Proxy Group

Dividend Yield*	3.05%
Adjustment Factor	1.029
Adjusted Dividend Yield	3.14%
Growth Rate**	5.80%
Equity Cost Rate	8.95%

* Page 2 of Exhibit JRW-7
** Based on data provided on pages 3, 4, 5, and 6 of Exhibit JRW-7

I/A

Exhibit JRW-8

Dominion Energy North Carolina
Capital Asset Pricing Model

Panel A
Electric Proxy Group

Risk-Free Interest Rate	4.00%
Beta*	0.60
Ex Ante Equity Risk Premium**	5.50%
CAPM Cost of Equity	7.3%

* See page 3 of Exhibit JRW-8

** See pages 5 and 6 of Exhibit JRW-8

Panel B
Hevert Proxy Group

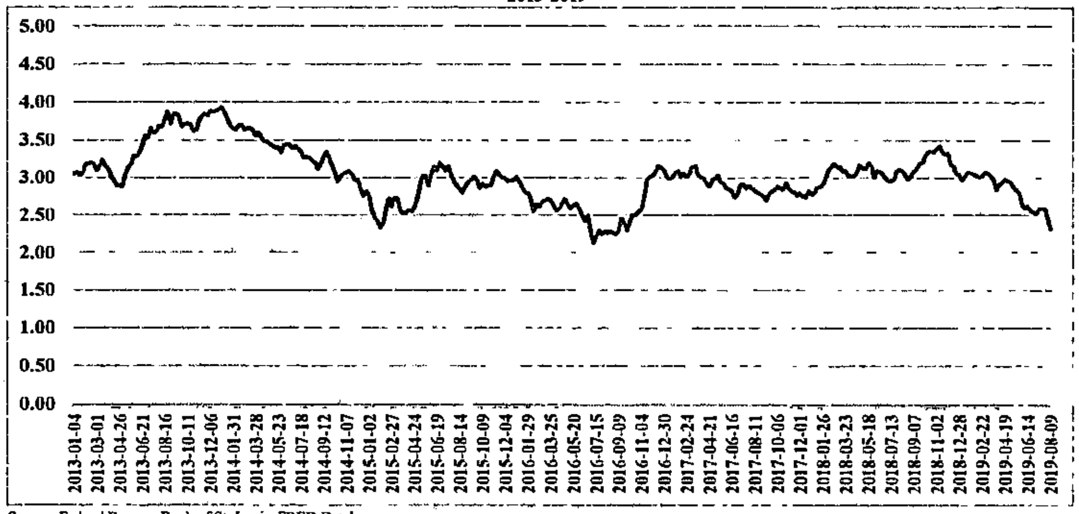
Risk-Free Interest Rate	4.00%
Beta*	0.58
Ex Ante Equity Risk Premium**	5.50%
CAPM Cost of Equity	7.2%

* See page 3 of Exhibit JRW-8

** See pages 5 and 6 of Exhibit JRW-8

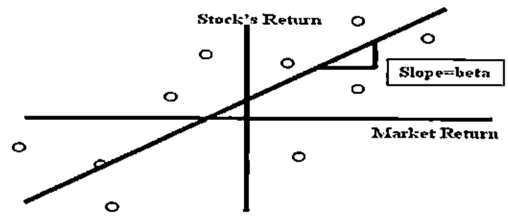
Exhibit JRW-8

Thirty-Year U.S. Treasury Yields
2013-2019



Source: Federal Reserve Bank of St Louis, FRED Database

Calculation of Beta



Panel A
Electric Proxy Group

Company Name	Beta
ALLETE, Inc. (NYSE-ALE)	0.65
Alliant Energy Corporation (NYSE-LNT)	0.60
Ameren Corporation (NYSE-AEE)	0.60
American Electric Power Co. (NYSE-AEP)	0.55
AVANGRID, Inc. (NYSE-AGR)	0.40
CMS Energy Corporation (NYSE-CMS)	0.55
Consolidated Edison, Inc. (NYSE-ED)	0.45
Duke Energy Corporation (NYSE-DUK)	0.50
Edison International (NYSE-EIX)	0.60
Entergy Corporation (NYSE-ETR)	0.60
Eversource Energy (NYSE-ES)	0.60
Exelon Corporation (NYSE-EXC)	0.70
FirstEnergy Corporation (NYSE-FE)	0.65
Hawaiian Electric Inductries (NYSE-HEC)	0.55
IDACORP, Inc. (NYSE-IDA)	0.60
MGE Energy, Inc. (NYSE-MGEE)	0.55
NextEra Energy, Inc. (NYSE-NEE)	0.60
NorthWestern Corporation (NYSE-NWE)	0.60
OGE Energy Corp. (NYSE-OGE)	0.80
Pinnacle West Capital Corp. (NYSE-PNW)	0.55
PNM Resources, Inc. (NYSE-PNM)	0.60
Portland General Electric Company (NYSE-POR)	0.60
PPL Corporation (NYSE-PPL)	0.70
Sempra Energy (NYSE-SRE)	0.75
Southern Company (NYSE-SO)	0.50
WEC Energy Group (NYSE-WEC)	0.50
Xcel Energy Inc. (NYSE-XEL)	0.50
Mean	0.59
Median	0.60

Data Source *Value Line Investment Survey*, 2019.

Panel B
Hevert Proxy Group

Company	Beta
ALLETE, Inc. (NYSE-ALE)	0.65
Alliant Energy Corporation (NYSE-LNT)	0.60
Ameren Corporation (NYSE-AEE)	0.60
American Electric Power Co. (NYSE-AEP)	0.55
Avangrid (NYSE-AVG)	0.40
Black Hills Corporation (NYSE-BKH)	0.75
CMS Energy Corporation (NYSE-CMS)	0.55
DTE Energy Company (NYSE-DTE)	0.55
Duke Energy Corporation (NYSE-DUK)	0.45
Evergy (NYSE-EVRG)	NMF
Hawaiian Electric Inductries (NYSE-HE)	0.55
Nextera Energy, Inc. (NYSE-NEE)	0.60
NorthWestern Corporation (NYSE-NWE)	0.60
OGE Energy Corp. (NYSE-OGE)	0.80
Otter Tail Corporation (NDQ-OTTR)	0.70
Pinnacle West Capital Corp. (NYSE-PNW)	0.55
PNM Resources, Inc. (NYSE-PNM)	0.60
Portland General Electric Company (NYSE-POR)	0.60
Southern Company (NYSE-SO)	0.50
WEC Energy Group (NYSE-WEC)	0.50
Xcel Energy Inc. (NYSE-XEL)	0.50
Mean	0.58
Median	0.58

Data Source *Value Line Investment Survey*, 2019.

Exhibit JRW-8
Risk Premium Approaches

	Historical Ex Post Returns	**Surveys**	**Expected Return Models and Market Data**
Means of Assessing The Market Risk Premium	Historical Average Stock Minus Bond Returns	Surveys of CFOs, Financial Forecasters, Companies, Analysts on Expected Returns and Market Risk Premiums	Use Market Prices and Market Fundamentals (such as Growth Rates) to Compute Expected Returns and Market Risk Premiums
Problems/Debated Issues	Time Variation in Required Returns, Measurement and Time Period Issues, and Biases such as Market and Company Survivorship Bias	Questions Regarding Survey Histories, Responses, and Representativeness Surveys may be Subject to Biases, such as Extrapolation	Assumptions Regarding Expectations, Especially Growth

Source: Adapted from Antti Ilmanen, Expected Returns on Stocks and Bonds," *Journal of Portfolio Management*, (Winter 2003)

Exhibit JRW-8

Capital Asset Pricing Model
Market Risk Premium

Category	Study Authors	Publication Date	Time Period Of Study	Methodology	Return Measure	Range Low	Range High	Midpoint of Range	Mean	Median
Historical Risk Premium										
	Ibbotson	2016	1928-2015	Historical Stock Returns - Bond Returns	Arithmetic				6.00%	
					Geometric				4.40%	
	Damodaran	2019	1928-2018	Historical Stock Returns - Bond Returns	Arithmetic				6.26%	
					Geometric				4.66%	
	Dimson, Marsh, Staunton Credit Suisse Repo	2019	1900-2018	Historical Stock Returns - Bond Returns	Arithmetic				5.50%	
					Geometric					
	Bate	2008	1900-2007	Historical Stock Returns - Bond Returns	Geometric				4.50%	
	Shiller	2006	1926-2005	Historical Stock Returns - Bond Returns	Arithmetic				7.00%	
					Geometric				5.50%	
	Siegel	2005	1926-2005	Historical Stock Returns - Bond Returns	Arithmetic				6.10%	
					Geometric				4.60%	
	Dimson, Marsh, and Staunton	2006	1900-2005	Historical Stock Returns - Bond Returns	Arithmetic				5.50%	
	Goyal & Welch	2006	1872-2004	Historical Stock Returns - Bond Returns					4.77%	
	Median									5.50%
Ex Ante Models (Puzzle Research)										
	Claus Thomas	2001	1985-1998	Abnormal Earnings Model					3.00%	
	Arnott and Bernstein	2002	1810-2001	Fundamentals - Div Yld + Growth					2.40%	
	Constantinides	2002	1872-2000	Historical Returns & Fundamentals - P/D & P/E					6.90%	
	Cornell	1999	1926-1997	Historical Returns & Fundamental GDP/Earnings		3.50%	5.50%	4.50%	4.50%	
	Easton, Taylor, et al	2002	1981-1998	Residual Income Model					5.30%	
	Fama French	2002	1951-2000	Fundamental DCF with EPS and DPS Growth		2.55%	4.32%		3.44%	
	Harris & Marston	2001	1982-1998	Fundamental DCF with Analysts' EPS Growth					7.14%	
	McKinsey	2002	1962-2002	Fundamental (P/E, D/P, & Earnings Growth)		3.50%	4.00%		3.75%	
	Siegel	2005	1802-2001	Historical Earnings Yield	Geometric				2.50%	
	Grabowski	2006	1926-2005	Historical and Projected		3.50%	6.00%	4.75%	4.75%	
	Maheu & McCurdy	2006	1885-2003	Historical Excess Returns, Structural Breaks,		4.02%	5.10%	4.56%	4.56%	
	Bostock	2004	1960-2002	Bond Yields, Credit Risk, and Income Volatility		3.90%	1.30%	2.60%	2.60%	
	Bakshi & Chen	2005	1982-1998	Fundamentals - Interest Rates					7.31%	
	Donaldson, Kamstra, & Kramer	2006	1952-2004	Fundamental, Dividend yld., Returns,, & Volatility		3.00%	4.00%	3.50%	3.50%	
	Campbell	2008	1982-2007	Historical & Projections (D/P & Earnings Growth)		4.10%	5.40%		4.75%	
	Best & Byrne	2001	Projection	Fundamentals - Div Yld + Growth					2.00%	
	Fernandez	2007	Projection	Required Equity Risk Premium					4.00%	
	DeLong & Magin	2008	Projection	Earnings Yield - TIPS					3.22%	
	Siegel - Rethink ERP	2011	Projection	Real Stock Returns and Components					5.50%	
	Duff & Phelps	2019	Projection	Normalized with 3.5% Long-Term Treasury Yield					5.50%	
	Mschchowski - VL - 2014	2014	Projection	Fundamentals - Expected Return Minus 10-Year Treasury Rate					5.50%	
	American Appraisal Quarterly ERP	2015	Projection	Fundamental Economic and Market Factors					6.00%	
	Market Risk Premia	2019	Projection	Fundamental Economic and Market Factors					4.29%	
	KPMG	2019	Projection	Fundamental Economic and Market Factors					5.50%	
	Damodaran - 3-1-19	2019	Projection	Fundamentals - Implied from FCF to Equity Model (Trailing 12 month, with adjusted payout)					4.98%	
	Social Security									
	Office of Chief Actuary		1900-1995							
	John Campbell	2001	1860-2000	Historical & Projections (D/P & Earnings Growth)	Arithmetic	3.00%	4.00%	3.50%	3.50%	
			Projected for 75 Years		Geometric	1.50%	2.50%	2.00%	2.00%	
	Peter Diamond	2001	Projected for 75 Year	Fundamentals (D/P, GDP Growth)		3.00%	4.80%	3.90%	3.90%	
	John Shoven	2001	Projected for 75 Year	Fundamentals (D/P, P/E, GDP Growth)		3.00%	3.50%	3.25%	3.25%	
	Median									4.29%
Surveys										
	New York Fed	2015	Five-Year	Survey of Wall Street Firms					5.70%	
	Survey of Financial Forecasters	2019	10-Year Projection	About 20 Financial Forecasters					1.85%	
	Duke - CFO Magazine Survey	2019	10-Year Projection	Approximately 200 CFOs					4.05%	
	Welch - Academics	2008	30-Year Projection	Random Academics		5.00%	5.74%	5.37%	5.37%	
	Fernandez - Academics, Analysts, and Compar	2019	Long-Term	Survey of Academics, Analysts, and Companies					5.60%	
	Median									5.37%
Building Block										
	Ibbotson and Chen	2015	Projection	Historical Supply Model (D/P & Earnings Growth)	Arithmetic			6.22%	5.21%	
					Geometric			4.20%		
	Chen - Rethink ERP	2010	20-Year Projection	Combination Supply Model (Historic and Projection)	Geometric				4.00%	
	Ilmanen - Rethink ERP	2010	Projection	Current Supply Model (D/P & Earnings Growth)	Geometric				3.00%	
	Grinold, Kroner, Siegel - Rethink ERP	2011	Projection	Current Supply Model (D/P & Earnings Growth)	Arithmetic			4.63%	4.12%	
					Geometric			3.60%		
	Median									4.06%
Mean										4.80%
Median										4.83%

Exhibit JRW-8

Capital Asset Pricing Model
Market Risk Premium

Summary of 2010-19 Equity Risk Premium Studies

Category	Study Authors	Publication Date	Time Period Of Study	Methodology	Return Measure	Range Low	Range High	Midpoint of Range	Mean	Average
Historical Risk Premium										
	Ibbotson	2016	1928-2015	Historical Stock Returns - Bond Returns	Arithmetic				6.00%	
					Geometric				4.40%	
	Damodaran	2019	1928-2018	Historical Stock Returns - Bond Returns	Arithmetic				6.26%	
					Geometric				4.66%	
	Dimson, Marsh, Staunton _Credit Suisse Report	2019	1900-2018	Historical Stock Returns - Bond Returns	Arithmetic				5.50%	
					Geometric					
	Median									5.36%
Ex Ante Models (Puzzle Research)										
	Siegel - Rethink ERP	2011	Projection	Real Stock Returns and Components					5.50%	
	Duff & Phelps	2019	Projection	Normalized with 3.5% Long-Term Treasury Yield					5.50%	
	Mschchowski - VL - 2014	2014	Projection	Fundamentals - Expected Return Minus 10-Year Treasury Rate					5.50%	
	American Appraisal Quarterly ERP	2015	Projection	Fundamental Economic and Market Factors					6.00%	
	Market Risk Premia	2019	Projection	Fundamental Economic and Market Factors					4.29%	
	KPMG	2019	Projection	Fundamental Economic and Market Factors					5.50%	
	Damodaran - 3-1-19	2019	Projection	Fundamentals - Implied from FCF to Equity Model (Trailing 12 month, with adjusted payout)					4.98%	
	Median									5.50%
Surveys										
	New York Fed	2015	Five-Year	Survey of Wall Street Firms					5.70%	
	Survey of Financial Forecasters	2019	10-Year Projection	About 20 Financial Forecasters					1.85%	
	Duke - CFO Magazine Survey	2019	10-Year Projection	Approximately 200 CFOs					4.05%	
	Fernandez - Academics, Analysts, and Companies	2019	Long-Term	Survey of Academics, Analysts, and Companies					5.60%	
	Median									4.83%
Building Block										
	Ibbotson and Chen	2015	Projection	Historical Supply Model (D/P & Earnings Growth)	Arithmetic			6.22%	5.21%	
					Geometric			4.20%		
	Chen - Rethink ERP	2010	20-Year Projection	Combination Supply Model (Historic and Projection)	Geometric				4.00%	
	Ilmanen - Rethink ERP	2010	Projection	Current Supply Model (D/P & Earnings Growth)	Geometric				3.00%	
	Grinold, Kroner, Siegel - Rethink ERP	2011	Projection	Current Supply Model (D/P & Earnings Growth)	Arithmetic			4.63%	4.12%	
					Geometric			3.60%		
	Median									4.06%
Mean										4.94%
Median										5.09%

Duff & Phelps Risk-Free Interest Rates and Equity Risk Premium Estimates

Duff & Phelps Recommended U.S. Equity Risk Premium (ERP) and Corresponding Risk-free Rates (R_f); January 2008–Present

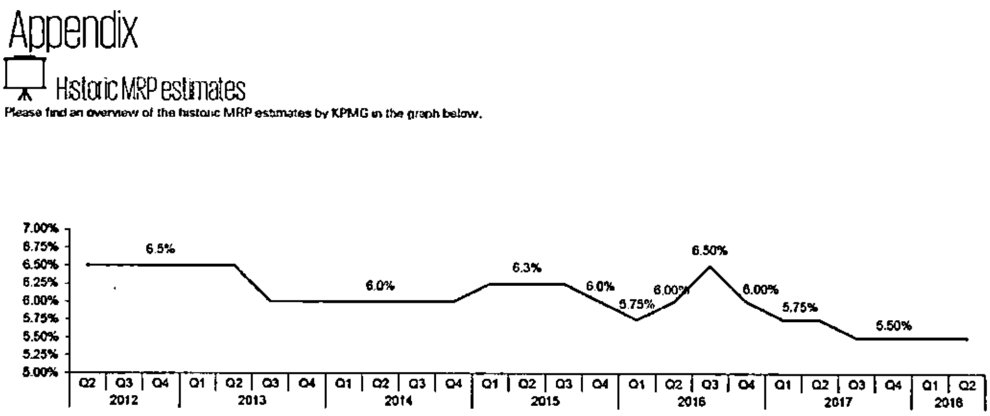
For additional information, please visit www.duffandphelps.com/CostofCapital

Date	*Risk-free Rate (R_f)*	*R_f (%)*	*Duff & Phelps Recommended ERP (%)*	*What Changed*
Current Guidance: December 31, 2018 – UNTIL FURTHER NOTICE	**Normalized 20-year U.S. Treasury yield**	**3.50**	**5.50**	**ERP**
September 5, 2017 – December 30, 2018	Normalized 20-year U.S. Treasury yield	3.50	5.00	ERP
November 15, 2016 – September 4, 2017	Normalized 20-year U.S. Treasury yield	3.50	5.50	R_f
January 31, 2016 – November 14, 2016	Normalized 20-year U.S. Treasury yield	4.00	5.50	ERP
December 31, 2015	Normalized 20-year U.S. Treasury yield	4.00	5.00	
December 31, 2014	Normalized 20-year U.S. Treasury yield	4.00	5.00	
December 31, 2013	Normalized 20-year U.S. Treasury yield	4.00	5.00	
February 28, 2013 – January 30, 2016	Normalized 20-year U.S. Treasury yield	4.00	5.00	ERP
December 31, 2012	Normalized 20-year U.S. Treasury yield	4.00	5.50	
January 15, 2012 – February 27, 2013	Normalized 20-year U.S. Treasury yield	4.00	5.50	ERP
December 31, 2011	Normalized 20-year U.S. Treasury yield	4.00	6.00	
September 30, 2011 – January 14, 2012	Normalized 20-year U.S. Treasury yield	4.00	6.00	ERP
July 1 2011 – September 29, 2011	Normalized 20-year U.S. Treasury yield	4.00	5.50	R_f
June 1, 2011 – June 30, 2011	Spot 20-year U.S. Treasury yield	Spot	5.50	R_f
May 1, 2011 – May 31, 2011	Normalized 20-year U.S. Treasury yield	4.00	5.50	R_f
December 31, 2010	Spot 20-year U.S. Treasury yield	Spot	5.50	
December 1, 2010 – April 30, 2011	Spot 20-year U.S. Treasury yield	Spot	5.50	R_f
June 1, 2010 – November 30, 2010	Normalized 20-year U.S. Treasury yield	4.00	5.50	R_f
December 31, 2009	Spot 20-year U.S. Treasury yield	Spot	5.50	
December 1, 2009 – May 31, 2010	Spot 20-year U.S. Treasury yield	Spot	5.50	ERP
June 1, 2009 – November 30, 2009	Spot 20-year U.S. Treasury yield	Spot	6.00	R_f
December 31, 2008	Normalized 20-year U.S. Treasury yield	4.50	6.00	
November 1, 2008 – May 31, 2009	Normalized 20-year U.S. Treasury yield	4.50	6.00	R_f
October 27, 2008 – October 31, 2008	Spot 20-year U.S. Treasury yield	Spot	6.00	ERP
January 1, 2008 – October 26, 2008	Spot 20-year U.S. Treasury yield	Spot	5.00	Initialized

"Normalized" in this context means that in months where the risk-free rate is deemed to be abnormally low, a proxy for a longer-term sustainable risk-free rate is used

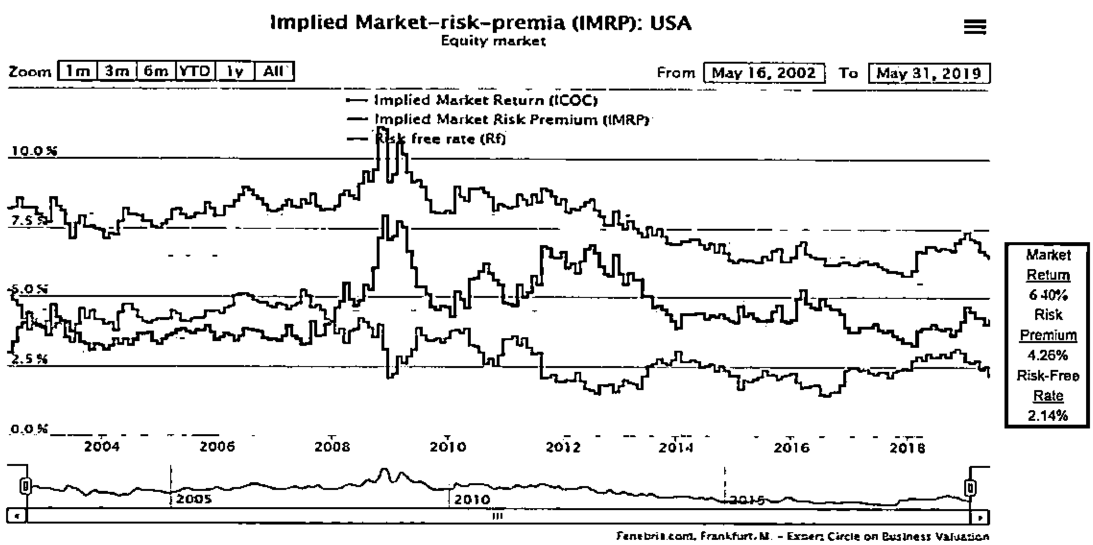
Source: https://www.duffandphelps.com/-/media/assets/pdfs/publications/valuation/coc/erp-risk-free-rates-jan-2008-present.ashx?la=en

Panel A
KPMG Equity Risk Premium Recommendation



Source: https://assets.kpmg/content/dam/kpmg/nl/pdf/2019/advisory/equity-market-research-summary.pdf

Panel B
Market-Risk-Premia.com Implied Market Risk Premium
31-May-19



Source: http://www market-risk-premia com/us html

I/A

Panel A
Mr. Hevert's DCF Results

	Mean Low	Mean	Mean High
30-Day Average	8.34%	9.24%	10.23%
90-Day Average	8.40%	9.31%	10.30%
180-Day Average	8.48%	9.39%	10.38%

Panel B
Mr. Hevert's CAPM Results

	Bloomberg Derived Market Risk Premium	Value Line Derived Market Risk Premium
Average Bloomberg Beta Coefficient		
Current 30-Year Treasury (3.04%)	8.25%	9.78%
Near-Term Projected 30-Year Treasury (3.25%)	8.47%	10.00%
Average Value Line Beta Coefficient		
Current 30-Year Treasury (3.04%)	9.29%	11.12%
Near-Term Projected 30-Year Treasury (3.25%)	9.50%	11.34%

	Bloomberg Derived Market Risk Premium	Value Line Derived Market Risk Premium
Average Bloomberg Beta Coefficient		
Current 30-Year Treasury (3.04%)	9.61%	11.54%
Near-Term Projected 30-Year Treasury (3.25%)	9.83%	11.75%
Average Value Line Beta Coefficient		
Current 30-Year Treasury (3.04%)	10.39%	12.54%
Near-Term Projected 30-Year Treasury (3.25%)	10.60%	12.76%

Panel C
Mr. Hevert's Risk Premium Results

	Return on Equity
Current 30-Year Treasury (3.04%)	9.93%
Near-Term Projected 30-Year Treasury (3.25%)	9.96%
Long-Term Projected 30-Year Treasury (4.05%)	10.17%

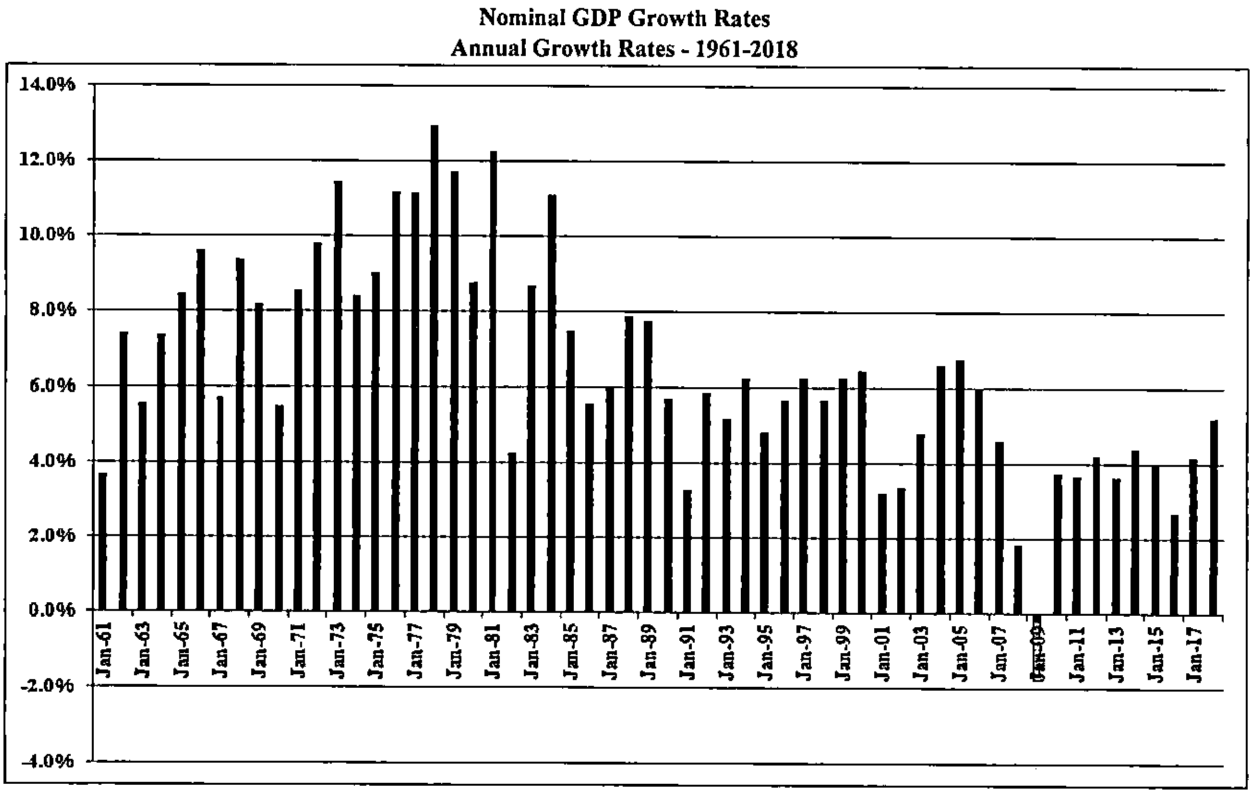
I/A

Growth Rates
GDP, S&P 500 Price, EPS, and DPS

		GDP	S&P 500	S&P 500 EPS	S&P 500 DPS	
	1960	542 38	58.11	3.10	1.98	
1	1961	562 21	71.55	3.37	2.04	
2	1962	603 92	63.10	3.67	2.15	
3	1963	637 45	75.02	4.13	2.35	
4	1964	684 46	84.75	4.76	2.58	
5	1965	742 29	92.43	5.30	2.83	
6	1966	813 41	80.33	5.41	2.88	
7	1967	859 96	96.47	5.46	2.98	
8	1968	940 65	103.86	5.72	3.04	
9	1969	1017 62	92.06	6.10	3.24	
10	1970	1073 30	92.15	5.51	3.19	
11	1971	1164 85	102.09	5.57	3.16	
12	1972	1279 11	118.05	6.17	3.19	
13	1973	1425 38	97.55	7.96	3.61	
14	1974	1545 24	68.56	9.35	3.72	
15	1975	1684 90	90.19	7.71	3.73	
16	1976	1873 41	107.46	9.75	4.22	
17	1977	2081 83	95.10	10.87	4.86	
18	1978	2351 60	96.11	11.64	5.18	
19	1979	2627 33	107.94	14.55	5.97	
20	1980	2857 31	135.76	14.99	6.44	
21	1981	3207 04	122.55	15.18	6.83	
22	1982	3343 79	140.64	13.82	6.93	
23	1983	3634 04	164.93	13.29	7.12	
24	1984	4037 61	167.24	16.84	7.83	
25	1985	4338 98	211.28	15.68	8.20	
26	1986	4579 63	242.17	14.43	8.19	
27	1987	4855 22	247.08	16.04	9.17	
28	1988	5236 44	277.72	24.12	10.22	
29	1989	5641 58	353.40	24.32	11.73	
30	1990	5963 14	330.22	22.65	12.35	
31	1991	6158 13	417.09	19.30	12.97	
32	1992	6520 33	435.71	20.87	12.64	
33	1993	6858 56	466.45	26.90	12.69	
34	1994	7287 24	459.27	31.75	13.36	
35	1995	7639 75	615.93	37.70	14.17	
36	1996	8073 12	740.74	40.63	14.89	
37	1997	8577 55	970.43	44.09	15.52	
38	1998	9062 82	1229.23	44.27	16.20	
39	1999	9630 66	1469.25	51.68	16.71	
40	2000	10252 35	1320.28	56.13	16.27	
41	2001	10581 82	1148.09	38.85	15.74	
42	2002	10936 42	879.82	46.04	16.08	
43	2003	11458 25	1111.91	54.69	17.88	
44	2004	12213 73	1211.92	67.68	19.41	
45	2005	13036 64	1248.29	76.45	22.38	
46	2006	13814 61	1418.30	87.72	25.05	
47	2007	14451 86	1468.36	82.54	27.73	
48	2008	14712 85	903.25	65.39	28.05	
49	2009	14448 93	1115.10	59.65	22.31	
50	2010	14992 05	1257.64	83.66	23.12	
51	2011	15542 58	1257.60	97.05	26.02	
52	2012	16197 01	1426.19	102.47	30.44	
53	2013	16784 85	1848.36	107.45	36.28	
54	2014	17521 75	2058.90	113.01	39.44	
55	2015	18219 30	2043.94	106.32	43.16	
56	2016	18707 19	2238.83	108.86	45.03	
57	2017	19485 39	2673.61	124.94	49.73	
58	2018	20500 64	2506.85	148.34	53.61	Average
	Growth Rates	**6.46**	**6.71**	**6.89**	**5.85**	**6.48**

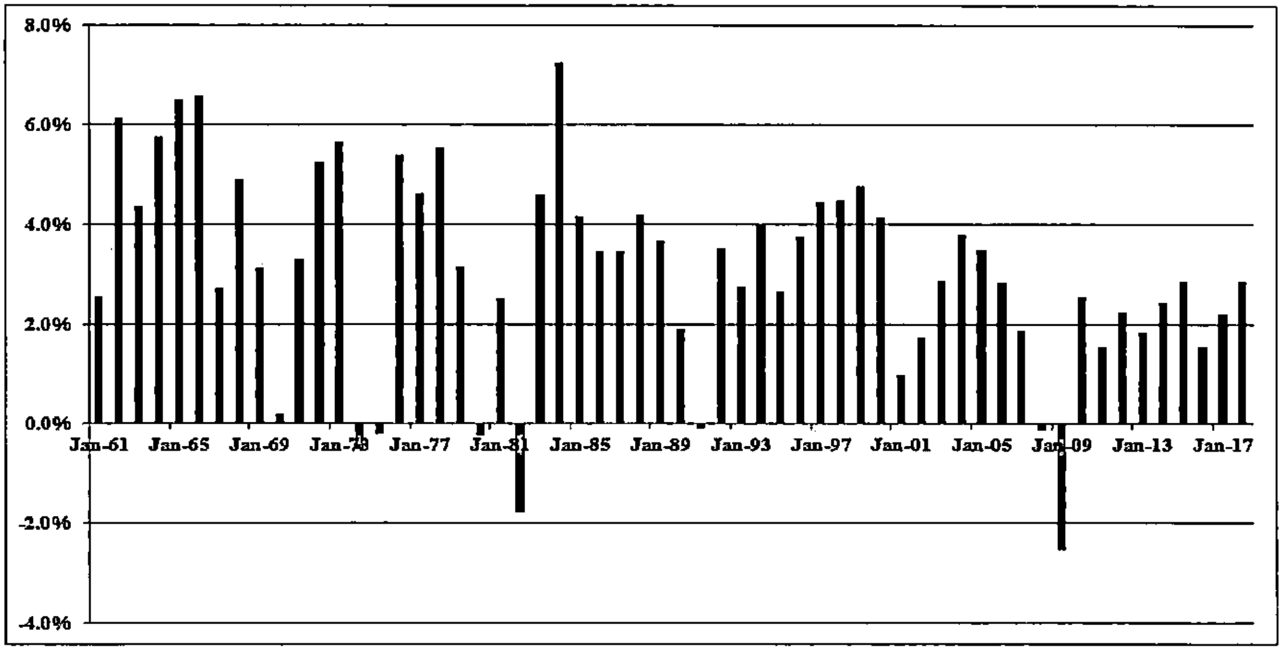
A -http://research stlouisfed org/fred2/series/GDPA/downloaddata

, EPS and DPS - http://pages stern nyu edu/~adamodar/



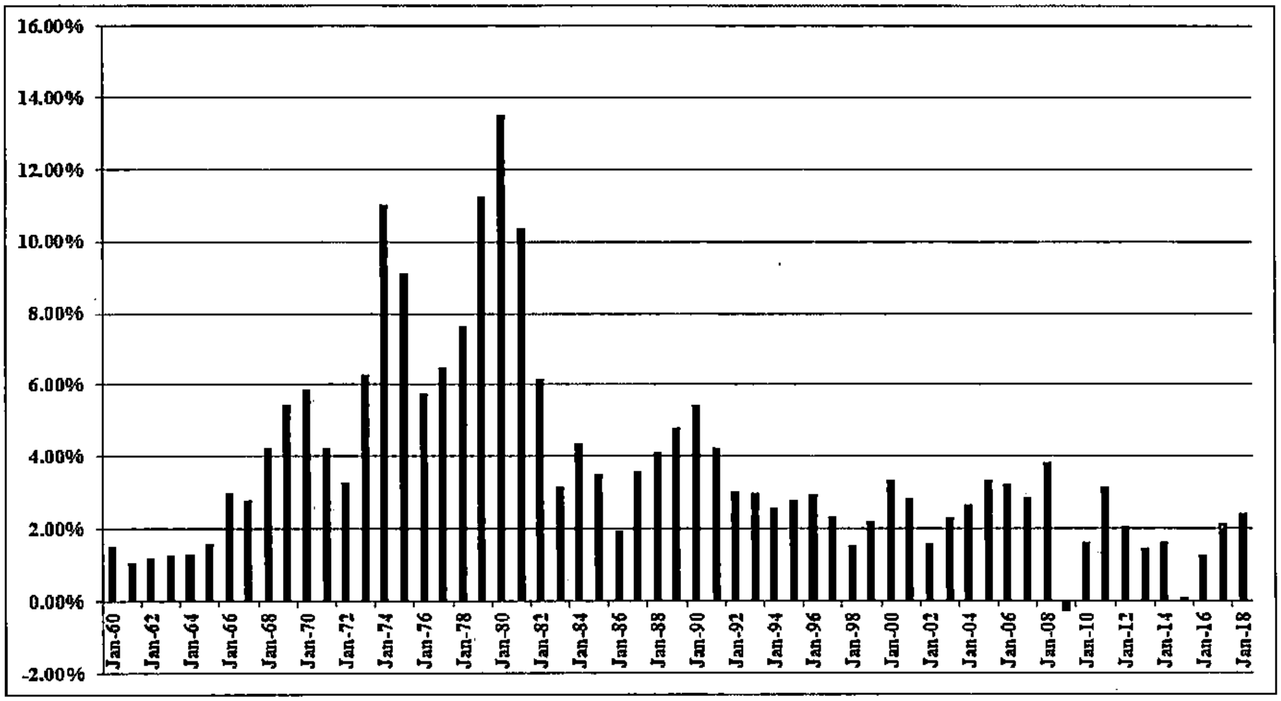
Data Sources: GDPA -https://fred.stlouisfed.org/series/GDPA

Annual Real GDP Growth Rates
1961-2018



Data Sources: GDPC1 - https://fred.stlouisfed.org/series/GDPCA

Annual Inflation Rates
1961-2018



Data Sources: CPIAUCSL - https://fred.stlouisfed.org/series/CPIAUCSL

Panel A
Historic GDP Growth Rates

10-Year Average		3.37%
20-Year Average		4.17%
30-Year Average		4.65%
40-Year Average		5.56%
50-Year Average		6.36%

Calculated using GDP data on Page 1 of Exhibit JRW-10

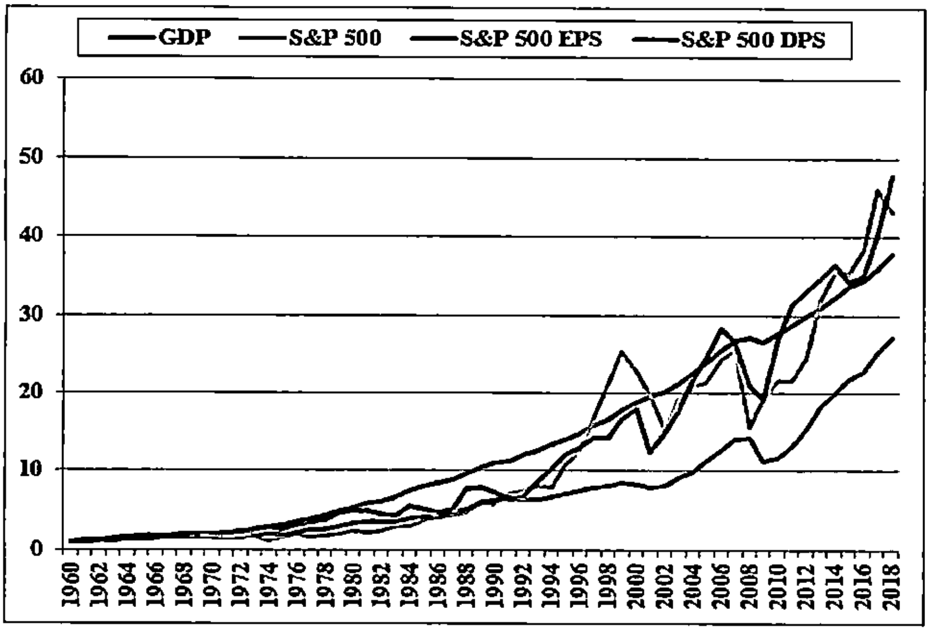
Panel B
Projected GDP Growth Rates

	Time Frame	Projected Nominal GDP Growth Rate
Congressional Budget Office	2018-2048	4.0%
Survey of Financial Forecasters	Ten Year	4.3%
Social Security Administration	2018-2095	4.4%
Energy Information Administration	2017-2050	4.3%

Sources:

Congressional Budget Office,The *2018 Long-Term Budget Outlook*, June 1, 2018.
https://www.cbo.gov/system/files?file=2018-06/53919-2018ltbo.pdf
U.S. Energy Information Administration, *Annual Energy Outlook 2018*, Table: Macroeconomic Indicators,
https://www.eia.gov/outlooks/aeo/data/browser/#/?id=18-AEO2018&sourcekey=0.
Social Security Administration, 2018 Annual Report of the Board of Trustees of the Old-Age, Survivors, and Disability Insurance (OASDI) Program, Table VI.G4, p. 211(June 15, 2018), https://www.ssa.gov/oact/tr/2018/lr6g4.html. The 4.4% represents the compounded growth rate in projected GDP from $20.307 trillion in 2018 to $548.108 trillion in 2095.
https://www.philadelphiafed.org/research-and-data/real-time-center/survey-of-professional-forecasters/

Long-Term Growth of GDP, S&P 500, S&P 500 EPS, and S&P 500 DPS



	GDP	S&P 500	S&P 500 EPS	S&P 500 DPS
Growth Rates	6.47	6.95	6.70	5.82

Exhibit JRW-7

Dominion Energy North Carolina
Monthly Dividend Yields

Panel A
Electric Proxy Group*

Company	Annual Dividend	Dividend Yield 30 Day	Dividend Yield 90 Day	Dividend Yield 180 Day
ALLETE, Inc. (NYSE-ALE)	$2.35	2.75%	2.83%	2.91%
Alliant Energy Corporation (NYSE-LNT)	$1.42	2.85%	2.95%	3.07%
Ameren Corporation (NYSE-AEE)	$1.90	2.49%	2.56%	2.65%
American Electric Power Co. (NYSE-AEP)	$2.68	2.98%	3.08%	3.24%
Avangrid (NYSE-AVG)	$1.76	3.50%	3.48%	3.51%
CMS Energy Corporation (NYSE-CMS)	$1.53	2.61%	2.70%	2.81%
Consolidated Edison, Inc. (NYSE-ED)	$2.96	3.36%	3.42%	3.57%
Duke Energy Corporation (NYSE-DUK)	$3.78	4.26%	4.27%	4.28%
Edison International (NYSE-EIX)	$2.45	3.60%	3.84%	4.01%
Entergy Corporation (NYSE-ETR)				
Eversource Energy (NYSE-ES)	$2.14	2.78%	2.89%	3.01%
Exelon Corp. (NYSE-EXC)				
FirstEnergy Corporation (ASE-FE)				
Hawaiian Electric Inductries (NYSE-HE)	$1.28	2.90%	3.02%	3.19%
IDACORP, Inc. (NYSE-IDA)	$2.52	2.44%	2.49%	2.54%
MGE Energy, Inc. (NYSE-MGEE)	$1.35	1.85%	1.94%	2.02%
NextEra Energy Inc. (NYSE-NEE)	$5.00	2.40%	2.51%	2.63%
NorthWestern Corporation (NYSE-NWE)	$2.30	3.17%	3.23%	3.39%
OGE Energy Corp. (NYSE-OGE)	$1.46	3.40%	3.43%	3.51%
Pinnacle West Capital Corp. (NYSE-PNW)	$2.95	3.12%	3.10%	3.20%
PNM Resources, Inc. (NYSE-PNM)	$1.16	2.29%	2.40%	2.54%
Portland General Electric Company (NYSE-POR)	$1.54	2.80%	2.89%	3.03%
PPL Corporation (NYSE-PPL)	$1.65	5.36%	5.33%	5.36%
SEMPRA Energy (NYSE-SRE)	$3.87	2.78%	2.91%	3.11%
Southern Company (NYSE-SO)	$2.48	4.44%	4.59%	4.87%
WEC Energy Group (NYSE-WEC)	$2.36	2.76%	2.90%	3.06%
Xcel Energy Inc. (NYSE-XEL)	$1.62	2.67%	2.78%	2.93%
Mean		3.1%	3.1%	3.3%
Median		2.8%	2.9%	3.1%

Data Sources: http://quote yahoo com, July, 2019

* Entergy, Exelon, and FirstEnergy was excluded from the DCF analysis due to negative projected EPS growth rates

Panel B
Hevert Proxy Group

Company	Annual Dividend	Dividend Yield 30 Day	Dividend Yield 90 Day	Dividend Yield 180 Day
ALLETE, Inc. (NYSE-ALE)	$2.35	2.75%	2.83%	2.91%
Alliant Energy Corporation (NYSE-LNT)	$1.42	2.85%	2.95%	3.07%
Ameren Corporation (NYSE-AEE)	$1.90	2.49%	2.56%	2.65%
American Electric Power Co. (NYSE-AEP)	$2.68	2.98%	3.08%	3.24%
Avangrid (NYSE-AVG)	$1.76	3.50%	3.48%	3.51%
Black Hills Corporation (NYSE-BKH)	$2.02	2.54%	2.65%	2.82%
CMS Energy Corporation (NYSE-CMS)	$1.53	2.61%	2.70%	2.81%
DTE Energy Company (NYSE-DTE)	$3.78	2.91%	2.98%	3.09%
Duke Energy Corporation (NYSE-DUK)	$3.78	4.26%	4.27%	4.28%
Evergy, Inc. (NYSE-EVRG)	$1.90	3.12%	3.22%	3.26%
Hawaiian Electric Inductries (NYSE-HE)	$1.28	2.90%	3.02%	3.19%
NextEra Energy Inc. (NYSE-NEE)	$5.00	2.40%	2.51%	2.63%
NorthWestern Corporation (NYSE-NWE)	$2.30	3.17%	3.23%	3.39%
OGE Energy Corp. (NYSE-OGE)	$1.46	3.40%	3.43%	3.51%
Otter Tail Corporation (NDQ-OTTR)	$1.40	2.67%	2.73%	2.79%
Pinnacle West Capital Corp. (NYSE-PNW)	$2.95	3.12%	3.10%	3.20%
PNM Resources, Inc. (NYSE-PNM)	$1.16	2.29%	2.40%	2.54%
Portland General Electric Company (NYSE-POR)	$1.54	2.80%	2.89%	3.03%
Southern Company (NYSE-SO)	$2.48	4.44%	4.59%	4.87%
WEC Energy Group (NYSE-WEC)	$2.36	2.76%	2.90%	3.06%
Xcel Energy Inc..(NYSE-XEL)	$1.62	2.67%	2.78%	2.93%
Mean		3.0%	3.1%	3.2%
Median		2.9%	3.0%	3.1%

Data Sources: http://quote yahoo com, July, 2019

Exhibit JRW-7

Dominion Energy North Carolina
DCF Equity Cost Growth Rate Measures
***Value Line* Historic Growth Rates**

Panel A
Electric Proxy Group

Company	*Value Line* Historic Growth					
	Past 10 Years			Past 5 Years		
	Earnings	Dividends	Book Value	Earnings	Dividends	Book Value
ALLETE, Inc. (NYSE-ALE)	1.0	3.0	5.5	4.0	3.0	5.5
Alliant Energy Corporation (NYSE-LNT)	4.5	7.5	4.0	4.5	7.0	4.5
Ameren Corporation (NYSE-AEE)	0.5	-3.5	-0.5	4.5	2.5	0.5
American Electric Power Co. (NYSE-AEP)	3.0	4.5	4.0	5.0	5.0	3.5
Avangrid (NYSE-AVG)						
CMS Energy Corporation (NYSE-CMS)	10.0	21.5	4.5	7.0	7.0	5.5
Consolidated Edison, Inc. (NYSE-ED)	2.5	2.0	4.0	2.0	2.5	4.0
Duke Energy Corporation (NYSE-DUK)	2.5	7.0	1.0	0.5	3.0	1.5
Edison International (NYSE-EIX)	-3.5	6.5	3.0	-9.0	11.0	3.0
Entergy Corporation (NYSE-ETR)						
Eversource Energy (NYSE-ES)	8.0	9.5	6.5	7.0	8.0	5.0
Exelon Corporation (NYSE-EXC)						
FirstEnergy Corporation (NYSE-FE)						
Hawaiian Electric Inductries (NYSE-HE)	5.0		3.0	4.0		3.5
IDACORP, Inc. (NYSE-IDA)	7.0	6.5	5.5	4.0	10.0	5.0
MGE Energy, Inc. (NYSE-MGEE)	4.5	3.0	5.5	3.5	4.0	6.0
Nextera Energy, Inc. (NYSE-NEE)	6.0	9.0	8.5	6.0	10.5	9.5
NorthWestern Corporation (NYSE-NWE)	8.5	5.0	5.5	7.0	7.0	8.0
OGE Energy Corp. (NYSE-OGE)	4.0	6.5	7.5	1.0	9.5	6.0
Pinnacle West Capital Corp. (NYSE-PNW)	4.5	2.5	2.5	5.0	3.0	4.5
PNM Resources, Inc. (NYSE-PNM)	7.0	2.5		6.0	11.0	1.0
Portland General Electric Company (NYSE-POR)	3.5	4.5	2.5	4.0	4.5	3.5
PPL Corporation (NYSE-PPL)		2.5	1.0	-0.5	2.0	-4.0
SEMPRA Energy (NYSE-SRE)	1.0	10.0	5.5	2.0	7.5	4.0
Southern Company (NYSE-SO)	3.0	3.5	4.0	2.5	3.5	3.0
WEC Energy Group (NYSE-WEC)	8.5	15.5	8.5	6.0	11.0	10.5
Xcel Energy Inc. (NYSE-XEL)	5.5	4.5	4.5	5.0	6.0	4.5
Mean	4.4	6.1	4.4	3.5	6.3	4.3
Median	4.5	4.8	4.3	4.0	6.5	4.5
Data Source: *Value Line Investment Survey.*	Average of Median Figures =			4.8		

* Entergy, Exelon, and FirstEnergy was excluded from the DCF analysis due to negative projected EPS growth rates

Panel B
Hevert Proxy Group

Company	*Value Line* Historic Growth					
	Past 10 Years			Past 5 Years		
	Earnings	Dividends	Book Value	Earnings	Dividends	Book Value
ALLETE, Inc. (NYSE-ALE)	1.0	3.0	5.5	4.0	3.0	5.5
Alliant Energy Corporation (NYSE-LNT)	4.5	7.5	4.0	4.5	7.0	4.5
Ameren Corporation (NYSE-AEE)	0.5	-3.5	-0.5	4.5	2.5	0.5
American Electric Power Co. (NYSE-AEP)	3.0	4.5	4.0	5.0	5.0	3.5
Avangrid (NYSE-AVG)						
Black Hills Corporation (NYSE-BKH)	6.5	3.0	2.5	11.0	4.0	3.0
CMS Energy Corporation (NYSE-CMS)	10.0	21.5	4.5	7.0	7.0	5.5
DTE Energy Company (NYSE-DTE)	8.0	4.5	4.0	8.0	6.5	4.5
Duke Energy Corporation (NYSE-DUK)	2.5	10.0	0.5	0.5	2.5	2.0
Evergy (NYSE-EVRG)						
Hawaiian Electric Inductries (NYSE-HE)	5.0		3.0	4.0		3.5
Nextera Energy, Inc. (NYSE-NEE)	6.0	9.0	8.5	6.0	10.5	9.5
NorthWestern Corporation (NYSE-NWE)	8.5	5.0	5.5	7.0	7.0	8.0
OGE Energy Corp. (NYSE-OGE)	4.0	6.5	7.5	1.0	9.5	6.0
Otter Tail Corporation (NDQ-OTTR)	2.0	1.0		14.0	1.5	3.5
Pinnacle West Capital Corp. (NYSE-PNW)	4.5	2.5	2.5	5.0	3.0	4.5
PNM Resources, Inc. (NYSE-PNM)	7.0	2.5		6.0	11.0	1.0
Portland General Electric Company (NYSE-POR)	3.5	4.5	2.5	4.0	4.5	3.5
Southern Company (NYSE-SO)	3.0	3.5	4.0	2.5	3.5	3.0
WEC Energy Group (NYSE-WEC)	7.5	15.5	8.5	5.5	14.0	10.5
Xcel Energy Inc. (NYSE-XEL)	5.5	4.5	4.5	5.0	6.0	4.5
Mean	4.9	5.8	4.2	5.5	6.0	4.6
Median	4.5	4.5	4.0	5.0	5.5	4.5
Data Source: *Value Line Investment Survey.*	Average of Median Figures =			4.7		

Exhibit JRW-7

Dominion Energy North Carolina
DCF Equity Cost Growth Rate Measures
Value Line Projected Growth Rates

Panel A
Electric Proxy Group

Company	*Value Line* Projected Growth Est'd. '16-'18 to '22-'24			*Value Line* Sustainable Growth		
	Earnings	Dividends	Book Value	Return on Equity	Retention Rate	Internal Growth
ALLETE, Inc. (NYSE-ALE)	5.0	5.0	3.0	9.0%	35.0%	3.2%
Alliant Energy Corporation (NYSE-LNT)	6.5	5.5	7.5	10.0%	38.0%	3.8%
Ameren Corporation (NYSE-AEE)	6.5	6.0	5.0	10.5%	41.0%	4.3%
American Electric Power Co. (NYSE-AEP)	4.0	6.0	4.5	10.5%	30.0%	3.2%
Avangrid (NYSE-AVG)	10.0	3.0	1.5	6.0%	35.0%	2.1%
CMS Energy Corporation (NYSE-CMS)	7.0	7.0	7.5	14.0%	41.0%	5.7%
Consolidated Edison, Inc. (NYSE-ED)	3.0	3.5	3.0	8.5%	34.0%	2.9%
Duke Energy Corporation (NYSE-DUK)	6.0	3.0	2.5	8.5%	28.0%	2.4%
Edison International (NYSE-EIX)	NMF	3.5	4.5	11.5%	47.0%	5.4%
Entergy Corporation (NYSE-ETR)						
Eversource Energy (NYSE-ES)	5.5	5.5	5.0	9.0%	37.0%	3.3%
Exelon Corporation (NYSE-EXC)						
FirstEnergy Corporation (NYSE-FE)						
Hawaiian Electric Inductries (NYSE-HEC)	4.5	3.0	4.0	10.0%	40.0%	4.0%
IDACORP, Inc. (NYSE-IDA)	3.5	6.0	4.0	9.5%	40.0%	3.8%
MGE Energy, Inc. (NYSE-MGEE)	9.0	4.5	6.0	11.5%	56.0%	6.4%
Nextera Energy, Inc. (NYSE-NEE)	10.0	10.0	5.5	13.5%	39.0%	5.3%
NorthWestern Corporation (NYSE-NWE)	3.0	4.5	3.0	9.0%	34.0%	3.1%
OGE Energy Corp. (NYSE-OGE)	6.5	7.5	3.5	11.5%	28.0%	3.2%
Pinnacle West Capital Corp. (NYSE-PNW)	5.5	6.0	4.0	10.5%	36.0%	3.8%
PNM Resources, Inc. (NYSE-PNM)	7.0	7.0	4.0	10.0%	43.0%	4.3%
Portland General Electric Company (NYSE-POR)	4.5	6.5	3.0	9.0%	34.0%	3.1%
PPL Corporation (NYSE-PPL)	1.5	2.0	6.0	13.0%	35.0%	4.6%
SEMPRA Energy (NYSE-SRE)	11.0	8.0	6.5	12.0%	42.0%	5.0%
Southern Company (NYSE-SO)	3.5	3.0	3.5	12.5%	27.0%	3.4%
WEC Energy Group (NYSE-WEC)	6.0	6.0	3.5	12.0%	33.0%	4.0%
Xcel Energy Inc. (NYSE-XEL)	5.5	6.0	4.5	11.0%	38.0%	4.2%
Mean	5.8	5.3	4.4	10.5%	37.1%	3.9%
Median	5.5	5.8	4.0	10.5%	36.5%	3.8%
Average of Median Figures =		5.1			Median =	3.8%

* 'Est'd. '16-'17 to '22-'24' is the estimated growth rate from the base period 2016 to 2018 until the future period 2022 to 2024.
Data Source: *Value Line Investment Survey.*
* Entergy, Exelon, and FirstEnergy was excluded from the DCF analysis due to negative projected EPS growth rates

Panel B
Hevert Proxy Group

Company	*Value Line* Projected Growth Est'd. '16-'18 to '22-'24			*Value Line* Sustainable Growth		
	Earnings	Dividends	Book Value	Return on Equity	Retention Rate	Internal Growth
ALLETE, Inc. (NYSE-ALE)	5.0	5.0	3.0	9.0%	35.0%	3.2%
Alliant Energy Corporation (NYSE-LNT)	6.5	5.5	7.5	10.0%	38.0%	3.8%
Ameren Corporation (NYSE-AEE)	6.5	6.0	5.0	10.5%	41.0%	4.3%
American Electric Power Co. (NYSE-AEP)	4.0	6.0	4.5	10.5%	30.0%	3.2%
Avangrid (NYSE-AVG)	10.0	3.0	1.5	6.0%	35.0%	2.1%
Black Hills Corporation (NYSE-BKH)	5.0	6.5	5.5	9.5%	39.0%	3.7%
CMS Energy Corporation (NYSE-CMS)	7.0	7.0	7.5	14.0%	41.0%	5.7%
DTE Energy Company (NYSE-DTE)	5.5	6.0	5.5	10.5%	37.0%	3.9%
Duke Energy Corporation (NYSE-DUK)	6.0	3.0	2.5	8.5%	28.0%	2.4%
Evergy (NYSE-EVRG)				8.5%	31.0%	2.6%
Hawaiian Electric Inductries (NYSE-HE)	3.5	2.0	4.0	9.5%	40.0%	3.8%
Nextera Energy, Inc. (NYSE-NEE)	10.0	10.0	5.5	13.5%	39.0%	5.3%
NorthWestern Corporation (NYSE-NWE)	3.0	4.5	3.0	9.0%	34.0%	3.1%
OGE Energy Corp. (NYSE-OGE)	6.5	7.5	3.5	11.5%	28.0%	3.2%
Otter Tail Corporation (NDQ-OTTR)	5.0	4.0	4.5	10.5%	34.0%	3.6%
Pinnacle West Capital Corp. (NYSE-PNW)	5.5	6.0	4.0	10.5%	36.0%	3.8%
PNM Resources, Inc. (NYSE-PNM)	7.0	7.0	4.0	10.0%	43.0%	4.3%
Portland General Electric Company (NYSE-POR)	4.5	6.5	3.0	9.0%	34.0%	3.1%
Southern Company (NYSE-SO)	3.5	3.0	3.5	12.5%	27.0%	3.4%
WEC Energy Group (NYSE-WEC)	6.0	6.0	3.5	12.0%	33.0%	4.0%
Xcel Energy Inc. (NYSE-XEL)	5.5	6.0	4.5	11.0%	38.0%	4.2%
Mean	5.8	5.5	4.3	10.3%	35.3%	3.6%
Median	5.5	6.0	4.0	10.5%	35.0%	3.7%
Average of Median Figures =		5.2			Median =	3.7%

* 'Est'd. '16-'17 to '22-'24' is the estimated growth rate from the base period 2016 to 2018 until the future period 2022 to 2024.
Data Source: *Value Line Investment Survey.*

Exhibit JRW-7

Dominion Energy North Carolina
DCF Equity Cost Growth Rate Measures
Analysts Projected EPS Growth Rate Estimates

Panel A
Electric Proxy Group

Company	Yahoo	Reuters	Zacks	Mean
ALLETE, Inc. (NYSE-ALE)	6.0%	NA	7.2%	6.6%
Alliant Energy Corporation (NYSE-LNT)	5.0%	5.0%	5.5%	5.2%
Ameren Corporation (NYSE-AEE)	5.0%	5.0%	6.5%	5.5%
American Electric Power Co. (NYSE-AEP)	6.1%	6.1%	5.7%	6.0%
Avangrid (NYSE-AVG)	6.6%	7.3%	7.5%	7.1%
CMS Energy Corporation (NYSE-CMS)	7.1%	7.2%	6.4%	6.9%
Consolidated Edison, Inc. (NYSE-ED)	3.4%	3.4%	2.0%	3.0%
Duke Energy Corporation (NYSE-DUK)	7.2%	7.2%	4.9%	6.4%
Edison International (NYSE-EIX)	5.9%	3.8%	5.4%	5.0%
Entergy Corporation (NYSE-ETR)	-1.9%	-1.9%	7.0%	
Eversource Energy (NYSE-ES)	5.6%	5.6%	5.6%	5.6%
Exelon Corporation (NYSE-EXC)	-1.9%	-0.3%	3.6%	
FirstEnergy Corporation (NYSE-FE)	-6.6%	NA	6.0%	
Hawaiian Electric Inductries (NYSE-HE)	6.1%	6.1%	5.6%	5.9%
IDACORP, Inc. (NYSE-IDA)	2.4%	2.4%	3.8%	2.9%
MGE Energy, Inc. (NYSE-MGEE)	4.0%	NA	NA	4.0%
Nextera Energy, Inc. (NYSE-NEE)	8.0%	7.0%	8.0%	7.7%
NorthWestern Corporation (NYSE-NWE)	3.5%	3.6%	3.0%	3.4%
OGE Energy Corp. (NYSE-OGE)	3.8%	3.8%	4.6%	4.1%
Pinnacle West Capital Corp. (NYSE-PNW)	5.3%	5.3%	5.1%	5.3%
PNM Resources, Inc. (NYSE-PNM)	6.3%	6.3%	5.5%	6.0%
Portland General Electric Company (NYSE-POR)	5.2%	5.2%	4.9%	5.1%
PPL Corporation (NYSE-PPL)	0.6%	NA	N/A	0.6%
SEMPRA Energy (NYSE-SRE)	8.2%	8.2%	7.7%	8.0%
Southern Company (NYSE-SO)	2.2%	3.4%	4.5%	3.4%
WEC Energy Group (NYSE-WEC)	5.9%	5.9%	5.9%	5.9%
Xcel Energy Inc. (NYSE-XEL)	5.8%	5.8%	5.6%	5.7%
Mean	4.2%	4.8%	5.5%	5.2%
Median	5.3%	5.3%	5.6%	5.5%

Data Sources: www reuters com, www zacks com, http://quote yahoo com, July, 2019
* Entergy, Exelon, and FirstEnergy was excluded from the DCF analysis due to negative projected EPS growth rates

Panel B
Hevert Proxy Group

Company	Yahoo	Reuters	Zacks	Mean
ALLETE, Inc. (NYSE-ALE)	6.0%	NA	7.2%	6.6%
Alliant Energy Corporation (NYSE-LNT)	5.0%	5.0%	5.5%	5.2%
Ameren Corporation (NYSE-AEE)	5.0%	5.0%	6.5%	5.5%
American Electric Power Co. (NYSE-AEP)	6.1%	6.1%	5.7%	6.0%
Avangrid (NYSE-AVG)	6.6%	7.3%	7.5%	7.1%
Black Hills Corporation (NYSE-BKH)	3.0%	3.0%	4.3%	3.4%
CMS Energy Corporation (NYSE-CMS)	7.1%	7.2%	6.4%	6.9%
DTE Energy Company (NYSE-DTE)	7.1%	7.2%	6.4%	6.9%
Duke Energy Corporation (NYSE-DUK)	7.2%	7.2%	4.9%	6.4%
Evergy (NYSE-EVRG)	6.2%	6.2%	6.6%	6.3%
Hawaiian Electric Inductries (NYSE-HE)	6.1%	6.1%	5.6%	5.9%
Nextera Energy, Inc. (NYSE-NEE)	8.0%	7.0%	8.0%	7.7%
NorthWestern Corporation (NYSE-NWE)	3.5%	3.6%	3.0%	3.4%
OGE Energy Corp. (NYSE-OGE)	3.8%	3.8%	4.6%	4.1%
Otter Tail Corporation (NDQ-OTTR)	9.0%	NA	7.0%	8.0%
Pinnacle West Capital Corp. (NYSE-PNW)	5.3%	5.3%	5.1%	5.3%
PNM Resources, Inc. (NYSE-PNM)	6.3%	6.3%	5.5%	6.0%
Portland General Electric Company (NYSE-POR)	5.2%	5.2%	4.9%	5.1%
Southern Company (NYSE-SO)	2.2%	3.4%	4.5%	3.4%
WEC Energy Group (NYSE-WEC)	5.9%	5.9%	5.9%	5.9%
Xcel Energy Inc. (NYSE-XEL)	5.8%	5.8%	5.6%	5.7%
Mean	5.7%	5.6%	5.7%	5.7%
Median	6.0%	5.9%	5.6%	5.9%

Data Sources: www reuters com, www zacks com, http://quote yahoo com, July, 2019

Exhibit JRW-7

Dominion Energy North Carolina
DCF Growth Rate Indicators

Electric and Hevert Proxy Groups

Growth Rate Indicator	Electric Proxy Group	Hevert Proxy Group
Historic *Value Line* Growth in EPS, DPS, and BVPS	4.8%	4.7%
Projected *Value Line* Growth in EPS, DPS, and BVPS	5.1%	5.2%
Sustainable Growth ROE * Retention Rate	3.8%	3.7%
Projected EPS Growth from Yahoo, Zacks, and Reuters - Mean/Median	5.2%/5.5%	5.7%/5.9%

Exhibit JRW-6

DCF Model
Consensus Earnings Estimates
Consolidated Edison. (ED)
www.reuters.com
7/26/2019

Line	Date	# of Estimates	Mean	High	Low
1	Quarter Ending Sep-19	12	1.60	1.70	1.53
2	Quarter Ending Dec-19	12	0.77	0.85	0.66
3	Year Ending Dec-19	18	4.35	4.39	4.30
4	Year Ending Dec-20	18	4.57	4.73	4.47
5	LT Growth Rate (%)	4	3.44	4.89	2.00

I/A

Exhibit JRW-2

Dominion Energy North Carolina

Panel A

Electric Proxy Group

Company	Ticker	Operating Revenue ($mil)	Percent Reg Elec Revenue	Percent Reg Gas Revenue	Net Plant ($mil)	Market Cap ($mil)	S&P Issuer Credit Rating	Moody's Long Term Rating	Pre-Tax Interest Coverage	Primary Service Area	Common Equity Ratio	Return on Equity	Market to Book Ratio
ALLETE, Inc. (NYSE-ALE)	ALE	$1,498.6	71%	0%	$3,904.4	$3,993.8	BBB+	Baa1	3.34	MN, WI	59.2%	8.2%	1.85
Alliant Energy Corporation (NYSE-LNT)	LNT	$3,534.5	85%	13%	$12,462.4	$10,172.3	A-	Baa1	3.31	WI,IA,IL,MN	44.6%	11.4%	2.13
Ameren Corporation (NYSE-AEE)	AEE	$6,291.0	85%	15%	$22,810.0	$16,366.8	BBB+	Baa1	3.64	IL,MO	46.2%	10.9%	2.11
American Electric Power Co. (NYSE-AEP)	AEP	$16,195.7	88%	0%	$55,099.1	$37,379.9	A-	Baa1	2.99	10 States	42.7%	10.3%	1.96
AVANGRID, Inc. (NYSE-AGR)	AGR	$6,291.0	56%	23%	$22,810.0	$16,366.8	BBB+	Baa1	3.53	NY,CT,ME	70.8%	3.9%	1.06
CMS Energy Corporation (NYSE-CMS)	CMS	$6,873.0	66%	28%	$18,126.0	$13,966.2	BBB+	Baa1	2.67	MI	28.9%	14.2%	2.91
Consolidated Edison, Inc. (NYSE-ED)	ED	$12,337.0	70%	19%	$41,749.0	$25,673.3	A-	A3	3.03	NY,PA	44.8%	8.6%	1.52
Duke Energy Corporation (NYSE-DUK)	DUK	$24,521.0	90%	7%	$91,694.0	$63,736.1	A-	Baa1	2.47	NC,OH,FL,SC,KY	43.1%	6.2%	1.45
Edison International (NYSE-EIX)	EIX	$12,657.0	100%	0%	$41,348.0	$18,107.4	BBB	Baa3	(0.48)	CA	45.1%	-2.4%	1.43
Entergy Corporation (NYSE-ETR)	ETR	$11,009.5	85%	1%	$31,974.4	$16,448.0	BBB+	Baa2	0.69	LA,AR,MS,TX	32.8%	10.2%	1.86
Eversource Energy (NYSE-ES)	ES	$8,448.2	79%	10%	$25,610.4	$21,470.9	A-	Baa1	3.67	CT,NH,MA	46.7%	9.2%	1.87
Exelon Corporation (NYSE-EXC)	EXC	$11,009.5	56%	5%	$31,974.4	$46,448.0	BBB+	Baa2	2.44	PA,NJ,IL,MD,DCDE	47.8%	6.4%	1.40
FirstEnergy Corporation (NYSE-FE)	FE	$11,261.0	91%	0%	$29,911.0	$18,851.1	BBB	Baa3	2.17	OH,PA,NY,NJ,WV,MD	25.8%	25.1%	2.77
Hawaiian Electric Industries (NYSE-HEC)	HE	$2,860.8	89%	0%	$4,830.1	$4,060.1	BBB-	NR	3.87	HI	51.2%	9.6%	1.88
IDACORP, Inc. (NYSE-IDA)	IDA	$1,370.8	100%	0%	$4,395.7	$8,562.5	BBB	Baa1	3.85	ID	56.4%	9.8%	3.60
MGE Energy, Inc. (NYSE-MGEE)	MGEE	$559.8	72%	28%	$1,509.4	$2,303.7	AA-	Aa2	7.69	WI	61.5%	10.6%	2.82
NextEra Energy, Inc. (NYSE-NEE)	NEE	$16,727.0	71%	0%	$70,334.0	$83,224.6	A-	Baa1	5.87	FL	49.8%	17.3%	2.22
NorthWestern Corporation (NYSE-NWE)	NWE	$1,192.0	77%	23%	$4,521.3	$2,991.2	BBB	NR	2.94	MT,SD,NE	47.8%	10.5%	1.54
OGE Energy Corp. (NYSE-OGE)	OGE	$2,270.3	100%	0%	$8,643.8	$7,899.1	BBB+	NR	4.19	OK,AR	56.0%	10.8%	1.97
Pinnacle West Capital Corp. (NYSE-PNW)	PNW	$3,691.2	95%	0%	$14,029.6	$16,260.8	A-	A3	4.04	AZ	50.6%	10.1%	3.04
PNM Resources, Inc. (NYSE-PNM)	PNM	$1,436.6	100%	0%	$5,234.6	$3,360.4	BBB+	Baa3	1.73	NM,TX	37.6%	5.8%	1.92
Portland General Electric Company (NYSE-POR)	POR	$1,991.0	100%	0%	$6,887.0	$4,287.2	BBB+	A3	2.85	OR	50.3%	8.6%	1.71
PPL Corporation (NYSE-PPL)	PPL	$7,785.0	94%	4%	$34,458.0	$20,457.2	A-	Baa2	3.37	PA,KY	34.6%	16.3%	1.75
Sempra Energy (NYSE-SRE)	SRE	$1,991.0	56%	44%	$6,887.0	$31,467.5	BBB+	Baa1	2.03	CA,TX	43.1%	6.5%	1.63
Southern Company (NYSE-SO)	SO	$23,495.0	65%	14%	$80,797.0	$48,493.6	A-	Baa2	2.49	GA,FL,NJ,IL,VA,TN,MS	38.3%	8.4%	1.67
WEC Energy Group (NYSE-WEC)	WEC	$7,679.5	58%	42%	$22,000.9	$22,541.0	A-	Baa1	3.76	WI,IL,MN,MI	45.3%	3.3%	2.30
Xcel Energy Inc. (NYSE-XEL)	XEL	$11,537.0	84%	15%	$36,944.0	$25,972.7	A-	Baa1	3.21	MN,WI,ND,SD,MI	41.5%	10.7%	2.13
Mean		$8,019.0	81%	11%	$27,072.1	$21,883.8	BBB+	Baa1	3.16		46.0%	9.7%	2.02
Median		$6,873.0	85%	5%	$22,810.0	$16,448.0	BBB+	Baa1	3.21		45.3%	9.8%	1.88

Data Source Company 2018 SEC 10-K filings; *Value Line Investment Survey*, 2019.

Panel B

Hevert Proxy Group

Company	Ticker	Operating Revenue ($mil)	Percent Reg Elec Revenue	Percent Reg Gas Revenue	Net Plant ($mil)	Market Cap ($bil)	S&P Issuer Credit Rating	Moody's Long Term Rating	Pre-Tax Interest Coverage	Primary Service Area	Common Equity Ratio	Return on Equity	Market to Book Ratio
ALLETE, Inc. (NYSE-ALE)	ALE	$1,498.6	71%	0%	$3,904.4	$3,993.8	BBB+	A3	3.34	MN, WI	59.2%	8.2%	1.85
Alliant Energy Corporation (NYSE-LNT)	LNT	$3,534.5	85%	13%	$12,462.4	$10,172.3	A-	Baa1	3.31	WI,IA,IL,MN	44.6%	11.4%	2.13
Ameren Corporation (NYSE-AEE)	AEE	$6,291.0	85%	15%	$22,810.0	$16,366.8	BBB+	Baa1	3.64	IL,MO	46.2%	10.9%	2.11
American Electric Power Co. (NYSE-AEP)	AEP	$16,195.7	88%	0%	$55,099.1	$37,379.9	A-	Baa1	2.99	10 States	42.7%	10.3%	1.96
AVANGRID, Inc. (NYSE-AGR)	AGR	$6,291.0	56%	23%	$22,810.0	$16,366.8	BBB+	Baa1	3.53	NY,CT,ME	70.8%	3.9%	1.06
Black Hills Corporation (NYSE-BKH)	BKH	$1,754.3	41%	58%	$4,854.9	$3,842.7	BBB+	Baa2	2.77	CO,SD,WY,MT	42.1%	13.3%	1.68
CMS Energy Corporation (NYSE-CMS)	CMS	$6,873.0	66%	28%	$18,126.0	$13,966.2	BBB+	Baa1	2.67	MI	28.9%	14.2%	2.91
DTE Energy Company (NYSE-DTE)	DTE	$14,212.0	37%	39%	$21,650.0	$20,066.4	BBB+	Baa1	3.15	MI	42.9%	10.8%	1.87
Duke Energy Corporation (NYSE-DUK)	DUK	$24,521.0	90%	7%	$91,694.0	$63,736.1	A-	Baa1	2.47	NC,OH,FL,SC,KY	43.1%	6.2%	1.45
Evergy (NYSE: EVRG)	EVRG	$4,275.9	100%	0%	$18,782.5	$14,840.0	A-	Baa1	3.11	KS,MO	54.2%	7.9%	1.49
Hawaiian Electric Industries (NYSE-HEC)	HE	$2,860.8	89%	0%	$4,830.1	$4,060.1	BBB-	NR	3.87	HI	51.2%	9.6%	1.88
NextEra Energy, Inc. (NYSE-NEE)	NEE	$16,727.0	71%	0%	$70,334.0	$83,224.6	A-	Baa1	5.87	FL	49.8%	17.3%	2.22
NorthWestern Corporation (NYSE-NWE)	NWE	$1,192.0	77%	23%	$4,521.3	$2,991.2	BBB	NR	2.94	MT,SD,NE	47.8%	10.5%	1.54
OGE Energy Corp. (NYSE-OGE)	OGE	$2,270.3	100%	0%	$8,643.8	$7,899.1	BBB+	Baa1	4.19	OK,AR	56.0%	10.8%	1.97
Otter Tail Corporation (NDQ-OTTR)	OTTR	$916.4	49%	0%	$1,581.1	$1,975.3	BBB	Baa2	4.19	OK,AR	54.5%	11.6%	2.71
Pinnacle West Capital Corp. (NYSE-PNW)	PNW	$3,691.2	95%	0%	$14,029.6	$16,260.8	A-	A3	4.04	AZ	50.6%	10.1%	3.04
PNM Resources, Inc. (NYSE-PNM)	PNM	$1,436.6	100%	0%	$5,234.6	$3,360.4	BBB+	Baa3	1.73	NM,TX	37.6%	5.8%	1.92
Portland General Electric Company (NYSE-POR)	POR	$1,991.0	100%	0%	$6,887.0	$4,287.2	BBB+	A3	2.85	OR	50.3%	8.6%	1.71
Southern Company (NYSE-SO)	SO	$23,495.0	65%	14%	$80,797.0	$48,493.6	A-	Baa2	2.49	GA,FL,NJ,IL,VA,TN,MS	38.3%	8.4%	1.67
WEC Energy Group (NYSE-WEC)	WEC	$7,679.5	58%	42%	$22,000.9	$22,541.0	A-	Baa1	3.76	WI,IL,MN,MI	45.3%	3.3%	2.30
Xcel Energy Inc. (NYSE-XEL)	XEL	$11,537.0	84%	15%	$36,944.0	$25,972.7	A-	A3	3.21	MN,WI,ND,SD,MI	41.5%	10.7%	2.13
Mean		$7,583.0	77%	13%	$25,142.7	$20,085.6	BBB+	Baa1	3.34		47.5%	9.7%	1.98
Median		$4,275.9	84%	7%	$18,126.0	$14,840.0	BBB+	Baa1	3.21		46.2%	10.3%	1.92

Data Source Company 2018 SEC 10-K filings; *Value Line Investment Survey*, 2019.

Exhibit JRW-2

Dominion Energy North Carolina

***Value Line* Risk Metrics**

Panel A
Electric Proxy Group

Company	Beta	Financial Strength	Safety	Earnings Predictability	Stock Price Stability
ALLETE, Inc. (NYSE-ALE)	0.65	A	2	85	95
Alliant Energy Corporation (NYSE-LNT)	0.60	A	2	85	100
Ameren Corporation (NYSE-AEE)	0.60	A	2	80	95
American Electric Power Co. (NYSE-AEP)	0.55	A+	1	85	100
AVANGRID, Inc. (NYSE-AGR)	0.40	B++	2	NMF	95
CMS Energy Corporation (NYSE-CMS)	0.55	B++	2	90	100
Consolidated Edison, Inc. (NYSE-ED)	0.45	A+	1	95	100
Duke Energy Corporation (NYSE-DUK)	0.50	A	2	85	100
Edison International (NYSE-EIX)	0.60	B+	3	15	85
Entergy Corporation (NYSE-ETR)	0.60	B++	3	60	95
Eversource Energy (NYSE-ES)	0.60	A	1	95	100
Exelon Corporation (NYSE-EXC)	0.70	B++	3	55	90
FirstEnergy Corporation (NYSE-FE)	0.65	B++	2	40	90
Hawaiian Electric Inductries (NYSE-HEC)	0.55	A	2	60	100
IDACORP, Inc. (NYSE-IDA)	0.60	A	2	95	95
MGE Energy, Inc. (NYSE-MGEE)	0.55	A	1	95	85
NextEra Energy, Inc. (NYSE-NEE)	0.60	A+	1	70	100
NorthWestern Corporation (NYSE-NWE)	0.60	B++	2	85	95
OGE Energy Corp. (NYSE-OGE)	0.80	A	2	80	95
Pinnacle West Capital Corp. (NYSE-PNW)	0.55	A+	1	95	100
PNM Resources, Inc. (NYSE-PNM)	0.60	B+	3	75	85
Portland General Electric Company (NYSE-POR)	0.60	B++	2	85	95
PPL Corporation (NYSE-PPL)	0.70	B++	2	70	95
Sempra Energy (NYSE-SRE)	0.75	A	2	75	95
Southern Company (NYSE-SO)	0.50	A	2	90	100
WEC Energy Group (NYSE-WEC)	0.50	A+	1	90	95
Xcel Energy Inc. (NYSE-XEL)	0.50	A+	1	100	100
Mean	0.59	A	1.9	78	96

Data Source: *Value Line Investment Survey*, 2019.

Panel B
Hevert Proxy Group

Company	Beta	Financial Strength	Safety	Earnings Predictability	Stock Price Stability
ALLETE, Inc. (NYSE-ALE)	0.65	A	2	85	95
Alliant Energy Corporation (NYSE-LNT)	0.60	A	2	85	95
Ameren Corporation (NYSE-AEE)	0.60	A	2	80	95
American Electric Power Co. (NYSE-AEP)	0.55	A+	1	85	100
AVANGRID, Inc. (NYSE-AGR)	0.40	B++	2	NMF	95
Black Hills Corporation (NYSE-BKH)	0.75	A	2	55	80
CMS Energy Corporation (NYSE-CMS)	0.55	B++	2	90	100
DTE Energy Company (NYSE-DTE)	0.55	B++	2	85	100
Duke Energy Corporation (NYSE-DUK)	0.45	A	2	85	100
Evergy (NYSE:EVRG)	NMF	B++	2	NMF	NMF
Hawaiian Electric Inductries (NYSE-HEC)	0.55	A	2	60	100
NextEra Energy, Inc. (NYSE-NEE)	0.60	A+	1	70	100
NorthWestern Corporation (NYSE-NWE)	0.60	B++	2	85	95
OGE Energy Corp. (NYSE-OGE)	0.80	A	2	80	95
Otter Tail Corporation (NDQ-OTTR)	0.70	A	2	60	90
Pinnacle West Capital Corp. (NYSE-PNW)	0.55	A+	1	95	100
PNM Resources, Inc. (NYSE-PNM)	0.60	B+	3	75	85
Portland General Electric Company (NYSE-POR)	0.60	B++	2	85	95
Southern Company (NYSE-SO)	0.50	A	2	90	100
WEC Energy Group (NYSE-WEC)	0.50	A+	1	90	95
Xcel Energy Inc. (NYSE-XEL)	0.50	A+	1	100	100
Mean	0.58	A	1.8	81	96

Data Source: *Value Line Investment Survey*, 2019.

Value Line Risk Metrics

Beta

A relative measure of the historical sensitivity of a stock's price to overall fluctuations in the New York Stock Exchange Composite Index. A beta of 1.50 indicates a stock tends to rise (or fall) 50% more than the New York Stock Exchange Composite Index. The "coefficient" is derived from a regression analysis of the relationship between weekly percentage changes in the price of a stock and weekly percentage changes in the NYSE Index over a period of five years. In the case of shorter price histories, a smaller time period is used, but two years is the minimum. Betas are adjusted for their long-term tendency to converge toward 1.00.

Financial Strength

A relative measure of the companies reviewed by *Value Line*. The relative ratings range from A++ (strongest) down to C (weakest).

Safety Rank

A measurement of potential risk associated with individual common stocks. The Safety Rank is computed by averaging two other *Value Line* indexes the Price Stability Index and the Financial strength Rating. Safety Ranks range from 1 (Highest) to 5 (Lowest). Conservative investors should try to limit their purchases to equities ranked 1 (Highest) and 2 (Above Average) for Safety.

Earnings Predictability

A measure of the reliability of an earnings forecast. Earnings Predictability is based upon the stability of year-to-year comparisons, with recent years being weighted more heavily than earlier ones. The most reliable forecasts tend to be those with the highest rating (100); the least reliable, the lowest (5). The earnings stability is derived from the standard deviation of percentage changes in quarterly earnings over an eight-year period. Special adjustments are made for comparisons around zero and from plus to minus.

Stock Price Stability

A measure of the stability of a stock's price. It includes sensitivity to the market (see Beta as well as the stock's inherent volatility. *Value Line's* Stability ratings range from 1 (highest) to 5 (lowest).

Source: *Value Line Investment Analyzer*.

I/A

Exhibit JRW-3

Dominion Energy North Carolina
Capital Structure Ratios and Debt Cost Rates

Panel A - DENC's Proposed Capital Structure and Debt Cost Rates

	Percent of Total	Cost
Long-Term Debt	46.35%	4.44%
Common Equity	53.65%	
Total Capital	100.00%	

Panel B - Dominion Energy's Capital Structure Ratios - 12-31-18

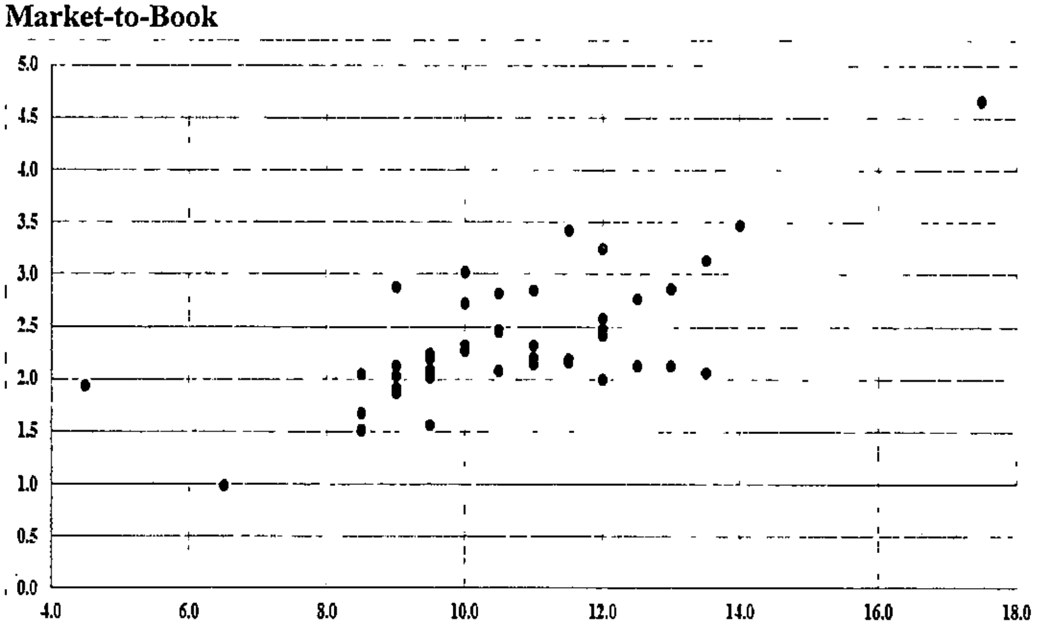
	12/31/2018	Percent with Short-Term Debt	Percent without Short-Term Debt
Short-Term Debt	$ 3,650,000	6.6%	0.0%
Long-Term Debt	$ 31,260,000.00	56.8%	60.9%
Common Equity	$ 20,107,000.00	36.5%	39.1%
Total Capital	$ 55,017,000.00	100.0%	100.00%

Panel C Staff's Capital Structure Ratios and Debt Cost Rates

	DENC Proposed	Adjustment	Staff Proposed	Cost
Long-Term Debt	46.35%	1.078725	50.00%	4.44%
Common Equity	53.65%	0.931984	50.00%	
Total Capital	100.00%		100.00%	

I/A

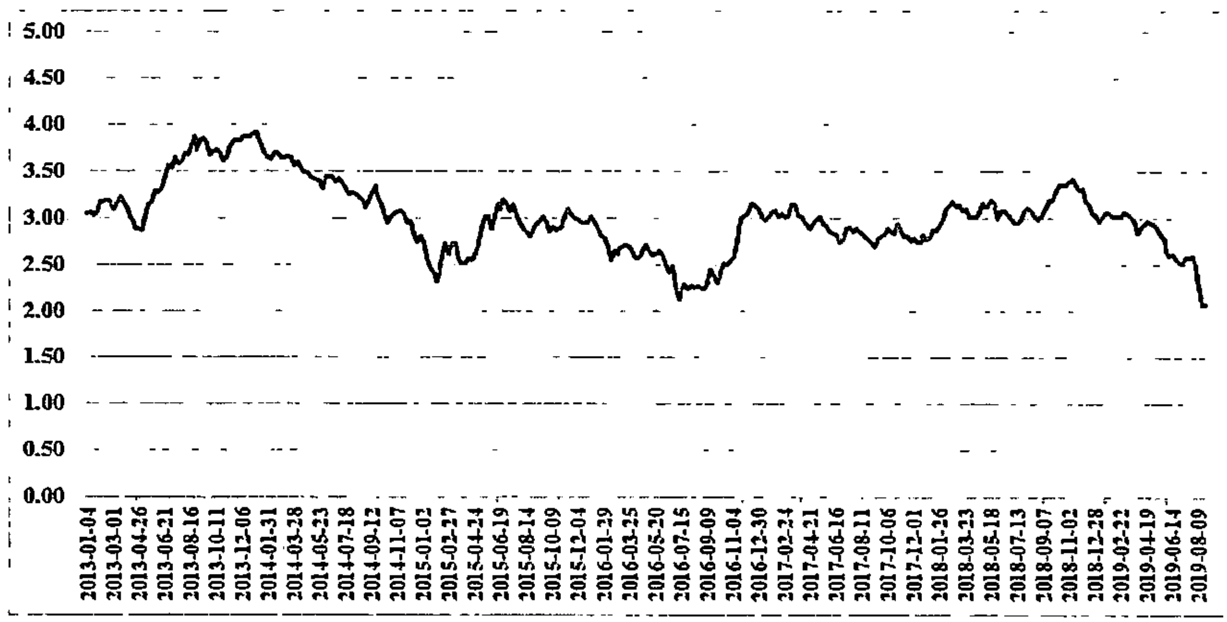
Exhibit JRW-4
Electric Utilities and Gas Distribution Companies



Expected Return on Equity
R-Square = .50, N=43

I / A

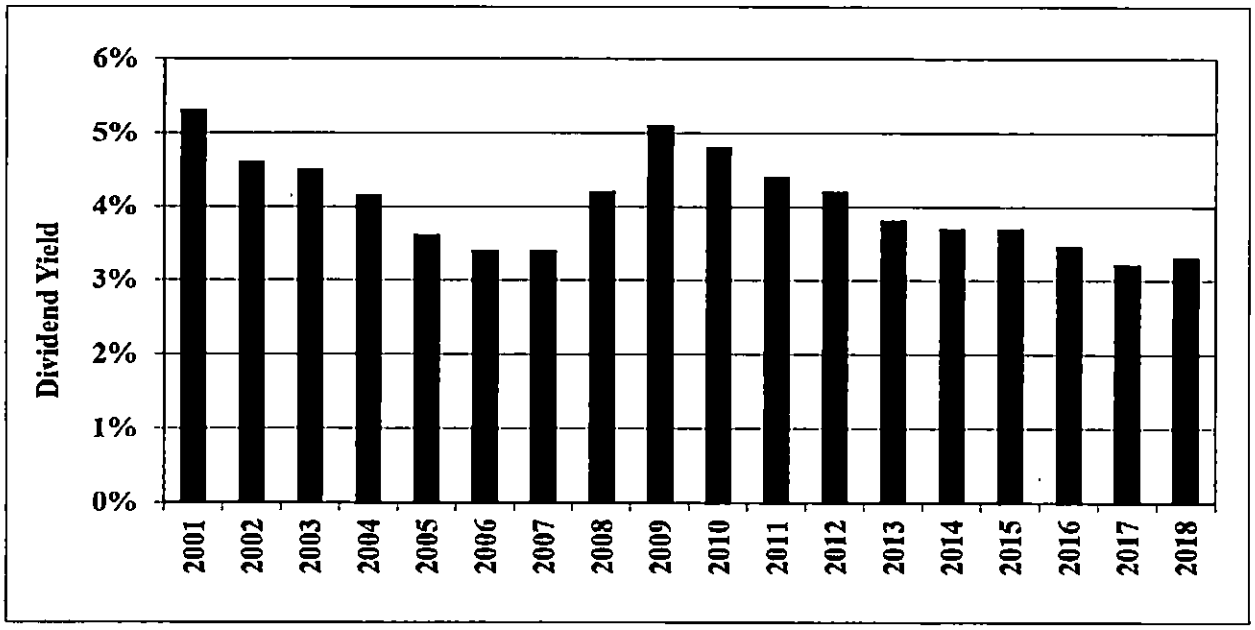
Exhibit JRW-5
Long-Term 'A' Rated Public Utility Bonds



Data Source: Mergent Bond Record

Exhibit JRW-5

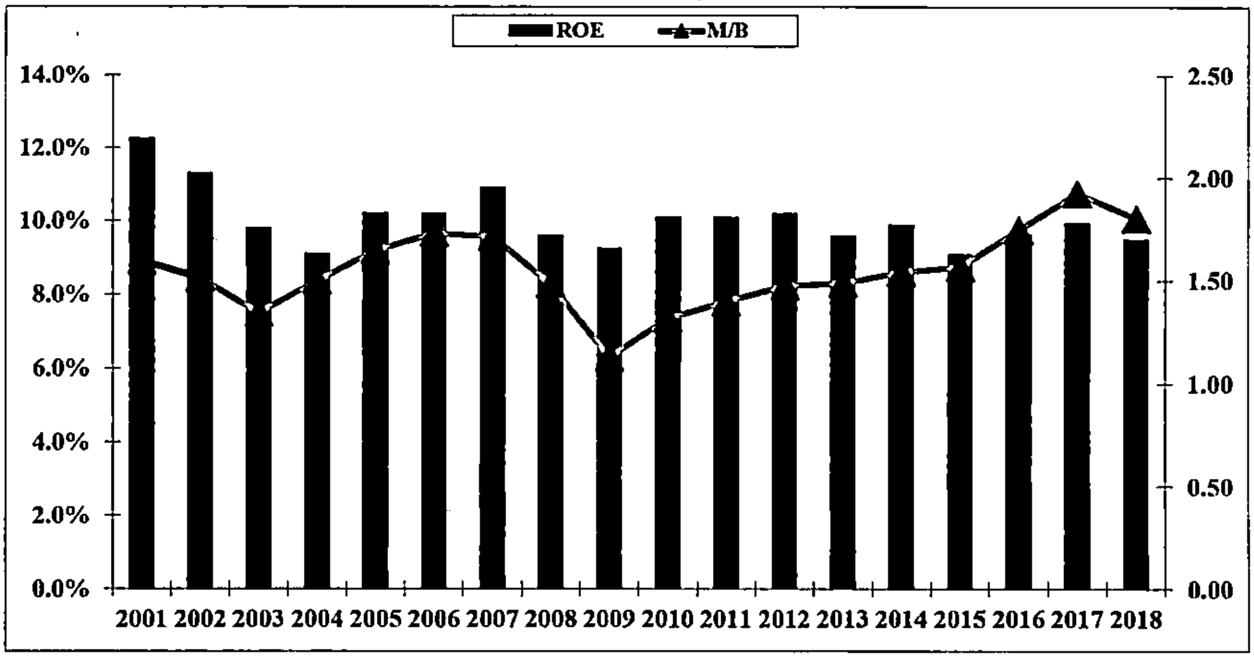
Electric Utility Average Dividend Yield



Data Source: *Value Line Investment Survey.*

Exhibit JRW-5

Electric Utility Average Return on Equity and Market-to-Book Ratios



Data Source: *Value Line Investment Survey.*

Exhibit JRW-5
Industry Average Betas*
Value Line Investment Survey* Betas*
22-Jan-19

Rank	Industry	Beta	Rank	Industry	Beta	Rank	Industry	Beta
1	Petroleum (Producing)	1.71	34	Telecom. Equipment	1.15	67	Medical Services	1.01
2	Metals & Mining (Div.)	1.64	35	Internet	1.15	68	Recreation	1.01
3	Natural Gas (Div.)	1.63	36	Financial Svcs. (Div.)	1.15	69	IT Services	1.01
4	Oilfield Svcs/Equip.	1.61	37	Retail (Hardlines)	1.14	70	Med Supp Non-Invasive	0.99
5	Maritime	1.51	38	Semiconductor Equip	1.14	71	Telecom. Services	0.99
6	Steel	1.49	39	Entertainment Tech	1.13	72	Retail Store	0.98
7	Oil/Gas Distribution	1.40	40	Publishing	1.13	73	Pharmacy Services	0.98
8	Metal Fabricating	1.37	41	Computer Software	1.13	74	Information Services	0.97
9	Chemical (Specialty)	1.34	42	Paper/Forest Products	1.13	75	Investment Co.(Foreign)	0.96
10	Chemical (Diversified)	1.33	43	Precision Instrument	1.12	76	Healthcare Information	0.96
11	Pipeline MLPs	1.33	44	Public/Private Equity	1.12	77	Funeral Services	0.95
12	Heavy Truck & Equip	1.31	45	Retail Automotive	1.12	78	Med Supp Invasive	0.95
13	Chemical (Basic)	1.30	46	Power	1.12	79	Reinsurance	0.92
14	Building Materials	1.30	47	Wireless Networking	1.12	80	Environmental	0.91
15	Petroleum (Integrated)	1.30	48	Retail Building Supply	1.11	81	Cable TV	0.90
16	Homebuilding	1.28	49	Bank (Midwest)	1.11	82	Insurance (Prop/Cas.)	0.90
17	Railroad	1.27	50	Packaging & Container	1.11	83	Thrift	0.89
18	Auto Parts	1.27	51	Furn/Home Furnishings	1.11	84	Restaurant	0.88
19	Biotechnology	1.27	52	Human Resources	1.10	85	Tobacco	0.88
20	Engineering & Const	1.25	53	Drug	1.10	86	Household Products	0.86
21	Office Equip/Supplies	1.24	54	Advertising	1.10	87	Investment Co.	0.85
22	Hotel/Gaming	1.24	55	Shoe	1.09	88	Beverage	0.83
23	Automotive	1.24	56	Bank	1.09	89	Food Processing	0.82
24	Insurance (Life)	1.24	57	Newspaper	1.08	90	R.E.I.T.	0.82
25	Semiconductor	1.21	58	Toiletries/Cosmetics	1.08	91	Precious Metals	0.82
26	Machinery	1.20	59	Entertainment	1.07	92	Retail/Wholesale Food	0.80
27	Air Transport	1.20	60	Telecom. Utility	1.07	93	Water Utility	0.70
28	Electrical Equipment	1.20	61	Foreign Electronics	1.07	94	Natural Gas Utility	0.67
29	Electronics	1.20	62	Aerospace/Defense	1.05	95	Electric Util. (Central)	0.63
30	Trucking	1.19	63	Industrial Services	1.05	96	Electric Utility (West)	0.62
31	E-Commerce	1.18	64	Apparel	1.05	97	Electric Utility (East)	0.55
32	Computers/Peripherals	1.16	65	Educational Services	1.03			
33	Diversified Co.	1.16	66	Retail (Softlines)	1.02		Mean	1.10

* Industry averages for 97 industries using *Value Line*'s database of 1,710 companies.

** *Value Line* computes betas using monthly returns regressed against the New York Stock Exchange Index for five years. These betas are then adjusted as follows: *VL* Beta = [{(2/3) * Regressed Beta} + {(1/3) * (1.0)}] to account to tendency for Betas to regress toward average of 1.0. See M. Blume, "On the Assessment of Risk," *Journal of Finance*, March 1971.

I, A

Public Staff - D. Williamson Exhibit #5
Docket No. E-22, Sub 562

	Amount	Organization
	$ 26,200,000	The Conservation Fund
	$ 1,500,000	Chickahominey Tribe donation
	$ 25,000,000	Virginia Dept of Conservation and Recreation
	$ 4,205,000	Virginia Dept of Game and Inland Fisheries
	$ 15,595,000	Virginia Environmental Endowment
	$ 12,500,000	Virginia Land Conservation Foundation
A	$ 85,000,000	
	$ 4,500,000	Pamunkey Indian Tribe donation
	$ 500,000	Pamunkey Indian Tribe land donation
	$ 400,000	Pamunkey Indian Tribe road donation
B	$ 5,400,000	
A+B	$ 90,400,000	Total

(filed under seal) I/A

Public Staff – D. Williamson Exhibit #6
Docket No. E-22, Sub 562

Williamson Confidential Exhibit 6 (Redacted)

*pg 1 of 84pgs previously filed in the docket. com

 RMM-1

7/A

Dominion Energy North Carolina
Table 1: Summary of Accrual Rates and Annual Accrual Amounts
As of December 31, 2016

			DENC Proposal		Public Staff Proposal		
Account	Description	12/31/16 Plant in Service	Accrual Rate	Accrual Amount	Accrual Rate	Accrual Amount	Difference from DENC
(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)=(G)-(E)
Steam Production Plant							
	Bremo Unit 3						
311.00	Structures and Improvements	3,086,946	1.18%	36,453	1.18%	36,453	0
312.00	Boiler Plant Equipment	19,408,240	3.95%	766,232	3.95%	766,232	0
314.00	Turbogenerator Units	11,095,013	2.08%	230,383	2.08%	230,383	0
315.00	Accessory Electric Equipment	4,199,835	2.48%	104,237	2.48%	104,237	0
316.00	Miscellaneous Power Plant Equip	208,423	2.06%	4,298	2.06%	4,298	0
	Total Bremo Unit 3	37,998,456	3.00%	1,141,603	3.00%	1,141,603	0
	Bremo Unit 4						
311.00	Structures and Improvements	2,949,841	1.24%	36,653	1.24%	36,653	0
312.00	Boiler Plant Equipment	35,290,059	3.40%	1,200,674	3.40%	1,200,674	0
314.00	Turbogenerator Units	15,482,529	2.11%	326,921	2.11%	326,921	0
315.00	Accessory Electric Equipment	3,361,856	2.86%	96,116	2.86%	96,116	0
316.00	Miscellaneous Power Plant Equip	135,543	1.93%	2,618	1.93%	2,618	0
	Total Bremo Unit 4	57,219,828	2.91%	1,662,982	2.91%	1,662,982	0
	Bremo Common						
310.00	Land and Land Rights	751	1.33%	10	1.33%	10	0
311.00	Structures and Improvements	15,215,428	2.17%	329,841	2.17%	329,841	0
312.00	Boiler Plant Equipment	6,826,092	2.39%	163,336	2.39%	163,336	0
314.00	Turbogenerator Units	1,413,072	1.86%	26,331	1.86%	26,331	0
315.00	Accessory Electric Equipment	9,402,742	2.61%	245,837	2.61%	245,837	0
316.00	Miscellaneous Power Plant Equip	3,320,468	2.50%	83,145	2.50%	83,145	0

I/A

Dominion Energy North Carolina
2019 NC Base Case – Docket No. E-22, Sub 562
Public Staff
Data Request No. 111

The following response to Question No. 1 of Public Staff Data Request No. 111, dated June 28, 2019 has been prepared under my supervision.

John J. Spanos
John Spanos
President
Gannett Fleming Valuation and Rate Consultants, LLC

Question No. 1:

The workpaper "Attachment Public Staff Set 71-3 DVP – 2016 – Generation – Summary Schedule" and "Attachment Public Staff Set 71-3 DVP – 2016 – Generation – Depreciation Calculations" show a Probable Retirement Date of 06-2051 for Woodland Solar, Whitehouse Solar, and Scott Solar. Pages VI-13 and IX-181 show a Probable Retirement Date of 06-2041 for Woodland Solar, Whitehouse Solar, and Scott Solar. What Probable Retirement Data is the Company proposing for Woodland Solar, Whitehouse Solar, and Scott Solar production plants?

Response:

The updated depreciation schedules utilize 06-2051 as the probable retirement date for the Woodland, Whitehouse, and Scott solar facilities. The 35-year life span for solar is consistent with the 06-2051 retirement date.

I/A

Dominion Energy North Carolina
2019 NC Base Case – Docket No. E-22, Sub 562
Public Staff
Data Request No. 71

The following response to Question No. 9 of Public Staff Data Request No. 71, dated June 3, 2019 has been prepared under my supervision.

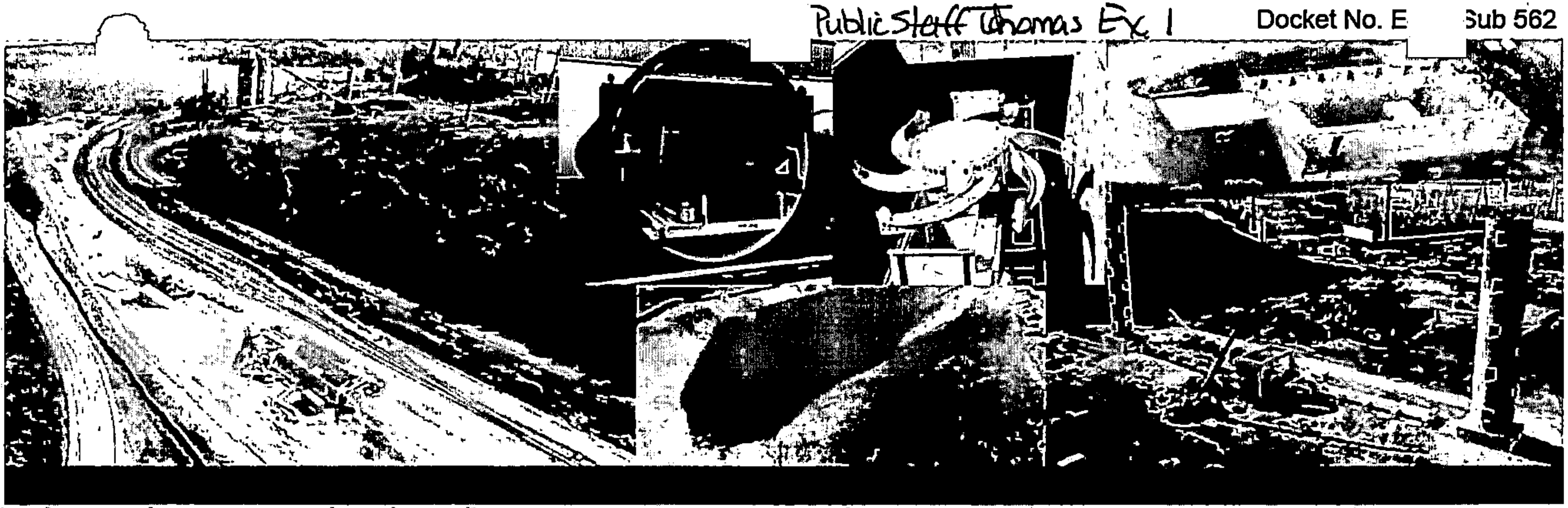
John Spanos
President
Gannett Fleming Valuation and Rate
Consultants, LLC

Question No. 9:

Please provide a complete copy of the database which was used in the Net Salvage Statistics Part VIII in the Company's Updated Depreciation Studies filed on August 23, 2017 in Docket No. E-22, Sub 493. This should include (but not necessarily be limited to) the transaction amount, account/subaccount number (leave in the account/subaccount name and any account/subaccount description that is on the file), transaction type, vintage year, and transaction year. Provide the meaning of any codes (transaction codes, location codes, account codes, etc.) used in these files. Please provide the database requested electronically in Excel (or in text delimited format if not available in Excel.)

Response:

There is no data recorded at this level of detail, which is why the simulated net salvage analysis is performed. Net Salvage is only recorded at the functional level by year.



Dominion Energy

Mount Storm Coal Yard Fuel Flexibility Project (CYFFP)
Project Evaluation Summary

April 12, 2019

Coal Yard Fuel Flexibility Project (CYFFP)

Project Evaluation Summary

Year	Budget	Confidence	Actual Cost (Calendar Year)	Actual Cost (Cumulative)
2011	$ 35,000,000	Engineering Estimate, 25% contingency on construction.	$ 35,446	$ 35,446

Analysis/Justification

- Mt Storm's traditional source of fuel (the local coal that could be trucked to the station by Mettiki) was either being depleted or was becoming very expensive to due to deteriorating geologic and quality conditions.
- Metikki contract was in danger of non-renewal after 2013.
- In order to maintain traditional levels of generation and be able to access cheaper sources of fuel, the station opted to expand its rail receiving capabilities.
- In 2011, the station could only receive about 40% of its coal via rail due to the rail design limitations.
- ***Recommendation: Proceed with Study of new Rail Unloading Facility.***

Source: Study PAR Justification, October 2011.

Dominion Energy™

Coal Yard Fuel Flexibility Project (CYFFP)

Project Evaluation Summary

Year	Budget	Confidence	Actual Cost (Calendar Year)	Actual Cost (Cumulative)
2012	$ 35,000,000	Engineering Estimate, 25% contingency on construction.	$ 140,345	$ 175,791

Analysis/Justification

- Based on forecast of future generation, recommend delaying COD of rail project by at least one year to Q4 2014.
- Allowed additional time to evaluate the fuel market & continued negotiations with Mettiki
- Analysis of rail capacity improvement remained favorable.

Source: Mt. Storm Rail Upgrade Project, Financial Review, May 2012.

Dominion Energy

Coal Yard Fuel Flexibility Project (CYFFP)

Project Evaluation Summary

Year	Budget	Confidence	Actual Cost (Calendar Year)	Actual Cost (Cumulative)
2013	$ 70,000,000 (Increased $35M)	Feasibility +/- 50%	$ 17,067	$ 192,858

Analysis/Justification

- Recommendation to invest $45 - $60 million to upgrade fuel receiving facility
- Expanded blending facility would allow for blending of NAPP, PRB and ILB coals to manage sulfur and mercury.
- Enable 100% delivery of coal by rail
- Failure to invest predicted replacement power costs of $14 million to $42 million per year.

NPV: Break-even point was estimated at 1 to 4 years.

Source: Mt. Storm Strategic Fuel Delivery/ Blending Plan Recommendation, September 2013

Dominion Energy

Coal Yard Fuel Flexibility Project (CYFFP)

Project Evaluation Summary

Year	Budget	Confidence	Actual Cost (Calendar Year)	Actual Cost (Cumulative)
2014	$ 116,000,000 (Increased $46M)	Conceptual +/- 30%, based on revised Engineering Study	$ 1,980,753	$ 2,173,611

Analysis/Justification

- Project Approved to proceed at $116M
  - NPV: $157M (low volume fuel case) to $365M (High volume fuel case)
  - Customer Payback Period: 3.5 to 6.5 years
  - Recommendation: Proceed with project.
  - Site work and equipment procurement to proceed in 2015, 2016 and 2017.
- Major cost increase due to extensive design additions affirmed by Owners Engineer
- A design/build contracting strategy was developed to utilize multiple prime contractors released in phases for site construction as scope design elements were completed.
- All equipment would be procured separately by Dominion.

Source: Mt. Storm Rail Project Analysis, October 2014

Dominion Energy

Coal Yard Fuel Flexibility Project (CYFFP)
Project Evaluation Summary

Year	Budget	Confidence	Actual Cost (Calendar Year)...	Actual Cost (Cumulative)
2015	$ 146,000,000 (Increased $30M)	Conceptual +/- 30%	$ 31,373,487	$ 33,547,098

Analysis/Justification

- Site Work & Procurement In Progress
  - Civil site work initiated in May 2015.
  - Equipment deliveries began in late 2015 and planned to continue through 2016.
  - Fire protection, electrical, mechanical and controls design work remained in progress.
- Cost increases continued due to design changes & contractor bids exceeding estimates.
- Budget Increase from $116M to $146M approved in May 2015.
- In August 2015, decision to delay/defer all 2017 construction work until 2018 due to 2017 fleet-wide capital budget constraints.

Dominion Energy

Coal Yard Fuel Flexibility Project (CYFFP)

Project Evaluation Summary

Year	Budget	Confidence	Actual Cost (Calendar Year)	Actual Cost (Cumulative)
2016	$ 184,000,000 (Increased $38M)	Conceptual +/- 30%	$ 21,548,597	$ 55,095,695

Analysis/Justification

- Significant cost increases recognized in early 2016
  - General Contractor bids for remaining work significantly higher than estimates.
  - Increased fire protection scope from original concept.
  - Escalation on deferred/delayed work.
- February 2016: Initiated an evaluation of reduced scope options while retaining overall functionality of the blending facility.
- April 2016: All site activities and fabrication work suspended pending cost reduction analysis.

Dominion Energy

Coal Yard Fuel Flexibility Project (CYFFP)
Project Evaluation Summary

Year	Budget	Confidence	Actual Cost (Calendar Year)	Actual Cost (Cumulative)
2017	$ 184,000,000	Conceptual +/- 30%	$ 3,859,528	$ 58,955,223

Analysis/Justification

- Closed out site activities, continued engineering on reduced scope options.
- Analysis of market conditions and cancellation/write-off vs. completing the project.
  - Cancel project
    - $58.6M write-off plus $8.7M repairs (O/M)
    - $16.3M (remaining CapEx for existing fuel handling system)
  - Complete the Project
    - Generates fuel savings ($39M @ 2.3 mtpy - $189M @ 4.5 mtpy)
    - NPV/Breakeven analysis shows 4 to 5 year payback at 3.0-3.5M tons/year coal consumption.
    - Maintains Dominion's fleet fuel diversity options & capability to manage SO2, Ash, Hg.

- ***Source: Mount Storm Coal Yard Fuel Flexibility Project, Executive Summary; April, 2017.***

Coal Yard Fuel Flexibility Project (CYFFP)

Project Evaluation Summary

Year	Budget	Confidence	Actual Cost (Calendar Year)	Actual Cost (Cumulative)
2018	$ 184,000,000	Conceptual +/- 30%	$ 2,327,694	$ 61,282,917

Analysis/Justification

- Continued engineering on reduced scope options & finalizing design work.
- Analysis performed to assess budget impacts due to site work suspension, market conditions, RGGI and ED11 impacts.
- Assessed NPV for "full project" vs. "partial project" scenarios.
  - $11.5M (Positive NPV, Partial Project, 10 year scenario)
  - -13.8M (Negative NPV, Full Project, 10 year scenario)
  - NPV basis assumed NAPP Price minus $5/ton savings with project.
- Recommendation to finalize design work on “partial project” and develop complete contractor bid packages for all remaining work.

- ***Source: Mount Storm Coal Yard Fuel Flexibility Project Project Status Update, April 2018.***

Dominion Energy

Coal Yard Fuel Flexibility Project (CYFFP)
Project Evaluation Summary

Year	Budget	Confidence	Actual Cost (Calendar Year)	Actual Cost (Cumulative)
2019 (April, YTD)	$ 184,000,000	Estimate revised to \$211M; Definitive, +/- 10% 10% Contingency on Construction	$ 406,405	$ 61,689,322

Analysis/Justification

- **January 2019:**
  - Further analysis of market conditions @ \$184M Budget.
  - NPV: -\$54M (Negative, Partial Project, 10 year scenario); NAPP minus \$5/ton savings basis; Assumes \$122M cost to go.
  - Cancel Project: O&M - \$77.7M (\$68.4M write-off plus \$9.3M repairs) & CapEx: \$5.2M (existing fuel handling system)

  Source: Mount Storm Coal Yard Fuel Flexibility Project (CYFFP) Project Status Update, Jan 2019.

- **April 2019:**
  - Received contractor bids, revised market conditions and increased project estimate to \$211M.
  - NPV: -\$67M (Negative, Partial Project, 10 year scenario); NAPP minus \$4.66/ton savings; \$149.5 cost to go.
  - Cancel Project: O&M - \$76.1M (\$62.0M write-off plus \$14.1M repairs & Demo) & CapEx - \$5.2M (existing fuel system)

  Source: Mount Storm Coal Yard Fuel Flexibility Project (CYFFP) Project Status Update, April 2019.

Dominion Energy

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190230230

February 27, 2019

VIA ELECTRONIC DELIVERY

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

Application of Virginia Electric and Power Company for Approval and Certification of Electric Facilities: Surry-Skiffes Creek 500 kV Transmission Line, Skiffes Creek-Whealton 230 kV Transmission Line and Skiffes Creek 500 kV-230 kV-115 kV Switching Station
Case No. PUE-2012-00029

Dear Mr. Peck:

Pursuant to Ordering Paragraph (1) of the Order issued by the State Corporation Commission in the above-captioned proceeding on June 5, 2015, enclosed please find, on behalf of Virginia Electric and Power Company (the "Company"), for electronic filing a true and accurate copy of the *Update on Status of Certificated Project (February 27, 2019)*. A blackline version showing the changes from the Company's most recent Update is included as Exhibit A.

On February 26, 2019, the Certificated Projected was energized and placed into service.

Please do not hesitate to call if you have any questions in regard to the enclosed.

Very truly yours,

Vishwa B. Link

Enc.

cc: Hon. Alexander F. Skirpan, Chief Hearing Examiner
William H. Chambliss, Esq.
K. Beth Clowers, Esq.
Alisson Klaiber, Esq.
Lisa S. Booth, Esq.
David J. DePippo, Esq.

COMMONWEALTH OF VIRGINIA

STATE CORPORATION COMMISSION

APPLICATION OF	)	
	)	
VIRGINIA ELECTRIC AND POWER COMPANY d/b/a DOMINION ENERGY VIRGINIA	))	
	)	Case No. PUE-2012-00029
For approval and certification of electric facilities: Surry-Skiffes Creek 500 kV Transmission Line, Skiffes Creek-Whealton 230 kV Transmission Line, and Skiffes Creek 500 kV-230 kV-115 kV Switching Station	))))	

UPDATE ON STATUS OF CERTIFICATED PROJECT
FEBRUARY 27, 2019

Virginia Electric and Power Company, d/b/a Dominion Energy Virginia ("Dominion Energy Virginia" or the "Company"),[1] by counsel, pursuant to Ordering Paragraph (1) of the Order issued by the State Corporation Commission ("Commission") in this proceeding on June 5, 2015 ("Order Directing Updates"), hereby files this Update regarding the status of the Surry-Skiffes Creek Line, Skiffes Creek Switching Station ("Skiffes Station"), Skiffes Creek-Whealton Line, and additional transmission facilities (collectively, the "Certificated Project"). This Update supersedes prior updates submitted by the Company. For this Update to the Commission, the Company respectfully states as follows:

1. By its November 26, 2013 Order, as modified by its February 28, 2014 Order Amending Certificates in the above-styled proceeding and confirmed by its April 10, 2014 Order Denying Petition, the Commission approved and certificated under § 56-46.1 of the Code of

[1] Effective May 10, 2017, Dominion Resources, Inc., the Company's publicly held parent company, changed its name to Dominion Energy, Inc. As part of this corporate-wide rebranding effort, Virginia Electric and Power Company has changed its "doing business as" ("d/b/a") names in Virginia and North Carolina effective May 12, 2017. In Virginia, the Company's d/b/a name has been changed from Dominion Virginia Power to Dominion Energy Virginia, and in North Carolina the d/b/a name has been changed from Dominion North Carolina Power to Dominion Energy North Carolina. The Company's legal corporate entity name "Virginia Electric and Power Company" will not be changing as a result of this rebranding effort.

Virginia ("Va. Code") and the Virginia Utility Facilities Act[2] the construction and operation by Dominion Energy Virginia of the electric transmission lines and related facilities proposed by the Company in its Application filed in this proceeding on June 11, 2012 ("2012 Application"). Those orders provide that this case is to remain open until the proposed facilities are in service.

2. Those orders were appealed by BASF Corporation and jointly by James City County, Save The James Alliance Trust and James River Association ("JCC Parties") to the Supreme Court of Virginia, which issued its unanimous opinion in those appeals on April 16, 2015, affirming the Commission's approval and certification of these transmission facilities, which comprise the Certificated Project. *BASF Corp. v. State Corp. Comm'n*, 289 Va. 375, 770 S.E.2d 458 (2015) ("*BASF*").

3. The Court's opinion in *BASF* also reversed and remanded (by a 4-3 vote) the holding in the Commission's November 26, 2013 Order that the term "transmission line" includes transmission switching stations such as Skiffes Station under Va. Code § 56-46.1 F, which exempts transmission lines approved by the Commission under that section from Va. Code § 15.2-2232 and local zoning ordinances. Petitions of the Commission and the Company seeking rehearing of this aspect of the *BASF* opinion were denied by the Court on May 15, 2015. As a result, the Company is now required to obtain local land use approval from James City County to construct Skiffes Station.

4. The Court issued its mandate and remand on June 4, 2015, returning the case to the Commission for further proceedings consistent with the views expressed in the written opinion of the Court.

[2] Va. Code § 56-265.1 *et seq.*

5. The Commission stated in its Order Directing Updates:

> The evidence in this proceeding shows that the North Hampton Roads Area is in critical need of a significant electric system upgrade. The need is severe and fast approaching, and the reliability risks are far reaching. The facilities approved in this case, for which judicial review thereof has concluded, are needed to avoid violations of mandatory electric reliability standards approved under federal law to prevent: the loss of electric service to customers; transmission system overloads; and outages in the North Hampton Roads Area with cascading outages into northern Virginia, the City of Richmond, and North Carolina. Given the time required for the construction of significant electric infrastructure projects like the Certificated Project, and the magnitude of the projected reliability violations, the Commission directs Dominion to provide regular updates on the status of the Certificated Project, including but not necessarily limited to the Skiffes Station, the status of the Army Corps process, and the Company's plans for maintaining system reliability in the North Hampton Roads Area.

Order Directing Updates at 2-3.

Updates on Status of the Certificated Project

6. **Applications for Section 404 and Section 10 Corps Permits.** The Company has continued with its permitting efforts to construct the facilities that have been approved and certificated by the Commission. As the Commission is aware, the Company must obtain permits from the U.S. Army Corps of Engineers ("Corps") under Section 404 of the Clean Water Act to place fill material in the James River for construction of the transmission line towers and Section 10 of the Rivers and Harbors Act of 1899 for resulting obstructions to navigation. The Company filed a Joint Permit Application ("JPA") for the Corps permits in March of 2012 for the Surry to Skiffes Creek portion of the Certificated Project and a separate JPA for the Skiffes Creek to Whealton portion in June of 2013. In August 2013, the Company submitted a combined JPA for the Surry-Skiffes Creek Line and the Skiffes Creek-Whealton Line. This combined JPA superseded the permit applications for each such transmission line that had been submitted in

March 2012 and June 2013.[3] On June 12, 2017, the Corps issued a provisional permit to the Company. The provisional permit was conditioned upon: (1) the issuance of a permit by the Virginia Marine Resources Commission ("VMRC"); and (2) certification by the Department of Environmental Quality ("DEQ") that the Company has obtained a Section 401 Water Quality Certification Certification/Virginia Water Protection Permit. On June 30, 2017, the VMRC issued a permit to the Company, and DEQ waived the requirement for a Section 401 Water Quality Certification. On July 3, 2017, the Corps issued the Company a final permit under Section 404 of the Clean Water Act and Section 10 of the Rivers and Harbors Act of 1899.[4] On July 12, 2017, the National Parks Conservation Association ("NPCA") sought to challenge the Corps permit by filing a Complaint for Declaratory and Injunctive Relief with the United States District Court for the District of Columbia, a copy of which was attached as Exhibit A to the Company's July 18, 2017 Status Update filed with the Commission. On August 3, 2017, the National Trust for Historic Preservation ("NTHP") and Association for the Preservation of Virginia Antiquities ("Preservation Virginia") also sought to challenge the Corps permit by filing a Complaint for Declaratory and Injunctive Relief with the United States District Court for the District of Columbia, a copy of which was attached as Exhibit A to the Company's August 8, 2017 Status Update. On July 24, 2017, the NPCA filed a Motion for Preliminary Injunction with the Court. On July 26, 2017, the Company moved to intervene in the NPCA's case. On July 28, 2017, the parties filed an agreed-upon briefing schedule regarding NPCA's Motion for Preliminary Injunction, which the court accepted. On August 18, 2017, the Corps and the

[3] The JPA also served as the application to obtain an authorization from the Virginia Marine Resources Commission for encroachment on subaqueous beds of the Commonwealth in the James River and a Virginia Water Protection Permit from the Virginia Department of Environmental Quality. The latter permit also serves as the required Certificate under Section 401 of the Clean Water Act that the discharges for the Certificated Project will not result in a violation of water quality standards.

[4] A copy of the Corps permit can be found on the Corps' website at: http://www.nao.usace.army.mil/Missions/Regulatory/SkiffesCreekPowerLine/.

Company filed their response briefs. On September 1, 2017, the NPCA filed a reply brief in support of its Motion for Preliminary Injunction. On August 16, 2017, the Coalition to Protect America's National Parks, Inc., Jonathan Jarvis, and American Rivers, Inc. (collectively, the "Coalition") filed a motion for leave to file an *amicus curiae* brief in support of the NPCA's Motion for Preliminary Injunction, and on August 31, 2017, the Sierra Club filed a similar motion to participate as *amicus curiae*. On September 5, 2017, the Chesapeake Conservancy and Scenic Virginia filed a motion to participate as *amici curiae* in support of the NTHP/Preservation Virginia's Motion for Preliminary Injunction. The Corps and the Company responded to the Coalition's motion on August 30, 2017, and the Coalition filed a reply on September 6, 2017. The Corps and the Company responded to: the NTHP/Preservation Virginia's Motion for Preliminary Injunction on September 13, 2017; the Sierra Club's *amicus curiae* motion on September 14, 2017; and the Chesapeake Conservancy/Scenic Virginia's *amici curiae* motion on September 15, 2017. The parties have moved to consolidate the NPCA and NTHP/Preservation Virginia cases. On September 20, 2017, the court held a hearing on both preliminary injunction motions. On October 6, 2017, the Corps and the Company filed answers to the NPCA's and the NTHP/Preservation Virginia's complaints. On October 20, 2017, the court denied both the NPCA's and the NTHP/Preservation Virginia's Motions for Preliminary Injunction. On December 15, 2017, NPCA and NTHP/Preservation Virginia each filed a Motion for Summary Judgment. On January 26, 2018, and January 29, 2018, the Company and the Corps filed Cross-Motions for Summary Judgment, respectively. On March 2, 2018, NPCA and NTHP/Preservation Virginia filed reply briefs in support of their Motions for Summary Judgment. On March 26, 2018, the Corps and the Company filed reply briefs in support of their cross-Motions for Summary Judgment. On May 24, 2018, the Court issued an order denying

NPCA's and NHTP/Preservation Virginia's Motions for Summary Judgment, granting the Corps's and the Company's Cross-Motions for Summary Judgment in their entirety, and dismissing both cases ("District Court MSJ Order"). On June 1, 2018, NPCA filed a notice of appeal in the District Court appealing the District Court MSJ Order to the United States Circuit Court of Appeals for the District of Columbia ("D.C. Circuit"). On June 11, 2018, NTHP/Preservation Virginia filed a notice of appeal in the District Court appealing the District Court MSJ Order to the D.C. Circuit. On July 3, 2018, the District Court denied NPCA's Emergency Motion for Injunction Pending Appeal. On July 31, 2018, the D.C. Circuit denied NPCA's Emergency Motion for Injunction Pending Appeal, and set a briefing schedule on the merits of the appeal. On August 10, 2018, NPCA and NTHP/Preservation Virginia filed their opening briefs on the merits in the D.C. Circuit. On September 28, 2018, the Corps filed its brief on the merits. On October 5, 2018, the Company filed its brief on the merits. Also on October 5, 2018, PJM Interconnection L.L.C. filed an amicus brief in the D.C. Circuit in support of the Corps and the Company. On October 19, 2018, NPCA and NTHP/Preservation Virginia filed their reply briefs. The D.C. Circuit heard oral argument on the appeal on December 7, 2018.

A. **National Environmental Policy Act ("NEPA").** The two Corps permits required for the placement of fill and obstruction to navigation trigger review under NEPA. The Corps has indicated it will prepare an Environmental Assessment ("EA") to satisfy this requirement. NEPA requires the Corps to evaluate alternatives as well as the direct, indirect and cumulative effects of the project on the human environment. As part of this NEPA review, on August 28, 2013, the Corps solicited public comments on the undertaking via public notice in accordance with the requirements of NEPA. The Corps received voluminous comments on the undertaking and has evaluated numerous alternatives. On October 1, 2015, the Corps published their Preliminary Alternatives Conclusions White Paper ("White Paper"), which concluded, in relevant part:

> Therefore, based on information presented to date, our preliminary finding is that two alternatives appear to meet the project purpose while reasonably complying with the evaluation criteria. These are Surry-Skiffes-Whealton 500 kV OH (AC) (Dominion's Preferred) and Chickahominy-Skiffes-Whealton 500kV. We have determined that other alternatives are unavailable due to cost, engineering constraints and/or logistics. Please note this is not a decision on whether Dominion's preferred alternative is or is not permittable, nor does it exclude further consideration of alternatives should new information become available.

White Paper at 7-8. A copy of the White Paper was attached as Exhibit A to the Company's October 2, 2015 Status Update filed with the Commission. On April 5, 2016, the Corps presented a response ("Corps Response" or "Response") to an Advisory Council on Historic Preservation ("ACHP") letter and indicated within its Response to ACHP that, "based on analysis of all information made available to date, the USACE finds nothing to indicate that Dominion's information regarding practicality of alternatives is flawed or incorrect. Additionally, Dominion has explored all feasible alternatives, including those identified by the consulting parties and the public to date." Corps Response at 3. A copy of the Corps Response was attached as Exhibit A to the Company's April 12, 2016 Status Update filed with the Commission. On March 30, 2017, the Corps published their updated Preliminary Alternatives Conclusions White Paper ("Updated White Paper"), a copy of which was attached as Exhibit A to the Company's April 4, 2017 Status Update filed with the Commission. The Updated White Paper concludes, in relevant part:

> Based on our thorough review of all information made available to date, it appears that only Dominion's proposed project and the Chickahominy-Skiffes 500kV alternative, meet project purpose and need and are practicable. Other alternatives do not satisfy the project purpose and need and/or are not practicable due to cost, engineering constraints and/or logistics. Please note this is not a

decision on whether Dominion's preferred alternative is or is not permittable, nor does it exclude further consideration of alternatives should new information become available.

Updated White Paper at 10. The Corps made its final selection of alternatives when it issued the EA which accompanied the permit decision.

B. **Endangered Species Act ("ESA").** The two Corps permits also trigger review under the ESA. The Corps must determine that the construction and operation of the facilities will not violate the ESA. The Corps has been consulting with the United States Fish and Wildlife Service ("USFWS") regarding the Certificated Project's potential effect on the Northern Long Eared Bat ("NLEB"), and the National Marine Fisheries Service ("NMFS") regarding the Atlantic Sturgeon. NMFS indicated in a January 28, 2016 letter that they agreed with the Corps that the Project is not likely to adversely affect listed species. On April 12, 2016, the USFWS concurred with the Corps conclusions regarding the NLEB, indicating the Corps would permit Project construction without a time of year restriction on tree clearing. The Corps sent out a request for the USFWS to update its concurrence for all species on May 11, 2017. Consultation was completed upon the issuance of the permit decision. On May 21, 2018, NPCA sent the Corps and NMFS a 60-day notice of intent to sue letter for alleged violations of the ESA based on claims that the agencies failed to consider the impacts of the project on juvenile Atlantic Sturgeon, Atlantic Sturgeon designated critical habitat, and Shortnose Sturgeon.

C. **National Historic Preservation Act ("NHPA").** Finally, the two Corps permits trigger review under the NHPA. Section 106 of the NHPA requires the Corps to take into consideration the effect of permitted activities on historic properties. The NHPA process has four components (a) evaluation of alternatives, (b) identification of historic properties that might be affected, (c) evaluation of whether and to what extent the federally permitted project will have an adverse effect on those historic properties and (d) mitigation of those adverse effects. This process commenced with the issuance of the initial public notice on August 28, 2013. The comments received helped facilitate the initial steps of the review process and provided interested members of the public with an opportunity to comment on alternatives, the identification of historic properties and potential effects, which includes Carter's Grove, Jamestown and Hog Island. The Corps identified an Area of Potential Effect ("APE") which is shown on a map included as Exhibit A to the Company's February 9, 2016 Status Update filed with the Commission. The Corps, in coordination with the State Historic Preservation Office ("SHPO"), then identified organizations that have a demonstrated interest in the treatment of historic properties associated with the Certificated Project ("Consulting Parties") within the APE.

(i) **Alternatives.** The Corps has conducted its alternative analysis under the NHPA concurrently with that under NEPA described in Paragraph 6 above.

(ii) **Historic Property Identification.** On November 13, 2014, the Corps issued a second public notice soliciting comments specific to historic property identification and an alternatives analysis. The Corps and SHPO reached initial agreement on historic properties within the APE on May 1, 2015. On June 19, 2015, the ACHP requested that the Corps consider whether a portion of the Captain John Smith Chesapeake National Historic Trail ("CAJO") is eligible for inclusion on the National Register of Historic Places. On July 2, 2015, the Corps made a request to the Keeper of the Register ("Keeper") concerning the eligibility of the CAJO within the APE. On August 14, 2015, the Keeper made a determination that a portion of the CAJO is eligible for listing on the National Register of Historic Places as a contributing element of a historic district within the APE.

(iii) **Determination of Effects.** On May 21, 2015 the Corps issued a third public notice to assist in evaluation of the effects of the Certificated Project on the identified historic properties and evaluation of alternatives or modifications which could avoid, minimize or mitigate adverse effects of the undertaking. As part of the process to assist in consideration of historic impacts, the Company prepared a Consolidated Effects Report ("CER") to merge the various studies that had been prepared beginning in 2011 into a single document. The Corps published the CER on October 1, 2015. The Corps and SHPO subsequently reached agreement on the list of adversely effected properties.

(iv) **Mitigation.** A draft mitigation plan was developed, and the Corps provided for a Consulting Parties comment period on the draft mitigation plan; the draft mitigation plan and comment period was noticed to the Consulting Parties on December 30, 2015, and ended January 29, 2016. A fifth Consulting Parties meeting was held February 2, 2016 to discuss mitigation for impacts to historic properties. A revised draft mitigation plan was developed, which the Corps noticed on June 13, 2016 to the Consulting Parties for a comment period ending July 13, 2016. A copy of the revised mitigation plan was attached as Exhibit A to the Company's June 14, 2016 Status Update filed with the Commission. On July 6, 2016, the Corps extended the comment period until July 27, 2016. On December 7, 2016, the

Corps noticed to the Consulting Parties a further revised mitigation plan for a comment period ending December 21, 2016, which subsequently was extended to January 11, 2017. Additionally, the Corps scheduled a conference call among Consulting Parties for January 19, 2017 to allow for any follow-up and / or clarifying discussion. A copy of the further revised mitigation plan was attached as Exhibit A to the Company's December 20, 2016 Status Update filed with the Commission. The Corps sent an updated Memorandum of Agreement ("MOA") to the Signatory Parties on March 24, 2017. On March 28, 2017, the Corps notified Consulting Parties via email of the latest draft MOA and posted the document on its website. Copies of the Corps' March 24 and March 28 emails and the updated MOA were attached as Exhibit B to the Company's April 4, 2017 Status Update filed with the Commission. On April 24, 2017, the Corps circulated to the Company, SHPO, ACHP, and the other consulting parties the final MOA for signature. A copy of the MOA was attached as Exhibit A to the Company's April 25, 2017 Status Update filed with the Commission. The April 24, 2017 MOA was executed by the four required Signatory Parties. On October 26, 2017, the Company sent the Corps a letter providing notice that it had taken and accomplished the actions that were a prerequisite to beginning "Limited Construction Within the James River," consistent with the definition of that term in the MOA, and the Company currently is conducting such work. On March 21, 2018, the Company sent a letter to the Corps providing notice that it had completed all prerequisite actions required to begin "Construction

Above the James River" as of March 7, 2018. The Company received a letter from the Corps dated July 31, 2018 noting that the Corps finds the Company to be in full compliance with the MOA obligations and has met its obligations to begin "Construction Above the James River."

(v) **Consulting Party Meetings.** In total, the Corps has hosted five Consulting Parties meetings to date (September and December 2014, June and October 2015, and February 2016) to discuss alternatives to the Certificated Project, identification of and impacts to historic properties and potential mitigation opportunities. On October 7, 2016, the Corps welcomed the Pamunkey Indian Tribe as a consulting party following their request to participate in the Section 106 consultation process. On March 28, 2017, the Corps also welcomed Kingsmill Resort as a consulting party following their request to participate in the Section 106 consultation process.

D. **Public Hearing.** A fourth public notice was published October 1, 2015 providing notice of a public hearing on all aspects of the Corps permitting process to be held on October 30, 2015 at Lafayette High School in Williamsburg, Virginia. The Corps conducted its public hearing on October 30, 2015, during which approximately 80 witnesses appeared to present their views to the Corps. The period for written public comments associated with the October 30, 2015 public hearing (originally scheduled to close on November 9, 2015) was subsequently extended to close of business November 13, 2015, concurrent with the public comment period for the CER and White Paper.

7. **Virginia Marine Resources Commission Permit.** The Company must obtain an authorization from the VMRC for encroachment on subaqueous beds of the Commonwealth in

the James River. The VMRC considered and unanimously approved the Company's JPA at the June 27, 2017 public hearing. On June 30, 2017, the VMRC issued the Company a permit.

8. **Federal Aviation Administration Review.** Additionally, the Federal Aviation Administration has completed its review of all of the proposed 500 kV structures; the 230 kV structures; and associated cranes and has made a determination of no hazard to air navigation.

9. **United States Fish and Wildlife Service.** Dominion Energy Virginia submitted an application to the USFWS for the removal of an inactive bald eagle nest on one of the 230 kV structures that is proposed to be replaced. The application is currently awaiting approval.

10. **James City County Special Use Permit.** Consistent with the Court's opinion in *BASF*, on June 17, 2015, the Company filed a special use permit application ("SUP"), a rezoning request, a substantial accord determination request and a height waiver application ("the Applications") for a switching station in James City County associated with the Certificated Project. Comments from County staff were received on July 2, 2015, and the Company responded to the County July 10, 2015. The County produced additional comments on the resubmission on July 17, 2015, and the Company responded on July 24, 2015. On July 23, 2015, an open house was hosted by Dominion Energy Virginia to discuss the switching station. There were 26 attendees. The switching station was placed on the James City County Planning Commission agenda scheduled for August 5, 2015, and legal notices were run on July 22 and July 29, 2015 to alert the public of the meeting. A favorable staff report was issued July 29, 2015 recommending approval of the switching station. On August 5, 2015, the James City County Planning Commission voted 4 to 2 against recommending approval of the Company's switching station. Pursuant to Va. Code § 15.2-2232, on August 17, 2015, the Company filed an appeal of the substantial accord determination to the James City County Board of Supervisors

(the "JCC Board"). The JCC Board is responsible for making the final determination on the SUP, rezoning and height waiver requests and for hearing the appeal on the substantial accord determination, and it was anticipated that all four items would be considered during the same meeting of the JCC Board. The appeal and the other pending applications were to be considered by the JCC Board at its October 13, 2015 public meeting, but the Company submitted a letter on September 17, 2015 requesting that action on the appeal be deferred until the JCC Board's meeting on November 24, 2015. The JCC Board approved that request at its meeting on September 22, 2015. A subsequent request was submitted by the Company on November 6, 2015 to defer the vote on the matter until the JCC Board's January 12, 2016 meeting; this request was approved by the JCC Board on November 10, 2015. The Company had anticipated that the decision of the JCC Board would be better informed by the status of the Corps process in January of 2016; so, on December 4, 2015, the Company submitted a letter of request for further deferral of the JCC Board's public hearing on this matter to the JCC Board's February 9, 2016 meeting; this request was approved by the JCC Board on December 8, 2015. The Company sought on January 8, 2016 an additional deferral until the March 8, 2016 JCC Board meeting. The JCC Board approved this request at their January 12, 2016 meeting. However, due to further delay in the Corps process, the Company sought an additional deferral until the August 9, 2016 JCC Board meeting unless the Corps issues its permits before that date, which deferral request was approved by the JCC Board on February 9, 2016. With continuing delays in the Corps process, the Company submitted an additional deferral request dated June 27, 2016 until the December 13, 2016 JCC Board meeting unless the Corps issues its permits before that date. The JCC Board approved the Company's June 27, 2016 deferral request. With additional delays in the Corps process, the Company submitted another deferral request dated November 14, 2016 until the June 27, 2017 JCC Board meeting. The JCC Board approved the Company's November 14, 2016 deferral request on November 22, 2016. On May 23, 2017, the JCC Board granted the Company's request to move the hearing date of the Applications to July 11, 2017, in accordance with the JCC Board's January 2017 policy change regarding public hearings. The JCC Board has made a policy change so that public hearing matters would be scheduled only during the first meeting of the month and that work session matters that do not require a public hearing would be scheduled for the second meeting of the month. At its regularly scheduled meeting on July 11, 2017, the JCC Board voted to approve (3-2 vote) the SUP, rezoning and height waiver requests and also upheld the Company's position regarding the appeal on the substantial accord determination that had been made by the James City County Planning Commission.

11. **James City County Site Plan.** On September 11, 2015, in advance of the JCC Board's vote on the aforementioned items, the Company, at its own risk, submitted the Switching Station site plan to the County for review. Comments from JCC and other review agencies were reviewed by the Company and were addressed in the Company's November 16, 2015 second submission of the Switching Station site plan. Review comments were received on the second submission of the site plan, and the Company reviewed and responded to these comments with a third submission of the site plan with revisions on February 2, 2016. All comments on the third submission were received, and the Company responded to these comments in their fourth submission of the site plan on April 27, 2016. On May 17, 2016, the County provided approval of the Company's Water Quality Impact Assessment. Further comments were generated by other departments. The Company resubmitted the site plan on July 19, 2016. The switching station site plan received its conditional approval from the County

review departments pending the legislative action by the JCC Board. An on-site pre-construction meeting was held between James City County departmental staff and Dominion Energy Virginia representatives on August 11, 2017. At that meeting, the land disturbance permit was issued by JCC to the Company. Subsequently, on August 14, 2017, the Company initiated phase 1 erosion and sediment control on the site. On September 19, 2017, JCC provided the Company final approval on its site plan for work at the switching station.

12. Upon obtaining the required approvals, the Company commenced construction of the applicable Certificated Project components. On February 26, 2019, the new 500 kV line and the 500 kV bus was energized. The fendering system below the surface is 100% complete, and the fender hall section above the surface is 25% complete. The fiberglass covers for the tower piles are at 50% complete; continued work on the covers will start back after the below the surface restrictions are lifted June 15, 2019.

13. **Mercury and Air Toxics Standards ("MATS") Extension.** Additionally, the Company notes that the inability to begin construction since the Application was filed with the Commission had made it impossible for the proposed facilities to be completed and in service by December 31, 2015, as provided in the Commission's February 28, 2014 Order Amending Certificates. As permitted by federal environmental regulations, the Company obtained from the Virginia Department of Environmental Quality a one-year extension of the April 16, 2015 deadline for Yorktown Units 1 and 2 to comply with the U.S. Environmental Protection Agency's ("EPA") MATS regulation that will be achieved by retiring the units, which drove the original June 1, 2015 need date for the new transmission facilities. On October 15, 2015, the Company submitted a Petition seeking from the EPA an administrative order under EPA's

Administrative Order Policy for the MATS rule,[5] which would provide an additional one-year waiver of non-compliance with the regulations that drive those retirements and further extend the need date for the Certificated Project to June 1, 2017. On December 2, 2015, the Federal Energy Regulatory Commission ("FERC") issued Comments on the Company's request to EPA, stating that Yorktown Unit Nos. 1 and 2 "are needed during the administrative order period, as requested by Dominion, to maintain electric reliability and to avoid possible NERC Reliability Standard violations."[6] On April 16, 2016, the EPA issued an Administrative Order[7] under Section 113(g) of the Clean Air Act ("CAA") authorizing the Company to operate the Yorktown coal-fired units (Units 1 and 2) through April 15, 2017 under certain limitations consistent with the MATS rule. Upon expiration of the EPA Administrative Order on April 15, 2017, the Yorktown coal-fired units ceased operations to comply with the MATS rule. On June 13, 2017, PJM Interconnection L.L.C. ("PJM") filed a request for emergency order pursuant to Section 202(c) of the Federal Power Act[8] with the Department of Energy ("DOE"), and on June 16, 2017, DOE granted an order ("DOE Order") to PJM to direct Dominion Energy Virginia to operate Yorktown Units 1 and 2 as needed to avoid reliability issues on the Virginia Peninsula for 90 days. A copy of the DOE Order was provided as Exhibit A to the Company's June 27, 2017 Status Update filed with the Commission. On July 13, 2017, the Sierra Club filed with DOE a Motion to Intervene and Petition for Rehearing. The Sierra Club alleges that, among other things, DOE failed to establish an emergency exists to support the issuance of the DOE

[5] *The Environmental Protection Agency's Enforcement Response Policy For Use of Clean Air Act Section 113(a) Administrative Orders In Relation To Electric Reliability and the Mercury and Air Toxics Standard.* EPA Memorandum from Cynthia Giles, Assistant Administrator of the Office of Enforcement and Compliance Assurance to EPA Regional Administrators, Regional Counsel, Regional Enforcement Directors and Regional Air Division Directors (December 16, 2011).

[6] *Virginia Electric and Power Company*, Docket No. AD16-11-000, 153 FERC ¶ 61,265.

[7] *See* https://www.epa.gov/sites/production/files/2016-04/documents/mats-caa-113a-admin-order-0416-virginia-electric-power-co-virginia.pdf.

[8] 16 U.S.C. § 824a(c).

Order, and that DOE failed to comply with NEPA before issuing the DOE Order. On July 31, 2017, PJM filed a Motion for Leave to Answer and Answer of PJM Interconnection, L.L.C. On August 1, 2017, the Company filed a Motion of Virginia Electric and Power Company to Strike the Procedurally Deficient Petition for Rehearing or, in the Alternative, Motion for Leave to Answer and Answer of Virginia Electric and Power Company. On August 18, 2017, the Sierra Club filed a Motion for Leave to File a Response and Response to the Answers by Dominion Energy Virginia and PJM. On September 15, 2017, the DOE issued an order dismissing the Sierra Club's Motion as moot because the DOE order for which the Sierra Club sought rehearing expired on September 14, 2017. On August 24, 2017, PJM submitted a request to the DOE for a 90-day renewal of the DOE Order. On September 14, 2017, the DOE issued a second 90-day emergency order pursuant to Section 202(c) of the Federal Power Act ("2d DOE Order"). On October 5, 2017, the Sierra Club filed a Motion to Intervene and Petition for Rehearing with DOE regarding the 2d DOE Order. On November 6, 2017, the DOE denied the Sierra Club's Petition for Rehearing. On November 29, 2017, PJM submitted a request to the DOE for a 90-day renewal of the 2d DOE Order. On December 13, 2017, the DOE issued a third 90-day emergency order pursuant to Section 202(c) of the Federal Power Act ("3d DOE Order"). On February 20, 2018, PJM submitted a request to the DOE for a 90-day renewal of the 3d DOE Order. On March 13, 2018, the DOE issued a fourth 90-day emergency order pursuant to Section 202(c) of the Federal Power Act ("4th DOE Order"). On May 21, 2018, PJM submitted a request to the DOE for a 90-day renewal of the 4th DOE Order. On June 8, 2018, the DOE issued a fifth 90-day emergency order pursuant to Section 202(c) of the Federal Power Act ("5th DOE Order"). On August 17, 2018, PJM submitted a request to the DOE for a 90-day renewal of the 5th DOE Order. On September 5, 2018, the DOE issued a sixth 90-day emergency order pursuant to Section 202(c) of the Federal Power Act ("6th DOE Order"). On November 13, 2018, PJM submitted a request to the DOE for a 90-day renewal of the 6th DOE Order. On December 6, 2018, the DOE issued a seventh 90-day emergency order pursuant to Section 202(c) of the Federal Power Act ("7th DOE Order"). On February 8, 2019, PJM submitted a request to the DOE for a 30-day renewal of the 7th DOE Order, for the period of March 9, 2019, through April 8, 2019.

14. On June 29, 2015, the United States Supreme Court ("Supreme Court") in *Michigan, et al. v. Environmental Protection Agency, et al.*, 576 U.S. __(2015), reversed and remanded (by a 5-4 vote) the EPA's MATS regulation to the United States Court of Appeals for the D.C. Circuit Court ("D.C. Court of Appeals") for further proceedings consistent with the Supreme Court's Opinion. This decision does not change the Company's plans to close coal units at Yorktown Power Station or the need to construct the Certificated Project by 2017. The Court's ruling required that EPA consider the cost of implementation., The decision neither vacated the rule nor placed a stay on its implementation. On July 31, 2015, the Supreme Court formally sent the litigation back to the D.C. Court of Appeals, to decide whether to vacate or leave in place the MATS rule while the EPA works to address the Supreme Court decision.

15. On November 20, 2015, in response to the Supreme Court decision, the EPA proposed a supplemental finding[9] that consideration of cost does not alter the agency's previous conclusion that it is appropriate and necessary to regulate coal- and oil-fired electric utility steam generating units ("EGUs") under Section 112 of the CAA. The proposed supplemental finding was published for public comment on December 1, 2015. 80 Fed. Reg. 75025 (Dec. 1, 2015). The public comment period closed on January 15, 2016.

[9] *See* http://www.gpo.gov/fdsys/pkg/FR-2015-12-01/pdf/2015-30360.pdf.

16. On December 15, 2015, the D.C. Court of Appeals in *White Stallion Energy, LLC v. Environmental Protection Agency*, No. 12-1100, 2015 U.S. App. LEXIS 21819 (D.C. Cir. 2015) issued an order remanding the MATS rulemaking proceeding back to EPA without vacatur. This action means that the MATS rule remains applicable and effective. The D.C. Court of Appeals noted that EPA had represented it was on track to issue by April 15, 2016, a final finding regarding its consideration of cost. EPA officially published a final rule on April 25, 2016.

17. On August 29, 2018, EPA announced that it will move ahead with a draft proposal to reconsider the MATS rule. The reconsideration proposal will address whether it was "appropriate and necessary" to regulate toxic emissions from power plants and will reevaluate the standards set by the rule itself. On February 7, 2019, EPA published a proposed rule revising the "appropriate and necessary" finding regarding the MATS rule, concluding that it is not "appropriate and necessary" to regulate hazardous air pollution ("HAP") emissions from power plants under Section 112 of the CAA.[10] Specifically, EPA proposes to find that a "proper" consideration of costs demonstrates that the total cost of compliance with MATS is larger than the monetized HAP benefits of the rule, and thus MATS could not be considered "appropriate and necessary." Notwithstanding this revised finding, EPA is proposing that the MATS rule would remain in place, citing legal precedent in *New Jersey v. EPA*, 517 F.3d 574 (D.C. Cir. 2008), that a negative "appropriate and necessary" finding cannot by itself remove a source category from regulation. In the proposed new finding, EPA would not remove or "de-list" coal- and oil-fired power plants from the list of affected source categories for regulation under CAA Section 112 and would leave MATS in place. The proposal also addresses the CAA requirement

[10] See https://www.epa.gov/sites/production/files/2018-12/documents/finmatsfindingandrtr_12_2018wdisc.pdf.

for EPA to conduct a residual risk and technology review for power plants, which is due for completion by 2020. EPA's proposal concludes that (i) the residual risks due to emissions of air toxics from power plants are acceptable and the current standards (*i.e.*, MATS) provide an ample margin of safety to protect public health; and (ii) no new developments in HAP emission controls to achieve further cost-effective emissions reductions were identified under the technology review. Therefore, EPA is proposing that revisions to tighten the limits imposed under MATS are not warranted at this time. EPA will accept public comment on the proposal through April 8, 2019. A final rule on this proposal could be issued later this year.

18. On December 1, 2015, the Company filed with the Commission a motion to extend the date for completion and placement in service of the Certificated Project to the date twenty (20) months after the date on which the Corps issues a construction permit for the Certificated Project. On December 22, 2015, the Commission issued an Order granting the Company's motion to extend.

Plans for Maintaining System Reliability in the North Hampton Roads Area

19. In order to ensure reliability for the Peninsula while the Surry-Skiffes Creek Line is being constructed, the Company is conducting a rigorous inspection and maintenance program ("Inspection Program"). The focus of the Inspection Program is transmission lines and stations for assets that directly serve the Peninsula. This includes, but is not limited to, the lines and stations from Chickahominy east to Newport News, as well as lines from Surry and Chuckatuck that feed into the southern end of the Peninsula. The Inspection Program focuses on the human performance factor that will be emphasized consistently over the work period to ensure the Electric Transmission and Station workforce involved in supporting the assets on the Peninsula are cognizant of the ongoing construction. The Inspection Program will also consist of a

complete evaluation of all abnormal equipment logs that require equipment maintenance or replacement in order to ensure that all equipment is in-service, and infrared reviews of stations and transmission lines prior to and during long critical outages to identify any weak links in the system that need attention to prevent unplanned outage events. More frequent aerial and foot patrols of transmission lines and stations will also be incorporated into the Inspection Program. Lastly, the outages required to address any outstanding equipment issues will be scheduled around the necessary planned outages to support the construction of the Certificated Project to limit the overall system exposure.

20. Additional inspection and maintenance work that is currently being conducted as part of the Inspection Program includes performing substation inspections quarterly; augmenting quarterly inspections with Technical Oversight Inspections of select stations; increasing infrared inspections of affected substations; performing infrared inspections every two weeks if load exceeds 18,000 MW; and reviewing all Corrective & Preventative Maintenance orders for substation equipment and relay systems to ensure they are completed or can be deferred during construction of the Certificated Project.

21. Foundation work on the existing transmission lines at the James River Bridge was completed at the end of 2015. Additional inspection and maintenance work also was performed prior to construction of the Certificated Project. This additional future work under the Inspection Program included the following: all line switches were inspected and any necessary maintenance performed; all questionable compression conductor connections were inspected and any necessary repairs were made prior to commencement of work; one month prior to beginning work, a foot patrol was done on the four 230 kV lines serving the Peninsula, and any issues found were corrected prior to commencement of work; one week prior to beginning work, an

aerial patrol was done on the four 230 kV lines serving the Peninsula, and any issues found were corrected prior to commencement of work; and bi-weekly aerial patrols will be done throughout the construction of the Certificated Project on these four 230 kV lines to identify any issues that may have surfaced since the previous patrol. The bi-weekly aerial patrols will specifically look for equipment integrity issues identified through visual inspection, corona camera, and infrared camera; and any third-party work on or near the right-of-way with a potential threat to the lines, which will be identified and addressed accordingly.

22. The plan for maintaining system reliability for the Peninsula will include careful planning of transmission outages and minimum work on assets on the Peninsula while the planned outages to support the construction of the Certificated Project are underway. Under some unplanned event scenarios, the reliability plan must include shedding of load in the amounts necessary to reduce stress on the system below critical demand levels. The shedding of load could occur in some instances at system load levels well below peak demand levels, on the order of 16,000 MW or higher. The exact system load level, load shed amounts and locations will be dependent on the circumstances that exist on the system at the time.

23. To minimize the potential for cascading outages to occur due to the unavailability of Yorktown Units 1 and 2 and until the proposed Skiffes Creek Project is in service, the Company has sought and received approval from SERC Reliability Corporation and PJM to install a Remedial Action Scheme ("RAS") beginning April of 2017. The RAS will reduce the likelihood of cascading outages from occurring by removing from service approximately 150,000 customers on the Peninsula, but would only be activated if certain contingency conditions occur. The RAS will take less than one second to make this determination and actually remove from service the affected customers. In the event the RAS is activated, the

Company and PJM's System Operators may initiate rotating outages on the Peninsula until the transmission system can be returned to a normal state. Notwithstanding the installation of the RAS, the Company is continuing to evaluate temporary measures for managing system operating conditions in order to minimize the need to activate the RAS.

24. The Company will continue to report to the Commission material developments of its plans for maintaining system reliability on the schedule set forth in the Order Directing Updates.

Respectfully submitted,
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February 27, 2019

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COMMONWEALTH OF VIRGINIA

STATE CORPORATION COMMISSION

APPLICATION OF VIRGINIA ELECTRIC AND POWER COMPANY d/b/a DOMINION ENERGY VIRGINIA For approval and certification of electric facilities: Surry-Skiffes Creek 500 kV Transmission Line, Skiffes Creek-Whealton 230 kV Transmission Line, and Skiffes Creek 500 kV-230 kV-115 kV Switching Station	Case No. PUE-2012-00029

UPDATE ON STATUS OF CERTIFICATED PROJECT
FEBRUARY ~~6~~27, 2019

Virginia Electric and Power Company, d/b/a Dominion Energy Virginia ("Dominion Energy Virginia" or the "Company"),[1] by counsel, pursuant to Ordering Paragraph (1) of the Order issued by the State Corporation Commission ("Commission") in this proceeding on June 5, 2015 ("Order Directing Updates"), hereby files this Update regarding the status of the Surry-Skiffes Creek Line, Skiffes Creek Switching Station ("Skiffes Station"), Skiffes Creek-Whealton Line, and additional transmission facilities (collectively, the "Certificated Project"). This Update supersedes prior updates submitted by the Company. For this Update to the Commission, the Company respectfully states as follows:

1. By its November 26, 2013 Order, as modified by its February 28, 2014 Order Amending Certificates in the above-styled proceeding and confirmed by its April 10, 2014 Order Denying Petition, the Commission approved and certificated under § 56-46.1 of the Code of

[1] Effective May 10, 2017, Dominion Resources, Inc., the Company's publicly held parent company, changed its name to Dominion Energy, Inc. As part of this corporate-wide rebranding effort, Virginia Electric and Power Company has changed its "doing business as" ("d/b/a") names in Virginia and North Carolina effective May 12, 2017. In Virginia, the Company's d/b/a name has been changed from Dominion Virginia Power to Dominion Energy Virginia, and in North Carolina the d/b/a name has been changed from Dominion North Carolina Power to Dominion Energy North Carolina. The Company's legal corporate entity name "Virginia Electric and Power Company" will not be changing as a result of this rebranding effort.

Virginia ("Va. Code") and the Virginia Utility Facilities Act[2] the construction and operation by Dominion Energy Virginia of the electric transmission lines and related facilities proposed by the Company in its Application filed in this proceeding on June 11, 2012 ("2012 Application"). Those orders provide that this case is to remain open until the proposed facilities are in service.

2. Those orders were appealed by BASF Corporation and jointly by James City County, Save The James Alliance Trust and James River Association ("JCC Parties") to the Supreme Court of Virginia, which issued its unanimous opinion in those appeals on April 16, 2015, affirming the Commission's approval and certification of these transmission facilities, which comprise the Certificated Project. *BASF Corp. v. State Corp. Comm'n*, 289 Va. 375, 770 S.E.2d 458 (2015) ("*BASF*").

3. The Court's opinion in *BASF* also reversed and remanded (by a 4-3 vote) the holding in the Commission's November 26, 2013 Order that the term "transmission line" includes transmission switching stations such as Skiffes Station under Va. Code § 56-46.1 F, which exempts transmission lines approved by the Commission under that section from Va. Code § 15.2-2232 and local zoning ordinances. Petitions of the Commission and the Company seeking rehearing of this aspect of the *BASF* opinion were denied by the Court on May 15, 2015. As a result, the Company is now required to obtain local land use approval from James City County to construct Skiffes Station.

4. The Court issued its mandate and remand on June 4, 2015, returning the case to the Commission for further proceedings consistent with the views expressed in the written opinion of the Court.

[2] Va. Code § 56-265.1 *et seq.*

5. The Commission stated in its Order Directing Updates:

> The evidence in this proceeding shows that the North Hampton Roads Area is in critical need of a significant electric system upgrade. The need is severe and fast approaching, and the reliability risks are far reaching. The facilities approved in this case, for which judicial review thereof has concluded, are needed to avoid violations of mandatory electric reliability standards approved under federal law to prevent: the loss of electric service to customers; transmission system overloads; and outages in the North Hampton Roads Area with cascading outages into northern Virginia, the City of Richmond, and North Carolina. Given the time required for the construction of significant electric infrastructure projects like the Certificated Project, and the magnitude of the projected reliability violations, the Commission directs Dominion to provide regular updates on the status of the Certificated Project, including but not necessarily limited to the Skiffes Station, the status of the Army Corps process, and the Company's plans for maintaining system reliability in the North Hampton Roads Area.

Order Directing Updates at 2-3.

Updates on Status of the Certificated Project

6. **Applications for Section 404 and Section 10 Corps Permits.** The Company has continued with its permitting efforts to construct the facilities that have been approved and certificated by the Commission. As the Commission is aware, the Company must obtain permits from the U.S. Army Corps of Engineers ("Corps") under Section 404 of the Clean Water Act to place fill material in the James River for construction of the transmission line towers and Section 10 of the Rivers and Harbors Act of 1899 for resulting obstructions to navigation. The Company filed a Joint Permit Application ("JPA") for the Corps permits in March of 2012 for the Surry to Skiffes Creek portion of the Certificated Project and a separate JPA for the Skiffes Creek to Whealton portion in June of 2013. In August 2013, the Company submitted a combined JPA for the Surry-Skiffes Creek Line and the Skiffes Creek-Whealton Line. This combined JPA

superseded the permit applications for each such transmission line that had been submitted in March 2012 and June 2013.[3] On June 12, 2017, the Corps issued a provisional permit to the Company. The provisional permit was conditioned upon: (1) the issuance of a permit by the Virginia Marine Resources Commission ("VMRC"); and (2) certification by the Department of Environmental Quality ("DEQ") that the Company has obtained a Section 401 Water Quality Certification Certification/Virginia Water Protection Permit. On June 30, 2017, the VMRC issued a permit to the Company, and DEQ waived the requirement for a Section 401 Water Quality Certification. On July 3, 2017, the Corps issued the Company a final permit under Section 404 of the Clean Water Act and Section 10 of the Rivers and Harbors Act of 1899.[4] On July 12, 2017, the National Parks Conservation Association ("NPCA") sought to challenge the Corps permit by filing a Complaint for Declaratory and Injunctive Relief with the United States District Court for the District of Columbia, a copy of which was attached as Exhibit A to the Company's July 18, 2017 Status Update filed with the Commission. On August 3, 2017, the National Trust for Historic Preservation ("NTHP") and Association for the Preservation of Virginia Antiquities ("Preservation Virginia") also sought to challenge the Corps permit by filing a Complaint for Declaratory and Injunctive Relief with the United States District Court for the District of Columbia, a copy of which was attached as Exhibit A to the Company's August 8, 2017 Status Update. On July 24, 2017, the NPCA filed a Motion for Preliminary Injunction with the Court. On July 26, 2017, the Company moved to intervene in the NPCA's case. On July 28, 2017, the parties filed an agreed-upon briefing schedule regarding NPCA's Motion for Preliminary Injunction,

[3] The JPA also served as the application to obtain an authorization from the Virginia Marine Resources Commission for encroachment on subaqueous beds of the Commonwealth in the James River and a Virginia Water Protection Permit from the Virginia Department of Environmental Quality. The latter permit also serves as the required Certificate under Section 401 of the Clean Water Act that the discharges for the Certificated Project will not result in a violation of water quality standards.

which the court accepted. On August 18, 2017, the Corps and the Company filed their response briefs. On September 1, 2017, the NPCA filed a reply brief in support of its Motion for Preliminary Injunction. On August 16, 2017, the Coalition to Protect America's National Parks, Inc., Jonathan Jarvis, and American Rivers, Inc. (collectively, the "Coalition") filed a motion for leave to file an *amicus curiae* brief in support of the NPCA's Motion for Preliminary Injunction, and on August 31, 2017, the Sierra Club filed a similar motion to participate as *amicus curiae*. On September 5, 2017, the Chesapeake Conservancy and Scenic Virginia filed a motion to participate as *amici curiae* in support of the NTHP/Preservation Virginia's Motion for Preliminary Injunction. The Corps and the Company responded to the Coalition's motion on August 30, 2017, and the Coalition filed a reply on September 6, 2017. The Corps and the Company responded to:, the NTHP/Preservation Virginia's Motion for Preliminary Injunction on September 13, 2017; the Sierra Club's *amicus curiae* motion on September 14, 2017; and the Chesapeake Conservancy/Scenic Virginia's *amici curiae* motion on September 15, 2017. The parties have moved to consolidate the NPCA and NTHP/Preservation Virginia cases. On September 20, 2017, the court held a hearing on both preliminary injunction motions. On October 6, 2017, the Corps and the Company filed answers to the NPCA's and the NTHP/Preservation Virginia's complaints. On October 20, 2017, the court denied both the NPCA's and the NTHP/Preservation Virginia's Motions for Preliminary Injunction. On December 15, 2017, NPCA and NTHP/Preservation Virginia each filed a Motion for Summary Judgment. On January 26, 2018, and January 29, 2018, the Company and the Corps filed Cross-Motions for Summary Judgment, respectively. On March 2, 2018, NPCA and NTHP/Preservation Virginia filed reply briefs in support of their Motions for Summary Judgment. On March 26, 2018, the Corps and the Company filed reply briefs in support

[4] A copy of the Corps permit can be found on the Corps' website at: http://www.nao.usace.army.mil/Missions/Regulatory/SkiffesCreekPowerLine/.

of their cross-Motions for Summary Judgment. On May 24, 2018, the Court issued an order denying NPCA's and NHTP/Preservation Virginia's Motions for Summary Judgment, granting the Corps's and the Company's Cross-Motions for Summary Judgment in their entirety, and dismissing both cases ("District Court MSJ Order"). On June 1, 2018, NPCA filed a notice of appeal in the District Court appealing the District Court MSJ Order to the United States Circuit Court of Appeals for the District of Columbia ("D.C. Circuit"). On June 11, 2018, NTHP/Preservation Virginia filed a notice of appeal in the District Court appealing the District Court MSJ Order to the D.C. Circuit. On July 3, 2018, the District Court denied NPCA's Emergency Motion for Injunction Pending Appeal. On July 31, 2018, the D.C. Circuit denied NPCA's Emergency Motion for Injunction Pending Appeal, and set a briefing schedule on the merits of the appeal. On August 10, 2018, NPCA and NTHP/Preservation Virginia filed their opening briefs on the merits in the D.C. Circuit. On September 28, 2018, the Corps filed its brief on the merits. On October 5, 2018, the Company filed its brief on the merits. Also on October 5, 2018, PJM Interconnection L.L.C. filed an amicus brief in the D.C. Circuit in support of the Corps and the Company. On October 19, 2018, NPCA and NTHP/Preservation Virginia filed their reply briefs. The D.C. Circuit heard oral argument on the appeal on December 7, 2018.

A. **National Environmental Policy Act ("NEPA").** The two Corps permits required for the placement of fill and obstruction to navigation trigger review under NEPA. The Corps has indicated it will prepare an Environmental Assessment ("EA") to satisfy this requirement. NEPA requires the Corps to evaluate alternatives as well as the direct, indirect and cumulative effects of the project on the human environment. As part of this NEPA review, on August 28, 2013, the Corps solicited public comments on the undertaking via public notice in accordance with the requirements of NEPA. The Corps received voluminous comments on the undertaking and has evaluated numerous alternatives. On October 1, 2015, the Corps published their Preliminary Alternatives Conclusions White Paper ("White Paper"), which concluded, in relevant part:

> Therefore, based on information presented to date, our preliminary finding is that two alternatives appear to meet the project purpose while reasonably complying with the evaluation criteria. These are Surry-Skiffes-Whealton 500 kV OH (AC) (Dominion's Preferred) and Chickahominy-Skiffes-Whealton 500kV. We have determined that other alternatives are unavailable due to cost, engineering constraints and/or logistics. Please note this is not a decision on whether Dominion's preferred alternative is or is not permittable, nor does it exclude further consideration of alternatives should new information become available.

White Paper at 7-8. A copy of the White Paper was attached as Exhibit A to the Company's October 2, 2015 Status Update filed with the Commission. On April 5, 2016, the Corps presented a response ("Corps Response" or "Response") to an Advisory Council on Historic Preservation ("ACHP") letter and indicated within its Response to ACHP that, "based on analysis of all information made available to date, the USACE finds nothing to indicate that Dominion's information regarding practicality of alternatives is flawed or incorrect. Additionally, Dominion has explored all feasible alternatives, including those identified by the consulting parties and the public to date." Corps Response at 3. A copy of the Corps Response was attached as Exhibit A to the Company's April 12, 2016 Status Update filed with the Commission. On March 30, 2017, the Corps published their updated Preliminary Alternatives Conclusions White Paper ("Updated White Paper"), a copy of which was attached as Exhibit A to the Company's April 4, 2017 Status Update filed with the Commission. The Updated White Paper concludes, in relevant part:

> Based on our thorough review of all information made available to date, it appears that only Dominion's proposed project and the Chickahominy-Skiffes 500kV alternative, meet project purpose and need and are practicable. Other alternatives do not satisfy the project purpose and need and/or are not practicable due to cost, engineering constraints and/or logistics. Please note this is not a

> decision on whether Dominion's preferred alternative is or is not permittable, nor does it exclude further consideration of alternatives should new information become available.

Updated White Paper at 10. The Corps made its final selection of alternatives when it issued the EA which accompanied the permit decision.

B. **Endangered Species Act ("ESA").** The two Corps permits also trigger review under the ESA. The Corps must determine that the construction and operation of the facilities will not violate the ESA. The Corps has been consulting with the United States Fish and Wildlife Service ("USFWS") regarding the Certificated Project's potential effect on the Northern Long Eared Bat ("NLEB"), and the National Marine Fisheries Service ("NMFS") regarding the Atlantic Sturgeon. NMFS indicated in a January 28, 2016 letter that they agreed with the Corps that the Project is not likely to adversely affect listed species. On April 12, 2016, the USFWS concurred with the Corps conclusions regarding the NLEB, indicating the Corps would permit Project construction without a time of year restriction on tree clearing. The Corps sent out a request for the USFWS to update its concurrence for all species on May 11, 2017. Consultation was completed upon the issuance of the permit decision. On May 21, 2018, NPCA sent the Corps and NMFS a 60-day notice of intent to sue letter for alleged violations of the ESA based on claims that the agencies failed to consider the impacts of the project on juvenile Atlantic Sturgeon, Atlantic Sturgeon designated critical habitat, and Shortnose Sturgeon.

C. **National Historic Preservation Act ("NHPA").** Finally, the two Corps permits trigger review under the NHPA. Section 106 of the NHPA requires the Corps to take into consideration the effect of permitted activities on historic properties. The NHPA process has four components (a) evaluation of alternatives, (b) identification of historic properties that might be affected, (c) evaluation of whether and to what extent the federally permitted project will have an adverse effect on those historic properties and (d) mitigation of those adverse effects. This process commenced with the issuance of the initial public notice on August 28, 2013. The comments received helped facilitate the initial steps of the review process and provided interested members of the public with an opportunity to comment on alternatives, the identification of historic properties and potential effects, which includes Carter's Grove, Jamestown and Hog Island. The Corps identified an Area of Potential Effect ("APE") which is shown on a map included as Exhibit A to the Company's February 9, 2016 Status Update filed with the Commission. The Corps, in coordination with the State Historic Preservation Office ("SHPO"), then identified organizations that have a demonstrated interest in the treatment of historic properties associated with the Certificated Project ("Consulting Parties") within the APE.

(i) **Alternatives.** The Corps has conducted its alternative analysis under the NHPA concurrently with that under NEPA described in Paragraph 6 above. .

(ii) **Historic Property Identification.** On November 13, 2014, the Corps issued a second public notice soliciting comments specific to historic property identification and an alternatives analysis. The Corps and SHPO reached initial agreement on historic properties within the APE on May 1, 2015. On June 19, 2015, the ACHP requested that the Corps consider whether a portion of the Captain John Smith Chesapeake National Historic Trail ("CAJO") is eligible for inclusion on the National Register of Historic Places. On July 2, 2015, the Corps made a request to the Keeper of the Register ("Keeper") concerning the eligibility of the CAJO within the APE. On August 14, 2015, the Keeper made a determination that a portion of the CAJO is eligible for listing on the National Register of Historic Places as a contributing element of a historic district within the APE.

(iii) **Determination of Effects.** On May 21, 2015 the Corps issued a third public notice to assist in evaluation of the effects of the Certificated Project on the identified historic properties and evaluation of alternatives or modifications which could avoid, minimize or mitigate adverse effects of the undertaking. As part of the process to assist in consideration of historic impacts, the Company prepared a Consolidated Effects Report ("CER") to merge the various studies that had been prepared beginning in 2011 into a single document. The Corps published the CER on October 1, 2015. The Corps and SHPO subsequently reached agreement on the list of adversely effected properties.

(iv) **Mitigation.** A draft mitigation plan was developed, and the Corps provided for a Consulting Parties comment period on the draft mitigation plan; the draft mitigation plan and comment period was noticed to the Consulting Parties on December 30, 2015, and ended January 29, 2016. A fifth Consulting Parties meeting was held February 2, 2016 to discuss mitigation for impacts to historic properties. A revised draft mitigation plan was developed, which the Corps noticed on June 13, 2016 to the Consulting Parties for a comment period ending July 13, 2016. A copy of the revised mitigation plan was attached as Exhibit A to the Company's June 14, 2016 Status Update filed with the Commission. On July 6, 2016, the Corps extended the comment period until July 27, 2016. On December 7, 2016, the Corps noticed to the Consulting

Parties a further revised mitigation plan for a comment period ending December 21, 2016, which subsequently was extended to January 11, 2017. Additionally, the Corps scheduled a conference call among Consulting Parties for January 19, 2017 to allow for any follow-up and / or clarifying discussion. A copy of the further revised mitigation plan was attached as Exhibit A to the Company's December 20, 2016 Status Update filed with the Commission. The Corps sent an updated Memorandum of Agreement ("MOA") to the Signatory Parties on March 24, 2017. On March 28, 2017, the Corps notified Consulting Parties via email of the latest draft MOA and posted the document on its website. Copies of the Corps' March 24 and March 28 emails and the updated MOA were attached as Exhibit B to the Company's April 4, 2017 Status Update filed with the Commission. On April 24, 2017, the Corps circulated to the Company, SHPO, ACHP, and the other consulting parties the final MOA for signature. A copy of the MOA was attached as Exhibit A to the Company's April 25, 2017 Status Update filed with the Commission. The April 24, 2017 MOA was executed by the four required Signatory Parties. On October 26, 2017, the Company sent the Corps a letter providing notice that it had taken and accomplished the actions that were a prerequisite to beginning "Limited Construction Within the James River," consistent with the definition of that term in the MOA, and the Company currently is conducting such work. On March 21, 2018, the Company sent a letter to the Corps providing notice that it had completed all prerequisite actions required to begin "Construction Above the James River" as of March 7, 2018. The Company received a letter from the

Corps dated July 31, 2018 noting that the Corps finds the Company to be in full compliance with the MOA obligations and has met its obligations to begin "Construction Above the James River."

(v) **Consulting Party Meetings.** In total, the Corps has hosted five Consulting Parties meetings to date (September and December 2014, June and October 2015, and February 2016) to discuss alternatives to the Certificated Project, identification of and impacts to historic properties and potential mitigation opportunities. On October 7, 2016, the Corps welcomed the Pamunkey Indian Tribe as a consulting party following their request to participate in the Section 106 consultation process. On March 28, 2017, the Corps also welcomed Kingsmill Resort as a consulting party following their request to participate in the Section 106 consultation process.

D. **Public Hearing.** A fourth public notice was published October 1, 2015 providing notice of a public hearing on all aspects of the Corps permitting process to be held on October 30, 2015 at Lafayette High School in Williamsburg, Virginia. The Corps conducted its public hearing on October 30, 2015, during which approximately 80 witnesses appeared to present their views to the Corps. The period for written public comments associated with the October 30, 2015 public hearing (originally scheduled to close on November 9, 2015) was subsequently extended to close of business November 13, 2015, concurrent with the public comment period for the CER and White Paper.

7. **Virginia Marine Resources Commission Permit.** The Company must obtain an authorization from the VMRC for encroachment on subaqueous beds of the Commonwealth in the James River. The VMRC considered and unanimously approved the Company's JPA at the June

27, 2017 public hearing. On June 30, 2017, the VMRC issued the Company a permit.

8. **Federal Aviation Administration Review.** Additionally, the Federal Aviation Administration has completed its review of all of the proposed 500 kV structures; the 230 kV structures; and associated cranes and has made a determination of no hazard to air navigation.

9. **United States Fish and Wildlife Service.** Dominion Energy Virginia submitted an application to the USFWS for the removal of an inactive bald eagle nest on one of the 230 kV structures that is proposed to be replaced. The application is currently awaiting approval.

10. **James City County Special Use Permit.** Consistent with the Court's opinion in *BASF*, on June 17, 2015, the Company filed a special use permit application ("SUP"), a rezoning request, a substantial accord determination request and a height waiver application ("the Applications") for a switching station in James City County associated with the Certificated Project. Comments from County staff were received on July 2, 2015, and the Company responded to the County July 10, 2015. The County produced additional comments on the resubmission on July 17, 2015, and the Company responded on July 24, 2015. On July 23, 2015, an open house was hosted by Dominion Energy Virginia to discuss the switching station. There were 26 attendees. The switching station was placed on the James City County Planning Commission agenda scheduled for August 5, 2015, and legal notices were run on July 22 and July 29, 2015 to alert the public of the meeting. A favorable staff report was issued July 29, 2015 recommending approval of the switching station. On August 5, 2015, the James City County Planning Commission voted 4 to 2 against recommending approval of the Company's switching station. Pursuant to Va. Code § 15.2-2232, on August 17, 2015, the Company filed an appeal of the substantial accord determination to the James City County Board of Supervisors (the "JCC Board"). The JCC Board is responsible for making the final determination on the SUP, rezoning and height waiver requests

and for hearing the appeal on the substantial accord determination, and it was anticipated that all four items would be considered during the same meeting of the JCC Board. The appeal and the other pending applications were to be considered by the JCC Board at its October 13, 2015 public meeting, but the Company submitted a letter on September 17, 2015 requesting that action on the appeal be deferred until the JCC Board's meeting on November 24, 2015. The JCC Board approved that request at its meeting on September 22, 2015. A subsequent request was submitted by the Company on November 6, 2015 to defer the vote on the matter until the JCC Board's January 12, 2016 meeting; this request was approved by the JCC Board on November 10, 2015. The Company had anticipated that the decision of the JCC Board would be better informed by the status of the Corps process in January of 2016; so, on December 4, 2015, the Company submitted a letter of request for further deferral of the JCC Board's public hearing on this matter to the JCC Board's February 9, 2016 meeting; this request was approved by the JCC Board on December 8, 2015. The Company sought on January 8, 2016 an additional deferral until the March 8, 2016 JCC Board meeting. The JCC Board approved this request at their January 12, 2016 meeting. However, due to further delay in the Corps process, the Company sought an additional deferral until the August 9, 2016 JCC Board meeting unless the Corps issues its permits before that date, which deferral request was approved by the JCC Board on February 9, 2016. With continuing delays in the Corps process, the Company submitted an additional deferral request dated June 27, 2016 until the December 13, 2016 JCC Board meeting unless the Corps issues its permits before that date. The JCC Board approved the Company's June 27, 2016 deferral request. With additional delays in the Corps process, the Company submitted another deferral request dated November 14, 2016 until the June 27, 2017 JCC Board meeting. The JCC Board approved the Company's November 14, 2016 deferral request on November 22, 2016. On May 23, 2017, the

JCC Board granted the Company's request to move the hearing date of the Applications to July 11, 2017, in accordance with the JCC Board's January 2017 policy change regarding public hearings. The JCC Board has made a policy change so that public hearing matters would be scheduled only during the first meeting of the month and that work session matters that do not require a public hearing would be scheduled for the second meeting of the month. At its regularly scheduled meeting on July 11, 2017, the JCC Board voted to approve (3-2 vote) the SUP, rezoning and height waiver requests and also upheld the Company's position regarding the appeal on the substantial accord determination that had been made by the James City County Planning Commission.

11. **James City County Site Plan.** On September 11, 2015, in advance of the JCC Board's vote on the aforementioned items, the Company, at its own risk, submitted the Switching Station site plan to the County for review. Comments from JCC and other review agencies were reviewed by the Company and were addressed in the Company's November 16, 2015 second submission of the Switching Station site plan. Review comments were received on the second submission of the site plan, and the Company reviewed and responded to these comments with a third submission of the site plan with revisions on February 2, 2016. All comments on the third submission were received, and the Company responded to these comments in their fourth submission of the site plan on April 27, 2016. On May 17, 2016, the County provided approval of the Company's Water Quality Impact Assessment. Further comments were generated by other departments. The Company resubmitted the site plan on July 19, 2016. The switching station site plan received its conditional approval from the County review departments pending the legislative action by the JCC Board. An on-site pre-construction meeting was held between James City County departmental staff and Dominion Energy Virginia representatives on August 11, 2017. At that meeting, the land disturbance permit was issued by JCC to the Company. Subsequently, on

August 14, 2017, the Company initiated phase 1 erosion and sediment control on the site. On September 19, 2017, JCC provided the Company final approval on its site plan for work at the switching station.

12. Upon obtaining the required approvals, the Company commenced construction of the applicable Certificated Project components. ~~As of December 1, 2018, the construction of the switching station is approximately 95% complete; the 230 kV and the 115 kV line work is approximately 85% complete; the new 500 kV line on land is approximately 98% complete and on water is approximately 70% complete. The Company will continue to report to the Commission material developments in its permitting and construction activities on the schedule set forth in the Order Directing Updates.~~<u>On February 26, 2019, the new 500 kV line and the 500 kV bus was energized. The fendering system below the surface is 100% complete, and the fender hall section above the surface is 25% complete. The fiberglass covers for the tower piles are at 50% complete; continued work on the covers will start back after the below the surface restrictions are lifted June 15, 2019.</u>

13. Mercury and Air Toxics Standards ("MATS") Extension. Additionally, the Company notes that the inability to begin construction since the Application was filed with the Commission had made it impossible for the proposed facilities to be completed and in service by December 31, 2015, as provided in the Commission's February 28, 2014 Order Amending Certificates. As permitted by federal environmental regulations, the Company obtained from the Virginia Department of Environmental Quality a one-year extension of the April 16, 2015 deadline for Yorktown Units 1 and 2 to comply with the U.S. Environmental Protection Agency's ("EPA") MATS regulation that will be achieved by retiring the units, which drove the original June 1, 2015 need date for the new transmission facilities. On October 15, 2015, the Company

submitted a Petition seeking from the EPA an administrative order under EPA's Administrative Order Policy for the MATS rule,[5] which would provide an additional one-year waiver of non-compliance with the regulations that drive those retirements and further extend the need date for the Certificated Project to June 1, 2017. On December 2, 2015, the Federal Energy Regulatory Commission ("FERC") issued Comments on the Company's request to EPA, stating that Yorktown Unit Nos. 1 and 2 "are needed during the administrative order period, as requested by Dominion, to maintain electric reliability and to avoid possible NERC Reliability Standard violations."[6] On April 16, 2016, the EPA issued an Administrative Order[7] under Section 113(g) of the Clean Air Act ("CAA") authorizing the Company to operate the Yorktown coal-fired units (Units 1 and 2) through April 15, 2017 under certain limitations consistent with the MATS rule. Upon expiration of the EPA Administrative Order on April 15, 2017, the Yorktown coal-fired units ceased operations to comply with the MATS rule. On June 13, 2017, PJM Interconnection L.L.C. ("PJM") filed a request for emergency order pursuant to Section 202(c) of the Federal Power Act[8] with the Department of Energy ("DOE"), and on June 16, 2017, DOE granted an order ("DOE Order") to PJM to direct Dominion Energy Virginia to operate Yorktown Units 1 and 2 as needed to avoid reliability issues on the Virginia Peninsula for 90 days. A copy of the DOE Order was provided as Exhibit A to the Company's June 27, 2017 Status Update filed with the Commission. On July 13, 2017, the Sierra Club filed with DOE a Motion to Intervene and Petition

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[5] *The Environmental Protection Agency's Enforcement Response Policy For Use of Clean Air Act Section 113(a) Administrative Orders In Relation To Electric Reliability and the Mercury and Air Toxics Standard.* EPA Memorandum from Cynthia Giles, Assistant Administrator of the Office of Enforcement and Compliance Assurance to EPA Regional Administrators, Regional Counsel, Regional Enforcement Directors and Regional Air Division Directors (December 16, 2011).

[6] *Virginia Electric and Power Company*, Docket No. AD16-11-000, 153 FERC ¶ 61,265.

[7] *See* https://www.epa.gov/sites/production/files/2016-04/documents/mats-caa-113a-admin-order-0416-virginia-electric-power-co-virginia.pdf.

[8] 16 U.S.C. § 824a(c).

for Rehearing. The Sierra Club alleges that, among other things, DOE failed to establish an emergency exists to support the issuance of the DOE Order, and that DOE failed to comply with NEPA before issuing the DOE Order. On July 31, 2017, PJM filed a Motion for Leave to Answer and Answer of PJM Interconnection, L.L.C. On August 1, 2017, the Company filed a Motion of Virginia Electric and Power Company to Strike the Procedurally Deficient Petition for Rehearing or, in the Alternative, Motion for Leave to Answer and Answer of Virginia Electric and Power Company. On August 18, 2017, the Sierra Club filed a Motion for Leave to File a Response and Response to the Answers by Dominion Energy Virginia and PJM. On September 15, 2017, the DOE issued an order dismissing the Sierra Club's Motion as moot because the DOE order for which the Sierra Club sought rehearing expired on September 14, 2017. On August 24, 2017, PJM submitted a request to the DOE for a 90-day renewal of the DOE Order. On September 14, 2017, the DOE issued a second 90-day emergency order pursuant to Section 202(c) of the Federal Power Act ("2d DOE Order"). On October 5, 2017, the Sierra Club filed a Motion to Intervene and Petition for Rehearing with DOE regarding the 2d DOE Order. On November 6, 2017, the DOE denied the Sierra Club's Petition for Rehearing. On November 29, 2017, PJM submitted a request to the DOE for a 90-day renewal of the 2d DOE Order. On December 13, 2017, the DOE issued a third 90-day emergency order pursuant to Section 202(c) of the Federal Power Act ("3d DOE Order"). On February 20, 2018, PJM submitted a request to the DOE for a 90-day renewal of the 3d DOE Order. On March 13, 2018, the DOE issued a fourth 90-day emergency order pursuant to Section 202(c) of the Federal Power Act ("4th DOE Order"). On May 21, 2018, PJM submitted a request to the DOE for a 90-day renewal of the 4th DOE Order. On June 8, 2018, the DOE issued a fifth 90-day emergency order pursuant to Section 202(c) of the Federal Power Act ("5th DOE Order"). On August 17, 2018, PJM submitted a request to the DOE for a 90-day renewal of the 5th

DOE Order. On September 5, 2018, the DOE issued a sixth 90-day emergency order pursuant to Section 202(c) of the Federal Power Act ("6th DOE Order"). On November 13, 2018, PJM submitted a request to the DOE for a 90-day renewal of the 6th DOE Order. On December 6, 2018, the DOE issued a seventh 90-day emergency order pursuant to Section 202(c) of the Federal Power Act ("7th DOE Order"). <u>On February 8, 2019,</u> PJM ~~plans to request further renewals of the DOE emergency orders on a rolling basis until the Certificated Project is placed into service. While this is not a long term solution to the reliability issues, Dominion Energy Virginia supports PJM's action and the DOE decision, and will work to ensure the units' availability as required.~~ <u>submitted a request to the DOE for a 30-day renewal of the 7th DOE Order, for the period of March 9, 2019, through April 8, 2019.</u>

14. On June 29, 2015, the United States Supreme Court ("Supreme Court") in *Michigan, et al. v. Environmental Protection Agency, et al.*, 576 U.S. __(2015), reversed and remanded (by a 5-4 vote) the EPA's MATS regulation to the United States Court of Appeals for the D.C. Circuit Court ("D.C. Court of Appeals") for further proceedings consistent with the Supreme Court's Opinion. This decision does not change the Company's plans to close coal units at Yorktown Power Station or the need to construct the Certificated Project by 2017. The Court's ruling required that EPA consider the cost of implementation. The decision neither vacated the rule nor placed a stay on its implementation. On July 31, 2015, the Supreme Court formally sent the litigation back to the D.C. Court of Appeals, to decide whether to vacate or leave in place the MATS rule while the EPA works to address the Supreme Court decision.

15. On November 20, 2015, in response to the Supreme Court decision, the EPA proposed a supplemental finding[9] that consideration of cost does not alter the agency's previous

[9] *See* http://www.gpo.gov/fdsys/pkg/FR-2015-12-01/pdf/2015-30360.pdf.

conclusion that it is appropriate and necessary to regulate coal- and oil-fired electric utility steam generating units ("EGUs") under Section 112 of the CAA. The proposed supplemental finding was published for public comment on December 1, 2015. 80 Fed. Reg. 75025 (Dec. 1, 2015). The public comment period closed on January 15, 2016.

16. On December 15, 2015, the D.C. Court of Appeals in *White Stallion Energy, LLC v. Environmental Protection Agency*, No. 12-1100, 2015 U.S. App. LEXIS 21819 (D.C. Cir. 2015) issued an order remanding the MATS rulemaking proceeding back to EPA without vacatur. This action means that the MATS rule remains applicable and effective. The D.C. Court of Appeals noted that EPA had represented it was on track to issue by April 15, 2016, a final finding regarding its consideration of cost. EPA officially published a final rule on April 25, 2016.

17. On August 29, 2018, EPA announced that it will move ahead with a draft proposal to reconsider the MATS rule. The reconsideration proposal will address whether it was "appropriate and necessary" to regulate toxic emissions from power plants and will reevaluate the standards set by the rule itself. On ~~December 27, 2018, EPA issued (but has not yet officially~~February 7, 2019, EPA published~~)~~ a proposed rule revising the "appropriate and necessary" finding regarding the MATS rule, concluding that it is not "appropriate and necessary" to regulate hazardous air pollution ("HAP") emissions from power plants under Section 112 of the CAA.[10] Specifically, EPA proposes to find that a "proper" consideration of costs demonstrates that the total cost of compliance with MATS is larger than the monetized HAP benefits of the rule, and thus MATS could not be considered "appropriate and necessary." Notwithstanding this revised finding, EPA is proposing that the MATS rule would remain in place, citing legal precedent in *New Jersey v. EPA*, 517 F.3d 574 (D.C. Cir. 2008), that a negative "appropriate and

[10] See https://www.epa.gov/sites/production/files/2018-12/documents/frnmatsfindingandrtr_12_2018wdisc.pdf.

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necessary" finding cannot by itself remove a source category from regulation. In the proposed new finding, EPA would not remove or "de-list" coal- and oil-fired power plants from the list of affected source categories for regulation under CAA Section 112 and would leave MATS in place. The proposal also addresses the CAA requirement for EPA to conduct a residual risk and technology review for power plants, which is due for completion by 2020. EPA's proposal concludes that (i) the residual risks due to emissions of air toxics from power plants are acceptable and the current standards (*i.e.*, MATS) provide an ample margin of safety to protect public health; and (ii) no new developments in HAP emission controls to achieve further cost-effective emissions reductions were identified under the technology review. Therefore, EPA is proposing that revisions to tighten the limits imposed under MATS are not warranted at this time. EPA will accept public comment on the proposal ~~for 60 days following official publication of the proposal in the *Federal Register*~~ through April 8, 2019. A final rule on this proposal could be issued later this year.

18. On December 1, 2015, the Company filed with the Commission a motion to extend the date for completion and placement in service of the Certificated Project to the date twenty (20) months after the date on which the Corps issues a construction permit for the Certificated Project. On December 22, 2015, the Commission issued an Order granting the Company's motion to extend.

Plans for Maintaining System Reliability in the North Hampton Roads Area

19. In order to ensure reliability for the Peninsula while the Surry-Skiffes Creek Line is being constructed, the Company is conducting a rigorous inspection and maintenance program ("Inspection Program"). The focus of the Inspection Program is transmission lines and stations for assets that directly serve the Peninsula. This includes, but is not limited to, the lines and stations

from Chickahominy east to Newport News, as well as lines from Surry and Chuckatuck that feed into the southern end of the Peninsula. The Inspection Program focuses on the human performance factor that will be emphasized consistently over the work period to ensure the Electric Transmission and Station workforce involved in supporting the assets on the Peninsula are cognizant of the ongoing construction. The Inspection Program will also consist of a complete evaluation of all abnormal equipment logs that require equipment maintenance or replacement in order to ensure that all equipment is in-service, and infrared reviews of stations and transmission lines prior to and during long critical outages to identify any weak links in the system that need attention to prevent unplanned outage events. More frequent aerial and foot patrols of transmission lines and stations will also be incorporated into the Inspection Program. Lastly, the outages required to address any outstanding equipment issues will be scheduled around the necessary planned outages to support the construction of the Certificated Project to limit the overall system exposure.

20. Additional inspection and maintenance work that is currently being conducted as part of the Inspection Program includes performing substation inspections quarterly; augmenting quarterly inspections with Technical Oversight Inspections of select stations; increasing infrared inspections of affected substations; performing infrared inspections every two weeks if load exceeds 18,000 MW; and reviewing all Corrective & Preventative Maintenance orders for substation equipment and relay systems to ensure they are completed or can be deferred during construction of the Certificated Project.

21. Foundation work on the existing transmission lines at the James River Bridge was completed at the end of 2015. Additional inspection and maintenance work also was performed prior to construction of the Certificated Project. This additional future work under the Inspection

Program included the following: all line switches were inspected and any necessary maintenance performed; all questionable compression conductor connections were inspected and any necessary repairs were made prior to commencement of work; one month prior to beginning work, a foot patrol was done on the four 230 kV lines serving the Peninsula, and any issues found were corrected prior to commencement of work; one week prior to beginning work, an aerial patrol was done on the four 230 kV lines serving the Peninsula, and any issues found were corrected prior to commencement of work; and bi-weekly aerial patrols will be done throughout the construction of the Certificated Project on these four 230 kV lines to identify any issues that may have surfaced since the previous patrol. The bi-weekly aerial patrols will specifically look for equipment integrity issues identified through visual inspection, corona camera, and infrared camera; and any third-party work on or near the right-of-way with a potential threat to the lines, which will be identified and addressed accordingly.

22. The plan for maintaining system reliability for the Peninsula will include careful planning of transmission outages and minimum work on assets on the Peninsula while the planned outages to support the construction of the Certificated Project are underway. Under some unplanned event scenarios, the reliability plan must include shedding of load in the amounts necessary to reduce stress on the system below critical demand levels. The shedding of load could occur in some instances at system load levels well below peak demand levels, on the order of 16,000 MW or higher. The exact system load level, load shed amounts and locations will be dependent on the circumstances that exist on the system at the time.

23. To minimize the potential for cascading outages to occur due to the unavailability of Yorktown Units 1 and 2 and until the proposed Skiffes Creek Project is in service, the Company has sought and received approval from SERC Reliability Corporation and PJM to install a

Remedial Action Scheme ("RAS") beginning April of 2017. The RAS will reduce the likelihood of cascading outages from occurring by removing from service approximately 150,000 customers on the Peninsula, but would only be activated if certain contingency conditions occur. The RAS will take less than one second to make this determination and actually remove from service the affected customers. In the event the RAS is activated, the Company and PJM's System Operators may initiate rotating outages on the Peninsula until the transmission system can be returned to a normal state. Notwithstanding the installation of the RAS, the Company is continuing to evaluate temporary measures for managing system operating conditions in order to minimize the need to activate the RAS.

24. The Company will continue to report to the Commission material developments of its plans for maintaining system reliability on the schedule set forth in the Order Directing Updates.

Respectfully submitted,

VIRGINIA ELECTRIC AND POWER COMPANY

By:______________________________

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Counsel for Virginia Electric and Power Company

February ~~6,~~27, 2019

190230236

CERTIFICATE OF SERVICE

I hereby certify that on this 27th day of February, 2019, copies of the foregoing were hand delivered, electronically mailed, and/or mailed first class postage prepaid to:

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DOMINION ENERGY NORTH CAROLINA
Docket No. E-22, Sub 562
CALCULATION OF ANNUITY FACTOR FOR EDIT
LIABILITY RIDER
For the Test Year Ended December 31, 2018

Boswell Exhibit I
Schedule 1(a)

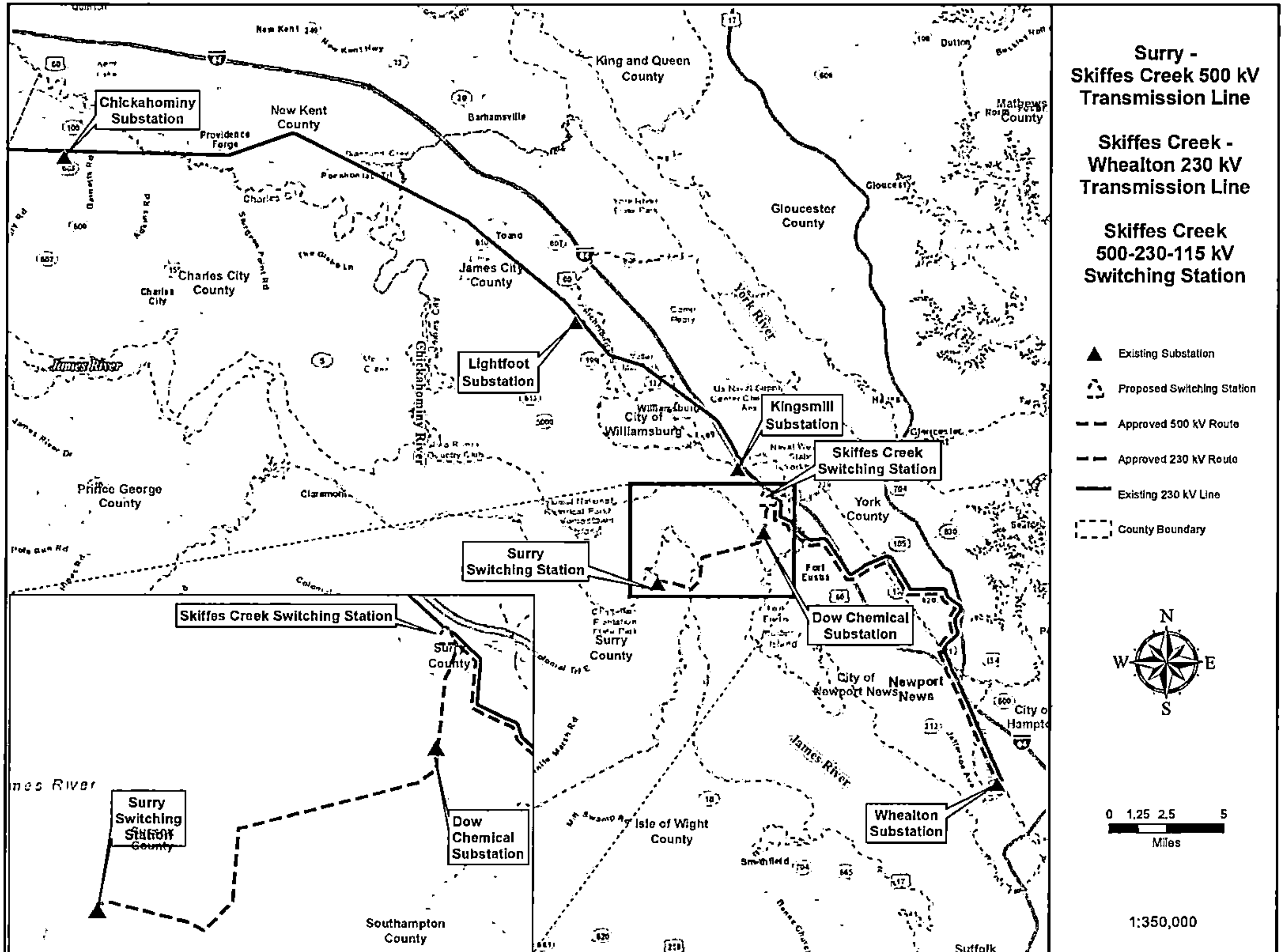
Line No.	Item	Amount	
	Annuity Factor		
1	Number of years	5	1/
2	Payment per period	1	
3	After tax rate of return (L9)	6.150%	
4	Present value of 1 dollar over number of years with with 1 payment per year	4.1952	
5	1 plus (interest rate divided by two)	1.0308	
6	Annuity factor (L4 x L5)	4.3244	

Line No.		Capital Structure (a)	Cost Rates (b)	Overall Rate of Return 6/ (c)	Net of Tax Rate (d)
	After Tax Rate of Return				
7	Long-term debt	50.00% 2/	4.44% 4/	2.22%	1.65% 7/
8	Common equity	50.00% 3/	9.00% 5/	4.50%	4.500% 8/
9	Total	100.00%		6.72%	6.150%

1/ Rider period recommended by Public Staff.
2/ Johnson Exh bit I, Schedule 1-2, Column (a), Line 2.
3/ Johnson Exh bit I, Schedule 1-2, Column (a), Line 3.
4/ Johnson Exh bit I, Schedule 1-2, Column (b), Line 2.
5/ Johnson Exh bit I, Schedule 1-2, Column (b), Line 3.
6/ Column (a) times Column (b).
7/ Column (c) times 1 minus the composite income tax rate of 25.6228%.
8/ Amount from Column (c).

Public Staff - D. Williamson Exhibit #1
Docket No. E-22, Sub 562

I/A



I/A

Public Staff - D. Williamson Exhibit # 2
Docket No. E-22, Sub 562

DOMINION ENERGY VIRGINIA ANNUAL PROJECT COST REPORT
REPORTING PERIOD ENDING 06/30/2019

PROJECT DESCRIPTION						
SCC Case Number	DEV Project Number	PJM RTEP #	Project Description	Construction Start Date	In-Service Date Identified in Final Order	Current In-Service Date
PUE-2012-00029	992245	b1905.1-b1905.9	Surry-Skiffes Creek-Whealton	October 2013	12/31/2015	2/26/2019

Please Note: 'Construction', and 'Material', and 'Other (Army Corps MOA)' columns are highlighted

ACTUAL/ESTIMATED COSTS ($)												
	Construction	Removal**	Engineering Services	Material	Land & Land Rights	Support Services	Other (Army Corps MOA)	Salvage	Project Costs Prior to AFE Approval	Total	TOTAL COST VARIANCE	COMMENTS/REASON FOR DEVIATIONS EXCEEDING +/-10%
SCC Application Filed Cost (a)	$64,540,515	$3,797,217	$2,456,838	$73,449,943	$636,903	$6,063,258	$0	-$344,673		$150,600,000		
Final Order Cost Estimate (b)	$64,540,515	$3,797,217	$2,456,838	$73,449,943	$636,903	$6,063,258	$0	-$344,673		$150,600,000	$0	U.S. Army Corps of Engineers federal permit delay and associated costs, including mitigation
Updated Estimate (c) 2018YE	$95,888,924	$5,375,609	$5,885,432	$98,175,026	$4,857,618	$20,057,460	$95,247,875	-$487,944		$325,000,000	$174,400,000	
Updated Estimate (c) 2019YE	$167,085,586	$3,797,217	$7,138,498	$112,967,341	$5,055,318	$33,922,076	$105,378,637	-$344,673		$435,000,000	$110,000,000	
Actual Expenditure to date (d)	$171,711,768	$1,355,140	$7,498,206	$112,556,412	$5,073,168	$32,917,195	$105,611,862	-$222,355	$2,128,021	$438,629,417	*Upon Project completion, calculated as (d) - (b)*	

** cost of removal stated on this report with 2018YE actual costs to accommodate a conversion in Fixed Asset reporting software. All other costs are stated through the defined reporting period ending.

List of overheads included in the conceptual estimate(s) identified above:

Conceptual estimate predates current estimating software. Below is a representative list of overheads.

VA Power Labor Surcharge, VA Power Labor AFUDC, DTECH Labor Surcharges, DTECH Labor AFUDC, Lump Sum Labor Surcharges, Lump Sum Labor AFUDC, External/Contractor Labor Surcharge, External/Contractor Labor AFUDC, Contractor Supplied Material Sales Tax, Contractor Supplied Material Surcharges, Contractor Supplied Material AFUDC, Stock Material Sales Tax, Stock Material Surcharge, Stock Material AFUDC, Non Stock Material Sales Tax, Non Stock Material Surcharges, Non Stock Material AFUDC, Equipment Surcharges, Equipment AFUDC, Other/Misc AFUDC

List of overheads in any updated estimate and the actual costs, if different from the Final Order Cost estimate

N/A

The total amount (total dollars) of contingency included in the conceptual estimates identified above

Unavailable, see above. For projects of this vintage, estimates typically included 10% to accommodate detailed design and contingency.

DEFINITIONS:

Construction	Cost of construction labor and equipment (DEV and Contractor)
Removal	Cost to remove any existing facilities, e.g. in rebuild projects.
Engineering Services	Cost of any necessary engineering services, such as substation engineering or transmission engineering.
Material	Cost of material ordered for the project.
Land & Land Rights	Cost of acquiring easements, rights-of-way, forestry (e.g. danger tree clearance rights), or other land-related costs
Support Services	Cost of project management and various other groups that provide support services such as Siting, Permitting, Legal, and Encroachment Management. Includes DEV and Contractors
Salvage	Compensation received for any salvage, such as scrap value for tower steel, conductors and transformer oil
Project Costs Prior to AFE Approval	Funds spent prior to internal authorization for expenditure (primarily conceptual design costs).
Total	Sum of all cost categories above.
SCC Application Filed Cost	Estimated Project cost stated in Application. May be different from Final Order cost
Final Order Cost Estimate	Estimated Project cost based on Final Order.
Updated Estimate	Updated costs as at the end of the reporting period, caused by factors such as scope change, higher-than-estimated contractor costs, increases in land acquisition costs, or other unforeseen circumstances
Total Cost Variance	Cost Difference between Final Order Cost and either the Updated Estimate, the SCC Application Filed Cost, or the final Project cost once the project is completed.
Comments/Reasons for Deviations exceeding +/-10%	To be provided only if the Total Cost Variance between Final Order Cost and Updated Estimate (or final cost upon Project completion) exceeds +/-10% of the Final Order Cost Estimate.
Contingency adders	Specific categories of markup to allow for inherent unknowns causing cost increases (e.g. weather-related construction delays)

I/A

Docket No. E-22, Sub 562
Nucor Exhibit JMT-2

CALCULATION OF 1-CP ALLOCATION FACTOR 1

JURISDICTIONAL 1-CP ALLOCATOR

Line No.	Item	Total System	Virginia Jurisdiction	Virginia Non-Juris.	FERC	NC Jurisdiction
(a)	(b)	(c)	(d)	(e)	(f)	(g)
1	Winter Coincident Peak	17,887,645	15,142,090	1,574,418	235,220	935,916
2	North Anna	1,052,204	890,703	92,612	13,836	55,053
3	Peak Demand Less North Anna	16,835,441	14,251,387	1,481,806	221,384	880,863
4	**Factor 1 (1-CP)**	**1.000000**	**0.846511**	**0.088017**	**0.013150**	**0.052322**

CLASS 1-CP ALLOCATOR

Line No.	Item	NC Total	Residential	SGS Co & Muni	LGS	6VP	NS	ST & OL	Traffic Lts
(a)	(b)								
5	Winter Coincident Peak	935,916	670,355	136,647	63,415	27,528	37,906	-	64
6	**Factor 1 (1-CP)**	**1.000000**	**0.716256**	**0.146004**	**0.067757**	**0.029413**	**0.040501**	-	**0.000069**

I/A

Docket No. E-22, Sub 562
Nucor Exhibit JMT-3

SUMMARY OUTPUT OF COST OF SERVICE MODEL
1-CP ALLOCATION OF PRODUCTION AND TRANSMISSION PLANT AND EXPENSES
REVENUE INCREASES COMPUTED TO ACHIEVE COMPANY RECOMMENDED ROR INDEX FOR EACH CLASS

PER BOOKS CLASS RATE OF RETURNS - FROM ITEM 45a

	North Carolina Juris Amount	Residential	SGS, County, & Muni	Large General Service	Schedule NS	6VP	Street & Outdoor Lights	Traffic Lights
Adjusted NOI	$73,230,462	$24,369,408	$19,725,054	$12,295,192	$12,067,592	$4,084,422	$675,681	$13,111
Rate Base	$1,220,893,345	$780,453,105	$199,875,297	$101,876,813	$78,145,028	$41,157,612	$19,233,807	$151,683
ROR	5.9981%	3.1225%	9.8687%	12.0687%	15.4426%	9.9239%	3.5130%	8.6438%
Index		0.52	1.65	2.01	2.57	1.65	0.59	1.44

PER BOOKS CLASS RATE OF RETURNS WITH ANNUALIZED REVENUE - FROM ITEM 45b

	North Carolina Juris Amount	Residential	SGS, County, & Muni	Large General Service	Schedule NS	6VP	Street & Outdoor Lights	Traffic Lights
Adjusted NOI	$78,780,972	$29,654,560	$20,053,682	$12,464,804	$11,526,878	$4,300,092	$768,664	$12,292
Rate Base	$1,220,893,345	$780,453,105	$199,875,297	$101,876,813	$78,145,028	$41,157,612	$19,233,807	$151,683
ROR	6.4527%	3.7997%	10.0331%	12.2352%	14.7506%	10.4479%	3.9964%	8.1037%
Index		0.63	1.67	2.04	2.46	1.74	0.67	1.35

CLASS RATE OF RETURNS AFTER ALL RATEMAKING ADJUSTMENTS BEFORE REVENUE INCREASE - FROM ITEM 45c, COL. 3

	North Carolina Juris Amount	Residential	SGS, County, & Muni	Large General Service	Schedule NS	6VP	Street & Outdoor Lights	Traffic Lights
Adjusted NOI	$69,610,333	$20,314,210	$18,325,045	$13,740,138	$11,787,197	$4,818,210	$613,090	$12,444
Rate Base	$1,173,317,884	$772,512,502	$188,621,596	$91,964,212	$64,093,372	$37,440,098	$18,541,967	$144,137
ROR	5.9328%	2.6296%	9.7152%	14.9407%	18.3907%	12.8691%	3.3065%	8.6331%
Index		0.44	1.64	2.52	3.10	2.17	0.56	1.46

CLASS RATE OF RETURNS AFTER ALL RATEMAKING ADJUSTMENTS AND AFTER REVENUE INCREASE TO MATCH ROR INDEX RECOMMENDATION FROM DENC

	North Carolina Juris Amount	Residential	SGS, County, & Muni	Large General Service	Schedule NS	6VP	Street & Outdoor Lights	Traffic Lights
Revenue Increase	$30,015,216	$51,927,500	($1,829,000)	($7,560,000)	($10,445,800)	($2,408,800)	$332,150	($834)
Adjusted NOI	$91,814,304	$58,727,949	$16,972,030	$8,147,574	$4,059,842	$3,036,283	$858,800	$11,827
Rate Base	$1,178,053,693	$774,775,943	$189,482,644	$92,577,386	$64,824,868	$37,687,425	$18,561,065	$144,362
ROR	7.7937%	7.5800%	8.9570%	8.8008%	6.2628%	8.0565%	4.6269%	8.1923%
Index		0.97	1.15	1.13	0.80	1.03	0.59	1.05

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Docket No. E-22, Sub 562
Nucor Exhibit JMT-4

CALCULATION OF RE-WEIGHTED ALLOCATION FACTOR 1
(Weight = 60% S/W Demand and 40% Average Demand)

JURISDICTIONAL RE-WEIGHT SWPA ALLOCATOR

Line No.	Item	Total System	Virginia Jurisdiction	Virginia Non-Juris.	FERC	NC Jurisdiction
(a)	(b)	(c)	(d)	(e)	(f)	(g)
1	Energy - Production	89,918,644	71,450,024	12,258,874	1,630,688	4,579,058
2	Average Demand	10,264,685	8,156,395	1,399,415	186,152	522,723
3	North Anna	603,800	479,784	82,318	10,950	30,748
4	Avg. Demand Less North Anna	9,660,885	7,676,611	1,317,097	175,202	491,975
5	Winter Coincident Peak	17,887,645	15,142,090	1,574,418	235,220	935,916
6	Summer Coincident Peak	16,958,384	14,061,656	1,881,941	296,382	718,405
7	Average CP Demand	17,423,014	14,601,873	1,728,180	265,801	827,161
8	North Anna	1,024,874	858,926	101,657	15,635	48,656
9	Avg. Peak Demand Less North Anna	16,398,140	13,742,947	1,626,523	250,166	778,505
10	Unweighted Average Demand Factor	1.000000	0.794607	0.136333	0.018135	0.050924
11	System Load Factor	40.0000%				
12	Weighted Average Demand Factor	0.400000	0.317843	0.054533	0.007254	0.020370
13	Unweighted Peak Demand Factor	1.000000	0.838080	0.099189	0.015256	0.047475
14	1 Minus System Load Factor	60.0000%				
15	Weighted Peak Demand Factor	0.600000	0.502848	0.059514	0.009153	0.028485
16	**Factor 1 (Re-weighted SWPA)**	**1.000000**	**0.820691**	**0.114047**	**0.016408**	**0.048855**

CLASS RE-WEIGHTED SWPA ALLOCATOR

Line No.	Item	NC Total	Residential	SGS Co & Muni	LGS	6VP	NS	ST & OL	Traffic Lts
(a)	(b)								
17	Energy - Production	4,579,058	1,781,071	873,326	686,156	280,465	932,119	25,368	552
18	Average Demand	522,723	203,319	99,695	78,328	32,017	106,406	2,896	63
19	North Anna								
20	Avg. Demand Less North Anna	522,723	203,319	99,695	78,328	32,017	106,406	2,896	63
21	Winter Coincident Peak	935,916	670,355	136,647	63,415	27,528	37,906	-	64
22	Summer Coincident Peak	718,405	395,218	161,872	89,165	26,053	46,035	-	62
23	Average CP Demand	827,161	532,787	149,260	76,290	26,791	41,970	-	63
24	North Anna								
25	Avg. Peak Demand Less North Anna	827,161	532,787	149,260	76,290	26,791	41,970	-	63
26	Unweighted Average Demand Factor	1.000000	0.388960	0.190722	0.149846	0.061250	0.203561	0.005540	0.000121
27	System Load Factor	40.0000%							
28	Weighted Average Demand Factor	0.316311	0.155584	0.076289	0.059939	0.024500	0.081425	0.002216	0.000048
29	Unweighted Peak Demand Factor	1.000000	0.644115	0.180448	0.092231	0.032389	0.050740	-	0.000076
30	1 Minus System Load Factor	60.0000%							
31	Weighted Peak Demand Factor	0.569510	0.386469	0.108269	0.055339	0.019433	0.030444	-	0.000046
32	**Factor 1 (Re-weighted SWPA)**	**1.000000**	**0.542053**	**0.184558**	**0.115277**	**0.043933**	**0.111868**	**0.002216**	**0.000094**

Docket No. E-22, Sub 562
Nucor Exhibit JMT-5

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SUMMARY OUTPUT OF COST OF SERVICE MODEL
RE-WEIGHTED SWPA ALLOCATION OF PRODUCTION AND TRANSMISSION PLANT AND EXPENSES
REVENUE INCREASES COMPUTED TO ACHIEVE COMPANY RECOMMENDED ROR INDEX FOR EACH CLASS

PER BOOKS CLASS RATE OF RETURNS - FROM ITEM 45a

	North Carolina Juris Amount	Residential	SGS, County, & Muni	Large General Service	Schedule NS	6VP	Street & Outdoor Lights	Traffic Lights
Adjusted NOI	$77,014,241	$37,857,678	$17,891,946	$9,611,679	$7,805,742	$3,297,486	$537,886	$11,823
Rate Base	$1,185,825,943	$661,654,237	$215,490,629	$125,053,960	$115,099,776	$47,933,392	$20,431,223	$162,726
ROR	6.4946%	5.7217%	8.3029%	7.6860%	6.7817%	6.8793%	2.6327%	7.2658%
Index		0.88	1.28	1.18	1.04	1.06	0.41	1.12

PER BOOKS CLASS RATE OF RETURNS WITH ANNUALIZED REVENUE - FROM ITEM 45b

	North Carolina Juris Amount	Residential	SGS, County, & Muni	Large General Service	Schedule NS	6VP	Street & Outdoor Lights	Traffic Lights
Adjusted NOI	$82,469,626	$41,793,995	$18,490,128	$10,124,203	$7,785,850	$3,617,107	$647,161	$11,181
Rate Base	$1,185,825,943	$661,654,237	$215,490,629	$125,053,960	$115,099,776	$47,933,392	$20,431,223	$162,726
ROR	6.9546%	6.3166%	8.5805%	8.0959%	6.7644%	7.5461%	3.1675%	6.8712%
Index		0.97	1.32	1.25	1.04	1.16	0.49	1.06

CLASS RATE OF RETURNS AFTER ALL RATEMAKING ADJUSTMENTS BEFORE REVENUE INCREASE - FROM ITEM 45c, COL. 3

	North Carolina Juris Amount	Residential	SGS, County, & Muni	Large General Service	Schedule NS	6VP	Street & Outdoor Lights	Traffic Lights
Adjusted NOI	$73,222,525	$32,176,232	$16,798,578	$11,457,692	$8,137,846	$4,152,917	$487,927	$11,333
Rate Base	$1,134,867,439	$640,372,162	$206,158,330	$117,893,941	$105,387,331	$45,028,862	$19,870,322	$156,491
ROR	6.4521%	5.0246%	8.1484%	9.7186%	7.7218%	9.2228%	2.4556%	7.2418%
Index		0.78	1.26	1.51	1.20	1.43	0.38	1.12

CLASS RATE OF RETURNS AFTER ALL RATEMAKING ADJUSTMENTS AND AFTER REVENUE INCREASE TO MATCH ROR INDEX RECOMMENDATION FROM DENC

	North Carolina Juris Amount	Residential	SGS, County, & Muni	Large General Service	Schedule NS	6VP	Street & Outdoor Lights	Traffic Lights
Revenue Increase	$21,207,388	$22,336,500	$2,362,000	($1,385,000)	($2,011,100)	($681,600)	$584,550	$2,038
Adjusted NOI	$88,910,841	$48,699,817	$18,545,885	$10,433,128	$6,650,120	$3,648,699	$920,352	$12,840
Rate Base	$1,139,603,248	$642,477,762	$207,053,337	$118,550,004	$106,184,454	$45,289,523	$19,891,432	$156,735
ROR	7.8019%	7.5800%	8.9571%	8.8006%	6.2628%	8.0564%	4.6269%	8.1924%
Index		0.97	1.15	1.13	0.80	1.03	0.59	1.05

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Docket No. E-22, Sub 562
Nucor Exhibit JMT-6

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SUMMARY OUTPUT OF COST OF SERVICE MODEL
EQUALLY WEIGHTED SWPA ALLOCATION OF PRODUCTION AND TRANSMISSION PLANT AND EXPENSES*
REVENUE INCREASES COMPUTED TO ACHIEVE COMPANY RECOMMENDED ROR INDEX FOR EACH CLASS

PER BOOKS CLASS RATE OF RETURNS - FROM ITEM 45a

	North Carolina Juris Amount	Residential	SGS, County, & Muni	Large General Service	Schedule NS	6VP	Street & Outdoor Lights	Traffic Lights
Adjusted NOI	$76,656,010	$39,251,315	$17,761,925	$9,211,798	$6,814,604	$3,102,148	$502,679	$11,541
Rate Base	$1,189,143,756	$649,645,081	$216,658,664	$128,554,663	$123,741,346	$49,640,951	$20,737,850	$165,201
ROR	6.4463%	6.0420%	8.1981%	7.1657%	5.5071%	6.2492%	2.4240%	6.9860%
Index		0.94	1.27	1.11	0.85	0.97	0.38	1.08

PER BOOKS CLASS RATE OF RETURNS WITH ANNUALIZED REVENUE - FROM ITEM 45b

	North Carolina Juris Amount	Residential	SGS, County, & Muni	Large General Service	Schedule NS	6VP	Street & Outdoor Lights	Traffic Lights
Adjusted NOI	$82,120,867	$43,004,940	$18,369,414	$9,767,828	$6,908,273	$3,443,428	$616,054	$10,929
Rate Base	$1,189,143,756	$649,645,081	$216,658,664	$128,554,663	$123,741,346	$49,640,951	$20,737,850	$165,201
ROR	6.9059%	6.6198%	8.4785%	7.5982%	5.5828%	6.9367%	2.9707%	6.6157%
Index		1.03	1.32	1.18	0.87	1.08	0.46	1.03

CLASS RATE OF RETURNS AFTER ALL RATEMAKING ADJUSTMENTS BEFORE REVENUE INCREASE - FROM ITEM 45c, COL. 3

	North Carolina Juris Amount	Residential	SGS, County, & Muni	Large General Service	Schedule NS	6VP	Street & Outdoor Lights	Traffic Lights
Adjusted NOI	$72,881,388	$33,358,081	$16,680,542	$11,109,408	$7,280,862	$3,983,229	$458,177	$11,089
Rate Base	$1,138,521,958	$626,939,039	$207,453,095	$121,795,994	$115,028,770	$46,932,780	$20,213,030	$159,250
ROR	6.4014%	5.3208%	8.0406%	9.1213%	6.3296%	8.4871%	2.2667%	6.9634%
Index		0.83	1.26	1.42	0.99	1.33	0.35	1.09

CLASS RATE OF RETURNS AFTER ALL RATEMAKING ADJUSTMENTS AND AFTER REVENUE INCREASE TO MATCH ROR INDEX RECOMMENDATION FROM DENC

	North Carolina Juris Amount	Residential	SGS, County, & Muni	Large General Service	Schedule NS	6VP	Street & Outdoor Lights	Traffic Lights
Revenue Increase	$21,958,113	$19,360,000	$2,678,500	($449,300)	($35,400)	($244,600)	$646,240	$2,673
Adjusted NOI	$89,125,059	$47,679,779	$18,661,981	$10,777,035	$7,254,675	$3,802,284	$936,238	$13,067
Rate Base	$1,143,257,767	$629,023,986	$208,348,929	$122,456,710	$115,838,276	$47,195,776	$20,234,592	$159,498
ROR	7.7957%	7.5800%	8.9571%	8.8007%	6.2628%	8.0564%	4.6269%	8.1923%
Index		0.97	1.15	1.13	0.80	1.03	0.59	1.05

* Model uses an SWPA factor in which the weighting is 50% on average demand and 50% on summer/winter peak demand.

DOMINION NORTH CAROLINA POWER
DOCKET NO. E-22, SUB 532
TWELVE MONTHS ENDED DECEMBER 31, 2015
SUMMARY NORTH CAROLINA JURISDICTION AND CUSTOMER CLASS RATES OF RETURN
PER BOOKS, ANNUALIZED, FULLY ADJUSTED AND FULLY ADJUSTED WITH INCREASE

PER BOOKS CLASS RATE OF RETURNS - FROM ITEM 45a

	North Carolina Juris. Amount	Residential	SGS, County & Muni	Large General Service	Sch. NS	6VP	Outdoor Street Lights	Traffic Lights
Adjusted NOI	$57,958,136	$31,327,939	$13,056,369	$2,554,171	$2,169,579	$7,509,639	$1,314,896	$15,343
Rate Base	$1,155,093,887	$607,105,199	$225,978,429	$149,387,074	$112,977,074	$41,553,266	$17,968,333	$124,511
ROR	5.02%	5.16%	5.78%	1.71%	1.92%	18.07%	7.32%	12.32%
Index		1.03	1.15	0.34	0.38	3.60	1.46	2.46

PER BOOKS CLASS RATE OF RETURNS WITH ANNUALIZED REVENUE - FROM ITEM 45b

	North Carolina Juris. Amount	Residential	SGS, County & Muni	Large General Service	Sch. NS	6VP	Outdoor Street Lights	Traffic Lights
Adjusted NOI	$57,698,203	$30,920,622	$12,702,920	$7,178,221	$2,280,319	$3,198,468	$1,402,762	$14,871
Rate Base	$1,155,093,887	$607,105,199	$225,978,429	$149,387,074	$112,977,074	$41,553,265	$17,968,333	$124,511
ROR	5.00%	5.09%	5.62%	4.81%	2.02%	7.70%	7.81%	11.94%
Index		1.02	1.12	0.96	0.40	1.53	1.56	2.38

CLASS RATE OF RETURNS AFTER ALL RATEMAKING ADJUSTMENTS BEFORE REVENUE INCREASE - FROM ITEM 45c, COL. 3

	North Carolina Juris. Amount	Residential	SGS, County & Muni	Large General Service	Sch. NS	6VP	Outdoor Street Lights	Traffic Lights
Adjusted NOI	$53,235,927	$26,960,155	$12,461,539	$7,220,649	$2,201,568	$3,103,319	$1,234,788	$13,769
Rate Base	$1,050,572,870	$551,149,948	$205,915,014	$136,435,038	$103,110,012	$37,883,240	$15,966,278	$113,340
ROR	5.07%	4.90%	6.06%	5.29%	2.14%	8.19%	7.73%	12.17%
Index		0.97	1.2	1.04	0.42	1.62	1.53	2.4

CLASS RATE OF RETURNS AFTER ALL RATEMAKING ADJUSTMENTS AND AFTER REVENUE INCREASE - FROM ITEM 45c, COLS. 4 & 5

	North Carolina Juris. Amount	Residential	SGS, County & Muni	Large General Service	Sch. NS	5VP	Outdoor Street Lights	Traffic Lights
Revenue Increase	$47,804,000	$26,765,115	$7,728,427	$5,464,758	$6,227,739	$796,979	$817,559	$3,423
Adjusted NOI	$82,311,597	$43,258,734	$17,163,402	$10,544,873	$5,886,011	$3,588,612	$1,732,092	$15,873
Rate Base	$1,054,930,870	$553,183,209	$206,777,054	$137,062,220	$103,677,613	$38,103,545	$16,013,324	$113,904
ROR	7.80%	7.82%	8.31%	7.69%	5.78%	9.42%	10.82%	13.94%
Index		1.00	1.07	0.99	0.74	1.21	1.39	1.79

4. Judgmental Energy Weightings

Some regulatory commissions, recognizing that energy loads are an important determinant of production plant costs, require the incorporation of judgmentally-established energy weighting into cost studies. One example is the "peak and average demand" allocator derived by adding together each class's contribution to the system peak demand (or to a specified group of system peak demands; e.g., the 12 monthly CPs) and its average demand. The allocator is effectively the average of the two numbers: class CP (however measured) and class average demand. Two variants of this allocation method are shown in Tables 4-14 and 4-15.

TABLE 4-14

CLASS ALLOCATION FACTORS AND ALLOCATED PRODUCTION PLANT REVENUE REQUIREMENT USING THE 1 CP AND AVERAGE DEMAND METHOD

Rate Class	Demand Allocation Factor - 1 CP MW (Percent)	Demand-Related Production Plant Revenue Requirement	Avg. Demand (Total MWH) Allocation Factor	Energy-Related Production Plant Revenue Requirement	Total Class Production Plant Revenue Requirement
DOM	34.84	233,869,251	30.96	120,512,062	354,381,313
LSMP	37.25	250,020,306	33.87	131,822,415	381,842,722
LP	24.63	165,313,703	31.21	121,450,476	286,764,179
AG&P	3.29	22,078,048	3.22	12,545,108	34,623,156
SL	0.00	0	0.74	2,864,631	2,864,631
TOTAL	100.00	671,281,308	100.00	389,194,692	$1,060,476,000

Notes: The portion of the production plant classified as demand-related is calculated by dividing the annual system peak demand by the sum of (a) the annual system peak demand, Table 4-3, column 2, plus (b) the average system demand for the test year, Table 4-10A, column 3. Thus, the percentage classified as demand-related is equal to 13591/(13591+7880), or 63.30 percent. The percentage classified as energy-related is calculated similarly by dividing the average demand by the sum of the system peak demand and the average system demand. For the example, this percentage is 36.70 percent.

Some columns may not add to indicated totals due to rounding.

TABLE 4-15

CLASS ALLOCATION FACTORS AND ALLOCATED PRODUCTION PLANT REVENUE REQUIREMENT USING THE 12 CP AND AVERAGE DEMAND METHOD

Rate Class	Demand Allocation Factor - 12 CP MW (Percent)	Demand-Related Production Plant Revenue	Average Demand (Total MWH) Allocation Factor	Energy-Related Production Plant Revenue Requirement	Total Class Production Plant Revenue Requirement
DOM	32.09	198,081,400	30.96	137,226,133	335,307,533
LSMP	38.43	237,225,254	33.87	150,105,143	387,330,397
LP	26.71	164,899,110	31.21	138,294,697	303,193,807
AG&P	2.42	14,960,151	3.22	14,285,015	29,245,167
SL	0.35	2,137,164	0.74	3,261,933	5,399,097
TOTAL	100.00	617,303,080	100.00	443,172,920	$1,060,476,000

Notes: The portion of production plant classified as demand-related is calculated by dividing the annual system peak demand by the sum of the 12 monthly system coincident peaks (Table 4-3, column 4) by the sum of that value plus the system average demand (Table 4-10A, column 3). Thus, for example, the percentage classified as demand-related is equal to 10976/(10976+7880), or 58.21 percent. The percentage classified as energy-related is calculated similarly by dividing the average demand by the sum of the average demand and the average of the twelve monthly peak demands. For the example, 41.79 percent of production plant revenue requirements are classified as energy-related.

Another variant of the peak and average demand method bases the production plant cost allocators on the 12 monthly CPs and average demand, with 1/13th of production plant classified as energy-related and allocated on the basis of the classes' KWH use or average demand, and the remaining 12/13ths classified as demand-related. The resulting allocation factors and allocations of revenue responsibility are shown in Table 4-16 for the example data.

TABLE 4-16

CLASS ALLOCATION FACTORS AND ALLOCATED PRODUCTION PLANT REVENUE REQUIREMENT USING THE 12 CP AND 1/13TH WEIGHTED AVERAGE DEMAND METHOD

Rate	Demand Allocation Factor - 12 CP MW (Percent)	Demand-Related Production Plant Revenue Requirement	Average Demand (Total MWH) Allocation Factor	Energy-Related Production Plant Revenue Requirement	Total Class Production Plant Revenue Requirement
DOM	32.09	314,111,612	30.96	25,259,288	339,370,900
LSMP	38.43	376,184,775	33.87	27,629,934	403,814,709
LP	26.71	261,492,120	31.21	25,455,979	286,948,099
AG&P	2.42	23,723,364	3.22	2,629,450	26,352,815
SL	0.35	3,389,052	0.74	600,426	3,989,478
TOTAL	100.00	978,900,923	100.00	81,575,077	$1,060,476,000

Notes: Using this method, 12/13ths (92.31 percent) of production plant revenue requirement is classified as demand-related and allocated using the 12 CP allocation factor, and 1/13th (7.69 percent) is classified as energy-related and allocated on the basis of total energy consumption or average demand.

Some columns may not add to indicated totals due to rounding.

C. Time-Differentiated Embedded Cost of Service Methods

Time-differentiated cost of service methods allocate production plant costs to baseload and peak hours, and perhaps to intermediate hours. These cost of service methods can also be easily used to allocate production plant costs to classes without specifically identifying allocation to time periods. Methods discussed briefly here include production stacking methods, system planning approaches, the base-intermediate-peak method, the LOLP production cost method, and the probability of dispatch method.

1. Production Stacking Methods

Objective: The cost of service analyst can use production stacking methods to determine the amount of production plant costs to classify as energy-related and to determine appropriate cost allocations to on-peak and off-peak periods. The basic

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Nucor
Data Request No. 2

The following response to Question No. 3 of Nucor Data Request No. 2, dated April 12, 2019 has been prepared under my supervision.

Horace P. Payne, Jr.
Assistant General Counsel

Question No. 3:

If Nucor were to relocate a portion (for example, twenty to forty percent) of Nucor Steel-Hertford's load from DENC's service territory, how would this impact the local community in northeastern North Carolina with regard to the multiplier effects (including the impact on local jobs, business revenues and tax revenues) resulting from Nucor's current load?

Response:

The Company recognizes Nucor as a valuable contributor to the economy in DENC's service territory and a valued customer but cannot speculate exactly how the relocation of any given percentage of its load would affect DENC's service territory.

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Nucor
Data Request No. 2

The following response to Question No. 4 of Nucor Data Request No. 2, dated April 12, 2019 has been prepared under my supervision.

Horace P. Payne, Jr.
Assistant General Counsel

Question No. 4:

If Nucor were to relocate a portion (for example, twenty to forty percent) of Nucor Steel-Hertford's load from DENC's service territory, how would this impact the state of North Carolina with regard to the multiplier effects (including the impact on local jobs, business revenues and tax revenues) resulting from Nucor's current load?

Response:

Similar to the Company's response to Question No. 3 of Nucor's Second Set, the Company recognizes Nucor as a valuable contributor to the economy in DENC's service territory and a valued customer but cannot speculate exactly how the relocation of any given percentage of its load would affect the state of North Carolina.

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Data Request No. 2

The following response to Question No. 17 of Nucor Data Request No. 2, dated April 12, 2019 has been prepared under my supervision.

Robert C. Rice FOR
Paul B. Haynes
Director - Regulation

Question No. 17:

In allocating generation-related capacity costs to a jurisdiction or intra-class, does the SWPA cost allocation method give equal weight to (1) peak load(s), and (2) energy consumption?

Response:

No, this is not the case for the 2018 test period. If the system load factor had been 50%, then the answer to this question would be yes. However, the system load factor was 58.9145%. The energy portion of the allocation factor was weighted by the system load factor, and the peak demand portion of the allocation factor was weighted by (1 minus the system load factor).

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Data Request No. 2

The following response to Question No. 21 of Nucor Data Request No. 2, dated April 12, 2019 has been prepared under my supervision.

Katherine Farmer
Senior Financial Analyst Specialist

Question No. 21

Does DENC invest in generation primarily in order to serve its annual or seasonal peak load(s)? Explain your answer in detail.

Response:

The Company invests in generation to provide reliable electric service during all seasons. These investments help the Company meet its electric service obligations and manage the capacity performance risk in the PJM capacity market.

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Nucor
Data Request No. 4

The following response to Question No. 2 of Nucor Data Request No. 4, dated May 17, 2019 has been prepared under my supervision.

Paul B. Haynes
Paul B. Haynes
Director – Regulation
Dominion Energy Services, Inc.

Question No. 2:

Regarding DENC's response to NUC-2-27, the Company responded that "the allocation of rate base to the Schedule NS class would decline under a 1 CP methodology thereby increasing the class' ROR." Is it accurate to state that using the SWPA methodology instead of the 1 CP methodology has, or almost certainly has, a greater negative impact on Schedule NS (i.e., the allocation of rate base to Schedule NS increases) than on any other class of customers?

Response:

The use of the 1 CP methodology considers customer class loads during the 1 hour of the year when the Company's power supply obligation is the highest for the entire system. During this hour, the Company provided Nucor a price signal and request to curtail its furnace load under its current contract.

The use of the SWPA methodology considers customer class usage not only during the 1 hour of the year when the Company's power supply obligation is the highest, but also considers the other 8,759 hours in which the Company has a power supply obligation. The SWPA methodology's consideration of all other hours, many of which Nucor's load has not been requested to be curtailed, does result in a greater allocation of power supply plant costs and related expenses to the Schedule NS class than the 1 CP method.

In terms of whether the Schedule NS class receives a greater relative allocation of cost under the SWPA methodology as compared to the 1 CP methodology, than any other class of customers, there is a greater negative relative cost impact, in terms of percentage, in the allocation of production plant cost to the street and outdoor lighting class. The Schedule NS class has the second most significant relative cost impact between use of the SWPA methodology, as proposed by the Company in this proceeding, and the 1 CP methodology.

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Nucor
Data Request No. 6

The following response to Question No. 10 of Nucor Data Request No. 6, dated July 9, 2019 has been prepared under my supervision.

Paul B. Haynes for
Robert C. Rice
Manager – Regulation
Dominion Energy Services, Inc.

Question No. 10:

What is the size of the Schedule NS load relative to DENC's total load?

Response:

The Company is providing 2018 data due to the time provided for the response. Nucor can derive the pre-2018 data using the model provided in this response. For purposes of this data request the Company is defining "load" as generation supply load or Factor 1. For supporting data for this response see Attachment Nucor Set 3-6 which is a spreadsheet with formulas intact. The data for this response is found next to Factor 1 on the NC CLASS tab. The size of the Schedule NS load relative to DENC's retail load is 20.1216% for Energy and 4.0136% for Demand.

2013													
20	21	22	23	24	25	26	27	28	29	30	31		
Jan.	Feb.	March	April	May	June	July	Aug.	Sept.	Oct.	Nov.	Dec.	Total	
-	-	-	-	-	-	-	-	-	-	-	-	1,028,025	
615	615	615	615	615	615	615	615	615	615	615	615		31
9,146	9,146	9,146	9,146	9,146	9,146	9,146	9,146	9,146	9,146	9,146	9,146		30
10,714	10,714	10,714	10,714	10,714	10,714	10,714	10,714	10,714	10,714	10,714	10,714		29
14,154	14,154	14,154	14,154	14,154	14,154	14,154	14,154	14,154	14,154	14,154	14,154		28
12,526	12,526	12,526	12,526	12,526	12,526	12,526	12,526	12,526	12,526	12,526	12,526		27
21,770	21,770	21,770	21,770	21,770	21,770	21,770	21,770	21,770	21,770	21,770	21,770		26
16,744	16,744	16,744	16,744	16,744	16,744	16,744	16,744	16,744	16,744	16,744	16,744		25
-	-	-	-	-	-	-	-	-	-	-	-		24
-	-	-	-	-	-	-	-	-	-	-	-		23
-	-	-	-	-	-	-	-	-	-	-	-		22
-	-	-	-	-	-	-	-	-	-	-	-		21
-	-	-	-	-	-	-	-	-	-	-	-		20
-	-	-	-	-	-	-	-	-	-	-	-		19
-	-	-	-	-	-	-	-	-	-	-	-		18
-	-	-	-	-	-	-	-	-	-	-	-		17
-	-	-	-	-	-	-	-	-	-	-	-		16
-	-	-	-	-	-	-	-	-	-	-	-		15
-	-	-	-	-	-	-	-	-	-	-	-		14
-	-	-	-	-	-	-	-	-	-	-	-		13
85,669	85,669	85,669	85,669	85,669	85,669	85,669	85,669	85,669	85,669	85,669	85,669		

2014													
32	33	34	35	36	37	38	39	40	41	42	43		
Jan.	Feb.	March	April	May	June	July	Aug.	Sept.	Oct.	Nov.	Dec.		Total
-	-	-	-	-	-	-	-	-	-	-	-		1,028,025
615	615	615	615	615	615	615	615	615	615	615	615	43	
9,146	9,146	9,146	9,146	9,146	9,146	9,146	9,146	9,146	9,146	9,146	9,146	42	
10,714	10,714	10,714	10,714	10,714	10,714	10,714	10,724	10,714	10,714	10,714	10,714	41	
14,154	14,154	14,154	14,154	14,154	14,154	14,154	14,154	14,154	14,154	14,154	14,154	40	
12,526	12,526	12,526	12,526	12,526	12,526	12,526	12,526	12,526	12,526	12,526	12,526	39	
21,770	21,770	21,770	21,770	21,770	21,770	21,770	21,770	21,770	21,770	21,770	21,770	38	
16,744	16,744	16,744	16,744	16,744	16,744	16,744	16,744	16,744	16,744	16,744	16,744	37	
-	-	-	-	-	-	-	-	-	-	-	-	36	
-	-	-	-	-	-	-	-	-	-	-	-	35	
-	-	-	-	-	-	-	-	-	-	-	-	34	
-	-	-	-	-	-	-	-	-	-	-	-	33	
-	-	-	-	-	-	-	-	-	-	-	-	32	
-	-	-	-	-	-	-	-	-	-	-	-	31	
-	-	-	-	-	-	-	-	-	-	-	-	30	
-	-	-	-	-	-	-	-	-	-	-	-	29	
-	-	-	-	-	-	-	-	-	-	-	-	28	
-	-	-	-	-	-	-	-	-	-	-	-	27	
-	-	-	-	-	-	-	-	-	-	-	-	26	
-	-	-	-	-	-	-	-	-	-	-	-	25	
85,669	85,669	85,669	85,669	85,669	85,669	85,669	85,669	85,669	85,669	85,669	85,660		

Actual kWh (Jan. - Dec., 2013): 1,028,025

Actual kWh (Jan. - Dec., 2014): 1,028,025

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	0	0
0	0	0	0	0	0	0	0	0	0	0	0	0
												0%

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Company Supplemental Exhibit DRK-1
Schedule 1

2015													2016												
44	45	46	47	48	49	50	51	52	53	54	55		56	57	58	59	60	61	62	63	64	65	66	67	
Jan.	Feb.	March	April	May	June	July	Aug.	Sept.	Oct.	Nov.	Dec.	Total	Jan.	Feb.	March	April	May	June	July	Aug.	Sept.	Oct.	Nov.	Dec.	Total
-	-	-	-	-	-	-	-	-	-	-	-	1,028,025	-	-	-	-	-	-	-	-	-	-	-	-	1,028,025
615	615	615	615	615	615	615	615	615	615	615	615	55	615	615	615	615	615	615	615	615	615	615	615	615	67
9,146	9,146	9,146	9,146	9,146	9,146	9,146	9,146	9,146	9,146	9,146	9,146	54	9,146	9,146	9,146	9,146	9,146	9,146	9,146	9,146	9,146	9,146	9,146	9,146	66
10,714	10,714	10,714	10,714	10,714	10,714	10,714	10,714	10,714	10,714	10,714	10,714	53	10,714	10,714	10,714	10,714	10,714	10,714	10,714	10,714	10,714	10,714	10,714	10,714	65
14,154	14,154	14,154	14,154	14,154	14,154	14,154	14,154	14,154	14,154	14,154	14,154	52	14,154	14,154	14,154	14,154	14,154	14,154	14,154	14,154	14,154	14,154	14,154	14,154	64
12,526	12,526	12,526	12,526	12,526	12,526	12,526	12,526	12,526	12,526	12,526	12,526	51	12,526	12,526	12,526	12,526	12,526	12,526	12,526	12,526	12,526	12,526	12,526	12,526	63
21,770	21,770	21,770	21,770	21,770	21,770	21,770	21,770	21,770	21,770	21,770	21,770	50	21,770	21,770	21,770	21,770	21,770	21,770	21,770	21,770	21,770	21,770	21,770	21,770	62
16,744	16,744	16,744	16,744	16,744	16,744	16,744	16,744	16,744	16,744	16,744	16,744	49	16,744	16,744	16,744	16,744	16,744	16,744	16,744	16,744	16,744	16,744	16,744	16,744	61
-	-	-	-	-	-	-	-	-	-	-	-	48	-	-	-	-	-	-	-	-	-	-	-	-	60
-	-	-	-	-	-	-	-	-	-	-	-	47	-	-	-	-	-	-	-	-	-	-	-	-	59
-	-	-	-	-	-	-	-	-	-	-	-	46	-	-	-	-	-	-	-	-	-	-	-	-	58
-	-	-	-	-	-	-	-	-	-	-	-	45	-	-	-	-	-	-	-	-	-	-	-	-	57
-	-	-	-	-	-	-	-	-	-	-	-	44	-	-	-	-	-	-	-	-	-	-	-	-	56
-	-	-	-	-	-	-	-	-	-	-	-	43	-	-	-	-	-	-	-	-	-	-	-	-	55
-	-	-	-	-	-	-	-	-	-	-	-	42	-	-	-	-	-	-	-	-	-	-	-	-	54
-	-	-	-	-	-	-	-	-	-	-	-	41	-	-	-	-	-	-	-	-	-	-	-	-	53
-	-	-	-	-	-	-	-	-	-	-	-	40	-	-	-	-	-	-	-	-	-	-	-	-	52
-	-	-	-	-	-	-	-	-	-	-	-	39	-	-	-	-	-	-	-	-	-	-	-	-	51
-	-	-	-	-	-	-	-	-	-	-	-	38	-	-	-	-	-	-	-	-	-	-	-	-	50
-	-	-	-	-	-	-	-	-	-	-	-	37	-	-	-	-	-	-	-	-	-	-	-	-	49
85,669	85,669	85,669	85,669	85,669	85,669	85,669	85,669	85,669	85,669	85,669	85,669		85,669	85,669	85,669	85,669	85,669	85,669	85,669	85,669	85,669	85,669	85,669	85,669	

Actual kWh (Jan. - Dec., 2015): [redacted] 1,028,025

Actual kWh (Jan. - Dec., 2016): [redacted] 1,028,025

0	0	0	0	0	0	0	0	0	0	0	0	[redacted] 0	0	0	0	0	0	0	0	0	0	0	0	0	[redacted] 0
0	0	0	0	0	0	0	0	0	0	0	0	[redacted] 0	0	0	0	0	0	0	0	0	0	0	0	0	[redacted] 0
												[redacted] 0%													[redacted] 0%

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2017												
68	69	70	71	72	73	74	75	76	77	78	79	
Jan.	Feb.	March	April	May	June	July	Aug	Sept.	Oct.	Nov.	Dec.	Total
-	-	-	-	-	-	-	-	-	-	-	-	1,028,025
615	615	615	615	615	615	615	615	615	615	615	615	79
9,146	9,146	9,146	9,146	9,146	9,146	9,146	9,146	9,146	9,146	9,146	9,146	78
10,714	10,714	10,714	10,714	10,714	10,714	10,714	10,714	10,714	10,714	10,714	10,714	77
14,154	14,154	14,154	14,154	14,154	14,154	14,154	14,154	14,154	14,154	14,154	14,154	76
12,526	12,526	12,526	12,526	12,526	12,526	12,526	12,526	12,526	12,526	12,526	12,526	75
21,770	21,770	21,770	21,770	21,770	21,770	21,770	21,770	21,770	21,770	21,770	21,770	74
16,744	16,744	16,744	16,744	16,744	16,744	16,744	16,744	16,744	16,744	16,744	16,744	73
-	-	-	-	-	-	-	-	-	-	-	-	72
-	-	-	-	-	-	-	-	-	-	-	-	71
-	-	-	-	-	-	-	-	-	-	-	-	70
-	-	-	-	-	-	-	-	-	-	-	-	69
-	-	-	-	-	-	-	-	-	-	-	-	68
-	-	-	-	-	-	-	-	-	-	-	-	67
-	-	-	-	-	-	-	-	-	-	-	-	66
-	-	-	-	-	-	-	-	-	-	-	-	65
-	-	-	-	-	-	-	-	-	-	-	-	64
-	-	-	-	-	-	-	-	-	-	-	-	63
-	-	-	-	-	-	-	-	-	-	-	-	62
-	-	-	-	-	-	-	-	-	-	-	-	61
85,669	85,669	85,669	85,669	85,669	85,669	85,669	85,669	85,669	85,669	85,669	85,669	

2018												
80	81	82	83	84	85	86	87	88	89	90	91	
Jan.	Feb.	March	April	May	June	July	Aug	Sept.	Oct.	Nov.	Dec.	Total
-	-	-	-	-	-	-	-	-	-	-	-	1,028,025
615	615	615	615	615	615	615	615	615	615	615	615	91
9,146	9,146	9,146	9,146	9,146	9,146	9,146	9,146	9,146	9,146	9,146	9,146	90
10,714	10,714	10,714	10,714	10,714	10,714	10,714	10,714	10,714	10,714	10,714	10,714	89
14,154	14,154	14,154	14,154	14,154	14,154	14,154	14,154	14,154	14,154	14,154	14,154	88
12,526	12,526	12,526	12,526	12,526	12,526	12,526	12,526	12,526	12,526	12,526	12,526	87
21,770	21,770	21,770	21,770	21,770	21,770	21,770	21,770	21,770	21,770	21,770	21,770	86
16,744	16,744	16,744	16,744	16,744	16,744	16,744	16,744	16,744	16,744	16,744	16,744	85
-	-	-	-	-	-	-	-	-	-	-	-	84
-	-	-	-	-	-	-	-	-	-	-	-	83
-	-	-	-	-	-	-	-	-	-	-	-	82
-	-	-	-	-	-	-	-	-	-	-	-	81
-	-	-	-	-	-	-	-	-	-	-	-	80
-	-	-	-	-	-	-	-	-	-	-	-	79
-	-	-	-	-	-	-	-	-	-	-	-	78
-	-	-	-	-	-	-	-	-	-	-	-	77
-	-	-	-	-	-	-	-	-	-	-	-	76
-	-	-	-	-	-	-	-	-	-	-	-	75
-	-	-	-	-	-	-	-	-	-	-	-	74
-	-	-	-	-	-	-	-	-	-	-	-	73
85,669	85,669	85,669	85,669	85,669	85,669	85,669	85,669	85,669	85,669	85,669	85,669	

Actual kWh (Jan. - Dec., 2017): [redacted] 1,028,025

Actual kWh (Jan. - Dec., 2018): [redacted] 1,028,025

0	0	0	0	0	0	0	0	0	0	0	0	[redacted] 0
0	0	0	0	0	0	0	0	0	0	0	0	[redacted] 0
												[redacted] 0%

0	0	0	0	0	0	0	0	0	0	0	0	[redacted] 0
0	0	0	0	0	0	0	0	0	0	0	0	[redacted] 0
												[redacted] 0%

	2019													
	92	93	94	95	96	97	98	99	100	101	102	103		
kWh (Net) in North Carolina	Jan.	Feb.	March	April	May	June	July	Aug	Sept.	Oct.	Nov.	Dec.	Total	Total
Residential Lighting - kWh /year Savings (Deemed with assumed realization and net-to-gross rates from May 1, 2019 EMV Report)	-	-	-	-	-	-							1,028,025	1,028,025
Monthly - Adjusted kWh (Net)														
Jun, 2011	615	615	615	615	615	615							97	
Jul	9,146	9,146	9,146	9,146	9,146	9,146							96	
Aug	10,714	10,714	10,714	10,714	10,714	10,714							95	
Sep	14,154	14,154	14,154	14,154	14,154	14,154							94	
Oct	12,526	12,526	12,526	12,526	12,526	12,526							93	
Nov	21,770	21,770	21,770	21,770	21,770	21,770							92	
Dec	16,744	16,744	16,744	16,744	16,744	16,744							91	
Jan, 2012	-	-	-	-	-	-							90	
Feb	-	-	-	-	-	-							89	
Mar	-	-	-	-	-	-							88	
Apr	-	-	-	-	-	-							87	
May	-	-	-	-	-	-							86	
Jun	-	-	-	-	-	-							85	
Jul	-	-	-	-	-	-							84	
Aug	-	-	-	-	-	-							83	
Sep	-	-	-	-	-	-							82	
Oct	-	-	-	-	-	-							81	
Nov	-	-	-	-	-	-							80	
Dec	-	-	-	-	-	-							79	
Total (Cumulative by Month) - Adjusted kWh (Net)	85,669	85,669	85,669	85,669	85,669	85,669	0	0	0	0	0	0	[illegible]	7,977,419 True-up

Actual kWh (Jan. - Dec., 2019	514,013	7,977,419

															Total
Planned:	Bulbs	0	0	0	0	0	0	0	0	0	0	0	0	0	127,975
Actual:	Bulbs	0	0	0	0	0	0	0	0	0	0	0	0	0	37,120
														0%	29%

NOTES:

1. The kWh savings are based on actual participation from Dominion North Carolina Power customers with program planning realization and net-to-gross adjustments assumptions applied
2. The May 1, 2019 EM&V Report was filed with the NC Public Utilities Commission and included EM&V data through the end of 2018.
3. The EM&V data reflected for January 2018 - June, 2019 was prepared by DNV GL using the same STEP (Standard Tracking Engineering Protocol) formulas used in preparing the EM&V data for 2018.
4. The kWh savings are inclusive of all EE measures installed from program inception through June 30, 2019.
5. Program measure life is 9.4 years (9 years, 5 months; or 113 months)

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	2012													2013												
	1	2	3	4	5	6	7	8	9	10	11	12		13	14	15	16	17	18	19	20	21	22	23	24	
kWh (Net) in North Carolina	Jan.	Feb.	March	April	May	June	July	Aug.	Sept.	Oct.	Nov.	Dec.	Total	Jan.	Feb.	March	April	May	June	July	Aug.	Sept.	Oct.	Nov.	Dec.	Total
Residential Low Income - kWh/year Savings (Deemed with assumed realization and net-to-gross rates from May 1, 2019 EMV Report)	30,122	25,219	17,216	8,019	-	-	-	-	-	-	-	-	80,576	8,942	7,554	8,217	1,053	2,259	-	306	12,718	7,082	9,696	9,555	7,619	155,617
Monthly - Adjusted kWh (Net)													Total Months													Total Months
Jan, 2012	2,510	2,510	2,510	2,510	2,510	2,510	2,510	2,510	2,510	2,510	2,510	2,510	12	2,510	2,510	2,510	2,510	2,510	2,510	2,510	2,510	2,510	2,510	2,510	2,510	24
Feb		2,102	2,102	2,102	2,102	2,102	2,102	2,102	2,102	2,102	2,102	2,102	11	2,102	2,102	2,102	2,102	2,102	2,102	2,102	2,102	2,102	2,102	2,102	2,102	23
Mar			1,435	1,435	1,435	1,435	1,435	1,435	1,435	1,435	1,435	1,435	10	1,435	1,435	1,435	1,435	1,435	1,435	1,435	1,435	1,435	1,435	1,435	1,435	22
Apr				668	668	668	668	668	668	668	668	668	9	668	668	668	668	668	668	668	668	668	668	668	668	21
May					-	-	-	-	-	-	-	-	8	-	-	-	-	-	-	-	-	-	-	-	-	20
Jun						-	-	-	-	-	-	-	7	-	-	-	-	-	-	-	-	-	-	-	-	19
Jul							-	-	-	-	-	-	6	-	-	-	-	-	-	-	-	-	-	-	-	18
Aug								-	-	-	-	-	5	-	-	-	-	-	-	-	-	-	-	-	-	17
Sep									-	-	-	-	4	-	-	-	-	-	-	-	-	-	-	-	-	16
Oct										-	-	-	3	-	-	-	-	-	-	-	-	-	-	-	-	15
Nov											-	-	2	-	-	-	-	-	-	-	-	-	-	-	-	14
Dec												-	1	-	-	-	-	-	-	-	-	-	-	-	-	13
Jan, 2013														745	745	745	745	745	745	745	745	745	745	745	745	12
Feb															630	630	630	630	630	630	630	630	630	630	630	11
Mar																685	685	685	685	685	685	685	685	685	685	10
Apr																	88	88	88	88	88	88	88	88	88	9
May																		192	192	192	192	192	192	192	192	8
Jun																			-	-	-	-	-	-	-	7
Jul																				26	26	26	26	26	26	6
Aug																					1,060	1,060	1,060	1,060	1,060	5
Sep																						590	590	590	590	4
Oct																							808	808	808	3
Nov																								796	796	2
Dec																									635	1
Total (Cumulative by Month) - Adjusted kWh (Net)	2,510	4,612	6,046	6,715	6,715	6,715	6,715	6,715	6,715	6,715	6,715	6,715		7,460	8,089	8,774	8,862	9,053	9,053	9,079	10,139	10,729	11,537	12,333	12,968	

Actual kWh (Jan. - Dec., 2012): 73,600

Actual kWh (Jan. - Dec., 2013): 118,077

Participation		1	2	3	4	5	6	7	8	9	10	11	12	Total	13	14	15	16	17	18	19	20	21	22	23	24	Total
	Planned:	43	43	43	43	43	43	43	43	43	43	43	46	619	2	2	2	2	2	2	2	2	2	2	2	11	33
	Actual:	55	46	35	20	0	0	0	0	0	0	0	0	158	13	13	13	3	3	0	1	25	15	14	11	9	120
														30%													364%

2014													2015												
25	26	27	28	29	30	31	32	33	34	35	36		37	38	39	40	41	42	43	44	45	46	47	48	
Jan.	Feb.	March	April	May	June	July	Aug	Sept.	Oct.	Nov.	Dec.	Total	Jan.	Feb.	March	April	May	June	July	Aug	Sept.	Oct.	Nov.	Dec.	Total
4,751	6,464	2,788	6,526	4,319	4,775	7,580	5,823	7,018	6,114	3,379	-	215,154	18,206	24,017	29,344	31,288	22,553	23,753	23,493	30,017	34,156	29,280	24,219	21,598	527,078
												Total Months													Total Months
2,510	2,510	2,510	2,510	2,510	2,510	2,510	2,510	2,510	2,510	2,510	2,510	36	2,510	2,510	2,510	2,510	2,510	2,510	2,510	2,510	2,510	2,510	2,510	2,510	48
2,102	2,102	2,102	2,102	2,102	2,102	2,102	2,102	2,102	2,102	2,102	2,102	35	2,102	2,102	2,102	2,102	2,102	2,102	2,102	2,102	2,102	2,102	2,102	2,102	47
1,435	1,435	1,435	1,435	1,435	1,435	1,435	1,435	1,435	1,435	1,435	1,435	34	1,435	1,435	1,435	1,435	1,435	1,435	1,435	1,435	1,435	1,435	1,435	1,435	46
668	668	668	668	668	668	668	668	668	668	668	668	33	668	668	668	668	668	668	668	668	668	668	668	668	45
-	-	-	-	-	-	-	-	-	-	-	-	32	-	-	-	-	-	-	-	-	-	-	-	-	44
-	-	-	-	-	-	-	-	-	-	-	-	31	-	-	-	-	-	-	-	-	-	-	-	-	43
-	-	-	-	-	-	-	-	-	-	-	-	30	-	-	-	-	-	-	-	-	-	-	-	-	42
-	-	-	-	-	-	-	-	-	-	-	-	29	-	-	-	-	-	-	-	-	-	-	-	-	41
-	-	-	-	-	-	-	-	-	-	-	-	28	-	-	-	-	-	-	-	-	-	-	-	-	40
-	-	-	-	-	-	-	-	-	-	-	-	27	-	-	-	-	-	-	-	-	-	-	-	-	39
-	-	-	-	-	-	-	-	-	-	-	-	26	-	-	-	-	-	-	-	-	-	-	-	-	38
-	-	-	-	-	-	-	-	-	-	-	-	25	-	-	-	-	-	-	-	-	-	-	-	-	37
745	745	745	745	745	745	745	745	745	745	745	745	24	745	745	745	745	745	745	745	745	745	745	745	745	36
630	630	630	630	630	630	630	630	630	630	630	630	23	630	630	630	630	630	630	630	630	630	630	630	630	35
685	685	685	685	685	685	685	685	685	685	685	685	22	685	685	685	685	685	685	685	685	685	685	685	685	34
88	88	88	88	88	88	88	88	88	88	88	88	21	88	88	88	88	88	88	88	88	88	88	88	88	33
192	192	192	192	192	192	192	192	192	192	192	192	20	192	192	192	192	192	192	192	192	192	192	192	192	32
-	-	-	-	-	-	-	-	-	-	-	-	19	-	-	-	-	-	-	-	-	-	-	-	-	31
26	26	26	26	26	26	26	26	26	26	26	26	18	26	26	26	26	26	26	26	26	26	26	26	26	30
1,060	1,060	1,060	1,060	1,060	1,060	1,060	1,060	1,060	1,060	1,060	1,060	17	1,060	1,060	1,060	1,060	1,060	1,060	1,060	1,060	1,060	1,060	1,060	1,060	29
590	590	590	590	590	590	590	590	590	590	590	590	16	590	590	590	590	590	590	590	590	590	590	590	590	28
808	808	808	808	808	808	808	808	808	808	808	808	15	808	808	808	808	808	808	808	808	808	808	808	808	27
796	796	796	796	796	796	796	796	796	796	796	796	14	796	796	796	796	796	796	796	796	796	796	796	796	26
635	635	635	635	635	635	635	635	635	635	635	635	13	635	635	635	635	635	635	635	635	635	635	635	635	25
396	396	396	396	396	396	396	396	396	396	396	396	12	396	396	396	396	396	396	396	396	396	396	396	396	24
	539	539	539	539	539	539	539	539	539	539	539	11	539	539	539	539	539	539	539	539	539	539	539	539	23
		232	232	232	232	232	232	232	232	232	232	10	232	232	232	232	232	232	232	232	232	232	232	232	22
			544	544	544	544	544	544	544	544	544	9	544	544	544	544	544	544	544	544	544	544	544	544	21
				360	360	360	360	360	360	360	360	8	360	360	360	360	360	360	360	360	360	360	360	360	20
					398	398	398	398	398	398	398	7	398	398	398	398	398	398	398	398	398	398	398	398	19
						632	632	632	632	632	632	6	632	632	632	632	632	632	632	632	632	632	632	632	18
							485	485	485	485	485	5	485	485	485	485	485	485	485	485	485	485	485	485	17
								585	585	585	585	4	585	585	585	585	585	585	585	585	585	585	585	585	16
									510	510	510	3	510	510	510	510	510	510	510	510	510	510	510	510	15
										282	282	2	282	282	282	282	282	282	282	282	282	282	282	282	14
											-	1	-	-	-	-	-	-	-	-	-	-	-	-	13
													1,517	1,517	1,517	1,517	1,517	1,517	1,517	1,517	1,517	1,517	1,517	1,517	12
														2,001	2,001	2,001	2,001	2,001	2,001	2,001	2,001	2,001	2,001	2,001	11
															2,445	2,445	2,445	2,445	2,445	2,445	2,445	2,445	2,445	2,445	10
																2,607	2,607	2,607	2,607	2,607	2,607	2,607	2,607	2,607	9
																	1,879	1,879	1,879	1,879	1,879	1,879	1,879	1,879	8
																		1,979	1,979	1,979	1,979	1,979	1,979	1,979	7
																			1,958	1,958	1,958	1,958	1,958	1,958	6
																				2,501	2,501	2,501	2,501	2,501	5
																					2,846	2,846	2,846	2,846	4
																						2,440	2,440	2,440	3
																							2,018	2,018	2
																								1,800	1
13,364	13,903	14,135	14,679	15,039	15,437	16,068	16,554	17,138	17,648	17,930	17,930		19,447	21,448	23,893	26,501	28,380	30,360	32,317	34,819	37,665	40,105	42,123	43,923	

Actual kWh (Jan. - Dec., 2014): 189,823

Actual kWh (Jan. - Dec., 2015): 380,981

11.0	11.0	11.0	11.0	11.0	11.0	11.0	11.0	11.0	11.0	11.0	11.0	132	50	50	50	50	50	50	50	50	50	50	50	50	600
9	12	10	11	10	12	14	11	12	12	7	0	120	46	50	65	67	50	47	50	62	60	60	57	39	653
												91%													109%

2016													
49	50	51	52	53	54	55	56	57	58	59	60		
Jan.	Feb.	March	April	May	June	July	Aug.	Sept.	Oct.	Nov.	Dec.	Total	
-	-	-	-	-	-	-	-	-	-	-	-	527,078	
													Total Months
2,510	2,510	2,510	2,510	2,510	2,510	2,510	2,510	2,510	2,510	2,510	2,510		60
2,102	2,102	2,102	2,102	2,102	2,102	2,102	2,102	2,102	2,102	2,102	2,102		59
1,435	1,435	1,435	1,435	1,435	1,435	1,435	1,435	1,435	1,435	1,435	1,435		58
668	668	668	668	668	668	668	668	668	668	668	668		57
-	-	-	-	-	-	-	-	-	-	-	-		56
-	-	-	-	-	-	-	-	-	-	-	-		55
-	-	-	-	-	-	-	-	-	-	-	-		54
-	-	-	-	-	-	-	-	-	-	-	-		53
-	-	-	-	-	-	-	-	-	-	-	-		52
-	-	-	-	-	-	-	-	-	-	-	-		51
-	-	-	-	-	-	-	-	-	-	-	-		50
-	-	-	-	-	-	-	-	-	-	-	-		49
745	745	745	745	745	745	745	745	745	745	745	745		48
630	630	630	630	630	630	630	630	630	630	630	630		47
685	685	685	685	685	685	685	685	685	685	685	685		46
88	88	88	88	88	88	88	88	88	88	88	88		45
192	192	192	192	192	192	192	192	192	192	192	192		44
-	-	-	-	-	-	-	-	-	-	-	-		43
26	26	26	26	26	26	26	26	26	26	26	26		42
1,060	1,060	1,060	1,060	1,060	1,060	1,060	1,060	1,060	1,060	1,060	1,060		41
590	590	590	590	590	590	590	590	590	590	590	590		40
808	808	808	808	808	808	808	808	808	808	808	808		39
796	796	796	796	796	796	796	796	796	796	796	796		38
635	635	635	635	635	635	635	635	635	635	635	635		37
396	396	396	396	396	396	396	396	396	396	396	396		36
539	539	539	539	539	539	539	539	539	539	539	539		35
232	232	232	232	232	232	232	232	232	232	232	232		34
544	544	544	544	544	544	544	544	544	544	544	544		33
360	360	360	360	360	360	360	360	360	360	360	360		32
398	398	398	398	398	398	398	398	398	398	398	398		31
632	632	632	632	632	632	632	632	632	632	632	632		30
485	485	485	485	485	485	485	485	485	485	485	485		29
585	585	585	585	585	585	585	585	585	585	585	585		28
510	510	510	510	510	510	510	510	510	510	510	510		27
282	282	282	282	282	282	282	282	282	282	282	282		26
-	-	-	-	-	-	-	-	-	-	-	-		25
1,517	1,517	1,517	1,517	1,517	1,517	1,517	1,517	1,517	1,517	1,517	1,517		24
2,001	2,001	2,001	2,001	2,001	2,001	2,001	2,001	2,001	2,001	2,001	2,001		23
2,445	2,445	2,445	2,445	2,445	2,445	2,445	2,445	2,445	2,445	2,445	2,445		22
2,607	2,607	2,607	2,607	2,607	2,607	2,607	2,607	2,607	2,607	2,607	2,607		21
1,879	1,879	1,879	1,879	1,879	1,879	1,879	1,879	1,879	1,879	1,879	1,879		20
1,979	1,979	1,979	1,979	1,979	1,979	1,979	1,979	1,979	1,979	1,979	1,979		19
1,958	1,958	1,958	1,958	1,958	1,958	1,958	1,958	1,958	1,958	1,958	1,958		18
2,501	2,501	2,501	2,501	2,501	2,501	2,501	2,501	2,501	2,501	2,501	2,501		17
2,846	2,846	2,846	2,846	2,846	2,846	2,846	2,846	2,846	2,846	2,846	2,846		16
2,440	2,440	2,440	2,440	2,440	2,440	2,440	2,440	2,440	2,440	2,440	2,440		15
2,018	2,018	2,018	2,018	2,018	2,018	2,018	2,018	2,018	2,018	2,018	2,018		14
1,800	1,800	1,800	1,800	1,800	1,800	1,800	1,800	1,800	1,800	1,800	1,800		13
43,923	43,923	43,923	43,923	43,923	43,923	43,923	43,923	43,923	43,923	43,923	43,923		

2017													
61	62	63	64	65	66	67	68	69	70	71	72		
Jan.	Feb.	March	April	May	June	July	Aug.	Sept.	Oct.	Nov.	Dec.	Total	
-	-	-	-	-	-	-	-	-	-	-	-	527,078	
													Total Months
2,510	2,510	2,510	2,510	2,510	2,510	2,510	2,510	2,510	2,510	2,510	2,510		72
2,102	2,102	2,102	2,102	2,102	2,102	2,102	2,102	2,102	2,102	2,102	2,102		71
1,435	1,435	1,435	1,435	1,435	1,435	1,435	1,435	1,435	1,435	1,435	1,435		70
668	668	668	668	668	668	668	668	668	668	668	668		69
-	-	-	-	-	-	-	-	-	-	-	-		68
-	-	-	-	-	-	-	-	-	-	-	-		67
-	-	-	-	-	-	-	-	-	-	-	-		66
-	-	-	-	-	-	-	-	-	-	-	-		65
-	-	-	-	-	-	-	-	-	-	-	-		64
-	-	-	-	-	-	-	-	-	-	-	-		63
-	-	-	-	-	-	-	-	-	-	-	-		62
-	-	-	-	-	-	-	-	-	-	-	-		61
745	745	745	745	745	745	745	745	745	745	745	745		60
630	630	630	630	630	630	630	630	630	630	630	630		59
685	685	685	685	685	685	685	685	685	685	685	685		58
88	88	88	88	88	88	88	88	88	88	88	88		57
192	192	192	192	192	192	192	192	192	192	192	192		56
-	-	-	-	-	-	-	-	-	-	-	-		55
26	26	26	26	26	26	26	26	26	26	26	26		54
1,060	1,060	1,060	1,060	1,060	1,060	1,060	1,060	1,060	1,060	1,060	1,060		53
590	590	590	590	590	590	590	590	590	590	590	590		52
808	808	808	808	808	808	808	808	808	808	808	808		51
796	796	796	796	796	796	796	796	796	796	796	796		50
635	635	635	635	635	635	635	635	635	635	635	635		49
396	396	396	396	396	396	396	396	396	396	396	396		48
539	539	539	539	539	539	539	539	539	539	539	539		47
232	232	232	232	232	232	232	232	232	232	232	232		46
544	544	544	544	544	544	544	544	544	544	544	544		45
360	360	360	360	360	360	360	360	360	360	360	360		44
398	398	398	398	398	398	398	398	398	398	398	398		43
632	632	632	632	632	632	632	632	632	632	632	632		42
485	485	485	485	485	485	485	485	485	485	485	485		41
585	585	585	585	585	585	585	585	585	585	585	585		40
510	510	510	510	510	510	510	510	510	510	510	510		39
282	282	282	282	282	282	282	282	282	282	282	282		38
-	-	-	-	-	-	-	-	-	-	-	-		37
1,517	1,517	1,517	1,517	1,517	1,517	1,517	1,517	1,517	1,517	1,517	1,517		36
2,001	2,001	2,001	2,001	2,001	2,001	2,001	2,001	2,001	2,001	2,001	2,001		35
2,445	2,445	2,445	2,445	2,445	2,445	2,445	2,445	2,445	2,445	2,445	2,445		34
2,607	2,607	2,607	2,607	2,607	2,607	2,607	2,607	2,607	2,607	2,607	2,607		33
1,879	1,879	1,879	1,879	1,879	1,879	1,879	1,879	1,879	1,879	1,879	1,879		32
1,979	1,979	1,979	1,979	1,979	1,979	1,979	1,979	1,979	1,979	1,979	1,979		31
1,958	1,958	1,958	1,958	1,958	1,958	1,958	1,958	1,958	1,958	1,958	1,958		30
2,501	2,501	2,501	2,501	2,501	2,501	2,501	2,501	2,501	2,501	2,501	2,501		29
2,846	2,846	2,846	2,846	2,846	2,846	2,846	2,846	2,846	2,846	2,846	2,846		28
2,440	2,440	2,440	2,440	2,440	2,440	2,440	2,440	2,440	2,440	2,440	2,440		27
2,018	2,018	2,018	2,018	2,018	2,018	2,018	2,018	2,018	2,018	2,018	2,018		26
1,800	1,800	1,800	1,800	1,800	1,800	1,800	1,800	1,800	1,800	1,800	1,800		25
43,923	43,923	43,923	43,923	43,923	43,923	43,923	43,923	43,923	43,923	43,923	43,923		

Actual kWh (Jan. - Dec., 2016): [redacted] 527,078

Actual kWh (Jan. - Dec., 2017): [redacted] 527,078

0	0	0	0	0	0	0	0	0	0	0	0	[redacted] 0
0	0	0	0	0	0	0	0	0	0	0	0	[redacted] 0
												[redacted] 0%

0	0	0	0	0	0	0	0	0	0	0	0	[redacted] 0
0	0	0	0	0	0	0	0	0	0	0	0	[redacted] 0
												[redacted] 0%

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	2018 73 Jan.	74 Feb.	75 March	76 April	77 May	78 June	79 July	80 Aug.	81 Sept.	82 Oct.	83 Nov.	84 Dec.	Total	Total Months
kWh (Net) in North Carolina														
Residential Low Income - kWh/year Savings (Deemed with assumed realization and net-to-gross rates from May 1, 2019 EMV Report)	-	-	-	-	-	-	-	-	-	-	-	-	527,078	
Monthly - Adjusted kWh (Net)														
Jan, 2012	2,510	2,510	2,510	2,510	2,510	2,510	2,510	2,510	2,510	2,510	2,510	2,510		84
Feb	2,102	2,102	2,102	2,102	2,102	2,102	2,102	2,102	2,102	2,102	2,102	2,102		83
Mar	1,435	1,435	1,435	1,435	1,435	1,435	1,435	1,435	1,435	1,435	1,435	1,435		82
Apr	668	668	668	668	668	668	668	668	668	668	668	668		81
May	-	-	-	-	-	-	-	-	-	-	-	-		80
Jun	-	-	-	-	-	-	-	-	-	-	-	-		79
Jul	-	-	-	-	-	-	-	-	-	-	-	-		78
Aug	-	-	-	-	-	-	-	-	-	-	-	-		77
Sep	-	-	-	-	-	-	-	-	-	-	-	-		76
Oct	-	-	-	-	-	-	-	-	-	-	-	-		75
Nov	-	-	-	-	-	-	-	-	-	-	-	-		74
Dec	-	-	-	-	-	-	-	-	-	-	-	-		73
Jan, 2013	745	745	745	745	745	745	745	745	745	745	745	745		72
Feb	630	630	630	630	630	630	630	630	630	630	630	630		71
Mar	685	685	685	685	685	685	685	685	685	685	685	685		70
Apr	88	88	88	88	88	88	88	88	88	88	88	88		69
May	192	192	192	192	192	192	192	192	192	192	192	192		68
Jun	-	-	-	-	-	-	-	-	-	-	-	-		67
Jul	26	26	26	26	26	26	26	26	26	26	26	26		66
Aug	1,060	1,060	1,060	1,060	1,060	1,060	1,060	1,060	1,060	1,060	1,060	1,060		65
Sep	590	590	590	590	590	590	590	590	590	590	590	590		64
Oct	808	808	808	808	808	808	808	808	808	808	808	808		63
Nov	796	796	796	796	796	796	796	796	796	796	796	796		62
Dec	635	635	635	635	635	635	635	635	635	635	635	635		61
Jan, 2014	396	396	396	396	396	396	396	396	396	396	396	396		60
Feb	539	539	539	539	539	539	539	539	539	539	539	539		59
Mar	232	232	232	232	232	232	232	232	232	232	232	232		58
Apr	544	544	544	544	544	544	544	544	544	544	544	544		57
May	360	360	360	360	360	360	360	360	360	360	360	360		56
Jun	398	398	398	398	398	398	398	398	398	398	398	398		55
Jul	632	632	632	632	632	632	632	632	632	632	632	632		54
Aug	485	485	485	485	485	485	485	485	485	485	485	485		53
Sep	585	585	585	585	585	585	585	585	585	585	585	585		52
Oct	510	510	510	510	510	510	510	510	510	510	510	510		51
Nov	282	282	282	282	282	282	282	282	282	282	282	282		50
Dec	-	-	-	-	-	-	-	-	-	-	-	-		49
Jan, 2015	1,517	1,517	1,517	1,517	1,517	1,517	1,517	1,517	1,517	1,517	1,517	1,517		48
Feb	2,001	2,001	2,001	2,001	2,001	2,001	2,001	2,001	2,001	2,001	2,001	2,001		47
Mar	2,445	2,445	2,445	2,445	2,445	2,445	2,445	2,445	2,445	2,445	2,445	2,445		46
Apr	2,607	2,607	2,607	2,607	2,607	2,607	2,607	2,607	2,607	2,607	2,607	2,607		45
May	1,879	1,879	1,879	1,879	1,879	1,879	1,879	1,879	1,879	1,879	1,879	1,879		44
Jun	1,979	1,979	1,979	1,979	1,979	1,979	1,979	1,979	1,979	1,979	1,979	1,979		43
Jul	1,958	1,958	1,958	1,958	1,958	1,958	1,958	1,958	1,958	1,958	1,958	1,958		42
Aug	2,501	2,501	2,501	2,501	2,501	2,501	2,501	2,501	2,501	2,501	2,501	2,501		41
Sep	2,846	2,846	2,846	2,846	2,846	2,846	2,846	2,846	2,846	2,846	2,846	2,846		40
Oct	2,440	2,440	2,440	2,440	2,440	2,440	2,440	2,440	2,440	2,440	2,440	2,440		39
Nov	2,018	2,018	2,018	2,018	2,018	2,018	2,018	2,018	2,018	2,018	2,018	2,018		38
Dec	1,800	1,800	1,800	1,800	1,800	1,800	1,800	1,800	1,800	1,800	1,800	1,800		37
Total (Cumulative by Month) - Adjusted kWh (Net):	(43,923)	(43,923)	(43,923)	(43,923)	(43,923)	(43,923)	(43,923)	(43,923)	(43,923)	(43,923)	(43,923)	(43,923)		

	2019 85 Jan.	86 Feb.	87 March	88 April	89 May	90 June	91 July	92 Aug.	93 Sept.	94 Oct.	95 Nov.	96 Dec.	Total	Total Months	Total
kWh (Net) in North Carolina															
Residential Low Income - kWh/year Savings (Deemed with assumed realization and net-to-gross rates from May 1, 2019 EMV Report)	-	-	-	-	-	-							527,078		527,078
Monthly - Adjusted kWh (Net)															
Jan, 2012	2,510	2,510	2,510	2,510	2,510	2,510								90	
Feb	2,102	2,102	2,102	2,102	2,102	2,102								89	
Mar	1,435	1,435	1,435	1,435	1,435	1,435								88	
Apr	668	668	668	668	668	668								87	
May	-	-	-	-	-	-								86	
Jun	-	-	-	-	-	-								85	
Jul	-	-	-	-	-	-								84	
Aug	-	-	-	-	-	-								83	
Sep	-	-	-	-	-	-								82	
Oct	-	-	-	-	-	-								81	
Nov	-	-	-	-	-	-								80	
Dec	-	-	-	-	-	-								79	
Jan, 2013	745	745	745	745	745	745								78	
Feb	630	630	630	630	630	630								77	
Mar	685	685	685	685	685	685								76	
Apr	88	88	88	88	88	88								75	
May	192	192	192	192	192	192								74	
Jun	-	-	-	-	-	-								73	
Jul	26	26	26	26	26	26								72	
Aug	1,060	1,060	1,060	1,060	1,060	1,060								71	
Sep	590	590	590	590	590	590								70	
Oct	808	808	808	808	808	808								69	
Nov	796	796	796	796	796	796								68	
Dec	635	635	635	635	635	635								67	
Jan, 2014	396	396	396	396	396	396								66	
Feb	539	539	539	539	539	539								65	
Mar	232	232	232	232	232	232								64	
Apr	544	544	544	544	544	544								63	
May	360	360	360	360	360	360								62	
Jun	398	398	398	398	398	398								61	
Jul	632	632	632	632	632	632								60	
Aug	485	485	485	485	485	485								59	
Sep	585	585	585	585	585	585								58	
Oct	510	510	510	510	510	510								57	
Nov	282	282	282	282	282	282								56	
Dec	-	-	-	-	-	-								55	
Jan, 2015	1,517	1,517	1,517	1,517	1,517	1,517								54	
Feb	2,001	2,001	2,001	2,001	2,001	2,001								53	
Mar	2,445	2,445	2,445	2,445	2,445	2,445								52	
Apr	2,607	2,607	2,607	2,607	2,607	2,607								51	
May	1,879	1,879	1,879	1,879	1,879	1,879								50	
Jun	1,979	1,979	1,979	1,979	1,979	1,979								49	
Jul	1,958	1,958	1,958	1,958	1,958	1,958								48	
Aug	2,501	2,501	2,501	2,501	2,501	2,501								47	
Sep	2,846	2,846	2,846	2,846	2,846	2,846								46	
Oct	2,440	2,440	2,440	2,440	2,440	2,440								45	
Nov	2,018	2,018	2,018	2,018	2,018	2,018								44	
Dec	1,800	1,800	1,800	1,800	1,800	1,800								43	
Total (Cumulative by Month) - Adjusted kWh (Net):	(43,923)	(43,923)	(43,923)	(43,923)	(43,923)	(43,923)	0	0	0	0	0	0			2,607,255 True-up

Actual kWh (Jan. - Dec., 2018):	527,078
Actual kWh (Jan. - Dec., 2019):	263,539
	2,607,255

Participation	Jan.	Feb.	March	April	May	June	July	Aug.	Sept.	Oct.	Nov.	Dec.	2018 Total	Jan.	Feb.	March	April	May	June	July	Aug.	Sept.	Oct.	Nov.	Dec.	2019 Total	Total
Planned:	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	1,284
Actual:	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	1,049
													0%													0%	82%

NOTES:

1. The kWh savings are based on actual participation from Dominion North Carolina Power customers with program planning realization and net-to-gross adjustments assumptions applied
2. The May 1, 2019 EM&V Report was filed with the NC Public Utilities Commission and included EM&V data through the end of 2018.
3. The EM&V data reflected for January 2018 - June, 2019 was prepared by DNV GL using the same STEP (Standard Tracking Engineering Protocol) formulas used in preparing the EM&V data for 2018.
4. The kWh savings are inclusive of all EE measures installed from program inception through June 30, 2019.
5. Program measure life is 13.6 years (13 years, 7 months; or 163 months)

		2012													2013												
		1	2	3	4	5	6	7	8	9	10	11	12		13	14	15	16	17	18	19	20	21	22	23	24	
kWh (Net) in North Carolina		Jan.	Feb.	March	April	May	June	July	Aug	Sept.	Oct.	Nov.	Dec.	Total	Jan.	Feb.	March	April	May	June	July	Aug	Sept.	Oct.	Nov.	Dec.	Total
Commercial HVAC - kWh /year Savings (Deemed with assumed realization and net-to-gross rates from May 1, 2019 EMV Report)		28,366	13,067	-	-	-	-	-	-	-	69,133	-	-	110,566	-	-	-	-	-	-	-	-	-	-	-	-	110,566
Monthly - Adjusted kWh (Net)														Total Months													Total Months
Jan, 2012		2,364	2,364	2,364	2,364	2,364	2,364	2,364	2,364	2,364	2,364	2,364	2,364	12	2,364	2,364	2,364	2,364	2,364	2,364	2,364	2,364	2,364	2,364	2,364	2,364	24
Feb			1,089	1,089	1,089	1,089	1,089	1,089	1,089	1,089	1,089	1,089	1,089	11	1,089	1,089	1,089	1,089	1,089	1,089	1,089	1,089	1,089	1,089	1,089	1,089	23
Mar				-	-	-	-	-	-	-	-	-	-	10	-	-	-	-	-	-	-	-	-	-	-	-	22
Apr					-	-	-	-	-	-	-	-	-	9	-	-	-	-	-	-	-	-	-	-	-	-	21
May						-	-	-	-	-	-	-	-	8	-	-	-	-	-	-	-	-	-	-	-	-	20
Jun							-	-	-	-	-	-	-	7	-	-	-	-	-	-	-	-	-	-	-	-	19
Jul								-	-	-	-	-	-	6	-	-	-	-	-	-	-	-	-	-	-	-	18
Aug									-	-	-	-	-	5	-	-	-	-	-	-	-	-	-	-	-	-	17
Sep										-	-	-	-	4	-	-	-	-	-	-	-	-	-	-	-	-	16
Oct											5,761	5,761	5,761	3	5,761	5,761	5,761	5,761	5,761	5,761	5,761	5,761	5,761	5,761	5,761	5,761	15
Nov												-	-	2	-	-	-	-	-	-	-	-	-	-	-	-	14
Dec													-	1	-	-	-	-	-	-	-	-	-	-	-	-	13
Jan, 2013															-	-	-	-	-	-	-	-	-	-	-	-	12
Feb																-	-	-	-	-	-	-	-	-	-	-	11
Mar																	-	-	-	-	-	-	-	-	-	-	10
Apr																		-	-	-	-	-	-	-	-	-	9
May																			-	-	-	-	-	-	-	-	8
Jun																				-	-	-	-	-	-	-	7
Jul																					-	-	-	-	-	-	6
Aug																						-	-	-	-	-	5
Sep																							-	-	-	-	4
Oct																								-	-	-	3
Nov																									-	-	2
Dec																										-	1
Total (Cumulative by Month) - Adjusted kWh (Net):		2,364	3,453	3,453	3,453	3,453	3,453	3,453	3,453	3,453	9,214	9,214	9,214		9,214	9,214	9,214	9,214	9,214	9,214	9,214	9,214	9,214	9,214	9,214	9,214	
DNV GL Tracking																											
Schedule 5	32%	279	408	408	408	403	408	408	408	408	1,089	1,089	1,089		1,089	1,089	1,089	1,089	1,089	1,089	1,089	1,089	1,089	1,089	1,089	1,089	
Schedule GP (TOU)	11%	269	392	392	392	392	392	392	392	392	1,047	1,047	1,047		1,047	1,047	1,047	1,047	1,047	1,047	1,047	1,047	1,047	1,047	1,047	1,047	
Schedule 10 (Variable Pricing)	63%	1,478	2,159	2,159	2,159	2,159	2,159	2,159	2,159	2,159	5,761	5,761	5,761		5,761	5,761	5,761	5,761	5,761	5,761	5,761	5,761	5,761	5,761	5,761	5,761	
Schedule 30 - Public Authority	14%	338	494	494	494	494	494	494	494	494	1,317	1,317	1,317		1,317	1,317	1,317	1,317	1,317	1,317	1,317	1,317	1,317	1,317	1,317	1,317	
		2,364	3,453	3,453	3,453	3,453	3,453	3,453	3,453	3,453	9,214	9,214	9,214		9,214	9,214	9,214	9,214	9,214	9,214	9,214	9,214	9,214	9,214	9,214	9,214	

Actual kWh (Jan. - Dec., 2012): 57,627

Actual kWh (Jan. - Dec., 2013): 110,566

Participation		1	2	3	4	5	6	7	8	9	10	11	12	2012	13	14	15	16	17	18	19	20	21	22	23	24	2013
	Planned:	1	1	1	1	1	1	1	1	1	1	1	0	11	0	0	0	0	0	0	0	0	0	0	0	0	0
	Actual:	2	1	0	0	0	0	0	0	0	1	0	0	4	0	0	0	0	0	0	0	0	0	0	0	0	0
														36%													0%

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2014												
25	26	27	28	29	30	31	32	33	34	35	36	
Jan.	Feb.	March	April	May	June	July	Aug	Sept.	Oct.	Nov.	Dec.	Total
-	-	-	-	-	-	-	-	-	-	-	-	110,566
												Total Months
2,364	2,364	2,364	2,364	2,364	2,364	2,364	2,364	2,364	2,364	2,364	2,364	36
1,089	1,089	1,089	1,089	1,089	1,089	1,089	1,089	1,089	1,089	1,089	1,089	35
-	-	-	-	-	-	-	-	-	-	-	-	34
-	-	-	-	-	-	-	-	-	-	-	-	33
-	-	-	-	-	-	-	-	-	-	-	-	32
-	-	-	-	-	-	-	-	-	-	-	-	31
-	-	-	-	-	-	-	-	-	-	-	-	30
-	-	-	-	-	-	-	-	-	-	-	-	29
-	-	-	-	-	-	-	-	-	-	-	-	28
5,761	5,761	5,761	5,761	5,761	5,761	5,761	5,761	5,761	5,761	5,761	5,761	27
-	-	-	-	-	-	-	-	-	-	-	-	26
-	-	-	-	-	-	-	-	-	-	-	-	25
-	-	-	-	-	-	-	-	-	-	-	-	24
-	-	-	-	-	-	-	-	-	-	-	-	23
-	-	-	-	-	-	-	-	-	-	-	-	22
-	-	-	-	-	-	-	-	-	-	-	-	21
-	-	-	-	-	-	-	-	-	-	-	-	20
-	-	-	-	-	-	-	-	-	-	-	-	19
-	-	-	-	-	-	-	-	-	-	-	-	18
-	-	-	-	-	-	-	-	-	-	-	-	17
-	-	-	-	-	-	-	-	-	-	-	-	16
-	-	-	-	-	-	-	-	-	-	-	-	15
-	-	-	-	-	-	-	-	-	-	-	-	14
-	-	-	-	-	-	-	-	-	-	-	-	13
9,214	9,214	9,214	9,214	9,214	9,214	9,214	9,214	9,214	9,214	9,214	9,214	
1,089	1,089	1,089	1,089	1,089	1,089	1,089	1,089	1,089	1,089	1,089	1,089	
1,047	1,047	1,047	1,047	1,047	1,047	1,047	1,047	1,047	1,047	1,047	1,047	
5,761	5,761	5,761	5,761	5,761	5,761	5,761	5,761	5,761	5,761	5,761	5,761	
1,317	1,317	1,317	1,317	1,317	1,317	1,317	1,317	1,317	1,317	1,317	1,317	
9,214	9,214	9,214	9,214	9,214	9,214	9,214	9,214	9,214	9,214	9,214	9,214	
											Actual kWh (Jan. - Dec., 2014):	110,566
0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	6
0	0	0	0	0	0	0	0	0	0	0	0	0
												0%

2015												
37	38	39	40	41	42	43	44	45	46	47	48	
Jan.	Feb.	March	April	May	June	July	Aug	Sept.	Oct.	Nov.	Dec.	Total
-	-	-	-	-	-	-	-	-	-	-	-	110,566
												Total Months
2,364	2,364	2,364	2,364	2,364	2,364	2,364	2,364	2,364	2,364	2,364	2,364	48
1,089	1,089	1,089	1,089	1,089	1,089	1,089	1,089	1,089	1,089	1,089	1,089	47
-	-	-	-	-	-	-	-	-	-	-	-	46
-	-	-	-	-	-	-	-	-	-	-	-	45
-	-	-	-	-	-	-	-	-	-	-	-	44
-	-	-	-	-	-	-	-	-	-	-	-	43
-	-	-	-	-	-	-	-	-	-	-	-	42
-	-	-	-	-	-	-	-	-	-	-	-	41
-	-	-	-	-	-	-	-	-	-	-	-	40
5,761	5,761	5,761	5,761	5,761	5,761	5,761	5,761	5,761	5,761	5,761	5,761	39
-	-	-	-	-	-	-	-	-	-	-	-	38
-	-	-	-	-	-	-	-	-	-	-	-	37
-	-	-	-	-	-	-	-	-	-	-	-	36
-	-	-	-	-	-	-	-	-	-	-	-	35
-	-	-	-	-	-	-	-	-	-	-	-	34
-	-	-	-	-	-	-	-	-	-	-	-	33
-	-	-	-	-	-	-	-	-	-	-	-	32
-	-	-	-	-	-	-	-	-	-	-	-	31
-	-	-	-	-	-	-	-	-	-	-	-	30
-	-	-	-	-	-	-	-	-	-	-	-	29
-	-	-	-	-	-	-	-	-	-	-	-	28
-	-	-	-	-	-	-	-	-	-	-	-	27
-	-	-	-	-	-	-	-	-	-	-	-	26
-	-	-	-	-	-	-	-	-	-	-	-	25
9,214	9,214	9,214	9,214	9,214	9,214	9,214	9,214	9,214	9,214	9,214	9,214	
1,089	1,089	1,089	1,089	1,089	1,089	1,089	1,089	1,089	1,089	1,089	1,089	
1,047	1,047	1,047	1,047	1,047	1,047	1,047	1,047	1,047	1,047	1,047	1,047	
5,761	5,761	5,761	5,761	5,761	5,761	5,761	5,761	5,761	5,761	5,761	5,761	
1,317	1,317	1,317	1,317	1,317	1,317	1,317	1,317	1,317	1,317	1,317	1,317	
9,214	9,214	9,214	9,214	9,214	9,214	9,214	9,214	9,214	9,214	9,214	9,214	
											Actual kWh (Jan. - Dec., 2015):	110,566
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%

2016

49	50	51	52	53	54	55	56	57	58	59	60	
Jan.	Feb.	March	April	May	June	July	Aug	Sept.	Oct.	Nov.	Dec.	Total
-	-	-	-	-	-	-	-	-	-	-	-	110,566
												Total Months
2,364	2,364	2,364	2,364	2,364	2,364	2,364	2,364	2,364	2,364	2,364	2,364	60
1,089	1,089	1,089	1,089	1,089	1,089	1,089	1,089	1,089	1,089	1,089	1,089	59
-	-	-	-	-	-	-	-	-	-	-	-	58
-	-	-	-	-	-	-	-	-	-	-	-	57
-	-	-	-	-	-	-	-	-	-	-	-	56
-	-	-	-	-	-	-	-	-	-	-	-	55
-	-	-	-	-	-	-	-	-	-	-	-	54
-	-	-	-	-	-	-	-	-	-	-	-	53
-	-	-	-	-	-	-	-	-	-	-	-	52
5,761	5,761	5,761	5,761	5,761	5,761	5,761	5,761	5,761	5,761	5,761	5,761	51
-	-	-	-	-	-	-	-	-	-	-	-	50
-	-	-	-	-	-	-	-	-	-	-	-	49
-	-	-	-	-	-	-	-	-	-	-	-	48
-	-	-	-	-	-	-	-	-	-	-	-	47
-	-	-	-	-	-	-	-	-	-	-	-	46
-	-	-	-	-	-	-	-	-	-	-	-	45
-	-	-	-	-	-	-	-	-	-	-	-	44
-	-	-	-	-	-	-	-	-	-	-	-	43
-	-	-	-	-	-	-	-	-	-	-	-	42
-	-	-	-	-	-	-	-	-	-	-	-	41
-	-	-	-	-	-	-	-	-	-	-	-	40
-	-	-	-	-	-	-	-	-	-	-	-	39
-	-	-	-	-	-	-	-	-	-	-	-	38
-	-	-	-	-	-	-	-	-	-	-	-	37
9,214	9,214	9,214	9,214	9,214	9,214	9,214	9,214	9,214	9,214	9,214	9,214	
1,089	1,089	1,089	1,089	1,089	1,089	1,089	1,089	1,089	1,089	1,089	1,089	
1,047	1,047	1,047	1,047	1,047	1,047	1,047	1,047	1,047	1,047	1,047	1,047	
5,761	5,761	5,761	5,761	5,761	5,761	5,761	5,761	5,761	5,761	5,761	5,761	
1,317	1,317	1,317	1,317	1,317	1,317	1,317	1,317	1,317	1,317	1,317	1,317	
9,214	9,214	9,214	9,214	9,214	9,214	9,214	9,214	9,214	9,214	9,214	9,214	
									Actual kWh (Jan. - Dec., 2016):			110,566
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%

2017

61	62	63	64	65	66	67	68	69	70	71	72	
Jan.	Feb.	March	April	May	June	July	Aug	Sept.	Oct.	Nov.	Dec.	Total
-	-	-	-	-	-	-	-	-	-	-	-	110,566
												Total Months
2,364	2,364	2,364	2,364	2,364	2,364	2,364	2,364	2,364	2,364	2,364	2,364	72
1,089	1,089	1,089	1,089	1,089	1,089	1,089	1,089	1,089	1,089	1,089	1,089	71
-	-	-	-	-	-	-	-	-	-	-	-	70
-	-	-	-	-	-	-	-	-	-	-	-	69
-	-	-	-	-	-	-	-	-	-	-	-	68
-	-	-	-	-	-	-	-	-	-	-	-	67
-	-	-	-	-	-	-	-	-	-	-	-	66
-	-	-	-	-	-	-	-	-	-	-	-	65
-	-	-	-	-	-	-	-	-	-	-	-	64
5,761	5,761	5,761	5,761	5,761	5,761	5,761	5,761	5,761	5,761	5,761	5,761	63
-	-	-	-	-	-	-	-	-	-	-	-	62
-	-	-	-	-	-	-	-	-	-	-	-	61
-	-	-	-	-	-	-	-	-	-	-	-	60
-	-	-	-	-	-	-	-	-	-	-	-	59
-	-	-	-	-	-	-	-	-	-	-	-	58
-	-	-	-	-	-	-	-	-	-	-	-	57
-	-	-	-	-	-	-	-	-	-	-	-	56
-	-	-	-	-	-	-	-	-	-	-	-	55
-	-	-	-	-	-	-	-	-	-	-	-	54
-	-	-	-	-	-	-	-	-	-	-	-	53
-	-	-	-	-	-	-	-	-	-	-	-	52
-	-	-	-	-	-	-	-	-	-	-	-	51
-	-	-	-	-	-	-	-	-	-	-	-	50
-	-	-	-	-	-	-	-	-	-	-	-	49
9,214	9,214	9,214	9,214	9,214	9,214	9,214	9,214	9,214	9,214	9,214	9,214	
1,089	1,089	1,089	1,089	1,089	1,089	1,089	1,089	1,089	1,089	1,089	1,089	
1,047	1,047	1,047	1,047	1,047	1,047	1,047	1,047	1,047	1,047	1,047	1,047	
5,761	5,761	5,761	5,761	5,761	5,761	5,761	5,761	5,761	5,761	5,761	5,761	
1,317	1,317	1,317	1,317	1,317	1,317	1,317	1,317	1,317	1,317	1,317	1,317	
9,214	9,214	9,214	9,214	9,214	9,214	9,214	9,214	9,214	9,214	9,214	9,214	
											Actual kWh (Jan. - Dec., 2017):	110,566
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%

	2018													2019													
	73	74	75	76	77	78	79	80	81	82	83	84		85	86	87	88	89	90	91	92	93	94	95	96		
kWh (Net) in North Carolina	Jan.	Feb.	March	April	May	June	July	Aug	Sept.	Oct.	Nov.	Dec.	Total	Jan.	Feb.	March	April	May	June	July	Aug	Sept.	Oct.	Nov.	Dec.	Total	Total
Commercial HVAC - kWh/year Savings (Deemed with assumed realization and net-to-gross rates from May 1, 2019 EMV Report)	-	-	-	-	-	-	-	-	-	-	-	-	110,566	-	-	-	-	-	-							110,566	110,566
Monthly - Adjusted kWh (Net)													Total Months													Total Months	
Jan, 2012	2,364	2,364	2,364	2,364	2,364	2,364	2,364	2,364	2,364	2,364	2,364	2,364	84	2,364	2,364	2,364	2,364	2,364	2,364							90	
Feb	1,089	1,089	1,089	1,089	1,089	1,089	1,089	1,089	1,089	1,089	1,089	1,089	83	1,089	1,089	1,089	1,089	1,089	1,089							89	
Mar	-	-	-	-	-	-	-	-	-	-	-	-	82	-	-	-	-	-	-							88	
Apr	-	-	-	-	-	-	-	-	-	-	-	-	81	-	-	-	-	-	-							87	
May	-	-	-	-	-	-	-	-	-	-	-	-	80	-	-	-	-	-	-							86	
Jun	-	-	-	-	-	-	-	-	-	-	-	-	79	-	-	-	-	-	-							85	
Jul	-	-	-	-	-	-	-	-	-	-	-	-	78	-	-	-	-	-	-							84	
Aug	-	-	-	-	-	-	-	-	-	-	-	-	77	-	-	-	-	-	-							83	
Sep	-	-	-	-	-	-	-	-	-	-	-	-	76	-	-	-	-	-	-							82	
Oct	5,761	5,761	5,761	5,761	5,761	5,761	5,761	5,761	5,761	5,761	5,761	5,761	75	5,761	5,761	5,761	5,761	5,761	5,761							81	
Nov	-	-	-	-	-	-	-	-	-	-	-	-	74	-	-	-	-	-	-							80	
Dec	-	-	-	-	-	-	-	-	-	-	-	-	73	-	-	-	-	-	-							79	
Jan, 2013	-	-	-	-	-	-	-	-	-	-	-	-	72	-	-	-	-	-	-							78	
Feb	-	-	-	-	-	-	-	-	-	-	-	-	71	-	-	-	-	-	-							77	
Mar	-	-	-	-	-	-	-	-	-	-	-	-	70	-	-	-	-	-	-							76	
Apr	-	-	-	-	-	-	-	-	-	-	-	-	69	-	-	-	-	-	-							75	
May	-	-	-	-	-	-	-	-	-	-	-	-	68	-	-	-	-	-	-							74	
Jun	-	-	-	-	-	-	-	-	-	-	-	-	67	-	-	-	-	-	-							73	
Jul	-	-	-	-	-	-	-	-	-	-	-	-	66	-	-	-	-	-	-							72	
Aug	-	-	-	-	-	-	-	-	-	-	-	-	65	-	-	-	-	-	-							71	
Sep	-	-	-	-	-	-	-	-	-	-	-	-	64	-	-	-	-	-	-							70	
Oct	-	-	-	-	-	-	-	-	-	-	-	-	63	-	-	-	-	-	-							69	
Nov	-	-	-	-	-	-	-	-	-	-	-	-	62	-	-	-	-	-	-							68	
Dec	-	-	-	-	-	-	-	-	-	-	-	-	61	-	-	-	-	-	-							67	
Total (Cumulative by Month) - Adjusted kWh (Net):	9,214	9,214	9,214	9,214	9,214	9,214	9,214	9,214	9,214	9,214	9,214	9,214		9,214	9,214	9,214	9,214	9,214	9,214	-	-	-	-	-	-		776,305 True-up
DNV GL Tracking																											
Schedule 5	1,089	1,089	1,089	1,089	1,089	1,089	1,089	1,089	1,089	1,089	1,089	1,089		1,089	1,089	1,089	1,089	1,089	1,089	-	-	-	-	-	-		
Schedule 6P (TOU)	1,047	1,047	1,047	1,047	1,047	1,047	1,047	1,047	1,047	1,047	1,047	1,047		1,047	1,047	1,047	1,047	1,047	1,047	-	-	-	-	-	-		
Schedule 10 (Variable Pricing)	5,761	5,761	5,761	5,761	5,761	5,761	5,761	5,761	5,761	5,761	5,761	5,761		5,761	5,761	5,761	5,761	5,761	5,761	-	-	-	-	-	-		
Schedule 30 - Public Authority	1,317	1,317	1,317	1,317	1,317	1,317	1,317	1,317	1,317	1,317	1,317	1,317		1,317	1,317	1,317	1,317	1,317	1,317	-	-	-	-	-	-		
	9,214	9,214	9,214	9,214	9,214	9,214	9,214	9,214	9,214	9,214	9,214	9,214		9,214	9,214	9,214	9,214	9,214	9,214	-	-	-	-	-	-		

Actual kWh (Jan. - Dec., 2018): 110,566

Actual kWh (Jan. - Dec., 2019): 55,283 | 776,305

																											Total
Participation	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	15
	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	4
													0%													0%	25%

NOTES:

1. The kWh savings are based on actual participation from Dominion North Carolina Power customers with program planning realization and net-to-gross adjustments assumptions applied
2. The May 1, 2019 EM&V Report was filed with the NC Public Utilities Commission and included EM&V data through the end of 2018.
3. The EM&V data reflected for January 2018 - June, 2019 was prepared by DNV GL using the same STEP (Standard Tracking Engineering Protocol) formulas used in preparing the EM&V data for 2018.
4. The kWh savings are inclusive of all EE measures installed from program inception through June 30, 2019.
5. Program measure life is 15 years (180 months)

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		2011								2012												
		1	2	3	4	5	6	7		8	9	10	11	12	13	14	15	16	17	18	19	
kWh (Net) in North Carolina		June	July	Aug	Sept.	Oct.	Nov.	Dec.	Total	Jan.	Feb.	March	April	May	June	July	Aug	Sept.	Oct.	Nov.	Dec.	Total
Commercial Lighting - kWh /year Savings (Deemed with assumed realization and net-to-gross rates from May 1, 2019 EMV Report)		-	-	-	-	-	-	1,581,849	1,581,849	63,302	2,180	2,824	21,725	-	174,582	18,769	10,280	-	-	71,303	-	1,946,814
Monthly - Adjusted kWh (Net)									Total Months													Total Months
Jun, 2011		-	-	-	-	-	-	-	7	-	-	-	-	-	-	-	-	-	-	-	-	19
Jul			-	-	-	-	-	-	6	-	-	-	-	-	-	-	-	-	-	-	-	18
Aug				-	-	-	-	-	5	-	-	-	-	-	-	-	-	-	-	-	-	17
Sep					-	-	-	-	4	-	-	-	-	-	-	-	-	-	-	-	-	16
Oct						-	-	-	3	-	-	-	-	-	-	-	-	-	-	-	-	15
Nov							-	-	2	-	-	-	-	-	-	-	-	-	-	-	-	14
Dec								131,821	1	131,821	131,821	131,821	131,821	131,821	131,821	131,821	131,821	131,821	131,821	131,821	131,821	13
Jan, 2012										5,275	5,275	5,275	5,275	5,275	5,275	5,275	5,275	5,275	5,275	5,275	5,275	12
Feb											182	182	182	182	182	182	182	182	182	182	182	11
Mar												235	235	235	235	235	235	235	235	235	235	10
Apr													1,810	1,810	1,810	1,810	1,810	1,810	1,810	1,810	1,810	9
May														-	-	-	-	-	-	-	-	8
Jun															14,549	14,549	14,549	14,549	14,549	14,549	14,549	7
Jul																1,564	1,564	1,564	1,564	1,564	1,564	6
Aug																	857	857	857	857	857	5
Sep																		-	-	-	-	4
Oct																			-	-	-	3
Nov																				5,942	5,942	2
Dec																					-	1
Total (Cumulative by Month) - Adjusted kWh (Net):		-	-	-	-	-	-	131,821		137,096	137,278	137,513	139,323	139,323	153,872	155,436	156,293	156,293	156,293	162,235	162,235	
DNV GL Tracking																						
Schedule 5	27%							34,984		36,384	36,432	36,494	36,975	36,975	40,836	41,251	41,478	41,478	41,478	43,055	43,055	
Schedule 5P	4%							5,872		6,107	6,115	6,126	6,206	6,206	6,854	6,924	6,962	6,962	6,962	7,227	7,227	
Schedule 6P (TOU)	61%							80,777		84,009	84,121	84,265	85,374	85,374	94,289	95,248	95,773	95,773	95,773	99,414	99,414	
Schedule 10 (Variable Pricing)	5%							6,668		6,935	6,944	6,956	7,048	7,048	7,784	7,863	7,906	7,906	7,906	8,207	8,207	
Schedule 30 - Public Authority	1%							816		848	849	851	862	862	952	962	967	967	967	1,004	1,004	
Schedule 42	0%							365		379	380	381	386	386	426	430	433	433	433	449	449	
Schedule 26 –NC Outdoor Lighting	2%							2,340		2,433	2,436	2,441	2,473	2,473	2,731	2,759	2,774	2,774	2,774	2,879	2,879	
			-	-	-	-	-	131,821	-	137,096	137,278	137,513	139,323	139,323	153,872	155,436	156,293	156,293	156,293	162,235	162,235	

Actual kWh (Jun. - Dec., 2011): 131,821

Actual kWh (Jan. - Dec., 2012): 1,793,188

Participation																				
Planned:	0	0	0	0	0	2	2	0	0	0	0	0	0	0	0	0	0	0	9	9
Actual:	0	0	0	0	0	1	1	1	2	2	12	0	3	3	1	0	0	1	0	25
							50%													278%

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2013													2014												
20	21	22	23	24	25	26	27	28	29	30	31		32	33	34	35	36	37	38	39	40	41	42	43	
Jan.	Feb.	March	April	May	June	July	Aug	Sept.	Oct.	Nov.	Dec.	Total	Jan.	Feb.	March	April	May	June	July	Aug	Sept.	Oct.	Nov.	Dec.	Total
-	-	-	-	-	-	-	-	-	-	-	-	1,946,814	-	-	-	-	158,762	138,779	83,621	-	135,305	-	263,736	16,450	2,743,467
												Total Months													Total Months
-	-	-	-	-	-	-	-	-	-	-	-	31	-	-	-	-	-	-	-	-	-	-	-	-	43
-	-	-	-	-	-	-	-	-	-	-	-	30	-	-	-	-	-	-	-	-	-	-	-	-	42
-	-	-	-	-	-	-	-	-	-	-	-	29	-	-	-	-	-	-	-	-	-	-	-	-	41
-	-	-	-	-	-	-	-	-	-	-	-	28	-	-	-	-	-	-	-	-	-	-	-	-	40
-	-	-	-	-	-	-	-	-	-	-	-	27	-	-	-	-	-	-	-	-	-	-	-	-	39
-	-	-	-	-	-	-	-	-	-	-	-	26	-	-	-	-	-	-	-	-	-	-	-	-	38
131,821	131,821	131,821	131,821	131,821	131,821	131,821	131,821	131,821	131,821	131,821	131,821	25	131,821	131,821	131,821	131,821	131,821	131,821	131,821	131,821	131,821	131,821	131,821	131,821	37
5,275	5,275	5,275	5,275	5,275	5,275	5,275	5,275	5,275	5,275	5,275	5,275	24	5,275	5,275	5,275	5,275	5,275	5,275	5,275	5,275	5,275	5,275	5,275	5,275	36
182	182	182	182	182	182	182	182	182	182	182	182	23	182	182	182	182	182	182	182	182	182	182	182	182	35
235	235	235	235	235	235	235	235	235	235	235	235	22	235	235	235	235	235	235	235	235	235	235	235	235	34
1,810	1,810	1,810	1,810	1,810	1,810	1,810	1,810	1,810	1,810	1,810	1,810	21	1,810	1,810	1,810	1,810	1,810	1,810	1,810	1,810	1,810	1,810	1,810	1,810	33
-	-	-	-	-	-	-	-	-	-	-	-	20	-	-	-	-	-	-	-	-	-	-	-	-	32
14,549	14,549	14,549	14,549	14,549	14,549	14,549	14,549	14,549	14,549	14,549	14,549	19	14,549	14,549	14,549	14,549	14,549	14,549	14,549	14,549	14,549	14,549	14,549	14,549	31
1,564	1,564	1,564	1,564	1,564	1,564	1,564	1,564	1,564	1,564	1,564	1,564	18	1,564	1,564	1,564	1,564	1,564	1,564	1,564	1,564	1,564	1,564	1,564	1,564	30
857	857	857	857	857	857	857	857	857	857	857	857	17	857	857	857	857	857	857	857	857	857	857	857	857	29
-	-	-	-	-	-	-	-	-	-	-	-	16	-	-	-	-	-	-	-	-	-	-	-	-	28
-	-	-	-	-	-	-	-	-	-	-	-	15	-	-	-	-	-	-	-	-	-	-	-	-	27
5,942	5,942	5,942	5,942	5,942	5,942	5,942	5,942	5,942	5,942	5,942	5,942	14	5,942	5,942	5,942	5,942	5,942	5,942	5,942	5,942	5,942	5,942	5,942	5,942	26
-	-	-	-	-	-	-	-	-	-	-	-	13	-	-	-	-	-	-	-	-	-	-	-	-	25
													-	-	-	-	-	-	-	-	-	-	-	-	12
														-	-	-	-	-	-	-	-	-	-	-	11
															-	-	-	-	-	-	-	-	-	-	10
																-	-	-	-	-	-	-	-	-	9
																	13,230	13,230	13,230	13,230	13,230	13,230	13,230	13,230	8
																		11,565	11,565	11,565	11,565	11,565	11,565	11,565	7
																			6,968	6,968	6,968	6,968	6,968	6,968	6
																				-	-	-	-	-	5
																					11,275	11,275	11,275	11,275	4
																						-	-	-	3
																							21,978	21,978	2
																								1,371	1
162,235	162,235	162,235	162,235	162,235	162,235	162,235	162,235	162,235	162,235	162,235	162,235		162,235	162,235	162,235	162,235	175,465	187,030	193,998	193,998	205,273	205,273	227,251	228,622	
43,055	43,055	43,055	43,055	43,055	43,055	43,055	43,055	43,055	43,055	43,055	43,055		43,055	43,055	43,055	43,055	46,566	49,635	51,485	51,485	54,477	54,477	60,310	60,674	
7,227	7,227	7,227	7,227	7,227	7,227	7,227	7,227	7,227	7,227	7,227	7,227		7,227	7,227	7,227	7,227	7,816	8,331	8,642	8,642	9,144	9,144	10,123	10,184	
99,414	99,414	99,414	99,414	99,414	99,414	99,414	99,414	99,414	99,414	99,414	99,414		99,414	99,414	99,414	99,414	107,521	114,607	118,878	118,878	125,787	125,787	139,254	140,095	
8,207	8,207	8,207	8,207	8,207	8,207	8,207	8,207	8,207	8,207	8,207	8,207		8,207	8,207	8,207	8,207	8,876	9,461	9,813	9,813	10,384	10,384	21,496	21,565	
1,004	1,004	1,004	1,004	1,004	1,004	1,004	1,004	1,004	1,004	1,004	1,004		1,004	1,004	1,004	1,004	1,086	1,157	1,200	1,200	1,270	1,270	1,406	1,415	
449	449	449	449	449	449	449	449	449	449	449	449		449	449	449	449	486	518	537	537	568	568	629	633	
2,879	2,879	2,879	2,879	2,879	2,879	2,879	2,879	2,879	2,879	2,879	2,879		2,879	2,879	2,879	2,879	3,114	3,319	3,443	3,443	3,643	3,643	4,033	4,058	
162,235	162,235	162,235	162,235	162,235	162,235	162,235	162,235	162,235	162,235	162,235	162,235		162,235	162,235	162,235	162,235	175,465	187,030	193,998	193,998	205,273	205,273	227,251	228,622	

Actual kWh (Jan. - Dec., 2013):	1,946,814
Actual kWh (Jan. - Dec., 2014):	2,255,849

0	0	0	0	0	0	0	0	0	0	0	0	0	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	4
0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	4	1	1	0	2	0	11	2	21
												0%													530%

Dominion Energy North Carolina
Docket No. E-22, Sub 562

2015

44 Jan.	45 Feb.	46 March	47 April	48 May	49 June	50 July	51 Aug.	52 Sept.	53 Oct.	54 Nov.	55 Dec.	Total
-	-	-	-	-	-	-	-	-	-	-	-	2,743,467
												Total Months
-	-	-	-	-	-	-	-	-	-	-	-	55
-	-	-	-	-	-	-	-	-	-	-	-	54
-	-	-	-	-	-	-	-	-	-	-	-	53
-	-	-	-	-	-	-	-	-	-	-	-	52
-	-	-	-	-	-	-	-	-	-	-	-	51
-	-	-	-	-	-	-	-	-	-	-	-	50
131,821	131,821	131,821	131,821	131,821	131,821	131,821	131,821	131,821	131,821	131,821	131,821	49
5,275	5,275	5,275	5,275	5,275	5,275	5,275	5,275	5,275	5,275	5,275	5,275	48
182	182	182	182	182	182	182	182	182	182	182	182	47
235	235	235	235	235	235	235	235	235	235	235	235	46
1,810	1,810	1,810	1,810	1,810	1,810	1,810	1,810	1,810	1,810	1,810	1,810	45
-	-	-	-	-	-	-	-	-	-	-	-	44
14,549	14,549	14,549	14,549	14,549	14,549	14,549	14,549	14,549	14,549	14,549	14,549	43
1,564	1,564	1,564	1,564	1,564	1,564	1,564	1,564	1,564	1,564	1,564	1,564	42
857	857	857	857	857	857	857	857	857	857	857	857	41
-	-	-	-	-	-	-	-	-	-	-	-	40
-	-	-	-	-	-	-	-	-	-	-	-	39
5,942	5,942	5,942	5,942	5,942	5,942	5,942	5,942	5,942	5,942	5,942	5,942	38
-	-	-	-	-	-	-	-	-	-	-	-	37
-	-	-	-	-	-	-	-	-	-	-	-	24
-	-	-	-	-	-	-	-	-	-	-	-	23
-	-	-	-	-	-	-	-	-	-	-	-	22
-	-	-	-	-	-	-	-	-	-	-	-	21
13,230	13,230	13,230	13,230	13,230	13,230	13,230	13,230	13,230	13,230	13,230	13,230	20
11,565	11,565	11,565	11,565	11,565	11,565	11,565	11,565	11,565	11,565	11,565	11,565	19
6,968	6,968	6,968	6,968	6,968	6,968	6,968	6,968	6,968	6,968	6,968	6,968	18
-	-	-	-	-	-	-	-	-	-	-	-	17
11,275	11,275	11,275	11,275	11,275	11,275	11,275	11,275	11,275	11,275	11,275	11,275	16
-	-	-	-	-	-	-	-	-	-	-	-	15
21,978	21,978	21,978	21,978	21,978	21,978	21,978	21,978	21,978	21,978	21,978	21,978	14
1,371	1,371	1,371	1,371	1,371	1,371	1,371	1,371	1,371	1,371	1,371	1,371	13
228,622	228,622	228,622	228,622	228,622	228,622	228,622	228,622	228,622	228,622	228,622	228,622	
60,674	60,674	60,674	60,674	60,674	60,674	60,674	60,674	60,674	60,674	60,674	60,674	
10,184	10,184	10,184	10,184	10,184	10,184	10,184	10,184	10,184	10,184	10,184	10,184	
140,095	140,095	140,095	140,095	140,095	140,095	140,095	140,095	140,095	140,095	140,095	140,095	
11,565	11,565	11,565	11,565	11,565	11,565	11,565	11,565	11,565	11,565	11,565	11,565	
1,415	1,415	1,415	1,415	1,415	1,415	1,415	1,415	1,415	1,415	1,415	1,415	
633	633	633	633	633	633	633	633	633	633	633	633	
4,058	4,058	4,058	4,058	4,058	4,058	4,058	4,058	4,058	4,058	4,058	4,058	
228,622	228,622	228,622	228,622	228,622	228,622	228,622	228,622	228,622	228,622	228,622	228,622	

Actual kWh (Jan. - Dec., 2015): [redacted] 2,743,467

0	0	0	0	0	0	0	0	0	0	0	0	[redacted] 0
0	0	0	0	0	0	0	0	0	0	0	0	[redacted] 0
												[redacted] 0%

2016

56 Jan.	57 Feb.	58 March	59 April	60 May	61 June	62 July	63 Aug.	64 Sept.	65 Oct.	66 Nov.	67 Dec.	Total
-	-	-	-	-	-	-	-	-	-	-	-	2,743,467
												Total Months
-	-	-	-	-	-	-	-	-	-	-	-	67
-	-	-	-	-	-	-	-	-	-	-	-	66
-	-	-	-	-	-	-	-	-	-	-	-	65
-	-	-	-	-	-	-	-	-	-	-	-	64
-	-	-	-	-	-	-	-	-	-	-	-	63
-	-	-	-	-	-	-	-	-	-	-	-	62
131,821	131,821	131,821	131,821	131,821	131,821	131,821	131,821	131,821	131,821	131,821	131,821	61
5,275	5,275	5,275	5,275	5,275	5,275	5,275	5,275	5,275	5,275	5,275	5,275	60
182	182	182	182	182	182	182	182	182	182	182	182	59
235	235	235	235	235	235	235	235	235	235	235	235	58
1,810	1,810	1,810	1,810	1,810	1,810	1,810	1,810	1,810	1,810	1,810	1,810	57
-	-	-	-	-	-	-	-	-	-	-	-	56
14,549	14,549	14,549	14,549	14,549	14,549	14,549	14,549	14,549	14,549	14,549	14,549	55
1,564	1,564	1,564	1,564	1,564	1,564	1,564	1,564	1,564	1,564	1,564	1,564	54
857	857	857	857	857	857	857	857	857	857	857	857	53
-	-	-	-	-	-	-	-	-	-	-	-	52
-	-	-	-	-	-	-	-	-	-	-	-	51
5,942	5,942	5,942	5,942	5,942	5,942	5,942	5,942	5,942	5,942	5,942	5,942	50
-	-	-	-	-	-	-	-	-	-	-	-	49
-	-	-	-	-	-	-	-	-	-	-	-	36
-	-	-	-	-	-	-	-	-	-	-	-	35
-	-	-	-	-	-	-	-	-	-	-	-	34
-	-	-	-	-	-	-	-	-	-	-	-	33
13,230	13,230	13,230	13,230	13,230	13,230	13,230	13,230	13,230	13,230	13,230	13,230	32
11,565	11,565	11,565	11,565	11,565	11,565	11,565	11,565	11,565	11,565	11,565	11,565	31
6,968	6,968	6,968	6,968	6,968	6,968	6,968	6,968	6,968	6,968	6,968	6,968	30
-	-	-	-	-	-	-	-	-	-	-	-	29
11,275	11,275	11,275	11,275	11,275	11,275	11,275	11,275	11,275	11,275	11,275	11,275	28
-	-	-	-	-	-	-	-	-	-	-	-	27
21,978	21,978	21,978	21,978	21,978	21,978	21,978	21,978	21,978	21,978	21,978	21,978	26
1,371	1,371	1,371	1,371	1,371	1,371	1,371	1,371	1,371	1,371	1,371	1,371	25
228,622	228,622	228,622	228,622	228,622	228,622	228,622	228,622	228,622	228,622	228,622	228,622	[redacted]
60,674	60,674	60,674	60,674	60,674	60,674	60,674	60,674	60,674	60,674	60,674	60,674	[redacted]
10,184	10,184	10,184	10,184	10,184	10,184	10,184	10,184	10,184	10,184	10,184	10,184	
140,095	140,095	140,095	140,095	140,095	140,095	140,095	140,095	140,095	140,095	140,095	140,095	
11,565	11,565	11,565	11,565	11,565	11,565	11,565	11,565	11,565	11,565	11,565	11,565	
1,415	1,415	1,415	1,415	1,415	1,415	1,415	1,415	1,415	1,415	1,415	1,415	
633	633	633	633	633	633	633	633	633	633	633	633	
4,058	4,058	4,058	4,058	4,058	4,058	4,058	4,058	4,058	4,058	4,058	4,058	
228,622	228,622	228,622	228,622	228,622	228,622	228,622	228,622	228,622	228,622	228,622	228,622	

Actual kWh (Jan. - Dec., 2016): [redacted] 2,743,467

0	0	0	0	0	0	0	0	0	0	0	0	[redacted] 0
0	0	0	0	0	0	0	0	0	0	0	0	[redacted] 0
												[redacted] 0%

2017												
68	69	70	71	72	73	74	75	76	77	78	79	
Jan.	Feb.	March	April	May	June	July	Aug.	Sept.	Oct.	Nov.	Dec.	Total
-	-	-	-	-	-	-	-	-	-	-	-	2,743,467
												Total Months
-	-	-	-	-	-	-	-	-	-	-	-	79
-	-	-	-	-	-	-	-	-	-	-	-	78
-	-	-	-	-	-	-	-	-	-	-	-	77
-	-	-	-	-	-	-	-	-	-	-	-	76
-	-	-	-	-	-	-	-	-	-	-	-	75
-	-	-	-	-	-	-	-	-	-	-	-	74
131,821	131,821	131,821	131,821	131,821	131,821	131,821	131,821	131,821	131,821	131,821	131,821	73
5,275	5,275	5,275	5,275	5,275	5,275	5,275	5,275	5,275	5,275	5,275	5,275	72
182	182	182	182	182	182	182	182	182	182	182	182	71
235	235	235	235	235	235	235	235	235	235	235	235	70
1,810	1,810	1,810	1,810	1,810	1,810	1,810	1,810	1,810	1,810	1,810	1,810	69
-	-	-	-	-	-	-	-	-	-	-	-	68
14,549	14,549	14,549	14,549	14,549	14,549	14,549	14,549	14,549	14,549	14,549	14,549	67
1,564	1,564	1,564	1,564	1,564	1,564	1,564	1,564	1,564	1,564	1,564	1,564	66
857	857	857	857	857	857	857	857	857	857	857	857	65
-	-	-	-	-	-	-	-	-	-	-	-	64
-	-	-	-	-	-	-	-	-	-	-	-	63
5,942	5,942	5,942	5,942	5,942	5,942	5,942	5,942	5,942	5,942	5,942	5,942	62
-	-	-	-	-	-	-	-	-	-	-	-	61
-	-	-	-	-	-	-	-	-	-	-	-	48
-	-	-	-	-	-	-	-	-	-	-	-	47
-	-	-	-	-	-	-	-	-	-	-	-	46
-	-	-	-	-	-	-	-	-	-	-	-	45
13,230	13,230	13,230	13,230	13,230	13,230	13,230	13,230	13,230	13,230	13,230	13,230	44
11,565	11,565	11,565	11,565	11,565	11,565	11,565	11,565	11,565	11,565	11,565	11,565	43
6,968	6,968	6,968	6,968	6,968	6,968	6,968	6,968	6,968	6,968	6,968	6,968	42
-	-	-	-	-	-	-	-	-	-	-	-	41
11,275	11,275	11,275	11,275	11,275	11,275	11,275	11,275	11,275	11,275	11,275	11,275	40
-	-	-	-	-	-	-	-	-	-	-	-	39
21,978	21,978	21,978	21,978	21,978	21,978	21,978	21,978	21,978	21,978	21,978	21,978	38
1,371	1,371	1,371	1,371	1,371	1,371	1,371	1,371	1,371	1,371	1,371	1,371	37
228,622	228,622	228,622	228,622	228,622	228,622	228,622	228,622	228,622	228,622	228,622	228,622	
60,674	60,674	60,674	60,674	60,674	60,674	60,674	60,674	60,674	60,674	60,674	60,674	
10,184	10,184	10,184	10,184	10,184	10,184	10,184	10,184	10,184	10,184	10,184	10,184	
140,095	140,095	140,095	140,095	140,095	140,095	140,095	140,095	140,095	140,095	140,095	140,095	
11,565	11,565	11,565	11,565	11,565	11,565	11,565	11,565	11,565	11,565	11,565	11,565	
1,415	1,415	1,415	1,415	1,415	1,415	1,415	1,415	1,415	1,415	1,415	1,415	
633	633	633	633	633	633	633	633	633	633	633	633	
4,058	4,058	4,058	4,058	4,058	4,058	4,058	4,058	4,058	4,058	4,058	4,058	
228,622	228,622	228,622	228,622	228,622	228,622	228,622	228,622	228,622	228,622	228,622	228,622	
										Actual kWh (Jan. - Dec., 2017):		2,743,467
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%

2018												
80	81	82	83	84	85	86	87	88	89	90	91	
Jan.	Feb.	March	April	May	June	July	Aug.	Sept.	Oct.	Nov.	Dec.	Total
-	-	-	-	-	-	-	-	-	-	-	-	2,743,467
												Total Months
-	-	-	-	-	-	-	-	-	-	-	-	91
-	-	-	-	-	-	-	-	-	-	-	-	90
-	-	-	-	-	-	-	-	-	-	-	-	89
-	-	-	-	-	-	-	-	-	-	-	-	88
-	-	-	-	-	-	-	-	-	-	-	-	87
-	-	-	-	-	-	-	-	-	-	-	-	86
131,821	131,821	131,821	131,821	131,821	131,821	131,821	131,821	131,821	131,821	131,821	131,821	85
5,275	5,275	5,275	5,275	5,275	5,275	5,275	5,275	5,275	5,275	5,275	5,275	84
182	182	182	182	182	182	182	182	182	182	182	182	83
235	235	235	235	235	235	235	235	235	235	235	235	82
1,810	1,810	1,810	1,810	1,810	1,810	1,810	1,810	1,810	1,810	1,810	1,810	81
-	-	-	-	-	-	-	-	-	-	-	-	80
14,549	14,549	14,549	14,549	14,549	14,549	14,549	14,549	14,549	14,549	14,549	14,549	79
1,564	1,564	1,564	1,564	1,564	1,564	1,564	1,564	1,564	1,564	1,564	1,564	78
857	857	857	857	857	857	857	857	857	857	857	857	77
-	-	-	-	-	-	-	-	-	-	-	-	76
-	-	-	-	-	-	-	-	-	-	-	-	75
5,942	5,942	5,942	5,942	5,942	5,942	5,942	5,942	5,942	5,942	5,942	5,942	74
-	-	-	-	-	-	-	-	-	-	-	-	73
-	-	-	-	-	-	-	-	-	-	-	-	60
-	-	-	-	-	-	-	-	-	-	-	-	59
-	-	-	-	-	-	-	-	-	-	-	-	58
-	-	-	-	-	-	-	-	-	-	-	-	57
13,230	13,230	13,230	13,230	13,230	13,230	13,230	13,230	13,230	13,230	13,230	13,230	56
11,565	11,565	11,565	11,565	11,565	11,565	11,565	11,565	11,565	11,565	11,565	11,565	55
6,968	6,968	6,968	6,968	6,968	6,968	6,968	6,968	6,968	6,968	6,968	6,968	54
-	-	-	-	-	-	-	-	-	-	-	-	53
11,275	11,275	11,275	11,275	11,275	11,275	11,275	11,275	11,275	11,275	11,275	11,275	52
-	-	-	-	-	-	-	-	-	-	-	-	51
21,978	21,978	21,978	21,978	21,978	21,978	21,978	21,978	21,978	21,978	21,978	21,978	50
1,371	1,371	1,371	1,371	1,371	1,371	1,371	1,371	1,371	1,371	1,371	1,371	49
228,622	228,622	228,622	228,622	228,622	228,622	228,622	228,622	228,622	228,622	228,622	228,622	
60,674	60,674	60,674	60,674	60,674	60,674	60,674	60,674	60,674	60,674	60,674	60,674	
10,184	10,184	10,184	10,184	10,184	10,184	10,184	10,184	10,184	10,184	10,184	10,184	
140,095	140,095	140,095	140,095	140,095	140,095	140,095	140,095	140,095	140,095	140,095	140,095	
11,565	11,565	11,565	11,565	11,565	11,565	11,565	11,565	11,565	11,565	11,565	11,565	
1,415	1,415	1,415	1,415	1,415	1,415	1,415	1,415	1,415	1,415	1,415	1,415	
633	633	633	633	633	633	633	633	633	633	633	633	
4,058	4,058	4,058	4,058	4,058	4,058	4,058	4,058	4,058	4,058	4,058	4,058	
228,622	228,622	228,622	228,622	228,622	228,622	228,622	228,622	228,622	228,622	228,622	228,622	
										Actual kWh (Jan. - Dec., 2018):		2,743,467
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%

	2019													
	92	93	94	95	96	97	98	99	100	101	102	103		
kWh (Net) in North Carolina	Jan.	Feb.	March	April	May	June	July	Aug.	Sept.	Oct.	Nov.	Dec.	Total	Total
Commercial Lighting - kWh /year Savings (Deemed with assumed realization and net-to-gross rates from May 1, 2019 EMV Report)	-	-	-	-	-	-							2,743,467	2,743,467
Monthly - Adjusted kWh (Net)													Total Months	
Jun, 2011	-	-	-	-	-	-							97	
Jul	-	-	-	-	-	-							96	
Aug	-	-	-	-	-	-							95	
Sep	-	-	-	-	-	-							94	
Oct	-	-	-	-	-	-							93	
Nov	-	-	-	-	-	-							92	
Dec	131,821	131,821	131,821	131,821	131,821	131,821							91	
Jan, 2012	5,275	5,275	5,275	5,275	5,275	5,275							90	
Feb	182	182	182	182	182	182							89	
Mar	235	235	235	235	235	235							88	
Apr	1,810	1,810	1,810	1,810	1,810	1,810							87	
May	-	-	-	-	-	-							86	
Jun	14,549	14,549	14,549	14,549	14,549	14,549							85	
Jul	1,564	1,564	1,564	1,564	1,564	1,564							84	
Aug	857	857	857	857	857	857							83	
Sep	-	-	-	-	-	-							82	
Oct	-	-	-	-	-	-							81	
Nov	5,942	5,942	5,942	5,942	5,942	5,942							80	
Dec	-	-	-	-	-	-							79	
Jan, 2014	-	-	-	-	-	-							66	
Feb	-	-	-	-	-	-							65	
Mar	-	-	-	-	-	-							64	
Apr	-	-	-	-	-	-							63	
May	13,230	13,230	13,230	13,230	13,230	13,230							62	
Jun	11,565	11,565	11,565	11,565	11,565	11,565							61	
Jul	6,968	6,968	6,968	6,968	6,968	6,968							60	
Aug	-	-	-	-	-	-							59	
Sep	11,275	11,275	11,275	11,275	11,275	11,275							58	
Oct	-	-	-	-	-	-							57	
Nov	21,978	21,978	21,978	21,978	21,978	21,978							56	
Dec	1,371	1,371	1,371	1,371	1,371	1,371							55	
Total (Cumulative by Month) - Adjusted kWh (Net):	228,622	228,622	228,622	228,622	228,622	228,622	-	-	-	-	-	-		18,483,273 True-up
DNV GL Tracking														
Schedule 5	60,674	60,674	60,674	60,674	60,674	60,674	0	0	0	0	0	0		
Schedule 5P	10,184	10,184	10,184	10,184	10,184	10,184	0	0	0	0	0	0		
Schedule 6P (TOU)	140,095	140,095	140,095	140,095	140,095	140,095	0	0	0	0	0	0		
Schedule 10 (Variable Pricing)	11,565	11,565	11,565	11,565	11,565	11,565	0	0	0	0	0	0		
Schedule 30 - Public Authority	1,415	1,415	1,415	1,415	1,415	1,415	0	0	0	0	0	0		
Schedule 42	633	633	633	633	633	633	0	0	0	0	0	0		
Schedule 26 –NC Outdoor Lighting	4,058	4,058	4,058	4,058	4,058	4,058	0	0	0	0	0	0		
	228,622	228,622	228,622	228,622	228,622	228,622	-	-	-	-	-	-		

Actual kWh (Jan. - Dec., 2019):	1,371,734	18,483,273

	Jan.	Feb.	March	April	May	June	July	Aug.	Sept.	Oct.	Nov.	Dec.		Total
Participation	0	0	0	0	0	0	0	0	0	0	0	0	0	15
	0	0	0	0	0	0	0	0	0	0	0	0	0	47
													0%	314%

NOTES:

1. The kWh savings are based on actual participation from Dominion North Carolina Power customers with program planning realization and net-to-gross adjustments assumptions applied
2. The May 1, 2019 EM&V Report was filed with the NC Public Utilities Commission and included EM&V data through the end of 2018.
3. The EM&V data reflected for January 2018 - June, 2019 was prepared by DNV GL using the same STEP (Standard Tracking Engineering Protocol) formulas used in preparing the EM&V data for 2018.
4. The kWh savings are inclusive of all EE measures installed from program inception through June 30, 2019.
5. Program measure life is 10 years (120 months)

	2014													2015												
					1	2	3	4	5	6	7	8		9	10	11	12	13	14	15	16	17	18	19	20	
kWh (Net) in North Carolina	Jan.	Feb.	March	April	May	June	July	Aug	Sept.	Oct.	Nov.	Dec.	Total	Jan.	Feb.	March	April	May	June	July	Aug	Sept.	Oct.	Nov.	Dec.	Total
Residential Heat Pump Tune Up - kWh /year Savings (Deemed with assumed realization and net-to-gross rates from May 1, 2019 EMV Report)	-	-	-	-	1,222	1,088	497	4,052	3,221	18,916	60,692	48,568	138,256	101,889	69,504	58,979	80,127	70,745	120,445	64,345	38,239	75,711	39,023	23,212	11,031	891,506
Monthly - Adjusted kWh (Net)													Total Months													Total Months
Jan, 2014	-	-	-	-	-	-	-	-	-	-	-	-	12	-	-	-	-	-	-	-	-	-	-	-	-	24
Feb		-	-	-	-	-	-	-	-	-	-	-	11	-	-	-	-	-	-	-	-	-	-	-	-	23
Mar			-	-	-	-	-	-	-	-	-	-	10	-	-	-	-	-	-	-	-	-	-	-	-	22
Apr				-	-	-	-	-	-	-	-	-	9	-	-	-	-	-	-	-	-	-	-	-	-	21
May					102	102	102	102	102	102	102	102	8	102	102	102	102	102	102	102	102	102	102	102	102	20
Jun						91	91	91	91	91	91	91	7	91	91	91	91	91	91	91	91	91	91	91	91	19
Jul							41	41	41	41	41	41	6	41	41	41	41	41	41	41	41	41	41	41	41	18
Aug								338	338	338	338	338	5	338	338	338	338	338	338	338	338	338	338	338	338	17
Sep									268	268	268	268	4	268	268	268	268	268	268	268	268	268	268	268	268	16
Oct										1,576	1,576	1,576	3	1,576	1,576	1,576	1,576	1,576	1,576	1,576	1,576	1,576	1,576	1,576	1,576	15
Nov											5,058	5,058	2	5,058	5,058	5,058	5,058	5,058	5,058	5,058	5,058	5,058	5,058	5,058	5,058	14
Dec												4,047	1	4,047	4,047	4,047	4,047	4,047	4,047	4,047	4,047	4,047	4,047	4,047	4,047	13
Jan, 2015														8,491	8,491	8,491	8,491	8,491	8,491	8,491	8,491	8,491	8,491	8,491	8,491	12
Feb															5,792	5,792	5,792	5,792	5,792	5,792	5,792	5,792	5,792	5,792	5,792	11
Mar																4,915	4,915	4,915	4,915	4,915	4,915	4,915	4,915	4,915	4,915	10
Apr																	6,677	6,677	6,677	6,677	6,677	6,677	6,677	6,677	6,677	9
May																		5,895	5,895	5,895	5,895	5,895	5,895	5,895	5,895	8
Jun																			10,037	10,037	10,037	10,037	10,037	10,037	10,037	7
Jul																				5,362	5,362	5,362	5,362	5,362	5,362	6
Aug																					3,187	3,187	3,187	3,187	3,187	5
Sep																						6,309	6,309	6,309	6,309	4
Oct																							3,252	3,252	3,252	3
Nov																								1,934	1,934	2
Dec																									919	1
Total (Cumulative by Month) - Adjusted kWh (Net):	-	-	-	-	102	193	234	572	840	2,416	7,474	11,521		20,012	25,804	30,719	37,396	43,292	53,329	58,691	61,877	68,187	71,439	73,373	74,292	

DNV GL Tracking																									
Schedule 1 [redacted]	99.1%	0	0	0	0	101	101	232	567	833	2,395	7,409	11,421	19,837	25,579	30,451	37,069	42,913	52,863	58,178	61,337	67,591	70,814	72,732	73,643
Schedule 10F [redacted]	0.3%	0	0	0	0	0	1	1	2	3	8	24	37	64	82	98	119	138	170	187	197	217	228	234	237
Schedule 1P [redacted]	0.3%	0	0	0	0	0	1	1	2	3	8	26	40	70	90	107	130	151	185	204	215	237	248	255	258
Schedule 1T [redacted]	0.2%	0	0	0	0	0	0	0	1	2	5	16	24	42	54	64	78	90	111	122	129	142	149	152	154
	100.0%	-	-	-	-	102	193	234	572	840	2,416	7,474	11,521	20,012	25,804	30,719	37,396	43,292	53,329	58,691	61,877	68,187	71,439	73,373	74,292

Actual kWh (Jan. - Dec., 2014): 23,352

Actual kWh (Jan. - Dec., 2015): 618,410

Participation																										
Planned:	111	167	194	417	389	278	222	194	194	194	278	139	2,777	111	167	194	417	389	278	272	194	194	194	278	139	2,777
Actual:					3	3	2	17	14	82	263	197	681	448	316	254	342	313	523	282	171	336	169	102	51	3,307
													21%													119%

2016													2017												
21	22	23	24	25	26	27	28	29	30	31	32		33	34	35	36	37	38	39	40	41	42	43	44	
Jan.	Feb.	March	April	May	June	July	Aug.	Sept.	Oct.	Nov.	Dec.	Total	Jan.	Feb.	March	April	May	June	July	Aug.	Sept.	Oct.	Nov.	Dec.	Total
22,051	36,481	26,668	35,213	21,526	40,810	24,038	26,099	11,514	12,011	17,077	14,600	1,179,594	18,174	6,340	4,100	-	-	-	-	-	-	-	-	-	1,208,208
												Total Months													Total Months
-	-	-	-	-	-	-	-	-	-	-	-	36	-	-	-	-	-	-	-	-	-	-	-	-	48
-	-	-	-	-	-	-	-	-	-	-	-	35	-	-	-	-	-	-	-	-	-	-	-	-	47
-	-	-	-	-	-	-	-	-	-	-	-	34	-	-	-	-	-	-	-	-	-	-	-	-	46
-	-	-	-	-	-	-	-	-	-	-	-	33	-	-	-	-	-	-	-	-	-	-	-	-	45
102	102	102	102	102	102	102	102	102	102	102	102	32	102	102	102	102	102	102	102	102	102	102	102	102	44
91	91	91	91	91	91	91	91	91	91	91	91	31	91	91	91	91	91	91	91	91	91	91	91	91	43
41	41	41	41	41	41	41	41	41	41	41	41	30	41	41	41	41	41	41	41	41	41	41	41	41	42
338	338	338	338	338	338	338	338	338	338	338	338	29	338	338	338	338	338	338	338	338	338	338	338	338	41
268	268	268	268	268	268	268	268	268	268	268	268	28	268	268	268	268	268	268	268	268	268	268	268	268	40
1,576	1,576	1,576	1,576	1,576	1,576	1,576	1,576	1,576	1,576	1,576	1,576	27	1,576	1,576	1,576	1,576	1,576	1,576	1,576	1,576	1,576	1,576	1,576	1,576	39
5,058	5,058	5,058	5,058	5,058	5,058	5,058	5,058	5,058	5,058	5,058	5,058	26	5,058	5,058	5,058	5,058	5,058	5,058	5,058	5,058	5,058	5,058	5,058	5,058	38
4,047	4,047	4,047	4,047	4,047	4,047	4,047	4,047	4,047	4,047	4,047	4,047	25	4,047	4,047	4,047	4,047	4,047	4,047	4,047	4,047	4,047	4,047	4,047	4,047	37
8,491	8,491	8,491	8,491	8,491	8,491	8,491	8,491	8,491	8,491	8,491	8,491	24	8,491	8,491	8,491	8,491	8,491	8,491	8,491	8,491	8,491	8,491	8,491	8,491	36
5,792	5,792	5,792	5,792	5,792	5,792	5,792	5,792	5,792	5,792	5,792	5,792	23	5,792	5,792	5,792	5,792	5,792	5,792	5,792	5,792	5,792	5,792	5,792	5,792	35
4,915	4,915	4,915	4,915	4,915	4,915	4,915	4,915	4,915	4,915	4,915	4,915	22	4,915	4,915	4,915	4,915	4,915	4,915	4,915	4,915	4,915	4,915	4,915	4,915	34
6,677	6,677	6,677	6,677	6,677	6,677	6,677	6,677	6,677	6,677	6,677	6,677	21	6,677	6,677	6,677	6,677	6,677	6,677	6,677	6,677	6,677	6,677	6,677	6,677	33
5,895	5,895	5,895	5,895	5,895	5,895	5,895	5,895	5,895	5,895	5,895	5,895	20	5,895	5,895	5,895	5,895	5,895	5,895	5,895	5,895	5,895	5,895	5,895	5,895	32
10,037	10,037	10,037	10,037	10,037	10,037	10,037	10,037	10,037	10,037	10,037	10,037	19	10,037	10,037	10,037	10,037	10,037	10,037	10,037	10,037	10,037	10,037	10,037	10,037	31
5,362	5,362	5,362	5,362	5,362	5,362	5,362	5,362	5,362	5,362	5,362	5,362	18	5,362	5,362	5,362	5,362	5,362	5,362	5,362	5,362	5,362	5,362	5,362	5,362	30
3,187	3,187	3,187	3,187	3,187	3,187	3,187	3,187	3,187	3,187	3,187	3,187	17	3,187	3,187	3,187	3,187	3,187	3,187	3,187	3,187	3,187	3,187	3,187	3,187	29
6,309	6,309	6,309	6,309	6,309	6,309	6,309	6,309	6,309	6,309	6,309	6,309	16	6,309	6,309	6,309	6,309	6,309	6,309	6,309	6,309	6,309	6,309	6,309	6,309	28
3,252	3,252	3,252	3,252	3,252	3,252	3,252	3,252	3,252	3,252	3,252	3,252	15	3,252	3,252	3,252	3,252	3,252	3,252	3,252	3,252	3,252	3,252	3,252	3,252	27
1,934	1,934	1,934	1,934	1,934	1,934	1,934	1,934	1,934	1,934	1,934	1,934	14	1,934	1,934	1,934	1,934	1,934	1,934	1,934	1,934	1,934	1,934	1,934	1,934	26
919	919	919	919	919	919	919	919	919	919	919	919	13	919	919	919	919	919	919	919	919	919	919	919	919	25
1,838	1,838	1,838	1,838	1,838	1,838	1,838	1,838	1,838	1,838	1,838	1,838	12	1,838	1,838	1,838	1,838	1,838	1,838	1,838	1,838	1,838	1,838	1,838	1,838	24
	3,040	3,040	3,040	3,040	3,040	3,040	3,040	3,040	3,040	3,040	3,040	11	3,040	3,040	3,040	3,040	3,040	3,040	3,040	3,040	3,040	3,040	3,040	3,040	23
		2,222	2,222	2,222	2,222	2,222	2,222	2,222	2,222	2,222	2,222	10	2,222	2,222	2,222	2,222	2,222	2,222	2,222	2,222	2,222	2,222	2,222	2,222	22
			2,934	2,934	2,934	2,934	2,934	2,934	2,934	2,934	2,934	9	2,934	2,934	2,934	2,934	2,934	2,934	2,934	2,934	2,934	2,934	2,934	2,934	21
				1,794	1,794	1,794	1,794	1,794	1,794	1,794	1,794	8	1,794	1,794	1,794	1,794	1,794	1,794	1,794	1,794	1,794	1,794	1,794	1,794	20
					3,401	3,401	3,401	3,401	3,401	3,401	3,401	7	3,401	3,401	3,401	3,401	3,401	3,401	3,401	3,401	3,401	3,401	3,401	3,401	19
						2,003	2,003	2,003	2,003	2,003	2,003	6	2,003	2,003	2,003	2,003	2,003	2,003	2,003	2,003	2,003	2,003	2,003	2,003	18
							2,175	2,175	2,175	2,175	2,175	5	2,175	2,175	2,175	2,175	2,175	2,175	2,175	2,175	2,175	2,175	2,175	2,175	17
								960	960	960	960	4	960	960	960	960	960	960	960	960	960	960	960	960	16
									1,001	1,001	1,001	3	1,001	1,001	1,001	1,001	1,001	1,001	1,001	1,001	1,001	1,001	1,001	1,001	15
										1,423	1,423	2	1,423	1,423	1,423	1,423	1,423	1,423	1,423	1,423	1,423	1,423	1,423	1,423	14
											1,217	1	1,217	1,217	1,217	1,217	1,217	1,217	1,217	1,217	1,217	1,217	1,217	1,217	13
													1,515	1,515	1,515	1,515	1,515	1,515	1,515	1,515	1,515	1,515	1,515	1,515	12
														528	528	528	528	528	528	528	528	528	528	528	11
															342	342	342	342	342	342	342	342	342	342	10
																-	-	-	-	-	-	-	-	-	9
																	-	-	-	-	-	-	-	-	8
																		-	-	-	-	-	-	-	7
																			-	-	-	-	-	-	6
																				-	-	-	-	-	5
																					-	-	-	-	4
																						-	-	-	3
																							-	-	2
																								-	1
76,130	79,170	81,392	84,327	86,120	89,521	91,524	93,699	94,659	95,660	97,083	98,300	[redacted]	99,814	100,342	100,684	100,684	100,684	100,684	100,684	100,684	100,684	100,684	100,684	100,684	[redacted]
75,464	78,478	80,681	83,590	85,368	88,739	90,724	92,880	93,831	94,824	96,234	97,440	[redacted]	98,942	99,465	99,804	99,804	99,804	99,804	99,804	99,804	99,804	99,804	99,804	99,804	[redacted]
243	252	259	269	274	285	292	299	302	305	309	313		318	320	321	321	321	321	321	321	321	321	321	321	
265	275	283	293	299	311	318	326	329	333	338	342		347	349	350	350	350	350	350	350	350	350	350	350	
158	164	169	175	179	186	190	195	197	199	202	204		207	208	209	209	209	209	209	209	209	209	209	209	
76,130	79,170	81,392	84,327	86,120	89,521	91,524	93,699	94,659	95,660	97,083	98,300		99,814	100,342	100,684	100,684	100,684	100,684	100,684	100,684	100,684	100,684	100,684	100,684	

Actual kWh (Jan. - Dec., 2016):	[redacted]	1,087,585
Actual kWh (Jan. - Dec., 2017):	[redacted]	1,208,997

129	129	129	129	129	129	129	129	129	129	129	129	[redacted] 1,842	0	0	0	0	0	0	0	0	0	0	0	0	[redacted] 0
94	170	117	159	96	179	100	113	54	54	71	67	[redacted] 1,274	80	29	16	0	0	0	0	0	0	0	0	0	[redacted] 128
												[redacted] 83%													[redacted] 0%

2018

kWh (Net) in North Carolina	Jan.	Feb.	March	April	May	June	July	Aug.	Sept.	Oct.	Nov.	Dec.	Total
	45	46	47	48	49	50	51	52	53	54	55	56	
Residential Heat Pump Tune Up - kWh/year Savings (Deemed with assumed realization and net-to-gross rates from May 1, 2019 EM&V Report)	-	-	-	-	-	-	-	-	-	-	-	-	1,208,208
Monthly - Adjusted kWh (Net)													Total Months
Jan, 2014	-	-	-	-	-	-	-	-	-	-	-	-	60
Feb	-	-	-	-	-	-	-	-	-	-	-	-	59
Mar	-	-	-	-	-	-	-	-	-	-	-	-	58
Apr	-	-	-	-	-	-	-	-	-	-	-	-	57
May	102	102	102	102	102	102	102	102	102	102	102	102	56
Jun	91	91	91	91	91	91	91	91	91	91	91	91	55
Jul	41	41	41	41	41	41	41	41	41	41	41	41	54
Aug	338	338	338	338	338	338	338	338	338	338	338	338	53
Sep	268	268	268	268	268	268	268	268	268	268	268	268	52
Oct	1,576	1,576	1,576	1,576	1,576	1,576	1,576	1,576	1,576	1,576	1,576	1,576	51
Nov	5,058	5,058	5,058	5,058	5,058	5,058	5,058	5,058	5,058	5,058	5,058	5,058	50
Dec	4,047	4,047	4,047	4,047	4,047	4,047	4,047	4,047	4,047	4,047	4,047	4,047	49
Jan, 2015	8,491	8,491	8,491	8,491	8,491	8,491	8,491	8,491	8,491	8,491	8,491	8,491	48
Feb	5,792	5,792	5,792	5,792	5,792	5,792	5,792	5,792	5,792	5,792	5,792	5,792	47
Mar	4,915	4,915	4,915	4,915	4,915	4,915	4,915	4,915	4,915	4,915	4,915	4,915	46
Apr	6,677	6,677	6,677	6,677	6,677	6,677	6,677	6,677	6,677	6,677	6,677	6,677	45
May	5,895	5,895	5,895	5,895	5,895	5,895	5,895	5,895	5,895	5,895	5,895	5,895	44
Jun	10,037	10,037	10,037	10,037	10,037	10,037	10,037	10,037	10,037	10,037	10,037	10,037	43
Jul	5,362	5,362	5,362	5,362	5,362	5,362	5,362	5,362	5,362	5,362	5,362	5,362	42
Aug	3,187	3,187	3,187	3,187	3,187	3,187	3,187	3,187	3,187	3,187	3,187	3,187	41
Sep	6,309	6,309	6,309	6,309	6,309	6,309	6,309	6,309	6,309	6,309	6,309	6,309	40
Oct	3,252	3,252	3,252	3,252	3,252	3,252	3,252	3,252	3,252	3,252	3,252	3,252	39
Nov	1,934	1,934	1,934	1,934	1,934	1,934	1,934	1,934	1,934	1,934	1,934	1,934	38
Dec	919	919	919	919	919	919	919	919	919	919	919	919	37
Jan, 2016	1,838	1,838	1,838	1,838	1,838	1,838	1,838	1,838	1,838	1,838	1,838	1,838	36
Feb	3,040	3,040	3,040	3,040	3,040	3,040	3,040	3,040	3,040	3,040	3,040	3,040	35
Mar	2,222	2,222	2,222	2,222	2,222	2,222	2,222	2,222	2,222	2,222	2,222	2,222	34
Apr	2,934	2,934	2,934	2,934	2,934	2,934	2,934	2,934	2,934	2,934	2,934	2,934	33
May	1,794	1,794	1,794	1,794	1,794	1,794	1,794	1,794	1,794	1,794	1,794	1,794	32
Jun	3,401	3,401	3,401	3,401	3,401	3,401	3,401	3,401	3,401	3,401	3,401	3,401	31
Jul	2,003	2,003	2,003	2,003	2,003	2,003	2,003	2,003	2,003	2,003	2,003	2,003	30
Aug	2,175	2,175	2,175	2,175	2,175	2,175	2,175	2,175	2,175	2,175	2,175	2,175	29
Sep	960	960	960	960	960	960	960	960	960	960	960	960	28
Oct	1,001	1,001	1,001	1,001	1,001	1,001	1,001	1,001	1,001	1,001	1,001	1,001	27
Nov	1,423	1,423	1,423	1,423	1,423	1,423	1,423	1,423	1,423	1,423	1,423	1,423	26
Dec	1,217	1,217	1,217	1,217	1,217	1,217	1,217	1,217	1,217	1,217	1,217	1,217	25
Jan, 2017	1,515	1,515	1,515	1,515	1,515	1,515	1,515	1,515	1,515	1,515	1,515	1,515	24
Feb	528	528	528	528	528	528	528	528	528	528	528	528	23
Mar	342	342	342	342	342	342	342	342	342	342	342	342	22
Apr	-	-	-	-	-	-	-	-	-	-	-	-	21
May	-	-	-	-	-	-	-	-	-	-	-	-	20
Jun	-	-	-	-	-	-	-	-	-	-	-	-	19
Jul	-	-	-	-	-	-	-	-	-	-	-	-	18
Aug	-	-	-	-	-	-	-	-	-	-	-	-	17
Sep	-	-	-	-	-	-	-	-	-	-	-	-	16
Oct	-	-	-	-	-	-	-	-	-	-	-	-	15
Nov	-	-	-	-	-	-	-	-	-	-	-	-	14
Dec	-	-	-	-	-	-	-	-	-	-	-	-	13
Total (Cumulative by Month) - Adjusted kWh (Net)	100,684	100,684	100,684	100,684	100,684	100,684	100,684	100,684	100,684	100,684	100,684	100,684	
DNV GL Tracking													
Schedule 1	99,804	99,804	99,804	99,804	99,804	99,804	99,804	99,804	99,804	99,804	99,804	99,804	
Schedule 10P	321	321	321	321	321	321	321	321	321	321	321	321	
Schedule 1P	350	350	350	350	350	350	350	350	350	350	350	350	
Schedule 1T	209	209	209	209	209	209	209	209	209	209	209	209	
	100,684	100,684	100,684	100,684	100,684	100,684	100,684	100,684	100,684	100,684	100,684	100,684	

Actual kWh (Jan. - Dec., 2018): 1,208,208

Participation	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%

2019

kWh (Net) in North Carolina	Jan.	Feb.	March	April	May	June	July	Aug.	Sept.	Oct.	Nov.	Dec.	Total
	57	58	59	60	61	62	63	64	65	66	67	68	
Residential Heat Pump Tune Up - kWh/year Savings (Deemed with assumed realization and net-to-gross rates from May 1, 2019 EM&V Report)	-	-	-	-	-	-							1,208,208
Monthly - Adjusted kWh (Net)													Total Months
Jan, 2014													66
Feb	-												65
Mar	-	-											64
Apr	-	-	-										63
May	102	102	102	102									62
Jun	91	91	91	91	91								61
Jul	41	41	41	41	41	41							60
Aug	338	338	338	338	338	338							59
Sep	268	268	268	268	268	268							58
Oct	1,576	1,576	1,576	1,576	1,576	1,576							57
Nov	5,058	5,058	5,058	5,058	5,058	5,058							56
Dec	4,047	4,047	4,047	4,047	4,047	4,047							55
Jan, 2015	8,491	8,491	8,491	8,491	8,491	8,491							54
Feb	5,792	5,792	5,792	5,792	5,792	5,792							53
Mar	4,915	4,915	4,915	4,915	4,915	4,915							52
Apr	6,677	6,677	6,677	6,677	6,677	6,677							51
May	5,895	5,895	5,895	5,895	5,895	5,895							50
Jun	10,037	10,037	10,037	10,037	10,037	10,037							49
Jul	5,362	5,362	5,362	5,362	5,362	5,362							48
Aug	3,187	3,187	3,187	3,187	3,187	3,187							47
Sep	6,309	6,309	6,309	6,309	6,309	6,309							46
Oct	3,252	3,252	3,252	3,252	3,252	3,252							45
Nov	1,934	1,934	1,934	1,934	1,934	1,934							44
Dec	919	919	919	919	919	919							43
Jan, 2016	1,838	1,838	1,838	1,838	1,838	1,838							42
Feb	3,040	3,040	3,040	3,040	3,040	3,040							41
Mar	2,222	2,222	2,222	2,222	2,222	2,222							40
Apr	2,934	2,934	2,934	2,934	2,934	2,934							39
May	1,794	1,794	1,794	1,794	1,794	1,794							38
Jun	3,401	3,401	3,401	3,401	3,401	3,401							37
Jul	2,003	2,003	2,003	2,003	2,003	2,003							36
Aug	2,175	2,175	2,175	2,175	2,175	2,175							35
Sep	960	960	960	960	960	960							34
Oct	1,001	1,001	1,001	1,001	1,001	1,001							33
Nov	1,423	1,423	1,423	1,423	1,423	1,423							32
Dec	1,217	1,217	1,217	1,217	1,217	1,217							31
Jan, 2017	1,515	1,515	1,515	1,515	1,515	1,515							30
Feb	528	528	528	528	528	528							29
Mar	342	342	342	342	342	342							28
Apr	-	-	-	-	-	-							27
May	-	-	-	-	-	-							26
Jun	-	-	-	-	-	-							25
Jul	-	-	-	-	-	-							24
Aug	-	-	-	-	-	-							23
Sep	-	-	-	-	-	-							22
Oct	-	-	-	-	-	-							21
Nov	-	-	-	-	-	-							20
Dec	-	-	-	-	-	-							19
Total (Cumulative by Month) - Adjusted kWh (Net)	100,684	100,684	100,684	100,684	100,582	100,492	0	0	0	0	0	0	
DNV GL Tracking													
Schedule 1	99,804	99,804	99,804	99,804	99,703	99,513	0		0	0		0	
Schedule 10P	321	321	321	321	320	320	0	0	0	0	0	0	
Schedule 1P	350	350	350	350	350	349		0	0		0	0	
Schedule 1T	209	209	209	209	209	209	0	0	0	0	0	0	
	100,684	100,684	100,684	100,684	100,582	100,492	-	-	-	-	-	-	

Actual kWh (Jan. - Dec., 2019): 688,810 | 4,728,361

Participation	0	0	0	0	0	0							0
	0	0	0	0	0	0							0
													0%

Total
1,208,208
4,728,361 True-up
7,096
5,287
75%

NOTES:

1. The kWh savings are based on actual participation from Dominion North Carolina Power customers with program planning realization and net-to-gross adjustments assumptions applied
2. The May 1, 2019 EM&V Report was filed with the NC Public Utilities Commission and included EM&V data through the end of 2018.
3. The EM&V data reflected for January 2018 - June, 2019 was prepared by DNV GL using the same STEP (Standard Tracking Engineering Protocol) formulas used in preparing the EM&V data for 2018.
4. The kWh savings are inclusive of all EE measures installed from program inception through June 30, 2019.
5. Program measure life is 5 years (60 months)

	2014													2015												
														1	2	3	4	5	6	7	8	9	10	11	12	
kWh (Net) in North Carolina	Jan.	Feb.	March	April	May	June	July	Aug.	Sept.	Oct.	Nov.	Dec.	Total	Jan.	Feb.	March	April	May	June	July	Aug.	Sept.	Oct.	Nov.	Dec.	Total
Residential Duct Sealing - kWh /year Savings (Deemed with assumed realization and net-to-gross rates from May 1, 2019 EMV Report)	-	-	-	-	-	-	-	-	-	-	-	-	-	274	7,820	20,538	15,038	18,259	14,250	3,217	-	-	236	-	-	79,632
Monthly - Adjusted kWh (Net)													Total Months													Total Months
Jan, 2014	-	-	-	-	-	-	-	-	-	-	-	-	12	-	-	-	-	-	-	-	-	-	-	-	-	24
Feb		-	-	-	-	-	-	-	-	-	-	-	11	-	-	-	-	-	-	-	-	-	-	-	-	23
Mar			-	-	-	-	-	-	-	-	-	-	10	-	-	-	-	-	-	-	-	-	-	-	-	22
Apr				-	-	-	-	-	-	-	-	-	9	-	-	-	-	-	-	-	-	-	-	-	-	21
May					-	-	-	-	-	-	-	-	8	-	-	-	-	-	-	-	-	-	-	-	-	20
Jun						-	-	-	-	-	-	-	7	-	-	-	-	-	-	-	-	-	-	-	-	19
Jul							-	-	-	-	-	-	6	-	-	-	-	-	-	-	-	-	-	-	-	18
Aug								-	-	-	-	-	5	-	-	-	-	-	-	-	-	-	-	-	-	17
Sep									-	-	-	-	4	-	-	-	-	-	-	-	-	-	-	-	-	16
Oct										-	-	-	3	-	-	-	-	-	-	-	-	-	-	-	-	15
Nov											-	-	2	-	-	-	-	-	-	-	-	-	-	-	-	14
Dec												-	1	-	-	-	-	-	-	-	-	-	-	-	-	13
Jan, 2015														23	22.83	22.83	22.83	22.83	22.83	22.83	22.83	22.83	22.83	22.83	22.83	12
Feb															652	651.67	651.67	651.67	651.67	651.67	651.67	651.67	651.67	651.67	651.67	11
Mar																1,712	1,712	1,712	1,712	1,712	1,712	1,712	1,712	1,712	1,712	10
Apr																	1,253	1,253	1,253	1,253	1,253	1,253	1,253	1,253	1,253	9
May																		1,522	1,522	1,522	1,522	1,522	1,522	1,522	1,522	8
Jun																			1,188	1,188	1,188	1,188	1,188	1,188	1,188	7
Jul																				268	268	268	268	268	268	6
Aug																					-	-	-	-	-	5
Sep																						-	-	-	-	4
Oct																							20	20	20	3
Nov																								-	-	2
Dec																									-	1
Total (Cumulative by Month) - Adjusted kWh (Net):	-	-	-	-	-	-	-	-	-	-	-	-		23	675	2,386	3,639	5,161	6,348	6,616	6,616	6,616	6,636	6,636	6,636	-
DNV GL Tracking																										
Schedule 1 99.9%	-	-	-	-	-	-	-	-	-	-	-	-		23	674	2,383	3,635	5,154	6,340	6,608	6,608	6,608	6,628	6,628	6,628	
Schedule 1DF 0.1%	-	-	-	-	-	-	-	-	-	-	-	-		0	1	3	5	6	8	8	8	8	8	8	8	
	-	-	-	-	-	-	-	-	-	-	-	-		23	675	2,386	3,639	5,161	6,348	6,616	6,616	6,616	6,636	6,636	6,635	

Actual kWh (Jan. - Dec., 2014): -

Actual kWh (Jan. - Dec., 2015): 67,689

Participation																									
Planned:	14	21	24	28	38	41	38	35	31	35	24	17	348	14	21	24	28	38	41	38	35	31	35	24	17	348
Actual:	0	0	0	0	0	0	0	0	0	0	0	0	0	1	28	85	60	77	59	12	0	0	1	0	0	323
													0%													93%

2016													2017												
13	14	15	16	17	18	19	20	21	22	23	24		25	26	27	28	29	30	31	32	33	34	35	36	
Jan.	Feb.	March	April	May	June	July	Aug.	Sept.	Oct.	Nov.	Dec.	Total	Jan.	Feb.	March	April	May	June	July	Aug.	Sept.	Oct.	Nov.	Dec.	Total
186	5,868	17,458	11,202	5,933	4,097	3,687	1,964	187	452	-	-	130,666	2,069	913	180	-	-	-	-	-	-	-	-	-	133,829
												Total Months													Total Months
-	-	-	-	-	-	-	-	-	-	-	-	36	-	-	-	-	-	-	-	-	-	-	-	-	48
-	-	-	-	-	-	-	-	-	-	-	-	35	-	-	-	-	-	-	-	-	-	-	-	-	47
-	-	-	-	-	-	-	-	-	-	-	-	34	-	-	-	-	-	-	-	-	-	-	-	-	46
-	-	-	-	-	-	-	-	-	-	-	-	33	-	-	-	-	-	-	-	-	-	-	-	-	45
-	-	-	-	-	-	-	-	-	-	-	-	32	-	-	-	-	-	-	-	-	-	-	-	-	44
-	-	-	-	-	-	-	-	-	-	-	-	31	-	-	-	-	-	-	-	-	-	-	-	-	43
-	-	-	-	-	-	-	-	-	-	-	-	30	-	-	-	-	-	-	-	-	-	-	-	-	42
-	-	-	-	-	-	-	-	-	-	-	-	29	-	-	-	-	-	-	-	-	-	-	-	-	41
-	-	-	-	-	-	-	-	-	-	-	-	28	-	-	-	-	-	-	-	-	-	-	-	-	40
-	-	-	-	-	-	-	-	-	-	-	-	27	-	-	-	-	-	-	-	-	-	-	-	-	39
-	-	-	-	-	-	-	-	-	-	-	-	26	-	-	-	-	-	-	-	-	-	-	-	-	38
-	-	-	-	-	-	-	-	-	-	-	-	25	-	-	-	-	-	-	-	-	-	-	-	-	37
22.83	22.83	22.83	22.83	22.83	22.83	22.83	22.83	22.83	22.83	22.83	22.83	24	22.83	22.83	22.83	22.83	22.83	22.83	22.83	22.83	22.83	22.83	22.83	22.83	36
651.67	651.67	651.67	651.67	651.67	651.67	651.67	651.67	651.67	651.67	651.67	651.67	23	651.67	651.67	651.67	651.67	651.67	651.67	651.67	651.67	651.67	651.67	651.67	651.67	35
1,712	1,712	1,712	1,712	1,712	1,712	1,712	1,712	1,712	1,712	1,712	1,712	22	1,712	1,712	1,712	1,712	1,712	1,712	1,712	1,712	1,712	1,712	1,712	1,712	34
1,253	1,253	1,253	1,253	1,253	1,253	1,253	1,253	1,253	1,253	1,253	1,253	21	1,253	1,253	1,253	1,253	1,253	1,253	1,253	1,253	1,253	1,253	1,253	1,253	33
1,522	1,522	1,522	1,522	1,522	1,522	1,522	1,522	1,522	1,522	1,522	1,522	20	1,522	1,522	1,522	1,522	1,522	1,522	1,522	1,522	1,522	1,522	1,522	1,522	32
1,188	1,188	1,188	1,188	1,188	1,188	1,188	1,188	1,188	1,188	1,188	1,188	19	1,188	1,188	1,188	1,188	1,188	1,188	1,188	1,188	1,188	1,188	1,188	1,188	31
268	268	268	268	268	268	268	268	268	268	268	268	18	268	268	268	268	268	268	268	268	268	268	268	268	30
-	-	-	-	-	-	-	-	-	-	-	-	17	-	-	-	-	-	-	-	-	-	-	-	-	29
-	-	-	-	-	-	-	-	-	-	-	-	16	-	-	-	-	-	-	-	-	-	-	-	-	28
20	20	20	20	20	20	20	20	20	20	20	20	15	20	20	20	20	20	20	20	20	20	20	20	20	27
-	-	-	-	-	-	-	-	-	-	-	-	14	-	-	-	-	-	-	-	-	-	-	-	-	26
-	-	-	-	-	-	-	-	-	-	-	-	13	-	-	-	-	-	-	-	-	-	-	-	-	25
16	15.50	15.50	15.50	15.50	15.50	15.50	15.50	15.50	15.50	15.50	15.50	12	15.50	15.50	15.50	15.50	15.50	15.50	15.50	15.50	15.50	15.50	15.50	15.50	24
	489	489.00	489.00	489.00	489.00	489.00	489.00	489.00	489.00	489.00	489.00	11	489.00	489.00	489.00	489.00	489.00	489.00	489.00	489.00	489.00	489.00	489.00	489.00	23
		1,455	1,455	1,455	1,455	1,455	1,455	1,455	1,455	1,455	1,455	10	1,455	1,455	1,455	1,455	1,455	1,455	1,455	1,455	1,455	1,455	1,455	1,455	22
			933	933	933	933	933	933	933	933	933	9	933	933	933	933	933	933	933	933	933	933	933	933	21
				494	494	494	494	494	494	494	494	8	494	494	494	494	494	494	494	494	494	494	494	494	20
					341	341	341	341	341	341	341	7	341	341	341	341	341	341	341	341	341	341	341	341	19
						307	307	307	307	307	307	6	307	307	307	307	307	307	307	307	307	307	307	307	18
							164	164	164	164	164	5	164	164	164	164	164	164	164	164	164	164	164	164	17
								16	16	16	16	4	16	16	16	16	16	16	16	16	16	16	16	16	16
									38	38	38	3	38	38	38	38	38	38	38	38	38	38	38	38	15
										-	-	2	-	-	-	-	-	-	-	-	-	-	-	-	14
											-	1	-	-	-	-	-	-	-	-	-	-	-	-	13
													172	172	172	172	172	172	172	172	172	172	172	172	12
														76	76	76	76	76	76	76	76	76	76	76	11
															15	15	15	15	15	15	15	15	15	15	10
																-	-	-	-	-	-	-	-	-	9
																	-	-	-	-	-	-	-	-	8
																		-	-	-	-	-	-	-	7
																			-	-	-	-	-	-	6
																				-	-	-	-	-	5
																					-	-	-	-	4
																						-	-	-	3
																							-	-	2
																								-	1
6,652	7,141	8,595	9,529	10,023	10,365	10,672	10,836	10,851	10,889	10,889	10,889		11,061	11,137	11,152	11,152	11,152	11,152	11,152	11,152	11,152	11,152	11,152	11,152	
6,643	7,132	8,585	9,517	10,011	10,352	10,659	10,822	10,838	10,875	10,875	10,875		11,048	11,124	11,139	11,139	11,139	11,139	11,139	11,139	11,139	11,139	11,139	11,139	
8	9	11	12	12	13	13	13	13	13	13	13		14	14	14	14	14	14	14	14	14	14	14	14	
6,652	7,141	8,595	9,529	10,023	10,365	10,672	10,836	10,851	10,889	10,889	10,889		11,061	11,137	11,152	11,152	11,152	11,152	11,152	11,152	11,152	11,152	11,152	11,152	

Actual kWh (Jan. - Dec., 2016): 117,330

Actual kWh (Jan. - Dec., 2017): 133,723

8	8	8	8	8	8	8	8	8	8	8	8	101	0	0	0	0	0	0	0	0	0	0	0	0	0
1	26	66	49	25	21	19	6	1	3	0	0	217	8	5	1	0	0	0	0	0	0	0	0	0	14
												215%													0%

	2018													2019												
	37	38	39	40	41	42	43	44	45	46	47	48		49	50	51	52	53	54	55	56	57	58	59	60	
kWh (Net) in North Carolina	Jan.	Feb.	March	April	May	June	July	Aug.	Sept.	Oct.	Nov.	Dec.	Total	Jan.	Feb.	March	April	May	June	July	Aug.	Sept.	Oct.	Nov.	Dec.	Total
Residential Duct Sealing - kWh /year Savings (Deemed with assumed realization and net-to-gross rates from May 1, 2019 EMV Report)	-	-	-	-	-	-	-	-	-	-	-	-	133,829	-	-	-	-	-	-							133,829
Monthly - Adjusted kWh (Net)													Total Months													Total Months
Jan, 2014	-	-	-	-	-	-	-	-	-	-	-	-	60	-	-	-	-	-	-							66
Feb	-	-	-	-	-	-	-	-	-	-	-	-	59	-	-	-	-	-	-							65
Mar	-	-	-	-	-	-	-	-	-	-	-	-	58	-	-	-	-	-	-							64
Apr	-	-	-	-	-	-	-	-	-	-	-	-	57	-	-	-	-	-	-							63
May	-	-	-	-	-	-	-	-	-	-	-	-	56	-	-	-	-	-	-							62
Jun	-	-	-	-	-	-	-	-	-	-	-	-	55	-	-	-	-	-	-							61
Jul	-	-	-	-	-	-	-	-	-	-	-	-	54	-	-	-	-	-	-							60
Aug	-	-	-	-	-	-	-	-	-	-	-	-	53	-	-	-	-	-	-							59
Sep	-	-	-	-	-	-	-	-	-	-	-	-	52	-	-	-	-	-	-							58
Oct	-	-	-	-	-	-	-	-	-	-	-	-	51	-	-	-	-	-	-							57
Nov	-	-	-	-	-	-	-	-	-	-	-	-	50	-	-	-	-	-	-							56
Dec	-	-	-	-	-	-	-	-	-	-	-	-	49	-	-	-	-	-	-							55
Jan, 2015	22.83	22.83	22.83	22.83	22.83	22.83	22.83	22.83	22.83	22.83	22.83	22.83	48	22.83	22.83	22.83	22.83	22.83	22.83							54
Feb	651.67	651.67	651.67	651.67	651.67	651.67	651.67	651.67	651.67	651.67	651.67	651.67	47	651.67	651.67	651.67	651.67	651.67	651.67							53
Mar	1,712	1,712	1,712	1,712	1,712	1,712	1,712	1,712	1,712	1,712	1,712	1,712	46	1,712	1,712	1,712	1,712	1,712	1,712							52
Apr	1,253	1,253	1,253	1,253	1,253	1,253	1,253	1,253	1,253	1,253	1,253	1,253	45	1,253	1,253	1,253	1,253	1,253	1,253							51
May	1,522	1,522	1,522	1,522	1,522	1,522	1,522	1,522	1,522	1,522	1,522	1,522	44	1,522	1,522	1,522	1,522	1,522	1,522							50
Jun	1,188	1,188	1,188	1,188	1,188	1,188	1,188	1,188	1,188	1,188	1,188	1,188	43	1,188	1,188	1,188	1,188	1,188	1,188							49
Jul	268	268	268	268	268	268	268	268	268	268	268	268	42	268	268	268	268	268	268							48
Aug	-	-	-	-	-	-	-	-	-	-	-	-	41	-	-	-	-	-	-							47
Sep	-	-	-	-	-	-	-	-	-	-	-	-	40	-	-	-	-	-	-							46
Oct	20	20	20	20	20	20	20	20	20	20	20	20	39	20	20	20	20	20	20							45
Nov	-	-	-	-	-	-	-	-	-	-	-	-	38	-	-	-	-	-	-							44
Dec	-	-	-	-	-	-	-	-	-	-	-	-	37	-	-	-	-	-	-							43
Jan, 2016	15.50	15.50	15.50	15.50	15.50	15.50	15.50	15.50	15.50	15.50	15.50	15.50	36	15.50	15.50	15.50	15.50	15.50	15.50							42
Feb	489.00	489.00	489.00	489.00	489.00	489.00	489.00	489.00	489.00	489.00	489.00	489.00	35	489.00	489.00	489.00	489.00	489.00	489.00							41
Mar	1,455	1,455	1,455	1,455	1,455	1,455	1,455	1,455	1,455	1,455	1,455	1,455	34	1,455	1,455	1,455	1,455	1,455	1,455							40
Apr	933	933	933	933	933	933	933	933	933	933	933	933	33	933	933	933	933	933	933							39
May	494	494	494	494	494	494	494	494	494	494	494	494	32	494	494	494	494	494	494							38
Jun	341	341	341	341	341	341	341	341	341	341	341	341	31	341	341	341	341	341	341							37
Jul	307	307	307	307	307	307	307	307	307	307	307	307	30	307	307	307	307	307	307							36
Aug	164	164	164	164	164	164	164	164	164	164	164	164	29	164	164	164	164	164	164							35
Sep	16	16	16	16	16	16	16	16	16	16	16	16	28	16	16	16	16	16	16							34
Oct	38	38	38	38	38	38	38	38	38	38	38	38	27	38	38	38	38	38	38							33
Nov	-	-	-	-	-	-	-	-	-	-	-	-	26	-	-	-	-	-	-							32
Dec	-	-	-	-	-	-	-	-	-	-	-	-	25	-	-	-	-	-	-							31
Jan, 2017	172	172	172	172	172	172	172	172	172	172	172	172	24	172	172	172	172	172	172							30
Feb	76	76	76	76	76	76	76	76	76	76	76	76	23	76	76	76	76	76	76							29
Mar	15	15	15	15	15	15	15	15	15	15	15	15	22	15	15	15	15	15	15							28
Apr	-	-	-	-	-	-	-	-	-	-	-	-	21	-	-	-	-	-	-							27
May	-	-	-	-	-	-	-	-	-	-	-	-	20	-	-	-	-	-	-							26
Jun	-	-	-	-	-	-	-	-	-	-	-	-	19	-	-	-	-	-	-							25
Jul	-	-	-	-	-	-	-	-	-	-	-	-	18	-	-	-	-	-	-							24
Aug	-	-	-	-	-	-	-	-	-	-	-	-	17	-	-	-	-	-	-							23
Sep	-	-	-	-	-	-	-	-	-	-	-	-	16	-	-	-	-	-	-							22
Oct	-	-	-	-	-	-	-	-	-	-	-	-	15	-	-	-	-	-	-							21
Nov	-	-	-	-	-	-	-	-	-	-	-	-	14	-	-	-	-	-	-							20
Dec	-	-	-	-	-	-	-	-	-	-	-	-	13	-	-	-	-	-	-							19
Total (Cumulative by Month) - Adjusted kWh (Net):	11,152	11,152	11,152	11,152	11,152	11,152	11,152	11,152	11,152	11,152	11,152	11,152		11,152	11,152	11,152	11,152	11,152	11,152	-	-	-	-	-	-	
DNV GL Tracking																										
Schedule 1 99.9%	11,139	11,139	11,139	11,139	11,139	11,139	11,139	11,139	11,139	11,139	11,139	11,139		11,139	11,139	11,139	11,139	11,139	11,139	-	-	-	-	-	-	
Schedule 10P 0.1%	14	14	14	14	14	14	14	14	14	14	14	14		14	14	14	14	14	14	-	-	-	-	-	-	
	11,152	11,152	11,152	11,152	11,152	11,152	11,152	11,152	11,152	11,152	11,152	11,152		11,152	11,152	11,152	11,152	11,152	11,152	-	-	-	-	-	-	

Total kWh
133,829

509,785	True-up

Actual kWh (Jan. - Dec., 2018): 133,829

Actual kWh (Jan. - Dec., 2019): 66,915 | 509,785

Participation		Jan.	Feb.	March	April	May	June	July	Aug.	Sept.	Oct.	Nov.	Dec.	Total	Jan.	Feb.	March	April	May	June	July	Aug.	Sept.	Oct.	Nov.	Dec.	Total	Total
	Planned:	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	793
	Actual:	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	554
														0%													0%	70%

NOTES:

1. The kWh savings are based on actual participation from Dominion North Carolina Power customers with program planning realization and net-to-gross adjustments assumptions applied
2. The May 1, 2019 EM&V Report was filed with the NC Public Utilities Commission and included EM&V data through the end of 2018.
3. The EM&V data reflected for January 2018 - June, 2019 was prepared by DNV GL using the same STEP (Standard Tracking Engineering Protocol) formulas used in preparing the EM&V data for 2018.
4. The kWh savings are inclusive of all EE measures installed from program inception through June 30, 2019.
5. Program measure life is 18 years (216 months)

	2014													2015												
						1	2	3	4	5	6	7		8	9	10	11	12	13	14	15	16	17	18	19	
kWh (Net) in North Carolina	Jan.	Feb.	March	April	May	June	July	Aug.	Sept.	Oct.	Nov.	Dec.	Total	Jan.	Feb.	March	April	May	June	July	Aug.	Sept.	Oct.	Nov.	Dec.	Total
Residential Heat Pump Upgrade - kWh /year Savings (Deemed with assumed realization and net-to-gross rates from May 1, 2019 EMV Report)	-	-	-	-	-	3,592	-	5,848	9,108	8,351	16,281	22,527	65,707	8,455	13,750	1,799	11,064	10,506	12,471	10,650	4,994	12,693	6,933	4,143	1,294	164,459
Monthly - Adjusted kWh (Net)													Total Months													Total Months
Jan, 2014	-	-	-	-	-	-	-	-	-	-	-	-	12	-	-	-	-	-	-	-	-	-	-	-	-	24
Feb		-	-	-	-	-	-	-	-	-	-	-	11	-	-	-	-	-	-	-	-	-	-	-	-	23
Mar			-	-	-	-	-	-	-	-	-	-	10	-	-	-	-	-	-	-	-	-	-	-	-	22
Apr				-	-	-	-	-	-	-	-	-	9	-	-	-	-	-	-	-	-	-	-	-	-	21
May					-	-	-	-	-	-	-	-	8	-	-	-	-	-	-	-	-	-	-	-	-	20
Jun						299	299	299	299	299	299	299	7	299	299	299	299	299	299	299	299	299	299	299	299	19
Jul							-	-	-	-	-	-	6	-	-	-	-	-	-	-	-	-	-	-	-	18
Aug								487	487	487	487	487	5	487	487	487	487	487	487	487	487	487	487	487	487	17
Sep									759	759	759	759	4	759	759	759	759	759	759	759	759	759	759	759	759	16
Oct										696	696	696	3	696	696	696	696	696	696	696	696	696	696	696	696	15
Nov											1,357	1,357	2	1,357	1,357	1,357	1,357	1,357	1,357	1,357	1,357	1,357	1,357	1,357	1,357	14
Dec												1,877	1	1,877	1,877	1,877	1,877	1,877	1,877	1,877	1,877	1,877	1,877	1,877	1,877	13
Jan, 2015														705	705	705	705	705	705	705	705	705	705	705	705	12
Feb															1,146	1,146	1,146	1,146	1,146	1,146	1,146	1,146	1,146	1,146	1,146	11
Mar																150	150	150	150	150	150	150	150	150	150	10
Apr																	922	922	922	922	922	922	922	922	922	9
May																		876	876	876	876	876	876	876	876	8
Jun																			1,039	1,039	1,039	1,039	1,039	1,039	1,039	7
Jul																				888	888	888	888	888	888	6
Aug																					416	416	416	416	416	5
Sep																						1,058	1,058	1,058	1,058	4
Oct																							578	578	578	3
Nov																								345	345	2
Dec																									108	1
Total (Cumulative by Month) - Adjusted kWh (Net):	-	-	-	-	-	299	299	787	1,546	2,242	3,598	5,476		6,180	7,326	7,476	8,398	9,273	10,313	11,200	11,616	12,674	13,252	13,597	13,705	

DNV GL Tracking		Jan.	Feb.	March	April	May	June	July	Aug.	Sept.	Oct.	Nov.	Dec.		Jan.	Feb.	March	April	May	June	July	Aug.	Sept.	Oct.	Nov.	Dec.
Schedule 1 [redacted]	[redacted] 99.3%	0	0	0	0	0	297	297	781	1,535	2,226	3,573	5,437		6,136	7,274	7,423	8,338	9,208	10,240	11,121	11,534	12,584	13,158	13,501	13,608
Schedule 1DF [redacted]	[redacted] 0.6%	0	0	0	0	0	2	2	4	9	13	20	31		35	41	42	47	52	58	63	66	72	75	77	77
Schedule 1P [redacted]	[redacted] 0.1%	0	0	0	0	0	0	0	1	2	3	5	8		9	11	11	12	13	15	16	17	18	19	20	20
		-	-	-	-	-	299	299	787	1,546	2,242	3,598	5,476		6,180	7,326	7,476	8,398	9,273	10,313	11,200	11,616	12,674	13,252	13,597	13,705

Actual kWh (Jan. - Dec., 2014): [redacted] 14,247

Actual kWh (Jan. - Dec., 2015): 125,011

Participation		Jan.	Feb.	March	April	May	June	July	Aug.	Sept.	Oct.	Nov.	Dec.	Total	Jan.	Feb.	March	April	May	June	July	Aug.	Sept.	Oct.	Nov.	Dec.	Total
	Planned:	48	72	84	180	168	120	96	84	84	84	120	60	[redacted] 1,200	48	72	84	180	168	120	96	84	84	84	120	60	1,200
	Actual:						1	0	4	5	9	12	13	[redacted] 44	34	15	20	58	57	99	83	48	103	43	29	8	[redacted] 897
														[redacted] 4%													[redacted] 50%

Dominion Energy North Carolina
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2016													2017												
20	21	22	23	24	25	26	27	28	29	30	31		32	33	34	35	36	37	38	39	40	41	42	43	
Jan.	Feb.	March	April	May	June	July	Aug.	Sept.	Oct.	Nov.	Dec.	Total	Jan.	Feb.	March	April	May	June	July	Aug.	Sept.	Oct.	Nov.	Dec.	Total
3,432	15,120	6,487	7,272	7,003	17,434	9,139	16,422	5,796	9,078	12,183	1,776	275,602	14,728	5,607	1,745	-	-	-	-	-	-	-	-	-	297,683
												Total Months													Total Months
-	-	-	-	-	-	-	-	-	-	-	-	36	-	-	-	-	-	-	-	-	-	-	-	-	48
-	-	-	-	-	-	-	-	-	-	-	-	35	-	-	-	-	-	-	-	-	-	-	-	-	47
-	-	-	-	-	-	-	-	-	-	-	-	34	-	-	-	-	-	-	-	-	-	-	-	-	46
-	-	-	-	-	-	-	-	-	-	-	-	33	-	-	-	-	-	-	-	-	-	-	-	-	45
-	-	-	-	-	-	-	-	-	-	-	-	32	-	-	-	-	-	-	-	-	-	-	-	-	44
299	299	299	299	299	299	299	299	299	299	299	299	31	299	299	299	299	299	299	299	299	299	299	299	299	43
-	-	-	-	-	-	-	-	-	-	-	-	30	-	-	-	-	-	-	-	-	-	-	-	-	42
487	487	487	487	487	487	487	487	487	487	487	487	29	487	487	487	487	487	487	487	487	487	487	487	487	41
759	759	759	759	759	759	759	759	759	759	759	759	28	759	759	759	759	759	759	759	759	759	759	759	759	40
696	696	696	696	696	696	696	696	696	696	696	696	27	696	696	696	696	696	696	696	696	696	696	696	696	39
1,357	1,357	1,357	1,357	1,357	1,357	1,357	1,357	1,357	1,357	1,357	1,357	26	1,357	1,357	1,357	1,357	1,357	1,357	1,357	1,357	1,357	1,357	1,357	1,357	38
1,877	1,877	1,877	1,877	1,877	1,877	1,877	1,877	1,877	1,877	1,877	1,877	25	1,877	1,877	1,877	1,877	1,877	1,877	1,877	1,877	1,877	1,877	1,877	1,877	37
705	705	705	705	705	705	705	705	705	705	705	705	24	705	705	705	705	705	705	705	705	705	705	705	705	36
1,146	1,146	1,146	1,146	1,146	1,146	1,146	1,146	1,146	1,146	1,146	1,146	23	1,146	1,146	1,146	1,146	1,146	1,146	1,146	1,146	1,146	1,146	1,146	1,146	35
150	150	150	150	150	150	150	150	150	150	150	150	22	150	150	150	150	150	150	150	150	150	150	150	150	34
922	922	922	922	922	922	922	922	922	922	922	922	21	922	922	922	922	922	922	922	922	922	922	922	922	33
876	876	876	876	876	876	876	876	876	876	876	876	20	876	876	876	876	876	876	876	876	876	876	876	876	32
1,039	1,039	1,039	1,039	1,039	1,039	1,039	1,039	1,039	1,039	1,039	1,039	19	1,039	1,039	1,039	1,039	1,039	1,039	1,039	1,039	1,039	1,039	1,039	1,039	31
888	888	888	888	888	888	888	888	888	888	888	888	18	888	888	888	888	888	888	888	888	888	888	888	888	30
416	416	416	416	416	416	416	416	416	416	416	416	17	416	416	416	416	416	416	416	416	416	416	416	416	29
1,058	1,058	1,058	1,058	1,058	1,058	1,058	1,058	1,058	1,058	1,058	1,058	16	1,058	1,058	1,058	1,058	1,058	1,058	1,058	1,058	1,058	1,058	1,058	1,058	28
578	578	578	578	578	578	578	578	578	578	578	578	15	578	578	578	578	578	578	578	578	578	578	578	578	27
345	345	345	345	345	345	345	345	345	345	345	345	14	345	345	345	345	345	345	345	345	345	345	345	345	26
108	108	108	108	108	108	108	108	108	108	108	108	13	108	108	108	108	108	108	108	108	108	108	108	108	25
286	286	286	286	286	286	286	286	286	286	286	286	12	286	286	286	286	286	286	286	286	286	286	286	286	24
	1,260	1,260	1,260	1,260	1,260	1,260	1,260	1,260	1,260	1,260	1,260	11	1,260	1,260	1,260	1,260	1,260	1,260	1,260	1,260	1,260	1,260	1,260	1,260	23
		541	541	541	541	541	541	541	541	541	541	10	541	541	541	541	541	541	541	541	541	541	541	541	22
			606	606	606	606	606	606	606	606	606	9	606	606	606	606	606	606	606	606	606	606	606	606	21
				584	584	584	584	584	584	584	584	8	584	584	584	584	584	584	584	584	584	584	584	584	20
					1,453	1,453	1,453	1,453	1,453	1,453	1,453	7	1,453	1,453	1,453	1,453	1,453	1,453	1,453	1,453	1,453	1,453	1,453	1,453	19
						762	762	762	762	762	762	6	762	762	762	762	762	762	762	762	762	762	762	762	18
							1,368	1,368	1,368	1,368	1,368	5	1,368	1,368	1,368	1,368	1,368	1,368	1,368	1,368	1,368	1,368	1,368	1,368	17
								483	483	483	483	4	483	483	483	483	483	483	483	483	483	483	483	483	16
									756	756	756	3	756	756	756	756	756	756	756	756	756	756	756	756	15
										1,015	1,015	2	1,015	1,015	1,015	1,015	1,015	1,015	1,015	1,015	1,015	1,015	1,015	1,015	14
											148	1	148	148	148	148	148	148	148	148	148	148	148	148	13
													1,227	1,227	1,227	1,227	1,227	1,227	1,227	1,227	1,227	1,227	1,227	1,227	12
														467	467	467	467	467	467	467	467	467	467	467	11
															145	145	145	145	145	145	145	145	145	145	10
																-	-	-	-	-	-	-	-	-	9
																	-	-	-	-	-	-	-	-	8
																		-	-	-	-	-	-	-	7
																			-	-	-	-	-	-	6
																				-	-	-	-	-	5
																					-	-	-	-	4
																						-	-	-	3
																							-	-	2
																								-	1
13,991	15,251	15,792	16,398	16,981	18,434	19,196	20,564	21,047	21,804	22,819	22,967	[redacted]	24,194	24,661	24,807	24,807	24,807	24,807	24,807	24,807	24,807	24,807	24,807	24,807	[redacted]
13,892	15,143	15,680	16,281	16,861	18,303	19,060	20,418	20,898	21,649	22,657	22,804	[redacted]	24,023	24,487	24,631	24,631	24,631	24,631	24,631	24,631	24,631	24,631	24,631	24,631	[redacted]
79	86	89	93	96	104	108	116	119	123	129	130		137	139	140	140	140	140	140	140	140	140	140	140	
20	22	23	24	24	27	28	30	30	31	33	33		35	36	36	36	36	36	36	36	36	36	36	36	
13,991	15,251	15,792	16,398	16,981	18,434	19,196	20,564	21,047	21,804	22,819	22,967		24,194	24,661	24,807	24,807	24,807	24,807	24,807	24,807	24,807	24,807	24,807	24,807	

Actual kWh (Jan. - Dec., 2016): [redacted] 226,243

Actual kWh (Jan. - Dec., 2017): [redacted] 290,928

21	21	21	21	21	21	21	21	21	21	21	21	[redacted] 252	0	0	0	0	0	0	0	0	0	0	0	0	[redacted] 0
23	72	48	65	44	88	70	105	37	57	46	10	[redacted] 668	76	36	6	0	0	0	0	0	0	0	0	0	[redacted] 118
												[redacted] 264%													[redacted] 0%

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	2018														2019													
	44	45	46	47	48	49	50	51	52	53	54	55			56	57	58	59	60	61								
kWh (Net) in North Carolina	Jan.	Feb.	March	April	May	June	July	Aug.	Sept.	Oct.	Nov.	Dec.	Total		Jan.	Feb.	March	April	May	June	July	Aug.	Sept.	Oct.	Nov.	Dec.	Total	
Residential Heat Pump Upgrade - kWh /year Savings (Deemed with assumed realization and net-to-gross rates from May 1, 2019 EMV Report)	-	-	-	-	-	-	-	-	-	-	-	-	297,683		-	-	-	-	-	-							297,683	
Monthly - Adjusted kWh (Net)														Total Months														Total Months
Jan, 2014	-	-	-	-	-	-	-	-	-	-	-	-		60	-	-	-	-	-	-								66
Feb	-	-	-	-	-	-	-	-	-	-	-	-		59	-	-	-	-	-	-								65
Mar	-	-	-	-	-	-	-	-	-	-	-	-		58	-	-	-	-	-	-								64
Apr	-	-	-	-	-	-	-	-	-	-	-	-		57	-	-	-	-	-	-								63
May	-	-	-	-	-	-	-	-	-	-	-	-		56	-	-	-	-	-	-								62
Jun	299	299	299	299	299	299	299	299	299	299	299	299		55	299	299	299	299	299	299								61
Jul	-	-	-	-	-	-	-	-	-	-	-	-		54	-	-	-	-	-	-								60
Aug	487	487	487	487	487	487	487	487	487	487	487	487		53	487	487	487	487	487	487								59
Sep	759	759	759	759	759	759	759	759	759	759	759	759		52	759	759	759	759	759	759								58
Oct	696	696	696	696	696	696	696	696	696	696	696	696		51	696	696	696	696	696	696								57
Nov	1,357	1,357	1,357	1,357	1,357	1,357	1,357	1,357	1,357	1,357	1,357	1,357		50	1,357	1,357	1,357	1,357	1,357	1,357								56
Dec	1,877	1,877	1,877	1,877	1,877	1,877	1,877	1,877	1,877	1,877	1,877	1,877		49	1,877	1,877	1,877	1,877	1,877	1,877								55
Jan, 2015	705	705	705	705	705	705	705	705	705	705	705	705		48	705	705	705	705	705	705								54
Feb	1,146	1,146	1,146	1,146	1,146	1,146	1,146	1,146	1,146	1,146	1,146	1,146		47	1,146	1,146	1,146	1,146	1,146	1,146								53
Mar	150	150	150	150	150	150	150	150	150	150	150	150		46	150	150	150	150	150	150								52
Apr	922	922	922	922	922	922	922	922	922	922	922	922		45	922	922	922	922	922	922								51
May	876	876	876	876	876	876	876	876	876	876	876	876		44	876	876	876	876	876	876								50
Jun	1,039	1,039	1,039	1,039	1,039	1,039	1,039	1,039	1,039	1,039	1,039	1,039		43	1,039	1,039	1,039	1,039	1,039	1,039								49
Jul	888	888	888	888	888	888	888	888	888	888	888	888		42	888	888	888	888	888	888								48
Aug	416	416	416	416	416	416	416	416	416	416	416	416		41	416	416	416	416	416	416								47
Sep	1,058	1,058	1,058	1,058	1,058	1,058	1,058	1,058	1,058	1,058	1,058	1,058		40	1,058	1,058	1,058	1,058	1,058	1,058								46
Oct	578	578	578	578	578	578	578	578	578	578	578	578		39	578	578	578	578	578	578								45
Nov	345	345	345	345	345	345	345	345	345	345	345	345		38	345	345	345	345	345	345								44
Dec	108	108	108	108	108	108	108	108	108	108	108	108		37	108	108	108	108	108	108								43
Jan, 2016	286	286	286	286	286	286	286	286	286	286	286	286		36	286	286	286	286	286	286								42
Feb	1,260	1,260	1,260	1,260	1,260	1,260	1,260	1,260	1,260	1,260	1,260	1,260		35	1,260	1,260	1,260	1,260	1,260	1,260								41
Mar	541	541	541	541	541	541	541	541	541	541	541	541		34	541	541	541	541	541	541								40
Apr	606	606	606	606	606	606	606	606	606	606	606	606		33	606	606	606	606	606	606								39
May	584	584	584	584	584	584	584	584	584	584	584	584		32	584	584	584	584	584	584								38
Jun	1,453	1,453	1,453	1,453	1,453	1,453	1,453	1,453	1,453	1,453	1,453	1,453		31	1,453	1,453	1,453	1,453	1,453	1,453								37
Jul	762	762	762	762	762	762	762	762	762	762	762	762		30	762	762	762	762	762	762								36
Aug	1,368	1,368	1,368	1,368	1,368	1,368	1,368	1,368	1,368	1,368	1,368	1,368		29	1,368	1,368	1,368	1,368	1,368	1,368								35
Sep	483	483	483	483	483	483	483	483	483	483	483	483		28	483	483	483	483	483	483								34
Oct	756	756	756	756	756	756	756	756	756	756	756	756		27	756	756	756	756	756	756								33
Nov	1,015	1,015	1,015	1,015	1,015	1,015	1,015	1,015	1,015	1,015	1,015	1,015		26	1,015	1,015	1,015	1,015	1,015	1,015								32
Dec	148	148	148	148	148	148	148	148	148	148	148	148		25	148	148	148	148	148	148								31
Jan, 2017	1,227	1,227	1,227	1,227	1,227	1,227	1,227	1,227	1,227	1,227	1,227	1,227		24	1,227	1,227	1,227	1,227	1,227	1,227								30
Feb	467	467	467	467	467	467	467	467	467	467	467	467		23	467	467	467	467	467	467								29
Mar	145	145	145	145	145	145	145	145	145	145	145	145		22	145	145	145	145	145	145								28
Apr	-	-	-	-	-	-	-	-	-	-	-	-		21	-	-	-	-	-	-								27
May	-	-	-	-	-	-	-	-	-	-	-	-		20	-	-	-	-	-	-								26
Jun	-	-	-	-	-	-	-	-	-	-	-	-		19	-	-	-	-	-	-								25
Jul	-	-	-	-	-	-	-	-	-	-	-	-		18	-	-	-	-	-	-								24
Aug	-	-	-	-	-	-	-	-	-	-	-	-		17	-	-	-	-	-	-								23
Sep	-	-	-	-	-	-	-	-	-	-	-	-		16	-	-	-	-	-	-								22
Oct	-	-	-	-	-	-	-	-	-	-	-	-		15	-	-	-	-	-	-								21
Nov	-	-	-	-	-	-	-	-	-	-	-	-		14	-	-	-	-	-	-								20
Dec	-	-	-	-	-	-	-	-	-	-	-	-		13	-	-	-	-	-	-								19
Total (Cumulative by Month) - Adjusted kWh (Net):	24,807	24,807	24,807	24,807	24,807	24,807	24,807	24,807	24,807	24,807	24,807	24,807			24,807	24,807	24,807	24,807	24,807	24,807	-	-	-	-	-	-		
DNV GL Tracking																												
Schedule 1 99.3%	24,631	24,631	24,631	24,631	24,631	24,631	24,631	24,631	24,631	24,631	24,631	24,631			24,631	24,631	24,631	24,631	24,631	24,631	-	-	-	-	-	-	-	
Schedule 1DF 0.6%	140	140	140	140	140	140	140	140	140	140	140	140			140	140	140	140	140	140	-	-	-	-	-	-	-	
Schedule 1P 0.1%	36	36	36	36	36	36	36	36	36	36	36	36			36	36	36	36	36	36	-	-	-	-	-	-	-	
	24,807	24,807	24,807	24,807	24,807	24,807	24,807	24,807	24,807	24,807	24,807	24,807			24,807	24,807	24,807	24,807	24,807	24,807	-	-	-	-	-	-	-	

LUM Total kWh
297,683

1,107,950 True-up

Actual kWh (Jan. - Dec., 2018): 297,683

Actual kWh (Jan. - Dec., 2019): 148,842 1,107,950

Participation		Jan.	Feb.	March	April	May	June	July	Aug.	Sept.	Oct.	Nov.	Dec.	Total	Jan.	Feb.	March	April	May	June	July	Aug.	Sept.	Oct.	Nov.	Dec.	Total	Total
	Planned:	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0							0	2,852
	Actual:	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0							0	1,424
														0%													0%	50%

NOTES:

1. The kWh savings are based on actual participation from Dominion North Carolina Power customers with program planning realization and net-to-gross adjustments assumptions applied
2. The May 1, 2019 EM&V Report was filed with the NC Public Utilities Commission and included EM&V data through the end of 2018.
3. The EM&V data reflected for January 2018 - June, 2019 was prepared by DNV GL using the same STEP (Standard Tracking Engineering Protocol) formulas used in preparing the EM&V data for 2018.
4. The kWh savings are inclusive of all EE measures installed from program inception through June 30, 2019.
5. Program measure life is 15 years (180 months)

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Company Supplemental Exhibit DRK-1
Schedule 1
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2014

kWh (Net) in North Carolina		Jan.	Feb.	March	April	May	June	July	Aug	Sept.	Oct.	Nov.	Dec.	Total
Residential Home Energy Check Up - kWh /year Savings (Deemed with assumed realization and net-to-gross rates from May 1, 2019 EMV Report)		-	-	-	-	-	-	-	-	-	-	-	-	-
Monthly - Adjusted kWh (Net)														Total Months
Jan, 2014		-	-	-	-	-	-	-	-	-	-	-	-	12
Feb			-	-	-	-	-	-	-	-	-	-	-	11
Mar				-	-	-	-	-	-	-	-	-	-	10
Apr					-	-	-	-	-	-	-	-	-	9
May						-	-	-	-	-	-	-	-	8
Jun							-	-	-	-	-	-	-	7
Jul								-	-	-	-	-	-	6
Aug									-	-	-	-	-	5
Sep										-	-	-	-	4
Oct											-	-	-	3
Nov												-	-	2
Dec													-	1
Jan, 2015														
Feb														
Mar														
Apr														
May														
Jun														
Jul														
Aug														
Sep														
Oct														
Nov														
Dec														
Total (Cumulative by Month) - Adjusted kWh (Net):		[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	
DNV GL Tracking														
Schedule 1	98.0%	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	
Schedule 101	1.0%	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	
Schedule 1P	0.8%	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	
Schedule 1T	0.0%	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	
Schedule 26	0.2%	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	
		-	-	-	-	-	-	-	-	-	-	-	-	

Actual kWh (Jan. - Dec., 2014): [illegible]

Participation		Jan.	Feb.	March	April	May	June	July	Aug	Sept.	Oct.	Nov.	Dec.	Total
	Planned:	13	11	10	11	13	13	14	14	14	16	18	13	180
	Actual:	0	0	0	0	0	0	0	0	0	0	0	0	0
														0%

2015

kWh (Net) in North Carolina	Jan.	Feb. (1)	March (2)	April (3)	May (4)	June (5)	July (6)	Aug (7)	Sept. (8)	Oct. (9)	Nov. (10)	Dec. (11)	Total
Residential Home Energy Check Up - kWh /year Savings (Deemed with assumed realization and net-to-gross rates from May 1, 2019 EMV Report)	-	149,378	131,032	93,772	158,871	134,795	50,612	3,300	19,830	3,229	-	895	745,714
Monthly - Adjusted kWh (Net)													Total Months
Jan, 2014	-	-	-	-	-	-	-	-	-	-	-	-	24
Feb	-	-	-	-	-	-	-	-	-	-	-	-	23
Mar	-	-	-	-	-	-	-	-	-	-	-	-	22
Apr	-	-	-	-	-	-	-	-	-	-	-	-	21
May	-	-	-	-	-	-	-	-	-	-	-	-	20
Jun	-	-	-	-	-	-	-	-	-	-	-	-	19
Jul	-	-	-	-	-	-	-	-	-	-	-	-	18
Aug	-	-	-	-	-	-	-	-	-	-	-	-	17
Sep	-	-	-	-	-	-	-	-	-	-	-	-	16
Oct	-	-	-	-	-	-	-	-	-	-	-	-	15
Nov	-	-	-	-	-	-	-	-	-	-	-	-	14
Dec	-	-	-	-	-	-	-	-	-	-	-	-	13
Jan, 2015	-	-	-	-	-	-	-	-	-	-	-	-	12
Feb		12,448	12,448	12,448	12,448	12,448	12,448	12,448	12,448	12,448	12,448	12,448	11
Mar			10,919	10,919	10,919	10,919	10,919	10,919	10,919	10,919	10,919	10,919	10
Apr				7,814	7,814	7,814	7,814	7,814	7,814	7,814	7,814	7,814	9
May					13,239	13,239	13,239	13,239	13,239	13,239	13,239	13,239	8
Jun						11,233	11,233	11,233	11,233	11,233	11,233	11,233	7
Jul							4,218	4,218	4,218	4,218	4,218	4,218	6
Aug								275	275	275	275	275	5
Sep									1,653	1,653	1,653	1,653	4
Oct										269	269	269	3
Nov											-	-	2
Dec												75	1
Total (Cumulative by Month) - Adjusted kWh (Net):	-	12,448	23,368	31,182	44,421	55,654	59,872	60,147	61,799	62,068	62,068	62,143	
DNV GL Tracking													
Schedule 1	[illegible]	12,198	22,898	30,555	43,578	54,536	58,669	58,938	60,557	60,821	60,821	60,894	
Schedule 101	[illegible]	121	227	303	432	541	582	585	601	603	603	604	
Schedule 1P	[illegible]	100	188	251	357	447	481	484	497	499	499	500	
Schedule 1T	[illegible]	6	11	14	21	26	28	28	29	29	29	29	
Schedule 26	[illegible]	23	44	58	83	104	112	112	116	116	116	118	
	-	12,448	23,368	31,182	44,421	55,654	59,872	60,147	61,799	62,068	62,068	62,143	

Actual kWh (Jan. - Dec., 2015): 635,189

Participation	Jan.	Feb.	March	April	May	June	July	Aug	Sept.	Oct.	Nov.	Dec.	Total
Planned:	13	11	10	11	13	13	14	14	14	16	18	13	160
Actual:	0	152	156	128	237	200	86	5	27	4	0	1	996
													623%

2016													2017												
12	13	14	15	16	17	18	19	20	21	22	23		24	25	26	27	28	29	30	31	32	33	34	35	
Jan.	Feb.	March	April	May	June	July	Aug.	Sept.	Oct.	Nov.	Dec.	Total	Jan.	Feb.	March	April	May	June	July	Aug.	Sept.	Oct.	Nov.	Dec.	Total
1,471	408	-	-	-	-	-	-	-	-	-	-	747,593	7,171	31,001	5,892	-	-	-	-	-	-	-	-	-	791,658
												Total Months													Total Months
-	-	-	-	-	-	-	-	-	-	-	-	36	-	-	-	-	-	-	-	-	-	-	-	-	48
-	-	-	-	-	-	-	-	-	-	-	-	35	-	-	-	-	-	-	-	-	-	-	-	-	47
-	-	-	-	-	-	-	-	-	-	-	-	34	-	-	-	-	-	-	-	-	-	-	-	-	46
-	-	-	-	-	-	-	-	-	-	-	-	33	-	-	-	-	-	-	-	-	-	-	-	-	45
-	-	-	-	-	-	-	-	-	-	-	-	32	-	-	-	-	-	-	-	-	-	-	-	-	44
-	-	-	-	-	-	-	-	-	-	-	-	31	-	-	-	-	-	-	-	-	-	-	-	-	43
-	-	-	-	-	-	-	-	-	-	-	-	30	-	-	-	-	-	-	-	-	-	-	-	-	42
-	-	-	-	-	-	-	-	-	-	-	-	29	-	-	-	-	-	-	-	-	-	-	-	-	41
-	-	-	-	-	-	-	-	-	-	-	-	28	-	-	-	-	-	-	-	-	-	-	-	-	40
-	-	-	-	-	-	-	-	-	-	-	-	27	-	-	-	-	-	-	-	-	-	-	-	-	39
-	-	-	-	-	-	-	-	-	-	-	-	26	-	-	-	-	-	-	-	-	-	-	-	-	38
-	-	-	-	-	-	-	-	-	-	-	-	25	-	-	-	-	-	-	-	-	-	-	-	-	37
-	-	-	-	-	-	-	-	-	-	-	-	24	-	-	-	-	-	-	-	-	-	-	-	-	36
12,448	12,448	12,448	12,448	12,448	12,448	12,448	12,448	12,448	12,448	12,448	12,448	23	12,448	12,448	12,448	12,448	12,448	12,448	12,448	12,448	12,448	12,448	12,448	12,448	35
10,919	10,919	10,919	10,919	10,919	10,919	10,919	10,919	10,919	10,919	10,919	10,919	22	10,919	10,919	10,919	10,919	10,919	10,919	10,919	10,919	10,919	10,919	10,919	10,919	34
7,814	7,814	7,814	7,814	7,814	7,814	7,814	7,814	7,814	7,814	7,814	7,814	21	7,814	7,814	7,814	7,814	7,814	7,814	7,814	7,814	7,814	7,814	7,814	7,814	33
13,239	13,239	13,239	13,239	13,239	13,239	13,239	13,239	13,239	13,239	13,239	13,239	20	13,239	13,239	13,239	13,239	13,239	13,239	13,239	13,239	13,239	13,239	13,239	13,239	32
11,233	11,233	11,233	11,233	11,233	11,233	11,233	11,233	11,233	11,233	11,233	11,233	19	11,233	11,233	11,233	11,233	11,233	11,233	11,233	11,233	11,233	11,233	11,233	11,233	31
4,218	4,218	4,218	4,218	4,218	4,218	4,218	4,218	4,218	4,218	4,218	4,218	18	4,218	4,218	4,218	4,218	4,218	4,218	4,218	4,218	4,218	4,218	4,218	4,218	30
275	275	275	275	275	275	275	275	275	275	275	275	17	275	275	275	275	275	275	275	275	275	275	275	275	29
1,653	1,653	1,653	1,653	1,653	1,653	1,653	1,653	1,653	1,653	1,653	1,653	16	1,653	1,653	1,653	1,653	1,653	1,653	1,653	1,653	1,653	1,653	1,653	1,653	28
269	269	269	269	269	269	269	269	269	269	269	269	15	269	269	269	269	269	269	269	269	269	269	269	269	27
-	-	-	-	-	-	-	-	-	-	-	-	14	-	-	-	-	-	-	-	-	-	-	-	-	26
75	75	75	75	75	75	75	75	75	75	75	75	13	75	75	75	75	75	75	75	75	75	75	75	75	25
123	123	123	123	123	123	123	123	123	123	123	123	12	123	123	123	123	123	123	123	123	123	123	123	123	24
	34	34	34	34	34	34	34	34	34	34	34	11	34	34	34	34	34	34	34	34	34	34	34	34	23
		-	-	-	-	-	-	-	-	-	-	10	-	-	-	-	-	-	-	-	-	-	-	-	22
			-	-	-	-	-	-	-	-	-	9	-	-	-	-	-	-	-	-	-	-	-	-	21
				-	-	-	-	-	-	-	-	8	-	-	-	-	-	-	-	-	-	-	-	-	20
					-	-	-	-	-	-	-	7	-	-	-	-	-	-	-	-	-	-	-	-	19
						-	-	-	-	-	-	6	-	-	-	-	-	-	-	-	-	-	-	-	18
							-	-	-	-	-	5	-	-	-	-	-	-	-	-	-	-	-	-	17
								-	-	-	-	4	-	-	-	-	-	-	-	-	-	-	-	-	16
									-	-	-	3	-	-	-	-	-	-	-	-	-	-	-	-	15
										-	-	2	-	-	-	-	-	-	-	-	-	-	-	-	14
											-	1	-	-	-	-	-	-	-	-	-	-	-	-	13
													598	598	598	598	598	598	598	598	598	598	598	598	12
														2,583	2,583	2,583	2,583	2,583	2,583	2,583	2,583	2,583	2,583	2,583	11
															491	491	491	491	491	491	491	491	491	491	10
																-	-	-	-	-	-	-	-	-	9
																	-	-	-	-	-	-	-	-	8
																		-	-	-	-	-	-	-	7
																			-	-	-	-	-	-	6
																				-	-	-	-	-	5
																					-	-	-	-	4
																						-	-	-	3
																							-	-	2
																								-	1
62,265	62,299	62,299	62,299	62,299	62,299	62,299	62,299	62,299	62,299	62,299	62,299		62,897	65,480	65,971	65,971	65,971	65,971	65,971	65,971	65,971	65,971	65,971	65,971	[redacted]
61,014	61,047	61,047	61,047	61,047	61,047	61,047	61,047	61,047	61,047	61,047	61,047		61,633	64,165	64,646	64,646	64,646	64,646	64,646	64,646	64,646	64,646	64,646	64,646	[redacted]
605	606	606	606	606	606	606	606	606	606	606	606		611	637	641	641	641	641	641	641	641	641	641	641	
501	501	501	501	501	501	501	501	501	501	501	501		506	526	530	530	530	530	530	530	530	530	530	530	
29	29	29	29	29	29	29	29	29	29	29	29		29	30	31	31	31	31	31	31	31	31	31	31	
116	116	116	116	116	116	116	116	116	116	116	116		128	122	123	123	123	123	123	123	123	123	123	123	
62,265	62,299	62,299	62,299	62,299	62,299	62,299	62,299	62,299	62,299	62,299	62,299		62,897	65,480	65,971	65,971	65,971	65,971	65,971	65,971	65,971	65,971	65,971	65,971	
											Actual kWh (Jan. - Dec., 2016):	[redacted] 747,669												Actual kWh (Jan. - Dec., 2017):	[redacted] 789,002
73	73	73	73	73	73	73	73	73	73	73	73	[redacted] 881	0	0	0	0	0	0	0	0	0	0	0	0	[redacted] 0
3	1	0	0	0	0	0	0	0	0	0	0	[redacted] 4	5	39	5	0	0	0	0	0	0	0	0	0	[redacted] 49
												[redacted] 0%													[redacted] 0%

	2018														2019													
	36	37	38	39	40	41	42	43	44	45	46	47			48	49	50	51	52	53								
kWh (Net) in North Carolina	Jan.	Feb.	March	April	May	June	July	Aug.	Sept.	Oct.	Nov.	Dec.	Total		Jan.	Feb.	March	April	May	June	July	Aug.	Sept.	Oct.	Nov.	Dec.	Total	Total
Residential Home Energy Check Up - kWh /year Savings (Deemed with assumed realization and net-to-gross rates from May 1, 2019 EMV Report)	-	-	-	-	-	-	-	-	-	-	-	-	791,658		-	-	-	-	-	-							791,658	791,658
Monthly - Adjusted kWh (Net)														Total Months														Total Months
Jan, 2014	-	-	-	-	-	-	-	-	-	-	-	-		60	-	-	-	-	-	-								60
Feb	-	-	-	-	-	-	-	-	-	-	-	-		59	-	-	-	-	-	-								59
Mar	-	-	-	-	-	-	-	-	-	-	-	-		58	-	-	-	-	-	-								58
Apr	-	-	-	-	-	-	-	-	-	-	-	-		57	-	-	-	-	-	-								57
May	-	-	-	-	-	-	-	-	-	-	-	-		56	-	-	-	-	-	-								56
Jun	-	-	-	-	-	-	-	-	-	-	-	-		55	-	-	-	-	-	-								55
Jul	-	-	-	-	-	-	-	-	-	-	-	-		54	-	-	-	-	-	-								54
Aug	-	-	-	-	-	-	-	-	-	-	-	-		53	-	-	-	-	-	-								53
Sep	-	-	-	-	-	-	-	-	-	-	-	-		52	-	-	-	-	-	-								52
Oct	-	-	-	-	-	-	-	-	-	-	-	-		51	-	-	-	-	-	-								51
Nov	-	-	-	-	-	-	-	-	-	-	-	-		50	-	-	-	-	-	-								50
Dec	-	-	-	-	-	-	-	-	-	-	-	-		49	-	-	-	-	-	-								49
Jan, 2015	-	-	-	-	-	-	-	-	-	-	-	-		48	-	-	-	-	-	-								48
Feb	12,448	12,448	12,448	12,448	12,448	12,448	12,448	12,448	12,448	12,448	12,448	12,448		47	12,448	12,448	12,448	12,448	12,448	12,448								47
Mar	10,919	10,919	10,919	10,919	10,919	10,919	10,919	10,919	10,919	10,919	10,919	10,919		46	10,919	10,919	10,919	10,919	10,919	10,919								46
Apr	7,814	7,814	7,814	7,814	7,814	7,814	7,814	7,814	7,814	7,814	7,814	7,814		45	7,814	7,814	7,814	7,814	7,814	7,814								45
May	13,239	13,239	13,239	13,239	13,239	13,239	13,239	13,239	13,239	13,239	13,239	13,239		44	13,239	13,239	13,239	13,239	13,239	13,239								44
Jun	11,233	11,233	11,233	11,233	11,233	11,233	11,233	11,233	11,233	11,233	11,233	11,233		43	11,233	11,233	11,233	11,233	11,233	11,233								43
Jul	4,218	4,218	4,218	4,218	4,218	4,218	4,218	4,218	4,218	4,218	4,218	4,218		42	4,218	4,218	4,218	4,218	4,218	4,218								42
Aug	275	275	275	275	275	275	275	275	275	275	275	275		41	275	275	275	275	275	275								41
Sep	1,653	1,653	1,653	1,653	1,653	1,653	1,653	1,653	1,653	1,653	1,653	1,653		40	1,653	1,653	1,653	1,653	1,653	1,653								40
Oct	269	269	269	269	269	269	269	269	269	269	269	269		39	269	269	269	269	269	269								39
Nov	-	-	-	-	-	-	-	-	-	-	-	-		38	-	-	-	-	-	-								38
Dec	75	75	75	75	75	75	75	75	75	75	75	75		37	75	75	75	75	75	75								37
Jan, 2016	123	123	123	123	123	123	123	123	123	123	123	123		36	123	123	123	123	123	123								36
Feb	34	34	34	34	34	34	34	34	34	34	34	34		35	34	34	34	34	34	34								35
Mar	-	-	-	-	-	-	-	-	-	-	-	-		34	-	-	-	-	-	-								34
Apr	-	-	-	-	-	-	-	-	-	-	-	-		33	-	-	-	-	-	-								33
May	-	-	-	-	-	-	-	-	-	-	-	-		32	-	-	-	-	-	-								32
Jun	-	-	-	-	-	-	-	-	-	-	-	-		31	-	-	-	-	-	-								31
Jul	-	-	-	-	-	-	-	-	-	-	-	-		30	-	-	-	-	-	-								30
Aug	-	-	-	-	-	-	-	-	-	-	-	-		29	-	-	-	-	-	-								29
Sep	-	-	-	-	-	-	-	-	-	-	-	-		28	-	-	-	-	-	-								28
Oct	-	-	-	-	-	-	-	-	-	-	-	-		27	-	-	-	-	-	-								27
Nov	-	-	-	-	-	-	-	-	-	-	-	-		26	-	-	-	-	-	-								26
Dec	-	-	-	-	-	-	-	-	-	-	-	-		25	-	-	-	-	-	-								25
Jan, 2017	598	598	598	598	598	598	598	598	598	598	598	598		24	598	598	598	598	598	598								24
Feb	2,583	2,583	2,583	2,583	2,583	2,583	2,583	2,583	2,583	2,583	2,583	2,583		23	2,583	2,583	2,583	2,583	2,583	2,583								23
Mar	491	491	491	491	491	491	491	491	491	491	491	491		22	491	491	491	491	491	491								22
Apr	-	-	-	-	-	-	-	-	-	-	-	-		21	-	-	-	-	-	-								21
May	-	-	-	-	-	-	-	-	-	-	-	-		20	-	-	-	-	-	-								20
Jun	-	-	-	-	-	-	-	-	-	-	-	-		19	-	-	-	-	-	-								19
Jul	-	-	-	-	-	-	-	-	-	-	-	-		18	-	-	-	-	-	-								18
Aug	-	-	-	-	-	-	-	-	-	-	-	-		17	-	-	-	-	-	-								17
Sep	-	-	-	-	-	-	-	-	-	-	-	-		16	-	-	-	-	-	-								16
Oct	-	-	-	-	-	-	-	-	-	-	-	-		15	-	-	-	-	-	-								15
Nov	-	-	-	-	-	-	-	-	-	-	-	-		14	-	-	-	-	-	-								14
Dec	-	-	-	-	-	-	-	-	-	-	-	-		13	-	-	-	-	-	-								13
Total (Cumulative by Month) - Adjusted kWh (Net):	65,971	65,971	65,971	65,971	65,971	65,971	65,971	65,971	65,971	65,971	65,971	65,971			65,971	65,971	65,971	65,971	65,971	65,971	-	-	-	-	-	-		3,258,307

DNV GL Tracking		Jan.	Feb.	March	April	May	June	July	Aug.	Sept.	Oct.	Nov.	Dec.	Jan.	Feb.	March	April	May	June	July	Aug.	Sept.	Oct.	Nov.	Dec.
Schedule 1	98.0%	64,646	64,646	64,646	64,646	64,646	64,646	64,646	64,646	64,646	64,646	64,646	64,646	64,646	64,646	64,646	64,646	64,646	64,646	-	-	-	-	-	-
Schedule 10P	1.0%	641	641	641	641	641	641	641	641	641	641	641	641	641	641	641	641	641	641	-	-	-	-	-	-
Schedule 1P	0.8%	530	530	530	530	530	530	530	530	530	530	530	530	530	530	530	530	530	530	-	-	-	-	-	-
Schedule 1T	0.0%	31	31	31	31	31	31	31	31	31	31	31	31	31	31	31	31	31	31	-	-	-	-	-	-
Schedule 30	0.2%	123	123	123	123	123	123	123	123	123	123	123	123	123	123	123	123	123	123	-	-	-	-	-	-
		65,971	65,971	65,971	65,971	65,971	65,971	65,971	65,971	65,971	65,971	65,971	65,971	65,971	65,971	65,971	65,971	65,971	65,971	-	-	-	-	-	-

Actual kWh (Jan. - Dec., 2018): 791,888

Actual kWh (Jan. - Dec., 2019): 398,820 | 3,258,307

Participation		Jan.	Feb.	March	April	May	June	July	Aug.	Sept.	Oct.	Nov.	Dec.	Total	Jan.	Feb.	March	April	May	June	July	Aug.	Sept.	Oct.	Nov.	Dec.	Total	Total
	Planned:	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0						0	1,201
	Actual:	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0						0	1,049
														0%													0%	87%

NOTES:

1. The kWh savings are based on actual participation from Dominion North Carolina Power customers with program planning realization and net-to-gross adjustments assumptions applied
2. The May 1, 2019 EM&V Report was filed with the NC Public Utilities Commission and included EM&V data through the end of 2018
3. The EM&V data reflected for January 2018 - June, 2019 was prepared by DNV GL using the same STEP (Standard Tracking Engineering Protocol) formulas used in preparing the EM&V data for 2018
4. The kWh savings are inclusive of all EE measures installed from program inception through June 30, 2019.
5. Program measure life is 10 years (120 months)

2014

kWh (Net) in North Carolina	Jan.	Feb.	March	April	May	June	July	Aug	Sept.	Oct.	Nov.	Dec.	Total
											1	2	
Non-Residential Duct Selaing and Testing - kWh /year Savings (Deemed with assumed realization and net-to-gross rates from May 1, 2019 EMV Report)	-	-	-	-	-	-	-	-	-	-	462,692	41,220	503,912
Monthly - Adjusted kWh (Net)													Total Months
Jan, 2014	-	-	-	-	-	-	-	-	-	-	-	-	12
Feb		-	-	-	-	-	-	-	-	-	-	-	11
Mar			-	-	-	-	-	-	-	-	-	-	10
Apr				-	-	-	-	-	-	-	-	-	9
May					-	-	-	-	-	-	-	-	8
Jun						-	-	-	-	-	-	-	7
Jul							-	-	-	-	-	-	6
Aug								-	-	-	-	-	5
Sep									-	-	-	-	4
Oct										-	-	-	3
Nov											38,558	38,558	2
Dec												3,435	1
Jan, 2015													
Feb													
Mar													
Apr													
May													
Jun													
Jul													
Aug													
Sep													
Oct													
Nov													
Dec													
Total (Cumulative by Month) - Adjusted kWh (Net):	-	-	-	-	-	-	-	-	-	-	38,558	41,993	

2015

kWh (Net) in North Carolina	Jan.	Feb.	March	April	May	June	July	Aug.	Sept.	Oct.	Nov.	Dec.	Total
	3	4	5	6	7	8	9	10	11	12	13	14	
Non-Residential Duct Selaing and Testing - kWh /year Savings (Deemed with assumed realization and net-to-gross rates from May 1, 2019 EMV Report)	364,561	13,352	20,345	632,108	208,230	384,301	205,708	135,602	-	30,366	35,652	-	2,534,136
Monthly - Adjusted kWh (Net)													Total Months
Jan, 2014	-	-	-	-	-	-	-	-	-	-	-	-	
Feb	-	-	-	-	-	-	-	-	-	-	-	-	
Mar	-	-	-	-	-	-	-	-	-	-	-	-	
Apr	-	-	-	-	-	-	-	-	-	-	-	-	
May	-	-	-	-	-	-	-	-	-	-	-	-	
Jun	-	-	-	-	-	-	-	-	-	-	-	-	
Jul	-	-	-	-	-	-	-	-	-	-	-	-	
Aug	-	-	-	-	-	-	-	-	-	-	-	-	
Sep	-	-	-	-	-	-	-	-	-	-	-	-	
Oct	-	-	-	-	-	-	-	-	-	-	-	-	
Nov	38,558	38,558	38,558	38,558	38,558	38,558	38,558	38,558	38,558	38,558	38,558	38,558	14
Dec	3,435	3,435	3,435	3,435	3,435	3,435	3,435	3,435	3,435	3,435	3,435	3,435	13
Jan, 2015	30,380	30,380	30,380	30,380	30,380	30,380	30,380	30,380	30,380	30,380	30,380	30,380	12
Feb		1,113	1,113	1,113	1,113	1,113	1,113	1,113	1,113	1,113	1,113	1,113	11
Mar			1,695	1,695	1,695	1,695	1,695	1,695	1,695	1,695	1,695	1,695	10
Apr				52,676	52,676	52,676	52,676	52,676	52,676	52,676	52,676	52,676	9
May					17,352	17,352	17,352	17,352	17,352	17,352	17,352	17,352	8
Jun						32,025	32,025	32,025	32,025	32,025	32,025	32,025	7
Jul							17,142	17,142	17,142	17,142	17,142	17,142	6
Aug								11,300	11,300	11,300	11,300	11,300	5
Sep									-	-	-	-	4
Oct										2,530	2,530	2,530	3
Nov											2,971	2,971	2
Dec												-	1
Total (Cumulative by Month) - Adjusted kWh (Net):	72,373	73,485	75,181	127,857	145,209	177,234	194,376	205,677	205,677	208,207	211,178	211,178	

DNV GL Tracking – 2014

DNV GL Tracking		Jan.	Feb.	March	April	May	June	July	Aug	Sept.	Oct.	Nov.	Dec.
Schedule 10	18.4%	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	7,102	7,733
Schedule 30	11.1%	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	4,294	4,677
Schedule 42	6.9%	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	2,665	2,902
Schedule 5	46.9%	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	18,075	19,685
Schedule 5P	12.2%	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	4,712	5,132
Schedule 6P	4.3%	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	1,642	1,789
Schedule 7	0.2%	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	67	73
		-	-	-	-	-	-	-	-	-	-	38,558	41,993

DNV GL Tracking – 2015

DNV GL Tracking	Jan.	Feb.	March	April	May	June	July	Aug.	Sept.	Oct.	Nov.	Dec.
Schedule 10	13,330	13,535	13,847	23,550	26,746	32,645	35,802	37,883	37,883	38,349	38,857	38,857
Schedule 30	8,060	8,184	8,373	14,240	16,172	19,739	21,648	22,907	22,907	23,189	23,520	23,520
Schedule 42	5,002	5,079	5,196	8,837	10,037	12,230	13,435	14,216	14,216	14,391	14,596	14,596
Schedule 5	33,926	34,448	35,243	59,935	68,070	83,082	91,118	96,415	96,415	97,601	98,994	98,994
Schedule 5P	8,845	8,981	9,188	15,626	17,746	21,660	23,755	25,136	25,136	25,446	25,809	25,809
Schedule 6P	3,083	3,130	3,202	5,446	6,185	7,549	8,280	8,761	8,761	8,869	8,995	8,995
Schedule 7	126	129	131	223	253	308	338	358	358	362	368	368
	72,373	73,485	75,181	127,857	145,209	177,234	194,376	205,677	205,677	208,207	211,178	211,178

Actual kWh (Jan. - Dec., 2014):	80,550
Actual kWh (Jan. - Dec., 2015):	1,907,631

Participation

Participation		Jan.	Feb.	March	April	May	June	July	Aug	Sept.	Oct.	Nov.	Dec.	Total
2014	Planned:	1	2	2	2	3	4	3	3	3	3	2	2	30
2014	Actual:	0	0	0	0	0	0	0	0	0	0	46	14	60
2014														200%
2015	Planned:	1	2	2	2	3	4	3	3	3	3	2	2	30
2015	Actual:	12	4	2	62	13	40	9	7	0	2	1	0	182
2015														507%

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2016													
15	16	17	18	19	20	21	22	23	24	25	26		
Jan.	Feb.	March	April	May	June	July	Aug.	Sept.	Oct.	Nov.	Dec.	Total	
-	27,363	-	2,767	5,072	3,409	168,216	180,485	2,385	10,838	64,682	-	2,999,352	
													Total Months
-	-	-	-	-	-	-	-	-	-	-	-		36
-	-	-	-	-	-	-	-	-	-	-	-		35
-	-	-	-	-	-	-	-	-	-	-	-		34
-	-	-	-	-	-	-	-	-	-	-	-		33
-	-	-	-	-	-	-	-	-	-	-	-		32
-	-	-	-	-	-	-	-	-	-	-	-		31
-	-	-	-	-	-	-	-	-	-	-	-		30
-	-	-	-	-	-	-	-	-	-	-	-		29
-	-	-	-	-	-	-	-	-	-	-	-		28
-	-	-	-	-	-	-	-	-	-	-	-		27
39,558	38,558	38,558	38,558	38,558	38,558	38,558	38,558	38,558	38,558	38,558	38,558		26
3,435	3,435	3,435	3,435	3,435	3,435	3,435	3,435	3,435	3,435	3,435	3,435		25
30,380	30,380	30,380	30,380	30,380	30,380	30,380	30,380	30,380	30,380	30,380	30,380		24
1,113	1,113	1,113	1,113	1,113	1,113	1,113	1,113	1,113	1,113	1,113	1,113		23
1,695	1,695	1,695	1,695	1,695	1,695	1,695	1,695	1,695	1,695	1,695	1,695		22
52,676	52,676	52,676	52,676	52,676	52,676	52,676	52,676	52,676	52,676	52,676	52,676		21
17,352	17,352	17,352	17,352	17,352	17,352	17,352	17,352	17,352	17,352	17,352	17,352		20
32,025	32,025	32,025	32,025	32,025	32,025	32,025	32,025	32,025	32,025	32,025	32,025		19
17,142	17,142	17,142	17,142	17,142	17,142	17,142	17,142	17,142	17,142	17,142	17,142		18
11,300	11,300	11,300	11,300	11,300	11,300	11,300	11,300	11,300	11,300	11,300	11,300		17
-	-	-	-	-	-	-	-	-	-	-	-		16
2,530	2,530	2,530	2,530	2,530	2,530	2,530	2,530	2,530	2,530	2,530	2,530		15
2,971	2,971	2,971	2,971	2,971	2,971	2,971	2,971	2,971	2,971	2,971	2,971		14
-	-	-	-	-	-	-	-	-	-	-	-		13
211,178	213,458	213,458	213,689	214,112	214,396	228,414	243,454	243,653	244,556	249,946	249,946		
38,897	39,317	39,317	39,359	39,437	39,489	42,071	44,842	44,878	45,044	46,037	46,037		
23,520	23,774	23,774	23,799	23,846	23,878	25,439	27,114	27,136	27,237	27,837	27,837		
14,596	14,754	14,754	14,770	14,799	14,819	15,789	16,827	16,841	16,903	17,276	17,276		
98,994	100,063	100,063	100,171	100,369	100,502	107,073	114,124	114,217	114,640	117,167	117,167		
25,809	26,087	26,087	26,116	26,167	26,202	27,915	29,753	29,778	29,888	30,547	30,547		
8,995	9,092	9,092	9,102	9,120	9,132	9,729	10,370	10,379	10,417	10,647	10,647		
368	372	372	372	373	373	398	424	424	426	435	435		
211,178	213,458	213,458	213,689	214,112	214,396	228,414	243,454	243,653	244,556	249,946	249,946		
											Actual kWh (Jan. - Dec., 2016):	2,740,258	
3	3	3	3	3	3	3	3	3	3	3	3	[illegible] 39	
0	1	0	4	3	5	4	5	1	2	8	0	[illegible] 33	
												[illegible] 85%	

2017													
27	28	29	30	31	32	33	34	35	36	37	38		
Jan.	Feb.	March	April	May	June	July	Aug.	Sept.	Oct.	Nov.	Dec.	Total	
8,564	8,599	138,650	-	-	-	-	-	-	-	-	-	3,155,266	
													Total Months
-	-	-	-	-	-	-	-	-	-	-	-		48
-	-	-	-	-	-	-	-	-	-	-	-		47
-	-	-	-	-	-	-	-	-	-	-	-		46
-	-	-	-	-	-	-	-	-	-	-	-		45
-	-	-	-	-	-	-	-	-	-	-	-		44
-	-	-	-	-	-	-	-	-	-	-	-		43
-	-	-	-	-	-	-	-	-	-	-	-		42
-	-	-	-	-	-	-	-	-	-	-	-		41
-	-	-	-	-	-	-	-	-	-	-	-		40
-	-	-	-	-	-	-	-	-	-	-	-		39
38,558	38,558	38,558	38,558	38,558	38,558	38,558	38,558	38,558	38,558	38,558	38,558		38
3,435	3,435	3,435	3,435	3,435	3,435	3,435	3,435	3,435	3,435	3,435	3,435		37
30,380	30,380	30,380	30,380	30,380	30,380	30,380	30,380	30,380	30,380	30,380	30,380		36
1,113	1,113	1,113	1,113	1,113	1,113	1,113	1,113	1,113	1,113	1,113	1,113		35
1,695	1,695	1,695	1,695	1,695	1,695	1,695	1,695	1,695	1,695	1,695	1,695		34
52,676	52,676	52,676	52,676	52,676	52,676	52,676	52,676	52,676	52,676	52,676	52,676		33
17,352	17,352	17,352	17,352	17,352	17,352	17,352	17,352	17,352	17,352	17,352	17,352		32
32,025	32,025	32,025	32,025	32,025	32,025	32,025	32,025	32,025	32,025	32,025	32,025		31
17,142	17,142	17,142	17,142	17,142	17,142	17,142	17,141	17,142	17,142	17,142	17,142		30
11,300	11,300	11,300	11,300	11,300	11,300	11,300	11,300	11,300	11,300	11,300	11,300		29
-	-	-	-	-	-	-	-	-	-	-	-		28
2,530	2,530	2,530	2,530	2,530	2,530	2,530	2,530	2,530	2,530	2,530	2,530		27
2,971	2,971	2,971	2,971	2,971	2,971	2,971	2,971	2,971	2,971	2,971	2,971		26
-	-	-	-	-	-	-	-	-	-	-	-		25
251,373	252,093	274,485	262,930	262,930	262,930	262,930	262,930	262,930	262,930	262,930	262,930		
46,300	46,433	50,557	48,429	48,429	48,429	48,429	48,429	48,429	48,429	48,429	48,429		
27,998	28,076	30,570	29,283	29,283	29,283	29,283	29,283	29,283	29,283	29,283	29,283		
17,374	17,424	18,972	18,173	18,173	18,173	18,173	18,173	18,173	18,173	18,173	18,173		
117,836	118,174	128,670	123,254	123,254	123,254	123,254	123,254	123,254	123,254	123,254	123,254		
30,721	30,809	33,546	32,134	32,134	32,134	32,134	32,134	32,134	32,134	32,134	32,134		
10,707	10,738	11,692	11,200	11,200	11,200	11,200	11,200	11,200	11,200	11,200	11,200		
438	439	478	458	458	458	458	458	458	458	458	458		
251,373	252,093	274,485	262,930	262,930	262,930	262,930	262,930	262,930	262,930	262,930	262,930		
											Actual kWh (Jan. - Dec., 2017):	3,144,325	
0	0	0	0	0	0	0	0	0	0	0	0	0	
3	1	1	0	0	0	0	0	0	0	0	0	5	
												0%	

2018

kWh (Net) in North Carolina	39 Jan.	40 Feb.	41 March	42 April	43 May	44 June	45 July	46 Aug.	47 Sept.	48 Oct.	49 Nov.	50 Dec.	Total	Total Months
Non-Residential Duct Sealing and Testing - kWh /year Savings (Deemed with assumed realization and net-to-gross rates from May 1, 2019 EMV Report)	-	-	-	-	-	-	-	-	-	-	-	-	3,155,166	
Monthly - Adjusted kWh (Net)														
Jan, 2014	-	-	-	-	-	-	-	-	-	-	-	-		60
Feb	-	-	-	-	-	-	-	-	-	-	-	-		59
Mar	-	-	-	-	-	-	-	-	-	-	-	-		58
Apr	-	-	-	-	-	-	-	-	-	-	-	-		57
May	-	-	-	-	-	-	-	-	-	-	-	-		56
Jun	-	-	-	-	-	-	-	-	-	-	-	-		55
Jul	-	-	-	-	-	-	-	-	-	-	-	-		54
Aug	-	-	-	-	-	-	-	-	-	-	-	-		53
Sep	-	-	-	-	-	-	-	-	-	-	-	-		52
Oct	-	-	-	-	-	-	-	-	-	-	-	-		51
Nov	38,558	38,558	38,558	38,558	38,558	38,558	38,558	38,558	38,558	38,558	38,558	38,558		50
Dec	3,435	3,435	3,435	3,435	3,435	3,435	3,435	3,435	3,435	3,435	3,435	3,435		49
Jan, 2015	30,380	30,380	30,380	30,380	30,380	30,380	30,380	30,380	30,380	30,380	30,380	30,380		48
Feb	1,113	1,113	1,113	1,113	1,113	1,113	1,113	1,113	1,113	1,113	1,113	1,113		47
Mar	1,695	1,695	1,695	1,695	1,695	1,695	1,695	1,695	1,695	1,695	1,695	1,695		46
Apr	52,676	52,676	52,676	52,676	52,676	52,676	52,676	52,676	52,676	52,676	52,676	52,676		45
May	17,352	17,352	17,352	17,352	17,352	17,352	17,352	17,352	17,352	17,352	17,352	17,352		44
Jun	32,025	32,025	32,025	32,025	32,025	32,025	32,025	32,025	32,025	32,025	32,025	32,025		43
Jul	17,142	17,142	17,142	17,142	17,142	17,142	17,142	17,142	17,142	17,142	17,142	17,142		42
Aug	11,300	11,300	11,300	11,300	11,300	11,300	11,300	11,300	11,300	11,300	11,300	11,300		41
Sep	-	-	-	-	-	-	-	-	-	-	-	-		40
Oct	2,530	2,530	2,530	2,530	2,530	2,530	2,530	2,530	2,530	2,530	2,530	2,530		39
Nov	2,971	2,971	2,971	2,971	2,971	2,971	2,971	2,971	2,971	2,971	2,971	2,971		38
Dec	-	-	-	-	-	-	-	-	-	-	-	-		37
[redacted] Total (Cumulative by Month) - Adjusted kWh (Net): [redacted]	262,930	262,930	262,930	262,930	262,930	262,930	262,930	262,930	262,930	262,930	262,930	262,930	[redacted]	
DNV GL Tracking														
Schedule 10 [redacted] 18.4%	48,429	48,429	48,429	48,429	48,429	48,429	48,429	48,429	48,429	48,429	48,429	48,429	[redacted]	
Schedule 30 [redacted] 11.1%	29,283	29,283	29,283	29,283	29,283	29,283	29,283	29,283	29,283	29,283	29,283	29,283	[redacted]	
Schedule 42 [redacted] 6.9%	18,173	18,173	18,173	18,173	18,173	18,173	18,173	18,173	18,173	18,173	18,173	18,173	[redacted]	
Schedule 5 [redacted] 46.9%	123,254	123,254	123,254	123,254	123,254	123,254	123,254	123,254	123,254	123,254	123,254	123,254	[redacted]	
Schedule 5P [redacted] 12.2%	32,134	32,134	32,134	32,134	32,134	32,134	32,134	32,134	32,134	32,134	32,134	32,134	[redacted]	
Schedule 6P [redacted] 4.3%	11,200	11,200	11,200	11,200	11,200	11,200	11,200	11,200	11,200	11,200	11,200	11,200	[redacted]	
Schedule 7 [redacted] 0.2%	458	458	458	458	458	458	458	458	458	458	458	458	[redacted]	
	262,930	262,930	262,930	262,930	262,930	262,930	262,930	262,930	262,930	262,930	262,930	262,930		

2019

kWh (Net) in North Carolina	51 Jan.	52 Feb.	53 March	54 April	55 May	56 June	July	Aug.	Sept.	Oct.	Nov.	Dec.	Total	Total Months
Non-Residential Duct Sealing and Testing - kWh /year Savings	-	-	-	-	-	-							3,155,166	
Jan, 2014	-	-	-	-	-	-								66
Feb	-	-	-	-	-	-								65
Mar	-	-	-	-	-	-								64
Apr	-	-	-	-	-	-								63
May	-	-	-	-	-	-								62
Jun	-	-	-	-	-	-								61
Jul	-	-	-	-	-	-								60
Aug	-	-	-	-	-	-								59
Sep	-	-	-	-	-	-								58
Oct	-	-	-	-	-	-								57
Nov	38,558	38,558	38,558	38,558	38,558	38,558								56
Dec	3,435	3,435	3,435	3,435	3,435	3,435								55
Jan, 2015	30,380	30,380	30,380	30,380	30,380	30,380								54
Feb	1,113	1,113	1,113	1,113	1,113	1,113								53
Mar	1,695	1,695	1,695	1,695	1,695	1,695								52
Apr	52,676	52,676	52,676	52,676	52,676	52,676								51
May	17,352	17,352	17,352	17,352	17,352	17,352								50
Jun	32,025	32,025	32,025	32,025	32,025	32,025								49
Jul	17,142	17,142	17,142	17,142	17,142	17,142								48
Aug	11,300	11,300	11,300	11,300	11,300	11,300								47
Sep	-	-	-	-	-	-								46
Oct	2,530	2,530	2,530	2,530	2,530	2,530								45
Nov	2,971	2,971	2,971	2,971	2,971	2,971								44
Dec	-	-	-	-	-	-								43
Total (Cumulative by Month) - Adjusted kWh (Net)	262,930	262,930	262,930	262,930	262,930	262,930	[redacted]							
Schedule 10	48,429	48,429	48,429	48,429	48,429	48,429	[redacted]							
Schedule 30	29,283	29,283	29,283	29,283	29,283	29,283	[redacted]							
Schedule 42	18,173	18,173	18,173	18,173	18,173	18,173	[redacted]							
Schedule 5	123,254	123,254	123,254	123,254	123,254	123,254	[redacted]							
Schedule 5P	32,134	32,134	32,134	32,134	32,134	32,134	[redacted]							
Schedule 6P	11,200	11,200	11,200	11,200	11,200	11,200	[redacted]							
Schedule 7	458	458	458	458	458	458	[redacted]							
	262,930	262,930	262,930	262,930	262,930	262,930	-	-	-	-	-	-	-	

Total
3,155,166

[redacted] 12,605,514 True-up

Actual kWh (Jan. - Dec., 2018): [redacted] 3,155,166

Actual kWh (Jan. - Dec., 2019): [redacted] 1,577,583 [redacted] 12,605,514

Participation		Jan.	Feb.	March	April	May	June	July	Aug.	Sept.	Oct.	Nov.	Dec.	Total 2018	Jan.	Feb.	March	April	May	June	July	Aug.	Sept.	Oct.	Nov.	Dec.	Total 2019	Total
	Planned:	0	0	0	0	0	0	0	0	0	0	0	0	[redacted] 0	0	0	0	0	0	0							[redacted] 0	[redacted] 99
	Actual:	0	0	0	0	0	0	0	0	0	0	0	0	[redacted] 0	0	0	0	0	0	0							[redacted] 0	[redacted] 260
														[redacted] 0%													[redacted] 0%	[redacted] 253%

NOTES:

1. The kWh savings are based on actual participation from Dominion North Carolina Power customers with program planning realization and net-to-gross adjustments assumptions applied
2. The May 1, 2019 EM&V Report was filed with the NC Public Utilities Commission and included EM&V data through the end of 2018.
3. The EM&V data reflected for January 2018 - June, 2019 was prepared by DNV GL using the same STEP (Standard Tracking Engineering Protocol) formulas used in preparing the EM&V data for 2018.
4. The kWh savings are inclusive of all EE measures installed from program inception through June 30, 2019.
5. Program measure life is 25 years (300 months)

		2014													2015												
											1	2	3		4	5	6	7	8	9	10	11	12	13	14	15	
kWh (Net) In North Carolina		Jan.	Feb.	March	April	May	June	July	Aug	Sept.	Oct.	Nov.	Dec.	Total	Jan.	Feb.	March	April	May	June	July	Aug.	Sept.	Oct.	Nov.	Dec.	Total
Non-Residential Energy Audit - kWh /year Savings (Deemed with assumed realization and net-to-gross rates from May 1, 2019 EMV Report)		-	-	-	-	-	-	-	-	-	65,429	422,300	-	487,729	-	-	-	-	-	1,796	89,383	62,319	-	-	-	-	641,227
Monthly - Adjusted kWh (Net)														Total Months													Total Months
Jan, 2014		-	-	-	-	-	-	-	-	-	-	-	-	12	-	-	-	-	-	-	-	-	-	-	-	-	24
Feb			-	-	-	-	-	-	-	-	-	-	-	11	-	-	-	-	-	-	-	-	-	-	-	-	23
Mar				-	-	-	-	-	-	-	-	-	-	10	-	-	-	-	-	-	-	-	-	-	-	-	22
Apr					-	-	-	-	-	-	-	-	-	9	-	-	-	-	-	-	-	-	-	-	-	-	21
May						-	-	-	-	-	-	-	-	8	-	-	-	-	-	-	-	-	-	-	-	-	20
Jun							-	-	-	-	-	-	-	7	-	-	-	-	-	-	-	-	-	-	-	-	19
Jul								-	-	-	-	-	-	6	-	-	-	-	-	-	-	-	-	-	-	-	18
Aug									-	-	-	-	-	5	-	-	-	-	-	-	-	-	-	-	-	-	17
Sep										-	-	-	-	4	-	-	-	-	-	-	-	-	-	-	-	-	16
Oct											5,452	5,452	5,452	3	5,452	5,452	5,452	5,452	5,452	5,452	5,452	5,452	5,452	5,452	5,452	5,452	15
Nov												35,192	35,192	2	35,192	35,192	35,192	35,192	35,192	35,192	35,192	35,192	35,192	35,192	35,192	35,192	14
Dec													-	1	-	-	-	-	-	-	-	-	-	-	-	-	13
Jan, 2015															-	-	-	-	-	-	-	-	-	-	-	-	12
Feb																-	-	-	-	-	-	-	-	-	-	-	11
Mar																	-	-	-	-	-	-	-	-	-	-	10
Apr																		-	-	-	-	-	-	-	-	-	9
May																			-	-	-	-	-	-	-	-	8
Jun																				150	150	150	150	150	150	150	7
Jul																					7,449	7,449	7,449	7,449	7,449	7,449	6
Aug																						5,193	5,193	5,193	5,193	5,193	5
Sep																							-	-	-	-	4
Oct																								-	-	-	3
Nov																									-	-	2
Dec																										-	1
Total (Cumulative by Month) - Adjusted kWh (Net):		-	-	-	-	-	-	-	-	-	5,452	40,644	40,644		40,644	40,644	40,644	40,644	40,644	40,794	48,242	53,436	53,436	53,436	53,436	53,436	
DNV GL Tracking																											
Schedule 10	23.80%	-	-	-	-	-	-	-	-	-	1,298	9,673	9,673		9,673	9,673	9,673	9,673	9,673	9,709	11,481	12,717	12,717	12,717	12,717	12,717	
Schedule 26	0.12%										7	50	50		50	50	50	50	50	50	59	66	66	66	66	66	
Schedule 30	0.01%										1	6	6		6	6	6	6	6	6	7	7	7	7	7	7	
Schedule 42	0.01%										1	5	5		5	5	5	5	5	5	6	7	7	7	7	7	
Schedule 5	17.97%										980	7,303	7,303		7,303	7,303	7,303	7,303	7,303	7,330	8,668	9,601	9,601	9,601	9,601	9,601	
Schedule 5P	54.11%										2,951	21,994	21,994		21,994	21,994	21,994	21,994	21,994	22,075	26,106	28,916	28,916	28,916	28,916	28,916	
Schedule 6P	3.97%										216	1,614	1,614		1,614	1,614	1,614	1,614	1,614	1,670	1,915	2,121	2,121	2,121	2,121	2,121	
		-	-	-	-	-	-	-	-	-	5,452	40,644	40,644		40,644	40,644	40,644	40,644	40,644	40,794	48,242	53,436	53,436	53,436	53,436	53,436	

Actual kWh (Jan. - Dec., 2014): 86,741

Actual kWh (Jan. - Dec., 2015): 559,434

Participation		Jan.	Feb.	March	April	May	June	July	Aug	Sept.	Oct.	Nov.	Dec.	Total	Jan.	Feb.	March	April	May	June	July	Aug.	Sept.	Oct.	Nov.	Dec.	Total
	Planned:	3	3	2	3	3	3	3	3	3	4	4	3	37	3	3	2	3	3	3	3	3	3	4	4	3	37
	Actual:	0	0	0	0	0	0	0	0	0	2	14	0	16	0	0	0	0	0	1	17	60	0	0	0	0	78
														43%													211%

2016													2017												
16	17	18	19	20	21	22	23	24	25	26	27		28	29	30	31	32	33	34	35	36	37	38	39	
Jan.	Feb.	March	April	May	June	July	Aug	Sept.	Oct.	Nov.	Dec.	Total	Jan.	Feb.	March	April	May	June	July	Aug	Sept.	Oct.	Nov.	Dec.	Total
-	-	-	-	-	-	-	1,973	198	138,708	-	112,692	894,798	218,089	201,319	72,310	-	-	-	-	-	-	-	-	-	1,386,517
												Total Months													Total Months
-	-	-	-	-	-	-	-	-	-	-	-	36	-	-	-	-	-	-	-	-	-	-	-	-	48
-	-	-	-	-	-	-	-	-	-	-	-	35	-	-	-	-	-	-	-	-	-	-	-	-	47
-	-	-	-	-	-	-	-	-	-	-	-	34	-	-	-	-	-	-	-	-	-	-	-	-	46
-	-	-	-	-	-	-	-	-	-	-	-	33	-	-	-	-	-	-	-	-	-	-	-	-	45
-	-	-	-	-	-	-	-	-	-	-	-	32	-	-	-	-	-	-	-	-	-	-	-	-	44
-	-	-	-	-	-	-	-	-	-	-	-	31	-	-	-	-	-	-	-	-	-	-	-	-	43
-	-	-	-	-	-	-	-	-	-	-	-	30	-	-	-	-	-	-	-	-	-	-	-	-	42
-	-	-	-	-	-	-	-	-	-	-	-	29	-	-	-	-	-	-	-	-	-	-	-	-	41
-	-	-	-	-	-	-	-	-	-	-	-	28	-	-	-	-	-	-	-	-	-	-	-	-	40
5,452	5,452	5,452	5,452	5,452	5,452	5,452	5,452	5,452	5,452	5,452	5,452	27	5,452	5,452	5,452	5,452	5,452	5,452	5,452	5,452	5,452	5,452	5,452	5,452	39
35,192	35,192	35,192	35,192	35,192	35,192	35,192	35,192	35,192	35,192	35,192	35,192	26	35,192	35,192	35,192	35,192	35,192	35,192	35,192	35,192	35,192	35,192	35,192	35,192	38
-	-	-	-	-	-	-	-	-	-	-	-	25	-	-	-	-	-	-	-	-	-	-	-	-	37
-	-	-	-	-	-	-	-	-	-	-	-	24	-	-	-	-	-	-	-	-	-	-	-	-	36
-	-	-	-	-	-	-	-	-	-	-	-	23	-	-	-	-	-	-	-	-	-	-	-	-	35
-	-	-	-	-	-	-	-	-	-	-	-	22	-	-	-	-	-	-	-	-	-	-	-	-	34
-	-	-	-	-	-	-	-	-	-	-	-	21	-	-	-	-	-	-	-	-	-	-	-	-	33
-	-	-	-	-	-	-	-	-	-	-	-	20	-	-	-	-	-	-	-	-	-	-	-	-	32
150	150	150	150	150	150	150	150	150	150	150	150	19	150	150	150	150	150	150	150	150	150	150	150	150	31
7,449	7,449	7,449	7,449	7,449	7,449	7,449	7,449	7,449	7,449	7,449	7,449	18	7,449	7,449	7,449	7,449	7,449	7,449	7,449	7,449	7,449	7,449	7,449	7,449	30
5,193	5,193	5,193	5,193	5,193	5,193	5,193	5,193	5,193	5,193	5,193	5,193	17	5,193	5,193	5,193	5,193	5,193	5,193	5,193	5,193	5,193	5,193	5,193	5,193	29
-	-	-	-	-	-	-	-	-	-	-	-	16	-	-	-	-	-	-	-	-	-	-	-	-	28
-	-	-	-	-	-	-	-	-	-	-	-	15	-	-	-	-	-	-	-	-	-	-	-	-	27
-	-	-	-	-	-	-	-	-	-	-	-	14	-	-	-	-	-	-	-	-	-	-	-	-	26
-	-	-	-	-	-	-	-	-	-	-	-	13	-	-	-	-	-	-	-	-	-	-	-	-	25
53,436	53,436	53,436	53,436	53,436	53,436	53,436	53,600	53,617	65,176	65,176	83,957		110,915	126,294	121,569	115,543	115,543	115,543	115,543	115,543	115,543	115,543	115,543	115,543	
12,717	12,717	12,717	12,717	12,717	12,717	12,717	12,757	12,760	15,511	15,511	19,981		26,397	30,057	28,933	27,499	27,499	27,499	27,499	27,499	27,499	27,499	27,499	27,499	
66	66	66	66	66	66	66	66	66	80	80	103		136	155	149	142	142	142	142	142	142	142	142	142	
7	7	7	7	7	7	7	7	7	9	9	12		15	17	17	16	16	16	16	16	16	16	16	16	
7	7	7	7	7	7	7	7	7	8	8	11		14	16	16	15	15	15	15	15	15	15	15	15	
9,601	9,601	9,601	9,601	9,601	9,601	9,601	9,631	9,634	11,710	11,710	15,085		19,929	22,692	21,843	20,760	20,760	20,760	20,760	10,760	20,760	20,760	20,760	20,760	
28,916	28,916	28,916	28,918	28,915	28,916	28,916	29,005	29,014	35,269	35,269	45,432		60,020	68,342	63,785	62,525	62,525	62,525	62,525	62,525	62,525	62,525	62,525	62,525	
2,121	2,121	2,121	2,131	2,121	2,121	2,121	2,128	2,129	2,587	2,587	3,331		4,403	5,014	4,826	4,587	4,587	4,587	4,587	4,587	4,587	4,587	4,587	4,587	
53,436	53,436	53,436	53,436	53,436	53,436	53,436	53,600	53,617	65,176	65,176	83,957		110,915	126,294	121,569	115,543	115,543	115,543	115,543	115,543	115,543	115,543	115,543	115,543	

Actual kWh (Jan. - Dec., 2016):	695,874
Actual kWh (Jan. - Dec., 2017):	1,388,655

4	4	4	4	4	4	4	4	4	4	4	4	48	0	0	0	0	0	0	0	0	0	0	0	0	0
0	0	0	0	0	0	0	6	1	2	0	3	12	0	1	1	0	0	0	0	0	0	0	0	0	2
												25%													0%

	2018													2019													
	40	41	42	43	44	45	46	47	48	49	50	51		52	53	54	55	56	57								
kWh (Net) in North Carolina	Jan.	Feb.	March	April	May	June	July	Aug	Sept.	Oct.	Nov.	Dec.	Total	Jan.	Feb.	March	April	May	June	July	Aug	Sept.	Oct.	Nov.	Dec.	Total	Total
Non Residential Energy Audit - kWh /year Savings (Deemed with assumed realization and net-to-gross rates from May 1, 2019 EMV Report)	-	-	-	-	-	-	-	-	-	-	-	-	1,386,517	-	-	-	-	-	-							1,386,517	1,386,517
Monthly - Adjusted kWh (Net)													Total Months													Total Months	
Jan, 2014	-	-	-	-	-	-	-	-	-	-	-	-	60	-	-	-	-	-	-							66	
Feb	-	-	-	-	-	-	-	-	-	-	-	-	59	-	-	-	-	-	-							65	
Mar	-	-	-	-	-	-	-	-	-	-	-	-	58	-	-	-	-	-	-							64	
Apr	-	-	-	-	-	-	-	-	-	-	-	-	57	-	-	-	-	-	-							63	
May	-	-	-	-	-	-	-	-	-	-	-	-	56	-	-	-	-	-	-							62	
Jun	-	-	-	-	-	-	-	-	-	-	-	-	55	-	-	-	-	-	-							61	
Jul	-	-	-	-	-	-	-	-	-	-	-	-	54	-	-	-	-	-	-							60	
Aug	-	-	-	-	-	-	-	-	-	-	-	-	53	-	-	-	-	-	-							59	
Sep	-	-	-	-	-	-	-	-	-	-	-	-	52	-	-	-	-	-	-							58	
Oct	5,452	5,452	5,452	5,452	5,452	5,452	5,452	5,452	5,452	5,452	5,452	5,452	51	5,452	5,452	5,452	5,452	5,452	5,452							57	
Nov	35,192	35,192	35,192	35,192	35,192	35,192	35,192	35,192	35,192	35,192	35,192	35,192	50	35,192	35,192	35,192	35,192	35,192	35,192							56	
Dec	-	-	-	-	-	-	-	-	-	-	-	-	49	-	-	-	-	-	-							55	
Jan, 2015	-	-	-	-	-	-	-	-	-	-	-	-	48	-	-	-	-	-	-							54	
Feb	-	-	-	-	-	-	-	-	-	-	-	-	47	-	-	-	-	-	-							53	
Mar	-	-	-	-	-	-	-	-	-	-	-	-	46	-	-	-	-	-	-							52	
Apr	-	-	-	-	-	-	-	-	-	-	-	-	45	-	-	-	-	-	-							51	
May	-	-	-	-	-	-	-	-	-	-	-	-	44	-	-	-	-	-	-							50	
Jun	150	150	150	150	150	150	150	150	150	150	150	150	43	150	150	150	150	150	150							49	
Jul	7,449	7,449	7,449	7,449	7,449	7,449	7,449	7,449	7,449	7,449	7,449	7,449	42	7,449	7,449	7,449	7,449	7,449	7,449							48	
Aug	5,193	5,193	5,193	5,193	5,193	5,193	5,193	5,193	5,193	5,193	5,193	5,193	41	5,193	5,193	5,193	5,193	5,193	5,193							47	
Sep	-	-	-	-	-	-	-	-	-	-	-	-	40	-	-	-	-	-	-							46	
Oct	-	-	-	-	-	-	-	-	-	-	-	-	39	-	-	-	-	-	-							45	
Nov	-	-	-	-	-	-	-	-	-	-	-	-	38	-	-	-	-	-	-							44	
Dec	-	-	-	-	-	-	-	-	-	-	-	-	37	-	-	-	-	-	-							43	
Total (Cumulative by Month) - Adjusted kWh (Net):	115,543	115,543	115,543	115,543	115,543	115,543	115,543	115,543	115,543	115,543	115,543	115,543		115,543	115,543	115,543	115,543	115,543	115,543	-	-	-	-	-	-		4,820,190 True-up

DNV GL Tracking	%	Jan.	Feb.	March	April	May	June	July	Aug	Sept.	Oct.	Nov.	Dec.	Jan.	Feb.	March	April	May	June	July	Aug	Sept.	Oct.	Nov.	Dec.
Schedule 10	23.80%	27,499	27,499	27,499	27,499	27,499	27,499	27,499	27,499	27,499	27,499	27,499	27,499	27,499	27,499	27,499	27,499	27,499	27,499	-	-	-	-	-	-
Schedule 26	0.12%	142	142	142	142	142	142	142	142	142	142	142	142	142	142	142	142	142	142	-	-	-	-	-	-
Schedule 30	0.01%	16	16	16	16	16	16	16	16	16	16	16	16	16	16	16	16	16	16	-	-	-	-	-	-
Schedule 42	0.01%	15	15	15	15	15	15	15	15	15	15	15	15	15	15	15	15	15	15	-	-	-	-	-	-
Schedule 5	17.97%	20,760	20,760	20,760	20,760	20,760	20,760	20,760	20,760	20,760	20,760	20,760	20,760	20,760	20,760	20,760	20,760	20,760	20,760	-	-	-	-	-	-
Schedule 5P	54.11%	62,525	62,525	62,525	62,525	62,525	62,525	62,525	62,525	62,525	62,525	62,525	62,525	62,525	62,525	62,525	62,525	62,525	62,525	-	-	-	-	-	-
Schedule 6P	3.97%	4,587	4,587	4,587	4,587	4,587	4,587	4,587	4,587	4,587	4,587	4,587	4,587	4,587	4,587	4,587	4,587	4,587	4,587	-	-	-	-	-	-
		115,543	115,543	115,543	115,543	115,543	115,543	115,543	115,543	115,543	115,543	115,543	115,543	115,543	115,543	115,543	115,543	115,543	115,543	-	-	-	-	-	-

Actual kWh (Jan. - Dec., 2018): 1,386,517

Actual kWh (Jan. - Dec., 2019): [illegible] 4,820,190

Participation		Jan.	Feb.	March	April	May	June	July	Aug	Sept.	Oct.	Nov.	Dec.	Total	Jan.	Feb.	March	April	May	June	July	Aug	Sept.	Oct.	Nov.	Dec.	Total	Total
	Planned:	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0							0	122
	Actual:	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0							0	108
														0%													0%	89%

NOTES:

1. The kWh savings are based on actual participation from Dominion North Carolina Power customers with program planning realization and net-to-gross adjustments assumptions applied
2. The May 1, 2019 EM&V Report was filed with the NC Public Utilities Commission and included EM&V data through the end of 2018.
3. The EM&V data reflected for January 2018 - June, 2019 was prepared by DNV GL using the same STEP (Standard Tracking Engineering Protocol) formulas used in preparing the EM&V data for 2018.
4. The kWh savings are inclusive of all EE measures installed from program inception through June 30, 2019.
5. Program measure life is 7 years (84 months)

	2015													2016											
				1	2	3	4	5	6	7	8	9		10	11	12	13	14	15	16	17	18	19	20	21	
kWh (Net) in North Carolina	Jan.	Feb.	March	April	May	June	July	Aug.	Sept.	Oct.	Nov.	Dec.	Total	Jan.	Feb.	March	April	May	June	July	Aug.	Sept.	Oct.	Nov.	Dec.	Total
Non-Residential Heating, Cooling Efficiency - kWh/year Savings (Deemed with assumed realization and net-to-gross rates from May 1, 2019 EMV Report)	-	-	-	26,568	37,233	-	-	-	-	-	-	-	63,801	-	-	-	7,683	43,077	146,545	-	4,483	-	-	861	-	266,451
Monthly - Adjusted kWh (Net)													Total Months													Total Months
Jan, 2015	-	-	-	-	-	-	-	-	-	-	-	-	12	-	-	-	-	-	-	-	-	-	-	-	-	24
Feb		-	-	-	-	-	-	-	-	-	-	-	11	-	-	-	-	-	-	-	-	-	-	-	-	23
Mar			-	-	-	-	-	-	-	-	-	-	10	-	-	-	-	-	-	-	-	-	-	-	-	22
Apr				2,214	2,214	2,214	2,214	2,214	2,214	2,214	2,214	2,214	9	2,214	2,214	2,214	2,214	2,214	2,214	2,214	2,214	2,214	2,214	2,214	2,214	21
May					3,103	3,103	3,103	3,103	3,103	3,103	3,103	3,103	8	3,103	3,103	3,103	3,103	3,103	3,103	3,103	3,103	3,103	3,103	3,103	3,103	20
Jun						-	-	-	-	-	-	-	7	-	-	-	-	-	-	-	-	-	-	-	-	19
Jul							-	-	-	-	-	-	6	-	-	-	-	-	-	-	-	-	-	-	-	18
Aug								-	-	-	-	-	5	-	-	-	-	-	-	-	-	-	-	-	-	17
Sep									-	-	-	-	4	-	-	-	-	-	-	-	-	-	-	-	-	16
Oct										-	-	-	3	-	-	-	-	-	-	-	-	-	-	-	-	15
Nov											-	-	2	-	-	-	-	-	-	-	-	-	-	-	-	14
Dec												-	1	-	-	-	-	-	-	-	-	-	-	-	-	13
Jan, 2016														-	-	-	-	-	-	-	-	-	-	-	-	12
Feb															-	-	-	-	-	-	-	-	-	-	-	11
Mar																-	-	-	-	-	-	-	-	-	-	10
Apr																	640	640	640	640	640	640	640	640	640	9
May																		3,590	3,590	3,590	3,590	3,590	3,590	3,590	3,590	8
Jun																			12,212	12,212	12,212	12,212	12,212	12,212	12,212	7
Jul																				-	-	-	-	-	-	6
Aug																					374	374	374	374	374	5
Sep																						-	-	-	-	4
Oct																							-	-	-	3
Nov																								72	72	2
Dec																									-	1
Total (Cumulative by Month) - Adjusted kWh (Net):	-	-	-	2,214	5,317	5,317	5,317	5,317	5,317	5,317	5,317	5,317		5,317	5,317	5,317	5,957	9,547	21,759	21,759	22,132	22,132	22,132	22,204	22,204	
DNV GL Tracking																										
Schedule 10 — 6.80%	-	-	-	151	362	362	362	362	362	362	362	362		362	362	362	405	649	1,480	1,480	1,506	1,506	1,506	1,511	1,511	
Schedule 30 — 19.12%				423	1,017	1,017	1,017	1,017	1,017	1,017	1,017	1,017		1,017	1,017	1,017	1,139	1,825	4,160	4,160	4,231	4,231	4,231	4,245	4,245	
Schedule 42 — 17.34%				384	922	921	922	922	922	922	922	922		922	922	922	1,033	1,655	3,773	3,773	3,837	3,837	3,837	3,850	3,850	
Schedule 5 — 56.69%				1,255	3,014	3,014	3,014	3,014	3,014	3,014	3,014	3,014		3,014	3,014	3,014	3,377	5,412	12,334	12,334	12,546	12,546	12,546	12,587	12,587	
Schedule 5P — 0.05%				1	3	3	3	3	3	3	3	3		3	3	3	3	5	12	12	12	12	12	12	12	
	-	-	-	2,214	5,317	5,317	5,317	5,317	5,317	5,317	5,317	5,317		5,317	5,317	5,317	5,957	9,547	21,759	21,759	22,132	22,132	22,132	22,204	22,204	

Actual kWh (Jan. - Dec., 2015): 44,748

Actual kWh (Jan. - Dec., 2016): 183,778

Participation	Jan.	Feb.	March	April	May	June	July	Aug.	Sept.	Oct.	Nov.	Dec.	Total	Jan.	Feb.	March	April	May	June	July	Aug.	Sept.	Oct.	Nov.	Dec.	Total
Planned:	4	4	4	4	4	4	4	4	4	4	4	4	48	4	4	4	4	4	4	4	4	4	4	4	4	62
Actual:	0	0	0	2	1	0	0	0	0	0	0	0	3	0	0	0	1	1	2	0	1	0	0	1	0	8
													6%													12%

2017

22 Jan.	23 Feb.	24 March	25 April	26 May	27 June	28 July	29 Aug.	30 Sept.	31 Oct.	32 Nov.	33 Dec.	Total
-	-	-	-	51,821	294	-	-	5,965	-	-	-	324,531
												Total Months
-	-	-	-	-	-	-	-	-	-	-	-	36
-	-	-	-	-	-	-	-	-	-	-	-	35
-	-	-	-	-	-	-	-	-	-	-	-	34
2,214	2,214	2,214	2,214	2,214	2,214	2,214	2,214	2,214	2,214	2,214	2,214	33
3,103	3,103	3,103	3,103	3,103	3,103	3,103	3,103	3,103	3,103	3,103	3,103	32
-	-	-	-	-	-	-	-	-	-	-	-	31
-	-	-	-	-	-	-	-	-	-	-	-	30
-	-	-	-	-	-	-	-	-	-	-	-	29
-	-	-	-	-	-	-	-	-	-	-	-	28
-	-	-	-	-	-	-	-	-	-	-	-	27
-	-	-	-	-	-	-	-	-	-	-	-	26
-	-	-	-	-	-	-	-	-	-	-	-	25
-	-	-	-	-	-	-	-	-	-	-	-	24
-	-	-	-	-	-	-	-	-	-	-	-	23
-	-	-	-	-	-	-	-	-	-	-	-	22
640	640	640	640	640	640	640	640	640	640	640	640	21
3,590	3,590	3,590	3,590	3,590	3,590	3,590	3,590	3,590	3,590	3,590	3,590	20
12,212	12,212	12,212	12,212	12,212	12,212	12,212	12,212	12,212	12,212	12,212	12,212	19
-	-	-	-	-	-	-	-	-	-	-	-	18
374	374	374	374	374	374	374	374	374	374	374	374	17
-	-	-	-	-	-	-	-	-	-	-	-	16
-	-	-	-	-	-	-	-	-	-	-	-	15
72	72	72	72	72	72	72	72	72	72	72	72	14
-	-	-	-	-	-	-	-	-	-	-	-	13
-	-	-	-	-	-	-	-	-	-	-	-	12
	-	-	-	-	-	-	-	-	-	-	-	11
		-	-	-	-	-	-	-	-	-	-	10
			-	-	-	-	-	-	-	-	-	9
				4,318.39	4,318	4,318	4,318	4,318	4,318	4,318	4,318	8
					25	25	25	25	25	25	25	7
						-	-	-	-	-	-	6
							-	-	-	-	-	5
								497	497	497	497	4
									-	-	-	3
										-	-	2
											-	1
22,204	22,204	22,204	22,204	26,523	26,547	26,547	26,547	27,044	27,044	27,044	27,044	
1,511	1,511	1,511	1,511	1,804	1,806	1,806	1,806	1,840	1,840	1,840	1,840	
4,245	4,245	4,245	4,245	5,071	5,076	5,076	5,076	5,171	5,171	5,171	5,171	
3,850	3,850	3,850	3,850	4,599	4,603	4,603	4,603	4,689	4,689	4,689	4,689	
12,587	12,587	12,587	12,587	15,035	15,048	15,048	15,048	15,330	15,330	15,330	15,330	
12	12	12	12	14	14	14	14	15	15	15	15	
22,204	22,204	22,204	22,204	26,523	26,547	26,547	26,547	27,044	27,044	27,044	27,044	

Actual kWh (Jan. - Dec., 2017): [redacted] 393,186

5	5	4	4	4	4	4	4	4	4	4	4	[redacted] 53
0	0	0	0	1	1	0	0	1	0	0	0	[redacted] 3
												[redacted] 6%

2018

34 Jan.	35 Feb.	36 March	37 April	38 May	39 June	40 July	41 Aug.	42 Sept.	43 Oct.	44 Nov.	45 Dec.	Total
-	-	53,223	104,819	-	-	-	-	-	-	-	-	482,573
												Total Months
-	-	-	-	-	-	-	-	-	-	-	-	48
-	-	-	-	-	-	-	-	-	-	-	-	47
-	-	-	-	-	-	-	-	-	-	-	-	46
2,214	2,214	2,214	2,214	2,214	2,214	2,214	2,214	2,214	2,214	2,214	2,214	45
3,103	3,103	3,103	3,103	3,103	3,103	3,103	3,103	3,103	3,103	3,103	3,103	44
-	-	-	-	-	-	-	-	-	-	-	-	43
-	-	-	-	-	-	-	-	-	-	-	-	42
-	-	-	-	-	-	-	-	-	-	-	-	41
-	-	-	-	-	-	-	-	-	-	-	-	40
-	-	-	-	-	-	-	-	-	-	-	-	39
-	-	-	-	-	-	-	-	-	-	-	-	38
-	-	-	-	-	-	-	-	-	-	-	-	37
-	-	-	-	-	-	-	-	-	-	-	-	36
-	-	-	-	-	-	-	-	-	-	-	-	35
-	-	-	-	-	-	-	-	-	-	-	-	34
640	640	640	640	640	640	640	640	640	640	640	640	33
3,590	3,590	3,590	3,590	3,590	3,590	3,590	3,590	3,590	3,590	3,590	3,590	32
12,212	12,212	12,212	12,212	12,212	12,212	12,212	12,212	12,212	12,212	12,212	12,212	31
-	-	-	-	-	-	-	-	-	-	-	-	30
374	374	374	374	374	374	374	374	374	374	374	374	29
-	-	-	-	-	-	-	-	-	-	-	-	28
-	-	-	-	-	-	-	-	-	-	-	-	27
72	72	72	72	72	72	72	72	72	72	72	72	26
-	-	-	-	-	-	-	-	-	-	-	-	25
-	-	-	-	-	-	-	-	-	-	-	-	24
-	-	-	-	-	-	-	-	-	-	-	-	23
-	-	-	-	-	-	-	-	-	-	-	-	22
-	-	-	-	-	-	-	-	-	-	-	-	21
4,318	4,318	4,318	4,318	4,318	4,318	4,318	4,318	4,318	4,318	4,318	4,318	20
25	25	25	25	25	25	25	25	25	25	25	25	19
-	-	-	-	-	-	-	-	-	-	-	-	18
-	-	-	-	-	-	-	-	-	-	-	-	17
497	497	497	497	497	497	497	497	497	497	497	497	16
-	-	-	-	-	-	-	-	-	-	-	-	15
-	-	-	-	-	-	-	-	-	-	-	-	14
-	-	-	-	-	-	-	-	-	-	-	-	13
-	-	-	-	-	-	-	-	-	-	-	-	12
	-	-	-	-	-	-	-	-	-	-	-	11
		4,435	4,435	4,435	4,435	4,435	4,435	4,435	4,435	4,435	4,435	10
			8,735	8,735	8,735	8,735	8,735	8,735	8,735	8,735	8,735	9
				-	-	-	-	-	-	-	-	8
					-	-	-	-	-	-	-	7
						-	-	-	-	-	-	6
							-	-	-	-	-	5
								-	-	-	-	4
									-	-	-	3
										-	-	2
											-	1
27,044	27,044	31,479	40,214	40,214	40,214	40,214	40,214	40,214	40,214	40,214	40,214	
1,840	1,840	2,141	2,736	2,736	2,736	2,736	2,736	2,736	2,736	2,736	2,736	
5,171	5,171	6,019	7,689	7,689	7,689	7,689	7,689	7,689	7,689	7,689	7,689	
4,689	4,689	5,458	6,973	6,973	6,973	6,973	6,973	6,973	6,973	6,973	6,973	
15,330	15,330	17,844	22,796	22,796	22,796	22,796	22,796	22,796	22,796	22,796	22,796	
15	15	17	22	22	22	22	22	22	22	22	22	
27,044	27,044	31,479	40,214	40,214	40,214	40,214	40,214	40,214	40,214	40,214	40,214	

Actual kWh (Jan. - Dec., 2018): [redacted] 447,498

5	5	4	4	4	4	4	4	4	4	4	4	[redacted] 53
0	0	1	2	0	0	0	0	0	0	0	0	[redacted] 3
												[redacted] 6%

Dominion Energy North Carolina
Docket No. E-22, Sub 562

Company Supplemental Exhibit DRK-1
Schedule 1

kWh (Net) in North Carolina	Jan.	Feb.	March	April	May	June	July	Aug.	Sept.	Oct.	Nov.	Dec.	Total	
	2019													
	46	47	48	49	50	51	52	53	54	55	56	57		
Non-Residential Heating, Cooling Efficiency - kWh /year Savings (Deemed with assumed realization and net-to-gross rates from May 1, 2019 EMV Report)	-	-	592	64,153	-	-							547,318	
Monthly - Adjusted kWh (Net)														Total Months
Jan, 2015	-	-	-	-	-	-								54
Feb	-	-	-	-	-	-								53
Mar	-	-	-	-	-	-								52
Apr	2,214	2,214	2,214	2,214	2,214	2,214								51
May	3,103	3,103	3,103	3,103	3,103	3,103								50
Jun	-	-	-	-	-	-								49
Jul	-	-	-	-	-	-								48
Aug	-	-	-	-	-	-								47
Sep	-	-	-	-	-	-								46
Oct	-	-	-	-	-	-								45
Nov	-	-	-	-	-	-								44
Dec	-	-	-	-	-	-								43
Jan, 2016	-	-	-	-	-	-								42
Feb	-	-	-	-	-	-								41
Mar	-	-	-	-	-	-								40
Apr	640	640	640	640	640	640								39
May	3,590	3,590	3,590	3,590	3,590	3,590								38
Jun	12,212	12,212	12,212	12,212	12,212	12,212								37
Jul	-	-	-	-	-	-								36
Aug	374	374	374	374	374	374								35
Sep	-	-	-	-	-	-								34
Oct	-	-	-	-	-	-								33
Nov	72	72	72	72	72	72								32
Dec	-	-	-	-	-	-								31
Jan, 2017	-	-	-	-	-	-								30
Feb	-	-	-	-	-	-								29
Mar	-	-	-	-	-	-								28
Apr	-	-	-	-	-	-								27
May	4,318	4,318	4,318	4,318	4,318	4,318								26
Jun	25	25	25	25	25	25								25
Jul	-	-	-	-	-	-								24
Aug	-	-	-	-	-	-								23
Sep	497	497	497	497	497	497								22
Oct	-	-	-	-	-	-								21
Nov	-	-	-	-	-	-								20
Dec	-	-	-	-	-	-								19
Jan, 2018	-	-	-	-	-	-								18
Feb	-	-	-	-	-	-								17
Mar	4,435	4,435	4,435	4,435	4,435	4,435								16
Apr	8,735	8,735	8,735	8,735	8,735	8,735								15
May	-	-	-	-	-	-								14
Jun	-	-	-	-	-	-								13
Jul	-	-	-	-	-	-								12
Aug	-	-	-	-	-	-								11
Sep	-	-	-	-	-	-								10
Oct	-	-	-	-	-	-								9
Nov	-	-	-	-	-	-								8
Dec	-	-	-	-	-	-								7
Jan, 2019	-	-	-	-	-	-								6
Feb		-	-	-	-	-								5
Mar			49	49	49	49								4
Apr				5,346	5,346	5,346								3
May					-	-								2
Jun						-								1
Total (Cumulative by Month) - Adjusted kWh (Net)	40,214	40,214	40,264	45,610	45,610	45,610	-	-	-	-	-	-		

Total

547,318

1,238,703 True-up

DNV GL Tracking		Jan.	Feb.	March	April	May	June	July	Aug.	Sept.	Oct.	Nov.	Dec.
Schedule 10	6.80%	2,736	2,736	2,739	3,103	3,103	3,103	-	-	-	-	-	-
Schedule 30	19.12%	7,689	7,689	7,098	8,720	8,720	8,720	-	-	-	-	-	-
Schedule 42	17.34%	6,973	6,978	6,981	7,900	7,908	7,908	-	-	-	-	-	-
Schedule 5	56.69%	22,796	22,796	22,824	25,854	25,854	25,854	-	-	-	-	-	-
Schedule 5P	0.05%	22	22	22	24	24	24	-	-	-	-	-	-
		40,214	40,214	40,264	45,610	45,610	45,610	-	-	-	-	-	-

Actual kWh (Jan. - Dec., 2019): 257,622 | 1,238,703

Participation		Jan.	Feb.	March	April	May	June	July	Aug.	Sept.	Oct.	Nov.	Dec.	Total
	Planned:	0	0	0	0	0	0							0
	Actual:	0	0	1	0	0	0							1
														10%

Total
206
16
8%

NOTES:

1. The kWh savings are based on actual participation from Dominion North Carolina Power customers with program planning realization and net-to-gross adjustments assumptions applied
2. The May 1, 2019 EM&V Report was filed with the NC Public Utilities Commission and included EM&V data through the end of 2018.
3. The EM&V data reflected for January 2018 - June, 2019 was prepared by DNV GL using the same STEP (Standard Tracking Engineering Protocol) formulas used in preparing the EM&V data for 2018.
4. The kWh savings are inclusive of all EE measures installed from program inception through June 30, 2019.
5. Program measure life is 15.0 years (15 years, 0 months; or 180 months)

2015

kWh (Net) in North Carolina		Jan.	Feb.	March	April	May	June	July	Aug	Sept.	Oct.	Nov.	Dec.	Total
					1	2	3	4	5	6	7	8	9	
Non-Residential Lighting Systems and Controls - kWh /year Savings (Deemed with assumed realization and net-to-gross rates from May 1, 2019 EMV Report)		-	-	-	22,633	-	-	-	-	83,023	250,826	10,080	28,466	395,028
Monthly - Adjusted kWh (Net)														Total Months
Jan, 2015		-	-	-	-	-	-	-	-	-	-	-	-	12
Feb			-	-	-	-	-	-	-	-	-	-	-	11
Mar				-	-	-	-	-	-	-	-	-	-	10
Apr					1,886	1,886	1,886	1,886	1,886	1,886	1,886	1,886	1,886	9
May						-	-	-	-	-	-	-	-	8
Jun							-	-	-	-	-	-	-	7
Jul								-	-	-	-	-	-	6
Aug									-	-	-	-	-	5
Sep										6,919	6,919	6,919	6,919	4
Oct											20,902	20,902	20,902	3
Nov												840	840	2
Dec													2,372	1
Jan, 2016														
Feb														
Mar														
Apr														
May														
Jun														
Jul														
Aug														
Sep														
Oct														
Nov														
Dec														
Total (Cumulative by Month) - Adjusted kWh (Net):		-	-	-	1,886	1,886	1,886	1,886	1,886	8,805	29,707	30,547	32,919	
DNV GL Tracking														
Schedule 10	13.3%				252	252	252	252	252	1,174	3,962	4,074	4,390	
Schedule 26	5.1%				97	97	97	97	97	452	1,525	1,568	1,690	
Schedule 30	2.0%				38	38	38	38	39	176	594	611	659	
Schedule 42	2.1%				40	40	40	40	40	184	622	640	690	
Schedule 5	40.5%				764	764	764	764	764	3,566	12,031	12,371	13,331	
Schedule 5C	0.2%				4	4	4	4	4	17	58	60	64	
Schedule 5P	20.8%				392	392	392	392	392	1,830	6,174	6,349	6,842	
Schedule 6P	16.0%				301	301	301	301	301	1,405	4,742	4,875	5,253	
		-	-	-	1,886	1,886	1,886	1,886	1,886	8,805	29,707	30,547	32,919	

Actual kWh (Jan. - Dec., 2015): 111,408

2016

kWh (Net) in North Carolina	Jan.	Feb.	March	April	May	June	July	Aug	Sept.	Oct.	Nov.	Dec.	Total
	10	11	12	13	14	15	16	17	18	19	20	21	
Non-Residential Lighting Systems and Controls - kWh /year Savings (Deemed with assumed realization and net-to-gross rates from May 1, 2019 EMV Report)	8,381	26,371	637,359	172,657	-	184,152	59,441	604,152	39,871	231,672	102,896	266,516	2,728,497
Monthly - Adjusted kWh (Net)													Total Months
Jan, 2015	-	-	-	-	-	-	-	-	-	-	-	-	24
Feb	-	-	-	-	-	-	-	-	-	-	-	-	23
Mar	-	-	-	-	-	-	-	-	-	-	-	-	22
Apr	1,886	1,886	1,886	1,886	1,886	1,886	1,886	1,886	1,886	1,886	1,886	1,886	21
May	-	-	-	-	-	-	-	-	-	-	-	-	20
Jun	-	-	-	-	-	-	-	-	-	-	-	-	19
Jul	-	-	-	-	-	-	-	-	-	-	-	-	18
Aug	-	-	-	-	-	-	-	-	-	-	-	-	17
Sep	6,919	6,919	6,919	6,919	6,919	6,919	6,919	6,919	6,919	6,919	6,919	6,919	16
Oct	20,902	20,902	20,902	20,902	20,902	20,902	20,902	20,902	20,902	20,902	20,901	20,902	15
Nov	840	840	840	840	840	840	840	840	840	840	840	840	14
Dec	2,372	2,372	2,372	2,372	2,372	2,372	2,372	2,372	2,372	2,372	2,372	2,372	13
Jan, 2016	698	698	698	698	698	698	698	698	698	698	698	698	12
Feb		2,198	2,198	2,198	2,198	2,198	2,198	2,198	2,198	2,198	2,198	2,198	11
Mar			53,113	53,113	53,113	53,113	53,113	53,113	53,113	53,113	53,113	53,113	10
Apr				14,389	14,388	14,388	14,388	14,388	14,388	14,388	14,388	14,388	9
May					-	-	-	-	-	-	-	-	8
Jun						15,346	15,346	15,346	15,346	15,346	15,346	15,346	7
Jul							4,953	4,953	4,953	4,953	4,953	4,953	6
Aug								50,346	50,346	50,346	50,346	50,346	5
Sep									3,323	3,323	3,323	3,323	4
Oct										19,306	19,306	19,306	3
Nov											8,575	8,575	2
Dec												22,210	1
Total (Cumulative by Month) - Adjusted kWh (Net):	33,617	35,815	88,928	103,318	103,316	118,662	123,616	173,962	177,284	196,590	205,165	227,375	
DNV GL Tracking													
Schedule 10	4,483	4,776	11,860	13,778	13,778	15,825	16,486	23,200	23,643	26,218	27,361	30,323	
Schedule 26	1,726	1,839	4,565	5,304	5,304	6,092	6,346	8,931	9,101	10,092	10,532	11,673	
Schedule 30	673	717	1,779	2,067	2,067	2,374	2,474	3,481	3,548	3,934	4,105	4,550	
Schedule 42	704	750	1,863	2,164	2,164	2,486	2,590	3,644	3,714	4,118	4,298	4,763	
Schedule 5	13,614	14,504	36,014	41,841	41,841	48,055	50,061	70,450	71,796	79,614	83,087	92,081	
Schedule 5C	66	70	174	202	202	232	242	340	346	384	401	444	
Schedule 5P	6,987	7,444	18,482	21,473	21,473	24,662	25,692	36,155	36,846	40,858	42,640	47,256	
Schedule 6P	5,365	5,715	14,191	16,487	16,487	18,936	19,726	27,761	28,291	31,372	32,740	36,284	
	33,617	35,815	88,928	103,316	103,316	118,662	123,616	173,962	177,284	196,590	205,165	227,375	

Actual kWh (Jan. - Dec., 2016): 1,687,648

Participation

		Jan.	Feb.	March	April	May	June	July	Aug	Sept.	Oct.	Nov.	Dec.	Total
2015	Planned:	8	8	8	8	8	8	8	8	8	8	8	8	96
2015	Actual:	0	0	0	1	0	1	0	0	3	5	1	2	13
2015														14%
2016	Planned:	9	9	9	9	9	9	9	9	9	9	9	9	102
2016	Actual:	1	1	2	1	0	10	1	16	1	5	2	3	43
2016														42%

	2017													2018												
	22	23	24	25	26	27	28	29	30	31	32	33		34	35	36	37	38	39	40	41	42	43	44	45	
	Jan.	Feb.	March	April	May	June	July	Aug.	Sept.	Oct.	Nov.	Dec.	Total	Jan.	Feb.	March	April	May	June	July	Aug.	Sept.	Oct.	Nov.	Dec.	Total
	81,985	34,470	113,715	197,931	350,999	-	-	90,711	336,391	17,678	13,289	516	3,945,182	-	327,820	207,147	23,185	24,928	50,884	541,183	-	-	95,148	-	2,350,157	7,545,835
													Total Months													Total Months
	-	-	-	-	-	-	-	-	-	-	-	-	36	-	-	-	-	-	-	-	-	-	-	-	-	48
	-	-	-	-	-	-	-	-	-	-	-	-	35	-	-	-	-	-	-	-	-	-	-	-	-	47
	-	-	-	-	-	-	-	-	-	-	-	-	34	-	-	-	-	-	-	-	-	-	-	-	-	46
	1,886	1,886	1,886	1,886	1,886	1,886	1,886	1,886	1,886	1,886	1,886	1,886	33	1,886	1,886	1,886	1,886	1,886	1,886	1,886	1,886	1,886	1,886	1,886	1,886	45
	-	-	-	-	-	-	-	-	-	-	-	-	32	-	-	-	-	-	-	-	-	-	-	-	-	44
	-	-	-	-	-	-	-	-	-	-	-	-	31	-	-	-	-	-	-	-	-	-	-	-	-	43
	-	-	-	-	-	-	-	-	-	-	-	-	30	-	-	-	-	-	-	-	-	-	-	-	-	42
	-	-	-	-	-	-	-	-	-	-	-	-	29	-	-	-	-	-	-	-	-	-	-	-	-	41
	6,919	6,919	6,919	6,919	6,919	6,919	6,919	6,919	6,919	6,919	6,919	6,919	28	6,919	6,919	6,919	6,919	6,919	6,919	6,919	6,919	6,919	6,919	6,919	6,919	40
	20,902	20,902	20,902	20,902	20,902	20,902	20,902	20,902	20,902	20,902	20,902	20,902	27	20,902	20,902	20,902	20,902	20,902	20,902	20,902	20,902	20,902	20,902	20,902	20,902	39
	840	840	840	840	840	840	840	840	840	840	840	840	26	840	840	840	840	840	840	840	840	840	840	840	840	38
	2,372	2,372	2,372	2,372	2,372	2,372	2,372	2,372	2,372	2,372	2,372	2,372	25	2,372	2,372	2,372	2,372	2,372	2,372	2,372	2,372	2,372	2,372	2,372	2,372	37
	698	698	698	698	698	698	698	698	698	698	698	698	24	698	698	698	698	698	698	698	698	698	698	698	698	36
	2,198	2,198	2,198	2,198	2,198	2,198	2,198	2,198	2,198	2,198	2,198	2,198	23	2,198	2,198	2,198	2,198	2,198	2,198	2,198	2,198	2,198	2,198	2,198	2,198	35
	53,113	53,113	53,113	53,113	53,113	53,113	53,113	53,113	53,113	53,113	53,113	53,113	22	53,113	53,113	53,113	53,113	53,113	53,113	53,113	53,113	53,113	53,113	53,113	53,113	34
	14,388	14,388	14,388	14,388	14,388	14,388	14,388	14,388	14,388	14,388	14,388	14,388	21	14,388	14,388	14,388	14,388	14,388	14,388	14,388	14,388	14,388	14,388	14,388	14,388	33
	-	-	-	-	-	-	-	-	-	-	-	-	20	-	-	-	-	-	-	-	-	-	-	-	-	32
	15,346	15,346	15,346	15,346	15,346	15,346	15,346	15,346	15,346	15,346	15,346	15,346	19	15,346	15,346	15,346	15,346	15,346	15,346	15,346	15,346	15,346	15,346	15,346	15,346	31
	4,953	4,953	4,953	4,953	4,953	4,953	4,953	4,953	4,953	4,953	4,953	4,953	18	4,953	4,953	4,953	4,953	4,953	4,953	4,953	4,953	4,953	4,953	4,953	4,953	30
	50,346	50,346	50,346	50,346	50,346	50,346	50,346	50,346	50,346	50,346	50,346	50,346	17	50,346	50,346	50,346	50,346	50,346	50,346	50,346	50,346	50,346	50,346	50,346	50,346	29
	3,323	3,323	3,323	3,323	3,323	3,323	3,323	3,323	3,323	3,323	3,323	3,323	16	3,323	3,323	3,323	3,323	3,323	3,323	3,323	3,323	3,323	3,323	3,323	3,323	28
	19,306	19,306	19,306	19,306	19,306	19,306	19,306	19,306	19,306	19,306	19,306	19,306	15	19,306	19,306	19,306	19,306	19,306	19,306	19,306	19,306	19,306	19,306	19,306	19,306	27
	8,575	8,575	8,575	8,575	8,575	8,575	8,575	8,575	8,575	8,575	8,575	8,575	14	8,575	8,575	8,575	8,575	8,575	8,575	8,575	8,575	8,575	8,575	8,575	8,575	26
	22,210	22,210	22,210	22,210	22,210	22,210	22,210	22,210	22,210	22,210	22,210	22,210	13	22,210	22,210	22,210	22,210	22,210	22,210	22,210	22,210	22,210	22,210	22,210	22,210	25
	4,332	4,332	4,332	4,332	4,332	4,332	4,332	4,332	4,332	4,332	4,332	4,332	12	4,332	4,332	4,332	4,332	4,332	4,332	4,332	4,332	4,332	4,332	4,332	4,332	24
		2,872	2,872	2,872	2,872	2,872	2,872	2,872	2,872	2,872	2,872	2,872	11	2,872	2,872	2,872	2,872	2,872	2,872	2,872	2,872	2,872	2,872	2,872	2,872	23
			9,476	9,476	9,476	9,476	9,476	9,476	9,476	9,476	9,476	9,476	10	9,476	9,476	9,476	9,476	9,476	9,476	9,476	9,476	9,476	9,476	9,476	9,476	22
				16,494	16,494	16,494	16,494	16,494	16,494	16,494	16,494	16,494	9	16,494	16,494	16,494	16,494	16,494	16,494	16,494	16,494	16,494	16,494	16,494	16,494	21
					30,000	30,000	30,000	30,000	30,000	30,000	30,000	30,000	8	30,000	30,000	30,000	30,000	30,000	30,000	30,000	30,000	30,000	30,000	30,000	30,000	20
						-	-	-	-	-	-	-	7	-	-	-	-	-	-	-	-	-	-	-	-	19
							-	-	-	-	-	-	6	-	-	-	-	-	-	-	-	-	-	-	-	18
								7,559	7,559	7,559	7,559	7,559	5	7,559	7,559	7,559	7,559	7,559	7,559	7,559	7,559	7,559	7,559	7,559	7,559	17
									28,033	28,033	28,033	28,033	4	28,033	28,033	28,033	28,033	28,033	28,033	28,033	28,033	28,033	28,033	28,033	28,033	16
										1,473	1,473	1,473	3	1,473	1,473	1,473	1,473	1,473	1,473	1,473	1,473	1,473	1,473	1,473	1,473	15
											1,107	1,107	2	1,107	1,107	1,107	1,107	1,107	1,107	1,107	1,107	1,107	1,107	1,107	1,107	14
												43	1	43	43	43	43	43	43	43	43	43	43	43	43	13
														-	-	-	-	-	-	-	-	-	-	-	-	12
															27,318	27,318	27,318	27,318	27,318	27,318	27,318	27,318	27,318	27,318	27,318	11
																17,262	17,262	17,262	17,262	17,262	17,262	17,262	17,262	17,262	17,262	10
																	1,932	1,932	1,932	1,932	1,932	1,932	1,932	1,932	1,932	9
																		2,077	2,077	2,077	2,077	2,077	2,077	2,077	2,077	8
																			4,240	4,240	4,240	4,240	4,240	4,240	4,240	7
																				45,099	45,099	45,099	45,099	45,099	45,099	6
																					-	-	-	-	-	5
																						-	-	-	-	4
																							7,929	7,929	7,929	3
																								-	-	2
																									395,846	1
	231,707	234,579	244,056	260,550	290,550	290,550	290,550	298,109	326,141	327,615	328,722	328,765		328,765	356,083	373,346	375,278	377,355	381,596	426,694	426,694	426,694	434,623	434,623	630,470	
	30,901	31,284	31,646	34,747	38,748	38,748	38,748	39,754	43,495	43,691	43,839	43,845		43,845	47,489	49,700	50,048	50,125	50,890	56,905	56,905	56,905	57,962	57,962	84,081	
	11,895	12,042	12,329	13,376	14,916	14,916	14,916	15,304	16,743	16,819	16,873	16,878		16,878	18,280	19,106	19,265	19,373	19,590	21,905	21,905	21,905	22,312	22,312	32,366	
	4,637	4,694	4,884	5,214	5,814	5,814	5,814	5,965	6,526	6,556	6,578	6,579		6,579	7,125	7,471	7,509	7,551	7,636	8,538	8,538	8,538	8,697	8,697	12,616	
	4,854	4,914	5,111	5,456	6,087	6,087	6,087	6,245	6,832	6,863	6,886	6,887		6,887	7,459	7,821	7,862	7,905	7,994	8,939	8,939	8,939	9,105	9,105	13,207	
	93,838	94,999	98,837	105,517	117,868	117,666	117,660	120,727	132,080	132,676	133,125	133,142		133,142	144,205	151,106	151,979	152,820	154,537	172,801	172,801	172,801	176,012	176,012	255,325	
	453	458	477	509	568	568	568	582	637	640	642	642		642	696	729	733	737	746	834	834	834	849	849	1,232	
	48,156	48,753	50,723	54,151	60,388	60,386	60,388	61,957	67,783	68,089	68,319	68,328		68,328	74,006	77,594	77,995	78,427	79,308	88,681	88,681	88,681	90,329	90,329	131,033	
	38,975	37,434	38,946	41,578	46,368	46,365	46,364	47,573	52,045	52,280	52,457	52,464		52,464	56,823	59,578	59,886	60,218	60,895	68,091	68,091	68,091	69,357	69,357	100,610	
	231,707	234,579	244,056	260,550	290,550	290,550	290,550	298,109	326,141	327,615	328,722	328,765		328,765	356,083	373,346	375,278	377,355	381,596	426,694	426,694	426,694	434,623	434,623	630,470	

Actual kWh (Jan. - Dec., 2017): 3,481,883

Actual kWh (Jan. - Dec., 2018): 4,872,228

	Jan.	Feb.	March	April	May	June	July	Aug.	Sept.	Oct.	Nov.	Dec.	2017	Jan.	Feb.	March	April	May	June	July	Aug.	Sept.	Oct.	Nov.	Dec.	2018
	9	9	9	9	9	9	9	9	8	8	8	8	104	10	10	10	10	10	10	10	10	10	10	10	9	118
	3	3	2	5	6	0	0	1	3	3	3	0	33	0	2	13	5	5	6	1	0	0	4	0	5	43
													32%													36%

Dominion Energy North Carolina
Docket No. E-22, Sub 562

Company Supplemental Exhibit DRK-1
Schedule 1

	2019													
	46	47	48	49	50	51	52	53	54	55	56	57		
kWh (Net) in North Carolina	Jan.	Feb.	March	April	May	June	July	Aug.	Sept.	Oct.	Nov.	Dec.	Total	
Non-Residential Lighting Systems and Controls - kWh /year Savings (Deemed with assumed realization and net-to-gross rates from May 1, 2019 EMV Report)	-	308,262	536,671	551,880	231,749	67,137							9,261,334	
Monthly - Adjusted kWh (Net)														Total Months
Jan, 2015	-	-	-	-	-	-								54
Feb	-	-	-	-	-	-								53
Mar	-	-	-	-	-	-								52
Apr	1,886	1,886	1,886	1,886	1,886	1,886								51
May	-	-	-	-	-	-								50
Jun	-	-	-	-	-	-								49
Jul	-	-	-	-	-	-								48
Aug	-	-	-	-	-	-								47
Sep	6,919	6,919	6,919	6,919	6,919	6,919								46
Oct	20,902	20,902	20,902	20,902	20,902	20,902								45
Nov	840	840	840	840	840	840								44
Dec	2,372	2,372	2,372	2,372	2,372	2,372								43
Jan, 2016	698	698	698	698	698	698								42
Feb	2,198	2,198	2,198	2,198	2,198	2,198								41
Mar	53,113	53,113	53,113	53,113	53,113	53,113								40
Apr	14,388	14,388	14,388	14,388	14,388	14,388								39
May	-	-	-	-	-	-								38
Jun	15,346	15,346	15,346	15,346	15,346	15,346								37
Jul	4,953	4,953	4,953	4,953	4,953	4,953								36
Aug	50,346	50,346	50,346	50,346	50,346	50,346								35
Sep	3,323	3,323	3,323	3,323	3,323	3,323								34
Oct	19,306	19,306	19,306	19,306	19,306	19,306								33
Nov	8,575	8,575	8,575	8,575	8,575	8,575								32
Dec	22,210	22,210	22,210	22,210	22,210	22,210								31
Jan, 2017	4,332	4,332	4,332	4,332	4,332	4,332								30
Feb	2,872	2,872	2,872	2,872	2,872	2,872								29
Mar	9,476	9,476	9,476	9,476	9,476	9,476								28
Apr	16,494	16,494	16,494	16,494	16,494	16,494								27
May	30,000	30,000	30,000	30,000	30,000	30,000								26
Jun	-	-	-	-	-	-								25
Jul	-	-	-	-	-	-								24
Aug	7,559	7,559	7,559	7,559	7,559	7,559								23
Sep	28,033	28,033	28,033	28,033	28,033	28,033								22
Oct	1,473	1,473	1,473	1,473	1,473	1,473								21
Nov	1,107	1,107	1,107	1,107	1,107	1,107								20
Dec	43	43	43	43	43	43								19
Jan, 2018	-	-	-	-	-	-								18
Feb	27,318	27,318	27,318	27,318	27,318	27,318								17
Mar	17,262	17,262	17,262	17,262	17,262	17,262								16
Apr	1,932	1,932	1,932	1,932	1,932	1,932								15
May	2,077	2,077	2,077	2,077	2,077	2,077								14
Jun	4,240	4,240	4,240	4,240	4,240	4,240								13
Jul	45,099	45,099	45,099	45,099	45,099	45,099								12
Aug	-	-	-	-	-	-								11
Sep	-	-	-	-	-	-								10
Oct	7,929	7,929	7,929	7,929	7,929	7,929								9
Nov	-	-	-	-	-	-								8
Dec	195,846	195,846	195,846	195,846	195,846	195,846								7
Jan, 2019	-	-	-	-	-	-								6
Feb		25,689	25,689	25,689	25,689	25,689								5
Mar			44,723	44,723	44,723	44,723								4
Apr				45,990	45,990	45,990								3
May					19,312	19,312								2
Jun						9,595								1
Total (Cumulative by Month) - Adjusted kWh (Net):	630,470	656,158	700,881	746,871	766,183	771,778	-	-	-	-	-	-		

Total	
9,261,334	
14,395,510	True-up

DNV GL Tracking		Jan.	Feb.	March	April	May	June	July	Aug.	Sept.	Oct.	Nov.	Dec.
Schedule 10	13.3%	84,081	87,307	93,471	99,804	102,180	102,926	-	-	-	-	-	-
Schedule 26	8.1%	32,304	33,883	35,981	38,342	39,133	39,020	-	-	-	-	-	-
Schedule 30	2.0%	12,816	13,130	14,025	14,945	15,332	15,444	-	-	-	-	-	-
Schedule 42	2.1%	13,207	13,746	14,682	15,646	16,030	16,168	-	-	-	-	-	-
Schedule 5	40.5%	255,325	265,720	283,840	302,465	310,280	312,582	-	-	-	-	-	-
Schedule 5C	0.2%	1,232	1,282	1,369	1,459	1,497	1,808	-	-	-	-	-	-
Schedule 5P	20.8%	131,033	136,372	149,666	155,225	159,230	160,401	-	-	-	-	-	-
Schedule 6P	16.0%	100,810	104,709	111,846	119,185	122,287	123,159	-	-	-	-	-	-
		630,470	656,158	700,881	746,871	766,183	771,778	-	-	-	-	-	-

Actual kWh (Jan. - Dec., 2019): 4,272,340 | 14,395,510

Participation		Jan.	Feb.	March	April	May	June	July	Aug.	Sept.	Oct.	Nov.	Dec.		Total
	Planned:	0	0	0	0	0	0							0	421
	Actual:	0	17	14	5	7	2							40	162
														0%	38%

NOTES:

1. The kWh savings are based on actual participation from Dominion North Carolina Power customers with program planning realization and net-to-gross adjustments assumptions applied
2. The May 1, 2019 EM&V Report was filed with the NC Public Utilities Commission and included EM&V data through the end of 2018.
3. The EM&V data reflected for January 2018 - June, 2019 was prepared by DNV GL using the same STEP (Standard Tracking Engineering Protocol) formulas used in preparing the EM&V data for 2018.
4. The kWh savings are inclusive of all EE measures installed from program inception through June 30, 2019.
5. Program measure life is 9.0 years (9 years, 0 months; or 108 months)

2018

kWh (Net) in North Carolina	Jan.	Feb.	March	April	May	June	July	Aug. (1)	Sept. (2)	Oct. (3)	Nov. (4)	Dec. (5)	Total
Non-Residential Window Film - kWh /year Savings (Deemed with assumed realization and net-to-gross rates from May 1, 2019 EMV Report)	-	-	-	-	-	-	-	3,613	-	-	-	-	3,613
Monthly - Adjusted kWh (Net)													Total Months
Jan, 2018	-	-	-	-	-	-	-	-	-	-	-	-	12
Feb		-	-	-	-	-	-	-	-	-	-	-	11
Mar			-	-	-	-	-	-	-	-	-	-	10
Apr				-	-	-	-	-	-	-	-	-	9
May					-	-	-	-	-	-	-	-	8
Jun						-	-	-	-	-	-	-	7
Jul							-	-	-	-	-	-	6
Aug								301	301	301	301	301	5
Sep									-	-	-	-	4
Oct										-	-	-	3
Nov											-	-	2
Dec												-	1
Total (Cumulative by Month) - Adjusted kWh (Net):	-	-	-	-	-	-	-	301	301	301	301	301	
DNV GL Tracking													
Schedule 5 — 100%	-	-	-	-	-	-	-	301	301	301	301	301	
	-	-	-	-	-	-	-	301	301	301	301	301	

2019

kWh (Net) in North Carolina	Jan. (6)	Feb. (7)	March (8)	April (9)	May (10)	June (11)	July (12)	Aug. (13)	Sept. (14)	Oct. (15)	Nov. (16)	Dec. (17)	Total	Total
Non-Residential Window Film - kWh /year Savings (Deemed with assumed realization and net-to-gross rates from May 1, 2019 EMV Report)	-	-	-	-	-	-							3,613	3,613
Monthly - Adjusted kWh (Net)													Total Months	
Jan, 2018	-	-	-	-	-	-							18	
Feb	-	-	-	-	-	-							17	
Mar	-	-	-	-	-	-							16	
Apr	-	-	-	-	-	-							15	
May	-	-	-	-	-	-							14	
Jun	-	-	-	-	-	-							13	
Jul	-	-	-	-	-	-							12	
Aug	301	301	301	301	301	301							11	
Sep	-	-	-	-	-	-							10	
Oct	-	-	-	-	-	-							9	
Nov	-	-	-	-	-	-							8	
Dec	-	-	-	-	-	-							7	
Jan, 2019	-	-	-	-	-	-							6	
Feb		-	-	-	-	-							5	
Mar			-	-	-	-							4	
Apr				-	-	-							3	
May					-	-							2	
Jun						-							1	
Jul														
Aug														
Sep														
Oct														
Nov														
Dec														
Total (Cumulative by Month) - Adjusted kWh (Net):	301	301	301	301	301	301	-	-	-	-	-	-		3,312
DNV GL Tracking														
Schedule 5 — 100%	301	301	301	301	301	301	-	-	-	-	-	-		
	301	301	301	301	301	301	-	-	-	-	-	-		

Actual kWh (Jan. - Dec., 2018): 1,505

Actual kWh (Jan. - Dec., 2019): 1,806 | 3,312

Participation

Participation	Jan.	Feb.	March	April	May	June	July	Aug.	Sept.	Oct.	Nov.	Dec.	Total 2018	Jan.	Feb.	March	April	May	June	July	Aug.	Sept.	Oct.	Nov.	Dec.	Total 2019	Total
Planned (sq. ft):	7,992	7,992	7,992	7,992	7,992	7,992	7,992	7,992	7,991	7,991	7,991	7,991	95,900	0	0	0	0	0	0							0	95,900
Actual (sq ft):	0	0	0	0	0	0	0	402	0	0	0	0	402	0	0	0	0	0	0							0	402
													0.4%													0%	0.4%

NOTES:

1. The kWh savings are based on actual participation from Dominion North Carolina Power customers with program planning realization and net-to gross adjustments assumptions applied
2. The May 1, 2019 EM&V Report was filed with the NC Public Utilities Commission and included EM&V data through the end of 2018.
3. The EM&V data reflected for January 2018 - June, 2019 was prepared by DNV GL using the same STEP (Standard Tracking Engineering Protocol) formulas used in preparing the EM&V data for 2018.
4. The kWh savings are inclusive of all EE measures installed from program inception through June 30, 2019.
5. Program measure life is 10.0 years (10 years, 0 months; or 120 months)

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Company Supplemental Exhibit DRK-1
Schedule 1
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	2016													2017												
							1	2	3	4	5	6		7	8	9	10	11	12	13	14	15	16	17	18	
kWh (Net) in North Carolina	Jan.	Feb.	March	April	May	June	July	Aug	Sept.	Oct.	Nov.	Dec.	Total	Jan.	Feb.	March	April	May	June	July	Aug	Sept.	Oct.	Nov.	Dec.	Total
Residential Income and Age Qualifying Home Improvement - kWh /year Savings (Deemed with assumed realization and net-to-gross rates from May 1, 2019 EMV Report)	-	-	-	-	-	-	9,345	5,975	5,223	11,979	28,463	24,118	85,103	32,850	8,357	8,814	5,700	3,453	2,156	1,457	4,378	4,253	[illegible]	3,490	12,928	172,939
Monthly - Adjusted kWh (Net)													Total Months													Total Months
Jan, 2016	-	-	-	-	-	-	-	-	-	-	-	-	12	-	-	-	-	-	-	-	-	-	-	-	-	24
Feb		-	-	-	-	-	-	-	-	-	-	-	11	-	-	-	-	-	-	-	-	-	-	-	-	23
Mar			-	-	-	-	-	-	-	-	-	-	10	-	-	-	-	-	-	-	-	-	-	-	-	22
Apr				-	-	-	-	-	-	-	-	-	9	-	-	-	-	-	-	-	-	-	-	-	-	21
May					-	-	-	-	-	-	-	-	8	-	-	-	-	-	-	-	-	-	-	-	-	20
Jun						-	-	-	-	-	-	-	7	-	-	-	-	-	-	-	-	-	-	-	-	19
Jul							779	779	779	779	779	779	6	779	779	779	779	779	779	779	779	779	779	779	779	18
Aug								498	498	498	498	498	5	498	498	498	498	498	498	498	498	498	498	498	498	17
Sep									435	435	435	435	4	435	435	435	435	435	435	435	435	435	435	435	435	16
Oct										998	998	998	3	998	998	998	998	998	998	998	998	998	998	998	998	15
Nov											2,372	2,372	2	2,372	2,372	2,372	2,372	2,372	2,372	2,372	2,372	2,372	2,372	2,372	2,372	14
Dec												2,010	1	2,010	2,010	2,010	2,010	2,010	2,010	2,010	2,010	2,010	2,010	2,010	2,010	13
Jan, 2017														2,738	2,738	2,738	2,738	2,738	2,738	2,738	2,738	2,738	2,738	2,738	2,738	12
Feb															696	696	696	696	696	696	696	696	696	696	696	11
Mar																735	735	735	735	735	735	735	735	735	735	10
Apr																	475	475	475	475	475	475	475	475	475	9
May																		288	288	288	288	288	288	288	288	8
Jun																			180	180	180	180	180	180	180	7
Jul																				121	121	121	121	121	121	6
Aug																					365	365	365	365	365	5
Sep																						354	354	354	354	4
Oct																							-	-	-	3
Nov																								291	291	2
Dec																									1,077	1
[redacted] Total (Cumulative by Month) - Adjusted kWh (Net):	-	-	-	-	-	-	779	1,277	1,712	2,710	5,082	7,092	[redacted]	9,829	10,526	11,260	11,735	12,023	12,203	12,324	12,689	13,043	13,043	13,334	14,412	[redacted]
DNV GL Tracking																										
Schedule 1 [redacted] 99.3%	-	-	-	-	-	-	773	1,267	1,700	2,691	5,045	7,041	[redacted]	9,758	10,450	11,179	11,651	11,936	12,115	12,235	12,598	12,949	12,949	13,238	14,308	[redacted]
Schedule 10F [redacted] 0.1%	-	-	-	-	-	-	1	2	2	3	6	9	[redacted]	12	13	14	14	15	15	15	16	16	16	16	18	[redacted]
Schedule 5 [redacted] 0.6%	-	-	-	-	-	-	5	8	10	16	30	42	[redacted]	59	63	67	70	72	73	74	76	78	78	80	86	[redacted]
	-	-	-	-	-	-	779	1,277	1,712	2,710	5,082	7,092		9,829	10,526	11,260	11,735	12,023	12,203	12,324	12,689	13,043	13,043	13,334	14,412	

Actual kWh (Jan. - Dec., 2016): [redacted] 18,882

Actual kWh (Jan. - Dec., 2017): [redacted] 148,423

Participation		Jan.	Feb.	March	April	May	June	July	Aug	Sept.	Oct.	Nov.	Dec.	Total	Jan.	Feb.	March	April	May	June	July	Aug	Sept.	Oct.	Nov.	Dec.	Total
	Planned:	21	21	21	21	21	21	21	21	21	21	21	21	[redacted] 257	22	22	21	21	21	21	21	21	21	21	21	21	[redacted] 254
	Actual:	0	0	0	0	0	0	20	12	9	25	37	54	[redacted] 167	42	16	12	13	6	4	2	4	2	0	7	22	[redacted] 130
														[redacted] 61%													[redacted] 51%

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2018

kWh (Net) in North Carolina	19 Jan.	20 Feb.	21 March	22 April	23 May	24 June	25 July	26 Aug.	27 Sept.	28 Oct.	29 Nov.	30 Dec.	Total
Residential Income and Age Qualifying Home Improvement - kWh/year Savings (Deemed with assumed realization and net-to-gross rates from May 1, 2019 EMV Report)	579	-	-	-	-	-	-	-	-	-	-	-	173,518
													Total Months
Monthly - Adjusted kWh (Net)													
Jan, 2016	-	-	-	-	-	-	-	-	-	-	-	-	36
Feb	-	-	-	-	-	-	-	-	-	-	-	-	35
Mar	-	-	-	-	-	-	-	-	-	-	-	-	34
Apr	-	-	-	-	-	-	-	-	-	-	-	-	33
May	-	-	-	-	-	-	-	-	-	-	-	-	32
Jun	-	-	-	-	-	-	-	-	-	-	-	-	31
Jul	779	779	779	779	779	779	779	779	779	779	779	779	30
Aug	498	498	498	498	498	498	498	498	498	498	498	498	29
Sep	435	435	435	435	435	435	435	435	435	435	415	435	28
Oct	998	998	998	998	998	998	998	998	998	998	998	998	27
Nov	2,372	2,372	2,372	2,372	2,372	2,372	2,372	2,372	2,372	2,372	2,372	2,372	26
Dec	2,010	2,010	2,010	2,010	2,010	2,010	2,010	2,010	2,010	2,010	2,010	2,010	25
Jan, 2017	2,738	2,738	2,738	2,738	2,738	2,738	2,738	2,738	2,738	2,738	2,738	2,738	24
Feb	696	696	696	696	696	696	696	696	696	696	696	696	23
Mar	735	735	735	735	735	735	735	735	735	735	735	735	22
Apr	475	475	475	475	475	475	475	475	475	475	475	475	21
May	288	288	288	288	288	288	288	288	288	288	288	288	20
Jun	180	180	180	180	180	180	180	180	180	180	180	180	19
Jul	121	121	121	121	121	121	121	121	121	121	121	121	18
Aug	365	365	365	365	365	365	365	365	365	365	365	365	17
Sep	354	354	354	354	354	354	354	354	354	354	354	354	16
Oct	-	-	-	-	-	-	-	-	-	-	-	-	15
Nov	291	291	291	291	291	291	291	291	291	291	291	291	14
Dec	1,077	1,077	1,077	1,077	1,077	1,077	1,077	1,077	1,077	1,077	1,077	1,077	13
Jan, 2018	48	48	48	48	48	48	48	48	48	48	48	48	12
Feb		-	-	-	-	-	-	-	-	-	-	-	11
Mar			-	-	-	-	-	-	-	-	-	-	10
Apr				-	-	-	-	-	-	-	-	-	9
May					-	-	-	-	-	-	-	-	8
Jun						-	-	-	-	-	-	-	7
Jul							-	-	-	-	-	-	6
Aug								-	-	-	-	-	5
Sep									-	-	-	-	4
Oct										-	-	-	3
Nov											-	-	2
Dec												-	1
Jan, 2019													
Feb													
Mar													
Apr													
May													
Jun													
Total (Cumulative by Month) - Adjusted kWh (Net):	14,460	14,460	14,460	14,460	14,460	14,460	14,460	14,460	14,460	14,460	14,460	14,460	
DNV GL Tracking													
Schedule 1 — 99.3%	14,356	14,356	14,356	14,356	14,356	14,356	14,356	14,356	14,356	14,356	14,356	14,356	
Schedule 10F — 0.1%	18	18	18	18	18	18	18	18	18	18	18	18	
Schedule 5 — 0.6%	86	86	86	86	86	86	86	86	86	86	86	86	
	14,460	14,460	14,460	14,460	14,460	14,460	14,460	14,460	14,460	14,460	14,460	14,460	

2019

kWh (Net) in North Carolina	31 Jan.	32 Feb.	33 March	34 April	35 May	36 June	37 July	38 Aug.	39 Sept.	40 Oct.	41 Nov.	42 Dec.	Total
Residential Income and Age Qualifying Home Improvement - kWh/year Savings (Deemed with assumed realization and net-to-gross rates from May 1, 2019 EMV Report)	-	-	-	1,193	-	4,614							179,325
													Total Months
Monthly - Adjusted kWh (Net)													
Jan, 2016	-	-	-	-	-	-							42
Feb	-	-	-	-	-	-							41
Mar	-	-	-	-	-	-							40
Apr	-	-	-	-	-	-							39
May	-	-	-	-	-	-							38
Jun	-	-	-	-	-	-							37
Jul	779	779	779	779	779	779							36
Aug	498	498	498	498	498	498							35
Sep	435	435	435	435	435	435							34
Oct	998	998	998	998	998	998							33
Nov	2,372	2,372	2,372	2,372	2,372	2,372							32
Dec	2,010	2,010	2,010	2,010	2,010	2,010							31
Jan, 2017	2,738	2,738	2,738	2,738	2,738	2,738							30
Feb	696	696	696	696	696	696							29
Mar	735	735	735	735	735	735							28
Apr	475	475	475	475	475	475							27
May	288	288	288	288	288	288							26
Jun	180	180	180	180	180	180							25
Jul	121	121	121	121	121	121							24
Aug	365	365	365	365	365	365							23
Sep	354	354	354	354	354	354							22
Oct	-	-	-	-	-	-							21
Nov	291	291	291	291	291	291							20
Dec	1,077	1,077	1,077	1,077	1,077	1,077							19
Jan, 2018	48	48	48	48	48	48							18
Feb	-	-	-	-	-	-							17
Mar	-	-	-	-	-	-							16
Apr	-	-	-	-	-	-							15
May	-	-	-	-	-	-							14
Jun	-	-	-	-	-	-							13
Jul	-	-	-	-	-	-							12
Aug	-	-	-	-	-	-							11
Sep	-	-	-	-	-	-							10
Oct	-	-	-	-	-	-							9
Nov	-	-	-	-	-	-							8
Dec	-	-	-	-	-	-							7
Jan, 2019	-	-	-	-	-	-							6
Feb		-	-	-	-	-							5
Mar			-	-	-	-							4
Apr				99	99	99							3
May					-	-							2
Jun						385							1
Total (Cumulative by Month) - Adjusted kWh (Net):	14,460	14,460	14,460	14,559	14,559	14,944	-	-	-	-	-	-	
DNV GL Tracking													
Schedule 1	14,356	14,356	14,356	14,454	14,454	14,836	-	-	-	-	-	-	
Schedule 10F	18	18	18	18	18	18	-	-	-	-	-	-	
Schedule 5	86	86	86	87	87	89	-	-	-	-	-	-	
	14,460	14,460	14,460	14,559	14,559	14,944	-	-	-	-	-	-	

Total
179,325

426,034 True-up

Actual kWh (Jan. - Dec., 2018): 173,618

Actual kWh (Jan. - Dec., 2019): 87,442 426,034

Participation	Jan.	Feb.	March	April	May	June	July	Aug.	Sept.	Oct.	Nov.	Dec.	Total 2018	Jan.	Feb.	March	April	May	June	July	Aug.	Sept.	Oct.	Nov.	Dec.	Total 2019
Planned:	0	0	0	0	0	0	0	0	0	0	0	0	0	24	24	24	23	23	23							141
Actual:	1	0	0	0	0	0	0	0	0	0	0	0	1	0	0	0	6	0	25							31
													0%													72%

Total
652
319
49%

NOTES:

1. The kWh savings are based on actual participation from Dominion North Carolina Power customers with program planning realization and net-to-gross adjustments assumptions applied
2. The May 1, 2019 EM&V Report was filed with the NC Public Utilities Commission and included EM&V data through the end of 2018.
3. The EM&V data reflected for January 2018 - June, 2019 was prepared by DNV GL using the same STEP (Standard Tracking Engineering Protocol) formulas used in preparing the EM&V data for 2018.
4. The kWh savings are inclusive of all EE measures installed from program inception through June 30, 2019.
5. Program measure life is 14.0 years (14 years, 0 months; or 168 months) for 2015-2017 and 15.0 years (15 years, 0 months; or 180 months) after 2018.

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	2017													2018												
						1	2	3	4	5	6	7		8	9	10	11	12	13	14	15	16	17	18	19	
kWh (Net) in North Carolina	Jan.	Feb.	March	April	May	June	July	Aug	Sept.	Oct.	Nov.	Dec.	Total	Jan.	Feb.	March	April	May	June	July	Aug	Sept.	Oct.	Nov.	Dec.	Total
Non-residential Small Business Improvement - kWh /year Savings (Deemed with assumed realization and net-to-gross rates from May 1, 2019 EMV Report)	-	-	-	-	-	12,591	47,782	-	-	-	-	94,478	154,851	-	35,555	20,949	31,718	210,581	205,206	97,932	-	-	303,706	-	25,018	1,085,517
Monthly - Adjusted kWh (Net)													Total Months													Total Months
Jan, 2017	-	-	-	-	-	-	-	-	-	-	-	-	12	-	-	-	-	-	-	-	-	-	-	-	-	24
Feb		-	-	-	-	-	-	-	-	-	-	-	11	-	-	-	-	-	-	-	-	-	-	-	-	23
Mar			-	-	-	-	-	-	-	-	-	-	10	-	-	-	-	-	-	-	-	-	-	-	-	22
Apr				-	-	-	-	-	-	-	-	-	9	-	-	-	-	-	-	-	-	-	-	-	-	21
May					-	-	-	-	-	-	-	-	8	-	-	-	-	-	-	-	-	-	-	-	-	20
Jun						1,049	1,049	1,049	1,049	1,049	1,049	1,049	7	1,049	1,049	1,049	1,049	1,049	1,049	1,049	1,049	1,049	1,049	1,049	1,049	19
Jul							3,982	3,982	3,982	3,982	3,982	3,982	6	3,982	3,982	3,982	3,982	3,982	3,982	3,982	3,982	3,982	3,982	3,982	3,982	18
Aug								-	-	-	-	-	5	-	-	-	-	-	-	-	-	-	-	-	-	17
Sep									-	-	-	-	4	-	-	-	-	-	-	-	-	-	-	-	-	16
Oct										-	-	-	3	-	-	-	-	-	-	-	-	-	-	-	-	15
Nov											-	-	2	-	-	-	-	-	-	-	-	-	-	-	-	14
Dec												7,873	1	7,873	7,873	7,873	7,873	7,873	7,873	7,873	7,873	7,873	7,873	7,873	7,873	13
Jan, 2018														-	-	-	-	-	-	-	-	-	-	-	-	12
Feb															2,963	2,963	2,963	2,963	2,963	2,963	2,963	2,963	2,963	2,963	2,963	11
Mar																1,746	1,746	1,746	1,746	1,746	1,746	1,746	1,746	1,746	1,746	10
Apr																	2,643	2,643	2,643	2,643	2,643	2,643	2,643	2,643	2,643	9
May																		17,548	17,548	17,548	17,548	17,548	17,548	17,548	17,548	8
Jun																			17,101	17,101	17,101	17,101	17,101	17,101	17,101	7
Jul																				8,161	8,161	8,161	8,161	8,161	8,161	6
Aug																					-	-	-	-	-	5
Sep																						-	-	-	-	4
Oct																							25,309	25,309	25,309	3
Nov																								-	-	2
Dec																									2,085	1
Total (Cumulative by Month) - Adjusted kWh (Net):	-	-	-	-	-	1,049	5,031	5,031	5,031	5,031	5,031	12,904		12,904	15,867	17,613	20,256	37,805	54,905	63,066	63,066	63,066	88,375	88,375	90,460	[illegible]
DNV GL Tracking																										
Schedule 5 100%	-	-	-	-	-	1,049	5,031	5,031	5,031	5,031	5,031	12,904		12,904	15,867	17,613	20,256	37,805	54,905	63,066	63,066	63,066	88,375	88,375	90,460	[illegible]
	-	-	-	-	-	1,049	5,031	5,031	5,031	5,031	5,031	12,904		12,904	15,867	17,613	20,256	37,805	54,905	63,066	63,066	63,066	88,375	88,375	90,460	

Actual kWh (Jan. - Dec., 2017): 39,108

Actual kWh (Jan. - Dec., 2018): 615,758

Participation																										
Planned:	4	4	4	4	4	4	3	3	3	3	3	3	42	5	5	5	5	5	4	4	4	4	4	4	4	[illegible] 83
Actual:	0	0	0	0	0	1	1	0	0	0	0	5	7	0	1	1	1	3	9	9	0	0	11	0	1	[illegible] 38
													17%													[illegible] 68%

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	2019													
	20	21	22	23	24	25	26	27	28	29	30	31		
kWh (Net) in North Carolina	Jan.	Feb.	March	April	May	June	July	Aug	Sept.	Oct.	Nov.	Dec.	Total	Total
Non-residential Small Business Improvement - kWh /year Savings (Deemed with assumed realization and net-to-gross rates from May 1, 2019 EMV Report)	86,055	150,942	1,218	99,687	-	77,737							1,501,155	1,501,155

Monthly - Adjusted kWh (Net)	Jan.	Feb.	March	April	May	June	July	Aug	Sept.	Oct.	Nov.	Dec.	Total Months
Jan, 2017	-	-	-	-	-	-							30
Feb	-	-	-	-	-	-							29
Mar	-	-	-	-	-	-							28
Apr	-	-	-	-	-	-							27
May	-	-	-	-	-	-							26
Jun	1,049	1,049	1,049	1,049	1,049	1,049							25
Jul	3,982	3,982	3,982	3,982	3,982	3,982							24
Aug	-	-	-	-	-	-							23
Sep	-	-	-	-	-	-							22
Oct	-	-	-	-	-	-							21
Nov	-	-	-	-	-	-							20
Dec	7,873	7,873	7,873	7,873	7,873	7,873							19
Jan, 2018	-	-	-	-	-	-							18
Feb	2,963	2,963	2,963	2,963	2,963	2,963							17
Mar	1,746	1,746	1,746	1,746	1,746	1,746							16
Apr	2,643	2,643	2,643	2,643	2,643	2,643							15
May	17,548	17,548	17,548	17,548	17,548	17,548							14
Jun	17,101	17,101	17,101	17,101	17,101	17,101							13
Jul	8,161	8,161	8,161	8,161	8,161	8,161							12
Aug	-	-	-	-	-	-							11
Sep	-	-	-	-	-	-							10
Oct	25,309	25,309	25,309	25,309	25,309	25,309							9
Nov	-	-	-	-	-	-							8
Dec	2,085	2,085	2,085	2,085	2,085	2,085							7
Jan, 2019	7,171	7,171	7,171	7,171	7,171	7,171							6
Feb		12,578	12,578	12,578	12,578	12,578							5
Mar			101	101	101	101							4
Apr				8,307	8,307	8,307							3
May					-	-							2
Jun						6,478							1
Jul													
Aug													
Sep													
Oct													
Nov													
Dec													
Total (Cumulative by Month) - Adjusted kWh (Net):	97,631	110,209	110,311	118,618	118,618	125,096	-	-	-	-	-	-	1,335,351 True-up
DNV GL Tracking													
Schedule 5 100%	97,631	110,209	110,311	118,618	118,618	125,096	-	-	-	-	-	-	
	97,631	110,209	110,311	118,618	118,618	125,096	-	-	-	-	-	-	

Actual kWh (Jan. - Dec., 2019):	680,484	1,335,351

Participation		Jan.	Feb.	March	April	May	June	July	Aug	Sept.	Oct.	Nov.	Dec.		Total
	Planned:	6	5	5	5	5	5							31	126
	Actual:	3	2	1	6	0	4							16	59
														52%	47%

NOTES:

1. The kWh savings are based on actual participation from Dominion North Carolina Power customers with program planning realization and net-to-gross adjustments assumptions applied
2. The May 1, 2019 EM&V Report was filed with the NC Public Utilities Commission and included EM&V data through the end of 2018.
3. The EM&V data reflected for January 2018 - June, 2019 was prepared by DNV GL using the same STEP (Standard Tracking Engineering Protocol) formulas used in preparing the EM&V data for 2018.
4. The kWh savings are inclusive of all EE measures installed from program inception through June 30, 2019.
5. Program measure life is 14.0 years (14 years, 0 months; or 168 months).

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	2017													2018													
								1	2	3	4	5		6	7	8	9	10	11	12	13	14	15	16	17	
kWh (Net) in North Carolina	Jan.	Feb.	March	April	May	June	July	Aug	Sept.	Oct.	Nov.	Dec.	Total	Jan.	Feb.	March	April	May	June	July	Aug	Sept.	Oct.	Nov.	Dec.	Total
Residential LED - kWh/year Savings (Deemed with assumed realization and net-to-gross rates from May 1, 2019 EMV Report)	-	-	-	-	-	-	-	132,963	382,628	387,651	544,016	435,554	1,882,812	237,492	571,505	263,188	404,047	227,939	293,205	384,648	473,320	548,971	242,724	773,721	609,763	6,913,336
Monthly - Adjusted kWh (Net)													Total Months													Total Months
Jan, 2017	-	-	-	-	-	-	-	-	-	-	-	-	12	-	-	-	-	-	-	-	-	-	-	-	-	24
Feb		-	-	-	-	-	-	-	-	-	-	-	11	-	-	-	-	-	-	-	-	-	-	-	-	23
Mar			-	-	-	-	-	-	-	-	-	-	10	-	-	-	-	-	-	-	-	-	-	-	-	22
Apr				-	-	-	-	-	-	-	-	-	9	-	-	-	-	-	-	-	-	-	-	-	-	21
May					-	-	-	-	-	-	-	-	8	-	-	-	-	-	-	-	-	-	-	-	-	20
Jun						-	-	-	-	-	-	-	7	-	-	-	-	-	-	-	-	-	-	-	-	19
Jul							-	-	-	-	-	-	6	-	-	-	-	-	-	-	-	-	-	-	-	18
Aug								11,080	11,080	11,080	11,080	11,080	5	11,080	11,080	11,080	11,080	11,080	11,080	11,080	11,080	11,080	11,080	11,080	11,080	17
Sep									31,886	31,886	31,886	31,886	4	31,886	31,886	31,886	31,886	31,886	31,886	31,886	31,886	31,886	31,886	31,886	31,886	16
Oct										32,304	32,304	32,304	3	32,304	32,304	32,304	32,304	32,304	32,304	32,304	32,304	32,304	32,304	32,304	32,304	15
Nov											45,335	45,335	2	45,335	45,335	45,335	45,335	45,335	45,335	45,335	45,335	45,335	45,335	45,335	45,335	14
Dec												36,296	1	36,296	36,296	36,296	36,296	36,296	36,296	36,296	36,296	36,296	36,296	36,296	36,296	13
Jan, 2018														19,791	19,791	19,791	19,791	19,791	19,791	19,791	19,791	19,791	19,791	19,791	19,791	12
Feb															47,625	47,625	47,625	47,625	47,625	47,625	47,625	47,625	47,625	47,625	47,625	11
Mar																21,932	21,932	21,932	21,932	21,932	21,932	21,932	21,932	21,932	21,932	10
Apr																	33,671	33,671	33,671	33,671	33,671	33,671	33,671	33,671	33,671	9
May																		18,995	18,995	18,995	18,995	18,995	18,995	18,995	18,995	8
Jun																			24,434	24,434	24,434	24,434	24,434	24,434	24,434	7
Jul																				32,054	32,054	32,054	32,054	32,054	32,054	6
Aug																					39,443	39,443	39,443	39,443	39,443	5
Sep																						45,748	45,748	45,748	45,748	4
Oct																							20,227	20,227	20,227	3
Nov																								64,477	64,477	2
Dec																									50,814	1
Total (Cumulative by Month) - Adjusted kWh (Net)	-	-	-	-	-	-	-	11,080	42,966	75,270	120,605	156,901		176,692	224,317	248,250	279,920	298,915	323,349	355,403	394,846	440,594	460,821	525,298	576,111	
DNV GL Tracking																										
Schedule 1 99.25%	-	-	-	-	-	-	-	10,998	42,646	74,709	119,706	155,732		175,376	222,646	244,415	277,835	296,688	320,940	352,755	391,904	437,311	457,388	521,384	571,819	
	-	-	-	-	-	-	-	10,998	42,646	74,709	119,706	155,732		175,376	222,646	244,415	277,835	296,688	320,940	352,755	391,904	437,311	457,388	521,384	571,819	

Actual kWh (Jan. - Dec., 2017): 406,822

Actual kWh (Jan. - Dec., 2018): 4,302,517

Participation																										
Planned (Bulbs)	13,750	13,750	13,750	13,750	13,750	13,750	13,750	13,750	13,750	13,750	13,750	13,750	165,000	18,334	18,334	18,334	18,334	18,333	18,333	18,333	18,333	18,333	18,333	18,333	18,333	220,000
Actual (Bulbs)	0	0	0	0	0	0	0	5,018	14,683	14,758	19,836	15,966	70,281	12,482	29,279	13,614	21,629	11,552	14,694	20,050	25,185	32,534	11,899	42,003	29,315	264,238
													43%													120%

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	2019														
	18	19	20	21	22	23	24	25	26	27	28	29			
kWh (Net) in North Carolina	Jan.	Feb.	March	April	May	June	July	Aug	Sept.	Oct.	Nov.	Dec.	Total		Total
Residential LED - kWh /year Savings (Deemed with assumed realization and net-to-gross rates from May 1, 2019 EMV Report)	-	-	-	-	-	-							6,913,336		6,913,336
Monthly - Adjusted kWh (Net)													Total Months		
Jan, 2017	-	-	-	-	-	-							30		
Feb	-	-	-	-	-	-							29		
Mar	-	-	-	-	-	-							28		
Apr	-	-	-	-	-	-							27		
May	-	-	-	-	-	-							26		
Jun	-	-	-	-	-	-							25		
Jul	-	-	-	-	-	-							24		
Aug	11,080	11,080	11,080	11,080	11,080	11,080							23		
Sep	31,886	31,886	31,886	31,886	31,886	31,886							22		
Oct	32,304	32,304	32,304	32,304	32,304	32,304							21		
Nov	45,335	45,335	45,335	45,335	45,335	45,335							20		
Dec	36,296	36,296	36,296	36,296	36,296	36,296							19		
Jan, 2018	19,791	19,791	19,791	19,791	19,791	19,791							18		
Feb	47,625	47,625	47,625	47,625	47,625	47,625							17		
Mar	21,932	21,932	21,932	21,932	21,932	21,932							16		
Apr	33,671	33,671	33,671	33,671	33,671	33,671							15		
May	18,995	18,995	18,995	18,995	18,995	18,995							14		
Jun	24,434	24,434	24,434	24,434	24,434	24,434							13		
Jul	32,054	32,054	32,054	32,054	32,054	32,054							12		
Aug	39,443	39,443	39,443	39,443	39,443	39,443							11		
Sep	45,748	45,748	45,748	45,748	45,748	45,748							10		
Oct	20,227	20,227	20,227	20,227	20,227	20,227							9		
Nov	64,477	64,477	64,477	64,477	64,477	64,477							8		
Dec	50,814	50,814	50,814	50,814	50,814	50,814							7		
Total (Cumulative by Month) - Adjusted kWh (Net):	576,111	576,111	576,111	576,111	576,111	576,111	-	-	-	-	-	-			8,166,007 True-up
DNV GL Tracking															
Schedule 1 — 99.25%	571,819	571,819	571,819	571,819	571,819	571,819	-	-	-	-	-	-			
	571,819	571,819	571,819	571,819	571,819	571,819	-	-	-	-	-	-			

Actual kWh (Jan. - Dec., 2019): [redacted] 3,456,668 | 8,166,007

Participation	Jan.	Feb.	March	April	May	June	July	Aug	Sept.	Oct.	Nov.	Dec.	Total		Total
Planned (Bulbs)	0	0	0	0	0	0	0	0	0	0	0	0	0		385,000
Actual (Bulbs)	0	0	0	0	0	0	0	0	0	0	0	0	0		334,497
													0%		87%

NOTES:

1. The kWh savings are based on actual participation from Dominion North Carolina Power customers with program planning realization and net-to-gross adjustments assumptions applied
2. The May 1, 2019 EM&V Report was filed with the NC Public Utilities Commission and included EM&V data through the end of 2018.
3. The EM&V data reflected for January 2018 - June, 2019 was prepared by DNV GL using the same STEP (Standard Tracking Engineering Protocol) formulas used in preparing the EM&V data for 2018.
4. The kWh savings are inclusive of all EE measures installed from program inception through June 30, 2019.
5. Program measure life is 20.0 years (20 years, 0 months; or 240 months).

	2018													2019													
											1	2		3	4	5	6	7	8	9	10	11	12	13	14		
kWh (Net) in North Carolina	Jan.	Feb.	March	April	May	June	July	Aug.	Sept.	Oct.	Nov.	Dec.	Total	Jan.	Feb.	March	April	May	June	July	Aug.	Sept.	Oct.	Nov.	Dec.	Total	Total
Non-Residential Prescriptive - kWh /year Savings (Deemed with assumed realization and net-to-gross rates from May 1, 2019 EMV Report)	-	-	-	-	-	-	-	-	-	-	136,322	52,190	188,512	66,941	61,905	33,810	21,180	397	-							372,759	372,759
Monthly - Adjusted kWh (Net)													Total Months													Total Months	
Jan, 2018	-	-	-	-	-	-	-	-	-	-	-	-	12	-	-	-	-	-	-							18	
Feb		-	-	-	-	-	-	-	-	-	-	-	11	-	-	-	-	-	-							17	
Mar			-	-	-	-	-	-	-	-	-	-	10	-	-	-	-	-	-							16	
Apr				-	-	-	-	-	-	-	-	-	9	-	-	-	-	-	-							15	
May					-	-	-	-	-	-	-	-	8	-	-	-	-	-	-							14	
Jun						-	-	-	-	-	-	-	7	-	-	-	-	-	-							13	
Jul							-	-	-	-	-	-	6	-	-	-	-	-	-							12	
Aug								-	-	-	-	-	5	-	-	-	-	-	-							11	
Sep									-	-	-	-	4	-	-	-	-	-	-							10	
Oct										-	-	-	3	-	-	-	-	-	-							9	
Nov											11,360	11,360	2	11,360	11,360	11,360	11,360	11,360	11,360							8	
Dec												4,349	1	4,349	4,349	4,349	4,349	4,349	4,349							7	
Jan, 2019														5,578	5,578	5,578	5,578	5,578	5,578							6	
Feb															5,159	5,159	5,159	5,159	5,159							5	
Mar																7,819	2,819	2,819	2,819							4	
Apr																	1,765	1,765	1,765							3	
May																		33	33							2	
Jun																			-							1	
Jul																											
Aug																											
Sep																											
Oct																											
Nov																											
Dec																											
Total (Cumulative by Month) - Adjusted kWh (Net):	-	-	-	-	-	-	-	-	-	-	11,360	15,709		21,288	26,446	29,266	31,031	31,063	31,063	-	-	-	-	-	-		197,226 True-up
DNV GL Tracking																											
Schedule 10 18%	-	-	-	-	-	-	-	-	-	-	2,817	2,789		3,779.29	4,895	5,195	5,509	5,515	5,515								
Schedule 5 16%	-	-	-	-	-	-	-	-	-	-	1,817	2,541		3,442.81	4,277	4,733	5,019	5,024	5,024								
Schedule 5P 60%	-	-	-	-	-	-	-	-	-	-	6,804	9,408		12,749.18	15,839	17,537	18,584	18,604	18,604								
Schedule 6P 6%	-	-	-	-	-	-	-	-	-	-	703	972		1,316.56	1,636	1,810	1,919	1,922	1,921								
	-	-	-	-	-	-	-	-	-	-	10,658	14,738		21,288	26,446	29,266	31,031	31,063	31,063	-	-	-	-	-	-		

Actual kWh (Jan. - Dec., 2018): 27,070

Actual kWh (Jan. - Dec., 2019): 170,157 | 197,226

Participation		Jan.	Feb.	March	April	May	June	July	Aug.	Sept.	Oct.	Nov.	Dec.	Total	Jan.	Feb.	March	April	May	June	July	Aug.	Sept.	Oct.	Nov.	Dec.	Total	Total
	Planned:	3	3	3	3	3	2	2	2	2	2	2	2	29	3	3	3	2	2	2							15	44
	Actual:	0	0	0	0	0	0	0	0	0	0	11	10	21	3	16	6	7	1	0							33	54
														72%													228%	124%

NOTES:

1. The kWh savings are based on actual participation from Dominion North Carolina Power customers with program planning realization and net-to-gross adjustments assumptions applied
2. The May 1, 2019 EM&V Report was filed with the NC Public Utilities Commission and included EM&V data through the end of 2018.
3. The EM&V data reflected for January 2018 - June, 2019 was prepared by DNV GL using the same STEP (Standard Tracking Engineering Protocol) formulas used in preparing the EM&V data for 2018.
4. The kWh savings are inclusive of all EE measures installed from program inception through June 30, 2019.
5. Program measure life is 6.3 years (6 years, 4 months; or 76 months).

DOMINION ENERGY NORTH CAROLINA
DOCKET NO. E-22, SUB 562
ENERGY AND FUEL EXPENSES
(8 + 4 Year End Projected)
Normalized and Adjusted Energy and Fuel Expense based on Actual + Projected 12-Months Ended June 2019
(Company Ownership Only)

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)
	12-Months Ended June 2019							June 2019			
	Expense ($)	Generation (MWh)	Rate ($/MWh)	Supply (%)	Ratio of Coal Oil, CT & CC NUG & Other MWH To Total Sum	Coal, Oil, CT & CC, NUG, Other, Nuclear Adj. and Growth MWh	Adjusted Generation (MWh)	Expense ($)	Generation (MWh)	Rate ($/MWh)	Normalized & Adjusted Fuel Expense at Applicable Rate (8) x (11)
Coal (1)	313,973,502	10,209,959	30.75	11.3	0.1669	59,152,510	9,869,892	39,177,455	1,186,626	30.75 (5)	303,499,179
Nuclear											
Surry	84,587,007	14,117,079	5.99	15.7			14,117,079	7,679,153	1,216,094		
North Anna	91,232,300	14,096,591	6.47	15.7			14,096,591	7,827,546	1,214,887		
Total Nuclear	175,819,307 (4)	27,914,622	6.30	31.0			28,213,670	15,506,699	2,430,980	6.30 (5)	177,746,123
Heavy Oil	0	0	0.00	0.0	0.0000	59,152,510	0	6,716,689	138,525	0.00 (5)	0
CC & CT (2)	995,568,789	36,825,319	27.03	40.9	0.6018	59,152,510	35,598,690	69,750,846	2,912,060	27.03 (5)	962,232,591
Hydro	0	4,319,137		4.8			4,319,137	0	378,644		0
Solar	0	97,562		0.1			97,562		7,585		
Power Transactions											
NUG Fuel (6)	59,241,654	3,728,474	15.89	4.1	0.0609	59,152,510	3,604,281	7,998,059	367,450	15.89 (5)	57,268,351
PJM Purchases	338,418,531	10,427,002	32.46	11.6	0.1704	59,152,510	10,079,706	21,462,163	223,702	32.46 (7)	327,146,714
Marketer Percent Adj to 71%											(30,370,894)
NUG Expense Adj (8)											57,015,416
NCEMC Expense Adj (9)											(23,683,023)
Greensville Adjustment (10)											(22,684,198)
Adjustments											
Sales for Resale	(5,522,163)	(253,812)		-0.3			(253,812)	0	(33,308)		(5,522,163) (3)
Net	392,138,023	13,901,664	28.21	15.4			13,430,175	29,460,222	557,844		359,170,204
Pumping	0	(3,229,818)		-3.6			(3,229,818)	0	(383,829)		0
Energy Supply	1,877,499,620	90,038,445	20.85	100.0			88,201,746	160,611,912	7,228,434	20.44	1,802,648,097

NOTE: ALL VALUES REFLECT COMPANY'S OWNERSHIP OF NORTH ANNA, CLOVER AND BATH COUNTY

(1) Coal includes wood and natural gas steam generation
(2) CC & CT includes jet oil, light oil and natural gas generation
(3) Fuel expense is equal to 12 months ended June 2019
(4) Nuclear expense excludes interim storage
(5) Fuel expense rate based on weather normalized fuel expense
(6) NUG fuel includes expenses related to dispatchable NUGs at 78% for those units subject to the marketer percentage
(7) Purchases include 71% of the fuel expense and the impact of the FTRs
(8) NUG Expense adjustment includes the impact of statuatory changes to NUG capacity and fuel expense
(9) System Expense adjustment includes the impact of the end of the NCEMC contract in March 2019
(10) System Expense adjustment includes the impact of the remainder of the year of operations for Greensville.

I/A

DOMINION ENERGY NORTH CAROLINA
ENERGY AND FUEL EXPENSES
Docket No. E-22, Sub 562
Normalized and Adjusted Energy and Fuel Expense based on Actual 12-Months Ended June 2019
(Company Ownership Only)

Company Supplemental Exhibit BEP-1
Schedule 1

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)
	12-Months Ended June 2019							June 2019			
	Expense ($)	Generation (MWh)	Rate ($/MWh)	Supply (%)	Ratio of Coal Oil, CT & CC NUG & Other MWH To Total Sum	Coal, Oil, CT & CC, NUG, Other, Nuclear Adj. and Growth MWh	Adjusted Generation (MWh)	Expense ($)	Generation (MWh)	Rate ($/MWh)	Normalized & Adjusted Fuel Expense at Applicable Rate (8) x (11)
Coal (1)	329,626,242	10,291,395	32.03	11.3	0.1671	59,532,474	9,950,079	38,640,485	999,127	32.03 (5)	318,701,030
Nuclear											
Surry	86,857,325	14,084,831	6.17	15.5			13,932,840	7,679,153	1,216,093		
North Anna	88,327,543	13,998,765	6.31	15.4			14,128,653	7,827,546	1,214,886		
Total Nuclear	175,184,868 (4)	28,083,596	6.24	30.9			28,061,493	15,506,699	2,430,979	6.24 (5)	175,103,716
Heavy Oil	0	0	0.00	0.0	0.0000	59,532,474	0	0	0	0.00 (5)	0
CC & CT (2)	967,449,526	35,509,724	27.24	39.1	0.5767	59,532,474	34,331,961	78,233,786	4,004,986	27.24 (5)	935,202,618
Hydro	0	4,533,733		5.0			4,533,733	0	322,191		0
Solar		76,055		0.1			76,055		11,894		
Power Transactions											
NUG Fuel (6)	48,928,014	3,604,032	13.58	4.0	0.0585	59,532,474	3,484,495	3,416,701	207,158	13.58 (5)	47,305,190
PJM Purchases	341,059,652	12,169,620	28.03	13.4	0.1976	59,532,474	11,765,998	174,907	196,459	28.03 (7)	329,747,945
Marketer Percent Adj to 71%											(30,607,918)
NUG Expense Adj (8)											44,736,521
NCEMC Expense Adj (9)											(23,683,023)
Greensville Adjustment (10)											(39,997,000)
Congestion removed from Base											31,820,071
Adjustments											
Sales for Resale	(4,947,928)	(472,518)	10.47	-0.5			(472,518)	0	(280,934)		(4,947,928) (3)
Net	385,039,738	15,301,134	25.16	16.9			14,777,975	3,591,608	122,683		354,373,859
Pumping	0	(3,038,494)		-3.3			(3,038,494)	0	(238,864)		0
Energy Supply	1,857,300,374	90,757,143	20.46	100.0			88,616,747	135,972,578	7,652,996	20.12	1,783,381,223

NOTE: ALL VALUES REFLECT COMPANY'S OWNERSHIP OF NORTH ANNA, CLOVER AND BATH COUNTY

(1) Coal includes wood and natural gas steam generation
(2) CC & CT includes jet oil, light oil and natural gas generation
(3) Fuel expense is equal to 12 months ended June 2019
(4) Nuclear expense excludes interim storage
(5) Fuel expense rate based on weather normalized fuel expense
(6) NUG fuel includes expenses related to dispatchable NUGs at 78% for those units subject to the marketer percentage
(7) Purchases include 71% of the fuel expense and the impact of the FTRs
(8) NUG Expense adjustment includes the impact of statutory changes to NUG capacity and fuel expense
(9) System Expense adjustment includes the impact of the end of the NCEMC contract in Dec 2019
(10) System Expense adjustment includes the impact of a full year of operations for Greensville.
(11) Purchased power expense adjusted for the impact of the removal of congestion expense from Base Rates

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EXAMINATIONS

EXHIBITS

P R O C E E D I N G S:

CHAIRMAN FINLEY: Let's go back on the record. Mr. Burnett.

MR. BURNETT: Thank you, Mr. Chairman.

MICHAEL MANESS and JAY LUCAS,

having previously been duly sworn, were examined and testified as follows:

CONTINUED CROSS EXAMINATION BY MR. BURNETT:

Q. Good morning, again.

MR. BURNETT: Mr. Chairman, at this time I would like to hand out what I would like to mark as DEP Lucas Cross Exhibit Number 4, please.

BY MR. BURNETT:

Q. Mr. Lucas, what I have handed out and marked as DEP Lucas Cross Exhibit 4 is a copy of your deposition in this matter. Do you need a copy, sir, or do you have one with you?

A. (Jay Lucas) I've got one.

CHAIRMAN FINLEY: We will mark it as Exhibit 4.

(Whereupon, DEP Lucas Cross Examination Exhibit Number 4 marked for identification.)

BY MR. BURNETT:

Q. Mr. Lucas, we left off yesterday with your second recommended category of cost disallowances.

You agree with me that the second category of disallowance that you recommend are costs to remedy environmental violations, as you say, where the costs exceed what CAMA would have required in the absence of the environmental violations; isn't that right?

A. Yes.

Q. And under the second category of recommended disallowance, at least in part, you suggest that cost for installing water extraction wells at our Sutton facility should be disallowed; isn't that right?

A. Also, when we did the calculations, we found extraction in treatment at H.F. Lee Plant and Asheville Plant. So those costs also we removed.

Q. That's right. And your suggested removal of those extraction wells is based on your theory that they are in excess or incremental to what CAMA or CCR would have required; is that correct?

A. That's correct.

Q. Yet you agree with me, though, that you have not conducted a site analysis under CAMA or the CCR rules for any of those sites, including Sutton, to determine whether those same extraction wells would have been required for compliance under CCR or CAMA, have you?

A. Well, to back up a little bit, Duke Energy would not have had to extract and treat clean groundwater. The Company contaminated groundwater, and as we established yesterday, the Company had over 2,800 groundwater violations. Also, the Company agreed to this extraction treatment as part of the Sutton settlement. I know that we talked yesterday, and we were talking about cash settlements, but there is a lot more to the case. In the Sutton settlement I will see -- I will just quote it here. It's just one paragraph. "Duke Energy will commence installation of extraction wells on the eastern portion of the Sutton Plant property where data show constituents associated with ash basins at concentrations over the 2L standards."

Q. Mr. Lucas, I appreciate that that is your theory of disallowance, but I will ask you my question again.

You will agree with me that you have not conducted a site analysis under CAMA or CCR --

A. That I --

Q. Can I finish my question?

A. Oh, I'm sorry.

Q. -- at the Sutton site or any other sites where you take issue with extraction wells; isn't that correct?

A. That's correct. We had two sources for our data. We had data provided to the Public Staff by Duke Energy Progress, and also, we had discussions with the groundwater section regarding these problems.

Q. In fact, Mr. Lucas, when it comes to calculating an actual cost that you claim the Company should be denied under your second category of disallowance, you admit that you have only looked at this issue, using your words, to a limited degree; isn't that right?

A. That's correct. And that sort of goes into my proposal for the sharing of costs of -- the costs and the problems are so vast, we can't assess everything that occurred. Through data requests, the Company's provided over half a million pages of data. There is no way I could have reviewed over half a million pages of data.

Q. In fact, Mr. Lucas, throughout all four of your proposals for disallowance for coal ash costs in this matter, you don't really attempt to quantify actual costs that you think the Company should be disallowed; isn't that right?

A. No. I talk about the $88,000 for litigation costs and the $6.7 million to extract and treat groundwater. I took those from -- the extraction of treatment of groundwater, I took that data from the Company's E-1 Item 10, Section NC-1800, and that's where the Company provided most of its coal ash costs. And the Public Staff sent a data request, and the Company came back with an itemized list of all the entries. There was about 27,000 entries. I scanned through there and found what were extraction and treatment costs. And I go back to my premise that the Company would not have had to extract and treat clean groundwater. I mean, the Company is responsible for doing that kind of cleanup.

MR. BURNETT: Mr. Chairman, at this time, I would like to hand out a package of demonstrative exhibits. There are three of them. I do not intend to mark them as cross exhibits or enter them into evidence. They will be citations of -- testimony citations or deposition citations in the hope of moving my questioning along.

BY MR. BURNETT:

Q. Mr. Lucas, do you have that package in front of you?

A. Yes, I do.

Q. If you would turn to Demonstrative Exhibit Number 3 for me in that package.

A. (Witness peruses document.)

Q. And I will go through these site by site, and you can have the references there in front of you, again, with the hope that we don't have to hunt and peck for each one of these in your testimony and your depositions, but you admit that you have not attempted to quantify the amount of coal ash costs for which you contend the Company has some degree of culpability; isn't that right?

A. Not the total amount. I know I just talked about the $88,000 litigation cost and $6.7 million extraction of treatment, but the other costs that we are talking about, the shared cost, I assume that's what you are talking about?

Q. I'm talking about any cost that you allege, other than those that you have, in fact, identified with specificity.

A. Yes. That's correct. I believe there is a shared responsibility.

Q. Right. And related to what you call in your testimony, quote, 200 distinct seeps at the Company's basins, you have not calculated any specific cost that you believe should be disallowed related to those, have you?

A. No. But those seeps were part of the lawsuits that DEP [sic] filed against the Company; had unpermitted seeps, which is a violation of state law, DEQ filed a lawsuit, and part of the resolution of that lawsuit was for the Company to comply with CAMA. And another part of my testimony, and I still adhere to this, is that the Company -- the Company's actions were a contributing factor to the creation of CAMA. So therefore, the Company, indeed, caused this -- or was -- had a contributing factor to making this law be created, and that did satisfy the requirements of the DEQ.

Q. Mr. Lucas, you have not calculated any specific costs that you contend should be disallowed due to alleged dam safety issues at the Company's sites, have you?

A. That's correct.

Q. And regarding an August 22, 2016, dam safety order that you attach as Exhibit 3 to your testimony, you did not calculate any specific cost that should be disallowed due to that exhibit, did you?

A. No. I was shown an exhibit where the Company had problems. That dam safety order came out in 2016. That was two years after the Dan River spill, and the DEQ was still finding problems at the Company's impoundments.

Q. Mr. Lucas, regarding what you call in your testimony, quote, other dam safety requirements outside of CAMA, you have not calculated any specific cost that should be disallowed under whatever those requirements are, have you?

A. No, I haven't.

Q. And you have not calculated any specific cost that you believe should be disallowed for the Company's alleged failure to comply with NPDES permits; isn't that right?

A. That's correct.

Q. And regarding several lawsuits that you list out on Exhibit 8 to your testimony, you admit, do you not, sir, that you are not sure whether those costs are in the Company's rate case request or not; isn't that right?

A. Oh, I believe they are. I mean, the

Company's asset retirement obligation, that request, I talked about the section NC-1800, I believe was, like, $236 million. And like I said, there were 27,000 entries that made up that money. I mean, there is a lot of costs that the Company is trying to put in rates regarding coal ash -- coal ash remediation.

Q. Mr. Lucas, let's turn to page 62 of your deposition, which I marked as DEP Lucas Cross Exhibit 4, and if you will let me know when you are there.

A. (Witness peruses document.)

Okay. I'm on page 62.

Q. And you will see there, Ms. Dinsmore asks -- starts to ask you on line 1 of page 62 of Cross Exhibit 4. She shows you Lucas Exhibit 8, which I just asked you about, and then she asked you the question, "You're not sure whether those costs are part of this rate recovery case?" Your response, "I am not sure. Some of those costs could be in the E-1. I might not have been able to identify them."

Isn't that what you said?

A. That's correct.

Q. And at least one of the reasons that you chose not to include specific cost recommendations for disallowances in this matter is, to use your words, quote, it would be too difficult to do so; isn't that right?

A. Yes. It goes back to my equitable sharing. And your witness, Dr. Wright, stating Friday -- find his words -- he says it's difficult -- and this is not an exact quote. This is pretty much what he said. It is difficult to make an engineering estimate on costs for past improvements. So if the Company had taken steps to prevent groundwater violations years and years ago, those costs would be in rates today. But Duke Energy did not take those steps. Those costs are not there. But to my equitable sharing recommendation, looking at what costs the Company incurred to remediate the violations, and also as part of the settlements to make environmental corrections, those costs have to be taken into account. We believe the customers don't bear full responsibility of all that environmental remediation.

Q. Mr. Lucas, rather than conducting what we just established you think is a difficult analysis to determine actual cost that should be disallowed, you relied on what you call -- and I will use your words again -- quote, the simplest way to determine disallowances in this case, which leads to your equitable sharing support; isn't that right?

A. Yeah. There is nothing wrong with a simple solution.

Q. Mr. Lucas, you would agree with me that simplicity is not a cost recovery standard that this Commission uses for recommending or approving disallowances, wouldn't you?

A. No. Simplicity -- I mean, that's not the reason I recommend equitable sharing. The reason I recommend equitable sharing, it's the only feasible method to figure out what costs should be borne by the ratepayers.

A. (Michael Maness) May I elaborate on Mr. Lucas' answer?

Q. No.

MR. BURNETT: If the choice is mine, Mr. Chairman.

CHAIRMAN FINLEY: When you have a panel, it's appropriate for Counsel to ask the particular witness a particular question. That does not prevent your lawyer from asking you a question in redirect. You can leave the question with Mr. Lucas.

THE WITNESS: (Jay Lucas) I'm sorry. Go ahead.

BY MR. BURNETT:

Q. Mr. Lucas, let's go ahead to your third recommended proposal for disallowance of cost, which is the exclusion of cost required to be excluded under probation conditions of Duke Energy's federal plea agreement.

A. Okay.

Q. You take no issue with the Company's contention that all of these costs have already been excluded from the Company's rate case request in this matter; isn't that right?

A. That's correct.

Q. All right. So we will move along to your fourth and final proposal for disallowance, what you call -- and I realize this is in support of Mr. Maness' equitable sharing proposal, but you contribute support for that, so I'm not going to call it your theory, but your contribution; is that fair enough?

A. That's fair.

Q. Okay. You agree with me that this Commission has historically based disallowances on some degree of utility fault attributable to specific decisions that constitute mismanagement; isn't that right?

A. That's correct.

Q. Mr. Lucas, would it surprise you to learn that, in your testimony, you make at least six references to instances where you admit that the Company has not been found to have been imprudent, but nonetheless, you recommend a disallowance via your support of the equitable sharing proposal?

A. Yeah. I will explain. Prudence analysis and rate recovery analysis are two different things, and I would like to give an example. Say the Company transformer broke and spilled oil. It's prudent for the Company to clean up that oil quickly and efficiently, and there would be costs associated with that spill of oil. Now, rate recovery analysis is a second step. If the Company had been negligent and had not maintained its transformers, and that results in an oil spill, Public Staff might say, well, that's Company fault. Company has to bear that cost. The other end of the spectrum would be, what if it's force majeure? What if there had been a storm that broke that transformer and spilled that oil? If -- it may be considered part of storm costs. So prudence analysis and cost recovery analysis are two different things.

Q. Mr. Lucas, if you would take a look at Demonstrative Exhibit 1 that I have handed out.

If you would agree with me that this is a fair citation and generally a fair experiment description of your prefiled testimony in this matter, I could avoid at least six questions to you, as long as you think I have fairly and accurately made a citation and characterization.

A. Please give me a moment.

Q. Yes, sir.

A. (Witness peruses document.)

Some of this looks a little bit taken out of context, but let's go with your questions.

Q. Well, you would agree with me, Mr. Lucas, that the Commissioners can read your prefiled testimony and draw whatever conclusions they wish on context?

A. That's correct.

Q. Okay. I will just go ahead and move along then.

You would agree with me, Mr. Lucas, that the best practice for making recommendations for disallowances is to wait until the full facts surrounding an issue are known; isn't that right?

A. That's usually ideal, but we rarely can get all full facts. We have to make decisions on the facts that we have at the time.

Q. And, in fact, in your summary that you read to the Commission yesterday on page 2, you seem to take issue with the use of speculation and "what if" scenarios as a basis for recommending disallowances; did I understand you correctly?

A. (Witness peruses document.)

Q. Top of the page of page 2, sir.

A. I see. Yes. So that's right, speculative. If the Company had installed -- for example, had installed liners when it constructed the ash basins, it's too difficult to go back in the past years and figure out -- I said liners. There are various types of liners. What kind of costs could have been in past years, and since the Company did not make those expenditures, it's speculative to come up with a dollar amount as to what they should have been.

Q. Mr. Lucas, notwithstanding your apparent distaste for speculation and "what if" scenarios as a basis for cost recovery, isn't it true that you have at least 10 instances in your testimony where you draw support for the equitable sharing proposal based on the events that you admit may have never happened or that may never happen in the future?

A. (No response.)

Q. We could take a look at Demonstrative Exhibit 2, if that gives you context.

A. Can you state your question again, please?

Q. Yes, sir. Would it surprise you to learn -- I will ask it that way -- that there are at least 10 instances in your testimony where you draw support for the equitable sharing concept based on events that you admit may have never happened or that may never happen in the future?

A. I disagree. Again, I think some of these are taken out of context. Like your second one, "Settlements may indicate probable violations." Well, we have gone back and established there were over -- definitely over 2,800 groundwater violations. Let's see. Okay. I talk about some things that could occur in the future. You don't number these, but take a look at the fourth bullet. Since you provided this to the Commission, I know you are not having this as a cross examination exhibit, but I feel like I need to answer them.

Q. Yes, sir. Take your time.

A. Yeah. This is in my prefiled testimony as I filed October 20th, but then I came back with my revised exhibit. Had to come back and -- we were -- just weren't sitting on our hands in this analysis. A lot of this data we didn't -- a lot of this information we didn't get back from DEQ until October, and we had to analyze it, and we weren't able to finish that analysis before filing. And then when I filed my revised testimony, I come back and say -- I know you got this "may be" data. Well, then I come back in my revised and there is definitely data -- there are definitely 2,800 -- definitely 2,800 groundwater violations. And I say, "Yeah, there appear to be extensive violations NPDES permits." That's data I took from the Department of Environmental Quality.

(Witness peruses document.)

Q. Mr. Lucas, I'm sorry. I don't want to interrupt you at all. You take all the time you need. If you'll just let me know when you've completed your answer. I just don't want to jump in and interrupt.

A. Oh, yeah. Sure. Sure. I will let you know when I'm done.

(Witness peruses document.)

I mean, I stand by what -- we were talking about Demonstrative Exhibit 2. I stand by these statements.

Q. Thank you, sir. Mr. Lucas, my next topic that I would like to discuss with you involves your assertion that the State's 2L groundwater rule creates what you call an effective, quote, strict paradigm in North Carolina; are you familiar with that?

A. Yes.

Q. You do realize, do you now, sir, that the term "strict liability" is a legal term; do you not?

A. Yes.

Q. And you are not a lawyer; isn't that right, sir?

A. That's correct. But, I mean, my testimony was developed -- I mean, I worked with our Public Staff's attorneys, and I worked with our Public Staff accountants to develop this testimony. So I worked with them to develop some of the words in my testimony.

Q. I'm glad you raised that, Mr. Lucas, because, while I see two instances in your testimony where you talk about advice your legal counsel gave you, specifically page 60, lines 20, and page 70, lines 13, I did not see any similar notations showing that you had received advice from your legal counsel on whether a 2L violation does, in fact, create a strict liability paradigm.

A. That's true. I believe that. I mean, I believe it does create a strict liability, and I want to explain why. If you go to my Lucas Exhibit Number 2, this is regarding groundwater violations. And the 2L rule says that whoever creates a violation has to implement an approved corrective action plan. It doesn't say you may implement it or you -- we'll talk to you, and maybe. It says you have to implement a corrective action plan, and I think that creates a strict liability.

Q. Just to be clear, though, Mr. Lucas, you're not rendering any legal opinions in your testimony or here today, of course; you will leave that to the lawyers to brief; isn't that right?

A. I'm not rendering a legal opinion, but the requirement to implement an approved correction action plan when there is an environment violation I believe is a strict liability. I mean, I believe that.

Q. Okay. Under this theory, Mr. Lucas, you contend that, if an electric utility allows a contaminant to reach the groundwater, that is automatically mismanagement; isn't that right?

A. Okay. Sorry. I have to flip back to my deposition now.

(Witness peruses document.)

I will just -- I will just read the entire question and answer. This is top of that -- starting at the top of the page 80, and this is the attorney that was asking me questions, and she asked me, "So, is it your opinion that the fact of groundwater contamination means there is mismanagement?" My answer is, "It could be. It could be the result of mismanagement of an ash basin." Back to her question, "It could be. Is it necessarily the result of mismanagement?" "Yes. If the electric utility is responsible for contaminants in the groundwater, that's mismanagement."

Q. Thank you, Mr. Lucas. Your read is actually better than my slide to make that point in context. I appreciate that.

You admit, though, don't you, that constituents from coal ash being in groundwater from ash basins is a national issue that's not unique to Duke Energy; isn't that right?

A. I believe there have been problems at other utilities, and to some extent, it is a national issue.

Q. You contend that the Company could have avoided the impacts of this alleged strict liability paradigm if it had retrofitted its ash basins with impervious bottom liners or dry ash stacking in the 1970s; isn't that right?

A. No, I don't -- I don't contend that. I don't -- don't recommend any specific technology to be implemented any certain year. I believe the Company had a duty, though, to prevent environmental violations, and it failed to do so. So it bears responsibility for correction of those violations.

Q. Well, let's take a look at your deposition testimony, Mr. Lucas, if you would. Let's go to page 81.

A. Okay. I'm there.

Q. Let's look at line 16. "Is there anything about the design of basins, themselves, rather than the operation or management that could have resulted in the groundwater exceedances?" "Yes." "Okay. Can you tell me about that?" "Not having impervious barriers could be a problem." Do you see that?

A. That could be one problem, yes.

Q. And you see on page 82 of your deposition, starting at line 7, where you testify, "I believe Duke Energy Progress should have brought the ash basins up to modern standards. Those ash basins were built decades ago. The Clean Water Act of 1972, the Resource Conservation Recovery Act of 1976, more and more environmental awareness was coming about, and I believe Duke Energy Progress, at that time, certainly should have been aware that there were potential problems that could have arisen from ash basins and causing groundwater problems." "Question: And when do you believe DEP should have taken those steps?" "In the 1970s." Do you see that there?

A. Yes. Let me finish answering the question.

Q. Yes, sir.

A. I know this part of my deposition, she's asking me questions about steps the Company could have taken. That's not really the premise of my testimony. I don't say the Company should have used -- absolutely used one type of technology at any particular year. The premise of my testimony is, somewhere, at some time, the Company should have prevented groundwater problems, it should have prevented unpermitted seeps, and it somewhere had -- somewhere, at some time, had the responsibility to prevent contamination of groundwater.

Q. Well, Mr. Lucas, let's look at page 61 of your prefiled testimony. Go to line 8. Just let me know when you are there, please.

A. (Witness peruses document.)

I'm there.

Q. You say there, don't you, sir, "For example, most violations could have arguably been avoided by taking a different approach to ash management in the earlier years, such as lining the ash basins with impervious materials or creating dry stack lined landfills"; isn't that right?

A. That's correct. And I see there I use the word "arguably" it could have been avoided by taking a different approach such as lining the basins. And I'm just opining to some types of technology, and lining an ash basin could take many permutations. I mean, it could be a clay liner, it could have been a plastic liner. I believe your witness opined on doing a concrete liner. And that's the premise of my equitable sharing. We can't go back in time and say, oh, they should have put in a clay liner in 1978 or done dry ash stacking in the 1980s. I mean, that's impossible to go back and put all these "what ifs" together and say exactly here's what they should have done, and here's what would have been the cost, and that cost would have been in the rates today for customers. That's why I sort of hedge when I say arguably could have been avoided, and just give examples of what could have been done.

Q. Mr. Lucas, let me ask you this question, hopefully a direct one, if I ask a good one.

From 1920 until 2014, with respect to my Company's ash basins in this state, what should we have done differently and when should we have done it?

A. Should not have contaminated groundwater, should not have allowed unpermitted seeps, and I'm going back to the basis of my testimony. I can't say exactly what year or exactly what technologies. I know I keep repeating this. And that difficulty is why I'm recommending an equitable sharing. The Company had a responsibility to protect groundwater, had a responsibility to not allow unpermitted seeps, and a responsibility to comply with its NPDES permit limits. In many cases it didn't. And DEQ brought lawsuits about -- not seeking settlements for cash, but they brought lawsuits because of groundwater violations and those seeps. I can't give you the exact year. That's -- it's the difficulty. I mean, I talk about this in my testimony. The difficulty of going back and determining, so I can't give you specific technology or a specific year.

Q. I see. So along that timeline, again, 1920 to 2014, you can't tell me any specific basin modifications I could have made, anything I should have done differently with handling or managing that ash at any given time?

A. There are lots of potential options. I'm not -- I feel like you keep asking me the same question. I'm not recommending any specific technology on any certain time. The Company -- there are steps the Company could have taken. That's why I give examples. Like I give examples such as lining the ash basins or creating dry ash handling. Somewhere along the line the Company should have taken some kind of action to not contaminate the groundwater. And looking at it another way, the Company can't sit there and claim, in order for us to generate electricity, there are no reasonable steps we could have done to prevent contamination of groundwater, and therefore prevented contamination of people's drinking water. I don't think the Company can take that position.

Q. But you would agree with me that it would be helpful if someone could simply tell me what I should have done and when I should have done it; isn't that right, with specificity?

MR. DROOZ: Asked and answered.

CHAIRMAN FINLEY: Overruled.

THE WITNESS: But that's going back to the past. Somebody could have gone back and said what you should have done back at a certain time, and that's -- you could be talking about the prudence, and I can't go back and -- I can't go back and tell you exactly what would have happened -- what you should have done at a certain time. I'm not sure what good it would have done for somebody to tell you, oh, 40 years ago you should have put in a clay liner at Asheville and Sutton, put in a concrete liner at the H.F. Lee plant. I mean, you just can't go back and do that kind of assessment.

BY MR. BURNETT:

Q. We have heard lots of discussion in this case, Mr. Lucas, about when the industry knew or should have knew that coal ash basin water making contact with groundwater was an issue, and we have had lots of discussion over whether people should have been concerned about that at given times or done things at given times; do you recall all that?

A. Yes.

Q. I have heard some indication that that date may be, in the intervenor's perspective, sometime around the 1980s; do you agree or disagree with that?

A. I mean, certain more -- the amount of information was changing over time. Give me a moment. Let me find a document.

(Witness peruses document.)

I have got a letter written by the North Carolina Department of Natural Resources and Community Development. That's the predecessor to the DEQ. And this is written August 16th of 1978. But I can make this a late-filed exhibit. And this is regarding Mayo project. Duke Energy was getting ready to build the Mayo Power Plant. I will just read one paragraph. This letter is to the Corps of Engineers, but the Company was copied on this letter. And it says, "The Company shall provide such testing as necessary to assure that pollutants are not discharged to the groundwaters, and thereby to the downstream point of the Crutchfield branch in violations of the provisions stated above." So this is 1978. Looks like DEQ was concerned about ash basins and their effects on groundwater.

Q. Sir, the issues in that letter that you just referenced, do you believe that these were serious issues?

A. Yeah, I believe -- yeah. Not creating groundwater pollution or contaminating people's drinking water is a serious issue.

Q. Do you think, at that time, that these issues put in jeopardy the health of the environment of this state?

A. I said there is a high possibility. I mean, we talked about some of these ash basins being decades old. The first groundwater violation wasn't found, according to what we have, until 1990. It's not like those ash basins were built in the 1950s and didn't create any problems; we just don't know. I mean, we started finding problems. Like with the Sutton test, it failed -- had a groundwater violation for chloride in 1990. I can't go back and say exactly when those basins would have contaminated groundwater. I don't believe the ash basins were perfectly sound and not contaminating groundwater for decades, and suddenly, once we start looking, oh, they did start contaminating groundwater.

Q. At that time that you referenced in the letter in 1978 that you just read, do you believe the issues that you reference presented a real and present harm to human health and safety?

A. I'm sorry, say that question again, please.

Q. Yes, sir. In the 1978 letter that you just referenced, do you believe that the groundwater issues referenced in that letter presented a real and present danger to human health and safety?

A. They could have. I mean, if they were downstream -- excuse me, if they were downgradient wells from homeowners, yeah, it could have presented a danger.

Q. If we are to believe some of the testimony that we have heard here in this proceeding, that coal ash water coming into contact with the ground presented hazards to health and safety and to the environment of this state that were real and present until as early as the 1978s -- '78, do you have any explanation for why the federal EPA or the state DEQ or its predecessor agency never came to my Company and said, "Stop. Don't use these unlined wet ash basins anymore"?

A. It's not necessarily their responsibility. It's the Company's responsibility -- overall, it's the

Company's responsibility to not create pollution problems. You don't have to wait for someone else to tell you not to.

Q. I agree, sir, but you would agree with me that a regulator charged with protecting the environment, this country, and this state, would also intervene and prohibit a practice if they felt necessary to do so; isn't that right?

A. If they had the staffing level and they had the data, they would intervene, yes.

Q. Thank you, sir. Nothing further.

CHAIRMAN FINLEY: Redirect?

MR. DROOZ: Yes.

REDIRECT EXAMINATION BY MR. DROOZ:

Q. Mr. Lucas, just on that last question, since we are there, do you know when the 2L groundwater standards were adopted in the state of North Carolina?

A. 1979.

Q. And did Duke Energy Progress and its predecessor company have an obligation to comply with those standards?

A. Yes.

Q. And was that obligation in effect without regard to whether there was any imprudence or negligence on their part?

A. Yeah. The two standards don't talk about negligence and prudence. They just say, here are the standards, and everyone must obey them.

Q. If you would, please turn to your revised Exhibit 5. You were asked some questions about what number of NPDES violations exist, and you had a larger number in your initial Exhibit 5; is that correct?

A. That's correct.

Q. And why did you file a Revised Exhibit 5?

A. For two reasons. First, in my original exhibit, I was concerned that some of those NPDES permit violations would be groundwater exceedances that might not later prove to be violations. A second reason I did is, my original exhibit had some groundwater data, and I wanted to really separate surface water violations and groundwater violations. That's why I have surface water violations in Exhibit -- my Revised Exhibit Number 5, and only groundwater violations in my Revised Lucas Exhibit Number 6.

Q. What was your source of data for coming up with these numbers of NPDES violations?

A. Took those from the monitoring reports of the

Department of Environmental Quality.

Q. And at the top of those reports, do they label them as violations?

A. Yes, they do. And for each parameter there are several columns on each report, and three of those columns reference a violation. So, really, "violations" is written four times on each page.

Q. And after you read the rebuttal testimony of the Company, did you realize that not all those numbers were necessarily violations?

A. That's correct.

Q. And when we look at your Revised Lucas Exhibit 5, having gone through that BIMS data, what is the number of violations you have determined that are truly violations and not just falling under the label?

A. 458 violations.

Q. What type of violations are those?

A. These are NPDES permit violations.

Q. Would that include unpermitted seeps or unlawful discharges?

A. No. This table does not include unpermitted seeps because they don't have an outfall -- they don't have a legal outfall point to be monitored.

Q. Are there, in addition to these NPDES violations, also unpermitted unlawful seeps at Duke Energy Progress coal ash basins?

A. Yes. In the joint factual statement that the Company agreed to, there were -- the Company agreed that there were over 200 unpermitted seeps.

Q. Let's turn to your Revised Exhibit 6 now. And there has been considerable discussion about the difference between an exceedance of 2L groundwater standards and a violation of 2L groundwater standards.

Have you done an analysis here that shows that difference?

A. Yes. My Revised Lucas Number 6, I separate what were -- separate between violations and exceedances, and I show that there were over 2,800 actual violations.

Q. Can you tell us which line and column that is on this exhibit?

A. Okay. On Revised Lucas Exhibit Number 6, second column from the right, down at the bottom, it's 2,857 violations.

Q. And what is the data source for this?

A. This is response to a Public Staff data request. The Company provided this data to us.

Q. Does the Company also report this data to

DEQ, if you know?

A. Yeah. It does have to report groundwater data, and those do also appear on the monitoring reports.

Q. Okay. Going back to your original exhibits, if you will look at Exhibit 7.

A. (Witness peruses document.)

Okay. I'm there.

Q. Okay. And what is the source of data for this exhibit?

A. This data was provided by consultants that were hired by the court-appointed monitor. In the federal criminal case, as a condition of probation, the court had a court-appointed monitor that had to hire a consultant to do audits of groundwater problems created by the Company.

Q. And in those audits, did they find exceedances of 2L standards?

A. They found exceedances of 2L standards that were caused by ash basins.

Q. And is that occurring at every single Duke Energy Progress plant in the state?

A. Yes.

Q. Okay. You were asked some questions about

settlements and lawsuits.
Is it your position that a lawsuit alleging environmental violations, by itself, would be evidence of the violations?
A. No.
Q. And why is that?
A. Anyone can file a lawsuit at any time, but the lawsuits that I reference in my Lucas Exhibit Number 8 were the result of true groundwater violations. That's why the Public Staff did its own investigation and determined whether they were true groundwater violations.
Q. What information do you have that supports that, apart from the allegations in the lawsuit?
A. The Company's response to our data request. We took data from the Company's information, and that's how we developed our number of violations.
Q. What type of data?
A. This is groundwater monitoring data.
Q. Turning to the settlements in the cases involving the Sutton plant where the Company paid out settlement amounts, does the mere fact that there is a settlement, by itself, establish that there has been a violation?

A. No.
Q. And what information did you draw on to come to the conclusion that there were violations?
A. Looking at the Company's records, and also, in the Sutton settlement, the Company agreed to do extraction and treatment of groundwater at three of its DEP power plants. The Company wouldn't have had to extract and treat clean groundwater.
Q. Did you examine any groundwater exceedance data that supported the allegations?
A. Yes. That was in the response to that data request I referred to. That's where I got the data on violations.
Q. Bear with me just a moment here.
The NPDES permit requirements and the 2L groundwater standards, did they exist before CAMA and the CCR rule were adopted?
A. Yes.
Q. And if there is a violation, say, of groundwater standards, does 2L require the Company to take corrective action?
A. Yes, it does.
Q. Does CAMA require the Company to take corrective action?

A. Yes, it does.
Q. If CAMA had never been passed, would the Company have had to remedy, through corrective action, the 2L violations that existed?
A. Yeah. That's a requirement in the rules.
Q. When CAMA came into play, did it require closure of five out of seven of the basins?
A. Yes.
Q. Excuse me, basins at five out of seven of the plants?
A. Yes.
Q. Okay. And is that, in effect, remedying the 2L violations?
A. Yeah. Closure of the basins would have certainly helped remedy the 2L violations.
Q. If there had been no CCR rule and CAMA, would the Company still have had to remedy the violations?
A. Yes.
Q. Is it possible that DEQ or legal judgments would have required different remedies than closure of the ash basins?
A. It could have, yeah, definitely.
Q. Is that something that it's just impossible to know because it's a scenario that did not happen?

A. Yeah. It didn't happen. Can't speculate, exactly, what the conclusion would have been without CAMA.

Q. In your opinion, would it be just and reasonable rate setting to charge consumers 100 percent of the cost of remedying environmental violations at Duke Energy basins?

A. No.

MR. DROOZ: That's all on redirect.

CHAIRMAN FINLEY: Questions by the Commission? Mr. Clodfelter.

EXAMINATION BY COMMISSIONER CLODFELTER:

Q. Mr. Maness.

A. (Michael Maness) Yes.

Q. You get a question.

A. Right.

Q. In your summary, you say that, for purposes of doing your jurisdictional allocation, you use the energy allocation factor to allocate the system level of coal ash cost of North Carolina operations rather than demand-related production costs?

A. Yes.

Q. I'm curious about something. How are -- for your jurisdictional allocation purposes, how are the costs of storage of spent nuclear fuel allocated?

A. I believe that there are various allocation factors. You could have some spent nuclear fuel capital investments that might be allocated by the demand factor. Then you have other, sort of, fuel-handling-type expenses that I expect would be allocated by the energy factor.

Q. Can you tell me more about how its actually done in North Carolina?

A. No. I would probably have to do some more research to determine the technical details of which ones are energy and which ones are demand, but I would be willing to do that if necessary, as a late-filed exhibit.

Q. For purposes of treating the system-level coal ash costs, you allocated 100 percent of that on an energy allocation factor basis?

A. Yes, because the majority of these costs are -- deal with the actual handling and moving of the coal ash, and the original coal, when burned, is allocated by the energy factor.

Q. Right. I will think about whether I want to ask you to do the analysis on the nuclear, but at one point in time, there was a charge paid by companies in order to pool storage of spent nuclear fuel; is that correct?

A. Yes.

Q. And how was that charge calculated? Was it calculated as a -- how was the rate established or the fee established?

A. Well, the federal government established the fee as so much per kWh generated at the nuclear stations. There were some lawsuits involving whether you use the kWh generated or kWh sold, but it was definitely kWh.

Q. It was an energy pricing?

A. Yes. And it was also passed through from the very -- from maybe not the original days, but somewhere along the way in the early days of the '80s, passed through to the Company's ratepayers as part of the fuel factor, and therefore, was inherently allocated according to energy.

Q. Okay. Thank you, sir.

CHAIRMAN FINLEY: Other questions by the Commission? I have some questions. Maybe quite a few.

EXAMINATION BY CHAIRMAN FINLEY:

Q. Mr. Maness, I'm trying to get a handle on what are the components of the coal ash costs that are at issue here. I think there is a number of approximately $66 million having to do with historical costs and $129 million with respect to future costs. I'm just -- where can I look to see what the components of those costs are, if anywhere?

A. If you excuse me a minute and let me pull up --

Q. Sure.

A. (Witness peruses document.)

MR. DROOZ: Mr. Chairman, I will note while he's looking for that, I think at least the first number has been revised somewhat between the Company and the Public Staff.

CHAIRMAN FINLEY: I understand that there is a different number between the Company and the Public Staff, and I appreciate that.

THE WITNESS: (Witness peruses document.)

Yes. The $66 million, as I recall, and during the hearing I did some analysis for Mr. Drooz based on the final positions of the Company and the final positions of the Public Staff, and my recollection is that the difference between the two parties' positions is about $54 million on the defer and amortize piece, and the -- I believe the number that we came to, as far as what the Company's request was, considering both the amortization expense and the inclusion in rate base, was in the neighborhood of $61 million.

BY CHAIRMAN FINLEY:

Q. And what are the -- can you help me with what are the components of those numbers?

A. Well, as I said, the Company's -- excuse me one second.

(Witness peruses document.)

The total Company amount of the cost that it wishes to be amortized is approximately $444 or $445 million. I believe that the North Carolina retail portion of that, I want to say it's in the neighborhood of $230 million, but when the Company put forth what it wanted in rate base for this case, it deducted the first year of its amortization, which I believe brought the number down to somewhere in the neighborhood of $190 million.

Q. All right. Let me go about it this way. My understanding is, and I may be wrong about this, that, by and large, these costs have to do with dewatering, excavation, and removing ash from existing basins to new basins or to cap in place existing basins; am I wrong about that?

A. No. I think that's correct, yes.

Q. Are there any -- let's take the historical piece, okay?

A. Yes, sir.

Q. Are there -- is there any money in there, with respect to remediation, for anything in Dan River?

A. No. My understanding, and I think the -- Mr. Lucas and Witnesses Garrett and Moore have verified that the Dan River costs -- cleanup costs are not included.

Q. What about remedying leaking risers?

A. My presumption, since the Company has indicated that all of its ash basin costs that are in the asset retirement obligation, my presumption is that those costs are included. I would have to rely on Mr. Lucas, who has done a closer examination of the actual charges, for whether any such specific charge might be included. But our assumption is that the Company had included everything that it believed was permitted to be included in its asset retirement obligation.

Q. All right. Mr. Lucas, are the costs in the historical components that include remediation of a riser -- leaking risers?

A. (Jay Lucas) We can't tell. To answer your question, I would have to work with the Company in the E-1 Item 10, NC-1800, like I said earlier, 27,000 entries. Not all those entries are perfectly clear as to what they are. So it's possible that I could work with the Company and get that data for you.

MR. DROOZ: I may be able to shortcut us a little bit. You know we have agreed that the Cape Fear leaking risers that were identified in the federal criminal case, those costs have been excluded from rate recovery. So that is not part of the Company's request here. I think the witnesses were struggling thinking about risers at all different plants.

CHAIRMAN FINLEY: I understand.

BY CHAIRMAN FINLEY:

Q. What about remedies to dikes, having to do with vegetation or remedying anything that had been done with respect to the dike?

A. To my knowledge, those costs haven't been -- that's part of operations and maintenance, so it's not specifically a coal ash cost.

Q. What about anything to remediate the toe pools at the bottom of the dikes?

A. I'm not aware of any costs of those in the rate case.

Q. What about surface water discharges?

A. I'm not aware of any. I -- but the Company -- and go back. Are you specifically talking about coal ash costs? I mean, costs for those things you listed as part of coal ash cost?

Q. What I am asking about are, what are the components of the historical costs that are being disputed between the Company and the Public Staff; the $61 million, the $54 million, I think, historical piece?

A. Okay. I believe -- like just your last question regarding NPDES outfalls, I don't think there are any of those costs in that $54 million.

Q. All right. With respect to the prospective costs -- not the historical costs, but the prospective costs, are they primarily, again, due to dewatering, excavation, movement of coal ash from ponds and capping in place?

A. Yes. And I explain a little bit. The

Company requested $129 million, we call it a run rate. And what they did, they just took all of their coal ash cost from 2016 and presumed that was a typical year, and for 2016 it was $129 million, and said, okay, we will be spending that for years to come. That's how they developed that number.

Q. I know. I understand all that about the process, but I'm looking for the components of the costs.

A. Like you said, the ash management is overall in those costs.

A. (Michael Maness) Mr. Chairman, if I may, I do have some information, at least on 2016. I'm not going to state in any of the numbers, because some of them may be confidential, but just to give sort of the feel for the numbers, particularly that our witnesses Garrett and Moore were examining, we do have costs, I think that the number for 2016 total Company that was incurred, or maybe 2015 and 2016, and I don't believe this number is confidential, was approximately $311 million. Now, there are costs related to coal ash remediation, in general, at all of the Company's utility plants that are involved: Mayo, Roxboro, Cape Fear, H.F. Lee, Weatherspoon, Asheville, Sutton, and

Robinson. And I will just talk about some of the categories, and I don't know if those will give you exactly what you are looking for, but for example, we have costs related to base enclosure including design and permits, mobilization, site preparation, site infrastructure, water treatment and management, ash processing, construct a landfill, and cap in place, site restoration, demobilization and closing, capital expenditures related to equipment and facilities, revenues, engineering closure plans, and some Duke internal costs. For non-basin closure costs we have several different types of overheads, including government and staff budgets, inspection and maintenance, engineering and projected budget, environmental health and safety, post-closure maintenance, and certain other amounts as well.

Q. Thank you. That's helpful, thank you, Mr. Maness. Now, let me ask you -- I guess this is primarily to you, Mr. Maness -- about the mechanism -- the cost of cover in this case. Seems like to me that there are a number of mechanisms that are before the Commission. I think Mr. Lucas sort of alluded to this earlier, and I'm looking, you know, how alternatives might be to facilitate your 50/50 sharing remedy. One way would be to treat the costs as test year expenditures, perhaps normalize those test year expenditures on the theory that they are recurring costs through perhaps 2028, and just, if you wanted to apply your 50/50 sharing, just cut that in half. That would be one mechanism that comes to mind. A second one would be what I understand your mechanism to be, which is to defer with a return the cost until the next case, the next rate case, and then amortize those over now I think 26 years with no return. Then my assumption is that, in the next case, you sort of start that process all over again for new costs that have been incurred; is that basically correct?

A. Yes, sir. And the 26 years is somewhat reliant on the rate of return. So if the rate of return was different, then the number of years might be different to reach the 50 percent mark.

Q. Okay. Aren't the acts and omissions that give rise to the sharing mechanism, that we have gone through substantially and in the testimony today, based on historical events? We can look back and, for the most part, and see what has happened already, those acts and omissions; is that right?

A. That's, I believe, partially correct, and that was the point I was trying to make earlier, is that the equitable sharing is a result of both the analysis conducted by Mr. Lucas and what appears in my testimony, which is, even after you would remove all of the truly imprudent and inappropriate costs that have been demonstrated to date, which Witnesses Garrett, Moore, and Lucas have done, and even if you were to hypothesize that there wasn't any further reason in acts and omissions for an equitable sharing, the history of the Commission's ratemaking treatment of other types of large costs, such as with abandonment of nuclear and coal facilities, supports a sharing of large and unique costs between -- in some cases, between the customers and the shareholders in order to provide rates that are reasonable. And so that's part of our recommendation.

Q. I understand that is the justification for your sharing, but I'm just trying to determine how to accomplish that if the Commission should adopt your recommendation. Most of that -- setting aside for the moment the theory and what has happened with abandoned nuclear and coal plants, manufacturing gas costs -- the acts and omission that you are basing the 50/50 ratio on, for the most part, have already occurred?

A. I would say that that's -- I'm not quite sure what you mean by "acts and omissions," but I would agree that the --

Q. What I'm talking about are the things that Mr. Lucas mentions in his testimony and your other experts have identified that we have been talking about for the last week and a half.

A. Well, I do agree that that's part of it, but as I said, even if you left out specific acts or omissions of the Company and assumed everything was prudent, aboveboard, it's still likely that we would recommend a sharing of the cost between the ratepayers and the shareholders. As far as the mechanism and how the mechanism works, I guess I would say that some of the activities that we would require sharing or recommend a sharing are things yet to come when the Company proceeds along its path of cleaning up its coal ash basins.

Q. And that might change the 50/50 to something -- a greater disallowance if you found additional things in the future, that is a lesser disallowance; wouldn't that be the case?

A. Yes, sir, that's a possibility.

Q. All right. And this process -- as I

understand it, we are gonna be -- to comply with the CAMA and the CCR rules, there are going to be costs incurred through 2028; is that correct?

A. (Jay Lucas) That's correct.

Q. So we may be having this sharing mechanism if we were to adopt what the Public Staff recommends, even many years beyond 2028, right?

A. (Michael Maness) Yes.

Q. All right. Then the other method would be the DEP method, which would be defer these costs until the next rate case and then true them up. Have a deferral and an amortization and a true-up. That would be a third method, correct?

A. The DEP method?

Q. Yes.

A. Well, they are proposing, of course, the run rate, and that any difference between the run rate and the actual costs that are incurred be deferred, and then subject to consideration by the Commission in the next case. Now, I think that what we have proposed with no run rate, but to have the deferral, in concept, is not different. It's just that our run rate would be zero.

Q. All right. A fourth method would be just to have a pure rider or a tractor, would it not, where you put a number in there, $129 million or whatever it happens to be, for a year, and then take a look at it. It would be based -- take a look at it historically, and true it up for reasonable and prudent costs and over and under recovery?

A. That would be possible.

Q. What's wrong with that? I guess that's my question to you.

A. If you are not -- from a practical standpoint, if you are not certain what the sharing percentage should be for costs incurred in future years, when you come to the next rate case, you are going to have to sort of reach back and say, well, what should the sharing have been for those particular years for -- and then apply that somehow to dollars that have already been potentially recovered from the customers. I don't know that that makes it an impossible task, but it does make it more difficult.

Mr. Drooz has also told me that it's -- that when we start dealing with expenses, and using those as a mechanism for sharing costs that are not necessarily imprudent, that that is something that may not have been reviewed by the courts of this state yet. And so there could be legal questions, in terms of how do you do that. And so we felt that it was -- besides being easier to do, that it was safer to proceed with the recommendation that there not be a run rate and that we simply defer the entire cost.

Q. Would you consider a rider mechanism at all?

A. We discussed it, but we did not seriously consider it.

Q. Well, I think I can tell you with some confidence that whatever we come up with is gonna have some legal challenges to it, so.

Let's talk about the used and useful debate that you would have with Dr. Wright. First of all, what difference does it make of whether it's used and useful in the recommendation you made in this case?

A. I was concerned that using Dr. Wright's interpretation somewhat muddies ratemaking treatment, and the application of the statutes, and how it -- really, the only place in 62-133 that we talk about "used and useful" is in property that should be allowed in rate base, not expenses that should be allowed for recovery. I don't remember the exact language sitting here, but it's something like "reasonable and appropriate expenses." And sometimes those expenses can be associated with used and useful property, but sometimes they may be somewhat independent. You know, for example, executive salaries and other administrative and general expenses might not be generally associated with used and useful property. So I didn't think it was appropriate to use that language to somehow support the fact that all of these expenses, which the Company, itself, has chosen not to try to classify as utility plant, but instead to classify as a regulatory asset, to not use the used and useful language to support that inclusion. They should stand on their own merits and not language that applies to utility plant.

Q. All right. But you didn't make an adjustment or recommendation -- your recommendation doesn't depend, does it, on what the Company has classified as used and useful; am I right about that?

A. That's correct.

Q. Just to be clear, one of the things we are doing -- we showed it up on the screen here yesterday -- we are putting liners under these coal ash pits, right?

A. Yes, sir.

Q. And that's -- and we are putting caps or purporting to put caps over some coal ash basins?

A. Yes.

Q. Isn't that used and useful expenditure to keep the coal ash where it belongs?

A. Well, that raises a number of interesting questions, and I can't pretend to be able to answer them in detail. I have been searching for some answers in the accounting literature and haven't found anything direct yet.

Q. Well, I tell you what, if it doesn't make any difference, I will just let it pass.

A. Well, I don't think it makes any difference in this case.

Q. Okay.

A. There are -- the question is that, when the Company makes an investment in order to provide for this type of cleanup, whether that investment is a capital investment or not, there is a question as to whether -- that this Commission hasn't dealt with -- as to whether that investment is a part of the utility plant and service or whether it's part of providing for the cost of retiring environmental -- the plants and dealing with the potential environmental or other liabilities that may arise. The Company -- and the reason I say it doesn't make any difference in this case, is the Company, itself, has chosen not to propose to include these type of costs, at least the ones that have been incurred so far, to my knowledge, as utility plant and service. They have said that these costs should be treated as regulatory assets, which puts them in another category entirely. And the Company also said, for example, when it -- I can't remember if it's notification of the initial deferral or its later proposal -- that it was at risk of having, I believe, DEP approximately a $291 million write-off to expense if they did not receive the deferral accounting treatment that they requested. Coincidentally, the amount that the Company has proposed as a regulatory asset for the 2015/2016 period is $311 million. Now I don't think those two numbers are calculated in the exact same fashion, but I think it does serve to illustrate that what we are talking about in this case is, I believe, for the most part, costs that would be written off to expense or as a loss and not costs that would otherwise be recorded as plant and service.

Q. All right. Now, I'm a little bit concerned that, if the Commission were to accept the Public Staff recommendation of this after you eliminated the cost --

the identified costs that Public Staff maintains should not be recovered, if we pick a 50/50 sharing, how are we gonna support that? Why not 40/60, 60/40, 35/65, 65/35? I mean, can you give me any better information as to why it ought to be 50/50 as opposed to some other percentage?

A. Not really, other than that we have proposed in our testimony, and with regard to the specific percentage, it was the judgment of the Public Staff, all of the members who served on the task force in the aggregate, that 50 percent was a reasonable percentage. I think these things have always been subject to the Commission's judgment through the years. There have been different amortization periods at times proposed. I think, for Harris Unit 2, some parties proposed a 15-year amortization, which would have been, obviously, a greater burden on the shareholders than the ratepayers, but the Commission ultimately decided that that should be a 10-year amortization. And, of course, there have been some parties that have proposed, from time to time, no recovery at all under various theories.

Q. So you think, if the Commission sort of followed your mechanism but disagreed with some of your justifications for coming up with the 50/50 sharing, that if we used something different that varied to some extent and justified that, that you think that would be, based on our judgment, on our discretion, that we could have that upheld if it were reviewed by an appellate court?

A. Speaking as an accounting person --

Q. Sure.

A. -- I believe it's ultimately up to the Commission's discretion to determine what their sharing should be.

Q. Now, we have made reference to nuclear costs, discontinued plants, the Harris plant out there in Wake County, for example. I understand that there is some similarity to that and the manufactured gas costs, but am I wrong that, by and large, when we got to the prudency cases with the Harris plant, for example, you sort of knew what the costs were? You were looking backward, historically, what the costs were. And in this case, to some extent, we are looking forward to what we anticipate some future costs to be out through 2028.

A. Yes, sir. I think that, inherent in our recommendation is the realization that the Company, and

I think -- I don't want to speak for our witnesses Garrett and Moore, but at least my understanding is that we all expect these costs to be, in the end, much higher than the costs that are just historical as of this point in time.

Q. All right. So let's talk about some of the recommended disallowances, justifications for sharing between ratepayers and the Company. Some of that, Mr. Lucas, has to do with assumptions, on your part, as to what some future tribunal or agency might be; isn't that right?

A. (Jay Lucas) Are you talking about my specific recommendations or the equitable sharing?

Q. The equitable sharing.

A. Yeah. Like we established, there is a lot more future costs to come with management of coal ash. But there are some specific costs in this case we would like removed based upon equitable sharing.

Q. I am talking about looking in advance.

A. Yes.

Q. You make some -- and I will point you to your testimony.

A. I'm aware of it, yeah.

Q. But are those -- are those known and

measurable changes?

A. We can't know them all at this point.

Q. And if you turn to page 44 of your testimony --

A. (Witness peruses document.)

Q. -- beginning at line 12 there -- and you could put this in the right context for me, but you say, "Instead, based on the available data, I believe it is fair to make a broad conclusion, at this time, that at least some of the exceedances are due to migration of CCR constituents. Exceedances of 2L standards and IMACs, or exceedances of PBTBs, if they are higher than TL standards or IMACs, at or beyond the compliance boundary represent a probable future to make environmental standards a violation that would need to be corrected to achieve compliance with 15-A NCAC 2L .0106," right?

A. Yes. And I believe my revised supplemental cleared it up a little bit. We definitely found some failures and definite violations.

Q. But I am talking about the probable future piece of your testimony.

A. Yes. One thing CAMA did, it required a lot more extensive groundwater monitoring. From 2014 to the present, the Company's tripled -- more than tripled the number of groundwater wells. One of the theories is, the more you look, the more you find. So I believe that there could be future problems that we don't even know about yet.

Q. But are those known and measurable at this point in time?

A. No.

Q. All right. Let's see. If you flip over to the next page, page 45, beginning on line 20 down there you say, "DEQ, and DEP, and Wake County Superior Court," you list the case numbers there, "they sued DEP and Wake County" -- DEQ alleged unlawful discharges from coal ash basins to surface waters of the state in violation of the statutes there for noncompliance with NPDES permits and known and potential groundwater exceedances in violation of 2L rules, for example -- then you list the complaint.

A. Yeah, I see that.

Q. I mean, weren't there responses to that?

A. You mean --

Q. In the litigation, weren't there -- you list the allegations, but weren't there responses to that? I mean, what --

A. What the Company's responses were?
Q. Sure.
A. In that case, I don't think the Company -- I'm sorry. I have to look at my Exhibit Number 8 to make sure I'm saying the right thing.
(Witness peruses document.)
That case was resolved because CAMA came about and resolved the concerns of the Division of Water Quality in that particular instance.
Q. But I think you're asking the Commission to draw conclusions based on what you're saying your --
A. Oh, I --
Q. Just a minute. What the allegations are, and we don't have the responses to what the Company said with respect to that. I mean, wouldn't you have to know all of that for us to make an informed decision about that?
A. Well, in the federal criminal case, there was a joint factual statement the Company agreed to, and the Company says yes, there are 200 unpermitted seeps.
Q. Well, I'm not talking about the federal right now. I'm talking about the state, which you cite here on page 45 and 46.
A. Well, one premise of my testimony is the

Company's actions in the Dan -- and the Company was -- the Company's actions were a contributing factor to the Dan River spill which led to the creation of CAMA. And so I go back to my equitable sharing. We can't specifically conclude, if there had never been a CAMA, what would the Division of Water Quality, or as it says earlier, or now, the Department of Environmental Quality, what they would have done of the seeps, but these seeps are illegal under state rules. The Company had to do something. I did have some discussions with the Department of Environment Quality back in October, and they are working on the NPDES permits. One option is to have the Company go into a special order by consent to give us some time to correct those seep problems. And the Company has taken some action. At the Mayo plant, they are taking the seeps and pumping the seep water back up into the ash basin. So that takes care of the problem of an illegal discharge.

Q. Does that complete your answer?

A. Yes.

Q. All right. Look at page 50 and 52, and that has to do with, as I read it, a DEQ assessed penalty of $25.1 million. And then you go through in your single-spaced on that page and the next page, and you

list the violations that DEQ contended in that dispute to have occurred, right?
A. That's correct.
Q. I want to show you those were contested by the Company.
A. Well, in that case, with that Sutton plant, there was a settlement. This wasn't just a cash settlement. That's where the Company agreed to install a groundwater extraction and treatment system to remediate the problem.
Q. As you say, it was a settlement?
A. Yes.
Q. The $25 million was reduced -- there are other aspects, as you say, but the $25 million was reduced to $7 million, right?
A. That's correct.
Q. And I think I heard you say yesterday that the settlement, that the Company pays a lot of money, that in your opinion, that's some evidence that they are guilty of the violations of which they are accused?
A. That is some evidence, but during our investigation we found -- Public Staff is convinced there were groundwater violations. It wasn't a baseless case. The Company had responsibility for

contaminating the groundwater.

Q. This was before Office of Administrative Hearings?

A. (No response.)

Q. On page 52, line 6.

A. (Witness peruses document.)

Yeah. Yes.

Q. Are you familiar with the Office of Administrative Hearings?

A. Somewhat. I have had some contested NPDES permits before the Office of Administrative Hearings.

Q. Do you know any of the judges over there?

A. No. None of them now.

Q. If I told you, Mr. Lucas, that as the Chairman of this Commission, I was involved in a case over in the Office of Administrative Hearings where I was absolutely 100 percent convinced that, in my dispute, I was absolutely right, and the other side was absolutely baseless, but based on the advice I was getting from my lawyer, and the other state agencies that were giving me advice, and the attitude of the judge, and the rulings that the judge had made, that I determined that I was gonna settle that case for hundreds of thousands of dollars, rather than what I was afraid might be the outcome based on what I believe the other side's position to be absolutely baseless; if I told you that, would you have any reason to dispute that?

A. No, I wouldn't dispute you.

Q. All right. Settlements mean a lot of different things to different people, right?

A. Yes. But I go back to my premise. I think the Company had illegal seeps. It was caught disobeying the law. So it had culpability. So there was going to be some negative outcome from the Company, whether it settled or waited for an opinion -- requirements for remediation by the Department of Environmental Quality.

Q. All right. Is part of the 50/50 sharing that you are recommending in this case based on that part of your testimony in the settlement before Office of Administrative Hearings?

A. In some part, yes. To a larger part, the fact that CAMA settled some of the plaintiff's concerns, that's why I also recommend equitable sharing.

Q. But again, it's -- the 50/50 is sort of subjective, and you don't attribute any part of that -- you can't attribute any part of that 50 percent disallowance to what happened before the Office of Administrative Hearings, right? The accumulation of things that you identified, and then you based on all of that, you came up with the 50/50.

A. Mr. Maness came up with the 50/50, but my equitable sharing, the settlement is such a small piece. The violations, CAMA, itself, I mean, I have a large story as to why we come up with equitable shares, and the settlements are one small piece of it.

Q. All right. Bear with me a minute here. But we have heard talk about Dan River, we have heard talk about risers, we've heard about dikes, we've heard about dike toe pools, we've heard about surface water discharges and groundwater seeps from the bottom of unlined pits, right?

A. That's correct.

Q. What other general category -- is that most of the categories, or are there others?

A. That's pretty much it, yes.

Q. All right. With respect to the releases from the groundwater -- releases into the groundwater from the bottom of the coal ash pits, have there been pleas of guilty, findings of guilt in the criminal context, a fine or penalty in a matter before an administrative agency or court, and a fine amount appealable, or appealed case having to do with leaks from the bottom of the coal ash pits into the groundwater?

A. Well, in the federal case, in the joint factual statement, the Company agrees that it created exceedance of groundwater standards, which is an indication of coal ash wastewater leaking into the groundwater.

Q. Anything else?

A. I'm trying to think of any -- another part of your question is regarding fines. So maybe the difference between a fine and a settlement and the payments DEQ --

Q. I want to leave settlements out.

A. Okay. I don't think they label it as a fine.

Q. All right. Once you dewater the pits that have to be dewatered and you move the coal ash from those pits and you put them in another place, if you do that right, and if you cap in place the ones that environmental regulators and legislature determine have to be capped in place, that's gonna eliminate things like risers, and dikes, and dike toe pools, and surface water discharges; would it not?

A. That's right. If they close the basin, that would all go away.

Q. And you could remedy those types of things without the ultimate remedy of dewatering, removing the ash, and taking them to another place?

A. Yeah, there are other remedies. Lining the basins, that sort of thing.

Q. But in order to prevent the leachate, as we heard it called, from the bottom of the impoundments into the groundwater, or I guess there are other remedies to do that, but ultimately that's the one that's -- is that the direct cause of the need to move this ash, dewater and move it to take it to another place?

A. Yes.

Q. That's all I have. Thank you.

CHAIRMAN FINLEY: Are there questions -- other questions from the Commissioners? Are there questions on the Commission's questions.

MR. BURNETT: No, sir.

MR. DROOZ: Just a few.

MR. SOMERS: I have just a couple for Mr. Maness.

EXAMINATION BY MR. SOMERS:

Q. Good morning.

A. (Michael Maness) Good morning.

Q. Mr. Clodfelter asked about cost allocations of nuclear spent fuel; do you remember that question or a couple questions around that?

A. Yes.

Q. I believe your answer was, some might be allocated based on demand, some might be based on energy, but you would want to do more research or analysis to fully answer the question; is that right?

A. Yes.

Q. But as to the spent fuel, itself, which is the by-product of producing electricity, that is allocated based on demand, correct?

A. The spent fuel, itself? I'm not sure how to answer the question, because you have -- first of all, you have interim storage of it; you have permanent storage of it at some point, hopefully; and you have the fuel, itself. So I think the fuel, itself, and its state of being used is allocated by energy. After that, you are talking about the costs of storing it on a -- on an interim basis, and then the costs of storing it that have been incurred so far on a permanent basis, and I think there is different allocation factors potentially for each one of those.

Q. And you reviewed Ms. Hager -- Company witness Janice Hager's rebuttal testimony on behalf of the Company where she testified that the end-of-life nuclear fuel costs and nuclear decommissioning costs are allocated based on demand, correct?

A. Yes. And I know there is an input for spent fuel on -- within the nuclear decommissioning costs, but I believe, subject to further research, that there are also certain interim storage costs which are not necessarily included in nuclear decommissioning, but are, in fact, included in O&M expenses, depreciation expenses that are being incurred today, but I would need to -- further research to make sure of that.

Q. You don't disagree with Ms. Hager's testimony, you just need more time in order to form an opinion; is that what I'm hearing you say?

A. Yes.

Q. Okay. Thank you.

MR. SOMERS: No further questions.

CHAIRMAN FINLEY: Mr. Drooz.

EXAMINATION BY MR. DROOZ:

Q. You were asked, Mr. Lucas, about the extent to which some of the violations might be something --

or even the coal ash issues, in general, something known in the future versus known from the past.

If you know, are you aware of pending lawsuits involving alleged Clean Water Act violations at the Mayo and Roxboro plants?

A. (Jay Lucas) Yes. Those are ongoing.

Q. Okay. And did the allegations there involve alleged exceedances that occurred in the past?

A. Yes.

Q. But the determination by the court has yet to be made?

A. That's correct.

Q. In terms of reported 2L exceedances, does DEQ go through a review process to determine which ones could be caused by natural background and which ones are due to coal ash migration to the compliance boundary or beyond?

A. They have looked at it and determined if some are violations where some of these exceedances were caused by coal ash.

Q. And do you know the timing on when that assessment about provisional background levels has been reviewed at DEQ?

A. That wasn't done until October.

Q. Okay. And are there pending NPDES permit renewal requests that involve what are currently unauthorized seeps?

A. That's correct. The Department of Environmental Quality is still trying to make a determination how it's going to treat seeps in these permits that are under review.

Q. You were asked -- and I will go back to this question -- if the Company, when it was sued in these state enforcement actions and elsewhere, like the Sutton penalty assessment, did the Company deny the allegations, if you know?

A. No, it didn't deny them.

Q. Are you sure about that?

A. To my knowledge, they didn't.

Q. If they admitted the allegations, then wouldn't there have just been a judgment against them by default or, in fact, without a settlement or without a dismissal?

A. If they admitted fault, they could have gone into a plea agreement. I mean, they could have --

Q. Let me redirect your attention back to your Exhibit 6, the revised exhibit.

A. Okay.

Q. Are you there?

A. (Witness peruses document.)

Yes.

Q. The first column is parameters and the second column is Asheville?

A. Yes.

Q. And then if you go a bit further, you see a column entitled Sutton?

A. Yes.

Q. And you go down to the violation subtotal; what is the number of violations for Asheville shown on this exhibit?

A. For Asheville is --

MR. BURNETT: Mr. Chairman, objection. I think this is outside the scope of any Commission question.

MR. DROOZ: This actually goes to the question of the Company having denied the allegations, and then whether or not there was some evidence to support it.

CHAIRMAN FINLEY: Okay. Overruled.

BY MR. DROOZ:

Q. If you could read the number of violations for Asheville.

A. Asheville is 725 groundwater violations.
Q. What about Sutton?
A. Sutton was 723 groundwater violations.
Q. Even if the Company denied the allegations, in your judgment as an engineer, what does this exhibit show?
A. It shows, in fact, that there were groundwater violations.
Q. Thank you. That's all.

CHAIRMAN FINLEY: All right. Thank you all. We will accept the exhibits into evidence and the cross examination exhibits into evidence.

(Whereupon, Direct Lucas Exhibit Numbers 1 through 9, Supplemental Revised Lucas Exhibit Numbers 5 and 6, Direct Maness Exhibit Numbers 1 through 3, Supplemental Maness Exhibit Number 1, and DEP Lucas Cross Examination Exhibit Numbers 1 through 4 were admitted into evidence.)

CHAIRMAN FINLEY: Mr. Maness and Mr. Lucas, you may be excused. We're going to take a recess until 11:25.

(Whereupon, a recess was taken from

CERTIFICATE OF REPORTER

STATE OF NORTH CAROLINA)
COUNTY OF WAKE)

I, Joann Bunze, RPR, the officer before whom the foregoing hearing was taken, do hereby certify that the witnesses whose testimony appears in the foregoing hearing were duly sworn; that the testimony of said witnesses was taken by me to the best of my ability and thereafter reduced to typewriting under my direction; that I am neither counsel for, related to, nor employed by any of the parties to this; and further, that I am not a relative or employee of any attorney or counsel employed by the parties thereto, nor financially or otherwise interested in the outcome of the action.

This the 10th day of December, 2017.

JOANN BUNZE, RPR
Notary Public #200707300112

Public Staff – Lucas Redirect Exhibit 1
I/A

JAY B. LUCAS, PE

Public Staff – North Carolina Utilities Commission
430 North Salisbury Street
Raleigh, North Carolina 27699
(919) 733-0882

EXPERIENCE

August 2007 to Present

North Carolina Utilities Commission, Public Staff - Electric Division
Public Utilities Engineer III

- Manage regulatory aspects of the NC Renewable Energy Portfolio Standard to include enforcement, application review, and environmental assessments.
- Review depreciation expenses of electric public utilities.
- Make recommendations to the Utilities Commission and other divisions of the Public Staff on engineering issues regarding electric utilities.
- Resolve consumer complaints that involve technical issues.

April 2005 to August 2007

North Carolina Utilities Commission, Public Staff - Communications Division
Public Utilities Engineer II

- Reviewed new franchise applications for long distance companies and testified before the Commission on recommendations.
- Assisted in resolving disputes between telephone companies.
- Resolved consumer complaints that involve technical issues.
- Drafted recommendations to the Utilities Commission on new rules for companies that terminate operations.

January 2000 to March 2005

North Carolina Utilities Commission, Public Staff - Water & Sewer Division
Public Utilities Engineer I

- Reviewed applications for actions taken by water and sewer utilities to include new franchises, rate increases, transfers, and extensions of service.
- Negotiated and wrote testimony and affidavits regarding actions taken by water and sewer utilities to ensure adequate service at a fair rate for the state's utility customers.

April 1996 to January 2000

North Carolina Division of Water Quality - Construction Grants & Loans Section
Supervisor of the Facilities Evaluation Unit

- Supervised the Facilities Evaluation Unit which consisted of two other engineers and one environmental assessment coordinator for the long range planning of municipal wastewater facilities.
- Planned municipal wastewater facilities to include all technical and environmental concerns.

January 1993 to March 1996	**North Carolina Division of Water Quality - Permits and Engineering Unit** ***Environmental Engineer I*** • Reviewed applications and prepared wastewater and stormwater discharge permits for industries, municipalities, and utilities to include calculating discharge limits. • Reviewed plans and specifications for construction of wastewater treatment plants.
January 1992 to January 1993	**Wiley & Wilson, Inc. Architects, Engineers, and Planners, Lynchburg, Virginia** ***Environmental Engineer*** • Assisted in the design and review of water and wastewater treatment plants. • Co-authored sewage treatment plant operations and maintenance manual. • Planned and conducted waste oil management survey for Navy installations in the Norfolk, Virginia area.
August 1989 to December 1991	**Department of Environmental Engineering, Virginia Tech** ***Graduate Research Assistant and Research Associate*** • Conducted research project funded by CH2M Hill Consulting Engineers and the City of Newport News, Virginia to determine the effect of land applied water treatment sludge on plant growth and find optimum loading rates. • Planned upgrade of the Nottoway County, Virginia, water supply system which included an evaluation of existing distribution systems and potential resources.
October 1985 to August 1989	**3800th Civil Engineering Squadron, Maxwell Air Force Base, Alabama** ***Captain - U. S. Air Force, Civil Engineer*** • Managed storage and disposal of hazardous wastes, asbestos, and PCB contaminated electrical equipment. • Designed storm drainage improvements, athletic fields, and training areas to include site plans, drawings, specifications, and cost estimates. • Reviewed and corrected designs completed for the Air Force by engineering consultants. • Led 40-person combat engineering team during exercises to repair bomb-damaged infrastructure.
	EDUCATION
1989 to 1991	Master of Science, Environmental Engineering Virginia Tech - Blacksburg, Virginia
1981 to 1985	Bachelor of Science, Civil Engineering Virginia Military Institute - Lexington, Virginia

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION
DOCKET NO. EMP-103, SUB 0

Testimony of Evan D. Lawrence
On Behalf of the Public Staff
North Carolina Utilities Commission

May 24, 2019

Q. PLEASE STATE YOUR NAME AND ADDRESS FOR THE RECORD.

A. My name is Evan D. Lawrence. My business address is 430 North Salisbury Street, Raleigh, North Carolina.

Q. WHAT IS YOUR POSITION WITH THE PUBLIC STAFF?

A. I am an engineer in the Electric Division of the Public Staff.

Q. WOULD YOU BRIEFLY DISCUSS YOUR EDUCATION AND EXPERIENCE?

A. Yes. My education and experience are summarized in Appendix A to my testimony.

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. The purpose of my testimony is to make recommendations to the Commission on the request for a Certificate of Public Convenience and Necessity (CPCN) filed by Albemarle Beach Solar, LLC (Applicant), to construct an 80 megawatt AC (MW_{AC}) solar photovoltaic (PV) merchant electric generating facility in Washington County, North Carolina (the Facility).

The purpose of my testimony is as follows:

1. To discuss the compliance of the application with N.C. Gen. Stat. § 62-110.1 and Commission Rule R8-63;
2. To discuss any concerns raised by the application; and
3. To make a recommendation regarding whether the Commission should grant the requested certificate.

Q. PLEASE BRIEFLY DESCRIBE THE GENERATION FACILITY PROPOSED TO BE CONSTRUCTED BY THE APPLICANT.

A. The Applicant proposes to construct an 80 MW_{AC} solar PV electric generating facility in Washington County, North Carolina. The Facility will utilize single axis tracking, ground mounted, solar PV modules. Approximately 367,213 solar PV modules will be used along with fifty-four 1.56 MW inverters. A 34.5 kV collector substation will be constructed adjacent to an existing Dominion Energy North Carolina (DENC) 230 kV substation. The point of interconnection (POI) will be located at the existing DENC substation. The Applicant states that either overhead or underground medium-voltage cable will be used to connect the multiple sections of panels. The yearly generation is anticipated to be 193,957 MWh. Due to the fact that solar is an intermittent energy source, the maximum dependable capacity of the plant is 0 MW. The expected life of the facility is a minimum of twenty years.

Q. HAS THE APPLICANT COMPLIED WITH THE COMMISSION'S FILING REQUIREMENTS?

A. Yes. The original application for the Facility was filed on September 21, 2015, in Docket SP-6476, Sub 0. On November 12, 2018, the Applicant filed an amended application modifying the site layout to reflect both the addition and removal of parcels of land.

On November 29, 2018, the Commission issued an Order Transferring Record, Closing Docket, and Finding Application Incomplete. This Order determined that the Applicant erred in applying for a CPCN pursuant to Commission Rule R8-64, the rule governing CPCN applications by CPRE program participants, qualifying cogenerators, or small power producers, and that the application is instead governed by Commission Rule R8-63, the rule governing CPCN applications for merchant plants. Based on this determination, the Order directs that Docket No. SP-6476, Sub 0, be closed, and that the record from that docket be transferred to Docket No. EMP-103, Sub 0. The Order further finds the Applicant's CPCN application, as transferred to Docket No. EMP-103, Sub 0, to be incomplete as it does not include pre-filed direct testimony incorporating and supporting the application, as required by Commission Rule R8-63(b)(5). The Order declares that the Applicant's amended CPCN application filed in Docket No. SP-6476, Sub 0, is an application for a CPCN for the construction of an electric generating facility to be operated as a merchant plant pursuant to Commission Rule R8-63, and that the Commission will consider the application once the Applicant has supplemented it with the pre-filed direct testimony required by Commission Rule R8-63(b)(5).

On March 28, 2019, the Applicant filed the direct testimony of Linda Nwadike, Project Manager for SunEnergy1, LLC, along with four accompanying exhibits. On April 11, 2019, the Applicant filed Amended Pre-Filed Direct Testimony of Linda Nwadike along with ten accompanying exhibits.

On April 11, 2019, the Public Staff notified the Commission that it considered the application to be complete and requested that the Commission issue a procedural order setting it for hearing. On April 26, 2019, the Commission issued an Order requiring public notice, scheduling a hearing on June 4, 2019, for the purpose of receiving public and expert testimony, and addressing other necessary procedural matters. On May 1, 2019, the Commission issued an Amended Order Scheduling Hearing and Requiring Public Notice to correct scrivener's errors in the April 26, 2019, Order.

On May 20, 2019, the Applicant filed a certificate of service to show compliance with Ordering Paragraph Number 3 of the Commission's May 1, 2019 Order. This paragraph ordered the Applicant to mail a copy of the public notice, no later than the first day of publication, to each person who has filed a complaint in the proceeding, and to file a certificate of service with the Commission on or before the date of the hearing.

Q. HAS THE APPLICANT SHOWN A NEED FOR ITS PROPOSED FACILITY?

A. Yes. The Applicant states that the Facility will interconnect with the transmission system of DENC, which is a member of PJM. The Applicant believes there are strong market conditions in the PJM market that will create sustainable off-take for its power production. The Applicant states that Dominion Energy has committed to increasing its use of renewable power to generate 5,000 MW of electricity by 2028. The Applicant states that it anticipates contracting the sale of energy, capacity, and renewable energy credits (RECs) through PJM. The annual net energy growth rates for PJM over the next ten years is expected to grow by 0.4% for PJM and by 1.1% for the Dominion Virginia Power zone. Summer peak load for PJM and the Dominion Virginia Power zone is expected to grow by 0.9% per year over the next ten years. The winter peak load growth in PJM is expected to grow at an average of 0.4% per year over the next ten year period, and by 1.1% per year for the Dominion Virginia Power zone. The Applicant cites the March 2019 PJM Load Forecast Report to support the growth in PJM, the growth in the Dominion Virginia Power zone, and the need for the facility.

Q. HAS THE STATE CLEARINGHOUSE COMPLETED ITS APPLICATION REVIEW?

A. No. The State Clearinghouse has not filed a letter in the docket in response to the Commission's Order Scheduling Hearing and Requiring Public Notice filed on April 26, 2019.

Q. DOES THE PUBLIC STAFF HAVE ANY RECOMMENDATIONS REGARDING THE SITING OF THE PROPOSED FACILITY OR ITS ENVIRONMENTAL IMPACT?

A. No. The Public Staff has reviewed the consumer statements of position in this docket. With regard to the concerns raised regarding compatibility with existing land uses and environmental impacts, the Public Staff believes that these concerns are more appropriately addressed through the local permitting process and through the environmental permitting process. In its April 24, 2008, Order in Docket No. SP-231, Sub 0, the Commission discussed local authority over the siting of facilities, stating that "such decisions are, in most instances, best left to the local community through the exercise of its zoning authority rather than made by the Commission." The Public Staff notes that, according to the Applicant's witness, Linda Nwadike, Washington County has a Solar Farm Ordinance that requires a solar development permit for all solar projects proposed in the county.

In addition, the Public Staff does not have particular expertise in the area of the impacts of electric generation on the environment. Those issues are best left to the purview of environmental regulators who do have this expertise, and who are responsible for issuing specific environmental permits for electric generating facilities. To that end, as stated below, the Public Staff recommends that the Commission require compliance with all permitting requirements as a condition to the issuance of the CPCN.

Q. WHAT IS THE PUBLIC STAFF'S RECOMMENDATION ON THE APPLICATION FOR A CPCN AND THE REGISTRATION STATEMENT?

A. The Public Staff recommends that the application be approved subject to the following conditions:

1. The Applicant shall construct and operate the Facility in strict accordance with applicable laws and regulations, including the provisions of all permits issued by the North Carolina Department of Environmental Quality;
2. The Applicant shall not begin construction until the State Clearinghouse files comments indicating that no further review action by the Commission is required for compliance with the North Carolina Environmental Policy Act;

3. The CPCN shall be subject to Commission Rule R8-63(e) and all orders, rules and regulations as are now or may hereafter be lawfully made by the Commission; and

4. The Applicant shall file with the Commission in this docket a progress report and any revisions in the cost estimates for the Facility on an annual basis, including any storage systems to be constructed at a later date, with the first report due no later than six months from the date of issuance of the CPCN.

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes, it does.

APPENDIX A

Evan D. Lawrence

I graduated from East Carolina University in Greenville, North Carolina in May of 2016 earning a Bachelor of Science degree in Engineering and a concentration in Electrical Engineering. I started my current position with the Public Staff in September of 2016. Since that time my duties and responsibilities have focused around the review of renewable energy projects, rate design, and renewable energy portfolio standards compliance. I have filed affidavits in Dominion Energy North Carolina's 2017 and 2018 REPS cost recovery proceeding, testimony in New River Light and Power's (NRLP) most recent rate case proceeding, and testimony in additional small power producer and merchant electric generating facilities (EMPs). I have also assisted other Public Staff personnel with the review and investigation of REPS Compliance Plans filed by the electric power suppliers, previous DEC and DEP REPS cost recovery proceedings, and multiple other cases.

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Also Present: DeANDRAE SHIVERS, Videographer

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Video Deposition of JAY LUCAS, taken by Duke Energy Progress, at McGuire Woods LLP, 434 Fayetteville Street, Suite 2600, Raleigh, North Carolina, on the 2nd day of November, 2017 at 9:02 a.m., before Marisa Munoz-Vourakis, Registered Merit Reporter, Certified Realtime Reporter and Notary Public.

I N D E X

P R O C E E D I N G S

THE VIDEOGRAPHER: This is the beginning of disk number one in the deposition of Jay Lucas in the matter of Application of Duke Energy Progress, LLC for Adjustment of Rates and Charges Applicable to Electric Utility Service in North Carolina, docket number E2 sub 1142.

Today's date is November 2, 2017, and the time is approximately 9:02 a.m.

My name is DeAndrae Shivers, I'm the videographer. Our court reporter is Marisa Munoz.

Will our court reporter please swear in the witness.

Whereupon, JAY LUCAS, having been first duly sworn, was examined and testified as follows:

EXAMINATION BY COUNSEL FOR DUKE ENERGY

BY MS. DINSMORE:

Q. Good morning, Mr. Lucas.

A. Good morning.

Q. My name is Joan Dinsmore. I'm with the law firm of McGuire Woods. I, along with my partner, Mary Lynn Grigg, represent Duke Progress Energy in this

matter.
Can you please state your full name and business address for the record?
A. My name is Jay Lucas. My business address is 430 North Salisbury Street, Raleigh, North Carolina.
Q. Have you had your deposition taken before?
A. No.
Q. I believe you were present for some of yesterday's festivities, is that right?
A. Yes.
Q. So you heard me give a few introductory instructions, but I'll just remind you. We have a court reporter here who's taking down everything we say, so if you could just wait until I finish my question before you begin your answer so she can get a clean transcript, and likewise I'll wait for you to finish before starting my next question, is that okay?
A. Sure.
Q. And your attorney may interpose objections. If he does, just wait for him to finish his objection before you answer. But after he objects, you'll be expected to answer the question, unless he instructs you not to, is that okay?
A. Sure.
Q. And please feel free to ask for a break at

any time. I am happy to take breaks, as long as there's no question pending.

A. Okay, sure.

Q. I read through your report and the exhibits, and attached to your report there was a brief blurb about your experience, but I didn't see a CV. Do you have a CV?

A. No, I don't.

Q. Okay. So I'm going to just fill in some background.

A. Sure.

Q. You went to VMI and graduated, I believe, in '85 with a degree in civil engineering?

A. Yes.

Q. And then you went to Virginia Tech thereafter, but there's a period of time, so --

A. Yes, I spent four years in the Air Force as an environmental engineer.

MR. DROOZ: Let her finish the questions.

THE WITNESS: I'm sorry.

BY MS. DINSMORE:

Q. Right. So when we talk in normal conversation, you can see where my question is going and you answer.

A. I'm sorry.
Q. So but for purposes of the deposition, just wait for me to finish, even if you know where I'm going.
A. Okay, sure.
Q. Thank you. So you mentioned that you were an environmental engineer in the Air Force, is that right?
A. Yes.
Q. What were your job duties?
A. We had many environmental compliance requirements. The Air Force had a program or the entire Department of Defense had a program called the Installation Restoration Program, that was very similar to the EPA's Superfund program, as remediation of sites where hazardous waste had been disposed of improperly. Our Air Force base had a landfill, had to manage that. We had storm water permits. We had an asbestos removal program, hazardous waste disposal. Those are the environmental requirements. Had a war time training job of doing bomb damage repair.
Q. You mentioned a landfill?
A. Yes.
Q. Requiring remediation, is that right?
A. No, the Installation Restoration Program

was a remediation program for past disposal sites. The landfill had been closed. We just had to do active ground water monitoring at that landfill.

Q. What were some of the constituents at that landfill that were found through the ground water monitoring program?

A. Iron and chlorides. We also had to monitor for PH, and that's all I can remember.

Q. Did you, in that work, do any analysis of those levels as compared to background levels to determine the impact from the landfill?

A. Yes, we had upstream wells, and we checked for background levels.

Q. Did you personally do that analysis?

A. We had a chemical lab that actually did the chemical analysis. We did compare them to background levels.

Q. But you personally, was that part of your job or was that just --

A. Yes, to take a look at background levels of contaminates and the downgradient contaminant levels.

Q. What, if anything, did you conclude about any impacts from that landfill on ground water?

A. We did find some elevated levels of iron and chlorides, but our state regulatory agency, the

Alabama Department of Environmental Management, never took any action.

Q. Did you take any action on your own?

A. No.

Q. Why not?

A. We didn't think the elevated levels were creating any problems. There were no water supply wells downgradient.

Q. Okay. And can you describe a little bit about the separate remediation program you talked about?

A. Yeah, the Installation Restoration Program?

Q. Yes, sir.

A. Like I said earlier, it was similar to EPA's Superfund Program. A lot of industries, including military installations, had been improperly disposing of hazardous waste for decades. A lot of times they would just bury it and forget about it, and we're starting to find ground water contamination problems as a result.

Q. And what was your role in that program?

A. I took some of the analysis data and reviewed that, but we were -- my particular base were not finding any problems.

Q. So there was no remediation action taken as

a result of that?
A. No.
Q. So about how long were you an environmental engineer in the Air Force?
A. Four years.
Q. And then after that, you went to Virginia Tech, is that right?
A. Yes.
Q. And you got a master's in environmental engineering in '91?
A. Yes.
Q. What did you do in 1991 upon your graduation?
A. I went to work for a small consulting firm called Wylie & Wilson in Lynchburg, Virginia.
Q. What did Wylie & Wilson do?
A. They were a consulting firm, and they did a wide range of activities, one of them was environmental engineering.
Q. What type of clients did Wylie & Wilson have?
A. The main client we had was the Department of the Navy. The main project I worked on was a study of oily waste and waste oil that was generated at 11 Naval installations in Norfolk, Virginia.

Q. What specifically were you asked to evaluate?
A. All of the sources of the waste streams and what the Navy's current disposition was, and then to make recommendations on how the Navy could improve cost recovery from waste materials and also improve disposal of waste materials.
Q. And as it relates to recommendations related to cost recovery, what were your recommendations?
A. We thought the Navy had some valuable products, even though it had determined they were waste products, something like waste oils did have some value in the open market. There were companies that would buy waste oil.
Q. So you recommended that the waste be sold?
A. Yeah, the Navy do a better job -- well, first they had to do a better job of segregating. They were mixing various types of waste that made them unmarketable. By segregating waste, they would become more marketable.
Q. Did you provide specific recommendations as to whom the waste should be sold?
A. No.
Q. You also mentioned that you made

recommendations as to disposal, is that right?
A. Yes.
Q. What were those recommendations?
A. That the Navy consolidate its contracts for disposal. Like I said, there were 11 Naval installations and smaller units on each installation, and they had a scattered plan. A lot of units had their own separate contracts from waste disposal. We recommended that they consolidate it.
Q. Did you make any recommendations as to how they should be consolidated to which company?
A. No, we didn't make a recommendation on a specific company.
Q. Okay. How long were you with Wylie & Wilson?
A. About a year.
Q. Where did you go -- so that would take us to about 1992?
A. End of '92 to 1993.
1993 I went to the Department of Environment Health and Natural Resources in their Division of Environmental Management.
Q. What did you do there?
A. I wrote storm water permits, wastewater discharge permits and non-discharge permits, which are

sewer systems, pump stations and land application of treated wastewater.

After that, in 1996, I became the supervisor of the facilities evaluation unit, and that was in the construction grants section. That section is currently called Division of Water Infrastructure. Our primary task was to do the long-range planning for wastewater collection and treatment and disposal.

Q. And from the 1993 to 1996 time frame, where you were with the Division of Environmental Management writing permits, did you focus on any particular type of industry?

A. I did a wide range of industries; municipal wastewater plants, extraction and treatment of contaminated ground water. I did permits for a few small package plants for subdivisions.

Q. Did any of these industries involve disposal of coal ash particularly?

A. No.

Q. And you discussed in 1996 moving to the construction grants section and doing long-range planning?

A. Yes.

Q. And can you tell me a little bit more about that?

A. In order for local government to get a grant or a loan, they first have to do a planning document. For small projects, it was called a preliminary engineering report. That covered cost estimate, site plan and a description of the project.

Larger projects had to do what's called a 401 plan, and that was a federally administrative program the state ran. That was a much more involved planning document, looking at alternatives for waste disposal, a long list of items to consider.

Q. Okay. And you started that position in 1996. Does that take us up to the year 2000, when I understand you joined the public staff?

A. Yes.

Q. Okay. You are a licensed engineer in North Carolina, is that right?

A. Yes.

Q. And when did you get that license?

A. Officially it was in January of 1995.

Q. And what was the procedure for obtaining that license?

A. I had to take an eight-hour exam, solve engineering problems and answer engineering questions.

Q. Are there any continuing education requirements?

A. Yes, I have to get 15 hours, and they call them professional development hours, every year.
Q. Are there any requirements in terms of subject matter?
A. General engineering field. That's about the only requirement.
Q. Are you licensed as an engineer in any other state?
A. No.
Q. Do you have any other degrees or certifications that we haven't talked about?
A. Before becoming a professional engineer, I took the engineer-in-training exam, that was in 1985.
Q. Anything else?
A. That's it.
Q. Okay. Have you ever consulted for, worked at a facility that has a coal ash impoundment?
A. No.
Q. And before this case, meaning the rate proceedings we're talking about today, have you had experience with coal ash impoundments?
A. No.
Q. And I understand now you're an engineer with the electric division, the public staff, is that right?

A. Yes.
Q. Can you describe generally your job responsibilities?
A. I review issues that come across -- environmental issues, like coal ash in this case, the clean power plan, help manage the renewable energy portfolio standard management, help review customer complaints and get those resolved, review depreciation expenses and generate cases.
Q. So as it relates specifically to utility cost recovery, what has been your role with the public staff.
A. Reviewing depreciation costs. Reviewing contracts for construction or maintenance of power plants.
Q. When did you --
A. I'm sorry, I'm done.
Q. When did you begin working in a role that involved looking at materials related to utility cost recovery?
A. For electric utilities?
Q. Let's start there, yes, sir.
A. When I first got to the Electric Division, it was 2007. Electric Division was working on a Duke Energy Carolinas rate case, and I started right away

working on that.
Q. What was your role in that case?
A. In that case, I looked at cost of service and rate design.
Q. Can you explain a little more particularly what you were doing?
A. Look at all of the utilities costs that it claims, and try best how to figure out which customer classes were responsible for those costs; residential class, general class, industrial class. I think hourly pricing was also separated as a customer class and a couple of others.
Q. Did you have any role in determining the reasonableness or prudency of the costs themselves?
A. Not for the first two years.
For 2007, I worked on two Duke Energy Carolinas' rate cases, and that's where I did those tasks I just told you.
There was a later case, I can't remember whatever the next rate case was, it might have even been a Dominion rate case, I started picking up review of depreciation expenses. Also started reviewing contracts for construction processes and maintenance processes of power plants.
Q. Have you provided testimony on behalf of

the public staff before in a rate recovery case?
A. Yes.
Q. How many times?
A. Several. I don't know the exact number.
Q. When was the most recent?
A. Previous case was a Dominion rate case a year ago. I believe, I can't remember if that case was settled. A lot of times I will have testimony ready and the case gets settled.
Q. What was the scope of your testimony in that case?
A. Review of coal ash costs that Dominion had, and review of Dominion's depreciation expenses.
Q. And just in general, what was the substance of your recommendations in that case?
A. I had developed recommendations on the decommissioning of some of the Dominion's power plants.
One of the recommendations I was working on, Dominion, I believe, wanted to cover all the decommissioning costs. They were five years, and I was wanting to push for ten years, and that's all I can remember.
Q. Do you recall whether in that case, you recommended the wholesale exclusion of any costs from recovery?

A. No.
Q. You don't recall, or you did not?
A. I believe I did not.
Q. Okay. We've gone through, I think, your professional history. Are there any areas that we haven't gone through that you worked on as a professional engineer?
A. When I first joined the public staff, my first five years I was in the Water Division, and then I went two and a half years in the public staff's Communication Division, and after that is when I went to the Electric Division.
Q. What did you do in the Water Division?
A. Reviewed general rate cases, customer complaints, provision of emergency operators and worked on development of a program where apartment complexes can resell water.
Q. Okay. So as it relates to this matter, what areas of expertise are you relying on to offer opinions in this case?
A. All the experience I've gathered over the past 30-some years.
Q. So the areas we've just discussed?
A. Yes. Yes.
Q. Who asked you to prepare testimony for this

case?

A. My supervisor, James McLawhorn.

Q. When was that?

A. Very shortly after the rate case was filed, back in June.

Q. At that time, what were your instructions?

A. To review coal ash costs, depreciation costs and other plant additions by Duke Energy Progress.

Q. Did those instructions change at all in the intervening months?

A. I took a lesser role in reviewing depreciation expenses once the public staff hired a depreciation consultant.

Q. So as it evolved, what did you understand your role to be as you prepared your testimony?

A. When I shortly realized it was Duke's request to place the sale of byproducts, coal ash byproducts in the Feel(sic) case. That's another item I took.

Q. And that came later?

A. A little bit later, but not too much later.

Q. When you started looking at these issues, did anyone at the public staff express to you their opinion on these issues?

A. Oh, yes.
Q. Who did you speak with?
A. Let's see, I spoke with Dianna Downey, David Drooz and Layla Cummings in the legal division. I spoke with James McLawhorn and Bevin Lawrence in the Electric Division, and I spoke with Mike Maness and Darlene Peaden in the accounting division.
Q. What did you talk about with Mr. McLawhorn? Am I saying that correctly?
A. Yes. Just in general what items I was finding that concerned me, and the Electric Division meet as a team, and we would discuss how everybody's review was proceeding in the case.
Q. What did you tell Mr. McLawhorn about what concerns you?
A. I was concerned about the costs of the Mayo power plant's zero liquid discharge system. I believed that we had a strong case to remove some coal ash byproduct sales from the fuel case. Also removal of some of the coal ash management costs.
Q. As it relates to the removal of the coal ash management costs, what were the discussions surrounding those costs?
A. Whether Duke Energy could have complied with the Coal Ash Management Act in a more

cost-effective manager.

Also if Duke Energy Progress was trying to include costs that should not have been passed on to ratepayers.

Q. Okay, we'll come back to those issues.

And in terms of how you arrived at the opinions expressed in your testimony, you discussed talking with others on the public staff. What about review of documents? What did you review?

A. The responses to the debtor requests that was at Duke Energy Progress. All the testimony of Duke Energy Progress' witness and their exhibits. I communicated with some members of the Department of Environmental Quality and got some information from them.

Q. Were there any documents you wanted to review but didn't have a chance to?

A. Coal ash data request number 26, in which I had chosen 45 items from a list of about 27,000 items that were in the E1 item 10 NC1800, and that wasn't necessarily a document I wanted Duke Energy Progress' description. I just don't think I got a clear description.

Q. And why do you not think the description was clear?

A. I wanted a written description, just an explanation of the costs. I feel like I received spreadsheets and accounting documents but not the written explanation.
Q. How would the written explanation have aided your analysis?
A. It would have been very clear, more clear than just numbers on spreadsheets. Just a verbal description would have helped.
MS. DINSMORE: Could we go off the record for just a minute?
THE VIDEOGRAPHER: The time is 9:28. We're going off the record.
(Recess.)
THE VIDEOGRAPHER: The time is 9:32 a.m. We're back on the record.
BY MS. DINSMORE:
Q. Mr. Lucas, before we took a break, we discussed some of the conversations you had with other members of the public staff. Did you have any conversations about this matter with individuals outside the public staff?
A. Yes.
Q. Who were those people?
A. I talked to several people at the

Department of Environmental Quality; Jeff Poupart who is the supervisor for surface water discharges; one of his employees, John Hennessey, who is in charge of NPDES enforcement and someone on his staff; Brianna Young, who generates and reviews the discharge monitoring violation reports. I talked to Debra Watts in the Ground Water Section. I talked to Sergei Chernikov, who is the NPDES permit supervisor.

Q. With regards to your discussion with Mr. Poupart, what did you discuss with him?

A. Talked about DEQ's plans for how they would permit seeps from coal ash basins.

Q. And what did you learn from Mr. Poupart?

A. DEQ is still in the process of determining how it will put seeps into NPDES permits, and if necessary, may enter special orders by consent, which would require Duke Energy Progress to eliminate seeps.

Q. Did you have any discussion with Mr. Poupart about when DEQ first learned about seeps at any DEP sites?

A. Not with him.

Q. Did you discuss with anybody at DEQ when they first learned about seeps at any DEP sites?

A. No.

Q. So when I asked you about Mr. Poupart, you qualified and said not with him. Was there anybody you discussed that issue with?

A. No.

Q. Do you know when DEQ first learned of any seeps at any DEP sites?

A. Let's see, there was a court case at the Asheville plant in 2013. Also the same court cases covered Cape Fear. And to clarify this, I'm going on Lucas Exhibit number 8.

Q. Thank you.

A. Sure. It involved the H.F. Lee plant, the Mayo plant, the Roxboro plant, the Sutton plant and the Weatherspoon plant, and these cases start in 2013. So at least by 2013 they knew about seeps.

Q. Do you know if 2013 represents the first time DEQ was aware of seeps at any of the DEP plants?

A. I don't know.

Q. Did you discuss with Mr. Poupart anything other than DEQ's planned treatment of seeps?

A. Let me check my notes. No -- no, that's all I did.

Q. Okay. What about with Mr. Hennessey? What did you discuss with Mr. Hennessey?

A. Also discussed DEQ's plan for seeps, and he referred me to Mr. Poupart. Also discussed with him getting copies of the discharge monitoring violation reports.

Q. Did Mr. Hennessey provide you with copies of those reports?

A. One of his staff members did, Brianna Young.

Q. And was there -- did you place any time frame on your request for those reports in terms of how far back you wanted them?

A. I wanted about ten years of data. I think they gave me more than ten years, but when I developed my Lucas Exhibit number 5, I only went back ten years.

Q. And Ms. Young is the one who provided those to you?

A. Yes.

Q. Did she provide you any other substantive information?

A. No.

Q. Did you have conversations with Ms. Young?

A. Just to get the reports. It was phone conversations and by email.

Q. What about your conversations with Ms. Watts? What did you discuss with Ms. Watts?

A. The 2L ground water rules. The Ground Water Section's efforts related to the Coal Ash

Management Act. That was generally the subject matter.
Q. What, if anything, did you learn from Ms. Watts about the 2L ground water rules?
A. Whenever I saw them, I got it -- my Lucas Exhibit number 2, we went through some of the 2L rules and what Duke Energy Progress was required to do to comply. And we talked about the timetables that CAMA set, the Coal Ash Management Act set for ground water monitoring for Duke Energy Progress.
Q. Did you have any discussion with Ms. Watts about the distinction between an exceedance and a violation under the ground water rules?
A. Yes.
Q. What did you discuss with her about that distinction?
A. I can't remember exactly how we distinguished those two items.
Q. Did you, yourself, ever come to a conclusion regarding the distinction under the 2L rules of an exceedance versus a violation?
A. Yes, and I'm quoting from my testimony.
Q. Why don't we -- before you quote from it, just for the record, I'll introduce as Exhibit 1 a copy of your testimony. This does not contain the exhibits, but just so we have it with the transcript.

A. Okay.

(The document referred to was marked Lucas Exhibit Number 1 for identification.)

Q. Please go ahead.

A. This is from page 44 of my testimony, starting on line 14.

Q. Okay.

A. Exceedances of 2L standards in IMACS or exceedances of the PBTVs, if they are higher than the 2L standards or IMACS, at or beyond the compliance boundary, represent a probable failure to meet environmental standards, a violation, that would be -- that would need to be corrected to achieve compliance with 15A NCAC 2L.0106.

Q. Okay. So did you draw any distinction between an exceedance and a violation?

A. Ground water quality can exceed the standards. That's not necessarily a violation. A violation occurs if there's a responsible party for exceeding the standards beyond the compliance boundary.

Q. Okay. And so you understand then that what the 2L rules require is that upon finding an exceedance, corrective action is required, is that right?

A. Yes. The responsible party creates an exceedance beyond the compliance boundary. There is a set of requirements that that entity must do.

Q. Right. And those include controlling the source of the pollution, assessing the extent of the contamination and identifying, implementing a remedial strategy, is that right?

A. I can read you a quote from 2L.0106, Section E.

Q. Sure.

A. It lays out the requirements, mostly what you just said: Within 24 hours of discovery, notify the Department of Environmental Quality, prepare a response, submit a report to the secretary of DEQ, implement and approve correction action plan.

Q. Yes, sir, that's upon the discovery of an exceedance, correct?

A. Beyond the compliance boundary, yes.

Q. And in terms of any fines or penalties or punitive measures, those don't come into play until -- unless and until the property owner doesn't implement the corrective action, is that right?

A. That's up to DEQ to determine the extent of the exceedance and whether or not it's going to take any enforcement action.

Q. Upon giving the owner the opportunity for corrective action, is that right?

A. I don't know if DEQ has to give the responsible party time to correct the action.

Q. That wasn't part of your discussions with Debra Watts?

A. No, but I don't see that in the 2L rule, that there's anything that prevents DEQ from taking any kind of enforcement action.

Q. You cited in your testimony the settlement of the Sutton civil penalty, is that right?

A. Yes.

Q. And wasn't that part of what's set forth in the settlement that DEQ has to allow the opportunity for corrective action before implementing a penalty?

A. Now you're talking about the case that was brought about by DEQ?

Q. Yes, sir.

A. Okay. And I'm quoting from page 53, line 12 of my testimony: DEQ agreed to dismiss its ground water exceedance claims against all Duke Energy coal plants in North Carolina and agreed not to file any notices, claims, enforcement actions or penalties against Duke Energy for ground water conditions, past or future, as long as Duke Energy was complying with

CAMA.

Q. Yes, sir. And a little bit above that in your testimony, you actually quote from the agreement, which sets forth DEQ's policy regarding enforcement, is that correct?

A. Can you give me the page and line number?

Q. Also on page 53. Starting on page 52 and 53, quoting from the settlement.

A. Sorry, which particular line?

Q. Sure. Start on one through four.

A. On page 53?

Q. Yes, sir.

A. Okay. I can read that into the record.

The 2011 policy for compliance evaluation states that as long as the permittee is cooperative with the division in taking necessary steps of bringing the facility into compliance, a notice of violation may not be necessary.

I want to point out though this says a notice of violation may not be necessary. That paragraph doesn't preclude DEQ from taking enforcement action as it sees fit, whether or not Duke Energy Carolina -- excuse me, Duke Energy Progress is taking necessary steps.

Q. Did you discuss with DEQ whether at any stage, DEP failed to cooperate with regulators in terms of corrective action?

A. No, they never said that Duke Energy Progress was not cooperating.

Q. Did you ask?

A. No. I didn't ask specifically.

Q. Okay. You said you also talked with Mr. Chernikov, is that right?

A. Yes.

Q. And what did you discuss with him?

A. The way NPDES permits are reviewed and issued.

Q. What did you learn from Mr. Chernikov that's relevant to your testimony here?

A. I discussed with him the possibility of the Mayo power plant routing its treated wastewater from its flue-gas desulfurization process into a nearby stream. Also the possibility of rerouteing that wastewater to the Town of Roxboro Wastewater Treatment Plant. Also talked with him about permitting of seeps from coal ash basins.

Q. In terms of your discussion regarding the permitting of seeps, what was that discussion?

A. He told me that seeps are not currently permitted.

Q. Did you learn from him whether seeps had ever been permitted?

A. He said there are discharges from coal ash basins that are permitted, they are called outfalls, and they receive a number NPDES permit. He said there are seeps that were definitely unpermitted and were going on. And he agreed with Mr. Poupart that evaluation of seeps was still being unreviewed by the Department of Environmental Quality.

Q. But, again, you didn't learn anything from DEQ about when DEQ first became aware of these seeps?

A. No, that's just from my review of the court cases in 2013.

Q. And I believe you testified that you, based on the review of the court cases, you believe that they were aware of these by 2013, but you didn't know how long before that?

A. That's correct.

Q. Okay. Is there any other research that you did in the course of preparing your testimony that we have not discussed?

A. I mean, I did a lot of research. I'm going to the responses to the debtor requests.

I discussed with outside consultants the treatment of flue-gas desulfurization wastewater.

Q. Who were the outside consultants?

A. I talked with a Dow Chemical. I talked with a couple of other companies, and that was by email. I could possibly make that a late-filed exhibit, if necessary. I don't remember their names offhand.

Q. Okay. Anything else that comes to mind that you did in the course of preparing your testimony?

A. No.

Q. Was there any analysis that you would have liked to do but were not able to do?

A. I would have liked to analyze further the actions that the Department of Environmental Quality would have taken in the absence of CAMA, but that's a very difficult task.

CAMA was promulgated in 2014. I know there were lawsuits pending at the time. It would be virtually impossible to see what actions or how those court proceedings would have occurred without CAMA.

Q. How would it have helped you, for purposes of your opinions, to understand how DEQ may have proceeded absent CAMA?

A. It would have helped me determine how costs for coal ash management could be spread between the shareholders and the ratepayers.

Q. And is that something you think with enough time you could have determined, or do you not think that was possible?
A. I really can't fully answer that question. It's hard to tell what else I would have discovered, given more time.
Q. What analysis would that entail?
A. Further discussion with DEQ's engineers and their counsel, how those cases are proceeding and where they perceive the cases are headed.
Q. But you did not have those discussions with anybody at DEQ?
A. No.
Q. Do you have any plans to have those discussions or do that analysis?
A. Not at this time.
Q. Did you visit any of DEP's impoundments in preparing your testimony?
A. Yes, in this case in particular, I visited the impoundment at the Mayo power plant.
Q. And why did you do that?
A. For several reasons; first, we had some new people on the public staff, just become generally aware of how the power plant was built and operated; to take a look at the Mayo zero liquid discharge system; see

the ash basin of the outfall and also see the landfill or the Mayo power plant and some of its coal ash.

Q. When was this visit?

A. It was in July of this year.

Q. And how did this visit aid you in preparing your testimony here?

A. I saw the construction of the Mayo ZLD system. I saw the construction of the impoundment. I saw the pumping system, how it gathers seep water and puts it back into the ash basin. I saw locations of outfall from the ash basin and other outfalls from wastewater operations that go into the basin. I saw DEP's trucking and landfilling of its coal ash.

Q. At the visit, did DEP give you access to see everything you wanted to see?

A. Yes, they did.

Q. Did you meet with any DEP employees in preparing your testimony?

A. Yes, I met with a plant operator.

Q. Was that at Mayo?

A. That was at Mayo. I met Joe Miller, who is in charge of fossil and hydro operations. That was Shannon Langley, who does environmental compliance with DEQ. I met some other staff members, but I can't remember their names.

Q. And we discussed the meeting at Mayo that was July of this year. And what did you discuss, if anything, with the plant operator?
A. The plant operator, I discussed the general operations of combustion of coal and making electricity.
Q. Okay. And you mentioned Joe Miller?
A. Yes.
Q. Okay. What did you discuss with Joe Miller?
A. I discussed with him how the plant is dispatched.
Q. Again, specifically related to Mayo?
A. Just to Mayo, yes.
Q. And then Shannon Langley?
A. He along with some other staff members from DEP showed us the operation of the Mayo ZLD.
Q. Okay. So did you meet with any DEP employees regarding any plants other than Mayo?
A. No.
Q. Is there any reason why meeting with DEP employees on plants other than Mayo wasn't helpful to you?
A. Well, I was able to gather other information I needed from data requests.

Q. In preparing your testimony, did anybody help you actually write your testimony?
A. Yes.
Q. Who helped you?
A. Some folks from the public staff's legal division, that was Dianna Downey, David Drooz and Layla Cummings. Also from the public staff's Water Division was Charles Junis, and I believe that's all the people that helped me in actually writing it.
Q. Who sat down and wrote the first draft?
A. It was in various pieces. All the people I just mentioned wrote pieces of it. There was no one first draft. It was various sections were written.
Q. In terms of earlier drafts, was there any opinions contained in any of the earlier drafts that were removed from the final draft?
A. Oh, we removed sections, yes.
Q. Can you describe those?
A. We attached -- we were planning to attach some of the responses to data requests that we removed. Other sections sometimes we don't believe are legally defensible. The draft phase is sort of like brainstorming. We initially write a pretty large draft, and we try to determine what's legal, defensible, where we can provide evidence to back up

our claims. That's about all I have to say on that.

Q. Can you recall any of those portions that were removed?

A. Yes. I had a portion that talked about some of the personnel changes at Duke Energy regarding construction of the Mayo ZLD. I had planned an exhibit, some of the letters between Duke Energy and its contractors on the Mayo ZLD and decided not to use that as an exhibit, ZLD and it stands for zero liquid discharge.

Q. Anything else?

A. I'm thinking more about the coal ash environmental portion. I can't recall any specifics, what we took out in my discussion of coal ash management environmental violations.

Q. Did any of the portions removed during the drafting process impact your ultimate opinions in this matter?

A. No. The final draft is my ultimate opinion.

Q. Did any of the portions removed change any of the recommendations, as compared to prior drafts?

A. No.

Q. And before we look at those opinions and recommendations, you had mentioned that part of your

discussions with Mr. Chernikov involved the permitting of seeps, is that right?
A. Yes.
Q. Okay. And did you discuss with him DEP's permit requests as they relate to seeps?
A. No. What I discussed with him was DEP's review of those seeps, and what DEQ plans to do as far as permitting those seeps.
He and along with Mr. Poupart, told me that DEQ is still reviewing seeps and has not made a final determination. It may seek to have some of those seeps as permitted outfalls, or it could attempt to enter into special orders by consent to get seeps corrected.
Q. In the course of your discussions, did you give an understanding that DEP has actually submitted permit requests?
A. Yeah, they told me -- permit renewals is what they called them. Yeah, DEP had submitted the permit renewals. Some of those permits had gone through hearing. So those permits appeared to be in the later stages of decision making.
Q. Do you know how long ago DEP submitted those permit requests or permit renewals?
A. I might have that information, give me a moment. I don't have that information.

Q. Okay. But you do know that DEQ has not acted on those permits yet?

A. It has not made a final decision. It has held public hearings on some of those permits.

Q. Okay. So if you could just give me a broad view of what are your recommendations to the utilities commission in this matter?

A. Okay. My recommendations, I say that -- I'm looking at page 62.

Q. That's page 62 of your testimony?

A. Page 62 of my testimony, let's start with line 6, and I'll read -- I'll start reading from there: Certain costs are so clearly due to company failure to comply with environmental regulations that none of these costs should be assigned to ratepayers. However, for most of the coal ash-related costs in the DEP rate request, there is some degree of DEP culpability for those costs due to noncompliance with environmental regulations, but it may fall short of imprudence.

In this situation, an equitable sharing of those costs is reasonable and appropriate, as discussed by public staff witness Maness.

Q. Thank you. Would you say that then page 62, line 6 through 13, summarize your recommendations to the utilities commission?

A. Yes.
Q. Are there any other recommendations you're making in this matter?
A. When I start on line six, I talk about certain costs. Specifically, I recommended removal of $6.6 million of costs for ground water extraction and treatment. Also recommend removal of $88,000 of litigation costs.
Q. And those are the certain costs you reference on line 6 of page 62?
A. Yes.
Q. We'll come back to those in just a minute.
So that's the certain costs on line 6, and then it looks like on line 8, you start with what it looks to be like a second recommendation where it starts however, is that right?
A. Yes, that's correct.
Q. Okay. And it says: For most of the coal ash-related costs, there's some degree of DEP culpability for these costs, is that right?
A. That's correct.
Q. And have you quantified those costs?
A. I have not, but other witnesses may have. Like I said, there's public staff witness Maness and also public staff witness Darlene Peaden who go into

more detail about cost exclusion.

Q. Have you reviewed the testimony of those witnesses?

A. Yes.

Q. Okay. And so those costs, as set forth by those witnesses, you understand those costs -- those witnesses have set forth those costs? That's your understanding?

A. Yes.

Q. Okay. And you have not personally analyzed what those costs are?

A. We took a look at a lot of costs. I'll give an example.

In DEP's E1 item 10 NC1800, I reviewed a lot of those costs along with public staff witness Maness.

Q. Okay. Anything else that you reviewed?

A. I reviewed the cost of the Mayo zero liquid discharge system.

Also worked with public staff witness Darlene Peaden at O&M expenses, took a look at any coal ash costs that might have been in operations and maintenance.

Q. And the last sentence, page 62, lines 11 through 13, it states: In this situation, an equitable sharing of those costs is reasonable and appropriate, as discussed by public staff witness Maness, is that right?

A. Yes.

Q. So the opinion that an equitable sharing of those costs is reasonable and appropriate, is that your opinion?

A. Yes.

Q. How did you arrive at that opinion?

A. I looked at some of the litigation that's in my Lucas Exhibit number 8. I looked at the requirements of the Coal Ash Management Act. I looked at NPDES violations, ground water exceedances, dam safety problems, and those are given in Lucas Exhibits 5, 6 and 7. And I can mention the costs in the NC1800, and we submitted data requests and asked DEP to explain its reason for including costs in the case. I reviewed those responses to data requests.

Q. Yes, sir. In terms of the portion of the opinion regarding equitable sharing, how did you arrive at that conclusion?

A. The equitable sharing?

Q. Yes, sir.

A. Like I said earlier, there was litigation in progress when CAMA became enacted. Since CAMA being state law, DEP had to comply with state law.

So since those cases were in progress, we can't determine exactly to the extent that DEP was at fault.

So balancing the requirements in CAMA with litigation that was in progress, that's how we came up with that word equitable -- that phrase equitable sharing.

Q. Okay. So as I understand it, you came up with the idea of equitable sharing, which, as I understand from your testimony, is a 50/50 cost sharing proposal, is that right?

A. That's not my testimony. That's a public staff witness Maness' testimony. He came up with that ratio.

Q. Okay, but the equitable sharing is part of your opinion?

A. Yes, where I came up with the idea that some of these costs should be shared between shareholders and ratepayers.

Q. So do you have an opinion on the ratio that's appropriate?

A. No.

Q. That was not part of your testimony?

A. No.

Q. And sitting here today, you do not have an opinion on a proper ratio of cost sharing?
A. No.
Q. But you did say that based upon the stage of litigation when CAMA was enacted, you were unable to determine fault as to any of the allegations made in that litigation, is that right?
A. I determined there was some fault by DEP. I couldn't determine the exact extent of the fault.
Q. How did you determine there was fault?
A. The millions of dollars of settlement costs that DEP paid out. The numerous NPDES violations with ground water exceedances and the dam safety problems.
Q. Okay. Let's take those one by one.
A. Okay.
Q. You determined there was some fault, that's your word, on behalf of DEP because of settlement payments, is that right?
A. That's correct.
Q. And why do you believe that the fact that a company pays a settlement means the company is at fault?
A. I don't believe DEP would have paid millions of dollars of settlement costs if it didn't believe it had some degree of fault.

Q. Have you ever worked at a private company?
A. I worked for a consulting firm, yes.
Q. Have you ever worked -- have you ever been involved in litigation at a large public company?
A. You mean, as an employee of a large company?
Q. Yes, sir.
A. No, I have not.
Q. Have you ever been involved in analyzing risks and benefits of litigation versus settlement for a private company?
A. Not until this case.
Q. And in this case, you were involved in weighing risks and benefits of settlement?
A. Yes.
Q. Okay. How so?
A. Reviewing the settlement -- the court orders in these cases, reviewing the evidence that the plaintiffs had, and just the dollar amount of the settlements.
Q. Okay. You were not then privy to any of Duke Energy Progress' decision making as it relates to entering into those settlements?
A. No, I was not.
Q. And you're not aware of the analysis that

they conducted, is that right?

A. No.

Q. And you're not aware as to what Duke Energy Progress calculated would be the costs of litigating the cases, even if they got a favorable outcome, is that right?

A. That's correct.

Q. Okay. So your conclusion though that the fact that they paid money in settlement allows you to conclude that DEP must have had some fault?

A. That and the NPDES violations of the ground water exceedances.

Q. Okay, we'll move on to there.

I think we did discuss a little bit about exceedances versus violations. Do you remember that?

A. Yes.

Q. Okay. So when you discuss here how ground water violations led you to believe that DEP shares some fault, what are you referring to?

A. I'm referring to my Lucas Exhibit number 6 and 7.

Q. Okay. And did you come to any conclusion as to the cost to DEP resulting specifically from what you call ground water violations?

A. Well, there's a cost I came up with the extraction and treatment of ground water that I recommended be removed at $6.6 million.

Q. Yes, sir. Anything else? Any other costs other than the $6.6 million that you attribute to the what you call ground water violations?

A. There's costs for litigation, costs for the settlements.

Q. Do you know --

A. I'm sorry, I believe DEP was culpable of creating the problems that led to those costs.

Q. Meaning the costs of the extraction?

A. Extraction and treatment of ground water.

Q. You mentioned costs of litigation and settlements. Do you know whether DEP is seeking to recover those costs in this matter?

A. A lot of the settlements it's not. There is that one $88,000 recommendation that I believe should not be passed on to ratepayers.

Q. Yes, sir. So as I understand it, with regard to ground water violations, you have two specific recommendations; the $6.6 million be excluded?

A. Yes.

Q. The $88,000 be excluded?

A. Yes.

Q. And in addition to that, there be cost

sharing?
A. Yes.
Q. But aside from the 6.6 and the $88,000, you, yourself, don't have any opinion on whether there are any increased costs because of the supposed violations that DEP is seeking to recover in this matter?
A. I believe DEP has a responsibility for a lot of other costs. I believe DEP was in trouble because of the NPDES violations, the ground water exceedances. There were similar cases against DEP. I believe there was definitely a lot of responsibility on DEP's part for those costs.
Q. Okay. What costs exactly were those?
A. Some of those costs were in the E1 item 10 1800. There were costs for settlement that DEP has not included in this case.
Q. I'm sorry, that they have not included?
A. They have not, that's correct. They have not included in this case. And since CAMA was enacted and satisfied some of their requirements that DEQ wanted, I believe there was some other costs that should be shared between the shareholders and the ratepayers.
Q. And why is that? I didn't quite understand

your last sentence.
A. Okay. Well, it was a long answer.
The first part of my answer I talk about DEP was in trouble. It had several court cases going on and documented violations and exceedances. CAMA cut some of that short. Also let me refer to another exhibit. First, let me -- I want to go to my testimony.
Q. Yes, sir.
A. Page 42 and -- page 42, beginning line 20, that presentation about the federal criminal case. And in that case, there was a court-appointed monitor, and DEP had to provide final audit reports that were done by a consultant. And those final audit reports show up on my Lucas Exhibit number 7. So they show ground water constituents that either exceeded the 2L or the IMAC.
Also I'd like to refer to my Exhibit number 9, and this is also -- these are excerpts from the joint factual statement in the criminal case, and this is a joint factual statement that DEP signed onto in, I believe there were 200 distinct seeps identified, and that's in paragraph 133. Later in that joint factual statement that DEP signed to it, this is paragraph 191, and it refers to the Flemington public utility, which

is close by the Sutton plant, and it had contaminated ground water that was entering drinking water wells.

I will read that paragraph 191: In June and July of 2013, Flemington's public utility concluded that boron from Sutton's ash ponds was entering its water supply. Tests of water from various wells at and near Sutton from that period showed elevated levels of boron, iron, manganese, thallium, selenium, cadmium and total dissolved solids.

So with all the information I just said, I believe that's one reason that led Duke to settle for millions of dollars in some of these cases listed here.

Q. Okay. So going through those three items that you identified, you first discuss the federal criminal case, and you talked about the costs of the consulting report, is that right?

A. I just talk about the results of the consulting report, not the costs.

Q. Okay. So are there costs you identified in connection with that item?

A. No, I don't define specific costs.

Q. Okay. And then in terms of you noted the seeps, the 200 distinct seeps, is that right?

A. Yes.

Q. Do you identify any costs that should be excluded as they relate to those seeps?

A. Not specifically. But going back to my equitable sharing statement that we discussed earlier, I believe that's how some costs could be excluded from Duke Energy Progress' rate request.

Q. Okay. But you don't have an opinion on the proper ratio?

A. No.

Q. Okay. And then you mentioned the Flemington community?

A. Yes.

Q. And, of course, Duke donated money to run a water line to Flemington, you understand that?

A. Yes.

Q. And that that -- those costs are not part of this rate recovery case, is that right?

A. As far as we know. We were not able to find those costs in Duke Energy Progress' rate request.

Q. Do you know when the donation was made?

A. I don't have the date.

MR. DROOZ: When you get to an appropriate point, I don't want to interrupt your flow.

MS. DINSMORE: Any time. This is fine.

MR. DROOZ: Fine with you?

THE WITNESS: Yes.

MS. DINSMORE: We'll go off the record.

THE VIDEOGRAPHER: The time is 10:24 a.m. We're off the record.

(Recess.)

THE VIDEOGRAPHER: The time is 10:46 a.m. We're back on the record.

BY MS. DINSMORE:

Q. Mr. Lucas, before the break, we were discussing some of the reasons you believe equitable sharing is appropriate in this matter. Do you remember that?

A. Yes.

Q. Okay. And I'd like to just talk about some specific costs. And one of the things that you noted were, in your mind, some issues regarding dam safety, is that right? You noted that as one of the reasons you support this equitable sharing principle, is that right?

A. That's correct.

Q. Okay. And have you undertaken any analysis of any specific costs you contend should be excluded from DEP's recovery based on dam safety issues?

A. I have not identified any specific costs.

Q. Do you have any opinion on what those specific costs might be?

A. Now DEP incurred some costs, and I want to refer to one of my exhibits. It's Lucas Exhibit number 3. It was the August 22, 2016 dam safety order. In that dam safety order, DEQ identified some corrective action that DEP must take to resolve any potential problems with dam safety.

Q. And in terms of the corrective action you're referring to in Exhibit 3, are there costs associated with that that you contend should be excluded?

A. I don't come up with specific costs, but I put this exhibit in along with the NPDES violation and ground water exceedance exhibits to show that DEP had not done a perfect job of managing its coal ash dams and that supports my equitable sharing where DEP's customers should not bear the full cost of problems that occurred with coal ash management.

Q. Okay. And with regard to the dam safety issues in particular, did you identify whether any of those issues increased the cost of clients with CAMA?

A. Yes, it did increase some costs, and I've gone back to pages 34 and 35 of my testimony. I will talk in general a little bit instead of having to read a lot of paragraphs.

Coal ash impoundment dam safety was under the responsibility of the utilities commission until 2009. That responsibility was given to DEQ at that time, but the coal ash impoundments that DEP owned were grandfathered. They didn't have to start all over and apply to DEQ like a brand new impoundment would have.

CAMA, removed the grandfathering provision, the Coal Ash Management Act, CAMA, removed that grandfathering provision. And I want to go back to page 35, specifically on line 13, and I'll read that sentence: CAMA further required that all CCR surface impoundments comply with more frequent and detailed inspection requirements.

On August 22, 2016, DEQ sent the company a dam safety order requiring repairs on several coal ash ponds, as shown in Lucas Exhibit number 3, and that's where I conclude DEQ's increased oversight did increase some costs.

Q. Okay. So the dam safety issues, as I understand it, in your mind, increased the cost of compliance under CAMA because of the dam safety order?

A. Yeah, DEP had some problems with its coal ash dams, and this was still two years after the Dan

River spill. DEQ still found some problems and required those to be corrected.

Q. And so the repairs you refer to on line 16 of page 35, those are the increased costs you contend due to the dam safety issues?

A. Yeah, they had increased -- DEP was under obligation to, of course, operate its coal ash dams correctly, and those corrections did lead to some increased costs.

Q. Okay. And I'm just trying to understand what those costs are.

What are the increased costs of CAMA compliance because of the dam safety issues you identified?

A. Oh, there's no specific cost requirements in CAMA. There are other law(sic) dam safety requirements outside of CAMA that DEP would have had to meet.

Q. Okay. So what are the costs of meeting those requirements that you believe should be excluded in this case?

A. I don't have a specific amount, but I would have to go back to any additional costs that DEP incurred, should be treated in that equitable sharing that I recommend.

Q. Okay. So you're not recommending an exclusion of any specific cost based on dam safety issues, as you describe them?

A. That's correct.

Q. Okay. You also mentioned a failure to comply with NPDES permit requirements, is that right?

A. Yes.

Q. Okay. And what costs, if any, do you contend should be excluded from rate recovery because DEP failed to comply with NPDES permit requirements?

A. I don't recommend any specific costs, but what happened, the failure of some of the impoundments to meet their NPDES requirements led to some of the lawsuits that I show in Lucas Exhibit number 8.

Q. Okay. And is DEP seeking to recover the costs of those lawsuits in this case?

A. I don't know of any specific costs they were trying to recover.

Q. That's not an analysis you perform?

A. I'm sorry, say that again?

Q. You didn't perform that type of analysis, as to any specific costs resulting from NPDES permit violations?

A. Not directly, but like I said earlier, some of those NPDES violations led to some of the lawsuits that I showed in Lucas Exhibit number 8. So indirectly, those violations did create costs.

Q. That -- you're not sure whether -- and you're not sure whether those costs are part of this rate recovery case?

A. I am not sure. Some of those costs could be in the E1 item 10 NC1800. I might not have been able to identify them, and like I said earlier, that's what led me to make my equitable sharing recommendation.

Q. So, again, just like with the dam safety issues, you're not recommending the exclusion of any specific costs, it's just part of your rationale for equitable sharing, is that right?

A. Yes.

Q. Okay. Going back to the dam safety issues, do you have any knowledge or did you acquire any knowledge of what permits are required to make dam repairs?

A. Permits aren't required to make dam repairs.

Q. Permits are not required?

A. To make repairs.

Q. What about enhancements to dams?

A. Yes, raising a dam, increasing the amount

of impounded water.
Q. Are you aware as to when any of -- any dam enhancement permits were issued by DEQ to DEP?
A. No.
Q. You didn't look at that as part of your analysis?
A. No.
Q. Finally, I think you mentioned, and we talked a little bit about ground water exceedances, and that was part of your rationale for cost sharing?
A. Yes.
Q. Okay. And did you identify any costs, specific costs you contend should be excluded from rate recovery because of ground water exceedances?
A. Yes, the extraction and treatment of ground water and some of the litigation costs.
Q. So that was the $6.6 million for the ground water extraction, and the $88,000 in litigation costs, is that right?
A. Yes. And also ground water exceedances, I believe, support my recommendation of equitable sharing.
Q. Okay. But other than those two things, there were no specific costs that you recommend for exclusion?

A. That's correct.
Q. Okay. If the commission accepted the equitable cost sharing principle, did you undertake any analysis of how much of the total cost allowance that would afford DEP?
A. No, that was done by public staff's witness Mike Maness.
Q. And do you know what that figure is?
A. He recommended a 50/50 sharing.
Q. Do you know the dollar value that would entail?
A. I don't have that in front of me.
Q. Have you seen it?
A. I've seen it, but I don't remember the exact amount.
Q. Okay. Are you aware of any instance of which the commission has supported the type of cost sharing that you're talking about?
A. Yes.
Q. Okay. So can you provide some examples?
A. Yes. One example is a abandoned nuclear construction, order and docket number E2 sub 481. I'll list off some docket numbers here. This is for abandoned nuclear construction, docket number E22 sub 224; E7 sub 338; E7 sub 358; E22 sub 273; E2 sub 537.

Q. And I'm sorry, were all of those docket numbers related to an abandoned nuclear construction?
A. That's correct.
Q. And did you review material from those matters in connection with preparing your testimony in this case?
A. No, that was reviewed by witness Mike Maness and is -- that's in his testimony.
Q. Okay. What do you understand about those matters?
A. That's cases where the commission determined that costs for nuclear abandonment should not be totally borne by the ratepayers. They should be shared between shareholders and ratepayers.
Q. Do you know the reason for that decision?
A. The reason is the companies take on some risk when they start investigating construction of nuclear power plants. It's a very expensive process. The early engineering, license applications are somewhat of a risk, and the utilities commission determined that risk should be shared between the shareholders and the ratepayers. It's a sharing of risk.
Q. Okay. Do you know what ratio the commission concluded was appropriate in that matter?

A. No.

Q. Do you know to what costs the commission applied that ratio of cost sharing?

A. No. I want to further clarify, Duke Energy Progress sent the public staff a data request, and they specifically reference witness Maness, and that was question number 2-47. His response to that data request would more fully answer your questions.

Q. Okay. But in terms of your opinions, you did not rely on any of that, that information in forming your opinions here?

A. Well, I did rely on it. I mean, I just see the case. It passed. Like I mentioned, there was some sharing of risk, so that did inform my opinion on equitable sharing.

Q. Okay. So the idea of sharing of risk informed your opinion in terms of sharing of future costs in this matter, is that right?

A. Yes.

Q. Okay. Why was that relevant to you?

A. Part of what we have to do is figure out responsibility between the shareholders and ratepayers. Since we weren't able to identify every cost we thought should be removed, each specific cost, and since CAMA came about in 2014, which cut some of the litigation short, but the test(sic) in this case is 2016, so we have two years of lapse, two years of CAMA would have been very, very difficult to determine specific costs.

So we thought there was good precedent for the equitable sharing of costs. And give me a moment, I want to --

Q. Please.

A. -- more fully answer your question.

(Pause.)

A. Just the difficulty of determining what costs imposed by the lawsuits would have been without CAMA, that's why I recommended equitable sharing.

Q. Okay. Because -- so as I understand it, because of the difficulty in determining specific costs, the solution is the wholesale equitable sharing? That's the rationale?

A. That's why I recommend equitable sharing. Of course, I want to clear, there are lots of instances in witness Darlene Peaden's testimony where we do identify specific costs. I don't want to say there were none. I'm just talking about my testimony and my recommendations.

Q. Understood, okay. You have been with the public staff since 2000, is that right?

A. Yes.

Q. When was the public staff first created? Do you know?
A. 1977.
Q. Okay. And you mentioned before, I believe, that until somewhat recently, the utilities commission actually received dam safety reports, is that right?
A. That was correct.
Q. And those dam safety reports you've reviewed, right, in the course of preparing your testimony?
A. No, I didn't.
Q. You did not?
A. No.
Q. Okay. So you're not familiar with the content of those dam safety reports?
A. That's correct.
Q. In the course of preparing your testimony, did you become aware of the public staff ever raising any concerns as to coal ash handling methodologies in the course of any prior rate proceedings?
A. We did with the Dominion, the previous Dominion rate case. We did review coal ash handling by Dominion Energy.
Q. And that was what year?
A. 2016.

Q. So recently?
A. Yes.
Q. And prior to 2014, have you -- are you aware of any instance in which the public staff has raised concerns as to coal ash handling methodologies in North Carolina?
A. No.
Q. And that's either by DEP or any company, is that right?
A. That's correct.
Q. Did you become aware of any concern on the part of the public staff, whether expressed to utility companies or not, regarding alleged ground water violations at any DEP site?
A. Yes, we talked a bit about the Sutton problems. Also it's about two and a half years ago, we suspected coal ash constituents were reaching some of the wells owned by Aqua North Carolina.
Q. And what did you do in response to those concerns? We'll start with the Aqua wells, is that over down in Belmont?
A. Yes.
Q. Okay. And what were the discussions surrounding that issue?
A. Just as part of this rate case, I discussed

that problem with Charles Junis of the public staff's Water Division.

Q. Did that issue impact your opinion from this case?

A. Yes.

Q. Okay. How so?

A. It was another instance of DEP being responsible for ground water contamination.

Q. Have you looked at the ground water monitoring results for the Aqua wells in Belmont?

A. No.

Q. Okay. Have you read any of the scientific literature about what impact, if any, the coal ash impoundments were having on those wells?

A. No.

Q. So you're not familiar with the Duke Energy study regarding those issues?

A. No.

Q. I'm sorry, the Duke University study?

A. Duke University study? No, I'm not familiar with it.

Q. Okay. Has the -- prior to this case, has the public staff ever informed DEP or its legacy companies that it was concerned with the history of environmental compliance?

A. Environmental compliance, as in previous cases, is air pollution requirements, example, the Clean Smokestacks Act of 2002 has come up in discussions in rate recovery.

Q. Okay. What about any concerns related to coal ash handling by Duke Energy? Has the public staff addressed those issues with Duke Energy prior to the current rate proceedings?

A. We had discussions very soon after the Dan River ash spill. I, along with Chairman Finley of the utilities commission; Chris Ayers, the executive director for the public staff, and my supervisor James McLawhorn, went up to the site a week or two after the spill and saw that the spilling would have occurred. We had been in some discussions ever since. I'm not -- and those discussions might not -- you said to public staff, it might not -- I might not necessarily be involved in all of them. Other people on the public staff might have been involved in discussions.

Q. Yes, sir. With respect to some of the issues you identified when we were talking earlier about dam safety issues, ground water issues, where you in your testimony you talk about what you call a history of issues going back several decades, do you know whether there have ever been any discussions

between the public staff of the utilities commission and DEP regarding those issues?
A. Not to my knowledge.
Q. Okay.
A. But I just want to preface, I'm one engineer on the public staff.
Q. I understand, and I am just asking for your personal knowledge.
A. Okay, yeah.
Q. You were here yesterday for Mr. Wittliff's testimony, is that right?
A. I was here for the morning but not the afternoon.
Q. Have you read his testimony?
A. Yeah, I've read a lot of it.
Q. And with respect to the costs that DEP is asking to recover in this matter, what is your understanding of Mr. Wittliff's position?
A. He's trying to remove a lot of the CAMA costs.
Q. Anything else?
A. That's all I remember from it.
Q. Do you agree with that position?
A. I don't believe I'm in a position to agree or disagree. The attorney general and the public staff

develop its recommendations independently of each other. And in my testimony, I discuss the complexity, I discuss some of the options that could be considered, and I discuss how the public staff developed its opinion. I can't really opine on the quality or what his recommendations were. It certainly fell into one of the options that I discussed.

Q. But not one of the options you ultimately concluded was appropriate, is that right?

A. That's correct.

Q. Okay. Have you read the testimony of CUCA witness O'Donnell?

A. No, I haven't.

Q. Do you have -- we've discussed a number of your opinions and conclusions. Do you have opinions or conclusions regarding this matter, other than what appears in your written testimony?

A. No.

Q. Do you think that during the course of our discussion today, we have summarized your opinions and conclusions?

A. We have. I would like to be a little more specific though.

Q. Yes, sir, please.

A. Okay. Page 62, I read lines 6 through 13 of my testimony, page 62, and at that time, you were asking me questions in general, I'd like to read a little bit more, just to be clear. I'd like to go more into the specifics.

Q. Yes, sir.

A. I want to read page 62, starting on line 14: In particular, the public staff recommends that the following expenditures be excluded from rate recovery: One, DEP litigation costs and settlement payments in cases where there are environmental violations; two, costs to remedy environmental violations where the costs exceed what CAMA would have required in the absence of environmental violations and three, costs required to be excluded under probation conditions of the federal plea agreement.

These exclusions are in addition to the recommended disallowances from Garrett & Moore to the extent there is no double disallowance for the same item.

Q. Okay. So with regard to those three items, to make sure that we fully cover your testimony today, with regard to number one, which starts on page 62, line 15, it reads: DEP litigation costs and settlement payments in cases where there are environmental violations.

So you and the public staff recommend that that be excluded?

A. That's correct.

Q. Have you identified, other than the $88,000 we discussed, have you identified any specific costs related to number one?

A. No.

Q. Okay. Number two states: Costs to remedy environmental violations, where the costs exceeded what CAMA would have required in the absence of environmental violations.

We discussed your proposal for equitable sharing. Have you identified any specific costs outside of the $6.6 million we discussed that would fall under this provision?

A. No.

Q. Okay. And then three, costs required to be excluded under the probation conditions of the federal plea agreement.

Have you identified any specific costs that fall under that provision that DEP is seeking to recover?

A. No, to my knowledge, DEP has excluded those costs for rate recovery.

Q. Okay. Having gone through those in

addition to our prior discussion, have we now today fully summarized your testimony and opinions in this case?

A. Yes..

MS. DINSMORE: If you don't mind, I'll just take five minutes, make sure I have enough to wrap up.

THE WITNESS: Okay.

MS. DINSMORE: Off the record.

THE VIDEOGRAPHER: The time is 11:17 a.m. We're off the record.

(Recess.)

THE VIDEOGRAPHER: The time is 11:31 a.m. We're back on the record.

BY MS. DINSMORE:

Q. Mr. Lucas, I just wanted to discuss a little bit about the -- one of the two specific costs that you identified, which is the $6.6 million for -- related to extraction. Do you recall?

A. Yes. Yes.

Q. And I believe in response to a data request, the public staff stated that in its opinion, the necessity of extracting and treating water at Sutton is the result of mismanagement. Do you recall that?

A. Yes. And part of my review of that cost was going through the E1 item 10 NC1800. That's where I first identified those costs, and some of those costs are attributable also to the Asheville plant and the H.F. Lee plant.

Q. Okay. So in terms of the $6.6 million, but -- the idea is that the necessity of extracting and treating the water at those plants is the result of mismanagement, is that the --

A. Yes, if the ground water was clean, Duke Energy would not have gone to the expense of extracting and treating the ground water.

Q. Okay. So it's based on the fact of exceedances, or do you believe it's based on mismanagement that they undertook that expense?

A. I believe mismanagement created the exceedances.

Q. Okay. And what experience do you have specifically with ground water remediation that supports that opinion?

A. When I was working on NPDES permits in the mid-1990s, one of the types of permits I worked on was ground water extraction and treatment.

Q. How did that experience inform your opinion here, as it relates to exceedances being the result of mismanagement?

A. Part of the documentation that I saw was identifying a responsible party and who was going to pay for that extraction and treatment.

Q. The responsible party in terms of the responsible financial party, is that right?

A. Yes. Well, it's not just -- the responsible party for creating environmental violation frequently was the financial responsible party, but not always.

Q. Okay. In the course of preparing your testimony in this case, did you learn anything about ground water contamination at ash basins, other than those owned by Duke Energy?

A. I'm sorry, can you say that question again, please?

Q. Sure. Do you have any knowledge about ground water exceedances or ground water contamination at other ash basin facilities, other than those owned by Duke Energy?

A. No.

Q. Do you know whether ground water exceedances of certain constituents near coal ash basins is an issue unique to Duke Energy?

A. It's not unique to Duke Energy, that's why

EPA CCR rule was promulgated.

Q. And part of the development of the CCR rule involved EPA studying damage cases regarding ground water, is that right?

A. Do you mean legal damages? Can you please clarify the question?

Q. Sure. How do you understand that EPA studied the ground water in connection with coal ash cases in promulgating the CCR rule?

A. It looked at actual problems that occurred at power plants around the United States. It mentioned some of them in the preamble. It talks about Dan River. It talks about Duke Energy. It talks about the TVA spill in 2008.

Q. Actually, the EPA cited 60 instances across the country, is that right?

A. I don't know the number.

Q. Okay. But it certainly wasn't an issue unique to Duke Energy?

A. That's correct.

Q. Is it your opinion that in all of those cases, there was a degree of mismanagement by all of those companies?

A. I can't state what was going on at the other companies.

Q. So is it your opinion that the fact of ground water contamination means there is mismanagement?

A. It could be. It could be the result of mismanagement of an ash basin.

Q. It could be. Is it necessarily the result of mismanagement?

A. Yes, if the electric utility is responsible for contaminant in the ground water, that's mismanagement.

Q. So in all the cases cited by the EPA across the country, it's your opinion that there must have been mismanagement in all those cites?

A. I really can't speak what was going on in other companies, and specifically what led to the promulgation of the EPA's CCR rule.

Q. Okay. So whether applicable to this case, you could envision a situation where there are ground water exceedances around a coal ash impoundment that are not the result of mismanagement?

A. If they're the responsibility of the utility company, I believe it is. Maybe I'm misunderstanding your question. There could be exceedances of 2L standards due to background levels, but in this case, the background level becomes the new standard.

Q. And that involves an analysis to determine what the background levels were?

A. Yes.

Q. And if I recall your testimony, that's not an analysis you did in this case?

A. Well, the public staff sent DEP a data request, where DEP believed it had exceedances, and DEP responded. It did point out thousands of exceedances.

Q. Okay. And you believe that all of those exceedances are the result of mismanagement?

A. I can't say every single one of them. Certainly some of them were that led to my conclusion, that ground water extraction treatment should not be passed on to the ratepayers.

Q. Is there anything about the design of the basins themselves, rather than the operation or management that could have resulted in the ground water exceedances?

A. Yes.

Q. Okay. Can you tell me about that?

A. Not having impervious barriers could be one problem.

Q. Any other problems regarding the design?

A. Improper outfall drainage, that could lead to higher levels, which would put more pressure on the ground water. That's all I can think of at the moment.

Q. And thinking about Sutton, what, if anything, do you think that DEP should have done to avoid the need to extract and treat the ground water at that plant?

A. I believe Duke Energy Progress should have brought the ash basins up to modern standards. Those ash basins were built decades ago. The Clean Water Act of 1972, the Resource Conservation Recovery Act of 1976, more and more environmental awareness was coming about, and I believe Duke Energy Progress at that time certainly should have been aware that there were potential problems that could have arisen from ash basins and causing ground water problems.

Q. And when do you think that DEP should have taken those steps?

A. The 1970s.

Q. And if in the 1970s, DEP had taken those steps and incurred costs related to doing so, do you think at that time, those costs would have been recoverable?

A. Yes.

Q. In regards to those types of actions, do you think it's reasonable for DEP to follow DEQ's

direction with regards to management of ash basins?
A. Yes.
Q. So certainly it wouldn't be mismanagement to follow DEQ's directions?
A. It would not be mismanagement, but absent DEQ's direction, I believe DEP is still responsible if it created ground water contamination.
MS. DINSMORE: Okay. That's all the questions I have. Thank you so much for your time, Mr. Lucas.
THE WITNESS: Thank you.
EXAMINATION BY COUNSEL FOR THE UTILITIES COMMISSION
BY MR. DROOZ:
Q. Just a few follow-up questions here.
Mr. Lucas, you were asked about the distinction between exceedance and violation. Is there any guidance in 2L about that?
A. Yes. I'm going to go back to my Exhibit number 2. This is on the second page, middle of that page starts Section E. And in that section it's a long sentence, but I'll start halfway through that sentence. I guess I'll summarize it.
If a person conducting or controlling activity that results in an increase in concentration

of a substance in excess, which is an exceedance of the standards at or beyond the compliance boundaries specified in the permit, shall do the following steps.

The steps are numbered one through four.

Step number three -- and there's one thing that the responsible party has to do. To submit a report to the secretary assessing the cause, significance and extent of the violation, and that's a distinction where an exceedance becomes a violation.

Q. If the concentration of a constituent of interest is above the 2L threshold because a naturally-occurring background, would that be a violation?

A. No, if the background level is higher than the 2L standard, then the background level becomes the standard.

Q. If the constituent of interest is above the 2L threshold, not because of natural background causes, but because of migration from an ash basin, would that be a violation?

MS. DINSMORE: Objection. Go ahead.

A. If that exceedance is beyond the compliance boundary, then that would be a violation.

Q. You were asked about your -- to summarize your conclusions and recommendations, and you referenced page 62 regarding the environmental violations in coal ash. Did you have other recommendations?

A. Yes. At that time, we were discussing coal ash, I mean, I have other recommendations, and I'd like to start on page 3, line 10. That's where I'm asked to summarize my recommendations, and I'll do that again here, starting on line 13 on page 3: Exclude $34.3 million from the rate base related to Mayo plant ZLD construction delays and cost overruns.

Item two: Certain coal ash disposal costs should be excluded from the fuel clause.

And number three goes more toward -- we spent most of the time talking about exclusions include DEP's litigation costs in cases where there are environmental violations, costs to remedy environmental violations, where the costs exceed what CAMA would have required in the absence of environmental violations; and three, costs required to be excluded under the probation conditions of the federal plea agreement.

Q. And does that summarize all the different areas of your testimony?

A. Yes, it does.

Q. You were asked about visiting Duke Energy Progress coal fired plants in the course of your investigation, and you mentioned Mayo. Have you visited other Duke Progress coal fired plants?

A. Yes, before the rate case, I visited the H.F. Lee plant, I visited the Sutton plant and the Asheville plant.

Q. You were asked if the public staff had raised any concerns regarding exceedances, seeps, dam safety issues in the past. What is the public staff's role as a state agency?

A. Public staff is to protect the using and consuming public while reviewing the managerial, financial and technical aspects of the company. We're not environmental regulators.

Q. Is the focus of the commission authority and the public staff role regulation of cost and rates?

A. Yes.

Q. And who does environmental regulation for the State of North Carolina?

A. That's the Department of Environmental Quality.

Q. You were asked if the fact of an exceedance, and I think this is in reference to settlement, but also generally, if that by itself constituted mismanagement, and if there's one or a minor number of noncompliances, would that be mismanagement?

A. Yes, if the exceedances of the ground water standards were the responsibility or caused by Duke Energy Progress, I would call that mismanagement.

Q. How many exceedances do you show in your Exhibit 6, I think it is --

A. Over 8,000.

Q. Does the extent of exceedances matter?

A. I'll give an example. In the EPA CCR rule, there's an appendix three, and there's a list of several constituents there, and just statistically significant exceedance of just one of those constituents requires remediation action by the company.

Q. Do you have a copy of the response that has your name on it with -- to the data request from Duke Energy Progress.

A. Sorry?

Q. Data request two that they --

A. No, I don't have a copy of that, the response to that data request.

MR. DROOZ: Do you mind if I hand him one?

A. This is coal ash data request number two.

MS. DINSMORE: Can I just see what

you're going to reference? I assume you're not marking it as an exhibit?

MR. DROOZ: We're not, 2-36.

MS. DINSMORE: Oh, that's fine.

A. Oh, I'm sorry, I'm mistaking your question completely. You mean data request number two to the company, or data request number two to the public staff?

Q. From the company to the public staff after your testimony was filed.

A. Okay, I'm sorry, I misunderstood.

I don't have a copy of that.

Q. Could you read the response that appears there?

A. And this response 2-36, question 2, item 36, and the question relates to extracting and treating contaminated ground water. There was extraction and treatment at Sutton, Asheville and H.F. Lee. DEP agreed to this in settlement. Absent years of ground water violations at those plants, there would not have been a need to settle. Years of ground water violations show a pattern of noncompliance. That is the mismanagement. Regardless of whether this constitutes traditional imprudence, a properly managed utility would not have had to extract and treat ground water, unless it was contaminated.

Q. Were you involved in preparing that response?

A. Yes..

Q. Do you agree with that response?

A. Yes.

MR. DROOZ: Okay. That's all my questions.

FURTHER EXAMINATION BY COUNSEL FOR DUKE ENERGY

BY MS. DINSMORE:

Q. Just one follow up.

We went back on the cross to page three of your testimony?

A. Yes.

Q. Where it(sic) please summarize your recommendations.

A. Yes.

Q. And I just wanted to clarify with regards to number three, which is page three line 18 through page 4, line 5.

A. Yes,

Q. Have we fully discussed your opinions, as it relates to that recommendation at today's deposition?

A. Yes.

MS. DINSMORE: Okay, thank you. Nothing further.

THE VIDEOGRAPHER: The time is 11:52 a.m. We're off the record.

(Whereupon the deposition was concluded at 11:52 a.m.)

(Signature reserved.)

SIGNATURE PAGE

____

JAY LUCAS

SUBSCRIBED AND SWORN to before me this ______ day of ______________________, 2017.

____

NOTARY PUBLIC

My Commission expires: ______________________

ERRATA PAGE

MMV

CASE NAME: In the Matter of Duke Energy Progress

WITNESS NAME: JAY LUCAS

DATE: November 2, 2017

PAGE	LINE	READS	SHOULD READ	REASON FOR CHANGE

CERTIFICATE

I, Marisa Munoz-Vourakis, RMR, CRR and Notary Public, the officer before whom the foregoing proceeding was conducted, do hereby certify that the witness(es) whose testimony appears in the foregoing proceeding were duly sworn by me; that the testimony of said witness(es) were taken by me to the best of my ability and thereafter transcribed under my supervision; and that the foregoing pages, inclusive, constitute a true and accurate transcription of the testimony of the witness(es).

I do further certify that I am neither counsel for, related to, nor employed by any of the parties to this action in which this proceeding was conducted, and further, that I am not a relative or employee of any attorney or counsel employed by the parties thereof, nor financially or otherwise interested in the outcome of the action.

IN WITNESS WHEREOF, I have hereunto subscribed my name this 6th day of November, 2017.

Marisa Munoz-Vourakis

MARISA MUNOZ-VOURAKIS

Notary #20032900127

85:10

I/A

DOMINION ENERGY NORTH CAROLINA
Docket No. E-22, Sub 562
North Carolina Retail Operations
AMORTIZATION SCHEDULE FOR DEFERRED
CCR COSTS
For the Test Year Ended December 31, 2018
(in Thousands)

Maness Exhibit I
Schedule 1-1

		DENC Coal Ash Spend			DENC N.C. Retail Coal Ash Deferral							
Line No.	Month	System Spend per Company 1/	Public Staff Prudence Adjustments 2/	System Spend per Public Staff 3/	% to NC for Spend 4/	Beginning Balance 5/	NC Spend 6/	Ending Balance 7/	Deferred Cost of Debt 8/	Deferred Cost of Equity 9/	Total Return 10/	Ending Balance 11/
		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)
1	Jun-16							$ -				
2	Jul-16	$ 8,385	$ -	$ 8,385	5.0924%	$ -	$ 427	427	$ 0	$ 1	$ 1	$ 428
3	Aug-16	8,504	-	8,504	5.0924%	427	433	860	1	3	4	865
4	Sep-16	15,634	-	15,634	5.0924%	860	796	1,656	2	5	7	1,668
5	Oct-16	10,413	-	10,413	5.0924%	1,656	530	2,186	3	8	11	2,209
6	Nov-16	9,958	-	9,958	5.0924%	2,186	507	2,694	3	10	14	2,730
7	Dec-16	34,895	-	34,895	5.0924%	2,694	1,777	4,471	5	15	20	4,527
8	Jan-17	(342)	-	(342)	5.0924%	4,471	(17)	4,453	6	19	25	4,535
9	Feb-17	7,055	-	7,055	5.0924%	4,453	359	4,812	6	20	26	4,921
10	Mar-17	11,081	-	11,081	5.0924%	4,812	564	5,377	7	22	29	5,514
11	Apr-17	16,106	-	16,106	5.0924%	5,377	820	6,197	8	25	33	6,367
12	May-17	5,783	-	5,783	5.0924%	6,197	295	6,491	9	27	36	6,697
13	Jun-17	13,484	-	13,484	5.0924%	6,491	687	7,178	10	29	39	7,423
14	Jul-17	5,304	-	5,304	5.0924%	7,423	270	7,693	11	32	43	7,735
15	Aug-17	19,983	-	19,983	5.0924%	7,693	1,018	8,710	11	35	46	8,799
16	Sep-17	11,814	-	11,814	5.0924%	8,710	602	9,312	13	38	51	9,452
17	Oct-17	13,689	-	13,689	5.0924%	9,312	697	10,009	13	41	55	10,204
18	Nov-17	6,321	-	6,321	5.0924%	10,009	322	10,331	14	43	58	10,583
19	Dec-17	20,347	-	20,347	5.0924%	10,331	1,036	11,367	15	46	61	11,681
20	Jan-18	6,396	-	6,396	5.0924%	11,367	326	11,693	16	49	65	12,072
21	Feb-18	9,058	-	9,058	5.0924%	11,693	461	12,154	17	51	67	12,601
22	Mar-18	10,001	-	10,001	5.0924%	12,154	509	12,663	17	53	70	13,180
23	Apr-18	8,899	-	8,899	5.0924%	12,663	453	13,117	18	55	73	13,706
24	May-18	8,945	-	8,945	5.0924%	13,117	456	13,572	19	57	76	14,237
25	Jun-18	6,001	-	6,001	5.0924%	13,572	306	13,878	19	59	78	14,621
26	Jul-18	9,256	-	9,256	5.0924%	14,621	471	15,092	21	63	84	15,176
27	Aug-18	8,805	-	8,805	5.0924%	15,092	448	15,540	21	65	87	15,711
28	Sep-18	7,889	-	7,889	5.0924%	15,540	402	15,942	22	67	89	16,202
29	Oct-18	12,255	-	12,255	5.0924%	15,942	624	16,566	23	69	92	16,918
30	Nov-18	7,088	-	7,088	5.0924%	16,566	361	16,927	23	71	95	17,374
31	Dec-18	21,667	-	21,667	5.0924%	16,927	1,103	18,031	24	75	99	18,576
32	Jan-19	3,464	-	3,464	5.0924%	18,031	176	18,207	25	77	103	18,855
33	Feb-19	5,173	-	5,173	5.0924%	18,207	263	18,470	26	78	104	19,222
34	Mar-19	7,223	-	7,223	5.0924%	18,470	368	18,838	26	80	106	19,696
35	Apr-19	6,973	-	6,973	5.0924%	18,838	355	19,193	26	81	108	20,158
36	May-19	6,457	-	6,457	5.0924%	19,193	329	19,522	27	83	110	20,597
37	Jun-19	12,729	-	12,729	5.0924%	19,522	648	20,170	28	85	112	21,357
38	Jul-19	-	-	-	5.0924%	21,357	-	21,357	30	91	121	21,478
39	Aug-19	-	-	-	5.0924%	21,357	-	21,357	30	91	121	21,599
40	Sep-19	-	-	-	5.0924%	21,357	-	21,357	30	91	121	21,720
41	Oct-19	-	-	-	5.0924%	21,357	-	21,357	30	91	121	21,841
42	Total	$ 376,693	$ -	$ 376,693			$ 19,183		$ 653	$ 2,005	$ 2,658	

1/ NCUC Form E-1, Supplemental Item 10, Page 174 of 350, Column (1).
2/ There are no Public Staff recommended prudence disallowances to the deferred CCR costs.
3/ Column (a) plus Column (b).
4/ NCUC Form E-1, Supplemental Item 10, Page 174 of 350, Column (2).
5/ Amount in Column (g) of previous line, plus return for prior 12 months in July of each year.
6/ Column (c) times Column (d).
7/ Column (e) plus Column (f).
8/ Column (e) plus Column (g), divided by 2, times after tax cost of debt per NCUC Form E-1, Supplemental Item 10, Page 179 of 350, divided by 12.
9/ Column (e) plus Column (g), divided by 2, times after tax cost of equity per NCUC Form E-1, Supplemental Item 10, Page 179 of 350, divided by 12.
10/ Column (h) plus Column (i).
11/ Column (g) plus total return for year to date from Column (j).

I, A

DOMINION ENERGY NORTH CAROLINA
Docket No. E-22, Sub 562
North Carolina Retail Operations
ADJUSTMENTS TO DEFERRED CCR COSTS
For the Test Year Ended December 31, 2018
(in Thousands)

Maness Supplemental Exhibit I
Schedule 1

Line No.	Item	NC Retail Amount	
	Income statement impact		
1	Balance for Amortization	$ 21,841	1/
2	Years to Amortize	18	2/
3	Annual amortization per Public Staff (L1 / L2)	1,213	
4	Annual amortization per Company	7,303	3/
5	Public Staff adjustment to other O&M expense (L3 - L4)	$ (6,090)	
6	Statutory tax rate	25.6228%	4/
7	Public Staff adjustment to income taxes (-L5 x L6)	$ 1,560	
	Rate base impact		
8	Coal Ash Balance at May 1, 2018 per Public Staff (L1)	$ 21,841	
9	Less annual amortization (-L3)	(1,213)	
10	Annualized Coal Ash Deferral Balance per Public Staff (L8 + L9)	20,627	
11	Coal Ash Deferral Balance per Company filings	14,607	5/
12	Public Staff annualization adjustment to coal ash deferral balance (L10 - L11)	6,020	
13	Adjustment to remove remaining coal ash deferral balance from rate base (-L10)	(20,627)	
14	Total Public Staff adjustment to total additions (L12 + L13)	$ (14,607)	
15	Adjustment to ADIT (-L14 x L6)	$ 3,743	

1/ Maness Supplemental Exh bit I, Schedule 1-1, Line 41, Column (k).
2/ Amortization period recommended by Public Staff to achieve equitable sharing - approx. 60% to ratepayers, 40% to stockholders.
3/ Supplemental Company Exhibit PMM-1, Schedule 3, Page 2, Line NC-33.
4/ Johnson Exh bit 1, Schedule 1-3, Line 8.
5/ NCUC Form E-1, Supplemental Item 10, Page 310 of 350, Line 4.

DOMINION ENERGY NORTH CAROLINA
Docket No. E-22, Sub 562
North Carolina Retail Operations
AMORTIZATION SCHEDULE FOR DEFERRED
CCR COSTS
For the Test Year Ended December 31, 2018
(in Thousands)

Maness Supplemental Exhibit I
Schedule 1-1

Line No.	Month	DENC Coal Ash Spend: System Spend per Company 1/	Public Staff Prudence Adjustments 2/	System Spend per Public Staff 3/	DENC N.C. Retail Coal Ash Deferral: % to NC for Spend 4/	Beginning Balance 5/	NC Spend 6/	Ending Balance 7/	Deferred Cost of Debt 8/	Deferred Cost of Equity 9/	Total Return 10/	Ending Balance 11/
		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)
1	Jun-16							$ -				
2	Jul-16	$ 8,385	$ -	$ 8,385	5.0924%	$ -	$ 427	427	$ 0	$ 1	$ 1	$ 428
3	Aug-16	8,504	-	8,504	5.0924%	427	433	860	1	3	4	865
4	Sep-16	15,634	-	15,634	5.0924%	860	796	1,656	2	5	7	1,668
5	Oct-16	10,413	-	10,413	5.0924%	1,656	530	2,186	3	8	11	2,209
6	Nov-16	9,958	-	9,958	5.0924%	2,186	507	2,694	3	10	14	2,730
7	Dec-16	34,895	-	34,895	5.0924%	2,694	1,777	4,471	5	15	20	4,527
8	Jan-17	(342)	-	(342)	5.0924%	4,471	(17)	4,453	6	19	25	4,535
9	Feb-17	7,055	-	7,055	5.0924%	4,453	359	4,812	6	20	26	4,921
10	Mar-17	11,081	-	11,081	5.0924%	4,812	564	5,377	7	22	29	5,514
11	Apr-17	16,106	-	16,106	5.0924%	5,377	820	6,197	8	25	33	6,367
12	May-17	5,783	-	5,783	5.0924%	6,197	295	6,491	9	27	36	6,697
13	Jun-17	13,484	-	13,484	5.0924%	6,491	687	7,178	10	29	39	7,423
14	Jul-17	5,304	-	5,304	5.0924%	$\boxed{7,423}$	270	7,693	11	32	43	7,735
15	Aug-17	19,983	-	19,983	5.0924%	7,693	1,018	8,710	11	35	46	8,799
16	Sep-17	11,814	-	11,814	5.0924%	8,710	602	9,312	13	38	51	9,452
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21	Feb-18	9,058	-	9,058	5.0924%	11,693	461	12,154	17	51	67	12,601
22	Mar-18	10,001	-	10,001	5.0924%	12,154	509	12,663	17	53	70	13,180
23	Apr-18	8,899	-	8,899	5.0924%	12,663	453	13,117	18	55	73	13,706
24	May-18	8,945	-	8,945	5.0924%	13,117	456	13,572	19	57	76	14,237
25	Jun-18	6,001	-	6,001	5.0924%	13,572	306	13,878	19	59	78	14,621
26	Jul-18	9,256	-	9,256	5.0924%	$\boxed{14,621}$	471	15,092	21	63	84	15,176
27	Aug-18	8,805	-	8,805	5.0924%	15,092	448	15,540	21	65	87	15,711
28	Sep-18	7,889	-	7,889	5.0924%	15,540	402	15,942	22	67	89	16,202
29	Oct-18	12,255	-	12,255	5.0924%	15,942	624	16,566	23	69	92	16,918
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34	Mar-19	7,223	-	7,223	5.0924%	18,470	368	18,838	26	80	106	19,696
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37	Jun-19	12,729	-	12,729	5.0924%	19,522	648	20,170	28	85	112	21,357
38	Jul-19	-	-	-	5.0924%	$\boxed{21,357}$	-	21,357	30	91	121	21,478
39	Aug-19	-	-	-	5.0924%	21,357	-	21,357	30	91	121	21,599
40	Sep-19	-	-	-	5.0924%	21,357	-	21,357	30	91	121	21,720
41	Oct-19	-	-	-	5.0924%	21,357	-	21,357	30	91	121	21,841
42	Total	$ 376,693	$ -	$ 376,693			$ 19,183		$ 653	$ 2,005	$ 2,658	

1/ NCUC Form E-1, Supplemental Item 10, Page 174 of 350, Column (1).
2/ There are no Public Staff recommended prudence disallowances to the deferred CCR costs.
3/ Column (a) plus Column (b).
4/ NCUC Form E-1, Supplemental Item 10, Page 174 of 350, Column (2).
5/ Amount in Column (g) of previous line, plus return for prior 12 months in July of each year.
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8/ Column (e) plus Column (g), divided by 2, times after tax cost of debt per NCUC Form E-1, Supplemental Item 10, Page 179 of 350, divided by 12.
9/ Column (e) plus Column (g), divided by 2, times after tax cost of equity per NCUC Form E-1, Supplemental Item 10, Page 179 of 350, divided by 12.
10/ Column (h) plus Column (i).
11/ Column (g) plus total return for year to date from Column (j).

Dominion Energy North Carolina
Docket No. E-22, Sub 562
Twelve Months ended December 31, 2018
(000's)

Annualize Depreciation Expense

Purpose Depreciation expense is annualized based on the Plant in Service balance at June 30, 2019.

Method The first step in determining the increase in Depreciation Expense is to calculate the amount of North Carolina Jurisdiction Depreciation Expense at the end of the test period (line 2).

The amount of Depreciation Expense for each segment is then determined (Page 3). Depreciation Expense through June 2019 for each segment (Page 3, line 4) is multiplied by 12 to calculate the annualized Depreciation Expense amount. The North Carolina Jurisdiction amount is determined by applying the North Carolina Jurisdictional factor calculated on page 7 to each segment amount.

The End of Test Period amount on line 2 is compared to the amount on line 1 to determine the total adjustment amount found on line 3.

On line 4, the amount calculated on line 3 is reflected as an adjustment to the Provision for Accumulated Depreciation to reflect the annualization of depreciation expense.

Additionally, line 6 of the adjustment calculates an adjustment to the accumulated deferred income taxes amount to reflect the annualization of depreciation expense.

Dominion Energy North Carolina
Annualize Depreciation Expense

Line No.	Description	Production	Transmission	Distribution	General	Intangible	Capital Lease	Total
1	Depreciation Expense for June 2019 Excluding ARO Activity (Page 4)	$ 44,279	$ 20,273	$ 30,477	$ 2,980	$ 2,609	$ 451	
2	Less Ringfenced Projects (Page 5)	1,253	5	31	12	0	-	
3	Less Distribution Strategic Underground Project (VA Only Activity) (Page 6)	-	-	1,167	-	-	-	
4	Total Depreciation Expense as of June 2019 (Line 1 - Line 2 - Line 3)	$ 43,026	$ 20,267	$ 29,279	$ 2,968	$ 2,609	$ 451	
5	Annualized Depreciation Expense (Line 4 x 12)	$ 516,312	$ 243,205	$ 351,346	$ 35,617	$ 31,307	$ 5,407	
6	North Carolina Jurisdictional Factor (Page 7)	5.2081%	4.2715%	5.1132%	6.9901%	4.9997%	5.0642%	
7	**North Carolina Jurisdiction Depreciation Expense (Line 5 x Line 6)**	$ 26,890	$ 10,388	$ 17,965	$ 2,490	$ 1,565	$ 274	$ 59,572

Dominion Energy North Carolina					
Annualize Depreciation Expense					
Page 4 of 8					
			Amort of Limited	**Amort of Other**	
	Functional	**Deprec Expense**	**Electric Plant**	**Elec Plant**	
Line No.	**Classification**	**Account 403**	**Account 404**	**Account 405**	**TOTAL**
1	Intang ble Plant	-	2,609,042	-	2,609,042
2	Steam Production Plant	16,512,533	-	-	16,512,533
3	Nuclear Production Plant	9,673,402	-	-	9,673,402
4	Hydraulic Production	2,356,446	-	-	2,356,446
6	Other Production Plant	15,165,793	-	570,893	15,736,686
7	Transmission Plant	20,272,535	-	-	20,272,535
8	Distr bution Plant	30,477,402	-	-	30,477,402
9	Regional Transmission & Market Operation	-	-	-	-
10	General Plant	2,979,582	450,569	-	3,430,151
11	Common Plant - Electric	-	-	-	-
12	TOTAL	97,437,693	3,059,611	570,893	101,068,197
	Source: Fixed Asset Accounting				

Dominion Energy North Carolina
Annualize Depreciation Expense
Ring-fence Solar June 2019 Dep Exp

Function	June 2019 Expense
Intangible Plant	142
Other Production	1,253,051
Transmission Plant	5,444
Distribution Plant	31,249
General Plant	11,511
	1,301,396

Note: Excludes ARC Expense

Dominion Energy North Carolina
Annualize Depreciation Expense
Rider U June 2018 Expense

FERC	**Amount**
Distribution	1,167,310

Display Document: Data Entry View

Display Currency   General Ledger View

Data Entry View

Document Number	100505026	Company Code	1000	Fiscal Year	2019	Archive	☐
Document Date	06/30/2019	Posting Date	06/30/2019	Period	6		
Reference	UG RIDER	Cross-Comp.No.					
Currency	USD	Texts Exist	☐	Ledger Group			

Co	Itm	Clrng doc.	PK	G/L Account	A	S	D	BusA	TPBA	Tx	W	Tax Jurisdiction	Loc.curr.amount	Value Date	Assignment	Text
1000	1		40	5501050	S		S	1300					251,733.83		20190630	RECLASS DEP EXP TO CORRECT CO
	2		40	5501050	S		S	1300					82,853.22		20190630	RECLASS DEP EXP TO CORRECT CO
	3		40	5501050	S		S	1300					141,370.92		20190630	RECLASS DEP EXP TO CORRECT CO
	4		40	5501050	S		S	1300					381,615.45		20190630	RECLASS DEP EXP TO CORRECT CO
	5		40	5501050	S		S	1300					309,736.72		20190630	RECLASS DEP EXP TO CORRECT CO
	6		50	5501050	S		H	1300					1,167,310.14-		20190630	RECLASS DEP EXP TO CORRECT CO

Dominion Energy North Carolina
Annualize Depreciation Expense
North Carolina Jurisdictional Allocation Factors

(000s)

Line No.	Description	(a) System	(b) NC
1	Production Plant Depreciation & Amortization (COS Sch 4, line 47) (Page 8)	476,526	24,529
2	Less Ringfenced Projects including Ringfenced ARO (COS Sch 4, line 47) (Page 8)	5,099	0
3	Less Production ARO other than Ringfenced Projects (COS Sch 4, line 36) (Page 8)	9,100	451
4	Total Production Plant Depreciation & Amortization (Line 1 - Lines 2-3)	462,327	24,078
5	**North Carolina Jurisdictional Allocation Factor (Line 4, col b / col a)**	**5.2081%**	
6	Transmission Plant Depreciation (COS Sch 4, line 72) (Page 8)	219,880	9,389
7	Less Ringfenced Projects including Ringfenced ARO (COS Sch 4, line 72) (Page 8)	65	0
8	Less Transmission ARO other than Ringfenced Projects (COS Sch 4, lines 61-62) (Page 8)	-19	-1
9	Total Transmission Plant Depreciation & Amortization (Line 6 - Lines 7-8)	219,834	9,390
10	**North Carolina Jurisdictional Allocation Factor (Line 9, col b / col a)**	**4.2715%**	
11	Distribution Plant Depreciation (COS Sch 4, line 114) (Page 8)	376,114	18,715
12	Less Ringfenced Projects including Ringfenced ARO (COS Sch 4, line 114) (Page 8)	127	0
13	Less Distribution ARO other than Ringfenced Projects (COS Sch 4, lines 105-106) (Page 8)	0	0
14	Less Distribution Strategic Underground Depreciation (VA Only Activity) (COS Sch 4, lines 81, 83, 85, 87, 89, 91, 93 and 104) (Page 8)	9,975	0
15	Total Distribution Plant Depreciation & Amortization (Line 11 - Lines 12-14)	366,012	18,715
16	**North Carolina Jurisdictional Allocation Factor (Line 15, col b / col a)**	**5.1132%**	
17	General Plant Depreciation (COS Sch 4, line 142) (Page 8)	37,910	2,623
18	Less Ringfenced Projects including Ringfenced ARO (COS Sch 4, line 142) (Page 8)	60	0
19	Less General ARO other than Ringfenced Projects (COS Sch 4, lines 130-131) (Page 8)	-228	-14
20	Less Amortized Capital Leases (Line 27)	1,271	64
21	Total General Plant Depreciation & Amortization (Line 17 - Lines 18-20)	36,808	2,573
22	**North Carolina Jurisdictional Allocation Factor (Line 21, col b / col a)**	**6.9901%**	
23	Intangible Plant Depreciation (COS Sch 4, line 16) (Page 8)	31,580	1,579
24	Less Ringfenced Projects including Ringfenced ARO (COS Sch 4, line 16) (Page 8)	1	0
25	Total Intangible Plant Depreciation & Amortization (Line 23 - Line 24)	31,578	1,579
26	**North Carolina Jurisdictional Allocation Factor (Line 25, col b / col a)**	**4.9997%**	
27	Amortized Capital Leases (COS Sch 4, line 119) (Page 8)	1,271	64
28	**North Carolina Jurisdictional Allocation Factor (Line 27, col b / col a)**	**5.0642%**	
29	Total North Carolina Jurisdiction Depreciation and Amortization (Sum of Column b, Lines 1, 6, 11, 17 and 23)		56,835
30	Less: ARO (Sum of Column b, Lines 3, 8, 13, and 19)		436
31	**Total North Carolina Jurisdiction Depreciation and Amortization, YTD 12/31/2018 excluding ARO (Sum of Column b, Lines 4, 9, 15, 21, 25 and 27)**		**56,400**

Dominion Energy North Carolina
Annualize Depreciation Expense

Line #		System	Va Juris	Va Non-Juris	FERC	N C Juris	Ringfenced Projects	Allocation Basis	Calculation: System Excluding Ringfenced Projects
				DOMINION ENERGY NORTH CAROLINA				SCHEDULE 4	
			SUMMER WINTER PEAK & AVERAGE STUDY - EOP - PERIOD ENDED DECEMBER 31, 2018						
				DOCKET NO. E-22, SUB 562					
				SCHEDULE 4 - DEPRECIATION & AMORTIZATION					
3	D:[DEPRECIATION & AMORTIZATION EXPENSES]								
4	E:[]								
5	F:[INTANGIBLE PLANT]								
16	Q:[TOTAL INTANGIBLE PLANT DEPR. EXPENSES]	31,579,851	25,245,133	3,703,450	1,051,032	1,578,817	1,418		
17	R:[]								
18	S:[PRODUCTION PLANT]								
36	AK:[ARO]	9,210,377	7,393,352	1,101,758	154,261	450,507	110,520	FACTOR1	9,099,857
47	AV:[TOTAL PROD PLANT DEPRE & AMORT]	476,525,764	381,319,857	57,410,250	8,167,648	24,528,724	5,099,285		
48	AX:[]								
49	AY:[TRANSMISSION PLANT]								
61	BK:[359.1 ARO - DECOMMISSIONING]	0	0	0	0	0	0		0
62	BL:[ARO - NON - DECOMMISSIONING]	(19,220)	(15,257)	(1,973)	(3,183)	(807)	0	FACTOR2	(19,220)
72	BV:[TOTAL TRANSMISSION PLANT DEPREC]	219,880,168	152,987,925	22,935,564	34,501,982	9,389,370	65,327		
73	BW:[]								
74	BX:[]								
75	BY:[DISTRIBUTION PLANT]								
81	CE:[364 POLES, TOWERS & FXTURES - RIDER U]	356,005	316,354	39,669	0	0	0	FACTORU	
83	CG:[365 OVERHEAD CONDUCT & DEVICES - RIDER U]	416,247	369,866	46,382	0	0	0	FACTORU	
85	CI:[366 UNDERGROUND CONDUIT - RIDER U]	559,043	496,750	62,293	0	0	0	FACTORU	
87	CK:[367 UNDERGROUND COND & DEVICES - RIDER U]	4,932,036	4,382,469	549,567	0	0	0	FACTORU	
89	CM:[368 LINE TRANSFORMERS - RIDER U]	1,071,097	951,747	119,350	0	0	0	FACTORU	
91	CO:[369 SERVICES - RIDER U]	2,572,525	2,285,874	286,651	0	0	0	FACTORU	
93	CQ:[370 METERS - RIDER U]	835	742	93	0	0	0	FACTORU	
104	DB:[373 STREET LIGHTING - RIDER U]	67,246	59,753	7,493	0	0	0	FACTORU	
105	DC:[374 ARO - DECOMMISSIONING]	0	0	0	0	0	0		0
106	DD:[ARO - NON - DECOMMISSIONING]	0	0	0	0	0	0		0
114	DL:[TOTAL DISTRIBUTION PLANT]	376,113,822	314,719,890	40,557,022	1,995,088	18,714,993	126,829		
115	DN:[]								
116	DO:[GENERAL PLANT]								
119	DR:[390 AMORTIZED CAPITALIZED LEASES]	1,270,638	1,041,234	138,897	26,160	64,347	0	PLANT_ACCT_389_390_391_398	
130	EC:[399.3 ARO - DECOMMISSIONING]	0	0	0	0	0	0		0
131	ED:[ARO - NON - DECOMMISSIONING]	(228,383)	(185,421)	(24,816)	(4,073)	(14,073)	0	TOTAL_GEN_PLANT	(228,383)
142	ER:[TOTAL GENERAL PLANT DEPREC NA]	37,910,242	29,444,353	4,794,845	988,275	2,623,234	59,536		
143	ES:[]								
144	ET:[TOTAL DEPREC & AMORT EXPENSES]	1,142,009,847	903,717,158	129,401,131	46,704,025	56,835,138	5,352,394		

DOMINION ENERGY NORTH CAROLINA
Docket No. E-22, Sub 562
Twelve Months ended December 31, 2018
(000's)

Annualize Depreciation Expense

Purpose Depreciation expense is updated to a June 30, 2019, level based on the Projected Gross Plant balance at June 30, 2019, and he overall depreciation rate presented in DENC's most recent depreciation study, as modified by the Va Commission Staff pursuant to their review in 2018. Additionally, accumulated depreciation is adjusted for the annualization of depreciation expense. Lastly, accumulated deferred income taxes are adjusted for the annualiza ion of depreciation expense.

Method Gross Plant Projected, line 1 of adjustment, is calculated on page 3. On page 3, projected monthly balances for Dec18-Jun19 for Gross Plant (excluding CWIP), as provided by the approved 2018-2022 Five Year Plan, are shown on line 3. Balances for the Distribution Strategic Underground Project, a Virginia-only activity, and the Ring-Fenced Projects are shown on lines 4-5. These balances are subtracted from line 3 to give projected Monthly Plant in Service balances without CWIP (line 6).

Line 7 of page 3 shows the incremental monthly projected change, per line 6, for months Jan19-Jun19.

Line 8 of page 3 shows the December 2018 Electric Plant in Service balance (excluding CWIP) as provided by the COS, Sch 9. Lines 9-15 remove the Underground and Ring Fenced Projects and ARO from the plant in service balances.

The incremental monthly projected changes from line 7 for Jan19-Jun19 are added to the adjusted Dec2018 balance to determine he projected balance at June 2019 (line 1 of adjustment).

Line 2 of he adjustment reflects the overall depreciation rate presented in DENC's most recent depreciation study, as modified by the Va Commission Staff pursuant to their review in 2018.

Annualized Depreciation Expense at June 30, 2019, is compared to the Test Year Depreciation Expense found on line 4. The difference is the Increase in Depreciation Expense (line 5 of adjustment).

The North Carolina Jurisdictional Factor is found by dividing the North Carolina Jurisdiction Depreciation Expense by System Depreciation Expense as adjusted (see calcula ion on page 1, line 22) This factor is applied to the amount on line 5 to determine the North Carolina Adjustment for Depreciation Expense, line 7.

On line 8, he amount calculated on line 7 is reflected as an adjustment to the Provision for Accumulated Depreciation to reflect the annualization of depreciation expense.

Additionally, line 10 of the adjustment calculates an adjustment to the accumulated deferred income taxes amount to reflect the annualization of depreciation expense.

DOMINION ENERGY NORTH CAROLINA
Annualize Depreciation Expense

Line #	Plant In Service (in millions)	Dec-18	Jan-19	Feb-19	Mar-19	Apr-19	May-19	Jun-19
1	Gross Plant in Service (Excluding CWIP) - Projection (1)	42,446.2	42,563 2	42,632.3	42,943.4	43,057.5	43,142.8	43,405 2
2	Nuclear Fuel (Excluding CWIP) - Projec ion (1)	1,741.8	1,741 8	1,741.8	1,741.8	1,809.1	1,809.1	1,809.1
3	Gross Plant Plus Nuclear Fuel (Excluding CWIP) (line 1 + line 2) (1)	44,188.0	44,305 0	44,374.1	44,685.2	44,866.6	44,951.9	45,214 3
4	Less: Distribution Strategic Underground Project (VA Only Activity) (Dec 2018 - page 5; Projection - page 7)	476.6	486 5	497.5	508.8	520.5	532.1	543.1
5	Less: Ring-fenced Projects (1)	237.2	273.4	273.4	273.4	274.0	274.0	412.7
6	Plant in Service Excluding CWIP, Underground Project, & Ring-fenced Projects - Projec ion (line 3 - line 4 - line 5)	43,474.3	43,545.1	43,603.2	43,903.0	44,072.2	44,145.8	44,258.4
7	Incremental Monthly Change		70 8	58.1	299.8	169.2	73.7	112.6
8	Electric Plant in Service (Excluding CWIP) - COS Sch 9, line 13 (2)	43,152.3						
9	Less: Distribution Strategic Underground Program (VA Only Activity); COS Sch 10, lines 235, 249, 263, 277, 287, 301, 310, and 328 (see page 5)	476.6						
10	Less: Ring-fenced Projects (Includes Ring-fenced ARO) - COS Sch 9, line 13 (2)	367.7						
11	Less ARO other than Ring-fence projects (see Page 5):							
12	Production (COS Sch 10, lines 82-83)	134.9						
13	Transmission (COS Sch 10, line 151)	(0.0)						
14	Distribution (COS Sch 10, line 331)	-						
15	General (COS Sch 10, lines 421-422)	(0.4)						
16	Electric Plant in Service (excluding CWIP) Less ARO (line 8 - sum lines 9-15)	42,173.6						
17	Total Electric Plant in Service (including Nuclear Fuel) (line 16 plus incremental change)	42,173.6	42,244.4	42,302.6	42,602.3	42,771.5	42,845.2	42,957 8

Source:
(1) Projected Dec 2018 - Jun 2019 balances from the Approved 2018 - 2022 Five Year Plan, Financial Analysis & Planning.
(2) Dec 2018 plant in service balance provided by the COS (SWPA) 12/2018 Schedule 9, Line 13 (see page 4).

VIRGINIA ELECTRIC AND POWER COMPANY — SCHEDULE 9
SUMMER WINTER PEAK & AVERAGE STUDY - EOP - PERIOD ENDED DECEMBER 31, 2018
DOCKET NO. E-22, SUB 562

SCHEDULE 9 - SUMMARY OF PLANT

Line #		System	Va Juris	Va Non-Juris	FERC	N C Juris	Ringfenced Projects	Allocation Basis
1	Dec 2018							
2								
3	C:[SUMMARY OF PLANT]							
4	D:[]							
5	E:[ELECTRIC PLANT IN SERVICE]							
6	F:[TOTAL PRODUCTION PLANT]	19,462,638,590	15,405,629,611	2,348,567,601	338,846,338	1,018,465,681	351,129,360	NC Schedule 10 - Plant in Serv
7	G:[TOTAL TRANSMISSION PLANT]	9,364,258,761	6,503,160,844	974,802,446	1,484,705,439	399,622,473	1,967,559	NC Schedule 10 - Plant in Serv
8	H:[TOTAL DISTRIBUTION PLANT]	11,734,137,966	9,808,660,726	1,240,705,227	78,277,234	592,534,798	13,959,981	NC Schedule 10 - Plant in Serv
9	I:[TOTAL GENERAL PLANT]	827,650,747	671,452,926	89,837,575	14,733,945	50,958,003	668,298	NC Schedule 10 - Plant in Serv
10	J:[TOTAL INTANGIBLE PLANT]	291,078,393	220,803,668	37,620,700	13,231,496	19,422,529	0	NC Schedule 10 - Plant in Serv
11	K:[PLANT PURCHASED / SOLD]	0	0	0	0	0	0	NC Schedule 10 - Plant in Serv
12	L:[-NUCLEAR FUEL]	1,472,572,459	1,159,927,734	205,590,923	27,979,318	79,074,483	0	NC Schedule 10 - Plant in Serv
13	M:[TOTAL ELECTRIC PLANT IN SERVICE]	43,152,336,916	33,769,635,510	4,897,124,472	1,957,773,769	2,160,077,967	367,725,198	

VIRGINIA ELECTRIC AND POWER COMPANY — SCHEDULE 10
SUMMER WINTER PEAK & AVERAGE STUDY - EOP - PERIOD ENDED DECEMBER 31, 2018
DOCKET NO. E-22, SUB 562
SCHEDULE 10 - PLANT IN SERVICE

Line #		System	Va Juris	Va Non-Juris	FERC	N C Juris	Ringfenced Projects	Allocation Basis
235	IC:[364 VA - RIDER U]	19,435,797	17,290,377	2,145,420	0	0	0	FACTORU
249	IR:[365 VA - RIDER U]	19,800,337	17,614,677	2,185,660	0	0	0	FACTORU
263	JF:[366 VA - RIDER U]	47,514,164	42,269,313	5,244,851	0	0	0	FACTORU
277	JT:[367 VA - RIDER U]	200,691,742	178,538,384	22,153,358	0	0	0	FACTORU
287	KD:[368 VA - RIDER U]	45,734,907	40,686,459	5,048,448	0	0	0	FACTORU
301	KR:[369 VA - RIDER U]	140,967,695	125,406,976	15,560,719	0	0	0	FACTORU
310	LA:[370 VA - RIDER U]	0	0	0	0	0	0	
328	LS:[373 RIDER U]	2,423,047	2,155,579	267,468	0	0	0	FACTORU

VIRGINIA ELECTRIC AND POWER COMPANY — SCHEDULE 10
SUMMER WINTER PEAK & AVERAGE STUDY - EOP - PERIOD ENDED DECEMBER 31, 2018
DOCKET NO. E-22, SUB 562
SCHEDULE 10 - PLANT IN SERVICE

Line #		System	Va Juris	Va Non-Juris	FERC	N C Juris	Ringfenced Projects	Allocation Basis
81	CE:[]							
82	CF:[346 ARO DECOMMISSIONING]	(178,146,695)	(144,738,667)	(21,568,577)	(3,019,943)	(8,819,508)	0	FACTOR1
83	CG:[ARO - OTHER PRODUCTION]	316,197,929	254,323,494	37,898,620	5,306,408	15,496,952	3,172,455	FACTOR1
151	EW:[359.1 ARO - OTHER TRANSMISSIOM]	(49,774)	(34,345)	(5,110)	(8,227)	(2,092)	0	FACTOR2
331	LW:[374 ARO DISTRIBUTION - OTHER]	0	0	0	0	0	0	OUTPUT Template-Plant in S
421	PJ:[399.3 ARO - DECOMMISSIONING]	0	0	0	0	0	0	
422	PK:[399.3 ARO GENERAL OTHER]	(413,220)	(338,970)	(45,267)	(8,036)	(20,947)	0	TOTAL_GEN_x3993AFC

DOMINION ENERGY NORTH CAROLINA
Annualize Depreciation Expense

VIRGINIA ELECTRIC AND POWER COMPANY — SCHEDULE 4
SUMMER WINTER PEAK & AVERAGE STUDY - EOP - PERIOD ENDED DECEMBER 31, 2018
DOCKET NO. E-22, SUB 562
SCHEDULE 4 - DEPRECIATION & AMORTIZATION

Line #		System	Va Juris	Va Non-Juris	FERC	N C Juris	Ringfenced Projects	Allocation Basis
145	ES:[]							
144	ET:[TOTAL DEPREC & AMORT EXPENSES]	1,142,009,847	903,783,168	129,395,664	46,640,212	56,838,408	5,352,394	

VIRGINIA ELECTRIC AND POWER COMPANY — SCHEDULE 4
SUMMER WINTER PEAK & AVERAGE STUDY - EOP - PERIOD ENDED DECEMBER 31, 2018
DOCKET NO. E-22, SUB 562
SCHEDULE 4 - DEPRECIATION & AMORTIZATION

Line #		System	Va Juris	Va Non-Juris	FERC	N C Juris	Ringfenced Projects	Allocation Basis
81	CE:[364 POLES, TOWERS & FXTURES - RIDER U]	356,003	316,706	39,297	0	0	0	FACTORU
83	CG:[365 OVERHEAD CONDUCT & DEVICES - RIDER U]	416,247	370,300	45,947	0	0	0	FACTORU
85	CI:[366 UNDERGROUND CONDUIT - RIDER U]	559,043	497,333	61,710	0	0	0	FACTORU
87	CK:[367 UNDERGROUND COND & DEVICES - RIDER U	4,932,036	4,387,613	544,423	0	0	0	FACTORU
89	CM:[368 LINE TRANSFORMERS - RIDER U]	1,071,097	952,864	118,233	0	0	0	FACTORU
91	CO:[369 SERVICES - RIDER U]	2,572,525	2,288,557	283,968	0	0	0	FACTORU
93	CQ:[370 METERS - RIDER U]	835	743	92	0	0	0	FACTORU
104	DB:[373 STREET LIGHTING - RIDER U]	67,246	59,823	7,423	0	0	0	FACTORU

VIRGINIA ELECTRIC AND POWER COMPANY — SCHEDULE 4
SUMMER WINTER PEAK & AVERAGE STUDY - EOP - PERIOD ENDED DECEMBER 31, 2018
DOCKET NO. E-22, SUB 562
SCHEDULE 4 - DEPRECIATION & AMORTIZATION

Line #		System	Va Juris	Va Non-Juris	FERC	N C Juris	Ringfenced Projects	Allocation Basis
36	AK:[ARO]	9,210,377	7,393,352	1,101,738	154,261	450,507	110,520	FACTOR1
61	BK:[359.1 ARO - DECOMMISSIONING]	0	0	0	0	0	0	
62	BL:[ARO - NON - DECOMMISSIONING]	(19,220)	(13,262)	(1,973)	(3,177)	(808)	0	FACTOR2
105	DC:[374 ARO - DECOMMISSIONING]	0	0	0	0	0	0	
106	DD:[ARO - NON - DECOMMISSIONING]	0	0	0	0	0	0	
130	EC:[399.3 ARO - DECOMMISSIONING]	0	0	0	0	0	0	
131	ED:[ARO - NON - DECOMMISSIONING]	(228,383)	(185,431)	(24,810)	(4,069)	(14,073)	0	TOTAL_GEN_PLANT

DOMINION ENERGY NORTH CAROLINA
Annualize Depreciation Expense

Distribution Strategic Underground Project

Description	January-19	February-19	March-19	April-19	May-19	June-19
Plant in Service (Phase I - Phase V and later)	486,531	497,505	508,813	520,454	532,095	543,070

Source: Financial and Business Services

DOMINION ENERGY NORTH CAROLINA
Docket No. E-22, Sub 562
Twelve Months ended December 31, 2018
(000's)

Annualize Depreciation Expense

Purpose Depreciation expense is updated to a June 30, 2019, level based on the Projected Gross Plant balance at June 30, 2019, and he overall depreciation rate presented in DENC's most recent depreciation study, as modified by the Va Commission Staff pursuant to their review in 2018. Additionally, accumulated depreciation is adjusted for the annualization of depreciation expense. Lastly, accumulated deferred income taxes are adjusted for the annualiza ion of depreciation expense.

Method Gross Plant Projected, line 1 of adjustment, is calculated on page 3. On page 3, projected monthly balances for Dec18-Jun19 for Gross Plant (excluding CWIP), as provided by the approved 2018-2022 Five Year Plan, are shown on line 3. Balances for the Distribution Strategic Underground Project, a Virginia-only activity, and the Ring-Fenced Projects are shown on lines 4-5. These balances are subtracted from line 3 to give projected Monthly Plant in Service balances without CWIP (line 6).

Line 7 of page 3 shows the incremental monthly projected change, per line 6, for months Jan19-Jun19.

Line 8 of page 3 shows the December 2018 Electric Plant in Service balance (excluding CWIP) as provided by the COS, Sch 9. Lines 9-15 remove the Underground and Ring Fenced Projects and ARO from the plant in service balances.

The incremental monthly projected changes from line 7 for Jan19-Jun19 are added to the adjusted Dec2018 balance to determine he projected balance at June 2019 (line 1 of adjustment).

Line 2 of he adjustment reflects the overall depreciation rate presented in DENC's most recent depreciation study, as modified by the Va Commission Staff pursuant to their review in 2018.

Annualized Depreciation Expense at June 30, 2019, is compared to the Test Year Depreciation Expense found on line 4. The difference is the Increase in Depreciation Expense (line 5 of adjustment).

The North Carolina Jurisdictional Factor is found by dividing the North Carolina Jurisdiction Depreciation Expense by System Depreciation Expense as adjusted (see calcula ion on page 1, line 22) This factor is applied to the amount on line 5 to determine the North Carolina Adjustment for Depreciation Expense, line 7.

On line 8, he amount calculated on line 7 is reflected as an adjustment to the Provision for Accumulated Depreciation to reflect the annualization of depreciation expense.

Additionally, line 10 of the adjustment calculates an adjustment to the accumulated deferred income taxes amount to reflect the annualization of depreciation expense.

DOMINION ENERGY NORTH CAROLINA
Annualize Depreciation Expense

Line #	Plant In Service (in millions)	Dec-18	Jan-19	Feb-19	Mar-19	Apr-19	May-19	Jun-19
1	Gross Plant in Service (Excluding CWIP) - Projection (1)	42,446.2	42,563 2	42,632.3	42,943.4	43,057.5	43,142.8	43,405 2
2	Nuclear Fuel (Excluding CWIP) - Projec ion (1)	1,741.8	1,741 8	1,741.8	1,741.8	1,809.1	1,809.1	1,809.1
3	Gross Plant Plus Nuclear Fuel (Excluding CWIP) (line 1 + line 2) (1)	44,188.0	44,305 0	44,374.1	44,685.2	44,866.6	44,951.9	45,214 3
4	Less: Distribution Strategic Underground Project (VA Only Activity) (Dec 2018 - page 5; Projection - page 7)	476.6	486 5	497.5	508.8	520.5	532.1	543.1
5	Less: Ring-fenced Projects (1)	237.2	273.4	273.4	273.4	274.0	274.0	412.7
6	Plant in Service Excluding CWIP, Underground Project, & Ring-fenced Projects - Projec ion (line 3 - line 4 - line 5)	43,474.3	43,545.1	43,603.2	43,903.0	44,072.2	44,145.8	44,258.4
7	Incremental Monthly Change		70 8	58.1	299.8	169.2	73.7	112.6
8	Electric Plant in Service (Excluding CWIP) - COS Sch 9, line 13 (2)	43,152.3						
9	Less: Distribution Strategic Underground Program (VA Only Activity); COS Sch 10, lines 235, 249, 263, 277, 287, 301, 310, and 328 (see page 5)	476.6						
10	Less: Ring-fenced Projects (Includes Ring-fenced ARO) - COS Sch 9, line 13 (2)	367.7						
11	Less ARO other than Ring-fence projects (see Page 5):							
12	Production (COS Sch 10, lines 82-83)	134.9						
13	Transmission (COS Sch 10, line 151)	(0.0)						
14	Distribution (COS Sch 10, line 331)	-						
15	General (COS Sch 10, lines 421-422)	(0.4)						
16	Electric Plant in Service (excluding CWIP) Less ARO (line 8 - sum lines 9-15)	42,173.6						
17	Total Electric Plant in Service (including Nuclear Fuel) (line 16 plus incremental change)	42,173.6	42,244.4	42,302.6	42,602.3	42,771.5	42,845.2	42,957 8

Source:
(1) Projected Dec 2018 - Jun 2019 balances from the Approved 2018 - 2022 Five Year Plan, Financial Analysis & Planning.
(2) Dec 2018 plant in service balance provided by the COS (SWPA) 12/2018 Schedule 9, Line 13 (see page 4).

VIRGINIA ELECTRIC AND POWER COMPANY

SCHEDULE 9

SUMMER WINTER PEAK & AVERAGE STUDY - EOP - PERIOD ENDED DECEMBER 31, 2018

DOCKET NO. E-22, SUB 562

SCHEDULE 9 - SUMMARY OF PLANT

Line #		System	Va Juris	Va Non-Juris	FERC	N C Juris	Ringfenced Projects	Allocation Basis
1	Dec 2018							
2								
3	C:[SUMMARY OF PLANT]							
4	D:[]							
5	E:[ELECTRIC PLANT IN SERVICE]							
6	F:[TOTAL PRODUCTION PLANT]	19,462,638,590	15,405,629,611	2,348,567,601	338,846,338	1,018,465,681	351,129,360	NC Schedule 10 - Plant in Ser
7	G:[TOTAL TRANSMISSION PLANT]	9,364,258,761	6,503,160,844	974,802,446	1,484,705,439	399,622,473	1,967,559	NC Schedule 10 - Plant in Ser
8	H:[TOTAL DISTRIBUTION PLANT]	11,734,137,966	9,808,660,726	1,240,705,227	78,277,234	592,534,798	13,959,981	NC Schedule 10 - Plant in Ser
9	I:[TOTAL GENERAL PLANT]	827,650,747	671,452,926	89,837,575	14,733,945	50,958,003	668,298	NC Schedule 10 - Plant in Ser
10	J:[TOTAL INTANGIBLE PLANT]	291,078,393	220,803,668	37,620,700	13,231,496	19,422,529	0	NC Schedule 10 - Plant in Ser
11	K:[PLANT PURCHASED / SOLD]	0	0	0	0	0	0	NC Schedule 10 - Plant in Ser
12	L:[NUCLEAR FUEL]	1,472,572,459	1,159,927,734	205,590,923	27,979,318	79,074,483	0	NC Schedule 10 - Plant in Ser
13	M:[TOTAL ELECTRIC PLANT IN SERVICE]	43,152,336,916	33,769,635,510	4,897,124,472	1,957,773,769	2,160,077,967	367,725,198	

DOMINION ENERGY NORTH CAROLINA
Annualize Depreciation Expense

VIRGINIA ELECTRIC AND POWER COMPANY

SCHEDULE 10

SUMMER WINTER PEAK & AVERAGE STUDY - EOP - PERIOD ENDED DECEMBER 31, 2018

DOCKET NO. E-22, SUB 562

SCHEDULE 10 - PLANT IN SERVICE

Line #		System	Va Juris	Va Non-Juris	FERC	N C Juris	Ringfenced Projects	Allocation Basis
235	IC:[364 VA - RIDER U]	19,435,797	17,290,377	2,145,420	0	0	0	FACTORU
249	IR:[365 VA - RIDER U]	19,800,337	17,614,677	2,185,660	0	0	0	FACTORU
263	JF:[366 VA - RIDER U]	47,514,164	42,269,313	5,244,851	0	0	0	FACTORU
277	JT:[367 VA - RIDER U]	200,691,742	178,538,384	22,153,358	0	0	0	FACTORU
287	KD:[368 VA - RIDER U]	45,734,907	40,686,459	5,048,448	0	0	0	FACTORU
301	KR:[369 VA - RIDER U]	140,967,695	125,406,976	15,560,719	0	0	0	FACTORU
310	LA:[370 VA - RIDER U]	0	0	0	0	0	0	
328	LS:[373 RIDER U]	2,423,047	2,155,579	267,468	0	0	0	FACTORU

VIRGINIA ELECTRIC AND POWER COMPANY

SCHEDULE 10

SUMMER WINTER PEAK & AVERAGE STUDY - EOP - PERIOD ENDED DECEMBER 31, 2018

DOCKET NO. E-22, SUB 562

SCHEDULE 10 - PLANT IN SERVICE

Line #		System	Va Juris	Va Non-Juris	FERC	N C Juris	Ringfenced Projects	Allocation Basis
81	CE:[]							
82	CF:[346 ARO DECOMMISSIONING]	(178,146,695)	(144,738,667)	(21,568,577)	(3,019,945)	(8,819,508)	0	FACTOR1
83	CG:[ARO - OTHER PRODUCTION]	316,197,929	254,323,494	37,898,620	5,306,408	15,496,952	3,172,455	FACTOR1
151	EW:[359.1 ARO - OTHER TRANSMISSIOM]	(49,774)	(34,345)	(5,110)	(8,227)	(2,092)	0	FACTOR2
331	LW:[374 ARO DISTRIBUTION - OTHER]	0	0	0	0	0	0	OUTPUT Template-Plant in S
421	PJ:[399.3 ARO - DECOMMISSIONING]	0	0	0	0	0	0	
422	PK:[399.3 ARO GENERAL OTHER]	(413,220)	(338,970)	(45,267)	(8,036)	(20,947)	0	TOTAL_GEN_x3993AFC

VIRGINIA ELECTRIC AND POWER COMPANY — SCHEDULE 4
SUMMER WINTER PEAK & AVERAGE STUDY - EOP - PERIOD ENDED DECEMBER 31, 2018
DOCKET NO. E-22, SUB 562
SCHEDULE 4 - DEPRECIATION & AMORTIZATION

Line #		System	Va Juris	Va Non-Juris	FERC	N C Juris	Ringfenced Projects	Allocation Basis
143	ES:[]							
144	ET:[TOTAL DEPREC & AMORT EXPENSES]	1,142,009,847	903,783,168	129,395,664	46,640,212	56,838,408	5,352,394	

VIRGINIA ELECTRIC AND POWER COMPANY — SCHEDULE 4
SUMMER WINTER PEAK & AVERAGE STUDY - EOP - PERIOD ENDED DECEMBER 31, 2018
DOCKET NO. E-22, SUB 562
SCHEDULE 4 - DEPRECIATION & AMORTIZATION

Line #		System	Va Juris	Va Non-Juris	FERC	N C Juris	Ringfenced Projects	Allocation Basis
81	CE:[364 POLES, TOWERS & FXTURES - RIDER U]	356,003	316,706	39,297	0	0	0	FACTORU
83	CG:[365 OVERHEAD CONDUCT & DEVICES - RIDER U]	416,247	370,300	45,947	0	0	0	FACTORU
85	CI:[366 UNDERGROUND CONDUIT - RIDER U]	559,043	497,333	61,710	0	0	0	FACTORU
87	CK:[367 UNDERGROUND COND & DEVICES - RIDER U	4,932,036	4,387,613	544,423	0	0	0	FACTORU
89	CM:[368 LINE TRANSFORMERS - RIDER U]	1,071,097	952,864	118,233	0	0	0	FACTORU
91	CO:[369 SERVICES - RIDER U]	2,572,525	2,288,557	283,968	0	0	0	FACTORU
93	CQ:[370 METERS - RIDER U]	835	743	92	0	0	0	FACTORU
104	DB:[373 STREET LIGHTING - RIDER U]	67,246	59,823	7,423	0	0	0	FACTORU

VIRGINIA ELECTRIC AND POWER COMPANY — SCHEDULE 4
SUMMER WINTER PEAK & AVERAGE STUDY - EOP - PERIOD ENDED DECEMBER 31, 2018
DOCKET NO. E-22, SUB 562
SCHEDULE 4 - DEPRECIATION & AMORTIZATION

Line #		System	Va Juris	Va Non-Juris	FERC	N C Juris	Ringfenced Projects	Allocation Basis
36	AK:[ARO]	9,210,377	7,393,352	1,101,738	154,261	450,507	110,520	FACTOR1
61	BK:[359.1 ARO - DECOMMISSIONING]	0	0	0	0	0	0	
62	BL:[ARO - NON - DECOMMISSIONING]	(19,220)	(13,262)	(1,973)	(3,177)	(808)	0	FACTOR2
105	DC:[374 ARO - DECOMMISSIONING]	0	0	0	0	0	0	
106	DD:[ARO - NON - DECOMMISSIONING]	0	0	0	0	0	0	
130	EC:[399.3 ARO - DECOMMISSIONING]	0	0	0	0	0	0	
131	ED:[ARO - NON - DECOMMISSIONING]	(228,383)	(185,431)	(24,810)	(4,069)	(14,073)	0	TOTAL_GEN_PLANT

Distribution Strategic Underground Project

Description	January-19	February-19	March-19	April-19	May-19	June-19
Plant in Service (Phase I - Phase V and later)	486,531	497,505	508,813	520,454	532,095	543,070

Source: Financial and Business Services

Question No. 2:

Please provide any estimates of total coverage by insurers for claims or potential claims related to any liability for CCR related damages.

[redacted]

[redacted]

Question No. 3:

Please provide a narrative summary of any attempts the Company has made to recover insurance proceeds for liability related to CCR.

[redacted]

[redacted]

Question No. 4:

In response to Public Staff DR 81-1, the Company provided communications to insurance carriers regarding lawsuits and/or intent to sue notices filed by the Sierra Club and nearby property owners at Possum Point. Please confirm whether these were the only claims or notices sent relating to the Company's insurance carriers regarding potential or existing environmental liabilities. If there were other claims or notices of potential claims identified above, please list any claims made for CCR liability, including legal liability, cleanup, compliance, or other relevant liability that would go towards the costs being recovered in this proceeding.

[redacted]

[redacted]

Question No. 5:

Please confirm whether any insurance proceeds have been recovered to date by the Company for any occurrences related to CCR operations.

[redacted]

[redacted]

END CONFIDENTIAL

Bremo

No. of CCR Rule Groundwater Monitoring Exceedances by Constituent

Parameters	Annual Report 2017	Annual Report 2018	Notification 2018 2nd Semi-Annual	Exceedances Total
Appendix III Constituents				
Boron	5	5	N/A	10
Calcium	2	2	N/A	4
Chloride	-	-	N/A	-
Fluoride	1	1	N/A	2
pH	-	-	N/A	-
Sulfate	1	1	N/A	2
Total Dissolved Solids	1	1	N/A	2
Appendix IV Constituents				
Antimony	N/A	-	-	-
Arsenic	N/A	-	-	-
Barium	N/A	-	-	-
Beryllium	N/A	-	-	-
Cadmium	N/A	-	-	-
Chromium	N/A	-	-	-
Cobalt	N/A	-	-	-
Fluoride	N/A	-	-	-
Lead	N/A	-	-	-
Lithium	N/A	1 (2)	1	2
Mercury	N/A	-	-	-
Molybdenum	N/A	-	-	-
Selenium	N/A	-	-	-
Thallium	N/A	-	-	-
Total Radium	N/A	-	-	-
Exceedances Total	10	11	1	22

Notes:

*Parentheses (Virginia GWPS Exeedance)

*Data compiled from Domminion responses to Public Staff Data Request 3-11, dated April 18, 2019.

*The annual data is from a singular sampling event and was collected from five (5) downgradient wells.

*1. For constituents for which a Maximum Contaminant Level (MCL) has been established, the MCL was used.
2. For constituents for which a health-based GWPS has been adopted under the August 29, 2018 Phase 1, Part 1 amendment to the CCR Rule, the health-based GWPS was used for the Federal CCR Rule GWPS.
3. Under 9VAC20-81-800, for constituents for which an MCL has not been established, the background concentration for the constituent was used for GWPS. Note that Virginia CCR site-specific background values were calculated using existing groundwater data collected for the Solid Waste Permit from February 2016 through August 2017 along with CCR background data collected during the same period.
4. For constituents for which the background level is higher than the MCL or health-based GWPS, the background concentration was used for GWPS.

Chesapeake

No. of CCR Rule Groundwater Monitoring Exceedances by Constituent

Parameters	Annual Report 2017	Annual Report 2018	Exceedances Total
Appendix III Constituents			
Boron	N/A	N/A	-
Calcium	N/A	N/A	-
Chloride	N/A	N/A	-
Fluoride	N/A	N/A	-
pH	N/A	N/A	-
Sulfate	N/A	N/A	-
Total Dissolved Solids	N/A	N/A	-
Appendix IV Constituents			
Antimony	N/A	N/A	-
Arsenic	N/A	N/A	-
Barium	N/A	N/A	-
Beryllium	N/A	N/A	-
Cadmium	N/A	N/A	-
Chromium	N/A	N/A	-
Cobalt	N/A	N/A	-
Fluoride	N/A	N/A	-
Lead	N/A	N/A	-
Lithium	N/A	N/A	-
Mercury	N/A	N/A	-
Molybdenum	N/A	N/A	-
Selenium	N/A	N/A	-
Thallium	N/A	N/A	-
Total Radium	N/A	N/A	-
Exceedances Total	-	-	-

Notes:

*Parentheses (Virginia GWPS Exeedance)

*Data compiled from Domminion responses to Public Staff Data Request 3-11, dated April 18, 2019.

*The inactive bottom ash pond was intended to be closed in place per the CCR Rule prior to April 17, 2018 and therefore be exempt from the detection and assessment monitoring requirements. However, there is no longer an exemption for inactive CCR surface impoundments and a 547-day extension was granted by the USEPA.

Chesterfield

No. of CCR Rule Groundwater Monitoring Exceedances by Constituent

	Annual Report		Notification	Exceedances
Parameters	2017	2018	2018 2nd Semi-Annual	Total
Appendix III Constituents				
Boron	9	28	N/A	37
Calcium	3	15	N/A	18
Chloride	6	8	N/A	14
Fluoride	4	5	N/A	9
pH	2	6	N/A	8
Sulfate	7	29	N/A	36
Total Dissolved Solids	3	16	N/A	19
Appendix IV Constituents				
Antimony	N/A	-	-	-
Arsenic	N/A	5	3	8
Barium	N/A	-	-	-
Beryllium	N/A	-	-	-
Cadmium	N/A	-	-	-
Chromium	N/A	-	-	-
Cobalt	N/A	16	17	33
Fluoride	N/A	-	-	-
Lead	N/A	0 (1)	-	-
Lithium	N/A	5 (4)	6 (2)	11
Mercury	N/A	-	-	-
Molybdenum	N/A	0 (1)	0 (4)	-
Selenium	N/A	-	-	-
Thallium	N/A	-	-	-
Total Radium	N/A	4	4	8
Exceedances Total	34	137	30	201

Notes:

*Parentheses (Virginia GWPS Exeedance)

*Data compiled from Domminion responses to Public Staff Data Request 3-11, dated April 18, 2019.

*The annual data is from a singular sampling event at each of the CCR storage units on site (LAP, UAP, and the landfill).

*1. For constituents for which a Maximum Contaminant Level (MCL) has been established, the MCL was used.
2. For constituents for which a health-based GWPS has been adopted under the August 29, 2018 Phase 1, Part 1 amendment to the CCR Rule, the health-based GWPS was used for the Federal CCR Rule GWPS.
3. Under 9VAC20-81-800, for constituents for which an MCL has not been established, the background concentration for the constituent was used for GWPS. Note that Virginia CCR site-specific background values were calculated using existing groundwater data collected for the Solid Waste Permit from February 2016 through August 2017 along with CCR background data collected during the same period.
4. For constituents for which the background level is higher than the MCL or health-based GWPS, the background concentration was used for GWPS.

Chesterfield - Lower Ash Pond

No. of CCR Rule Groundwater Monitoring Exceedances by Constituent

Parameters	Annual Report 2017	Annual Report 2018	Notification 2018 2nd Semi-Annual	Exceedances Total
Appendix III Constituents				
Boron	9	10	N/A	19
Calcium	3	2	N/A	5
Chloride	6	5	N/A	11
Fluoride	4	3	N/A	7
pH	2	1	N/A	3
Sulfate	7	7	N/A	14
Total Dissolved Solids	3	1	N/A	4
Appendix IV Constituents				
Antimony	N/A	-	-	-
Arsenic	N/A	1	1	2
Barium	N/A	-	-	-
Beryllium	N/A	-	-	-
Cadmium	N/A	-	-	-
Chromium	N/A	-	-	-
Cobalt	N/A	3	4	7
Fluoride	N/A	-	-	-
Lead	N/A	-	-	- -
Lithium	N/A	-	-	-
Mercury	N/A	-	-	-
Molybdenum	N/A	0 (1)	0 (1)	-
Selenium	N/A	-	-	-
Thallium	N/A	-	-	-
Total Radium	N/A	1	-	1
Exceedances Total	34	34	5	73

Notes:

*Parentheses (Virginia GWPS Exeedance)

*Data compiled from Domminion responses to Public Staff Data Request 3-11, dated April 18, 2019.

*The annual data is from a singular sampling event and was collected from fourteen (14) downgradient wells.

*1. For constituents for which a Maximum Contaminant Level (MCL) has been established, the MCL was used.

2. For constituents for which a health-based GWPS has been adopted under the August 29, 2018 Phase 1, Part 1 amendment to the CCR Rule, the health-based GWPS was used for the Federal CCR Rule GWPS.

3. Under 9VAC20-81-800, for constituents for which an MCL has not been established, the background concentration for the constituent was used for GWPS. Note that Virginia CCR site-specific background values were calculated using existing groundwater data collected for the Solid Waste Permit from February 2016 through August 2017 along with CCR background data collected during the same period.

4. For constituents for which the background level is higher than the MCL or health-based GWPS, the background concentration was used for GWPS.

Chesterfield - Upper Aash Pond Columbia

No. of CCR Rule Groundwater Monitoring Exceedances by Constituent

Parameters	Annual Report 2017	Annual Report 2018	Notification 2018 2nd Semi-Annual	Exceedances Total
Appendix III Constituents				
Boron	N/A	13	N/A	13
Calcium	N/A	11	N/A	11
Chloride	N/A	2	N/A	2
Fluoride	N/A	1	N/A	1
pH	N/A	2	N/A	2
Sulfate	N/A	13	N/A	13
Total Dissolved Solids	N/A	11	N/A	11
Appendix IV Constituents				
Antimony	N/A	-	-	-
Arsenic	N/A	3	2	5
Barium	N/A	-	-	-
Beryllium	N/A	-	-	-
Cadmium	N/A	-	-	-
Chromium	N/A	-	-	-
Cobalt	N/A	9	9	18
Fluoride	N/A	-	-	-
Lead	N/A	-	-	-
Lithium	N/A	2 (1)	3 (2)	5
Mercury	N/A	-	-	-
Molybdenum	N/A	-	0 (2)	-
Selenium	N/A	-	-	-
Thallium	N/A	-	-	-
Total Radium	N/A	2	3	5
Exceedances Total	-	69	17	86

Notes:

*Parentheses (Virginia GWPS Exeedance)

*Data compiled from Domminion responses to Public Staff Data Request 3-11, dated April 18, 2019.

*The annual data is from a singular sampling event and was collected from fourteen (14) downgradient wells.

*"The data for the initial Detection Monitoring Program compliance sampling event are being evaluated against the calculated background concentrations for the Unit. The results from those evaluations will be presented in the 2018 annual groundwater monitoring and corrective action report." The 2018 Report does not present the initial Detection Monitoring Program compliance sampling event.
https://www.dominionenergy.com/company/community/environment/reports-and-performance/ccr-rule-compliance-data-and-information

*1. For constituents for which a Maximum Contaminant Level (MCL) has been established, the MCL was used.
2. For constituents for which a health-based GWPS has been adopted under the August 29, 2018 Phase 1, Part 1 amendment to the CCR Rule, the health-based GWPS was used for the Federal CCR Rule GWPS.
3. Under 9VAC20-81-800, for constituents for which an MCL has not been established, the background concentration for the constituent was used for GWPS. Note that Virginia CCR site-specific background values were calculated using existing groundwater data collected for the Solid Waste Permit from February 2016 through August 2017 along with CCR background data collected during the same period.
4. For constituents for which the background level is higher than the MCL or health-based GWPS, the background concentration was used for GWPS.

Chesterfield - Upper Ash Pond Potomac

No. of CCR Rule Groundwater Monitoring Exceedances by Constituent

Parameters	Annual Report 2017	Annual Report 2018	Notification 2018 2nd Semi-Annual	Exceedances Total
Appendix III Constituents				
Boron	N/A	5	N/A	5
Calcium	N/A	2	N/A	2
Chloride	N/A	1	N/A	1
Fluoride	N/A	1	N/A	1
pH	N/A	3	N/A	3
Sulfate	N/A	9	N/A	9
Total Dissolved Solids	N/A	4	N/A	4
Appendix IV Constituents				
Antimony	N/A	-	-	-
Arsenic	N/A	1	-	1
Barium	N/A	-	-	-
Beryllium	N/A	-	-	-
Cadmium	N/A	-	-	-
Chromium	N/A	-	-	-
Cobalt	N/A	4	4	8
Fluoride	N/A	-	-	-
Lead	N/A	0 (1)	-	-
Lithium	N/A	3	3	6
Mercury	N/A	-	-	-
Molybdenum	N/A	0 (1)	0 (1)	-
Selenium	N/A	-	-	-
Thallium	N/A	-	-	-
Total Radium	N/A	1	1	2
Exceedances Total	-	34	8	42

Notes:

*Parentheses (Virginia GWPS Exeedance)

*Data compiled from Domminion responses to Public Staff Data Request 3-11, dated April 18, 2019.

*The annual data is from a singular sampling event and was collected from nine (9) downgradient wells.

*"The data for the initial Detection Monitoring Program compliance sampling event are being evaluated against the calculated background concentrations for the Unit. The results from those evaluations will be presented in the 2018 annual groundwater monitoring and corrective action report." The 2018 Report does not present the initial Detection Monitoring Program compliance sampling event. https://www.dominionenergy.com/company/community/environment/reports-and-performance/ccr-rule-compliance-data-and-information

*1. For constituents for which a Maximum Contaminant Level (MCL) has been established, the MCL was used.
2. For constituents for which a health-based GWPS has been adopted under the August 29, 2018 Phase 1, Part 1 amendment to the CCR Rule, the health-based GWPS was used for the Federal CCR Rule GWPS.
3. Under 9VAC20-81-800, for constituents for which an MCL has not been established, the background concentration for the constituent was used for GWPS. Note that Virginia CCR site-specific background values were calculated using existing groundwater data collected for the Solid Waste Permit from February 2016 through August 2017 along with CCR background data collected during the same period.
4. For constituents for which the background level is higher than the MCL or health-based GWPS, the background concentration was used for GWPS.

Chesterfield - Landfill

No. of CCR Rule Groundwater Monitoring Exceedances by Constituent

Parameters	Annual Report 2017	Annual Report 2018	Notification 2018 2nd Semi-Annual	Exceedances Total
Appendix III Constituents				
Boron	-	-	-	-
Calcium	-	-	-	-
Chloride	-	-	-	-
Fluoride	-	-	-	-
pH	-	-	-	-
Sulfate	-	-	-	-
Total Dissolved Solids	-	-	-	-
Appendix IV Constituents				
Antimony	-	-	-	-
Arsenic	-	-	-	-
Barium	-	-	-	-
Beryllium	-	-	-	-
Cadmium	-	-	-	-
Chromium	-	-	-	-
Cobalt	-	-	-	-
Fluoride	-	-	-	-
Lead	-	-	-	-
Lithium	-	-	-	-
Mercury	-	-	-	-
Molybdenum	-	-	-	-
Selenium	-	-	-	-
Thallium	-	-	-	-
Total Radium	-	-	-	-
Exceedances Total	-	-	-	-

Notes:

*Parentheses (Virginia GWPS Exeedance)

*Data compiled from Domminion responses to Public Staff Data Request 3-11, dated April 18, 2019.

*The annual data is from a singular sampling event and was collected from eight (8) downgradient wells.

*1. For constituents for which a Maximum Contaminant Level (MCL) has been established, the MCL was used.
2. For constituents for which a health-based GWPS has been adopted under the August 29, 2018 Phase 1, Part 1 amendment to the CCR Rule, the health-based GWPS was used for the Federal CCR Rule GWPS.
3. Under 9VAC20-81-800, for constituents for which an MCL has not been established, the background concentration for the constituent was used for GWPS. Note that Virginia CCR site-specific background values were calculated using existing groundwater data collected for the Solid Waste Permit from February 2016 through August 2017 along with CCR background data collected during the same period.
4. For constituents for which the background level is higher than the MCL or health-based GWPS, the background concentration was used for GWPS.

Clover

No. of CCR Rule Groundwater Monitoring Exceedances by Constituent

Parameters	Annual Report 2017	Annual Report 2018	Notification 2018 2nd Semi-Annual	Exceedances Total
Appendix III Constituents				
Boron	2	2	3	7
Calcium	6	6	6	18
Chloride	4	5	6	15
Fluoride	-	-	-	-
pH	2	-	-	2
Sulfate	8	7	8	23
Total Dissolved Solids	5	4	5	14
Appendix IV Constituents				
Antimony	N/A	-	-	-
Arsenic	N/A	-	-	-
Barium	N/A	-	-	-
Beryllium	N/A	-	-	-
Cadmium	N/A	-	-	-
Chromium	N/A	-	-	-
Cobalt	N/A	-	-	-
Fluoride	N/A	-	-	-
Lead	N/A	-	-	-
Lithium	N/A	-	-	-
Mercury	N/A	-	-	-
Molybdenum	N/A	-	-	-
Selenium	N/A	-	-	-
Thallium	N/A	-	-	-
Total Radium	N/A	-	-	-
Exceedances Total	27	24	28	79

Notes:

*Parentheses (Virginia GWPS Exeedance)

*Data compiled from Domminion responses to Public Staff Data Request 3-11, dated April 18, 2019.

*The annual data is from a singular sampling event at each of the CCR storage units on site (sedimentation basins and the landfill).

*1. For constituents for which a Maximum Contaminant Level (MCL) has been established, the MCL was used.
2. For constituents for which a health-based GWPS has been adopted under the August 29, 2018 Phase 1, Part 1 amendment to the CCR Rule, the health-based GWPS was used for the Federal CCR Rule GWPS.
3. Under 9VAC20-81-800, for constituents for which an MCL has not been established, the background concentration for the constituent was used for GWPS. Note that Virginia CCR site-specific background values were calculated using existing groundwater data collected for the Solid Waste Permit from February 2016 through August 2017 along with CCR background data collected during the same period.
4. For constituents for which the background level is higher than the MCL or health-based GWPS, the background concentration was used for GWPS.

Clover - Sludge Sedimentation Basins

No. of CCR Rule Groundwater Monitoring Exceedances by Constituent

Parameters	Annual Report 2017	Annual Report 2018	Notification 2018 2nd Semi-Annual	Exceedances Total
Appendix III Constituents				
Boron	2	2	2	6
Calcium	4	4	4	12
Chloride	3	3	3	9
Fluoride	-	-	-	-
pH	-	-	-	-
Sulfate	4	3	4	11
Total Dissolved Solids	4	4	4	12
Appendix IV Constituents				
Antimony	N/A	-	-	-
Arsenic	N/A	-	-	-
Barium	N/A	-	-	-
Beryllium	N/A	-	-	-
Cadmium	N/A	-	-	-
Chromium	N/A	-	-	-
Cobalt	N/A	-	-	-
Fluoride	N/A	-	-	-
Lead	N/A	-	-	-
Lithium	N/A	-	-	-
Mercury	N/A	-	-	-
Molybdenum	N/A	-	-	-
Selenium	N/A	-	-	-
Thallium	N/A	-	-	-
Total Radium	N/A	-	-	-
Exceedances Total	17	16	17	50

Notes:

*Parentheses (Virginia GWPS Exeedance)

*Data compiled from Domminion responses to Public Staff Data Request 3-11, dated April 18, 2019.

*The annual data is from a singular sampling event and was collected from five (5) downgradient wells.

*1. For constituents for which a Maximum Contaminant Level (MCL) has been established, the MCL was used.
2. For constituents for which a health-based GWPS has been adopted under the August 29, 2018 Phase 1, Part 1 amendment to the CCR Rule, the health-based GWPS was used for the Federal CCR Rule GWPS.
3. Under 9VAC20-81-800, for constituents for which an MCL has not been established, the background concentration for the constituent was used for GWPS. Note that Virginia CCR site-specific background values were calculated using existing groundwater data collected for the Solid Waste Permit from February 2016 through August 2017 along with CCR background data collected during the same period.
4. For constituents for which the background level is higher than the MCL or health-based GWPS, the background concentration was used for GWPS.

Clover - Landfill

No. of CCR Rule Groundwater Monitoring Exceedances by Constituent

Parameters	Annual Report 2017	Annual Report 2018	Notification 2018 2nd Semi-Annual	Exceedances Total
Appendix III Constituents				
Boron	-	-	1	1
Calcium	2	2	2	6
Chloride	1	2	3	6
Fluoride	-	-	-	-
pH	2	-	-	2
Sulfate	4	4	4	12
Total Dissolved Solids	1	-	1	2
Appendix IV Constituents				
Antimony	N/A	-	-	-
Arsenic	N/A	-	-	-
Barium	N/A	-	-	-
Beryllium	N/A	-	-	-
Cadmium	N/A	-	-	-
Chromium	N/A	-	-	-
Cobalt	N/A	0 (1)	-	-
Fluoride	N/A	-	-	-
Lead	N/A	-	-	-
Lithium	N/A	-	-	-
Mercury	N/A	-	-	-
Molybdenum	N/A	-	-	-
Selenium	N/A	-	-	-
Thallium	N/A	-	-	-
Total Radium	N/A	-	-	-
Exceedances Total	10	8	11	29

Notes:
*Parentheses (Virginia GWPS Exeedance)

*Data compiled from Domminion responses to Public Staff Data Request 3-11, dated April 18, 2019.

*The annual data is from a singular sampling event and was collected from five (5) downgradient wells.

*1. For constituents for which a Maximum Contaminant Level (MCL) has been established, the MCL was used.
2. For constituents for which a health-based GWPS has been adopted under the August 29, 2018 Phase 1, Part 1 amendment to the CCR Rule, the health-based GWPS was used for the Federal CCR Rule GWPS.
3. Under 9VAC20-81-800, for constituents for which an MCL has not been established, the background concentration for the constituent was used for GWPS. Note that Virginia CCR site-specific background values were calculated using existing groundwater data collected for the Solid Waste Permit from February 2016 through August 2017 along with CCR background data collected during the same period.
4. For constituents for which the background level is higher than the MCL or health-based GWPS, the background concentration was used for GWPS.

Mount Storm

No. of CCR Rule Groundwater Monitoring Exceedances by Constituent

Parameters	Annual Report 2017	Annual Report 2018	Notification 2018 2nd Semi-Annual	Exceedances Total
Appendix III Constituents				
Boron	3	2	N/A	5
Calcium	-	-	N/A	-
Chloride	3	2	N/A	5
Fluoride	2	4	N/A	6
pH	5	6	N/A	11
Sulfate	2	1	N/A	3
Total Dissolved Solids	-	-	N/A	-
Appendix IV Constituents				
Antimony	N/A	-	-	-
Arsenic	N/A	-	2	2
Barium	N/A	-	-	-
Beryllium	N/A	-	-	-
Cadmium	N/A	-	-	-
Chromium	N/A	-	-	-
Cobalt	N/A	-	1	1
Fluoride	N/A	1	-	1
Lead	N/A	-	-	-
Lithium	N/A	-	-	-
Mercury	N/A	-	-	-
Molybdenum	N/A	1	-	1
Selenium	N/A	-	-	-
Thallium	N/A	-	-	-
Total Radium	N/A	-	-	-
Exceedances Total	15	17	3	35

Notes:

*Parentheses (Virginia GWPS Exeedance)

*Data compiled from Domminion responses to Public Staff Data Request 3-11, dated April 18, 2019.

*The annual data is from a singular sampling event at each of the CCR storage units on site (sedimentation basins and the landfill).

*1. For constituents for which a Maximum Contaminant Level (MCL) has been established, the MCL was used.
2. For constituents with no MCL and for which a health-based GWPS has been adopted under the August 29, 2018, Phase 1, Part 1 amendment to the CCR Rule, the health-based GWPS was used for the Federal CCR Rule GWPS.
3. For constituents for which the background level is higher than the MCL or health-based GWPS, the background concentration was used for GWPS.

Mount Storm - Phase A Landfill

No. of CCR Rule Groundwater Monitoring Exceedances by Constituent

Parameters	Annual Report 2017	Annual Report 2018	Notification 2018 2nd Semi-Annual	Exceedances Total
Appendix III Constituents				
Boron	-	-	N/A	-
Calcium	-	-	N/A	-
Chloride	2	2	N/A	4
Fluoride	-	-	N/A	-
pH	1	1	N/A	2
Sulfate	-	-	N/A	-
Total Dissolved Solids	-	-	N/A	-
Appendix IV Constituents				
Antimony	N/A	-	-	-
Arsenic	N/A	-	-	-
Barium	N/A	-	-	-
Beryllium	N/A	-	-	-
Cadmium	N/A	-	-	-
Chromium	N/A	-	-	-
Cobalt	N/A	-	-	-
Fluoride	N/A	-	-	-
Lead	N/A	-	-	-
Lithium	N/A	-	-	-
Mercury	N/A	-	-	-
Molybdenum	N/A	-	-	-
Selenium	N/A	-	-	-
Thallium	N/A	-	-	-
Total Radium	N/A	-	-	-
Exceedances Total	3	3	-	6

Notes:

*Parentheses (Virginia GWPS Exeedance)

*Data compiled from Domminion responses to Public Staff Data Request 3-11, dated April 18, 2019.

*The annual data is from a singular sampling event and was collected from four (4) downgradient wells.

*1. For constituents for which a Maximum Contaminant Level (MCL) has been established, the MCL was used.
2. For constituents with no MCL and for which a health-based GWPS has been adopted under the August 29, 2018, Phase 1, Part 1 amendment to the CCR Rule, the health-based GWPS was used for the Federal CCR Rule GWPS.
3. For constituents for which the background level is higher than the MCL or health-based GWPS, the background concentration was used for GWPS.

Mount Storm - Phase B Landfill

No. of CCR Rule Groundwater Monitoring Exceedances by Constituent

Parameters	Annual Report		Notification	Exceedances
	2017	2018	2018 2nd Semi-Annual	Total
Appendix III Constituents				
Boron	-	-	N/A	-
Calcium	-	-	N/A	-
Chloride	1	-	N/A	1
Fluoride	1	1	N/A	2
pH	4	4	N/A	8
Sulfate	2	1	N/A	3
Total Dissolved Solids	-	-	N/A	-
Appendix IV Constituents				
Antimony	N/A	-	-	-
Arsenic	N/A	-	-	-
Barium	N/A	-	-	-
Beryllium	N/A	-	-	-
Cadmium	N/A	-	-	-
Chromium	N/A	-	-	-
Cobalt	N/A	-	-	-
Fluoride	N/A	-	-	-
Lead	N/A	-	-	-
Lithium	N/A	-	-	-
Mercury	N/A	-	-	-
Molybdenum	N/A	-	-	-
Selenium	N/A	-	-	-
Thallium	N/A	-	-	-
Total Radium	N/A	-	-	-
Exceedances Total	8	6	-	14

Notes:

*Parentheses (Virginia GWPS Exeedance)

*Data compiled from Domminion responses to Public Staff Data Request 3-11, dated April 18, 2019.

*The annual data is from a singular sampling event and was collected from six (6) downgradient wells.

*1. For constituents for which a Maximum Contaminant Level (MCL) has been established, the MCL was used.
2. For constituents with no MCL and for which a health-based GWPS has been adopted under the August 29, 2018, Phase 1, Part 1 amendment to the CCR Rule, the health-based GWPS was used for the Federal CCR Rule GWPS.
3. For constituents for which the background level is higher than the MCL or health-based GWPS, the background concentration was used for GWPS.

Mount Storm - Low Volume Waste Settling Ponds

No. of CCR Rule Groundwater Monitoring Exceedances by Constituent

Parameters	Annual Report		Notification	Exceedances
	2017	2018	2018 2nd Semi-Annual	Total
Appendix III Constituents				
Boron	3	2	N/A	5
Calcium	-	-	N/A	-
Chloride	-	-	N/A	-
Fluoride	1	3	N/A	4
pH	-	1	N/A	1
Sulfate	-	-	N/A	-
Total Dissolved Solids	-	-	N/A	-
Appendix IV Constituents				
Antimony	N/A	-	-	-
Arsenic	N/A	-	2	2
Barium	N/A	-	-	-
Beryllium	N/A	-	-	-
Cadmium	N/A	-	-	-
Chromium	N/A	-	-	-
Cobalt	N/A	-	1	1
Fluoride	N/A	1	-	1
Lead	N/A	-	-	-
Lithium	N/A	-	-	-
Mercury	N/A	-	-	-
Molybdenum	N/A	1	-	1
Selenium	N/A	-	-	-
Thallium	N/A	-	-	-
Total Radium	N/A	-	-	-
Exceedances Total	4	8	3	15

Notes:

*Parentheses (Virginia GWPS Exeedance)

*Data compiled from Domminion responses to Public Staff Data Request 3-11, dated April 18, 2019.

*The annual data is from a singular sampling event and was collected from five (5) downgradient wells.

*1. For constituents for which a Maximum Contaminant Level (MCL) has been established, the MCL was used.
2. For constituents with no MCL and for which a health-based GWPS has been adopted under the August 29, 2018, Phase 1, Part 1 amendment to the CCR Rule, the health-based GWPS was used for the Federal CCR Rule GWPS.
3. For constituents for which the background level is higher than the MCL or health-based GWPS, the background concentration was used for GWPS.

Possum Point - Pond D

No. of CCR Rule Groundwater Monitoring Exceedances by Constituent

	Annual Report		Notification	Exceedances
Parameters	2017	2018	2018 2nd Semi-Annual	Total
Appendix III Constituents				
Boron	5	2	2	9
Calcium	5	5	5	15
Chloride	6	6	6	18
Fluoride	-		-	-
pH	-		-	-
Sulfate	6	6	6	18
Total Dissolved Solids	6	6	6	18
Appendix IV Constituents				
Antimony	N/A	-	-	-
Arsenic	N/A	-	-	-
Barium	N/A	-	-	-
Beryllium	N/A	-	-	-
Cadmium	N/A	-	-	-
Chromium	N/A	-	-	-
Cobalt	N/A	0 (1)	1 (2)	1
Fluoride	N/A	-	-	-
Lead	N/A	-	-	-
Lithium	N/A	0 (2)	-	-
Mercury	N/A	-	-	-
Molybdenum	N/A	-	-	-
Selenium	N/A	-	-	-
Thallium	N/A	-	-	-
Total Radium	N/A	-	-	-
Exceedances Total	28	25	26	79

Notes:
*Parentheses (Virginia GWPS Exeedance)

*Data compiled from Domminion responses to Public Staff Data Request 3-11, dated April 18, 2019.

*The annual data is from a singular sampling event and was collected from six (6) downgradient wells.

*1. For constituents for which a Maximum Contaminant Level (MCL) has been established, the MCL was used.
2. For constituents for which a health-based GWPS has been adopted under the August 29, 2018 Phase 1, Part 1 amendment to the CCR Rule, the health-based GWPS was used for the Federal CCR Rule GWPS.
3. Under 9VAC20-81-800, for constituents for which an MCL has not been established, the background concentration for the constituent was used for GWPS. Note that Virginia CCR site-specific background values were calculated using existing groundwater data collected for the Solid Waste Permit from February 2016 through August 2017 along with CCR background data collected during the same period.
4. For constituents for which the background level is higher than the MCL or health-based GWPS, the background concentration was used for GWPS.

Virginia City Hybrid Energy Center - Curley Hollow Solid Waste Management Facility

No. of CCR Rule Groundwater Monitoring Exceedances by Constituent

Parameters	Annual Report 2017	Annual Report 2018	Notification 2018 2nd Semi-Annual	Exceedances Total
Appendix III Constituents				
Boron	1	1	1	3
Calcium	3	3	3	9
Chloride	-	-	-	-
Fluoride	1	1	1	3
pH	3	1	1	5
Sulfate	3	3	3	9
Total Dissolved Solids	2	2	2	6
Appendix IV Constituents				
Antimony	N/A	-	-	-
Arsenic	N/A	-	-	-
Barium	N/A	-	-	-
Beryllium	N/A	-	-	-
Cadmium	N/A	-	-	-
Chromium	N/A	-	-	-
Cobalt	N/A	-	-	-
Fluoride	N/A	-	-	-
Lead	N/A	-	-	-
Lithium	N/A	1 (2)	2	3
Mercury	N/A	-	-	-
Molybdenum	N/A	-	-	-
Selenium	N/A	-	-	-
Thallium	N/A	-	-	-
Total Radium	N/A	-	-	-
Exceedances Total	13	12	13	38

Notes:
*Parentheses (Virginia GWPS Exeedance)

*Data compiled from Domminion responses to Public Staff Data Request 3-11, dated April 18, 2019.

*The annual data is from a singular sampling event and was collected from four (4) downgradient wells.

*1. For constituents for which a Maximum Contaminant Level (MCL) has been established, the MCL was used.
2. For constituents for which a health-based GWPS has been adopted under the August 29, 2018 Phase 1, Part 1 amendment to the CCR Rule, the health-based GWPS was used for the Federal CCR Rule GWPS.
3. Under 9VAC20-81-800, for constituents for which an MCL has not been established, the background concentration for the constituent was used for GWPS. Note that Virginia CCR site-specific background values were calculated using existing groundwater data collected for the Solid Waste Permit from February 2016 through August 2017 along with CCR background data collected during the same period.
4. For constituents for which the background level is higher than the MCL or health-based GWPS, the background concentration was used for GWPS.

Yorktown - Industrial Landfill

No. of CCR Rule Groundwater Monitoring Exceedances by Constituent

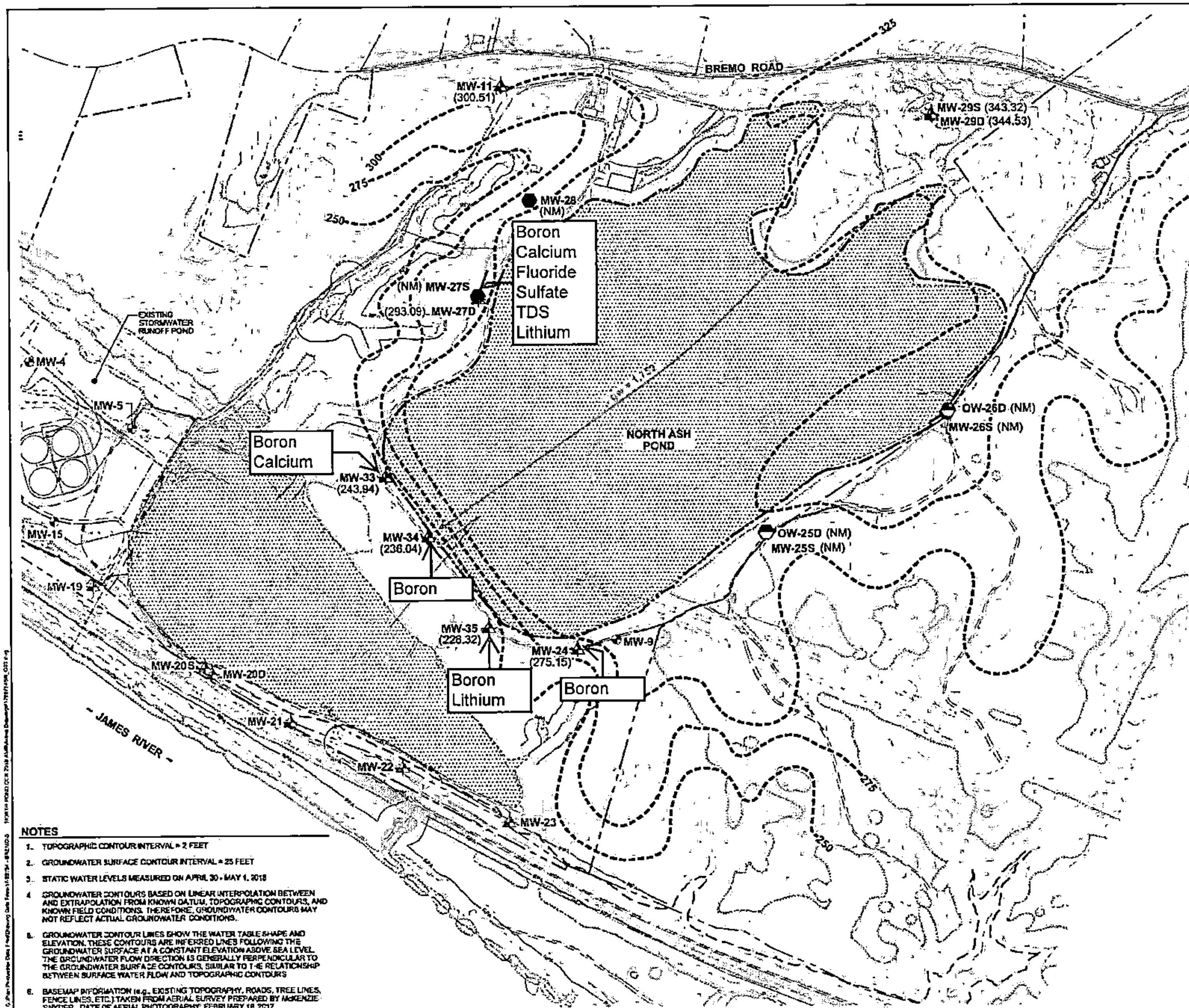
Parameters	Annual Report		Notification	Exceedances
	2017	2018	2018 2nd Semi-Annual	Total
Appendix III Constituents				
Boron	3	1	1	5
Calcium	3	2	2	7
Chloride	1	1	-	2
Fluoride	2	-	1	3
pH	-	-	-	-
Sulfate	4	3	3	10
Total Dissolved Solids	3	4	2	9
Appendix IV Constituents				
Antimony	N/A	-	-	-
Arsenic	N/A	-	-	-
Barium	N/A	-	-	-
Beryllium	N/A	-	-	-
Cadmium	N/A	-	-	-
Chromium	N/A	-	-	-
Cobalt	N/A	0 (1)	-	-
Fluoride	N/A	-	-	-
Lead	N/A	-	-	-
Lithium	N/A	-	-	-
Mercury	N/A	-	-	-
Molybdenum	N/A	-	0 (1)	-
Selenium	N/A	-	-	-
Thallium	N/A	-	-	-
Total Radium	N/A	-	-	-
Exceedances Total	16	11	9	36

Notes:
*Parentheses (Virginia GWPS Exeedance)

*Data compiled from Domminion responses to Public Staff Data Request 3-11, dated April 18, 2019.

*The annual data is from a singular sampling event and was collected from seven (7) downgradient wells.

*1. For constituents for which a Maximum Contaminant Level (MCL) has been established, the MCL was used.
2. For constituents for which a health-based GWPS has been adopted under the August 29, 2018 Phase 1, Part 1 amendment to the CCR Rule, the health-based GWPS was used for the Federal CCR Rule GWPS.
3. Under 9VAC20-81-800, for constituents for which an MCL has not been established, the background concentration for the constituent was used for GWPS. Note that Virginia CCR site-specific background values were calculated using existing groundwater data collected for the Solid Waste Permit from February 2016 through August 2017 along with CCR background data collected during the same period.
4. For constituents for which the background level is higher than the MCL or health-based GWPS, the background concentration was used for GWPS.



LEGEND

	APPROXIMATE PROPERTY BOUNDARY
	EXISTING TOPOGRAPHIC CONTOURS (2' INTERVALS) (FROM AERIAL SURVEY - SEE NOTE 6)
300	POTENTIOMETRIC SURFACE CONTOURS
	APPROXIMATE GROUNDWATER FLOW LINE
	WETLANDS
	APPROXIMATE LIMITS OF EXISTING ASH PONDS
	PROPOSED LIMITS OF FINAL COVER SYSTEM (ANCHOR TRENCH)
	LIMITS OF 100-YR FLOOD PLAIN
MW-24	FEDERAL CCR RULE COMPLIANCE WELL LOCATION AND IDENTIFICATION
MW-28	STATE GROUNDWATER COMPLIANCE WELL LOCATION AND IDENTIFICATION
OW-25D	GROUNDWATER OBSERVATION WELL LOCATION AND IDENTIFICATION
MW-4	EXISTING VPDES MONITORING WELL LOCATION AND IDENTIFICATION
(275.15)	STATIC GROUNDWATER ELEVATION (FEET ABOVE MEAN SEA LEVEL)
(NM)	NOT MEASURED
	GROUNDWATER FLOW PATH LENGTH (FEET)
Constituent	Exceedance

NOTES

1. TOPOGRAPHIC CONTOUR INTERVAL = 2 FEET
2. GROUNDWATER SURFACE CONTOUR INTERVAL = 25 FEET
3. STATIC WATER LEVELS MEASURED ON APRIL 30 - MAY 1, 2018
4. GROUNDWATER CONTOURS BASED ON LINEAR INTERPOLATION BETWEEN AND EXTRAPOLATION FROM KNOWN DATUM, TOPOGRAPHIC CONTOURS, AND KNOWN FIELD CONDITIONS. THEREFORE, GROUNDWATER CONTOURS MAY NOT REFLECT ACTUAL GROUNDWATER CONDITIONS.
5. GROUNDWATER CONTOUR LINES SHOW THE WATER TABLE SHAPE AND ELEVATION. THESE CONTOURS ARE INFERRED LINES FOLLOWING THE GROUNDWATER SURFACE AT A CONSTANT ELEVATION ABOVE SEA LEVEL. THE GROUNDWATER FLOW DIRECTION IS GENERALLY PERPENDICULAR TO THE GROUNDWATER SURFACE CONTOURS, SIMILAR TO THE RELATIONSHIP BETWEEN SURFACE WATER FLOW AND TOPOGRAPHIC CONTOURS
6. BASEMAP INFORMATION (e.g., EXISTING TOPOGRAPHY, ROADS, TREE LINES, FENCE LINES, ETC.) TAKEN FROM AERIAL SURVEY PREPARED BY McKENZIE SNYDER. DATE OF AERIAL PHOTOGRAPHY: FEBRUARY 16, 2017.

CLIENT
DOMINION ENERGY
BREMO POWER STATION
FLUVANNA COUNTY, VIRGINIA

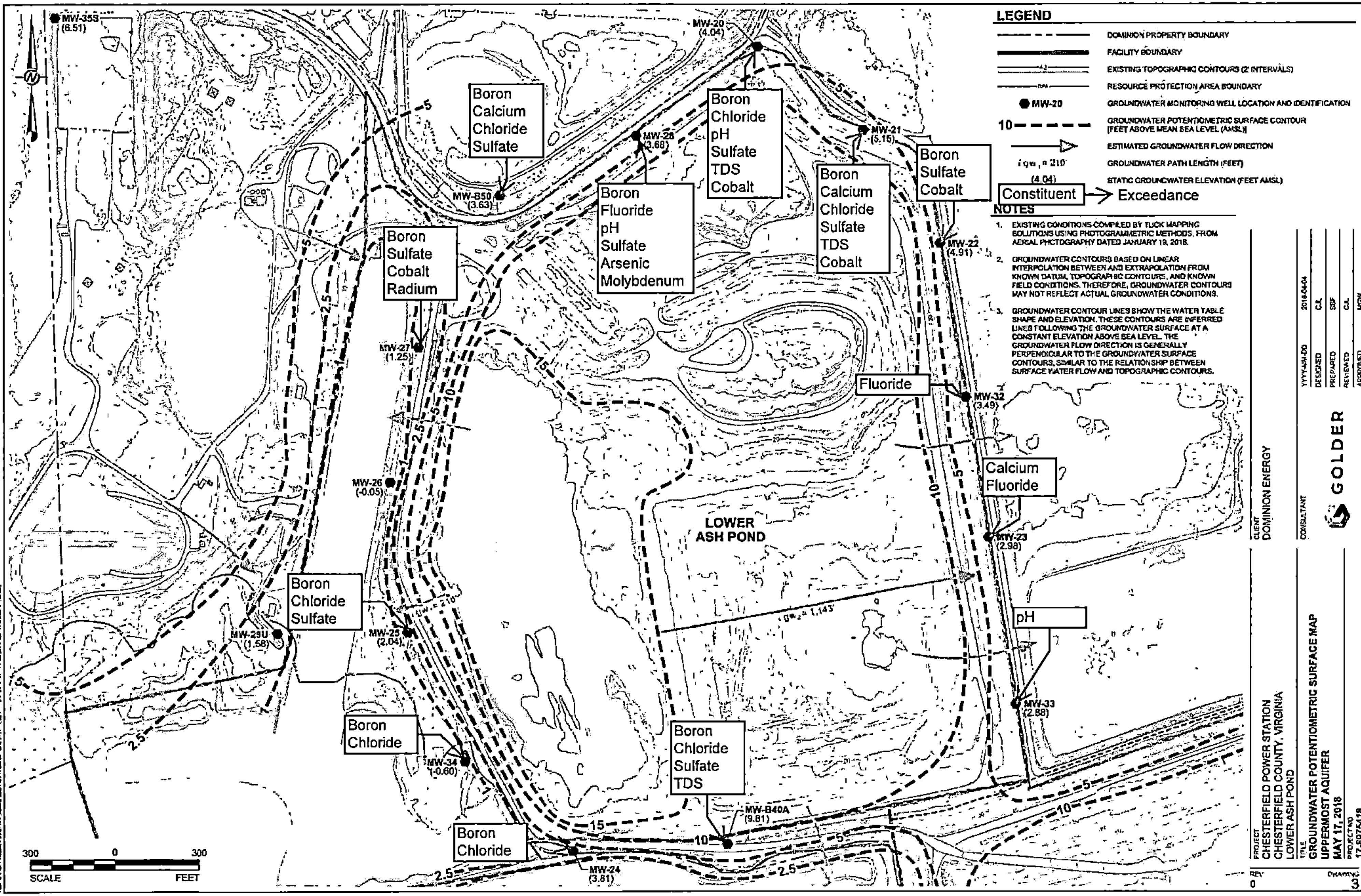
PROJECT
NORTH POND CCR
GROUNDWATER SAMPLING EVENT

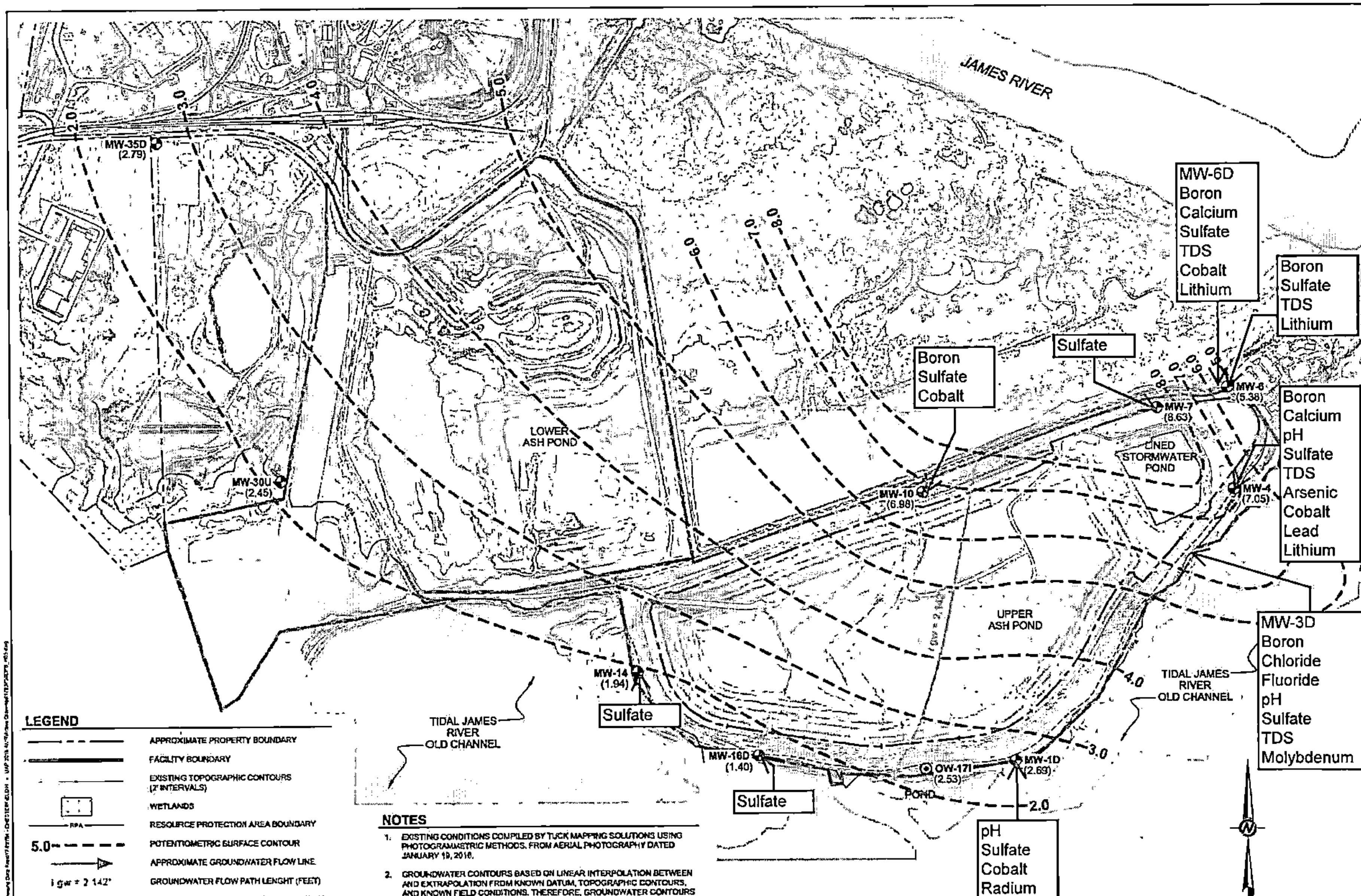
TITLE
GROUNDWATER POTENTIOMETRIC SURFACE MAP
APRIL 30 - MAY 1, 2018

CONSULTANT
GOLDER

YYYY-MM-DD	2018-10-31
DESIGNED	ALR
PREPARED	SBF
REVIEWED	ALR
APPROVED	MGW

PROJECT NO.	REV.	DRAWING
17-8975418	0	3


LEGEND
DOMINION PROPERTY BOUNDARY
FACILITY BOUNDARY
EXISTING TOPOGRAPHIC CONTOURS (2' INTERVALS)
RESOURCE PROTECTION AREA BOUNDARY
MW-20
GROUNDWATER MONITORING WELL LOCATION AND IDENTIFICATION
10
GROUNDWATER POTENTIOMETRIC SURFACE CONTOUR [FEET ABOVE MEAN SEA LEVEL (AMSL)]
ESTIMATED GROUNDWATER FLOW DIRECTION
GROUNDWATER PATH LENGTH (FEET)
(4.04)
STATIC GROUNDWATER ELEVATION (FEET AMSL)
Constituent
Exceedance
NOTES
1. EXISTING CONDITIONS COMPILED BY TUCK MAPPING SOLUTIONS USING PHOTOGRAMMETRIC METHODS, FROM AERIAL PHOTOGRAPHY DATED JANUARY 19, 2018.
2. GROUNDWATER CONTOURS BASED ON LINEAR INTERPOLATION BETWEEN AND EXTRAPOLATION FROM KNOWN DATUM, TOPOGRAPHIC CONTOURS, AND KNOWN FIELD CONDITIONS. THEREFORE, GROUNDWATER CONTOURS MAY NOT REFLECT ACTUAL GROUNDWATER CONDITIONS.
3. GROUNDWATER CONTOUR LINES SHOW THE WATER TABLE SHAPE AND ELEVATION. THESE CONTOURS ARE INFERRED LINES FOLLOWING THE GROUNDWATER SURFACE AT A CONSTANT ELEVATION ABOVE SEA LEVEL. THE GROUNDWATER FLOW DIRECTION IS GENERALLY PERPENDICULAR TO THE GROUNDWATER SURFACE CONTOURS, SIMILAR TO THE RELATIONSHIP BETWEEN SURFACE WATER FLOW AND TOPOGRAPHIC CONTOURS.
MW-35S (6.51)
MW-20 (4.04)
Boron Chloride pH Sulfate TDS Cobalt
Boron Calcium Chloride Sulfate
MW-28 (3.68)
Boron Fluoride pH Sulfate Arsenic Molybdenum
MW-B50 (3.63)
MW-21 (5.15)
Boron Calcium Chloride Sulfate TDS Cobalt
Boron Sulfate Cobalt
MW-22 (4.91)
Boron Sulfate Cobalt Radium
MW-27 (1.25)
Fluoride
MW-32 (3.49)
MW-26 (-0.05)
Calcium Fluoride
MW-23 (2.98)
LOWER ASH POND
Boron Chloride Sulfate
MW-29U (1.58)
MW-25 (2.04)
pH
MW-33 (2.88)
Boron Chloride
MW-34 (-0.60)
Boron Chloride Sulfate TDS
MW-B40A (9.81)
Boron Chloride
MW-24 (3.81)
2.5
5
10
15
300 0 300
SCALE FEET
CLIENT
DOMINION ENERGY
CONSULTANT
GOLDER
YYYY-MM-DD 2018-04-04
DESIGNED CJL
PREPARED SSF
REVIEWED CJL
APPROVED MGW
PROJECT
CHESTERFIELD POWER STATION
CHESTERFIELD COUNTY, VIRGINIA
LOWER ASH POND
TITLE
GROUNDWATER POTENTIOMETRIC SURFACE MAP
UPPERMOST AQUIFER
MAY 17, 2018
PROJECT NO 17-8975418
REV 0
DRAWING 3



LEGEND

- APPROXIMATE PROPERTY BOUNDARY
- FACILITY BOUNDARY
- EXISTING TOPOGRAPHIC CONTOURS (2' INTERVALS)
- WETLANDS
- RPA — RESOURCE PROTECTION AREA BOUNDARY
- 5.0 — POTENTIOMETRIC SURFACE CONTOUR
- APPROXIMATE GROUNDWATER FLOW LINE
- i gw = 2,142' — GROUNDWATER FLOW PATH LENGHT (FEET)
- MW-6 — EXISTING GROUNDWATER MONITORING WELL LOCATION AND IDENTIFICATION
- OW-17I — OBSERVATION WELL WITH STATIC WATER LEVEL ELEVATION (FEET ABOVE MEAN SEA LEVEL)
- (5.38) — STATIC GROUNDWATER ELEVATION (FEET ABOVE MEAN SEA LEVEL)
- Constituent → Exceedance

NOTES

1. EXISTING CONDITIONS COMPILED BY TUCK MAPPING SOLUTIONS USING PHOTOGRAMMETRIC METHODS. FROM AERIAL PHOTOGRAPHY DATED JANUARY 19, 2016.
2. GROUNDWATER CONTOURS BASED ON LINEAR INTERPOLATION BETWEEN AND EXTRAPOLATION FROM KNOWN DATUM, TOPOGRAPHIC CONTOURS, AND KNOWN FIELD CONDITIONS. THEREFORE, GROUNDWATER CONTOURS MAY NOT REFLECT ACTUAL GROUNDWATER CONDITIONS.
3. GROUNDWATER CONTOUR LINES SHOW THE WATER TABLE SHAPE AND ELEVATION. THESE CONTOURS ARE INFERRED LINES FOLLOWING THE GROUNDWATER SURFACE AT A CONSTANT ELEVATION ABOVE SEA LEVEL. THE GROUNDWATER FLOW DIRECTION IS GENERALLY PERPENDICULAR TO THE GROUNDWATER SURFACE CONTOURS. SIMILAR TO THE RELATIONSHIP BETWEEN SURFACE WATER FLOW AND TOPOGRAPHIC CONTOURS.

CLIENT
DOMINION ENERGY

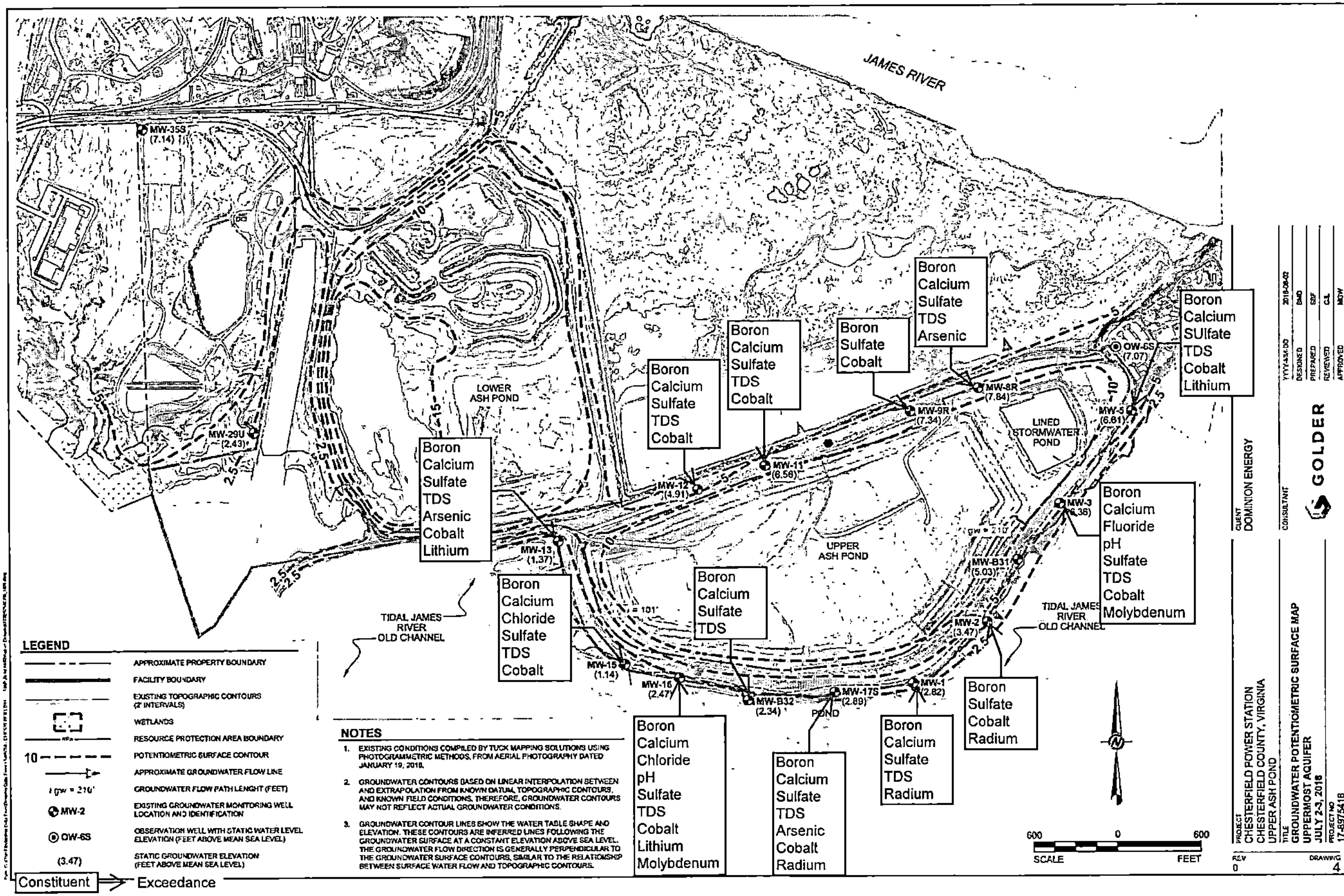
CONSULTANT
GOLDER

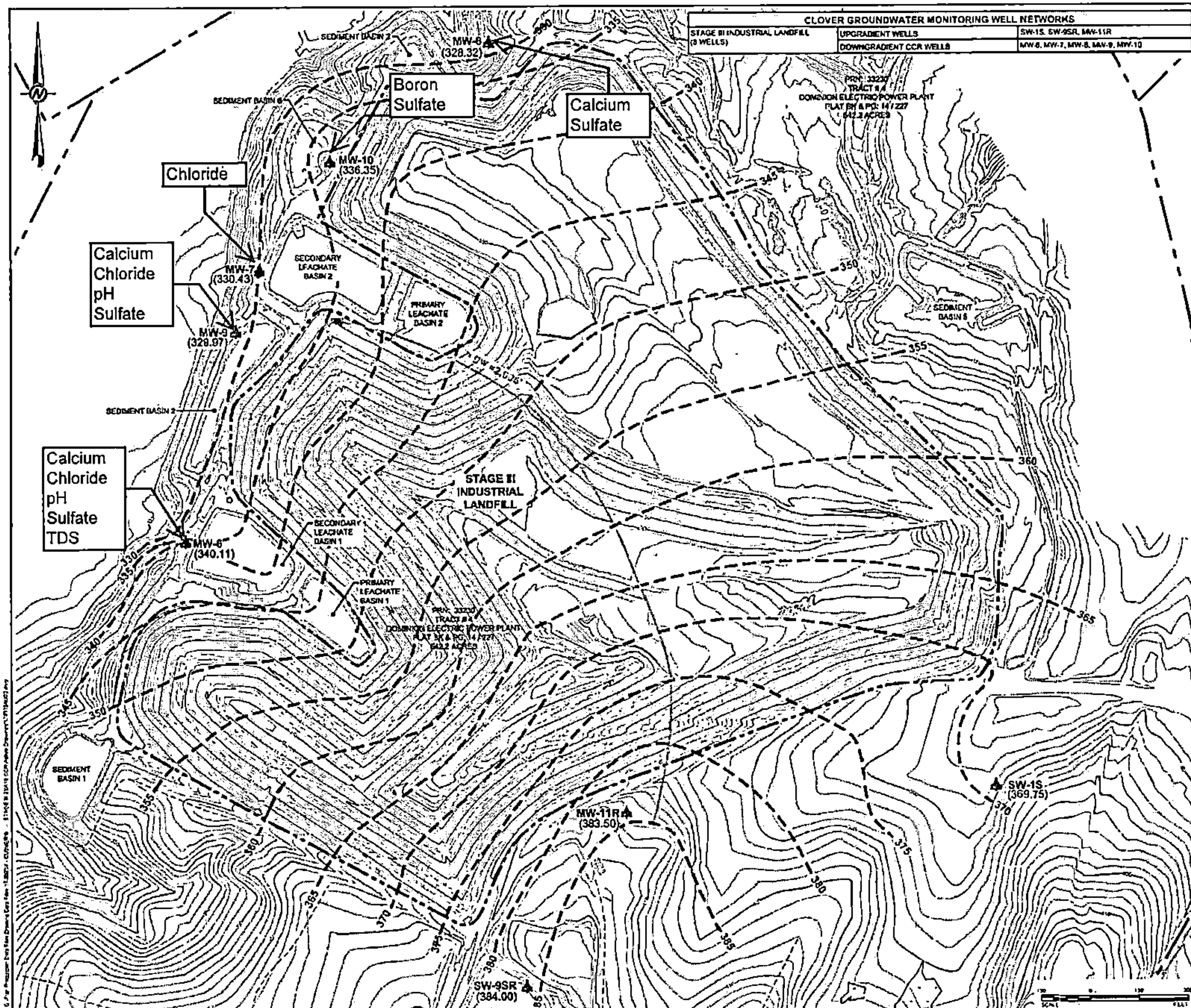
YYYY-MM-DD	2018-08-02
DESIGNED	BMD
PREPARED	SSF
REVIEWED	CJL
APPROVED	MSW

PROJECT
CHESTERFIELD POWER STATION
CHESTERFIELD COUNTY, VIRGINIA
UPPER ASH POND

TITLE
GROUNDWATER POTENTIOMETRIC SURFACE MAP
POTOMAC AQUIFER
JULY 2, 2018

PROJECT NO. 17-8975418 REV. 0 DRAWING 5


JAMES RIVER
MW-35S (7.14)
MW-29U (2.43)
LOWER ASH POND
UPPER ASH POND
LINED STORMWATER POND
TIDAL JAMES RIVER OLD CHANNEL
TIDAL JAMES RIVER OLD CHANNEL
POND
MW-13 (1.37)
MW-12 (4.91)
MW-11 (6.56)
MW-9R (7.34)
MW-8R (7.84)
OW-6S (7.07)
MW-5 (6.81)
MW-3 (6.36)
MW-B31 (5.03)
MW-2 (3.47)
MW-1 (2.82)
MW-17S (2.89)
MW-B32 (2.34)
MW-16 (2.47)
MW-15 (1.14)
Boron Calcium Sulfate TDS Arsenic Cobalt Lithium
Boron Calcium Chloride Sulfate TDS Cobalt
Boron Calcium Sulfate TDS Cobalt
Boron Calcium Sulfate TDS Cobalt
Boron Sulfate Cobalt
Boron Calcium Sulfate TDS Arsenic
Boron Calcium SUlfate TDS Cobalt Lithium
Boron Calcium Fluoride pH Sulfate TDS Cobalt Molybdenum
Boron Calcium Sulfate TDS
Boron Sulfate Cobalt Radium
Boron Calcium Sulfate TDS Radium
Boron Calcium Sulfate TDS Arsenic Cobalt Radium
Boron Calcium Chloride pH Sulfate TDS Cobalt Lithium Molybdenum
LEGEND
APPROXIMATE PROPERTY BOUNDARY
FACILITY BOUNDARY
EXISTING TOPOGRAPHIC CONTOURS (2' INTERVALS)
WETLANDS
RESOURCE PROTECTION AREA BOUNDARY
POTENTIOMETRIC SURFACE CONTOUR
APPROXIMATE GROUNDWATER FLOW LINE
GROUNDWATER FLOW PATH LENGHT (FEET)
EXISTING GROUNDWATER MONITORING WELL LOCATION AND IDENTIFICATION
OBSERVATION WELL WITH STATIC WATER LEVEL ELEVATION (FEET ABOVE MEAN SEA LEVEL)
STATIC GROUNDWATER ELEVATION (FEET ABOVE MEAN SEA LEVEL)
Constituent
Exceedance
NOTES
1. EXISTING CONDITIONS COMPILED BY TUCK MAPPING SOLUTIONS USING PHOTOGRAMMETRIC METHODS, FROM AERIAL PHOTOGRAPHY DATED JANUARY 19, 2018.
2. GROUNDWATER CONTOURS BASED ON LINEAR INTERPOLATION BETWEEN AND EXTRAPOLATION FROM KNOWN DATUM, TOPOGRAPHIC CONTOURS, AND KNOWN FIELD CONDITIONS. THEREFORE, GROUNDWATER CONTOURS MAY NOT REFLECT ACTUAL GROUNDWATER CONDITIONS.
3. GROUNDWATER CONTOUR LINES SHOW THE WATER TABLE SHAPE AND ELEVATION. THESE CONTOURS ARE INFERRED LINES FOLLOWING THE GROUNDWATER SURFACE AT A CONSTANT ELEVATION ABOVE SEA LEVEL. THE GROUNDWATER FLOW DIRECTION IS GENERALLY PERPENDICULAR TO THE GROUNDWATER SURFACE CONTOURS, SIMILAR TO THE RELATIONSHIP BETWEEN SURFACE WATER FLOW AND TOPOGRAPHIC CONTOURS.
600 0 600
SCALE FEET
CLIENT
DOMINION ENERGY
CONSULTANT
GOLDER
YYYY-MM-DD 2018-08-02
DESIGNED BMD
PREPARED SDF
REVIEWED CL
APPROVED MDW
PROJECT
CHESTERFIELD POWER STATION
CHESTERFIELD COUNTY, VIRGINIA
UPPER ASH POND
TITLE
GROUNDWATER POTENTIOMETRIC SURFACE MAP
UPPERMOST AQUIFER
JULY 2-3, 2018
PROJECT NO
17-8975418
REV
0
DRAWING
4



CLOVER GROUNDWATER MONITORING WELL NETWORKS		
STAGE III INDUSTRIAL LANDFILL (8 WELLS)	UPGRADIENT WELLS	SW-1S, SW-9SR, MW-11R
	DOWNGRADIENT CCR WELLS	MW-6, MW-7, MW-8, MW-9, MW-10

LEGEND

APPROXIMATE PROPERTY BOUNDARY

LIMITS OF CCR UNIT

EXISTING TOPOGRAPHIC CONTOURS (2' INTERVALS) (SEE REFERENCE NOTE 1)

WETLANDS

350 POTENTIOMETRIC SURFACE CONTOURS

APPROXIMATE GROUNDWATER FLOW LINE

MW-11R CCR RULE COMPLIANCE WELL LOCATION AND IDENTIFICATION

(383.50) STATIC GROUNDWATER ELEVATION (FEET ABOVE MEAN SEA LEVEL)

Constituent → Exceedance

REFERENCE

1. EXISTING TOPOGRAPHY IS BASED ON PHOTOGRAMMETRY FLOWN ON 04/06/2014 BY AXIS GEOSPATIAL, LLC AND UPDATED IN 2015, AND 2016 BY HEADWATERS PLANT SERVICES. THE DATABASE HAS BEEN CONVERTED TO NAD 83 VIRGINIA STATE PLANE, SOUTH ZONE, US FOOT.
2. GROUNDWATER CONTOURS BASED ON LINEAR INTERPOLATION BETWEE AND EXTRAPOLATION FROM KNOWN DATUM, TOPOGRAPHIC CONTOURS, AND KNOWN FIELD CONDITIONS. THEREFORE, GROUNDWATER CONTOURS MAY NOT REFLECT ACTUAL GROUNDWATER CONDITIONS.
3. GROUNDWATER CONTOUR LINES SHOW THE WATER TABLE SHAPE AN ELEVATION. THESE CONTOURS ARE INFERRED LINES FOLLOWING THE GROUNDWATER SURFACE AT A CONSTANT ELEVATION ABOVE SEA LEVEL. THE GROUNDWATER FLOW DIRECTION IS GENERALLY PERPENDICULAR TO THE GROUNDWATER SURFACE CONTOURS, SIMILAR TO THE RELATIONSHIP BETWEEN SURFACE WATER FLOW AND TOPOGRAPHIC CONTOURS.

CLIENT
DOMINION / ODEC

PROJECT
CLOVER POWER STATION
STAGE III LANDFILL
HALIFAX COUNTY, VIRGINIA

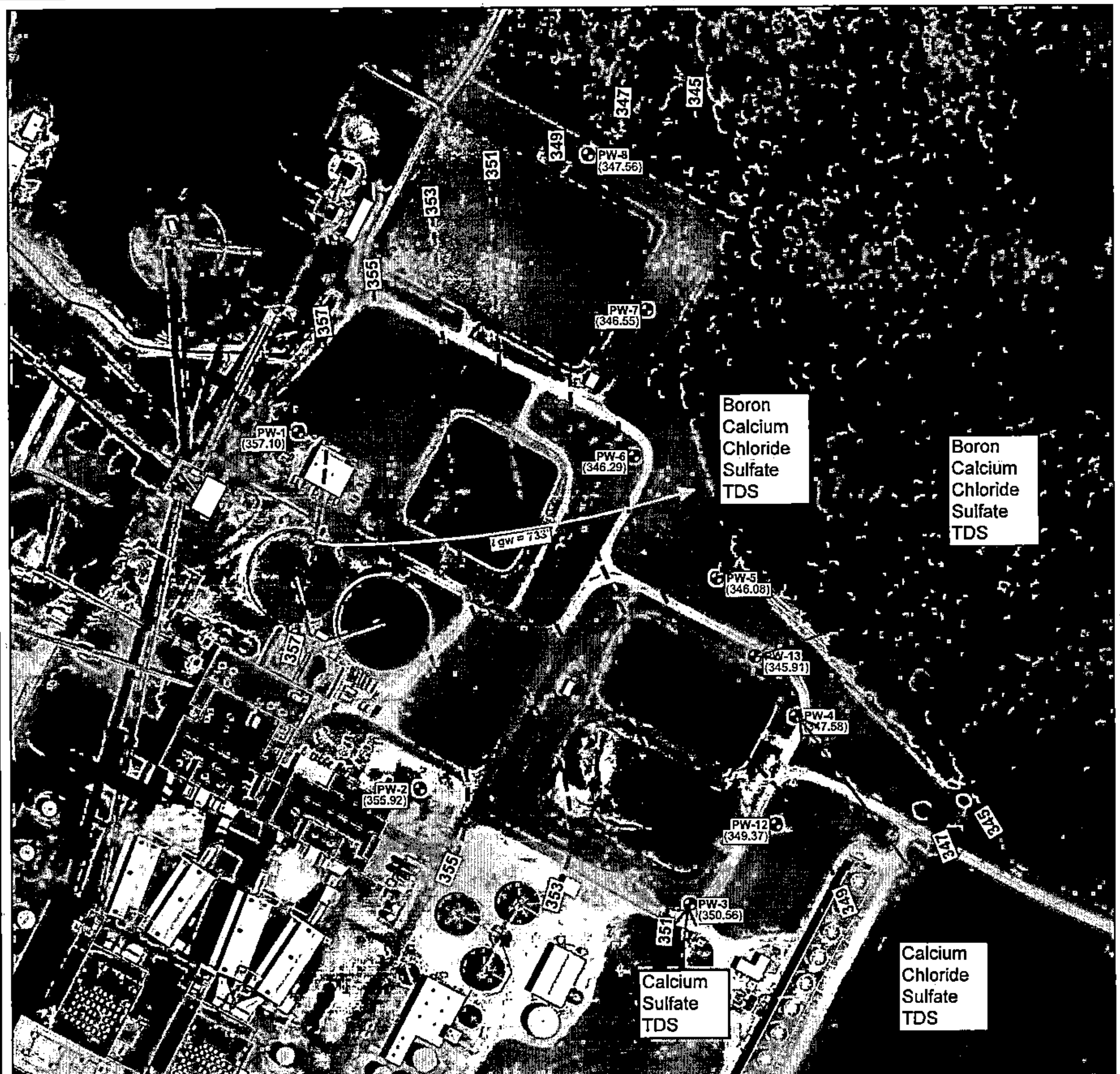
TITLE
GROUNDWATER POTENTIOMETRIC SURFACE MAP
MAY 23, 2018

CONSULTANT

GOLDER

YYYY-MM-DD	2018-11-30
DESIGNED	RIP
PREPARED	SIB
REVIEWED	MGW
APPROVED	MGW

PROJECT NO. 17-8975418 REV. 0 DRAWING 3



LEGEND

349 — — —	POTENTIOMETRIC SURFACE CONTOUR
——▷	APPROXIMATE GROUNDWATER FLOW LINE
l gw = 733'	GROUNDWATER FLOW PATH LENGHT (FEET)
PW-13	EXISTING GROUNDWATER MONITORING WELL LOCATION AND IDENTIFICATION (SHALLOW AQUIFER)
(345.91)	STATIC GROUNDWATER ELEVATION (FEET ABOVE MEAN SEA LEVEL)
Constituent	→ Exceedance

REFERENCE

1. AERIAL IMAGE TAKEN FROM GOOGLE EARTH PRO ON 03/22/2018. MAP DATA BY: GOOGLE, IMAGERY DATE: 05/13/2018
2. GROUNDWATER CONTOURS BASED ON LINEAR INTERPOLATION BETWEEN AND EXTRAPOLATION FROM KNOWN DATUM, TOPOGRAPHIC CONTOURS, AND KNOWN FIELD CONDITIONS. THEREFORE, GROUNDWATER CONTOURS MAY NOT REFLECT ACTUAL GROUNDWATER CONDITIONS.
3. GROUNDWATER CONTOUR LINES SHOW THE WATER TABLE SHAPE AND ELEVATION. THESE CONTOURS ARE INFERRED LINES FOLLOWING THE GROUNDWATER SURFACE AT A CONSTANT ELEVATION ABOVE SEA LEVEL. THE GROUNDWATER FLOW DIRECTION IS GENERALLY PERPENDICULAR TO THE GROUNDWATER SURFACE CONTOURS, SIMILAR TO THE RELATIONSHIP BETWEEN SURFACE WATER FLOW AND TOPOGRAPHIC CONTOURS.

200 0 200
SCALE FEET

CLIENT
DOMINION ENERGY

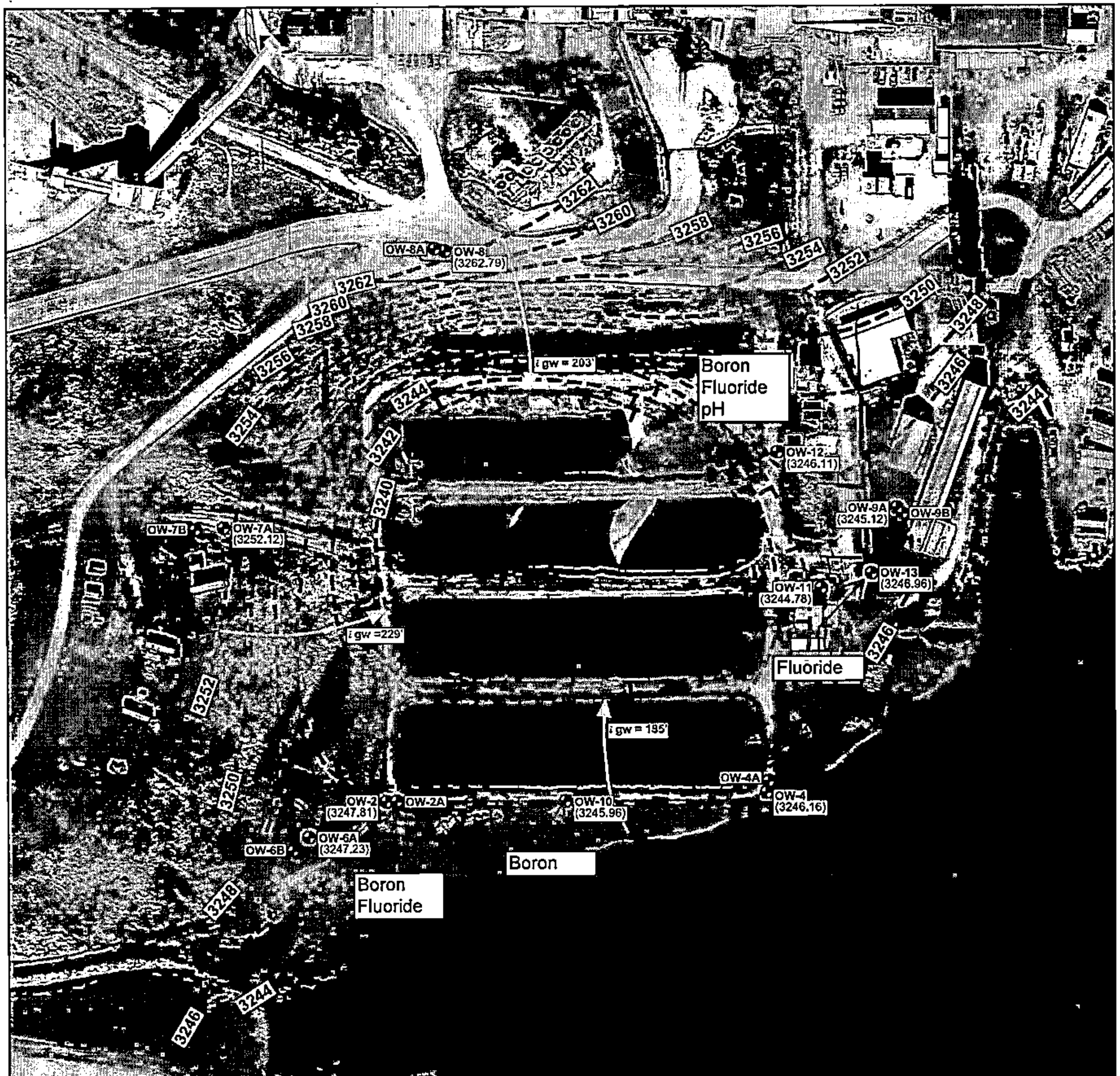
CONSULTANT
GOLDER

YYYY-MM-DD	2018-11-13
DESIGNED	RJP
PREPARED	SIB
REVIEWED	MGW
APPROVED	MGW

PROJECT
CLOVER POWER STATION
SLUDGE SEDIMENTATION PONDS

TITLE
POTENTIOMETRIC SURFACE MAP
JUNE 19, 2018

PROJECT NO. 17-8375418
REV. 0
FIGURE 4



LEGEND

3250 - - - -	POTENTIOMETRIC SURFACE CONTOUR
——→	APPROXIMATE GROUNDWATER FLOW LINE
i gw = 256'	GROUNDWATER FLOW PATH LENGHT (FEET)
OW-9A	EXISTING GROUNDWATER MONITORING WELL LOCATION AND IDENTIFICATION (SHALLOW AQUIFER)
OW-9B	EXISTING GROUNDWATER MONITORING WELL LOCATION AND IDENTIFICATION (DEEP AQUIFER)
(3245.22)	STATIC GROUNDWATER ELEVATION (FEET ABOVE MEAN SEA LEVEL)

Constituent → Exceedance

REFERENCE

1. AERIAL IMAGE TAKEN FROM GOOGLE EARTH PRO ON 05/14/2018. MAP DATA BY: GOOGLE, IMAGERY DATE: 11/19/2013
2. GROUNDWATER CONTOURS BASED ON LINEAR INTERPOLATION BETWEEN AND EXTRAPOLATION FROM KNOWN DATUM, TOPOGRAPHIC CONTOURS, AND KNOWN FIELD CONDITIONS. THEREFORE, GROUNDWATER CONTOURS MAY NOT REFLECT ACTUAL GROUNDWATER CONDITIONS.
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NOTES

1. SURFACE WATER ELEVATION = 3,244 FEET ABOVE MEAN SEA LEVEL.

N

150 0 150
SCALE FEET

CLIENT
DOMINION ENERGY

CONSULTANT
GOLDER

YYYY-MM-DD	2019-01-04
DESIGNED	MGW
PREPARED	ASR
REVIEWED	MGW
APPROVED	MGW

PROJECT
MOUNT STORM POWER STATION
LOW VOLUME WASTE SETTLING PONDS

TITLE
POTENTIOMETRIC SURFACE MAP
JUNE 4, 2018

PROJECT NO. 17-6975418
REV. 0
DRAWING 3

LEGEND

— — —	APPROXIMATE LANDFILL BOUNDARY
3300 — — —	POTENTIOMETRIC SURFACE CONTOUR
———▷	APPROXIMATE GROUNDWATER FLOW LINE
ℓ gw = 3,697'	GROUNDWATER FLOW PATH LENGTH (FEET)
MW-22	EXISTING GROUNDWATER MONITORING WELL LOCATION AND IDENTIFICATION
MWFGDW3	EXISTING GROUNDWATER OBSERVATION WELL LOCATION AND IDENTIFICATION
(3553.96)	STATIC GROUNDWATER ELEVATION (FEET ABOVE MEAN SEA LEVEL)
(NM)	NOT MEASURED
Constituent	→ Exceedance

REFERENCE

1. AERIAL IMAGE TAKEN FROM GOOGLE EARTH PRO ON 05/14/2018. MAP DATA BY: GOOGLE, IMAGERY DATE: 11/19/2013
2. GROUNDWATER CONTOURS BASED ON LINEAR INTERPOLATION BETWEEN AND EXTRAPOLATION FROM KNOWN DATUM, TOPOGRAPHIC CONTOURS, AND KNOWN FIELD CONDITIONS. THEREFORE, GROUNDWATER CONTOURS MAY NOT REFLECT ACTUAL GROUNDWATER CONDITIONS.
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N

1000 0 1000

SCALE FEET

CLIENT
DOMINION ENERGY

CONSULTANT
GOLDER

YYYY-MM-DD	2018-07-02
DESIGNED	RJP
PREPARED	SBF
REVIEWED	MGW
APPROVED	MGW

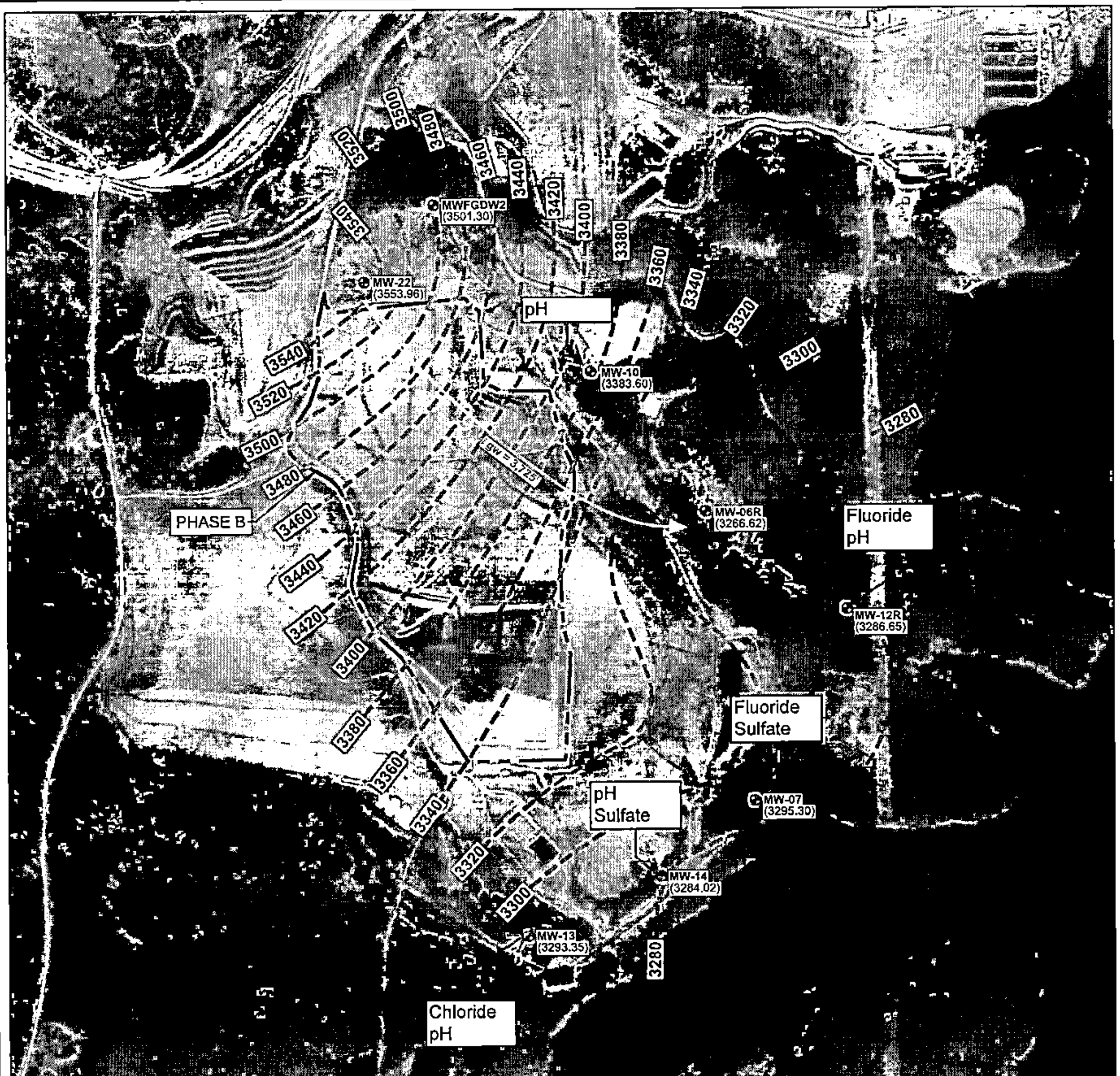
PROJECT
MOUNT STORM POWER STATION
PHASE A LANDFILL

TITLE
POTENTIOMETRIC SURFACE MAP
UPPERMOST AQUIFER
JUNE 5, 2018

PROJECT NO.
17-8975418

REV.
0

DRAWING
3



LEGEND

— — — —	APPROXIMATE LANDFILL BOUNDARY
3300 — — —	POTENTIOMETRIC SURFACE CONTOUR
⟹	APPROXIMATE GROUNDWATER FLOW LINE
l gw = 3,813'	GROUNDWATER FLOW PATH LENGTH (FEET)
MW-22	EXISTING GROUNDWATER MONITORING WELL LOCATION AND IDENTIFICATION
(3553.96)	STATIC GROUNDWATER ELEVATION (FEET ABOVE MEAN SEA LEVEL)
Constituent →	Exceedance

REFERENCE

1. AERIAL IMAGE TAKEN FROM GOOGLE EARTH PRO ON 05/14/2018, MAP DATA BY: GOOGLE, IMAGERY DATE: 11/19/2013
2. GROUNDWATER CONTOURS BASED ON LINEAR INTERPOLATION BETWEEN AND EXTRAPOLATION FROM KNOWN DATUM, TOPOGRAPHIC CONTOURS, AND KNOWN FIELD CONDITIONS, THEREFORE, GROUNDWATER CONTOURS MAY NOT REFLECT ACTUAL GROUNDWATER CONDITIONS.
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1000 0 1000
SCALE FEET

CLIENT
DOMINION ENERGY

CONSULTANT
GOLDER

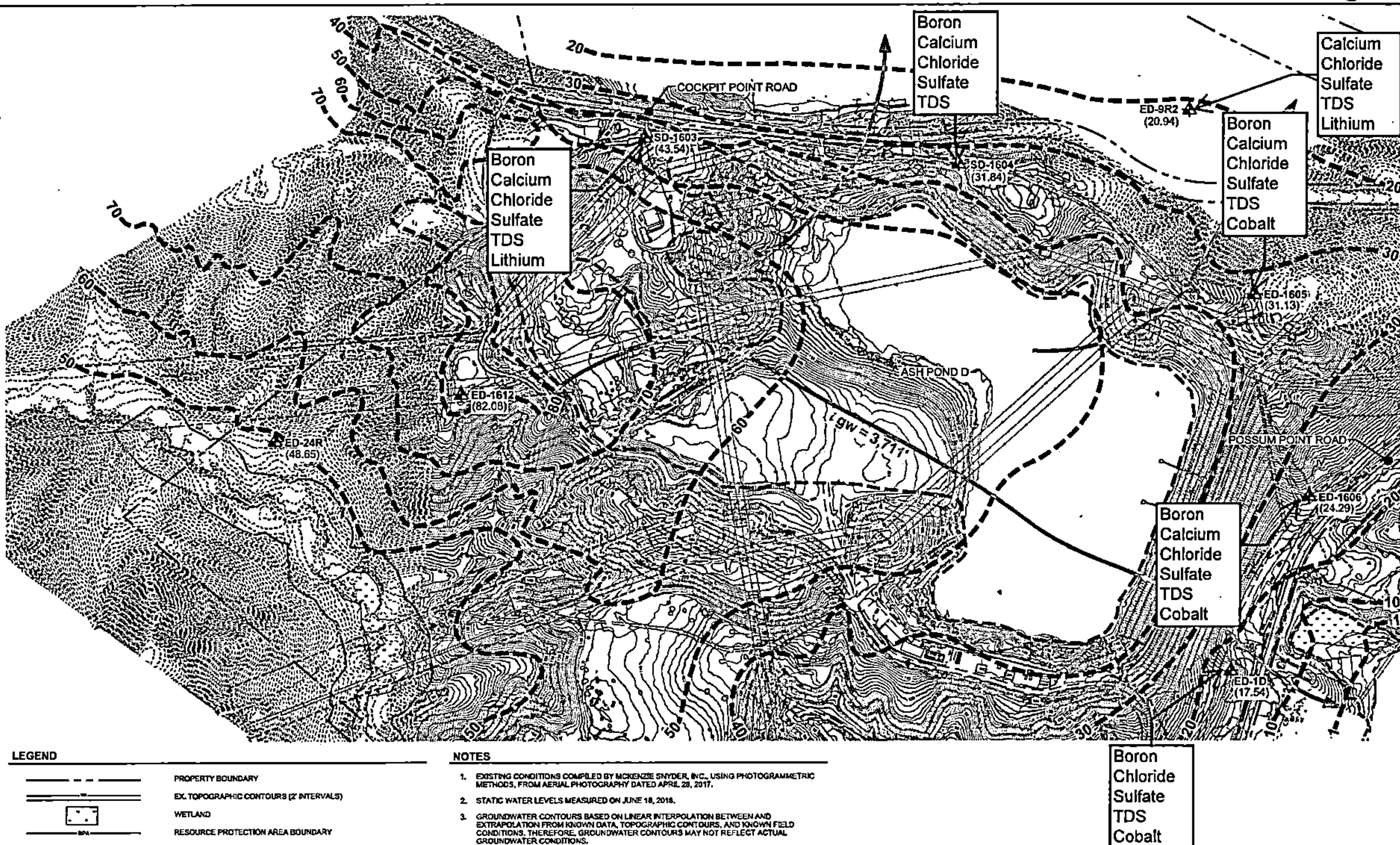
YYYY-MM-DD	2018-07-02
DESIGNED	RJP
PREPARED	SBF
REVIEWED	MGW
APPROVED	MGW

PROJECT
MOUNT STORM POWER STATION
PHASE B LANDFILL

TITLE
POTENTIOMETRIC SURFACE MAP
UPPERMOST AQUIFER
JUNE 5, 2018

PROJECT NO. 17-8975418
REV. 0
DRAWING 3

IF THIS MEASUREMENT DOES NOT MATCH WHAT IS SHOWN, THE SHEET SIZE HAS BEEN MODIFIED FROM: ANSI B



LEGEND

	PROPERTY BOUNDARY
	EX. TOPOGRAPHIC CONTOURS (2' INTERVALS)
	WETLAND
	RESOURCE PROTECTION AREA BOUNDARY
	100-YEAR FLOOD PLAIN
	ASH POND LIMITS
ED-1606	EX. GROUNDWATER MONITORING WELL (POND D CCR)
(24.29)	STATIC GROUNDWATER LEVEL ELEVATION (FEET ABOVE MEAN SEA LEVEL (AMSL))
50	GROUNDWATER SURFACE CONTOUR (FEET AMSL)
	APPROXIMATE GROUNDWATER FLOW PATHWAY USED TO CALCULATE HYDRAULIC GRADIENT
i gw = 3,711'	GROUNDWATER PATH LENGTH (FEET)
Constituent →	Exceedance

NOTES

1. EXISTING CONDITIONS COMPILED BY MCKENZIE SNYDER, INC., USING PHOTOGRAMMETRIC METHODS, FROM AERIAL PHOTOGRAPHY DATED APRIL 28, 2017.
2. STATIC WATER LEVELS MEASURED ON JUNE 18, 2018.
3. GROUNDWATER CONTOURS BASED ON LINEAR INTERPOLATION BETWEEN AND EXTRAPOLATION FROM KNOWN DATA, TOPOGRAPHIC CONTOURS, AND KNOWN FIELD CONDITIONS. THEREFORE, GROUNDWATER CONTOURS MAY NOT REFLECT ACTUAL GROUNDWATER CONDITIONS.
4. GROUNDWATER CONTOUR LINES SHOW THE WATER TABLE SHAPE AND ELEVATION. THESE CONTOURS ARE INFERRED LINES FOLLOWING THE GROUNDWATER SURFACE AT A CONSTANT ELEVATION ABOVE SEA LEVEL. THE GROUNDWATER FLOW DIRECTION IS GENERALLY PERPENDICULAR TO THE GROUNDWATER SURFACE CONTOURS, SIMILAR TO THE RELATIONSHIP BETWEEN SURFACE WATER FLOW AND TOPOGRAPHIC CONTOURS.

CLIENT
DOMINION ENERGY

CONSULTANT
GOLDER

YYYY-MM-DD	2018-10-31
DESIGNED	ALR
PREPARED	SBF
REVIEWED	ALR
APPROVED	MGW

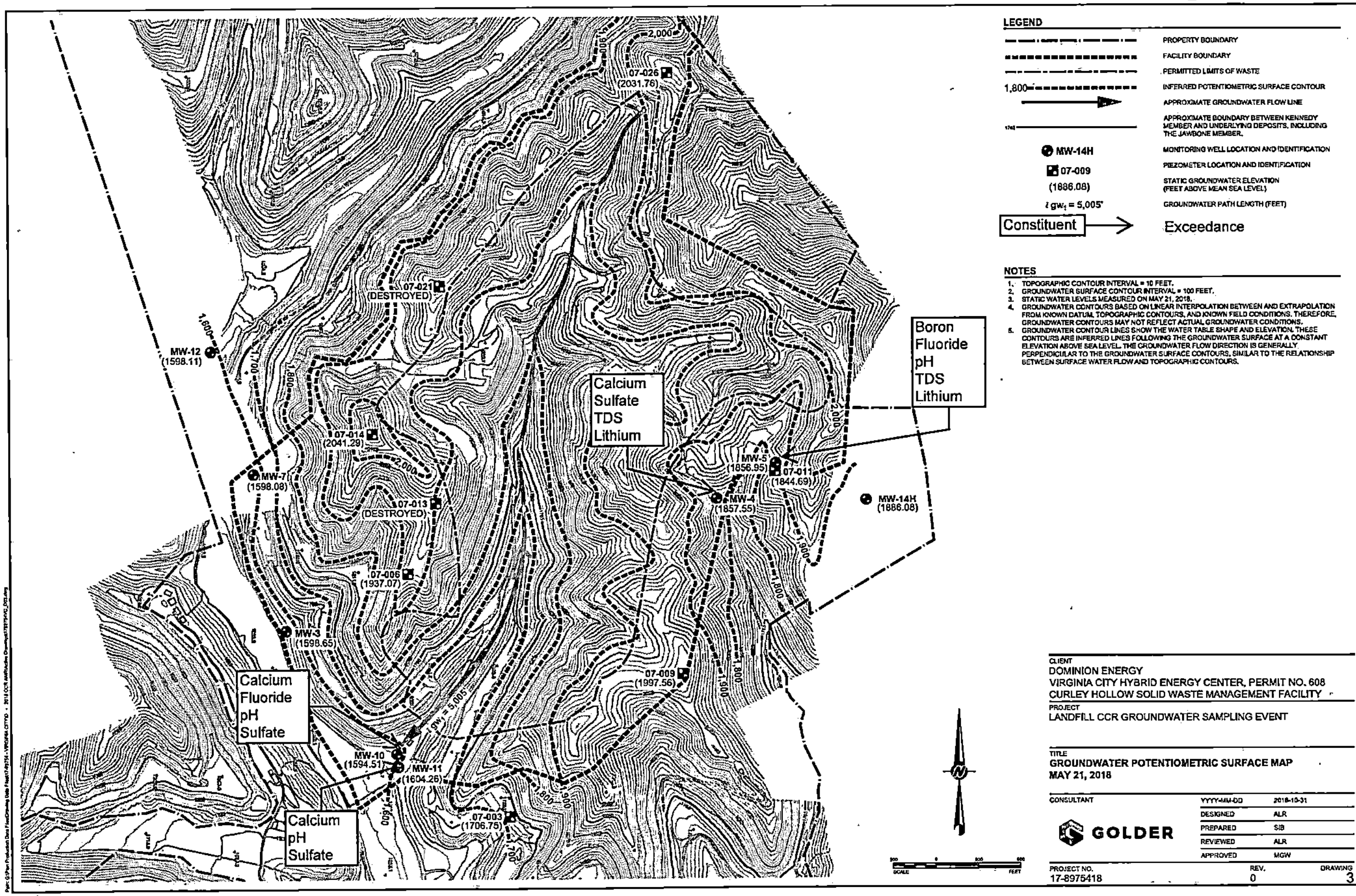
PROJECT
POSSUM POINT POWER STATION
ASH POND D CCR
GROUNDWATER SAMPLING EVENT

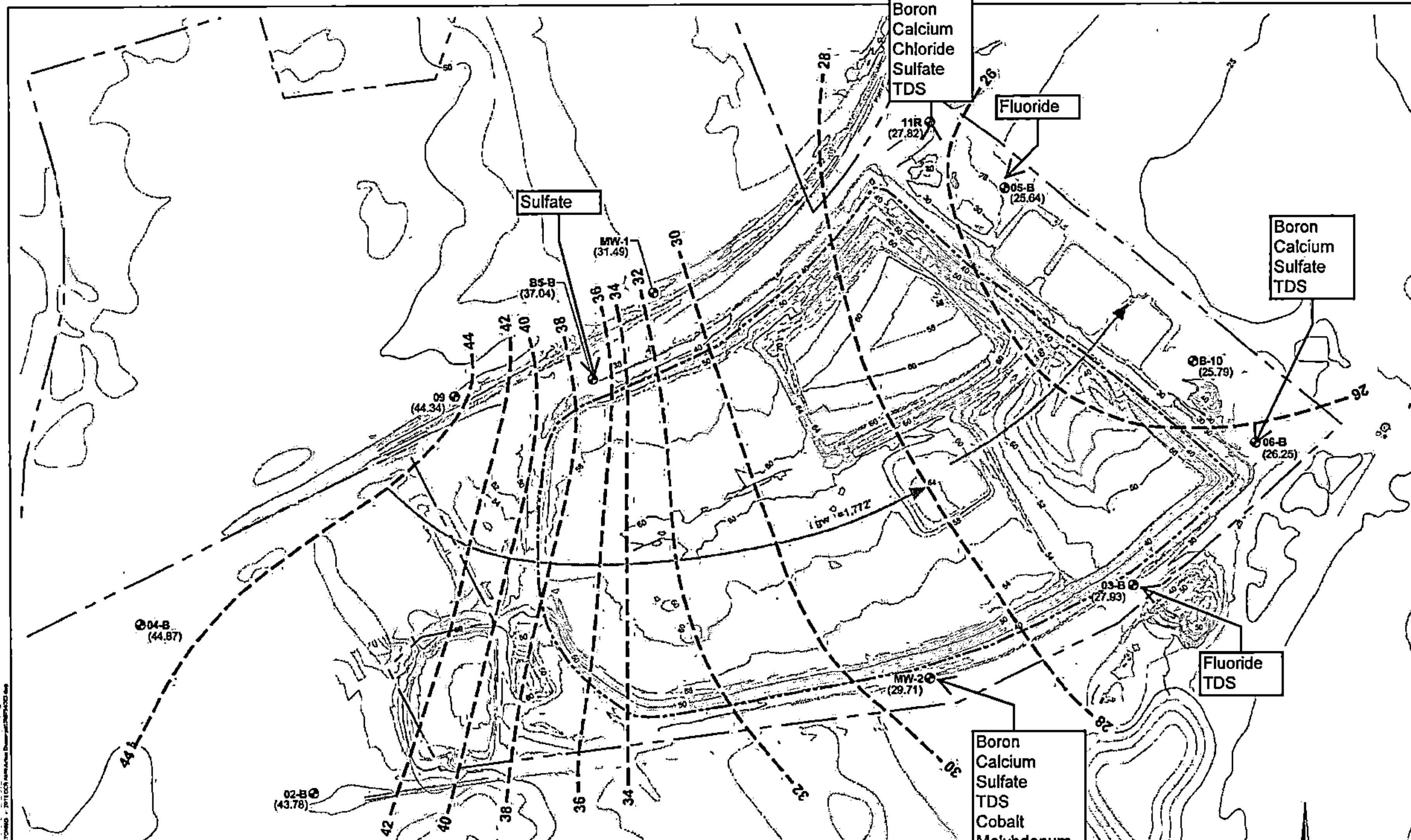
TITLE
GROUNDWATER SURFACE CONTOUR MAP
JUNE 18, 2018

PROJECT NO. 17-8975418

REV. 0

DRAWING 3


LEGEND
PROPERTY BOUNDARY
FACILITY BOUNDARY
PERMITTED LIMITS OF WASTE
1,800
INFERRED POTENTIOMETRIC SURFACE CONTOUR
APPROXIMATE GROUNDWATER FLOW LINE
APPROXIMATE BOUNDARY BETWEEN KENNEDY MEMBER AND UNDERLYING DEPOSITS, INCLUDING THE JAWBONE MEMBER.
MW-14H
MONITORING WELL LOCATION AND IDENTIFICATION
07-009
PIEZOMETER LOCATION AND IDENTIFICATION
(1886.08)
STATIC GROUNDWATER ELEVATION (FEET ABOVE MEAN SEA LEVEL)
ℓ gw₁ = 5,005'
GROUNDWATER PATH LENGTH (FEET)
Constituent
Exceedance
NOTES
1. TOPOGRAPHIC CONTOUR INTERVAL = 10 FEET.
2. GROUNDWATER SURFACE CONTOUR INTERVAL = 100 FEET.
3. STATIC WATER LEVELS MEASURED ON MAY 21, 2018.
4. GROUNDWATER CONTOURS BASED ON LINEAR INTERPOLATION BETWEEN AND EXTRAPOLATION FROM KNOWN DATUM, TOPOGRAPHIC CONTOURS, AND KNOWN FIELD CONDITIONS. THEREFORE, GROUNDWATER CONTOURS MAY NOT REFLECT ACTUAL GROUNDWATER CONDITIONS.
5. GROUNDWATER CONTOUR LINES SHOW THE WATER TABLE SHAPE AND ELEVATION. THESE CONTOURS ARE INFERRED LINES FOLLOWING THE GROUNDWATER SURFACE AT A CONSTANT ELEVATION ABOVE SEA LEVEL. THE GROUNDWATER FLOW DIRECTION IS GENERALLY PERPENDICULAR TO THE GROUNDWATER SURFACE CONTOURS, SIMILAR TO THE RELATIONSHIP BETWEEN SURFACE WATER FLOW AND TOPOGRAPHIC CONTOURS.
2,000
07-026 (2031.76)
07-021 (DESTROYED)
MW-12 (1598.11)
07-014 (2041.29)
MW-7 (1598.08)
07-013 (DESTROYED)
07-006 (1937.07)
MW-3 (1598.65)
Calcium Fluoride pH Sulfate
MW-10 (1594.51)
MW-11 (1604.26)
Calcium pH Sulfate
07-003 (1706.75)
07-009 (1997.56)
Calcium Sulfate TDS Lithium
MW-5 (1856.95)
07-011 (1844.69)
MW-4 (1857.55)
MW-14H (1886.08)
Boron Fluoride pH TDS Lithium
CLIENT
DOMINION ENERGY
VIRGINIA CITY HYBRID ENERGY CENTER, PERMIT NO. 608
CURLEY HOLLOW SOLID WASTE MANAGEMENT FACILITY
PROJECT
LANDFILL CCR GROUNDWATER SAMPLING EVENT
TITLE
GROUNDWATER POTENTIOMETRIC SURFACE MAP
MAY 21, 2018
CONSULTANT
GOLDER
YYYY-MM-DD 2018-10-31
DESIGNED ALR
PREPARED SIB
REVIEWED ALR
APPROVED MGW
PROJECT NO. 17-8975418
REV. 0
DRAWING 3



LEGEND

- APPROXIMATE PROPERTY BOUNDARY
- LIMITS OF CCR UNIT
- 50 EXISTING TOPOGRAPHIC CONTOURS (2' INTERVALS)
- 34 POTENTIOMETRIC SURFACE CONTOUR
- APPROXIMATE GROUNDWATER FLOW LINE
- l_{gw}=1,772' GROUNDWATER FLOW PATH LENGTH (FEET)
- 06-B MONITORING WELL LOCATION AND IDENTIFICATION
- (26.25) STATIC GROUNDWATER ELEVATION

Constituent → Exceedance

NOTES

1. TOPOGRAPHY INSIDE OF PROPERTY BOUNDARY PROVIDED BY D & M SURVEYORS, P.C. OF TAPPAHANNOCK, VIRGINIA. TOPOGRAPHY COMPILED FROM VARIOUS SURVEYS DONE IN 2013.
2. TOPOGRAPHY DATA OUTSIDE OF PROPERTY BOUNDARY DIGITIZED FROM USGS 7.5-MINUTE TOPOGRAPHIC QUADRANGLE NAMED POQUOSON WEST, VIRGINIA.
3. GROUNDWATER CONTOURS BASED ON LINEAR INTERPOLATION BETWEEN AND EXTRAPOLATION FROM KNOWN DATUM, TOPOGRAPHIC CONTOURS, AND KNOWN FIELD CONDITIONS. THEREFORE, GROUNDWATER CONTOURS MAY NOT REFLECT ACTUAL GROUNDWATER CONDITIONS.
4. GROUNDWATER CONTOUR LINES SHOW THE WATER TABLE SHAPE AND ELEVATION. THESE CONTOURS ARE INFERRED LINES FOLLOWING THE GROUNDWATER SURFACE AT A CONSTANT ELEVATION ABOVE SEA LEVEL. THE GROUNDWATER FLOW DIRECTION IS GENERALLY PERPENDICULAR TO THE GROUNDWATER SURFACE CONTOURS, SIMILAR TO THE RELATIONSHIP BETWEEN SURFACE WATER FLOW AND TOPOGRAPHIC CONTOURS.

CLIENT
DOMINION ENERGY

CONSULTANT
GOLDER

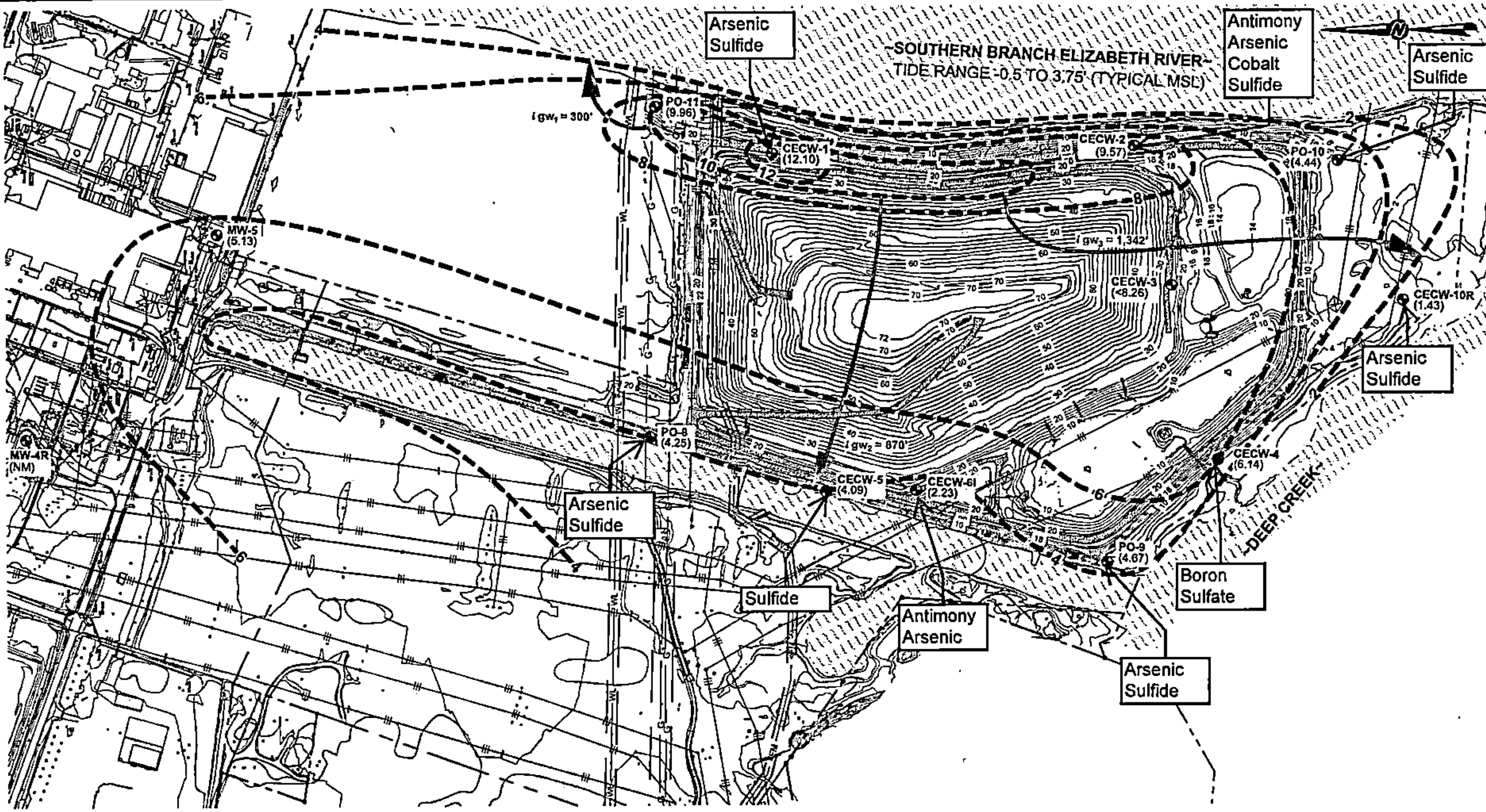
YYYY-MM-DD	2018-08-29
DESIGNED	RIP
PREPARED	SSF
REVIEWED	MGW
APPROVED	MGW

PROJECT
YORKTOWN LANDFILL
YORKTOWN, VIRGINIA

TITLE
GROUNDWATER POTENTIOMETRIC SURFACE MAP
UPPERMOST AQUIFER
MAY 7, 2018

PROJECT NO. 17-8975416 REV. 0 DRAWING 3

Public Staff [illegible]as
Exhibit 12



LEGEND

PROPERTY LINE

ADJACENT PARCEL PROPERTY LINE

50 MAJOR TOPOGRAPHIC CONTOUR

MINOR TOPOGRAPHIC CONTOUR

10 GROUNDWATER SURFACE CONTOUR (FEET ABOVE MEAN SEA LEVEL (AMSL))

APPROXIMATE GROUNDWATER FLOW LINE

ℓgw_1 = 300' GROUNDWATER FLOW PATH LENGTH (FEET)

PO-8 MONITORING WELL LOCATION AND IDENTIFICATION

(4.25) STATIC WATER LEVEL ELEVATION (FEET AMSL)

(NM) NOT MEASURED

Constituent → Exceedance

REFERENCE

1. EXISTING TOPOGRAPHY SHOWN IN THIS DRAWING SET IS PREPARED BY PHOTOGRAMMETRIC METHODS BASED ON AERIAL PHOTOGRAPHY PREPARED BY MCKENZIE & SNYDER INC., FOR H&B SURVEYING, DATED APRIL, 2016. BOTTOM ASH GRADES SHOWN ARE FROM FIELD SURVEY COMPLETED ON JANUARY 15, 2018 BY D & M SURVEYORS, P.C.
2. NORTH SHOWN IN REFERENCE TO VIRGINIA STATE PLANE, NAD27 DATUM, VIRGINIA SOUTH ZONE. VERTICAL DATUM IS NGVD 29.
3. GROUNDWATER CONTOURS BASED ON LINEAR INTERPOLATION BETWEEN AND EXTRAPOLATION FROM KNOWN DATUM, TOPOGRAPHIC CONTOURS, AND KNOWN FIELD CONDITIONS. THEREFORE, GROUNDWATER CONTOURS MAY NOT REFLECT ACTUAL GROUNDWATER CONDITIONS.
4. GROUNDWATER CONTOUR LINES SHOW THE WATER TABLE SHAPE AND ELEVATION. THESE CONTOURS ARE INFERRED LINES FOLLOWING THE GROUNDWATER SURFACE AT A CONSTANT ELEVATION ABOVE SEA LEVEL. THE GROUNDWATER FLOW DIRECTION IS GENERALLY PERPENDICULAR TO THE GROUNDWATER SURFACE CONTOURS, SIMILAR TO THE RELATIONSHIP BETWEEN SURFACE WATER FLOW AND TOPOGRAPHIC CONTOURS.

CLIENT
DOMINION ENERGY

CONSULTANT
GOLDER

YYYY-MM-DD	2018-11-28
DESIGNED	RP
PREPARED	SJB
REVIEWED	MGW
APPROVED	MGW

PROJECT
CHESAPEAKE ENERGY CENTER
CHESAPEAKE, VIRGINIA

TITLE
POTENTIOMETRIC SURFACE MAP
AUGUST 27, 2018

PROJECT NO. 17-8975418
REV. 0
FIGURE 2

Dominion Energy North Carolina
2019 NC Base Case – Docket No. E-22, Sub 562
Public Staff
Data Request No. 42

The following response to Question No. 6 of Public Staff Data Request No. 42, dated May 7, 2019 has been prepared under my supervision.

Jason E. Williams
Director, Environmental Services
Dominion Energy Services, Inc.

Question No. 6:

In response to PS DR-3, Question 15, DENC states that "VEPCO understands the term 'seep' to mean a channelized flow of water emanating from the berm of an impoundments that does or has the potential to reach surface waters." Please identify, by plant and basin location, which discharges are authorized in NPDES permits, and which are not. Please include all engineered and non-engineered discharges, including all locations in which a pollutant is conveyed, in any manner, from an impoundment to waters of the United States or a water of the State.

a. For the discharges not authorized by NPDES permits (including those for which permit applications are pending), please explain whether VEPCO contends they were or were not violations of NPDES permit requirements, or violations of Virginia's § 62.1-44.15 or West Virginia's § 22-11-6, and why.
b. Please include whether the discharge was engineered or not.
c. Please provide the date the discharge was first identified and, if applicable, the year the discharge was eliminated.

Response:

a. The Company is not aware of any unauthorized or unpermitted discharges from its basins. Permitted discharges are reflected in the NPDES permits that were provided in response to Request 3-16.

b. Not applicable.

c. Not applicable.

Dominion Energy Services, Inc.
5000 Dominion Boulevard, Glen Allen, VA 23060
DominionEnergy.com

Dominion Energy

VIA EMAIL

May 30, 2018

Mr. Jeremy Kazio
DEQ – Piedmont Regional Office
4949-A Cox Road
Glen Allen, Virginia 23060
Jeremy.Kazio@deq.virginia.gov

Re: **Chesterfield Power Station VPDES Permit No. VA0004146: Follow-up Notification Letter**

Dear Mr. Kazio:

On May 11, 2018, Dominion Energy personnel observed a small area of apparent groundwater seepage visible along the shoreline south of the Upper Ash Pond located at the Chesterfield Power Station. Dominion Energy made a verbal notification to DEQ that day, and committed to perform additional investigation into the nature, source and cause of the seep. Following additional investigation and sampling, Dominion Energy made a second verbal notification of the seep to the Department on May 29, 2018. This letter is being provided as a follow-up written report of Dominion Energy's investigation.

1. **Description of the nature and location of the observed seep:** Chesterfield Power Station (Station) is a coal fired power generating station located at 500 Coxendale Road, Chester, Virginia. On May 11, 2018, Dominion Energy personnel observed a small (two-foot square) area of apparent groundwater seepage south of the Upper Ash Pond at the shoreline of the James River. The attached map shows the general area of the seep.

   Following observation of the area, Dominion Energy collected a sample of the trickle flow from the seep. The sample was analyzed for total and dissolved coal combustion residuals (CCR) indicator parameters boron, chloride, fluoride, and sulfate. The results show concentrations above background levels, which appear to be consistent with previously observed groundwater conditions near the Upper Ash Pond in the vicinity of the seep. Dominion Energy did not observe any adverse environmental impacts in its investigation.

2. **Cause of the observed seep:** The exact cause of the seep remains under investigation.

3. **Date on which the seep occurred:** An area of apparent seepage was first observed and

reported by Dominion Energy personnel on May 11, 2018. Further investigation resulted in Dominion Energy providing a second verbal notification to DEQ on May 29, 2018 (a voice mail was left on May 25, 2018 after receipt of the validated laboratory results) that constituents present in the seep appear to be consistent with groundwater conditions near the Upper Ash Pond in the vicinity of the seep.

4. **Length of time that the seep continued:** The duration of the seep is unknown and is currently ongoing.

5. **Volume of the observed seep:** The exact volume of groundwater emerging through the seep, which presently appears as a trickle flow, is unknown at this time. Additional investigation will be conducted to determine the groundwater flow rate and volumes in this area.

6. **If the seep is continuing, how long is it expected to continue:** Further investigation is needed to determine the full nature and extent of the seep and options to address it.

7. **If the seep is continuing, what is the expected total volume of the discharge will be:** The total volume will be dependent on further characterization of the seep and the nature and timing of corrective action, but given the size of the observed trickle flow, it is not anticipated to be significant.

8. **Describe any steps planned or taken to reduce, eliminate and prevent a reoccurrence of the observed seep or any future seeps:**

   In connection with pending DEQ Consent Order #7, Dominion Energy expects to prepare and implement plans to identify, characterize, and mitigate any observed groundwater seeps appearing along the James River shoreline at the Chesterfield Power Station. Additional characterization and potential corrective action of the subject seep could be incorporated in those plans or will otherwise be provided to DEQ as requested after follow-up discussions.

If you have any questions regarding this information, please contact Kelly Hicks, of Dominion Energy Environmental Services, at (804) 273-4903.

I certify under penalty of law that this document and all attachments were prepared under my direction or supervision in accordance with a system designed to assure that qualified personnel properly gather and evaluate the information submitted. Based on my inquiry of the person or persons who manage the system, or those persons directly responsible for gathering the information, the information submitted is, to the best of my knowledge and belief, true, accurate, and complete. I am aware that there are significant penalties for submitting false information, including the possibility of fine and imprisonment for knowing violations.

Sincerely,

Jason E. Williams
Director, Environmental

ec: Emilee Adamson (DEQ) Emilee.Adamson@deq.virginia.gov
Joseph Bryan (DEQ) Joseph.Bryan@deq.virginia.gov
Heather Deihls (DEQ) Heather.Deihls@deq.virginia.gov


Community
Approximate Seep Location

Dominion Energy Services, Inc.
5000 Dominion Boulevard, Glen Allen, VA 23060
DominionEnergy.com

Dominion Energy

BY EMAIL

August 28, 2018

Mr. Frank Lupini
Virginia Department of Environmental Quality
1111 East Main Street, Suite 1400
Richmond, Virginia 23219
Frank.Lupini@deq.virginia.gov

RE: Dominion Energy Chesterfield Power Station VPDES Permit No. VA0004146: Seep Mitigation Plan and Surface Water Monitoring Plan (Revision 2)

Dear Mr. Lupini:

Comments from the Virginia Department of Environmental Quality (DEQ) on the Revised Seep Mitigation Plan (SMP) were received on August 23, 2018. In response to the two comments provided, the SMP has been revised as requested and is included as an attachment to this letter. A summary of DEQ comments are listed below followed by our responses in *italics font*.

1. Revise Section 3.2 (pg. 11) to indicate that submissions will be done electronically and provide a set schedule for these submissions (i.e. 10th of the month).

   Section 3.2 has been revised as recommended.

2. Section 4.3.2 (pg. 13) states that "the annual review will quantify the success of the chosen mitigation method". The annual reviews should only contain what took place during each monitoring year and should not include any inferences about the success of the remedy. Please clarify that the success of the chosen mitigation method will be determined by the Remedy Effectiveness Evaluation notes in Section 4.3.3.

   Section 4.3.2 has been revised as recommended.

There were no comments on the Surface Water Monitoring Plan; as such, that plan remains unchanged. If you have any questions, please contact me at (804) 273-2646.

Sincerely,

Jason Williams

Jason E. Williams
Director, Environmental

Enclosure

ecc: Kyle Winter (DEQ) – kyle.winter@deq.virginia.gov
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Certification

I certify under penalty of law that this document and all attachments were prepared under my direction or supervision in accordance with a system designed to assure that qualified personnel properly gather and evaluate the information submitted. Based on my inquiry of the person or persons who manage the system, or those persons directly responsible for gathering the information, the information submitted is, to the best of my knowledge and belief, true, accurate, and complete. I am aware that there are significant penalties for submitting false information, including the possibility of fine and imprisonment for knowing violations.

Jason E. Williams	Director, Environmental
Name of Authorized Agent	Title
Jason Williams	August 28, 2018
Signature of Authorized Agent	Date

www.haleyaldrich.com

SEEP MITIGATION PLAN
CHESTERFIELD POWER STATION
CHESTER, VIRGINIA
VPDES PERMIT NO. VA0004146

by Haley & Aldrich, Inc.
Richmond, Virginia

for Virginia Electric and Power Company
Glen Allen, Virginia

File No. 130669
August 2018

Executive Summary

Haley & Aldrich, Inc. (Haley & Aldrich) has been contracted by Virginia Electric and Power Company (Dominion Energy) to prepare a Seep Mitigation Plan (SMP) that presents a summary of the proposed remedial approach to mitigate certain observed groundwater seepage points along the James River adjacent to the Chesterfield Power Station (CPS) located in Chester, Virginia.

Findings from previous environmental investigations completed in Fall 2017 were summarized in a Site Characterization Report (SCR) submitted to the Virginia Department of Environmental Quality (VDEQ) in February 2018. The primary goals of the Site characterization program were to evaluate groundwater and surface water quality within the area of interest, assess groundwater contribution to the seepage, and evaluate applicable remedial alternatives if groundwater concentrations were observed to be greater than the calculated Site-specific background.

Based on the exceedance of Site-specific Preliminary Background Concentrations in seep samples and the groundwater upgradient of the seeps, a remedial alternatives evaluation was conducted. This SMP describes the evaluation of the following remedial alternatives:

Remedial Alternatives	
Alternative 1	Shallow and Deep Hydraulic Control with Low Permeability Barrier Near River
Alternative 1a	Shallow and Deep Hydraulic Control with Low Permeability Barrier Near River and Eastern Collection Trench
Alternative 2	Shallow and Deep Hydraulic Control Near River
Alternative 2a	Shallow and Deep Hydraulic Control Near River and Eastern Collection Trench
Alternative 3	Shallow and Deep Hydraulic Control with Low Permeability Barrier at Source and In-Situ Treatment Downgradient
Alternative 4	Shallow and Deep Hydraulic Control at Source and In-Situ Treatment Downgradient
Alternative 5	In-Situ Treatment Downgradient

Based on the evaluation of the technical advantages and disadvantages of the various alternatives, Alternative 2a: Shallow and Deep Hydraulic Control Near River and Eastern Collection Trench is considered to be the most applicable approach for this Site. This selected remedy will include a form of hydraulic control designed to capture impacted groundwater from both the shallow and deeper aquifers within the area of interest and eliminate constituents of concern (COC) from daylighting along the river bank. The final selection and design of the hydraulic control will depend upon constructability within an area of high utility concentration. As the plume is cut-off from entering the local groundwater flow system, the COCs will no longer be discharged via natural seepage points along the river. This method uses proven technology and is capable of preventing contaminant migration to the river.

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List of Acronyms/Abbreviations

bgs	below ground surface
cm/sec	centimeters per second
COC	constituents of concern
CPS	Chesterfield Power Station
DO	dissolved oxygen
Dominion Energy	Virginia Electric and Power Company
ft/yr	feet per year
gpm	gallons per minute
Haley & Aldrich	Haley & Aldrich, Inc.
K	Hydraulic conductivity
LPB	Low permeability barrier
MCL	maximum contaminant level
MDL	Method detection limit
mg/L	milligrams per liter
MS	matrix spike
MSD	matrix spike duplicate
msl	mean sea level
ND	non-detect
O&M	Operations and Maintenance
ORP	oxidation-reduction potential
PRB	passive reactive barrier
SCR	Site Characterization Report
SMP	Seep Mitigation Plan
TPH-DRO	total petroleum hydrocarbons – diesel range organics
TPH-GRO	total petroleum hydrocarbons – gasoline range organics
VDEQ	Virginia Department of Environmental Quality
VELAP	Virginia Environmental Laboratory Accreditation Program
VPDES	Virginia Pollutant Discharge Elimination System

1. Introduction

Haley & Aldrich, Inc. (Haley & Aldrich) has been contracted by Virginia Electric and Power Company (Dominion Energy) to prepare a Seep Mitigation Plan (SMP) that presents a summary of the proposed remedial approach to mitigate the contaminant migration to the observed natural groundwater seepage points along the James River adjacent to the Chesterfield Power Station (CPS) located in Chester, Virginia.

The objectives of this SMP include:

- Identify remedial alternatives to mitigate the migration of Site-related constituents to the James River;
- Select a preferred remedial action and provide supporting rationale;
- Provide schedule for implementation of the preferred remedial action;
- Identify methods to monitor and quantify the success of the preferred remedial action implementation;
- Identify additional remedial actions if the preferred remedial action is ineffective; and
- Establish a reporting schedule to document the construction of the preferred remedial action, and to document the results of the proposed monitoring program to quantify the effectiveness of the remedial action after construction is complete.

1.1 SITE LOCATION

The Chesterfield Power Station is located at 500 Coxendale Road in Chester, Virginia along the James River (See Figure 1). Industrial and commercial properties are located to the west and southwest of the Site. The Site is bordered to the east by Henricus Historical Park and to the north by the James River. Surrounding lands to the east and north of the Station are currently wooded, undeveloped, and are owned by Dominion Energy. The Station consists of four coal-fired units and two combined-cycle natural gas units with a combined capacity of approximately 1,700 megawatts. This report focuses on the northeastern corner of the Site (See Figure 2).

1.2 SEEP DESCRIPTION

In September 2017, the Virginia Department of Environmental Quality (VDEQ) contacted Dominion Energy to report reddish-orange seepage observed daylighting along the riprap located on the banks of the James River along the northeast corner of the Station. The reddish-orange discoloration was observed to occur as a solid, scale-like deposit on rip-rap and substrate presumably caused by the oxidation of dissolved iron in the seepage water. Dominion Energy immediately surveyed the banks and initiated an investigation. The area of iron staining ranged from just east of the discharge tunnel eastward to the corner of the property just west of the Dutch Gap public boat ramp (See Figure 2).

1.3 SUMMARY OF FIELD ACTIVITIES

Site characterization activities were conducted in phases to identify potential contaminants associated with the seeps as described in the Site Characterization Report (SCR) submitted to the VDEQ in February

2018. Additional investigations were conducted subsequent to the submittal of the SCR to support the remedial design. A summary of Site characterization activities is as follows:

1.3.1 April 2018

Piezometer and Well Installation

Piezometers and wells were installed to collect the necessary data to better understand the hydrogeological regime, to delineate the source of contamination, and to evaluate remedial options. Four piezometers (designated PZ-1 through PZ-4) were installed along the banks of the James River. One well couplet (CP-MW-8 series) was installed at the southeast corner of Coxendale Road and the facility entrance road and one well couplet (CP-MW-9 series) was installed inside the facility at the southwest corner of the coal pile. The shallow wells are designated with an "S"'; the deeper wells are designated with a "D".

The locations of these explorations are shown on Figure 2. Well construction details for all wells installed to date are provided in Table 1. Well installation reports are provided in Appendix A.

Groundwater Sampling

Groundwater samples were collected from the four newly-installed wells (CP-MW-8 series and CP-MW-9 series) and PZ-2. Stabilization parameters (temperature, pH, conductivity, oxidation reduction potential [ORP], dissolved oxygen [DO], and turbidity) were measured with a multi-parameter water quality meter at regular volume intervals every three to five minutes and recorded on individual groundwater sample collection records (Appendix B) and summarized in Table 2. Samples were submitted to REI Consultants, Inc. (a division of Pace Analytical) of Beaver, West Virginia (VELAP No. 460148) for the chemical analysis. The results of the groundwater samples collected to date were validated and are provided in Table 3 (shallow) and Table 4 (deep).

The groundwater sample laboratory data reports and data validation reports for the April 2018 Site characterization program are provided in Appendix C.

In addition to groundwater sampling, a complete set of depth to water measurements were collected from the new wells and from several existing wells located upgradient and in the area of interest. Groundwater elevation measurements and associated survey information collected to date are provided in Table 5.

Pumping Tests

Two short-duration pumping tests (less than 8 hours) were conducted on CP-MW-2S and PZ-2. The pumping tests were conducted to further define the hydrogeologic properties of the shallow aquifer to define the capture zone of the proposed remedial alternatives, and to better understand anticipated flow rates to provide adequate groundwater capture. Water quality samples were collected at approximately three to four hours into the pumping test, and near the completion of the pumping test to evaluate changes in groundwater chemistry due to the pumping stresses. The results are presented in Table 6.

Geotechnical Testing

Geotechnical sampling was conducted at four of the well/piezometer locations (PZ-1 through PZ-4) and at one additional boring location (GT-1). The locations of these explorations are shown on Figure 2. Geotechnical samples were collected to further support soil classification and to provide data to evaluate future remedial options.

Soil samples were submitted for one or more of the following tests: particle size analysis (ASTM D422), particle size using sieve and hydrometer testing (ASTM D422), and Atterberg limits (ASTM D4318). The results of these geotechnical analyses are provided in Appendix D.

1.4 SUMMARY OF FINDINGS

1.4.1 Geology/Hydrogeology

Subsurface conditions observed in test borings indicate the presence of four major stratigraphic units in the study area.

- A fine-grained fill material of with thicknesses varying between approximately 10 to 28 ft across the Site.
- Gravelly sand deposit was encountered in all borings and also varies in thickness. This unit has been designated as the shallow aquifer, and monitoring wells have been screened within this unit for monitoring groundwater chemistry and piezometric elevations. The gravelly sand deposit thickness varies between 1.5 to 20.5 ft across the Site.
- Underlying the gravel/sand unit is a silt/clay aquitard of varying thickness that was observed across a majority of the study area. This aquitard thins and pinches out to the northwest portion of the study area. Within the study area, the primary groundwater flow path is believed to be within the shallow aquifer above the aquitard, but groundwater chemistry indicates that there is some flow from the shallow to deep aquifer. The silt/clay deposit thickness varies between 2 to 15.5 ft across the Site.
- A silty/clayey sand was observed below the aquitard/shallow aquifer within the study area. This deeper silty/clayey sand has been designated as the deeper aquifer in the study area. The bottom of the silty/clayey sand was not encountered during the Site subsurface investigations.

The lithology, supported by the geotechnical testing results, is also described on the soil boring logs (Appendix A).

The depth-to-water measurements are presented in Table 5. Groundwater contours observed during the April 2018 field investigation are included in Figures 3 and 4. The groundwater contours in both the shallow and deeper portion of the aquifer suggest that there is a shallow 'trough" that extends between well couplets CP-MW-2 and CP-MW-5. Observed groundwater elevations, coupled with preliminary water chemistry data, indicates that the primary flow pathway for groundwater appears to be through the center and northeastern portion of the current study area. This is also corroborated by the seep data collected earlier in the investigation and reported previously in the SCR.

1.4.1.1 *In-Situ Hydraulic Conductivity Testing*

The resulting hydraulic conductivity of the shallow aquifer was estimated between 1×10^{-5} to greater than 1×10^{-2} centimeters per second (cm/sec), with a majority of the aquifer estimated to range between 1×10^{-4} to 1×10^{-3} cm/sec. Results observed in CP-MW-4S were observed to be greater than 1×10^{-2} cm/sec indicating the presence of more granular deposits at this location (see Appendix A), which is consistent with the classification of the subsurface sediments at this boring location. Conversely, the observed results at CP-MW-7S (approx. 1×10^{-5} cm/sec) indicate the presence of finer grained material. The estimated hydraulic conductivity of the deeper aquifer ranged from 1×10^{-4} to 1×10^{-3} cm/sec with no observed outliers, indicating more consistent subsurface conditions. The following table provides a summary of the hydraulic conductivity test results.

Location ID	Elevation of Well Screen (feet msl)		Hydraulic Conductivity (K) (cm/sec)
	Top	Bottom	
CP-MW-1S	7.47	2.47	Not Measured
CP-MW-1D	-20.79	-25.79	6.0×10^{-4}
CP-MW-2S	3.39	-1.61	4.0×10^{-3}
CP-MW-2D	-16.47	-21.47	4.0×10^{-4}
CP-MW-3S	2.69	-2.31	2.0×10^{-4}
CP-MW-3D	-13.95	-18.95	2.0×10^{-3}
CP-MW-4S	0.70	-4.30	6.0×10^{-2}
CP-MW-4D	-22.29	-27.29	8.0×10^{-4}
CP-MW-5S	6.96	-3.04	6.0×10^{-4}
CP-MW-5D	-24.86	-29.86	1.0×10^{-3}
CP-MW-6S	6.76	1.76	Not Measured
CP-MW-6D	-23.45	-28.45	3.0×10^{-4}
CP-MW-7S	0.26	-4.74	2.0×10^{-5}
CP-MW-7D	-19.58	-24.58	2.0×10^{-4}
CP-MW-8S	7.3	-2.7	1.0×10^{-2}
CP-MW-8D	-18.7	-28.7	1.0×10^{-4}
CP-MW-9S	7.8	-2.2	5.0×10^{-3}
CP-MW-9D	-13.6	-23.6	1.0×10^{-3}
PZ-1	3.5	-1.5	Not Measured
PZ-2	2.2	-2.8	Not Measured
PZ-3	1.6	-3.4	Not Measured
PZ-4	1.6	-3.4	5.0×10^{-3}

1.4.1.2 *Estimated Groundwater Flow Velocity*

Groundwater in the study area is generally flowing from the southwest to the northeast (James River). The groundwater flow direction and horizontal gradient are consistent in both the shallow and deep aquifers.

Location-specific hydraulic conductivities, observed groundwater gradients, and an assumed effective porosity of 0.2 were calculated for each location. The geometric mean of these results was then calculated for the shallow and deep aquifer separately. The resulting groundwater flow velocity of the shallow and deep aquifers is estimated at 30 feet per year (ft/yr) and 14 ft/yr, respectively. These results will be compared to the groundwater modeling as part of the pre-design activities.

1.4.1.3 Vertical Head Potentials

Based on piezometric head observations from the recently installed well couplets, the vertical groundwater head potential is downward from the shallow aquifer to the deeper aquifer at all observed locations. The higher piezometric heads observed within the shallow aquifer and the difference in general water chemistry (i.e., pH and conductivity) and specific chemical concentrations indicate that the shallow aquitard in the study area has retarded the vertical migration of Site-related impacts. Evidence of Site-related impacts are observed in the deeper aquifer at lower concentrations than the shallow aquifer, indicating that there are likely discrete areas where the aquitard is either thin or incomplete, in the study area. The areas where the aquitard is incomplete allow Site-related constituents to migrate to the deeper aquifer but based on concentrations observed it is not the primary pathway for fate and transport of the constituents.

1.4.2 Analytical Results and Groundwater Quality

The groundwater data collected in April 2018 were compared to Site background data. The background values are split into two aquifers, Columbia and Potomac Aquifers, representing the shallower and deeper aquifers, respectively.

1.4.2.1 Monitoring Well Analytical Results

In April 2018, groundwater samples were collected from monitoring well couplets designated CP-MW-8 and CP-MW-9, and PZ-2 shown on Figure 2. These data, along with data collected during previous Site investigations, were compared to the Site-established preliminary background values.

Generally, the lowest observed values of pH and highest observed values of conductivity and sulfate concentrations are observed in the shallow aquifer, within the central and northeastern portion of the study area. Observed values of pH and conductivity in the deeper aquifer suggest that the shallow silty/clay layer has reduced the vertical migration of Site-related constituents, as compared to the shallow aquifer.

The data also exhibited dissolved metal groundwater concentrations in the shallower aquifer of boron, cadmium, chromium, cobalt, nickel, selenium, vanadium and zinc that were above background values by more than one order of magnitude. The deeper aquifer exhibited dissolved metal groundwater concentrations moderately above background of cadmium, cobalt, and nickel at all the locations. Detections in deeper well CP-MW-2D were above background for antimony, selenium, and thallium by more than one order of magnitude. This indicates that there is some groundwater interaction from the shallow to the deep aquifer, but it is not the primary flow mechanism for fate and transport of Site-related constituents. The shallow and deep groundwater analytical results are provided in Tables 3 and 4, respectively.

It should be noted that several April 2018 groundwater constituents (including antimony, lead, selenium and thallium) reported non-detect (ND) results with the method detection limits (MDLs) above the applicable background standards. The MDLs reflect the lowest detection limits achieved using analytical method 200.7. Post-construction samples will be analyzed using a combination of analytical methods which will ensure that the detection limits for each constituent are below applicable background standards, barring any required dilutions which may increase these limits.

2. Remedial Alternative Evaluation

The seeps observed along the James River are a result of groundwater daylighting at the river bank. The groundwater daylighting in the seeps contain levels of constituents above Site-specific background levels. As a result, applicable remedial alternatives were evaluated with a goal of minimizing the movement of anthropogenic groundwater constituents toward the James River. The objectives of this remedial alternative evaluation are as follows:

- Identify and evaluate potential remedial technologies that have been demonstrated to be effective with mitigating contaminated groundwater migration, specifically hydraulic control methods;
- Estimate areas and volumes of impacted areas to be remediated; and
- Indicate the relative certainty for obtaining remedial objectives.

2.1 ALTERNATIVES SCREENING

An alternative screening process was completed to screen appropriate remedial options and to recommend the most applicable option based on Site-specific conditions. Remedial technologies were evaluated for their applicability to mitigate contaminants being transported by groundwater to the river bank and to meet Dominion Energy's aggressive schedule. The alternative screening process was conducted based on discussions with remedial technology vendors, knowledge of Site conditions, and engineering judgment.

2.2 DESCRIPTION OF REMEDIATION ALTERNATIVES

A general description of each of the alternative considered as part of this remediation assessment is provided below.

2.2.1 Alternative 1. Shallow and Deep Hydraulic Control with Low Permeability Barrier Near River

Alternative 1 is shallow and deep hydraulic control system with a low permeability barrier extending through the deep aquifer to minimize the hydraulic influence from the river. The shallow groundwater would be collected via a collection trench and the deep water via recovery wells. The recovered groundwater will be managed using an existing on-site water treatment system or via a separate system designed to treat the constituents of concern.

2.2.2 Alternative 1a. Shallow and Deep Hydraulic Control with Low Permeability Barrier Near River and Eastern Collection Trench

Alternative 1a is the same as alternative 1, but also includes a shallow recovery trench perpendicular to the river on the eastern edge of the area. The added shallow trench is designed to capture any impacts that may be migrating to the northeast. The shallow groundwater would be collected via a collection trench and the deep water via recovery wells and managed using an existing on-site water treatment system or via a separate system designed to treat the constituents of concern.

2.2.3 Alternative 2. Shallow and Deep Hydraulic Control Near River

Alternative 2 is the same shallow and deep hydraulic control system described in Alternative 1, but without the downgradient low permeability barrier. The shallow groundwater would be collected via a collection trench and the deep water via recovery wells and managed using an existing on-site water treatment system or via a separate system designed to treat the constituents of concern.

2.2.4 Alternative 2a. Shallow and Deep Hydraulic Control Near River and Eastern Collection Trench

Alternative 2a is the same as Alternative 2, but also includes a shallow recovery trench perpendicular to the river on the eastern edge of the area. The added shallow trench is designed to capture any impacts that may be migrating to the northeast. The shallow groundwater would be collected via a collection trench and the deep water via recover wells and managed using an existing on-site water treatment system or via a separate system designed to treat the constituents of concern.

2.2.5 Alternative 3. Shallow and Deep Hydraulic Control with Low Permeability Barrier at Source and In-Situ Treatment Downgradient

Alternative 3 is a "funnel and gate" approach adjacent to the coal pile to hydraulically control shallow and deep groundwater. A low permeability barrier extending through the deep aquifer would be installed around the downgradient perimeter of the coal pile. The shallow and deep groundwater would then be collected via recovery wells situated in a "gate" in the barrier on the downgradient side of the coal pile. The extracted groundwater would be managed using an existing on-site water treatment system or via a separate system designed to treat the constituents of concern.

Additionally, near the river, a permeable reactive barrier made of reactive media emplaced with a series of closely-spaced injection wells would be installed to treat shallow and deep groundwater between the source and the river.

2.2.6 Alternative 4. Shallow and Deep Hydraulic Control at Source and In-Situ Treatment Downgradient

Alternative 4 is a shallow and deep hydraulic control system without the low permeability barrier. The shallow groundwater would be recovered close to the source using a shallow recovery trench and the deep groundwater would be recovered via recovery wells. The extracted groundwater would be managed using an existing on-site water treatment system or via a separate system designed to treat the constituents of concern.

Additionally, near the river, a permeable reactive barrier made of reactive media emplaced with a series of closely-spaced injection wells would be installed to treat shallow and deep groundwater between the source and the river.

2.2.7 Alternative 5. In-Situ Treatment Downgradient

Alternative 5 includes two permeable reactive barriers (injection barriers) with permanent injection wells. The first barrier would be installed at the source zone and the second near the river. Both barriers would be installed to treat shallow and deep groundwater. In addition to the reactive barriers close to the source and along the river, a series of injections wells in accessible areas within the body of the plume would be installed to address the impacts between the two reactive barriers.

2.3 REMEDIAL ALTERNATIVE EVALUATION

The remedial alternatives described above were evaluated based on their advantages and disadvantages described below:

Remedial Alternative	Advantages	Disadvantages
Alt. 1: Shallow and Deep Hydraulic Control with Low Permeability Barrier (LPB) Near River	• Intercepts groundwater before reaching riverbank • Permanent barrier requires minimal operation and maintenance (O&M) • Minimal data gaps needed to support design	• Does not mitigate source • May not capture all constituents migrating east-southeast • Requires long term O&M of pump and treat system • Utility relocation required
Alt. 1A: Shallow and Deep Hydraulic Control with LPB Near River and Eastern Collection Trench	• Intercepts groundwater before reaching riverbank • Permanent barrier requires minimal O&M • Minimal data gaps needed to support design • Additional groundwater capture on eastern edge of Site	• Does not mitigate source • Requires long term O&M of pump and treat system • Utility relocation required • Requires disruption of railroad spur
Alt. 2: Shallow and Deep Hydraulic Control Near River	• Intercepts groundwater before reaching riverbank • Minimal data gaps needed to support design	• Does not mitigate source • May not capture all constituents migrating east-southeast • Requires long term O&M of pump and treat system • Utility relocation required
Alt. 2A: Shallow and Deep Hydraulic Control Near River and Eastern Collection Trench	• Intercepts groundwater before reaching riverbank • Minimal data gaps needed to support design • Additional groundwater capture on eastern edge of Site	• Does not mitigate source • Requires long term O&M of pump and treat system • Utility relocation required • Requires disruption of railroad spur
Alt. 3: Shallow and Deep Hydraulic Control with LPB at Source and In-Situ Treatment Downgradient	• Collects and treats water at the source, minimizing downgradient impacts • Impacted groundwater is treated prior to seepage along the riverbank • Downgradient LPB customized to raise pH, and treat groundwater by immobilizing or precipitating out metals.	• Does not immediately address the seep, over time in-situ treatment will address impacted groundwater prior to seepage along the riverbank. • Requires long term O&M of pump and treat system
Alt. 4: Shallow and Deep Hydraulic Control at Source and In-Situ Treatment Downgradient	• Intercepts groundwater before reaching riverbank • Minimal data gaps needed to support design • Impacted groundwater is treated prior to seepage along the riverbank	• Does not immediately address the seep, over time in-situ treatment will address impacted groundwater prior to seepage along the riverbank. • Requires long term O&M of pump and treat system

	• Downgradient passive reactive barrier (PRB) customized to raise pH, and treat groundwater by immobilizing or precipitating out metals.	• Will require multiple injection rounds at the PRB
Alt. 5: In-Situ Treatment Downgradient	• Impacted groundwater is treated prior to seepage along the riverbank • Downgradient PRB customized to raise pH, and treat groundwater by immobilizing or precipitating out metals.	• Does not immediately address the seep, over time in-situ treatment will address impacted groundwater prior to seepage along the riverbank. • Will require multiple injection rounds at each of the PRBs

2.4 REMEDIAL TECHNOLOGY RECOMMENDATION

Based on our assessment of the technical advantages and disadvantages of the various alternatives, summarized above, Alternative 2a: Shallow and Deep Hydraulic Control Near River and Eastern Collection Trench is considered to be the most applicable alternative for this Site. This remedial alternative captures impacted groundwater to prevent migration to the shore line, and allows for flexibility regarding the pumping rates and hydraulic controls, should additional capture be required. This remedial technology consists of a shallow and deep hydraulic control system which includes three deep extraction wells installed to approximately 50 ft below ground surface (bgs) and a shallow recovery (groundwater interceptor) trench installed to a depth of approximately 30 ft bgs. Based on data gathered during pumping tests, it is assumed that combined groundwater extraction will occur at a rate of approximately 33 gallons per minute (gpm). Groundwater would then be treated on-site before being discharged to surface water via a Virginia Pollutant Discharge Elimination System (VPDES) permitted outfall. This alternative would minimize impacted groundwater movement and control potential off-site migration of impacted groundwater to the northeast. A conceptualized layout of this alternative is shown on Figure 5 and Figure 6.

The final selection and design of the hydraulic control described above will depend upon constructability within an area of high utility concentration. It is important to note that seeps are naturally occurring phenomena that may continue to exist after the remedial technology is installed; however, this method will mitigate the movement of pollutants detected at the observed groundwater seepage points. As the plume is cut-off from entering the local groundwater flow system, the constituents of concern will be diminished and ultimately no longer discharged via natural seepage points along the river. This method uses proven technology and is capable of preventing contaminant migration to the river.

3. Preliminary Implementation Schedule

3.1 PLANNING AND DESIGN

It is anticipated that the proposed remedy can be installed within four to six months. The following schedule is proposed[1]:

May 2018	Evaluate the need for and prepare the necessary permit applications to implement the proposed remedy. Permits/plans to include: • Stormwater Pollution Prevention Plan • VPDES Permit Modification • RPA Buffer Modification Request and Form C • Minor Site Plan Application
June 2018	Prepare and submit invitation to bid to Contractors
August 2018	Select Contractor and mobilize for construction
Fall 2018	Complete construction of remedial approach, and install post-construction monitoring wells

Notes
1. The proposed schedule is dependent on permitting and Contractor availability.

3.2 CONSTRUCTION STATUS REPORTS

During the Site preparation activities and construction phase of the remedial alternative, monthly status reports will be submitted electronically to the VDEQ to provide progress updates. Reports will be submitted by the 10th of each month.

Monthly status reports will generally include the following:

- Site preparation activities including utility relocation and required permitting;
- Trench excavation;
- Off-site soil disposal documentation (if applicable);
- Dewatering activities (if applicable);
- Deep well installation;
- Additional Site characterization activities (if applicable); and
- Updates on construction schedule.

As-built drawings will be provided to VDEQ within three months following the completion of the remedial alternative construction. This submission will include notification of any deviations, alterations or other changes that may occur during construction.

4. Post-Construction Monitoring Program

The proposed monitoring system will consist of the measurement of the changes in groundwater elevations in and around the trench and existing and new deep wells. The changes in water elevations over time as a result of the operation of the trench and deep recovery wells will be used to document the change in groundwater flow direction and propagation of the capture zone in the project area. The following sections describe the proposed monitoring program to be implemented after the installation of the shallow and deep hydraulic control system described in Section 2.3, above.

4.1 MONITORING WELL AND PIEZOMETER INSTALLATION

Four paired wells (8 total) will be installed downgradient of the shallow and deep groundwater control system to evaluate the effectiveness of the remedial control. Up to three (3) piezometers will also be installed inside the trench to monitor water levels during operation. Proposed locations of the monitoring wells and piezometers are shown on Figure 7.

Each shallow well will be installed to a depth of approximately 20 ft (El. -6). A screen will be installed between 9 and 19 ft (El. 5 to El. -5). Each deep well will be installed to a depth of 45 ft (El. -31). A screen will be installed between 34 and 44 ft. (El. -20 to -30). The piezometers will be distributed across the length of the trench at a depth of approximately 35 to 40 feet below grade.

For the first year of operation, water levels from each of the paired wells and piezometers will be collected continuously using Level loggers. These data will be used to track the propagation of the cone of influence around the linear trench and vertical wells.

4.2 MONITORING WELL SAMPLING PROGRAM

After the construction of the trench and deep recovery wells associated with the remedial alternative, the four paired wells described above will be sampled on a quarterly basis for the first year to evaluate the effectiveness of the remedial approach. The first quarterly sample is expected to be collected approximately three months after the installation of the remedial approach to allow for an adequate start-up period. Each quarterly sample will be collected using low-flow methods. The groundwater water will be directed through a flow cell and analyzed in the field for general water quality parameters including hardness, pH, conductivity, dissolved oxygen, oxidation-reduction potential and temperature.

The monitoring well samples will be submitted to a Virginia Environmental Laboratory Accreditation Program (VELAP) laboratory for the analysis of the constituents listed in Table 7. Table 7 also summarizes the sample preservation methods and holding times for each analysis. During each sampling event, one field duplicate and one matrix spike (MS)/matrix spike duplicate (MSD) sample will also be collected.

4.3 REPORTING SCHEDULE

4.3.1 Quarterly Reports

To demonstrate the effectiveness of the proposed remedial approach, quarterly status reports will be submitted electronically to the VDEQ approximately one month following the collection of the quarterly water levels and post-construction monitoring samples. The quarterly status reports will generally include a brief narrative of quarterly post-construction monitoring activities and tabulated sampling analytical data compared to applicable background standards.

4.3.2 Annual Reports

An annual review will be submitted concurrently with the fourth quarter monitoring report and will include a more in-depth analysis of the effectiveness of the implemented remedial approach. The annual report will generally include:

- A summary of post-construction monitoring activities conducted over the past year;
- Tabulated post-construction monitoring sampling analytical data compared to applicable background standards;
- A summary of depth to water readings and elevations;
- Figures to illustrate the hydraulic capture and change in concentrations as compared to baseline data;
- Validated laboratory reports associated with sampling data; and
- Low flow field sampling records.

The annual review will make recommendations for the scope and schedule of future performance monitoring. The annual review can also be used for additional topics, such as: recommendations for additional monitoring points, added/deleted constituents of concern, justification for reducing monitoring frequency, etc.

The quarterly and annual reports outlined above will be combined with and submitted concurrently with the quarterly and annual seep and surface water monitoring reports outlined in the Surface Water Monitoring Plan.

4.3.3 Remedy Effectiveness Evaluation

A Remedy Effectiveness Evaluation Report will be submitted to the VDEQ concurrently with the third annual report. Post-construction monitoring data will be used to review analytical trends, quantify the success of the chosen mitigation method and evaluate the effectiveness of the remedial system. The report will document the remedy effectiveness and if any additional steps might be necessary to adequately mitigate the seeps.

4.4 OPERATION AND MAINTENANCE

Inspections

Periodic operation and maintenance (O&M) Site inspections will be necessary to verify that the existing hydraulic control system, soil cover, and associated Site restoration features remain intact, and to identify and arrange for repair as required. Site inspections will also include monitoring the flushing of the new hydraulic control system, if needed.

Operation and Maintenance

An O&M plan for the Site will be finalized upon VDEQ approval of this SMP and after the remedial design has been completed. The O&M plan will provide a description of the long-term operation and maintenance components of the new hydraulic control system. The O&M plan will generally include the following:

- Overview of the shallow groundwater management system;
- Overview of the deep groundwater management system;
- Overview of the compliance monitoring network;
- Maintenance schedule;
- Standard operating procedures (including inspections and operation);
- Inspection and sampling field forms;
- Product information sheets; and
- Manufacturer O&M manuals

An example Table of Contents for an O&M plan is provided in Appendix E.

4.5 SUPPLEMENTAL REMEDIAL OPTIONS

If the results of the monitoring program described above indicate the need for increased hydraulic control, the system will be further evaluated to reduce the migration of constituents northeast to the James River. Additional evaluation, if necessary, may include reviewing the hydraulic control provided by the deep wells, and initiating any changes to the deep well system (i.e. increasing flow capacity, installing additional wells, etc.) to reduce contaminant migration.

References

Haley & Aldrich, Inc., 2018. Site Characterization Report, Chesterfield Power Station, Chester, Virginia, VPDES Permit No. VA0004146.

Haley & Aldrich, Inc., 2018. Surface Water Monitoring Plan – Seep Mitigation Project, Chesterfield Power Station, Chester, Virginia, VPDES Permit No. VA0004146.

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I / A

Public Staff

Lucas Exhibit 10

Docket No. E-22, Sub 562

COMMONWEALTH of VIRGINIA

DEPARTMENT OF ENVIRONMENTAL QUALITY
PIEDMONT REGIONAL OFFICE
4949-A Cox Road, Glen Allen, Virginia 23060
(804) 527-5020 Fax (804) 527-5106
www.deq.virginia.gov

Molly Joseph Ward
Secretary of Natural Resources

David K. Paylor
Director

Jeffery A. Steers
Regional Director

December 21, 2017

Mr. Jason Williams
Virginia Electric and Power Company
5000 Dominion Blvd.
Glen Allen, Virginia 23060

NOTICE OF VIOLATION

RE: NOV No. **W2017-12-P-0001**
Dominion Energy Services – Chesterfield Power Station
VPDES Permit No. VA0004146 (reissued/effective October 1, 2016)
VWP Permit No. 10-1787

Dear Mr. Williams:

This letter notifies you of information upon which the Department of Environmental Quality (Department or DEQ) may rely in order to institute an administrative or judicial enforcement action. Based on this information, DEQ has reason to believe that Virginia Electric and Power Company may be in violation of the State Water Control Law and Regulations at the Chesterfield Power Station.

This letter addresses conditions at the facility named above, and also cites compliance requirements of the State Water Control Law and Regulations. Pursuant to Va. Code § 62.1-44.15(8a), this letter is not a case decision under the Virginia Administrative Process Act, Va. Code § 2.2-4000 *et seq.* (APA). DEQ requests that you respond **within 10 days of the date of this letter** to arrange a prompt meeting.

OBSERVATIONS AND LEGAL REQUIREMENTS

The Chesterfield Power Station is subject to VPDES Permit No. VA0004146 dated October 1, 2016 and to VWP Permit No. 10-1787, issued on February 27, 2013 and most recently modified on December 6, 2016.

a) *Observations:* On July 6, 2017 the DEQ's Piedmont Regional Office (PRO) received a verbal notification that on July 5, 2017 an overflow from the Coal Pile Runoff Pond occurred resulting in a discharge of raw coal fines to Aiken Swamp. The facility estimated that the unauthorized discharge consisted of 277,000 gallons and started at approximately 5:40 p.m. and had ceased by 6:20 p.m.

On July 21, 2017, the Department of Game and Inland Fisheries observed a suspected unauthorized discharge (groundwater seep) along the James River shoreline, adjacent to the Chesterfield Power Station. On July 28, 2017, the permittee notified DEQ that it had commenced an investigation of the discharge, and DEQ conducted an inspection of this area on August 1, 2017. As part of its investigation, the permittee performed sampling, and analytical results indicated low pH values and elevated metals concentrations. The impacted groundwater is daylighting as trickle flows along the James River shoreline, and is observable at low tide. The duration and exact volume of the discharge is unknown. On September 28, 2017, the DEQ-PRO received a verbal notification from Dominion Energy of the seepage and sampling results, and on October 5, 2017, DEQ met with the permittee to discuss this apparent seepage.

On October 25, 2017 and November 1, 2017 the DEQ-PRO was informed of an oil sheen in the thermal discharge channel, downstream of permitted Outfall 003, at the Chesterfield Power Station. Follow up correspondence indicated that approximately 40 gallons of 'turbine lube oil' was released on October 25th.

Legal Requirements: **The cover page of VPDES Permit No. VA0004146 states, "In compliance with the provisions of the Clean Water Act as amended and pursuant to the State Water Control Law and regulations adopted pursuant thereto, the following owner is authorized to discharge in accordance with the information submitted with the permit application, and with this permit cover page, and Parts I and II of this permit, as set forth herein."**

9VAC25-31-50 states "Prohibitions. A. Except in compliance with a VPDES permit, or another permit, issued by the board or other entity authorized by the board, it shall be unlawful for any person to:

1. Discharge into state waters sewage, industrial wastes, other wastes, or any noxious or deleterious substances;

2. Otherwise alter the physical, chemical or biological properties of such state waters and make them detrimental to the public health, or to animal or aquatic life, or to the use of such waters for domestic or industrial consumption, or for recreation, or for other uses; or

3. Discharge stormwater into state waters from municipal separate storm sewer systems or land disturbing activities."

Part II.F of VPDES Permit VA0004146 states "Except in compliance with this permit, or another permit issued by the Board, it shall be unlawful for any person to:

1. Discharge into state waters sewage, industrial wastes, other wastes, or any noxious or deleterious substances; or

2. Otherwise alter the physical, chemical or biological properties of such state waters and make them detrimental to the public health, or to animal or aquatic life, or to the use of such waters for domestic or industrial consumption, or for recreation, or for other uses."

Part II.G. of VPDES Permit VA0004146 states, "Any permittee who discharges or causes or allows a discharge of sewage, industrial waste, other wastes or any noxious or deleterious substance into or upon state waters in violation of Part II F; or who discharges or causes or allows a discharge that may reasonably be expected to enter state waters in violation of Part II.F, shall notify the Department of the discharge immediately upon discovery of the discharge, but in no case later than 24 hours after said discovery. A written report of the unauthorized discharge shall be submitted to the Department within five days of discovery of the discharge."

Part I.C.3 of VPDES Permit VA0004146 states, "Any and all product, materials, industrial wastes, and/or other wastes resulting from the purchase, sale, mining, extraction, transport, preparation, and/or storage of raw or intermediate materials, final product, by-product or wastes, shall be handled, disposed of, and/or stored in such a manner and consistent with Best Management Practices, so as not to permit a discharge of such product, materials, industrial wastes, and/or other wastes to State waters, except as expressly authorized." In addition, Part II.R states "Solids, sludges, or other pollutants removed in the course of treatment or management of pollutants shall be disposed of in a manner so as to prevent any pollutant from such materials from entering state waters."

Va. Code § 62.1-44.5(A) states, "[e]xcept in compliance with a certificate or permit issued by the Board or other entity authorized by the Board to issue a certificate or permit pursuant to this chapter, it shall be unlawful for any person to: 1. Discharge into state waters sewage, industrial wastes, other wastes, or any noxious or deleterious substances; 2. Excavate in a wetland; 3. Otherwise alter the physical, chemical or biological properties of state waters and make them detrimental to the public health, or to animal or aquatic life, or to the uses of such waters for domestic or industrial consumption, or for recreation, or for other uses ..."

9 VAC 25-260-20(A) states, "State waters, including wetlands, shall be free from substances attributable to sewage, industrial waste, or other waste in concentrations, amounts, or combinations which contravene established standards

or interfere directly or indirectly with designated uses of such water or which are inimical or harmful to human, animal, plant, or aquatic life."

Va. Code § 62.1-44.34:18(A) states, "The discharge of oil into or upon state waters, lands, or storm drain systems within the Commonwealth is prohibited. For purposes of this section, discharges of oil into or upon state waters include discharges of oil that (i) violate applicable water quality standards or a permit or certificate of the Board or (ii) cause a film or sheen upon or discoloration of the surface of the water or adjoining shorelines or cause a sludge or emulsion to be deposited beneath the surface of the water or upon adjoining shorelines."

2. ***Observations:*** Dominion provided notification on August 23, 2017 of two sediment releases to surface waters located adjacent to construction activities associated with the new Low Volume Wastewater Treatment System (LVWWTS). On August 31, 2017, DEQ staff conducted a site inspection to determine compliance with the VWP Permit. DEQ staff observed that approximately 45 linear feet of stream channel and 0.23 acre of palustrine forested wetlands were impacted at Impact Area A by the discharge and accumulation of up to four inches of eroded sediment. Staff also observed that approximately 88 linear feet of stream channel and 0.18 acre of palustrine forested wetlands were impacted at Impact Area B by the discharge and accumulation of up to three inches of eroded sediment. The impacts appeared to have been caused by the failure of erosion and sediment control measures. The VWP Permit does not authorize these impacts.

   Legal Requirements: The Cover Page of VWP Permit No. 10-1787 states, "The activities shall result in the permanent impact of no more than 0.012 acre of tidal forested wetlands, 0.033 acre of palustrine forested wetlands, 0.078 acre of isolated palustrine scrub-shrub wetlands, 0.98 acre isolated palustrine emergent wetlands, 0.16 acre of palustrine emergent wetlands, 0.636 acre of open water, and 1,528 linear feet of stream channel. The activities shall result in the conversion of no more than 1.03 acres of tidal forested wetlands to scrub-shrub wetlands, and temporary impacts to no more than 0.994 acre of tidal forested wetland, 0.198 acre of palustrine forested wetlands, 0.01 acre of palustrine emergent wetlands, and 38 linear feet of stream channel. Permitted impacts shall be taken as illustrated on the plan sheets titled "Drawing 3: Jurisdictional Area Impacts Map", by Golder Associates dated May 5, 2015 and "Figure 3: Modified Wetland Impact Map," by Golder Associates dated August 10, 2015 and modified on September 14, 2016."

   Part I.C.22 of VWP Permit No. 10-1787 states, "Erosion and sedimentation controls shall be designed in accordance with the Virginia Erosion and Sediment Control Handbook, Third Edition, 1992, or the most recent version in effect at the time of construction. These controls shall be placed prior to clearing and grading activities and shall be maintained in good working order, to minimize impacts to surface waters. These controls shall remain in place only until clearing and grading activities cease and these areas have been stabilized."

Va. Code §62.1-44.15:20(A) states, "A. Except in compliance with an individual or general Virginia Water Protection Permit issued in accordance with this article, it shall be unlawful to: 1. Excavate in a wetland; 2. On or after October 1, 2001, conduct the following in a wetland: a. New activities to cause draining that significantly alters or degrades existing wetland acreage or function; b. Filling or dumping; c. Permanent flooding or impounding; or d. New activities that cause significant alteration or degradation of existing wetland acreage or functions; or 3. Alter the physical, chemical, or biological properties of state waters and make them detrimental to the public health, animal or aquatic life, or to the uses of such waters for domestic or industrial consumption, or for recreation, or for other uses unless authorized by a certificate issued by the Board."

9VAC 25-210-50 (A) states, "Except in compliance with a VWP permit, no person shall dredge, fill or discharge any pollutant into, or adjacent to surface waters, withdraw surface water, otherwise alter the physical, chemical or biological properties of surface waters and make them detrimental to the public health, or to animal or aquatic life, or to the uses of such waters for domestic or industrial consumption, or for recreation, or for other uses; excavate in wetlands or on or after October 1, 2001, conduct the following activities in a wetland: 1. New activities to cause draining that significantly alters or degrades existing wetland acreage or functions; 2. Filling or dumping; 3. Permanent flooding or impounding; or 4. New activities that cause significant alteration or degradation of existing wetland acreage or functions."

ENFORCEMENT AUTHORITY

Va. Code § 62.1-44.23 of the State Water Control Law provides for an injunction for any violation of the State Water Control Law, any State Water Control Board rule or regulation, an order, permit condition, standard, or any certificate requirement or provision. Va. Code §§ 62.1-44.15 and 62.1-44.32 provide for a civil penalty up to $32,500 per day of each violation of the same. In addition, Va. Code § 62.1-44.15 authorizes the State Water Control Board to issue orders to any person to comply with the State Water Control Law and regulations, including the imposition of a civil penalty for violations of up to $100,000. Also, Va. Code § 10.1-1186 authorizes the Director of DEQ to issue special orders to any person to comply with the State Water Control Law and regulations. Va. Code §§ 62.1-44.32(b) and 62.1-44.32(c) provide for other additional penalties.

FUTURE ACTIONS

DEQ staff wishes to discuss all aspects of their observations with you, including any actions needed to ensure compliance with state law and regulations, any relevant or related measures you plan to take or have taken, and a schedule, as needed, for further activities. In addition, please advise us if you dispute any of the observations recited herein or if there is other information of which DEQ should be aware. In order to avoid adversarial enforcement proceedings, Dominion Energy Services may be asked to enter into a Consent Order with the Department to formalize a plan and schedule of corrective action and to settle any outstanding issues regarding this matter, including the assessment of civil charges.

In the event that discussions with staff do not lead to a satisfactory conclusion concerning the contents of this letter, you may elect to participate in DEQ's Process for Early Dispute Resolution. Also, if informal discussions do not lead to a satisfactory conclusion, you may request in writing that DEQ take all necessary steps to issue a final decision or fact finding under the APA on whether or not a violation has occurred. For further information on the Process for Early Dispute Resolution, please see Agency Policy Statement No. 8-2005 posted on the Department's website under "Programs," "Enforcement," and "Laws, Regulations, & Guidance" http://www.deq.virginia.gov/Portals/0/DEQ/Enforcement/Guidance/process%20for%20early%20dispute%20resolution%20no8_2005.pdf or ask the DEQ contact listed below.

Please contact Frank Lupini at (804) 698-4187 or via email to Frank.Lupini@deq.virginia.gov **within 10 days** to discuss this matter.

Sincerely,

Kyle Ivar Winter, P.E.
Deputy Regional Director

cc: H. Deihls – PRO Water Compliance Manager (electronic copy)
A. Bilalagic – PRO Water Compliance Inspector (electronic copy)
C. Witte - PRO VWP Permits Inspector
J. Bryan – PRO Water Permits (electronic copy)
J. Kazio – PRO PREP Coordinator (electronic copy)
B. Wood – Dominion Chesterfield Power Station (electronic copy to Beverly.Wood@dominionenergy.com)
J. Williams – Dominion Generation Environmental Services (electronic copy to Jason.E.Williams@dominionenergy.com)
File/ECM

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Molly Joseph Ward
Secretary of Natural Resources

David K. Paylor
Director

Jeffery A. Steers
Regional Director

August 1, 2017

Cathy Taylor, Director, Electric Environmental Services
Dominion – Chesterfield Power Station
500 Coxendale Rd.
Chester, VA 23831

WARNING LETTER

RE: **WL # W2017-07-P-1008**
Dominion – Chesterfield Power Station
VPDES Permit No. VA0004146 (reissued/effective October 1, 2016)

Dear Ms. Taylor:

The Department of Environmental Quality (DEQ or the Department) has reason to believe that Dominion's Chesterfield Power Station may be in violation of the State Water Control Law and Regulations.

This letter addresses conditions at the facility named above, and also cites compliance requirements of the State Water Control Law and Regulations. Pursuant to Va. Code § 62.1-44.15(8a), this letter is not a case decision under the Virginia Administrative Process Act, Va. Code § 2.2-4000 *et seq.* (APA). **Due to the adequacy of information in your email dated July 10, 2017 no response to this correspondence is required.**

OBSERVATIONS AND LEGAL REQUIREMENTS

a) ***Observation:*** On July 5, 2017 an overflow from the Coal Pile Runoff Pond occurred resulting in a discharge of raw coal fines to Aiken Swamp. The facility estimated that the unauthorized discharge consisted of 277,000 gallons and started at approximately 5:40 p.m. and had ceased by 6:20 p.m.

Legal Requirement: Part I.C.3. of VPDES Permit VA0004146 effective October 1, 2016 states *"Any and all product, materials, industrial wastes, and/or storage of raw or intermediate materials, final product, by-product or wastes, shall be handled, disposed of, and/or stored in such a manner so as not to permit a discharge of such product, materials, industrial wastes, and/or other wastes to State waters, except as expressly authorized."*. In addition, Part II.R states *"Solids, sludges, or other pollutants removed in the course of treatment or management of pollutants shall be disposed of in a manner so as to prevent any pollutant from such materials from entering state waters."*

ENFORCEMENT AUTHORITY

Va. Code § 62.1-44.23 of the State Water Control Law provides for an injunction for any violation of the State Water Control Law, any State Water Control Board rule or regulation, an order, permit condition, standard, or any certificate requirement or provision. Va. Code §§ 62.1-44.15 and 62.1-44.32 provide for a civil penalty up to $32,500 per day of each violation of the same. In addition, Va. Code § 62.1-44.15 authorizes the State Water Control Board to issue orders to any person to comply with the State Water Control Law and regulations, including the imposition of a civil penalty for violations of up to $100,000. Also, Va. Code § 10.1-1186 authorizes the Director of DEQ to issue special orders to any person to comply with the State Water Control Law and regulations, and to impose a civil penalty of not more than $10,000. Va. Code §§ 62.1-44.32(b) and 62.1-44.32(c) provide for other additional penalties.

The Court has the inherent authority to enforce its injunction, and is authorized to award the Commonwealth its attorneys' fees and costs.

FUTURE ACTIONS

No response to this correspondence is required. However, if you have additional information please provide it within 20 days of the date of this letter. *It is DEQ policy that appropriate, timely, corrective action undertaken in response to a Warning Letter will avoid adversarial enforcement proceedings and the assessment of civil charges or penalties.*

Please advise us if you dispute any of the observations recited herein or if there is other information of which DEQ should be aware. In the event that discussions with staff do not lead to a satisfactory conclusion concerning the contents of this letter, you may elect to participate in DEQ's Process for Early Dispute Resolution. Also, if informal discussions do not lead to a satisfactory conclusion, you may request in writing that DEQ take all necessary steps to issue a final decision or fact finding under the APA on whether or not a violation has occurred. For further information on the Process for Early Dispute Resolution, please see Agency Policy Statement No. 8-2005 posted on the Department's website under "Programs," "Enforcement," and "Laws, Regulations, & Guidance" (http://www.deq.virginia.gov/Portals/0/DEQ/Enforcement/Guidance/process%20for%20early%20dispute%20resolution%20no8_2005.pdf) or ask the DEQ contact listed below.

Your point of contact at DEQ in this matter is Ms. Azra Bilalagic. Please direct written materials to her attention. If you have questions or wish to arrange a meeting, you may reach Ms. Bilalagic at (804) 527-5011 or via email to **Azra.Bilalagic@deq.virginia.,gov**.

Sincerely,

Heather A.H. Deihls

Heather A. H. Deihls
Water Compliance Manager

cc: File/ECM
J. Bryan– DEQ-PRO VPDES Permits (electronic copy)
A. Bilalagic – DEQ-PRO Water Compliance (electronic copy)
B. Wood – Dominion Chesterfield Power Station (electronic copy to Beverly.Wood@dominionenergy.com)
J. Williams – Dominion Generation Environmental Services (electronic copy to Jason.E.Wiliams@dominionenergy.com)

COMMONWEALTH of VIRGINIA

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Molly Joseph Ward
Secretary of Natural Resources

David K. Paylor
Director

Michael P. Murphy
Regional Director

December 6, 2016

Cathy Taylor, Director, Electric Environmental Services
Dominion – Chesterfield Power Station
500 Coxendale Rd.
Chester, VA 23831

WARNING LETTER

RE: **WL # W2016-11-P-1003**
Dominion – Chesterfield Power Station
VPDES Permit No. VA0004146 (reissued/effective October 1, 2016)
VPDES Industrial Stormwater General Permit No. VAR051023 (effective July 1, 2014)

Dear Ms. Taylor:

The Department of Environmental Quality (DEQ or the Department) has reason to believe that Dominion's Chesterfield Power Station may be in violation of the State Water Control Law and Regulations.

This letter addresses conditions at the facility named above, and also cites compliance requirements of the State Water Control Law and Regulations. Pursuant to Va. Code § 62.1-44.15(8a), this letter is not a case decision under the Virginia Administrative Process Act, Va. Code § 2.2-4000 *et seq.* (APA). **DEQ requests that you respond within 20 days of the date of this letter.**

OBSERVATIONS AND LEGAL REQUIREMENTS

a) ***Observation:*** On September 28 through September 29, 2016 an overflow from the Coal Pile Runoff Pond occurred resulting in a discharge of raw coal fines to Aiken Swamp. The facility estimated that the unauthorized discharge started at approximately 10:00 p.m. on September 28, 2016 and had ceased by 1:00 a.m. on September 29, 2016.

Legal Requirement: Part I.B.3. of VPDES Permit VA0004146 effective December 10, 2004 states *"Any and all product, materials, industrial wastes, and/or storage of raw or* *intermediate materials, final product, by-product or wastes, shall be handled, disposed of, and/or stored in such a manner so as not to permit a discharge of such product, materials, industrial wastes, and/or other wastes to State waters, except as expressly authorized.".* In addition, Part II.R states *"Solids, sludges, or other pollutants removed in the course of treatment or management of pollutants shall be disposed of in a manner so as to prevent any pollutant from such materials from entering state waters."*

b) ***Observation:*** On September 28 through September 29, 2016 an overflow from the Coal Pile Runoff Pond occurred resulting in a discharge of raw coal fines to stormwater Outfall 055 via curb inlets located on the parking lot in the vicinity of the coal pile. This outfall discharges to the James River.

Legal Requirement: Part I.B.1 of VPDES Permit VAR051023 effective July 1, 2014 states *"Allowable non-stormwater discharges. Except as provided in this section or in Part IV, all discharges covered by this permit shall be composed entirely of stormwater... "*, Va. Code § 62.1-44.5(A) states *"[e]xcept in compliance with a certificate or permit issued by the Board or other entity authorized by the Board to issue a certificate or permit pursuant to this chapter, it shall be unlawful for any person to: 1. Discharge into state waters sewage, industrial wastes, other wastes, or any noxious or deleterious substances; 2. Excavate in a wetland; 3. Otherwise alter the physical, chemical or biological properties of state waters and make them detrimental to the public health, or to animal or aquatic life, or to the uses of such waters for domestic or industrial consumption, or for recreation, or for other uses . . . . "* and 9 VAC 25-31-50 (A) *states "[e]xcept in compliance with a VPDES permit, or another permit, issued by the board, it shall be unlawful for any person to: 1. Discharge into state waters sewage, industrial wastes, other wastes, or any noxious or deleterious substances; or 2. Otherwise alter the physical, chemical or biological properties of such state waters and make them detrimental to the public health, or to animal or aquatic life, or to the use of such waters for domestic or industrial consumption, or for recreation, or for other uses."*

ENFORCEMENT AUTHORITY

Va. Code § 62.1-44.23 of the State Water Control Law provides for an injunction for any violation of the State Water Control Law, any State Water Control Board rule or regulation, an order, permit condition, standard, or any certificate requirement or provision. Va. Code §§ 62.1-44.15 and 62.1-44.32 provide for a civil penalty up to $32,500 per day of each violation of the same. In addition, Va. Code § 62.1-44.15 authorizes the State Water Control Board to issue orders to any person to comply with the State Water Control Law and regulations, including the imposition of a civil penalty for violations of up to $100,000. Also, Va. Code § 10.1-1186 authorizes the Director of DEQ to issue special orders to any person to comply with the State Water Control Law and regulations, and to impose a civil penalty of not more than $10,000. Va. Code §§ 62.1-44.32(b) and 62.1-44.32(c) provide for other additional penalties.

The Court has the inherent authority to enforce its injunction, and is authorized to award the Commonwealth its attorneys' fees and costs.

FUTURE ACTIONS

After reviewing this letter, please respond in writing to DEQ **within 20 days of the date of this letter** detailing actions you have taken or will be taking to ensure compliance with state law and regulations. If corrective action will take longer than 90 days to complete, you may be asked to sign a Letter of Agreement or enter into a Consent Order with the Department to formalize the plan and schedule. *It is DEQ policy that appropriate, timely, corrective action undertaken in response to a Warning Letter will avoid adversarial enforcement proceedings and the assessment of civil charges or penalties.*

Please advise us if you dispute any of the observations recited herein or if there is other information of which DEQ should be aware. In the event that discussions with staff do not lead to a satisfactory conclusion concerning the contents of this letter, you may elect to participate in DEQ's Process for Early Dispute Resolution. Also, if informal discussions do not lead to a satisfactory conclusion, you may request in writing that DEQ take all necessary steps to issue a final decision or fact finding under the APA on whether or not a violation has occurred. For further information on the Process for Early Dispute Resolution, please see Agency Policy Statement No. 8-2005 posted on the Department's website under "Programs," "Enforcement," and "Laws, Regulations, & Guidance" (http://www.deq.virginia.gov/Portals/0/DEQ/Enforcement/Guidance/process%20for%20early%20dispute%20resolution%20no8_2005.pdf) or ask the DEQ contact listed below.

Your point of contact at DEQ in this matter is Ms. Azra Bilalagic. Please direct written materials to her attention. If you have questions or wish to arrange a meeting, you may reach Ms. Bilalagic at (804) 527-5011 or via email to **Azra.Bilalagic@deq.virginia.,gov**.

Sincerely,

Heather A.H. Deihls

Heather A. H. Deihls
Water Compliance Manager

cc: File/ECM
J. Bryan and J. Abel – DEQ-PRO VPDES Permits (electronic copy)
A. Bilalagic – DEQ-PRO Water Compliance (electronic copy)
B. Wood – Dominion Chesterfield Power Station (electronic copy to Beverly.Wood@dom.com)
A. Boschen - Dominion Electric Environmental Services (electronic copy to amelia.h.boschen@dom.com)

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Douglas W. Domenech
Secretary of Natural Resources

David K. Paylor
Director

Michael P. Murphy
Regional Director

March 01, 2011

Ms. Cathy C. Taylor, Director, Electric Environmental Services
Dominion Virginia Power
5000 Dominion Blvd.
Glen Allen, VA 23060

WARNING LETTER

RE: **WL # W2011-02-P-1015**
Dominion Virginia Power – Chesterfield Power Station
VPDES Permit No. VA0004146 (effective December 10, 2004)

Dear Ms. Taylor:

The Department of Environmental Quality (DEQ), Piedmont Regional Office (PRO) has reason to believe that the Dominion Virginia Power – Chesterfield Power Station may be in violation of State Water Control Law. A review of our files has revealed the following:

a) On January 03, 2011 the DEQ-PRO received notification of an unpermitted discharge of approximately 150-200 gallons of 'ash sluice water' that was discharged to the James River via permitted outfall 005. A follow-up report received on January 06, 2011 indicated that the cause of the unpermitted discharge was due to 'a pipe failure in the Unit 6 fly ash sluice piping' and that 'a new pumping skid is currently in place and being tied in to station systems'.

As adequate permit required information has been provided in regards to this particular incident, no response to this correspondence is necessary. However, if additional information has been obtained please provide it, in writing, within 20 days of receipt of this letter. Any additional information will assist our staff in maintaining a complete and accurate record of the compliance status of your facility. Be aware that continued facility compliance may be verified by on-site inspection or other appropriate means.

This Warning Letter is not an agency proceeding or determination, which may be considered a case decision under the Virginia Administrative Process Act, Va. Code § 2.2 - 4000 *et seq*. Your point of contact for resolution of these deficiencies will be **Ms. Meredith Williams at (804) 527-5017**. Please contact her if you have any questions about the content of this letter or need additional guidance.

Sincerely,

Kyle Ivar Winter, P.E.
Deputy Regional Director

cc: M. Williams – DEQ-PRO Water Compliance (electronic copy)
E. Carpenter – DEQ-PRO Water Permitting (electronic copy)
S. Morris – DEQ-PRO Pollution Response (electronic copy)
File/ECM

COMMONWEALTH of VIRGINIA

DEPARTMENT OF ENVIRONMENTAL QUALITY
PIEDMONT REGIONAL OFFICE
4949-A Cox Road, Glen Allen, Virginia 23060
(804) 527-5020 Fax (804) 527-5106
www.deq.virginia.gov

Douglas W. Domenech
Secretary of Natural Resources

David K. Paylor
Director

February 26, 2010

Ms. Cathy C. Taylor, Director of Electric Environmental Services
Dominion Virginia Power
5000 Dominion Blvd.
Glen Allen, VA 23060

WARNING LETTER

RE: **WL # W2010-02-P-1008**
Dominion Virginia Power – Chesterfield Power Station
VPDES Permit No. VA0004146 (effective December 10, 2004)

Dear Ms. Taylor:

The Department of Environmental Quality (DEQ), Piedmont Regional Office (PRO) has reason to believe that the Dominion Virginia Power – Chesterfield Power Station may be in violation of State Water Control Law. A review of our files has revealed the following:

a) On February 2, 2010 the DEQ-PRO received notification of an unpermitted discharge of approximately 270 gallons of 'ash sluice water' that was discharged to the James River via permitted outfall 003. A follow-up report received on February 10, 2010 indicated that the cause of the unpermitted discharge was due to 'a pipe failure in the #6 bottom ash sluice piping system' and that an engineering review to minimize the risk associated with the ash sluice piping was ongoing.

As adequate permit required information has been provided in regards to this particular incident, no response to this correspondence is necessary. However, if additional information has been obtained please provide it, in writing, within 20 days of receipt of this letter. Any additional information will assist our staff in maintaining a complete and accurate record of the compliance status of your facility. Be aware that continued facility compliance may be verified by on-site inspection or other appropriate means.

This Warning Letter is not an agency proceeding or determination, which may be considered a case decision under the Virginia Administrative Process Act, Va. Code § 2.2 - 4000 *et seq*. Your point of contact for resolution of these deficiencies will be **Ms. Meredith Williams at (804) 527-5017**. Please contact her if you have any questions about the content of this letter or need additional guidance.

Sincerely,

Kyle Ivar Winter, P.E.
Deputy Regional Director

cc: M. Williams – DEQ-PRO Water Compliance (electronic copy)
E. Carpenter – DEQ-PRO Water Permitting (electronic copy)
File/ECM

COMMONWEALTH *of* VIRGINIA

DEPARTMENT OF ENVIRONMENTAL QUALITY
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(804) 527-5020 Fax (804) 527-5106
www.deq.virginia.gov

L. Preston Bryant, Jr.
Secretary of Natural Resources

David K. Paylor
Director

December 22, 2009

Ms. Cathy C. Taylor, Director of Electric Environmental Services
Dominion Virginia Power
5000 Dominion Blvd.
Glen Allen, VA 23060

WARNING LETTER

RE: **WL # W2009-12-P-1004**
Dominion Virginia Power – Chesterfield Power Station
VPDES Permit No. VA0004146 (effective December 10, 2004)

Dear Ms. Taylor:

The Department of Environmental Quality (DEQ), Piedmont Regional Office (PRO) has reason to believe that the Dominion Virginia Power – Chesterfield Power Station may be in violation of State Water Control Law. A review of our files has revealed the following:

a) On October 18, 2009 the DEQ-PRO received notification of an unpermitted discharge of approximately 175 gallons of 'ash sluice water' through the sparger channel (Outfall 003). The report indicated that the cause of the unpermitted discharge was due to 'a line rupture in the #6 Bottom Ash System'. A follow-up report received at the DEQ-PRO on October 23, 2009 indicated that the unpermitted discharge occurred through Stormwater Outfall 005.

Please review the above and submit a written explanation within 20 days of receipt of this letter clarifying which outfall was affected by the unpermitted discharge which occurred on October 18, 2009. In addition, please ensure that the response also addresses Part II.G.8, specifically "Any steps planned or taken to reduce, eliminate and prevent a recurrence of the present discharge or any future discharges not authorized by this permit."

Your letter will assist our staff in maintaining a complete and accurate record of the compliance status of your facility. Continued facility compliance may be verified by on-site inspection or other appropriate means. If corrective action will take longer than 90 days please submit a plan and schedule for inclusion in a Letter of Agreement or Consent Order. Failure to respond may result in enforcement action by DEQ.

This Warning Letter is not an agency proceeding or determination, which may be considered a case decision under the Virginia Administrative Process Act, Va. Code § 2.2 - 4000 *et seq*. Your point of contact for resolution of these deficiencies will be **Ms. Meredith Williams at (804) 527-5017**. Please contact her if you have any questions about the content of this letter or need additional guidance.

Sincerely,

Kyle Ivar Winter, P.E.
Deputy Regional Director

cc: M. Williams – DEQ-PRO Water Compliance (electronic copy)
E. Carpenter – DEQ-PRO Water Permitting (electronic copy)
File/ECM

I/A

Public Staff

Lucas Exhibit 10

Docket No. E-22, Sub 562

COMMONWEALTH of VIRGINIA

DEPARTMENT OF ENVIRONMENTAL QUALITY

PIEDMONT REGIONAL OFFICE
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Molly Joseph Ward
Secretary of Natural Resources

David K. Paylor
Director

Jeffery A. Steers
Regional Director

December 21, 2017

Mr. Jason Williams
Virginia Electric and Power Company
5000 Dominion Blvd.
Glen Allen, Virginia 23060

NOTICE OF VIOLATION

RE: NOV No. **W2017-12-P-0001**
Dominion Energy Services – Chesterfield Power Station
VPDES Permit No. VA0004146 (reissued/effective October 1, 2016)
VWP Permit No. 10-1787

Dear Mr. Williams:

This letter notifies you of information upon which the Department of Environmental Quality (Department or DEQ) may rely in order to institute an administrative or judicial enforcement action. Based on this information, DEQ has reason to believe that Virginia Electric and Power Company may be in violation of the State Water Control Law and Regulations at the Chesterfield Power Station.

This letter addresses conditions at the facility named above, and also cites compliance requirements of the State Water Control Law and Regulations. Pursuant to Va. Code § 62.1-44.15(8a), this letter is not a case decision under the Virginia Administrative Process Act, Va. Code § 2.2-4000 *et seq*. (APA). DEQ requests that you respond **within 10 days of the date of this letter** to arrange a prompt meeting.

OBSERVATIONS AND LEGAL REQUIREMENTS

The Chesterfield Power Station is subject to VPDES Permit No. VA0004146 dated October 1, 2016 and to VWP Permit No. 10-1787, issued on February 27, 2013 and most recently modified on December 6, 2016.

a) ***Observations:*** On July 6, 2017 the DEQ's Piedmont Regional Office (PRO) received a verbal notification that on July 5, 2017 an overflow from the Coal Pile Runoff Pond occurred resulting in a discharge of raw coal fines to Aiken Swamp. The facility estimated that the unauthorized discharge consisted of 277,000 gallons and started at approximately 5:40 p.m. and had ceased by 6:20 p.m.

On July 21, 2017, the Department of Game and Inland Fisheries observed a suspected unauthorized discharge (groundwater seep) along the James River shoreline, adjacent to the Chesterfield Power Station. On July 28, 2017, the permittee notified DEQ that it had commenced an investigation of the discharge, and DEQ conducted an inspection of this area on August 1, 2017. As part of its investigation, the permittee performed sampling, and analytical results indicated low pH values and elevated metals concentrations. The impacted groundwater is daylighting as trickle flows along the James River shoreline, and is observable at low tide. The duration and exact volume of the discharge is unknown. On September 28, 2017, the DEQ-PRO received a verbal notification from Dominion Energy of the seepage and sampling results, and on October 5, 2017, DEQ met with the permittee to discuss this apparent seepage.

On October 25, 2017 and November 1, 2017 the DEQ-PRO was informed of an oil sheen in the thermal discharge channel, downstream of permitted Outfall 003, at the Chesterfield Power Station. Follow up correspondence indicated that approximately 40 gallons of 'turbine lube oil' was released on October 25th.

Legal Requirements: **The cover page of VPDES Permit No. VA0004146 states, "In compliance with the provisions of the Clean Water Act as amended and pursuant to the State Water Control Law and regulations adopted pursuant thereto, the following owner is authorized to discharge in accordance with the information submitted with the permit application, and with this permit cover page, and Parts I and II of this permit, as set forth herein."**

9VAC25-31-50 states "Prohibitions. A. Except in compliance with a VPDES permit, or another permit, issued by the board or other entity authorized by the board, it shall be unlawful for any person to:

1. Discharge into state waters sewage, industrial wastes, other wastes, or any noxious or deleterious substances;

2. Otherwise alter the physical, chemical or biological properties of such state waters and make them detrimental to the public health, or to animal or aquatic life, or to the use of such waters for domestic or industrial consumption, or for recreation, or for other uses; or

3. Discharge stormwater into state waters from municipal separate storm sewer systems or land disturbing activities."

Part II.F of VPDES Permit VA0004146 states "Except in compliance with this permit, or another permit issued by the Board, it shall be unlawful for any person to:

1. Discharge into state waters sewage, industrial wastes, other wastes, or any noxious or deleterious substances; or

2. Otherwise alter the physical, chemical or biological properties of such state waters and make them detrimental to the public health, or to animal or aquatic life, or to the use of such waters for domestic or industrial consumption, or for recreation, or for other uses."

Part II.G. of VPDES Permit VA0004146 states, "Any permittee who discharges or causes or allows a discharge of sewage, industrial waste, other wastes or any noxious or deleterious substance into or upon state waters in violation of Part II F; or who discharges or causes or allows a discharge that may reasonably be expected to enter state waters in violation of Part II.F, shall notify the Department of the discharge immediately upon discovery of the discharge, but in no case later than 24 hours after said discovery. A written report of the unauthorized discharge shall be submitted to the Department within five days of discovery of the discharge."

Part I.C.3 of VPDES Permit VA0004146 states, "Any and all product, materials, industrial wastes, and/or other wastes resulting from the purchase, sale, mining, extraction, transport, preparation, and/or storage of raw or intermediate materials, final product, by-product or wastes, shall be handled, disposed of, and/or stored in such a manner and consistent with Best Management Practices, so as not to permit a discharge of such product, materials, industrial wastes, and/or other wastes to State waters, except as expressly authorized." In addition, Part II.R states "Solids, sludges, or other pollutants removed in the course of treatment or management of pollutants shall be disposed of in a manner so as to prevent any pollutant from such materials from entering state waters."

Va. Code § 62.1-44.5(A) states, "[e]xcept in compliance with a certificate or permit issued by the Board or other entity authorized by the Board to issue a certificate or permit pursuant to this chapter, it shall be unlawful for any person to: 1. Discharge into state waters sewage, industrial wastes, other wastes, or any noxious or deleterious substances; 2. Excavate in a wetland; 3. Otherwise alter the physical, chemical or biological properties of state waters and make them detrimental to the public health, or to animal or aquatic life, or to the uses of such waters for domestic or industrial consumption, or for recreation, or for other uses ..."

9 VAC 25-260-20(A) states, "State waters, including wetlands, shall be free from substances attributable to sewage, industrial waste, or other waste in concentrations, amounts, or combinations which contravene established standards

or interfere directly or indirectly with designated uses of such water or which are inimical or harmful to human, animal, plant, or aquatic life."

Va. Code § 62.1-44.34:18(A) states, "The discharge of oil into or upon state waters, lands, or storm drain systems within the Commonwealth is prohibited. For purposes of this section, discharges of oil into or upon state waters include discharges of oil that (i) violate applicable water quality standards or a permit or certificate of the Board or (ii) cause a film or sheen upon or discoloration of the surface of the water or adjoining shorelines or cause a sludge or emulsion to be deposited beneath the surface of the water or upon adjoining shorelines."

2. ***Observations:*** Dominion provided notification on August 23, 2017 of two sediment releases to surface waters located adjacent to construction activities associated with the new Low Volume Wastewater Treatment System (LVWWTS). On August 31, 2017, DEQ staff conducted a site inspection to determine compliance with the VWP Permit. DEQ staff observed that approximately 45 linear feet of stream channel and 0.23 acre of palustrine forested wetlands were impacted at Impact Area A by the discharge and accumulation of up to four inches of eroded sediment. Staff also observed that approximately 88 linear feet of stream channel and 0.18 acre of palustrine forested wetlands were impacted at Impact Area B by the discharge and accumulation of up to three inches of eroded sediment. The impacts appeared to have been caused by the failure of erosion and sediment control measures. The VWP Permit does not authorize these impacts.

    Legal Requirements: The Cover Page of VWP Permit No. 10-1787 states, "The activities shall result in the permanent impact of no more than 0.012 acre of tidal forested wetlands, 0.033 acre of palustrine forested wetlands, 0.078 acre of isolated palustrine scrub-shrub wetlands, 0.98 acre isolated palustrine emergent wetlands, 0.16 acre of palustrine emergent wetlands, 0.636 acre of open water, and 1,528 linear feet of stream channel. The activities shall result in the conversion of no more than 1.03 acres of tidal forested wetlands to scrub-shrub wetlands, and temporary impacts to no more than 0.994 acre of tidal forested wetland, 0.198 acre of palustrine forested wetlands, 0.01 acre of palustrine emergent wetlands, and 38 linear feet of stream channel. Permitted impacts shall be taken as illustrated on the plan sheets titled "Drawing 3: Jurisdictional Area Impacts Map", by Golder Associates dated May 5, 2015 and "Figure 3: Modified Wetland Impact Map," by Golder Associates dated August 10, 2015 and modified on September 14, 2016."

    Part I.C.22 of VWP Permit No. 10-1787 states, "Erosion and sedimentation controls shall be designed in accordance with the Virginia Erosion and Sediment Control Handbook, Third Edition, 1992, or the most recent version in effect at the time of construction. These controls shall be placed prior to clearing and grading activities and shall be maintained in good working order, to minimize impacts to surface waters. These controls shall remain in place only until clearing and grading activities cease and these areas have been stabilized."

Va. Code §62.1-44.15:20(A) states, "A. Except in compliance with an individual or general Virginia Water Protection Permit issued in accordance with this article, it shall be unlawful to: 1. Excavate in a wetland; 2. On or after October 1, 2001, conduct the following in a wetland: a. New activities to cause draining that significantly alters or degrades existing wetland acreage or function; b. Filling or dumping; c. Permanent flooding or impounding; or d. New activities that cause significant alteration or degradation of existing wetland acreage or functions; or 3. Alter the physical, chemical, or biological properties of state waters and make them detrimental to the public health, animal or aquatic life, or to the uses of such waters for domestic or industrial consumption, or for recreation, or for other uses unless authorized by a certificate issued by the Board."

9VAC 25-210-50 (A) states, "Except in compliance with a VWP permit, no person shall dredge, fill or discharge any pollutant into, or adjacent to surface waters, withdraw surface water, otherwise alter the physical, chemical or biological properties of surface waters and make them detrimental to the public health, or to animal or aquatic life, or to the uses of such waters for domestic or industrial consumption, or for recreation, or for other uses; excavate in wetlands or on or after October 1, 2001, conduct the following activities in a wetland: 1. New activities to cause draining that significantly alters or degrades existing wetland acreage or functions; 2. Filling or dumping; 3. Permanent flooding or impounding; or 4. New activities that cause significant alteration or degradation of existing wetland acreage or functions."

ENFORCEMENT AUTHORITY

Va. Code § 62.1-44.23 of the State Water Control Law provides for an injunction for any violation of the State Water Control Law, any State Water Control Board rule or regulation, an order, permit condition, standard, or any certificate requirement or provision. Va. Code §§ 62.1-44.15 and 62.1-44.32 provide for a civil penalty up to $32,500 per day of each violation of the same. In addition, Va. Code § 62.1-44.15 authorizes the State Water Control Board to issue orders to any person to comply with the State Water Control Law and regulations, including the imposition of a civil penalty for violations of up to $100,000. Also, Va. Code § 10.1-1186 authorizes the Director of DEQ to issue special orders to any person to comply with the State Water Control Law and regulations. Va. Code §§ 62.1-44.32(b) and 62.1-44.32(c) provide for other additional penalties.

FUTURE ACTIONS

DEQ staff wishes to discuss all aspects of their observations with you, including any actions needed to ensure compliance with state law and regulations, any relevant or related measures you plan to take or have taken, and a schedule, as needed, for further activities. In addition, please advise us if you dispute any of the observations recited herein or if there is other information of which DEQ should be aware. In order to avoid adversarial enforcement proceedings, Dominion Energy Services may be asked to enter into a Consent Order with the Department to formalize a plan and schedule of corrective action and to settle any outstanding issues regarding this matter, including the assessment of civil charges.

In the event that discussions with staff do not lead to a satisfactory conclusion concerning the contents of this letter, you may elect to participate in DEQ's Process for Early Dispute Resolution. Also, if informal discussions do not lead to a satisfactory conclusion, you may request in writing that DEQ take all necessary steps to issue a final decision or fact finding under the APA on whether or not a violation has occurred. For further information on the Process for Early Dispute Resolution, please see Agency Policy Statement No. 8-2005 posted on the Department's website under "Programs," "Enforcement," and "Laws, Regulations, & Guidance" http://www.deq.virginia.gov/Portals/0/DEQ/Enforcement/Guidance/process%20for%20early%20dispute%20resolution%20no8_2005.pdf or ask the DEQ contact listed below.

Please contact Frank Lupini at (804) 698-4187 or via email to Frank.Lupini@deq.virginia.gov **within 10 days** to discuss this matter.

Sincerely,

Kyle Ivar Winter

Kyle Ivar Winter, P.E.
Deputy Regional Director

cc: H. Deihls – PRO Water Compliance Manager (electronic copy)
A. Bilalagic – PRO Water Compliance Inspector (electronic copy)
C. Witte - PRO VWP Permits Inspector
J. Bryan – PRO Water Permits (electronic copy)
J. Kazio – PRO PREP Coordinator (electronic copy)
B. Wood – Dominion Chesterfield Power Station (electronic copy to Beverly.Wood@dominionenergy.com)
J. Williams – Dominion Generation Environmental Services (electronic copy to Jason.E.Williams@dominionenergy.com)
File/ECM

COMMONWEALTH of VIRGINIA

DEPARTMENT OF ENVIRONMENTAL QUALITY

PIEDMONT REGIONAL OFFICE
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(804) 527-5020 Fax (804) 527-5106
www.deq.virginia.gov

Molly Joseph Ward
Secretary of Natural Resources

David K. Paylor
Director

Jeffery A. Steers
Regional Director

August 1, 2017

Cathy Taylor, Director, Electric Environmental Services
Dominion – Chesterfield Power Station
500 Coxendale Rd.
Chester, VA 23831

WARNING LETTER

RE: **WL # W2017-07-P-1008**
Dominion – Chesterfield Power Station
VPDES Permit No. VA0004146 (reissued/effective October 1, 2016)

Dear Ms. Taylor:

The Department of Environmental Quality (DEQ or the Department) has reason to believe that Dominion's Chesterfield Power Station may be in violation of the State Water Control Law and Regulations.

This letter addresses conditions at the facility named above, and also cites compliance requirements of the State Water Control Law and Regulations. Pursuant to Va. Code § 62.1-44.15(8a), this letter is not a case decision under the Virginia Administrative Process Act, Va. Code § 2.2-4000 *et seq.* (APA). **Due to the adequacy of information in your email dated July 10, 2017 no response to this correspondence is required.**

OBSERVATIONS AND LEGAL REQUIREMENTS

a) ***Observation:*** On July 5, 2017 an overflow from the Coal Pile Runoff Pond occurred resulting in a discharge of raw coal fines to Aiken Swamp. The facility estimated that the unauthorized discharge consisted of 277,000 gallons and started at approximately 5:40 p.m. and had ceased by 6:20 p.m.

Legal Requirement: Part I.C.3. of VPDES Permit VA0004146 effective October 1, 2016 states *"Any and all product, materials, industrial wastes, and/or storage of raw or intermediate materials, final product, by-product or wastes, shall be handled, disposed of, and/or stored in such a manner so as not to permit a discharge of such product, materials, industrial wastes, and/or other wastes to State waters, except as expressly authorized."*. In addition, Part II.R states *"Solids, sludges, or other pollutants removed in the course of treatment or management of pollutants shall be disposed of in a manner so as to prevent any pollutant from such materials from entering state waters."*

ENFORCEMENT AUTHORITY

Va. Code § 62.1-44.23 of the State Water Control Law provides for an injunction for any violation of the State Water Control Law, any State Water Control Board rule or regulation, an order, permit condition, standard, or any certificate requirement or provision. Va. Code §§ 62.1-44.15 and 62.1-44.32 provide for a civil penalty up to $32,500 per day of each violation of the same. In addition, Va. Code § 62.1-44.15 authorizes the State Water Control Board to issue orders to any person to comply with the State Water Control Law and regulations, including the imposition of a civil penalty for violations of up to $100,000. Also, Va. Code § 10.1-1186 authorizes the Director of DEQ to issue special orders to any person to comply with the State Water Control Law and regulations, and to impose a civil penalty of not more than $10,000. Va. Code §§ 62.1-44.32(b) and 62.1-44.32(c) provide for other additional penalties.

The Court has the inherent authority to enforce its injunction, and is authorized to award the Commonwealth its attorneys' fees and costs.

FUTURE ACTIONS

No response to this correspondence is required. However, if you have additional information please provide it within 20 days of the date of this letter. *It is DEQ policy that appropriate, timely, corrective action undertaken in response to a Warning Letter will avoid adversarial enforcement proceedings and the assessment of civil charges or penalties.*

Please advise us if you dispute any of the observations recited herein or if there is other information of which DEQ should be aware. In the event that discussions with staff do not lead to a satisfactory conclusion concerning the contents of this letter, you may elect to participate in DEQ's Process for Early Dispute Resolution. Also, if informal discussions do not lead to a satisfactory conclusion, you may request in writing that DEQ take all necessary steps to issue a final decision or fact finding under the APA on whether or not a violation has occurred. For further information on the Process for Early Dispute Resolution, please see Agency Policy Statement No. 8-2005 posted on the Department's website under "Programs," "Enforcement," and "Laws, Regulations, & Guidance" (http://www.deq.virginia.gov/Portals/0/DEQ/Enforcement/Guidance/process%20for%20early%20dispute%20resolution%20no8_2005.pdf) or ask the DEQ contact listed below.

Your point of contact at DEQ in this matter is Ms. Azra Bilalagic. Please direct written materials to her attention. If you have questions or wish to arrange a meeting, you may reach Ms. Bilalagic at (804) 527-5011 or via email to **Azra.Bilalagic@deq.virginia.,gov**.

Sincerely,

Heather A.H. Deihls

Heather A. H. Deihls
Water Compliance Manager

cc: File/ECM
J. Bryan– DEQ-PRO VPDES Permits (electronic copy)
A. Bilalagic – DEQ-PRO Water Compliance (electronic copy)
B. Wood – Dominion Chesterfield Power Station (electronic copy to Beverly.Wood@dominionenergy.com)
J. Williams – Dominion Generation Environmental Services (electronic copy to Jason.E.Wiliams@dominionenergy.com)

COMMONWEALTH of VIRGINIA

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Molly Joseph Ward
Secretary of Natural Resources

David K. Paylor
Director

Michael P. Murphy
Regional Director

December 6, 2016

Cathy Taylor, Director, Electric Environmental Services
Dominion – Chesterfield Power Station
500 Coxendale Rd.
Chester, VA 23831

WARNING LETTER

RE: **WL # W2016-11-P-1003**
Dominion – Chesterfield Power Station
VPDES Permit No. VA0004146 (reissued/effective October 1, 2016)
VPDES Industrial Stormwater General Permit No. VAR051023 (effective July 1, 2014)

Dear Ms. Taylor:

The Department of Environmental Quality (DEQ or the Department) has reason to believe that Dominion's Chesterfield Power Station may be in violation of the State Water Control Law and Regulations.

This letter addresses conditions at the facility named above, and also cites compliance requirements of the State Water Control Law and Regulations. Pursuant to Va. Code § 62.1-44.15(8a), this letter is not a case decision under the Virginia Administrative Process Act, Va. Code § 2.2-4000 *et seq.* (APA). **DEQ requests that you respond within 20 days of the date of this letter.**

OBSERVATIONS AND LEGAL REQUIREMENTS

a) ***Observation:*** On September 28 through September 29, 2016 an overflow from the Coal Pile Runoff Pond occurred resulting in a discharge of raw coal fines to Aiken Swamp. The facility estimated that the unauthorized discharge started at approximately 10:00 p.m. on September 28, 2016 and had ceased by 1:00 a.m. on September 29, 2016.

Legal Requirement: Part I.B.3. of VPDES Permit VA0004146 effective December 10, 2004 states *"Any and all product, materials, industrial wastes, and/or storage of raw or* *intermediate materials, final product, by-product or wastes, shall be handled, disposed of, and/or stored in such a manner so as not to permit a discharge of such product, materials, industrial wastes, and/or other wastes to State waters, except as expressly authorized.".* In addition, Part II.R states *"Solids, sludges, or other pollutants removed in the course of treatment or management of pollutants shall be disposed of in a manner so as to prevent any pollutant from such materials from entering state waters."*

b) ***Observation:*** On September 28 through September 29, 2016 an overflow from the Coal Pile Runoff Pond occurred resulting in a discharge of raw coal fines to stormwater Outfall 055 via curb inlets located on the parking lot in the vicinity of the coal pile. This outfall discharges to the James River.

Legal Requirement: Part I.B.1 of VPDES Permit VAR051023 effective July 1, 2014 states *"Allowable non-stormwater discharges. Except as provided in this section or in Part IV, all discharges covered by this permit shall be composed entirely of stormwater...",* Va. Code § 62.1-44.5(A) states *"[e]xcept in compliance with a certificate or permit issued by the Board or other entity authorized by the Board to issue a certificate or permit pursuant to this chapter, it shall be unlawful for any person to: 1. Discharge into state waters sewage, industrial wastes, other wastes, or any noxious or deleterious substances; 2. Excavate in a wetland; 3. Otherwise alter the physical, chemical or biological properties of state waters and make them detrimental to the public health, or to animal or aquatic life, or to the uses of such waters for domestic or industrial consumption, or for recreation, or for other uses...."* and 9 VAC 25-31-50 (A) *states "[e]xcept in compliance with a VPDES permit, or another permit, issued by the board, it shall be unlawful for any person to: 1. Discharge into state waters sewage, industrial wastes, other wastes, or any noxious or deleterious substances; or 2. Otherwise alter the physical, chemical or biological properties of such state waters and make them detrimental to the public health, or to animal or aquatic life, or to the use of such waters for domestic or industrial consumption, or for recreation, or for other uses."*

ENFORCEMENT AUTHORITY

Va. Code § 62.1-44.23 of the State Water Control Law provides for an injunction for any violation of the State Water Control Law, any State Water Control Board rule or regulation, an order, permit condition, standard, or any certificate requirement or provision. Va. Code §§ 62.1-44.15 and 62.1-44.32 provide for a civil penalty up to $32,500 per day of each violation of the same. In addition, Va. Code § 62.1-44.15 authorizes the State Water Control Board to issue orders to any person to comply with the State Water Control Law and regulations, including the imposition of a civil penalty for violations of up to $100,000. Also, Va. Code § 10.1-1186 authorizes the Director of DEQ to issue special orders to any person to comply with the State Water Control Law and regulations, and to impose a civil penalty of not more than $10,000. Va. Code §§ 62.1-44.32(b) and 62.1-44.32(c) provide for other additional penalties.

The Court has the inherent authority to enforce its injunction, and is authorized to award the Commonwealth its attorneys' fees and costs.

FUTURE ACTIONS

After reviewing this letter, please respond in writing to DEQ **within 20 days of the date of this letter** detailing actions you have taken or will be taking to ensure compliance with state law and regulations. If corrective action will take longer than 90 days to complete, you may be asked to sign a Letter of Agreement or enter into a Consent Order with the Department to formalize the plan and schedule. *It is DEQ policy that appropriate, timely, corrective action undertaken in response to a Warning Letter will avoid adversarial enforcement proceedings and the assessment of civil charges or penalties.*

Please advise us if you dispute any of the observations recited herein or if there is other information of which DEQ should be aware. In the event that discussions with staff do not lead to a satisfactory conclusion concerning the contents of this letter, you may elect to participate in DEQ's Process for Early Dispute Resolution. Also, if informal discussions do not lead to a satisfactory conclusion, you may request in writing that DEQ take all necessary steps to issue a final decision or fact finding under the APA on whether or not a violation has occurred. For further information on the Process for Early Dispute Resolution, please see Agency Policy Statement No. 8-2005 posted on the Department's website under "Programs," "Enforcement," and "Laws, Regulations, & Guidance" (http://www.deq.virginia.gov/Portals/0/DEQ/Enforcement/Guidance/process%20for%20early%20dispute%20resolution%20no8_2005.pdf) or ask the DEQ contact listed below.

Your point of contact at DEQ in this matter is Ms. Azra Bilalagic. Please direct written materials to her attention. If you have questions or wish to arrange a meeting, you may reach Ms. Bilalagic at (804) 527-5011 or via email to **Azra.Bilalagic@deq.virginia.,gov**.

Sincerely,

Heather A.H. Deihls

Heather A. H. Deihls
Water Compliance Manager

cc: File/ECM
J. Bryan and J. Abel – DEQ-PRO VPDES Permits (electronic copy)
A. Bilalagic – DEQ-PRO Water Compliance (electronic copy)
B. Wood – Dominion Chesterfield Power Station (electronic copy to Beverly.Wood@dom.com)
A. Boschen - Dominion Electric Environmental Services (electronic copy to amelia.h.boschen@dom.com)

COMMONWEALTH of VIRGINIA

DEPARTMENT OF ENVIRONMENTAL QUALITY
PIEDMONT REGIONAL OFFICE
4949-A Cox Road, Glen Allen, Virginia 23060.
(804) 527-5020 Fax (804) 527-5106
www.deq.virginia.gov

Douglas W. Domenech
Secretary of Natural Resources

David K. Paylor
Director

Michael P. Murphy
Regional Director

March 01, 2011

Ms. Cathy C. Taylor, Director, Electric Environmental Services
Dominion Virginia Power
5000 Dominion Blvd.
Glen Allen, VA 23060

WARNING LETTER

RE: **WL # W2011-02-P-1015**
Dominion Virginia Power – Chesterfield Power Station
VPDES Permit No. VA0004146 (effective December 10, 2004)

Dear Ms. Taylor:

The Department of Environmental Quality (DEQ), Piedmont Regional Office (PRO) has reason to believe that the Dominion Virginia Power – Chesterfield Power Station may be in violation of State Water Control Law. A review of our files has revealed the following:

a) On January 03, 2011 the DEQ-PRO received notification of an unpermitted discharge of approximately 150-200 gallons of 'ash sluice water' that was discharged to the James River via permitted outfall 005. A follow-up report received on January 06, 2011 indicated that the cause of the unpermitted discharge was due to 'a pipe failure in the Unit 6 fly ash sluice piping' and that 'a new pumping skid is currently in place and being tied in to station systems'.

As adequate permit required information has been provided in regards to this particular incident, no response to this correspondence is necessary. However, if additional information has been obtained please provide it, in writing, within 20 days of receipt of this letter. Any additional information will assist our staff in maintaining a complete and accurate record of the compliance status of your facility. Be aware that continued facility compliance may be verified by on-site inspection or other appropriate means.

This Warning Letter is not an agency proceeding or determination, which may be considered a case decision under the Virginia Administrative Process Act, Va. Code § 2.2 - 4000 *et seq*. Your point of contact for resolution of these deficiencies will be **Ms. Meredith Williams at (804) 527-5017**. Please contact her if you have any questions about the content of this letter or need additional guidance.

Sincerely,

Kyle Ivar Winter, P.E.
Deputy Regional Director

cc: M. Williams – DEQ-PRO Water Compliance (electronic copy)
E. Carpenter – DEQ-PRO Water Permitting (electronic copy)
S. Morris – DEQ-PRO Pollution Response (electronic copy)
File/ECM

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www.deq.virginia.gov

Douglas W. Domenech
Secretary of Natural Resources

David K. Paylor
Director

February 26, 2010

Ms. Cathy C. Taylor, Director of Electric Environmental Services
Dominion Virginia Power
5000 Dominion Blvd.
Glen Allen, VA 23060

WARNING LETTER

RE: **WL # W2010-02-P-1008**
Dominion Virginia Power – Chesterfield Power Station
VPDES Permit No. VA0004146 (effective December 10, 2004)

Dear Ms. Taylor:

The Department of Environmental Quality (DEQ), Piedmont Regional Office (PRO) has reason to believe that the Dominion Virginia Power – Chesterfield Power Station may be in violation of State Water Control Law. A review of our files has revealed the following:

a) On February 2, 2010 the DEQ-PRO received notification of an unpermitted discharge of approximately 270 gallons of 'ash sluice water' that was discharged to the James River via permitted outfall 003. A follow-up report received on February 10, 2010 indicated that the cause of the unpermitted discharge was due to 'a pipe failure in the #6 bottom ash sluice piping system' and that an engineering review to minimize the risk associated with the ash sluice piping was ongoing.

As adequate permit required information has been provided in regards to this particular incident, no response to this correspondence is necessary. However, if additional information has been obtained please provide it, in writing, within 20 days of receipt of this letter. Any additional information will assist our staff in maintaining a complete and accurate record of the compliance status of your facility. Be aware that continued facility compliance may be verified by on-site inspection or other appropriate means.

This Warning Letter is not an agency proceeding or determination, which may be considered a case decision under the Virginia Administrative Process Act, Va. Code § 2.2 - 4000 *et seq*. Your point of contact for resolution of these deficiencies will be **Ms. Meredith Williams at (804) 527-5017**. Please contact her if you have any questions about the content of this letter or need additional guidance.

Sincerely,

Kyle Ivar Winter, P.E.
Deputy Regional Director

cc: M. Williams – DEQ-PRO Water Compliance (electronic copy)
E. Carpenter – DEQ-PRO Water Permitting (electronic copy)
File/ECM

COMMONWEALTH *of* VIRGINIA

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L. Preston Bryant, Jr.
Secretary of Natural Resources

David K. Paylor
Director

December 22, 2009

Ms. Cathy C. Taylor, Director of Electric Environmental Services
Dominion Virginia Power
5000 Dominion Blvd.
Glen Allen, VA 23060

WARNING LETTER

RE: **WL # W2009-12-P-1004**
Dominion Virginia Power – Chesterfield Power Station
VPDES Permit No. VA0004146 (effective December 10, 2004)

Dear Ms. Taylor:

The Department of Environmental Quality (DEQ), Piedmont Regional Office (PRO) has reason to believe that the Dominion Virginia Power – Chesterfield Power Station may be in violation of State Water Control Law. A review of our files has revealed the following:

a) On October 18, 2009 the DEQ-PRO received notification of an unpermitted discharge of approximately 175 gallons of 'ash sluice water' through the sparger channel (Outfall 003). The report indicated that the cause of the unpermitted discharge was due to 'a line rupture in the #6 Bottom Ash System'. A follow-up report received at the DEQ-PRO on October 23, 2009 indicated that the unpermitted discharge occurred through Stormwater Outfall 005.

Please review the above and submit a written explanation within 20 days of receipt of this letter clarifying which outfall was affected by the unpermitted discharge which occurred on October 18, 2009. In addition, please ensure that the response also addresses Part II.G.8, specifically "Any steps planned or taken to reduce, eliminate and prevent a recurrence of the present discharge or any future discharges not authorized by this permit."

Your letter will assist our staff in maintaining a complete and accurate record of the compliance status of your facility. Continued facility compliance may be verified by on-site inspection or other appropriate means. If corrective action will take longer than 90 days please submit a plan and schedule for inclusion in a Letter of Agreement or Consent Order. Failure to respond may result in enforcement action by DEQ.

This Warning Letter is not an agency proceeding or determination, which may be considered a case decision under the Virginia Administrative Process Act, Va. Code § 2.2 - 4000 *et seq*. Your point of contact for resolution of these deficiencies will be **Ms. Meredith Williams at (804) 527-5017**. Please contact her if you have any questions about the content of this letter or need additional guidance.

Sincerely,

Kyle Ivar Winter, P.E.
Deputy Regional Director

cc: M. Williams – DEQ-PRO Water Compliance (electronic copy)
E. Carpenter – DEQ-PRO Water Permitting (electronic copy)
File/ECM

2. **Data Request 3-2 (sent March 29, 2019—due April 8, 2019):**

For each location (original and relocation sites) where the Company has disposed of CCR, please provide:

k. All reports and notes that describe any problems or potential risks associated with the site.
l. All reports from consultants regarding the site.
m. All reports and communications from regulatory authorities regarding the site.
n. All Company notes, reports, and communications in response to the foregoing information from consultants and regulatory authorities, including any presented to or made available to the Board of Directors for VEPCO, Dominion Energy, and affiliates of Dominion Energy.

Response to Data Request 3-2 (received April 18, 2019):

Readily available non-privileged records have been provided in the following attachments in response to the above questions:

- Attachment Public Staff Set 3-2a (JW) – This attachment includes readily available reports prepared to address groundwater risks and corrective action, to the extent their preparation was necessary. This attachment is responsive to subrequests a. and b.
- Attachment Public Staff Set 3-2b (JW) – This attachment includes readily available records of regulatory communications largely including inspection reports issued by regulatory agencies. This attachment is responsive to c.
- Attachment Public Staff Set 3-2c (JW) – This attachment includes readily available dam stability reports associated with the Company's coal ash impoundments. This attachment is responsive to a. and b.

As of the date of this response, no documents responsive to subrequest d. have been identified.

3. **<u>Data Request 3-3 (sent March 29, 2019—due April 8, 2019)</u>:**

For each location (original and relocation sites) that has reported groundwater contamination or has otherwise been out of compliance with any laws, regulations, and other legal commitments involving disposal of CCR, including groundwater and surface water contamination and dam safety, please provide[1]:

a. A description of the nature of the non-compliance and which laws, regulations, and legal commitments applied.
b. The Company's reports and analysis on the cause of the non-compliance including any presented to or made available to the Board of Directors for VEPCO, Dominion Energy, and affiliates of Dominion Energy.
c. How and when the non-compliance was corrected or otherwise addressed.
d. A detailed itemized cost accounting for the Company's response to the non-compliance, including administrative, legal and indirect costs as well as direct remediation costs.

[1] Please include in the response any situations in which the Company is potentially out of compliance; that is, situations where there is a likelihood the Company is out of compliance based on known conditions but may not yet have the monitoring data or other information to establish whether it was or is out of compliance.

<u>Response to Data Request 3-3 (received April 18, 2019)</u>:

None of the Company's CCR disposal sites are or have been out of compliance with groundwater concentrations. Detection of a groundwater result above the applicable groundwater protection standard, on its own, is not a violation. A result above an applicable standard simply triggers additional action to characterize the condition of the groundwater and initiate corrective action, if necessary. The Company has followed all required actions relating to groundwater standards. However, the Company's CCR disposal sites located at Bremo, Clover, Mt. Storm, Possum Point, and Yorktown have received notifications of minor environmental non-compliance incidents for <u>non-groundwater</u> requirements. Information regarding readily available records of those non-compliance incidents is included in the Company's response to Question No. 5 of Public Staff's Third Set.

4. <u>Data Request 3-5 (sent March 29, 2019—due April 8, 2019)</u>:

Please provide a list of all administrative or regulatory findings of environmental non-compliance, including

a. Any communication from a regulatory state agency indicating non-compliance at CCR sites, including findings of environmental non-compliance for which a Notice of Violation or "NOV" was or was not issued.
b. A list by date, location, event, and resolution of regulatory non-compliance events since January 1, 1980. Please indicate in the list whether the event or finding was related to CCR or not.
c. A list of all situations at CCR locations that have or will require corrective action and the reason why corrective action is needed.

<u>Response to Data Request 3-5 (received April 18, 2019)</u>:

The Company's CCR disposal sites located at Bremo, Clover, Mt. Storm, Possum Point, and Yorktown have received notifications of minor environmental non-compliance incidents associated with CCR operations. Readily available records of these non-compliance events have been provided in Attachment Public Staff Set 3-5 (JW).

5. <u>Data Request 3-10 (sent March 29, 2019—due April 8, 2019)</u>:

Please provide the month and year when groundwater monitoring was first required for each ash basin. That is, when did the obligation to monitor begin basin by basin? Also please state the source of the requirement (e.g., NPDES permit, special consent order, or other).

<u>Response to Data Request 3-10 (received April 18, 2019)</u>:

The table included in Attachment Public Staff Set 3-10 (JW) provides the first year of groundwater results identified in our groundwater database. It is assumed the obligation to monitor began at the same time as the Company has no record of voluntary groundwater monitoring conducted prior to being required to do so under the station's VPDES permit and/or CCR Rule requirements.

<u>Revised Response to Data Request 3-10 (received August 16, 2019)</u>:

The table included in Attachment Public Staff Set 3-10 JW provides the first year of groundwater results identified in our groundwater database. Based upon information and belief, knowledge of the Company's history of monitoring and discussions with other employees, the Company understands that the obligation to monitor began at the same time. The Company has no record of voluntary groundwater monitoring conducted prior to being required to do so under the station's VPDES permit and/or CCR Rule requirements.

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6. **<u>Data Request 3-11 (sent March 29, 2019—due April 8, 2019)</u>:**

Please provide a spreadsheet showing the number of required and voluntary groundwater monitoring wells that were installed, the source of the requirement, where they were installed (plant name, whether each well was at, beyond, or inside the site boundary, and whether each well was up-gradient or downgradient), when they were installed, and if any of these wells provided data that indicated contaminants from coal ash were migrating from each ash basin. For wells that provided data showing exceedances, please state the dates that the exceedances were identified in well samples, the type (constituent) for each exceedance, whether the exceedance was due to natural background levels or due to coal ash or if there was insufficient background data to determine, and what corrective action was taken and when it was taken with respect to each exceedance.

<u>Response to Data Request 3-11 (received April 18, 2019)</u>:

Attachment Public Staff Set 3-11a (JW) and Attachment Public Staff Set 3-11b (JW) include the readily available information responsive to this question. Attachment Public Staff Set 3-11a (JW) includes the readily available annual groundwater monitoring reports for each CCR disposal unit. These monitoring reports detail any exceedances of groundwater protection standards and actions taken in response to these concentrations. These reports are included for both CCR Rule and VPDES monitoring. Attachment Public Staff Set 3-11b (JW) includes the readily available CCR Rule and VPDES permit groundwater monitoring plans which identify the monitoring networks and well information.

7. **<u>Data Request 3-14 (sent March 29, 2019—due April 8, 2019)</u>:**

Please state how many groundwater monitoring wells VEPCO had in place cumulatively prior to 1990, 2000, 2010, 2013, 2014, 2015, 2016, 2017, and 2018 and how many are in place today. Please provide this data for each generating plant site separately.

<u>Response to Data Request 3-14 (received April 18, 2019)</u>:

The table included in Attachment Public Staff Set 3-10 (JW) is provided to identify the number of wells at each generating plant based on readily available records. Based on these records, the total number of wells for the various groundwater monitoring programs could only be confirmed back to the year 2000.

8. **<u>Data Request 3-15 (sent March 29, 2019—due April 8, 2019)</u>:**

Please identify, by plant and basin location, which seeps are authorized in NPDES permits, and which are not.

a. For the seeps not authorized by NPDES permits (including those for which permit applications are pending), please explain whether VEPCO contends they were or were not violations of NPDES permit requirements, or violations of Virginia's § 62.1-44.15 or West Virginia's § 22-11-6, and why.
b. Please include whether the seep is an engineered seep or not.
c. Please provide the date the seep was first identified and, if applicable, the year the seep was eliminated.

<u>Response to Data Request 3-15 (received April 18, 2019)</u>:

There are no NPDES permitted or unpermitted seeps associated with VEPCO's CCR impoundments. VEPCO understands the term "seep" to mean a channelized flow of water emanating from the berm of an impoundment that does or has the potential to reach surface waters.

9. **<u>Data Request 3-16 (sent March 29, 2019—due April 8, 2019)</u>:**

Please provide copies of all current and historic NPDES permits by plant site.

<u>Response to Data Request 3-16 (received April 18, 2019)</u>:

Current and readily available prior NPDES permits are provided in Attachment Public Staff Set 3-16 (JW).

10. <u>Data Request 3-17 (sent March 29, 2019—due April 8, 2019):</u>

Please provide a list of all NPDES permit violations (other than groundwater exceedances and violations) for each VEPCO coal plant site from January 1, 2009 through January 1, 2019. Please include facility reporting errors and the reason for each error.

<u>Response to Data Request 3-17 (received May 22, 2019):</u>

Please see Attachment Public Staff Set 3-5 (JW).

11. Data Request 3-18 (sent March 29, 2019—due April 8, 2019):

For all current or former coal generating stations, please provide a spreadsheet of groundwater monitoring data taken at or beyond the site boundary for regulated coal ash constituents in each ash basin. Please include the following:

a. For each sample, include the sample collection date, monitoring well identification, location with respect to groundwater flow direction, elevation of the top of the well casing, the ground, and top and bottom of the well screen, water level or elevation of groundwater, and aquifer formation.
b. Only include any exceedances of the Virginia and West Virginia groundwater standards.
c. Include the most recent data from monitoring wells, as well as historical data dating back to when monitoring wells were installed.
d. Provide any proposed groundwater standards (e.g., action levels or background standards) that VEPCO has provided to Virginia or West Virginia regulatory authorities. Please indicate the status of the regulatory authority's review and acceptance, if applicable, of such standards.
e. Where naturally occurring substances exceed the Virginia or West Virginia groundwater standards, highlight or bold any exceedances of the State standard, and include information regarding the background concentration of the contaminant if it exceeds that standard.
f. Include for each constituent the total number of exceedances, both before and after consideration of any background standard.

Response to Data Request 3-18 (received May 22, 2019):

Attachment Public Staff Set 3-11a (JW) includes the readily available annual groundwater monitoring reports for each CCR disposal unit. These monitoring reports detail any exceedances of groundwater protection standards and actions taken in response to these concentrations. These reports are included for both CCR Rule and VPDES monitoring.

12. <u>Data Request 3-19 (sent March 29, 2019—due April 8, 2019)</u>:

For all current or former coal generating stations, please provide a spreadsheet of groundwater monitoring data taken <u>inside the site boundary</u> for regulated coal ash constituents in each ash basin. Please include the following:

d. For each sample include the sample collection date, monitoring well identification, location with respect to groundwater flow direction, location with respect to the waste boundary, elevation of the top of the casing, the ground, and top and bottom of the well screen, water level or elevation of groundwater, aquifer formation,
e. Only include any exceedances of the Virginia and West Virginia groundwater standards.
f. Include the most recent data from monitoring wells, as well as historical data dating back to when monitoring wells were installed.
g. Provide any proposed groundwater standards (e.g., action levels or background standards) that VEPCO has provided to Virginia or West Virginia regulatory authorities. Please indicate the status of the regulatory authority's review and acceptance, if applicable, of such standards.
h. Where naturally occurring substances exceed the Virginia or West Virginia groundwater standards, highlight or bold any exceedances of the State standard, and include information regarding the background concentration of the contaminant if it exceeds that standard.
i. Include for each constituent the total number of exceedances, both before and after consideration of any background standard.

<u>Response to Data Request 3-19 (received May 22, 2019)</u>:

Attachment Public Staff Set 3-11a (JW) includes the readily available annual groundwater monitoring reports for each CCR disposal unit. These monitoring reports detail any exceedances of groundwater protection standards and actions taken in response to these concentrations. These reports are included for both CCR Rule and VPDES monitoring.

13. **Data Request 3-20 (sent March 29, 2019—due April 8, 2019):**

Similar to data request items 19 and 20 above, for all generating stations, please provide a spreadsheet showing the monitoring data and any exceedances of constituents being monitored in compliance with the CCR rule groundwater requirements, including maximum contaminant levels and Groundwater Protection Standards (GWPS). Please include the total number of exceedances by site and constituent of the GWPS. Please provide a narrative statement of how federal CCR Rule groundwater protection requirements and standards differ from Virginia and West Virginia's groundwater standards, and how any such differences affect groundwater monitoring procedures and reporting.

Response to Data Request 3-20 (received May 22, 2019):

Attachment Public Staff Set 3-11a (JW) includes the readily available annual groundwater monitoring reports for each CCR disposal unit. These monitoring reports detail any exceedances of groundwater protection standards and actions taken in response to these concentrations. These reports are included for both CCR Rule and VPDES monitoring.

14. **Data Request 41-3 (sent May 7, 2019—due May 17, 2019):**

In response to PS DR-3, Question 10, DENC provided a table (Attachment Public Staff Set 3-10 (JW)) showing the year in which groundwater monitoring was first required for each ash basin. For each ash basin, please provide:

a. A detailed explanation as to why the Company was required to begin groundwater monitoring under the terms of its VPDES permit.
b. All reports and communications from regulatory authorities regarding the addition of groundwater monitoring requirements to the VPDES permit.
c. All Company notes, reports, and communications concerning the addition of groundwater monitoring requirements to the VPDES permit.

Response to Data Request 41-3 (received May 22, 2019):

a. The Virginia Department of Environmental Quality (VDEQ) began requiring groundwater monitoring in VPDES permits for wastewater ponds in the 1980s. Some background on this decision is provided in Guidance Document 98-2010 that was issued by VDEQ in 1998 (See Attachment Public Staff Set 41-3 JW). The guidance issued in 1998 was not specific to coal ash ponds, but rather all waste water impoundments.

b. All readily available VPDES permits and groundwater communications have been provided in DENC's response to Public Staff Set 3.

c. All readily available reports and communications regarding groundwater monitoring have been provided to DENC's response to Staff Set 3.

15. Data Request 41-4 (sent May 7, 2019—due May 17, 2019):

In response to PS DR-3, Question 11, DENC states that the attached responses include all "readily available information" responsive to the question. In response to Question 13, DENC states that it has no "readily available records" related to voluntary groundwater monitoring. In response to Question 14, DENC states that its response is based on "readily available records." In response to Question 16, DENC states it is providing all "readily available" prior permits. In response to Questions 18, 19, and 20, DENC states it provides the "readily available" groundwater reports

a. How does the Company define "readily available" throughout its responses?
b. Have any documents been identified as responsive to these requests since the date of the response? If so, please provide those documents.
c. What search parameters were used to identify records, such as search terms and dates?
d. Please provide any newly available responses to Questions 11, 13, 14, 16, 18, 19, and 20 on a continuing basis for the period of this proceeding.

Response to Data Request 41-4 (received May 22, 2019):

a. "Readily available records" means records in the Company's possession or control that were identified after a reasonable inquiry and thorough search of the Company's files for responsive information.

b. The Company has not identified any responsive documents.

c. The Company has reviewed its records stored at each plant as well as records held by groups within the Company reasonably expected to possess responsive information.

d. The Company will comply with its obligations to supplement its responses to discovery requests under the North Carolina Rules of Civil Procedure.

16. **Data Request 41-5 (sent May 7, 2019—due May 17, 2019):**

In response to PS DR-3, Question 14, DENC states that the number of wells for various groundwater monitoring programs could only be confirmed back to the year 2000. The attached response, Attachment Public Staff Set 3-10 (JW), however, indicates first sampling data from groundwater monitoring wells from the 1980s. Please provide further information about the groundwater monitoring well data from before 2000 and why groundwater monitoring programs before 2000 cannot be confirmed by DENC.

Response to Data Request 41-5 (received May 22, 2019):

The term "further information" as used in this request is overbroad, vague, and ambiguous. The documents provided in response to Public Staff Requests 3-10, 3-11, and 3-16 reflect the available information in the Company's possession and control regarding VDEQ's groundwater monitoring program. The guidance document provided herewith, Attachment Public Staff Set 41-3 JW, provides some background on VDEQ's groundwater monitoring program before 2000.

17. <u>Data Request 41-6 (sent May 7, 2019—due May 17, 2019)</u>:

In response to PS DR-3, Question 15, DENC states that "VEPCO understands the term 'seep' to mean a channelized flow of water emanating from the berm of an impoundments that does or has the potential to reach surface waters." Please identify, by plant and basin location, which discharges are authorized in NPDES permits, and which are not. Please include all engineered and non-engineered discharges, including all locations in which a pollutant is conveyed, in any manner, from an impoundment to waters of the United States or a water of the State.

a. For the discharges not authorized by NPDES permits (including those for which permit applications are pending), please explain whether VEPCO contends they were or were not violations of NPDES permit requirements, or violations of Virginia's § 62.1-44.15 or West Virginia's § 22-11-6, and why.
b. Please include whether the discharge was engineered or not.
c. Please provide the date the discharge was first identified and, if applicable, the year the discharge was eliminated.

<u>Response to Data Request 41-6 (received May 22, 2019)</u>:

a. The Company is not aware of any unauthorized or unpermitted discharges from its basins. Permitted discharges are reflected in the NPDES permits that were provided in response to Request 3-16.

b. Not applicable.

c. Not applicable.

18. Data Request 60-1 (sent May 23, 2019—due June 3, 2019):

The Company's response to Public Staff Data Request No. 3-5 contained several folders regarding environmental non-compliance at the Bremo, Clover, Mt. Storm, Possum Point, and Yorktown power plants. Please provide a response to this data request for the Chesterfield, Mecklenburg, and Virginia City power plants.

Response to Data Request 60-1 (received May 31, 2019):

All responsive documents in the Company's possession and control have been provided. The Company is not aware of non-compliance events at Chesterfield, Mecklenburg, and Virginia City related to CCR. As previously stated, there are no coal ash ponds or landfills at Mecklenburg.

19. Data Request 61-1 (sent May 28, 2019—due June 7, 2019):

With regard to the Company's record retention policies, please provide the following:

a. The Company's current record retention policy, with a date indicating when that policy was put in place.
b. All previous versions of the Company's record retention policy, with dates indicating when those policies were in place.
c. Any state or federal laws or regulations that govern the retention of records by the Company.

Response to Data Request 61-1 (received June 7, 2019):

a. The current records retention policy effective as of 2014 for the Environmental Services Department is included in Attachment Public Staff Set 61-1 JW.
b. The Company has only located one prior record retention policy for the Environmental Services Department, effective May 6, 2005, which is being produced herewith as Attachment Public Staff Set 61-1 JW. Prior to May 6, 2005, the Company would have complied with the applicable regulatory retention requirements.
c. Please see the policies included in Attachment Public Staff Set 61-1 JW. Additionally, the Company is subject to North Carolina Utilities Commission regulation R8-28 and State Corporation Commission Rule 20 VAC 5-300-40.

20. Data Request 61-3 (sent May 28, 2019—due June 7, 2019):

In response to a question by the Public Staff, the Company stated that it has possession of static spreadsheets containing groundwater monitoring well data for dates prior to 2000 for its coal-fired generating stations.

a. Please provide those spreadsheets.
b. Please describe the source for the static spreadsheets (e.g., name and type of database), who was/is custodian of the source, and whether it currently exists in any form or location.

Response to Data Request 61-3 (received June 7, 2019):

a. The spreadsheets are provided in Attachment Public Staff Set 61-3 JW.
b. The source of the spreadsheets is an export from a database that was managed by URS, which is now AECOM. That database was closed out in 2018 as the Company no longer uses AECOM as a groundwater consultant. When AECOM closed out the database, it provided the Company with the spreadsheets for our records, which contains the data that was stored in the database.

21. **Data Request 61-4 (sent May 28, 2019—due June 7, 2019):**

In response to a question by the Public Staff, the Company stated that it previously maintained a database of groundwater monitoring well data. Please provide clarification as to why the database no longer exists, whether the Company has contacted the contractor that previously maintained the database, and whether the static spreadsheets referred to above include all the data from the database.

Response to Data Request 61-4 (received June 7, 2019):

The source of the spreadsheets is an export from a database that was managed by URS, which is now AECOM. That database was closed out in 2018 as the Company no longer uses AECOM as a groundwater consultant. When AECOM closed out the database, it provided the Company with the spreadsheets for our records, which contains the data that was stored in the database.

22. **<u>Data Request 81-7 (sent June 5, 2019—due June 17, 2019)</u>:**

The Company response to Public Staff Data Request 3, item 3, states:

> None of the Company's CCR disposal sites are or have been out of compliance with groundwater concentrations. Detection of a groundwater result above the applicable groundwater protection standard, on its own, is not a violation. A result above an applicable standard simply triggers additional action to characterize the condition of the groundwater and initiate corrective action, if necessary. The Company has followed all required actions relating to groundwater standards. However, the Company's CCR disposal sites located at Bremo, Clover, Mt. Storm, Possum Point, and Yorktown have received notifications of minor environmental non-compliance incidents for <u>non-groundwater</u> requirements. Information regarding readily available records of those non-compliance incidents is included in the Company's response to Question No. 5 of Public Staff's Third Set.

a. Please respond to Public Staff Data Request 3, item 3, for all instances where groundwater exceedances were detected. That is, whether or not the Company considers an exceedance of Maximum Contaminant Levels (MCLs), Groundwater Protection Standards (GWPS), or other regulatory standards for constituents in groundwater to be a non-compliance , or not, please respond to DR 3-3 for all exceedances.
b. For each current and former coal-fired generating station, please provide two tables (in xcel spreadsheet) showing the number of exceedances (one for the VDEQ MCL and one for the CCR Rule GWPS) by year and by constituent (i.e. arsenic, manganese, total suspended solids, etc.). A sample template is below, but when completing the tables please include all years and all constituents:

Bremo

	Arsenic	Boron	Mercury	Selenium
2000				
2001				
2002				
2003...				

Chesapeake

	Arsenic	Boron	Mercury	Selenium
1983				
1984				
1985				
1986...				

For the purposes of this request, an exceedance means any laboratory analysis result (including historical) of water sample(s) taken from a downgradient groundwater monitoring well and showing constitutents above the regulatory standard such as the MCL or GWPS. Please indicate everywhere that an exceedance is above the regulatory standard but is below the established background levels.

Response to Data Request 81-7 (received June 17, 2019):

a. The Company believes that it fully and completely responded to Public Staff Set 3, question 3, which specifically relates to "non-compliance" events. As the Company stated in its response, the Company's CCR sites have not been out of compliance with groundwater standards. An exceedance of a groundwater protection standard is not considered a violation or "non-compliance". When there have been exceedances of groundwater standards requiring corrective action as determined by VADEQ, those incidences were documented in the groundwater reports provided in response Public Staff Set 3 and were corrected to the satisfaction of VADEQ. GWPS were adopted pursuant to the CCR Rule in 2015 and did not apply prior to the promulgation of the CCR Rule. Groundwater data and reports collected pursuant to the CCR Rule are available publicly at: https://www.dominionenergy.com/company/community/environment/reports-and-performance/ccr-rule-compliance-data-and-information. The Company is happy to discuss this further.

b. Groundwater monitoring data was provided in response to Public Staff Set 61. Please also see the Company's responses to Public Staff Set 3, which contain the available groundwater reports, with data, and corrective actions taken to resolve the documented groundwater exceedances. Please also see the Company's CCR Rule reports, which compare the Company's groundwater quality to the newly adopted GWPS under the CCR Rule.

23. **Data Request 100-1 (sent June 24, 2019—due July 5, 2019):**

With regard to the Bremo facility:

a. According to the Company's response to DR 3-10, Dominion has been required to conduct groundwater monitoring at the Bremo facility since the year 2000. Please confirm that this is the earliest date that groundwater monitoring was conducted at the Bremo facility.

b. In response to DR 3-11, the Company provided VPDES Annual Reports for the Bremo facility for the years 2000, 2006, and 2015-2018. Please provide VPDES Annual Reports for the Bremo facility for each of the missing years 2001-2005 and 2007-2014.

c. In response to DR 61-3, the Company provided a static spreadsheet with groundwater monitoring data for the Bremo facility. This spreadsheet was limited to data from March 11, 2013 through March 29, 2017. Please provide the missing data from the year 2000 through March 2013, and from April 2017 through the date the AECOM database was closed in 2018.

Response to Data Request 100-1 (received July 5, 2019):

a. Yes, this is the earliest record of groundwater sampling we have located after a thorough search for responsive information.

b. After a thorough search for responsive information, all available reports have been provided in DR 3-11. There are no groundwater reports for the time period 2001-2005. The VPDES permit for Bremo only required groundwater sampling once every permit cycle (5 years). We have no record of groundwater results between 2007 and 2013. 2013-

2018 data was provided in DR 61-3. The requirements for groundwater monitoring included in VPDES permits during the 80s-90s varied greatly between Virginia DEQ regional offices. As such, the date of first sampling as well as the frequency of sampling varied greatly from facility to facility during that time.

c. Data for 2000 and 2006 are included in the annual reports provided in DR 3-11. All available data after a thorough search for responsive information has been provided. As stated in 1.b above, groundwater monitoring was not conducted during 2001-2005.

24. Data Request 100-2 (sent June 24, 2019—due July 5, 2019):

With regard to the Mt. Storm facility:

a. According to the Company's response to DR 3-10, Dominion has been required to conduct groundwater monitoring at the Mt. Storm facility since the year 1987. Please confirm that this is the earliest date that groundwater monitoring was conducted at the Mt. Storm facility.

b. In response to DR 3-11, the Company provided NPDES Semi-Annual Reports for the Mt. Storm facility for the years 2002 and 2004-2018. Please provide NPDES Semi-Annual Reports for the Mt. Storm facility for each of the missing years 1987-2001 and 2003.

c. In the Company's response to DR 61-3, the folder labeled "Mt. Storm" was empty. Please provide the static spreadsheet containing groundwater monitoring data for the Mt. Storm facility.

Response to Data Request 100-2 (received July 5, 2019):

a. Yes, this is the earliest record of groundwater sampling we have located after a thorough search for responsive information.

b. All available reports after a thorough search for responsive infonnation have been provided in DR 3-11.

c. The Company has supplemented its response to DR 61-3 to include the requested spreadsheets.

25. Data Request 100-3 (sent June 24, 2019—due July 5, 2019):

With regard to the Possum Point facility:

a. According to the Company's response to DR 3-10, Dominion has been required to conduct groundwater monitoring at the Possum Point facility since the year 1985. Please confirm that this is the earliest date that groundwater monitoring was conducted at the Possum Point facility.

b. In response to DR 3-11, the Company provided VPDES Annual Reports for the Possum Point facility for the years 1999-2002 and 2004-2017. Please provide VPDES Annual Reports for the Possum Point facility for each of the missing years 1985-1998, 2003, and 2018.

c. In the Company's response to DR 61-3, the folder labeled "Possum" was empty. Please provide the static spreadsheet containing groundwater monitoring data for the Possum Point facility.

Response to Data Request 100-3 (received July 5, 2019):

a. Yes, this is the earliest record of groundwater sampling we have located after a reasonable inquiry and thorough search for responsive information.

b. All available reports after a thorough search for responsive information have been provided in DR 3-11.

c. The Company has supplemented its response to DR 61-3 to include the requested spreadsheets.

26. Data Request 100-5 (sent June 24, 2019—due July 5, 2019):

In response to DR 3-18 and 3-19, the Company referred the Public Staff to its responses to DR 3-11. As explained above, the Company's response to DR 3-11 was incomplete. In addition, DR 3-18 and 3-19 request the data in spreadsheet format, and request types of information not included in the request or response to DR 3-11. Please provide a complete response to DR 3-18 and 3-19 for each current and former coal-fired generating station in spreadsheet format.

Response to Data Request 100-5 (received July 5, 2019):

The Company's responses to DR 3-11, 3-18, and 3-19 are complete. With regards to the spreadsheets requested in 3-18 and 3-19, the Company does not maintain a spreadsheet in the format requested; however, the Company has provided the requested information in the format in which it is kept by the Company in the ordinary course of business. For the majority of stations, nearly twenty years of annual or semi-annual groundwater reports have been provided. Those reports contain all available information regarding any exceedances noted at that time. Prior to the CCR Rule, any exceedances of Virginia or West Virginia standards were addressed and resolved through VADEQ's or WVDEP's corrective action process. In addition, the Company provided in response to DR 61-3 spreadsheets with analytical groundwater data. With this response, the Company is also producing additional raw data for the most recent VPDES and Solid Waste Management reports to DEQ, along with the raw data for its CCR Rule compliance reports. Public staff has all available information to generate any variety of spreadsheets they feel are helpful.

27. **Data Request 100-6 (sent June 24, 2019—due July 5, 2019):**

In response to DR 81-7(b), the Company referred the Public Staff to its responses to DR 3-11 and DR 61-3. As explained above, the Company's responses to DR 3-11 and DR 61-3 were incomplete. In addition, DR 81-7(b) requests the data in spreadsheet format. Please provide a complete response to DR 81-7 for each current and former coal-fired generating station in spreadsheet format.

Response to Data Request 100-6 (received July 5, 2019):

The Company's responses to DR 3-11 and DR 61-3 are complete. With regards to the spreadsheets requested 81-7(b), the Company does not maintain a spreadsheet in the format requested; however, the Company has provided the requested information in the format in which it is kept by the Company in the ordinary course of business. For the majority of stations, nearly twenty years of annual or semi-annual groundwater reports have been provided. Those reports contain all available information regarding any exceedances noted at that time. Prior to the CCR Rule, any exceedances of Virginia or West Virginia standards were addressed and resolved through VADEQ's or WVDEP's corrective action process. In addition, the Company provided in response to DR 61-3 spreadsheets with analytical groundwater data. With this response, the Company is also producing additional raw data for the most recent VPDES and Solid Waste Management reports to DEQ, along with the raw data for its CCR Rule compliance reports. Public staff has all available information to generate any variety of spreadsheets they feel are helpful.

b. With regards to coal ash environmental compliance, yes, the roles of Judson White, Cathy Taylor, and Jason Williams were effectively the same.

c. Jason Williams assumed his coal ash environmental compliance role when he joined the company in August 2015.

Dominion Energy North Carolina
2019 NC Base Case – Docket No. E-22, Sub 562
Public Staff
Data Request No. 161

The following responses to Question No. 2 of Public Staff Data Request No. 161, dated August 7, 2019 has been prepared under my supervision.

Jason E. Williams
Director, Learning Development & Communications
Dominion Energy Services, Inc.

Question No. 2:

Please provide any records or other information in the possession of A.W. Howard and Pamela Faggert (or the correct person as identified in response to question 1), and their direct reports identified in the provided organizational charts, that have not already been produced, pertaining to the following subjects of historical coal ash management decisions and practices:

a. Each decision to line or leave unlined CCR basins, and what type of lining to use.
b. The existence and/or elimination of any seeps or other unpermitted discharges, whether engineered or non-engineered, that had or have the potential to reach surface waters.
c. The initial requirement for groundwater monitoring at each site and the response to the initial requirements.
d. Whether corrective action was needed at any CCR disposal site on the basis of surface or groundwater monitoring results, and what corrective action planning took place.
e. Whether any surface water or groundwater monitoring resulted in a decision that further monitoring was needed or no additional monitoring was needed, and why.
f. Any corrective action or additional monitoring installed at each site after initial monitoring results demonstrated constituents above the regulatory threshold in place at the time in the groundwater or surface water.
g. The risks of liability and the risks of exceedances of environmental requirements for groundwater and surface water at any CCR disposal sites.

Response:

After a thorough search for responsive information, all responsive documents for a.-g. have been provided in previous discovery responses. Cathy Taylor and Judson White are no longer Company employees. However, any records retained by those individuals would have been included in the files searched to respond to previous discovery requests. Likewise, Mr. Williams' files were included in the prior searches to produce those records previously provided.

Cncorrd 6/24/91

COMMONWEALTH of VIRGINIA

STATE WATER CONTROL BOARD
2111 Hamilton Street

Richard N. Burton
Executive Director

Post Office Box 11143
Richmond, Virginia 23230-1143
(804) 367-0056

STATE WATER CONTROL BOARD ENFORCEMENT ACTION

A SPECIAL ORDER

ISSUED TO

Virginia Power, Possum Point Station 9/12/89

This Special Order (hereinafter referred to as the "Order") is hereby issued by the State Water Control Board (hereinafter referred to as the "Board"), under the authority of Section 62.1-44.15(8a) of the Code of Virginia of 1950, as amended, (hereinafter referred to as the "Code"), to the Virginia Electric and Power Company (hereinafter referred to as "Virginia Power").

Virginia Power owns and operates an industrial wastewater treatment facility (hereinafter referred to as the "Facility"), which serves the Possum Point Power Station, and which is located in Dumfries, Virginia. The Facility discharges wastewater to State waters at Quantico Creek and the Potomac River Basin. Discharge of wastewater from the Facility is the subject of VPDES permit No. VA0002071 (hereinafter the "Permit"), which became effective April 26, 1985, and which will expire April 26, 1990.

Under a prior special order, effective April 14, 1987, Virginia Power was required to study groundwater contamination in the area of its two fly ash disposal ponds, D & E (hereinafter referred to as the "Site") at the Possum Point Power Station. The results of the study indicate that groundwater monitoring and remediation is required at the Site. Accordingly, the Board orders Virginia Power and Virginia Power agrees to implement the groundwater remediation and monitoring plan contained in Appendix A hereto and incorporated herein by reference.

Virginia Power waives its rights to service of, a hearing on, written findings of fact and conclusions of law in support of, and judicial review of this Order. Virginia Power agrees that the Board may cancel this Order, in its sole discretion, upon thirty days written notice, and that otherwise, the Order may be modified only with Virginia Power's consent or after due notice and opportunity for hearing.

This Order shall become effective upon the date of its execution by the Board's Executive Director or his designee.

And it is SO ORDERED this 12 day of Sept, 1989.

State Water Control Board

Richard N. Burton
Executive Director

The terms and conditions of this Order are hereby voluntarily agreed to by the Virginia Electric and Power Company:

Virginia Electric and Power Company

By:

VP-F&H (Title)

Date: 6/6/89

State of Virginia
~~City~~/County of Henrico

The foregoing Order was executed before me this 6th day of June, 1989, by E. Wayne Harrell, V.P. - Fossil & Hydro of Virginia Electric and Power Company, on behalf of said company.

Notary Public

My Commission Expires: February 1, 1992

APPENDIX A

GROUNDWATER REMEDIATION AND MONITORING PLAN

In order to address potential and existing groundwater contamination at the Site, Virginia Power shall:

1. Remediate the Site in accordance with the Final Conceptual Design Report for Dry Waste Disposal Site and Metals Pond Rehabilitation and Corrective Action Plan (hereinafter the "Corrective Action Plan"), prepared by GAI Consultants, Inc., dated November, 1988, and previously submitted to the Board, and shall additionally:

    a. Submit to the Board's Northern Regional Office, on or before forty-five (45) days after the effective date of this Order, a water balance, affirming that the capacity of the metals pond and Pond E is adequate for treatment and/or neutralization of all incoming flow;

    b. Submit to the Board's Northern Regional Office by December 19, 1989, the recommendation of consulting engineers concerning the treatment of any leachate collected from the dry waste disposal site. The method of leachate treatment selected should ensure that proper pH levels can be maintained in said leachate;

    c. Submit an amended Construction Schedule with reference dates to the Board's Northern Regional Office within sixty (60) days of the effective date of this Order. Both the Board and Virginia Power recognize that construction schedule dates are predicated upon timely receipt of appropriate permits and approvals from Prince William County, the Virginia Department of Waste Management and the Board, and may require additional amendment. Upon commencement of construction, quarterly progress reports on the status of construction shall be submitted to the Board's Northern Regional Office, during the first year of construction.

2. Submit results of quarterly sampling of monitoring wells PP-1, 3B, ED-18, ED-21, ED-22, ED-23, and ED-24 to the Board's Northern Regional Office in accordance with the existing VPDES permit schedule.

Both the Board and Virginia Power agree that should trends indicative of an increase in pollutants be identified by the above referenced Corrective Action Plan, the Corrective Action Plan shall be re-evaluated by the Board and that new or additional remediation measures may be required by the Board. Plans and schedules for construction of any such remediation measures must be submitted to the Board within forty-five (45) days after completion of such re-evaluation.

I/A

Public Staff - Lucas Exhibit 5
Docket No. E-22, Sub 562

Station	Unit Name	Operating Years	Total Volume (CuYd)	Closure Method	Closure Timeframe	Regulatory Driver
Bremo	East Pond	1930s-1980s	327,323***	Removal	2019	CCR Rule/SB 1355
Bremo	North Pond	1983-2014	6,200,000****	Removal	2034	CCR Rule/SB 1355
Bremo	West Pond	1970s-2014	1,577,205***	Removal	2019	CCR Rule/SB 1355
CEC	Bottom Ash Pond	1985-2014	60,000	Removal	2034	CCR Rule/SB 1355
CEC	Historic Pond	1950s-1980s	1,150,000	Removal	2034	CCR Rule/SB 1355
CEC	Landfill	1985-2014	975,000	Removal	2034	CCR Rule/SB 1355
Chesterfield	Lower Ash Pond	1964-2017	3,600,000	Removal	2034	CCR Rule/SB 1355
Chesterfield	Reymet Rd Landfill	2017-Present	100,000	Closure in Place	TBD	CCR Rule/VSWMR
Chesterfield	Upper Ash Pond	1985-2017	11,300,000	Removal	2034	CCR Rule/SB 1355
Clover	FGD Basins	1995-Present	Deminimus*****	Removal	TBD	CCR Rule/VSWMR
Clover	Landfill	1995-Present	6,369,200	Closure in Place	TBD	CCR Rule/VSWMR
Mt. Storm	Low Volume Ponds	2016-Present	Deminimus	Removal	TBD	CCR Rule
Mt. Storm	Phase A&B Landfill	1986-Present	19,305,000	Closure in Place	TBD	CCR Rule
Possum Point	Pond D	1960s -1971; 1986-2003	4,000,000**	Removal	2034	CCR Rule/SB 1355
Possum Point	Pond E	1968-2003	1,329,463*	Removal	2019	CCR Rule/SB 1355
Possum Point	Ponds A, B, C	1955-1967	358,250*	Removal	2019	CCR Rule/SB 1355
VCHEC	Landfill	2012-Present	7,435,929	Closure in Place	TBD	CCR Rule/VSWMR
Yorktown	Landfill	1985-Present	1,500,000	Closure in Place	2019	CCR Rule/VSWMR

* Ash originally disposed of in this impoundment has now been consolidated into Pond D.

** Includes the ash now removed from Ponds ABC and E and consolidated into D.

*** Ash originally disposed of in this impoundment has now been consolidated into the North Pond.

****Includes the ash now removed from the East and West Ponds and consolidated into the North Pond.

*****FGD solid are routinely removed from the FGD sludge pond and taken to the Stage III landfill for disposal. Liquids are recicrualted.

Note: All volumes above are estimates based on available design information combined with survey results. Dates of operation are also estimates and based on available records and communication with station personnel.

I/A

Public Staff - Lucas Exhibit 6
Docket No. E-22, Sub 562

Attachment Public Staff Set 162-1

	Retired Unit
	Active Unit
N/A	Equipment Installed. Year of Installation Not Available.
X	In use.

Station	Bremo		Chesapeake				Chesterfield						Clover		Mount Storm			NB	Possum Point		Yorktown		VCHEC	Mecklenburg	
Unit	Bremo 1 (Retired 1972)	Bremo 2 (Retired 1972)	Chesapeake 1 (Retired 2014)	Chesapeake 2 (Retired 2014)	Chesapeake 3 (Retired 2014)	Chesapeake 4 (Retired 2014)	Chesterfield 1 (Retired 1990)	Chesterfield 2 (Retired 1990)	Chesterfield 3 (Retired 2019)	Chesterfield 4 (Retired 2019)	Chesterfield 5	Chesterfield 6	Clover 1	Clover 2	Mount Storm 1	Mount Storm 2	Mount Storm 3	North Branch (Retired 2010)	Possum Point 1 (Retired 1991)	Possum Point 2 (Retired 1992)	Yorktown 1 (Retired 2019)	Yorktown 2 (Retired 2019)	VCHEC	Mecklenburg 1 (Retired 2019)	Mecklenburg 2 (Retired 2019)
Fuel	Coal	Coal	Coal	Coal	Coal	Coal	Coal	Coal	Coal	Coal	Coal	Coal	Coal	Coal	Coal	Coal	Coal	Coal	Coal	Coal	Coal	Coal	Coal	Coal	Coal
Environmental Control																									
SCR					2003	2003				2003	2002	2004			2003	2003	2004								
SNCR													1995	1996											
Circulating Fluidized Bed Boiler																							2012		
ROFA			N/A	N/A																	N/A	N/A			
Low NOx Burners					N/A						N/A	N/A	1995	1996	1964	1966	1973				N/A	N/A			
OFA											N/A	N/A	1995	1996	1964	1966	1973								
Dry Scrubber																		N/A						1992	1992
Wet Scrubber									2011	2011	2011	2008	1995	1996	2002	2002	1994								
Precipitator			1987	1987	1987	1987			1982	1982	1980				1972	1972	1972				N/A	N/A	2012		
Baghouse												2008	1995	1996				N/A					2012	1992	1992
Mech. Dust Collector																					N/A	N/A			
Dry Fly Ash											2018	2018													
Dry Bottom Ash											2018	2018													
Carbon Injection																							2012		
Permited Dry Landfill											X	X	X	X	X	X	X						X		
Wastewater Treatment FGD											2008	2008													
Wastewater Low Volume											2017	2017													
Wastewater Manganese Removal													2013	2013											

its sole discretion upon thirty days written notice; otherwise the Order may be modified only with Virginia Power's agreement or after due notice and opportunity for a hearing. By voluntarily agreeing to issuance of this Order, Virginia Power does not admit any violation of any law, regulation, or permit limitation, term or condition.

This Order shall become effective upon the date of its execution by the Executive Director of the Board or his designee.

This Order shall terminate and have no further effect when Virginia Power has completed the actions required by this Order.

And it is, SO ORDERED this 14 day of April 1987.

DATE: 04/14/87 BY: ____________________
Executive Director

The terms and conditions of this Order are accepted by Virginia Power.

VIRGINIA POWER

DATE: 03/06/87 BY: ____________________

VP
Title

APPENDIX A

The Board orders and Virginia Power agrees to conduct the following study to define the nature and extent of groundwater contamination in the vicinity of Ash Ponds D and E at its Possum Point Power Station and to evaluate the alternatives to comply with the Board's groundwater standards/antidegradation policy.

1. On or before April 15, 1987, Virginia Power will perform a resistivity or electromagnetic conductivity study to determine if a definable subsurface plume of increased dissolved solids is present. A pilot traverse will be performed first to determine whether the degree of resistivity contrast between contaminated and uncontaminated groundwater is sufficient for reliable plume definition. If a plume can be defined, the survey will be conducted around both Ash Ponds D and E.

2. On or before May 15, 1987, the results of the study performed in #1 above shall be submitted to the State Water Control Board for Executive Director approval. If the staff does not agree that this Study has defined the plume of contamination, then Virginia Power must submit a plan within 2 weeks of the disapproval which delineates additional monitoring wells. This plan and the location of the wells is also subject to the Executive Director's approval.

3. Through October 15, 1987, Virginia Power will continue to collect monthly groundwater quality data from the existing and subsequent (see #2 above) ash pond monitoring wells.

4. On or before July 15, 1988, Virginia Power will prepare and submit a report which will:

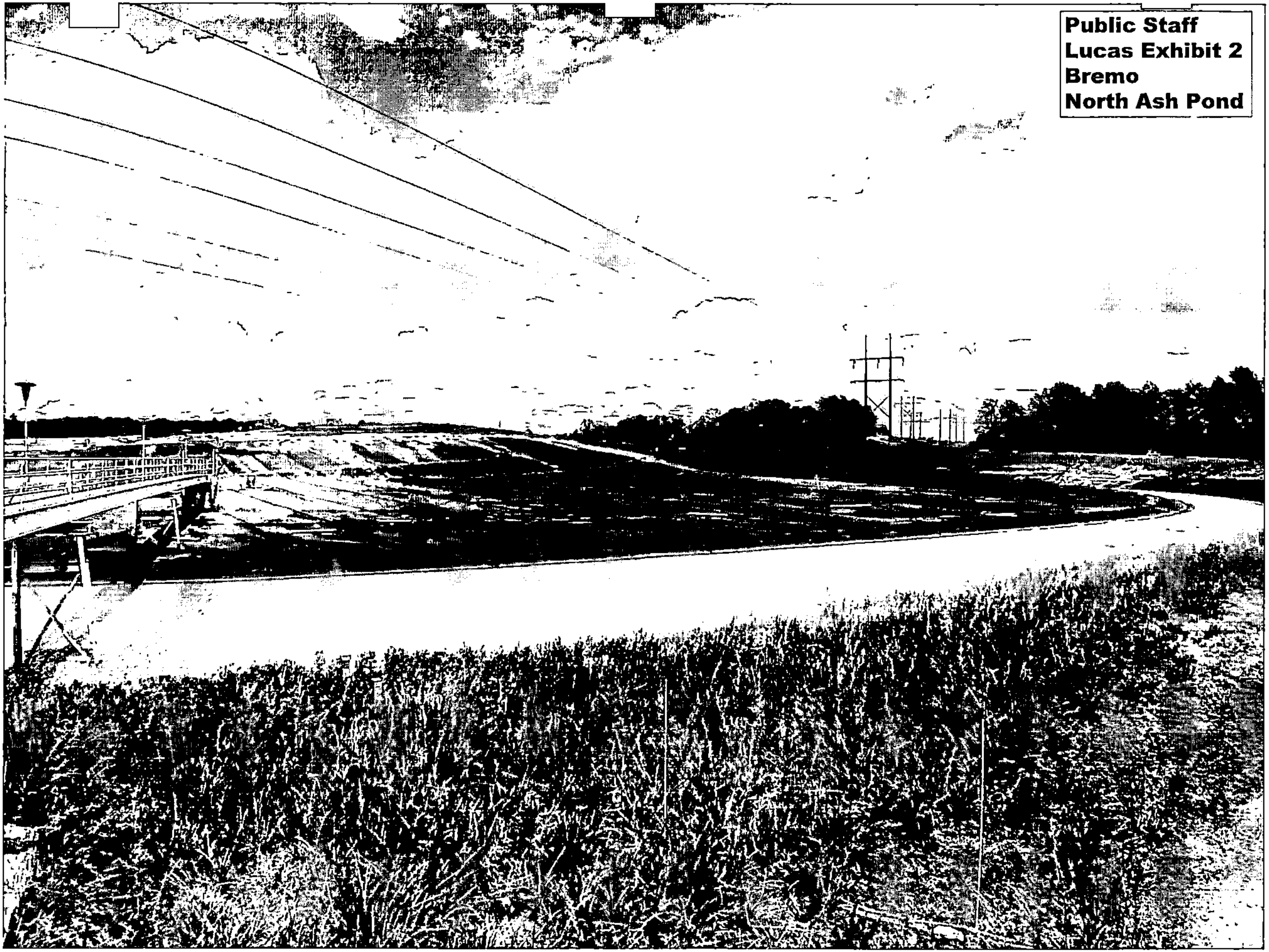
    a. describe the results of the study;

    b. provide an evaluation of existing data;

    c. define the extent and nature of the groundwater contamination; and

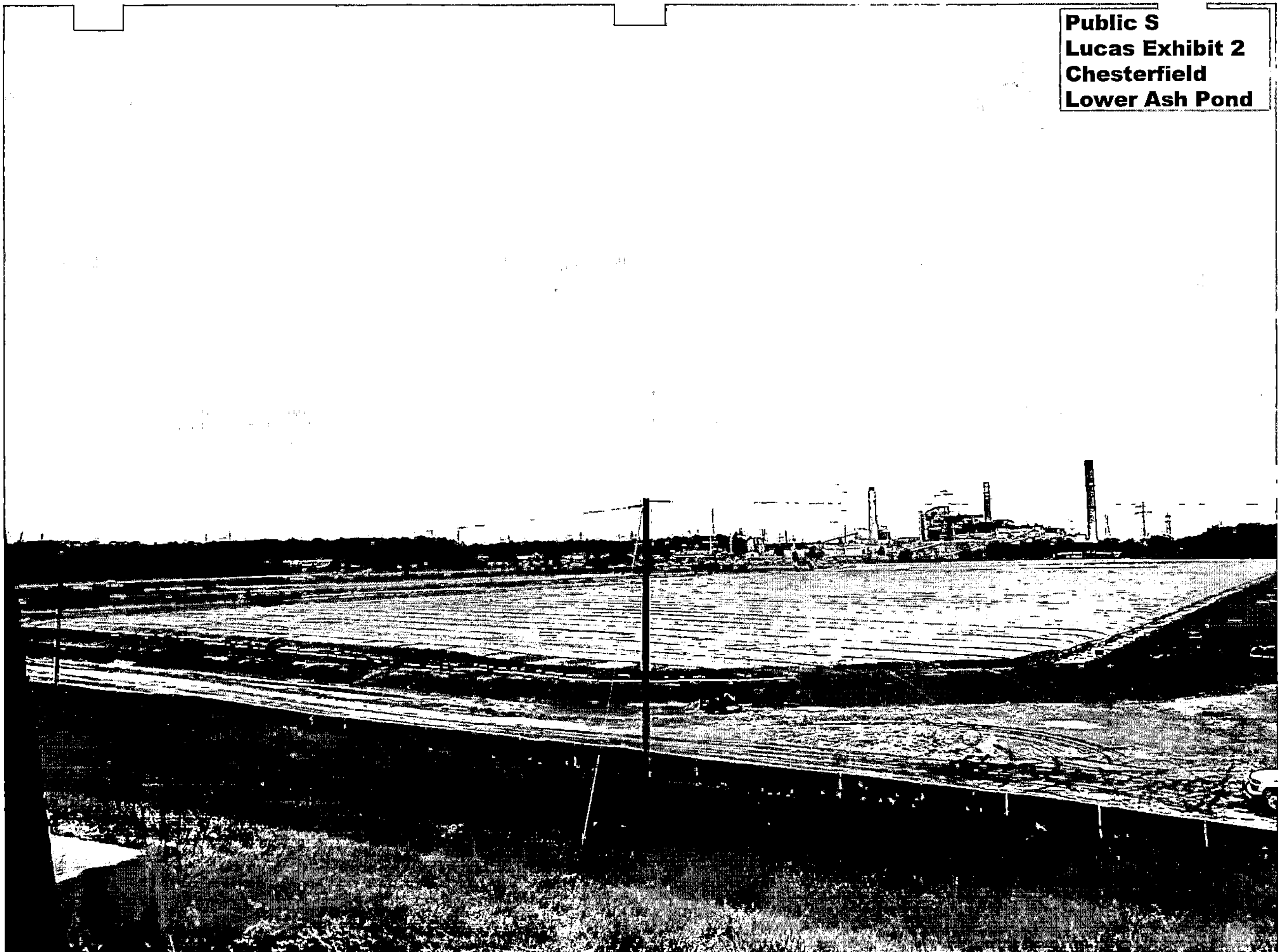
    d. evaluate the alternatives for remediation, including cost and a schedule, for complying with the Board's groundwater standards/antidegradation policy.

Public Staff
Lucas Exhibit 2
Bremo
West Ash Pond


Public Staff
Lucas Exhibit 2
Bremo
North Ash Pond

Public Staff
Lucas Exhibit 2
Chesterfield
Upper Ash Pond

Public S
Lucas Exhibit 2
Chesterfield
Lower Ash Pond




Public ff
Lucas Exhibit 2
Possum Point
Ponds ABC

Public Staff
Lucas Exhibit 2
Possum Point
Pond E

Public Staff
Lucas Exhibit 2
Possum Point
Pond D

I/A

Public Staff - Lucas Exhibit 1
Docket No. E-22, Sub 562

Summary of Groundwater Wells and Dates of First Sampling

Station	Unit	First GW Sampling Date	Number of Monitoring Wells Per Unit and Monitoring Program															
			2000				2010				2013				2014			
			NPDES	CUP	Solid Waste	CCR	NPDES	CUP	Solid Waste	CCR	NPDES	CUP	Solid Waste	CCR	NPDES	CUP	Solid Waste	CCR
Bremo Power Station	NAP	5/10/2000	2	–	–	–	2	–	–	–	4	–	–	–	4	–	–	–
	WAP	3/11/2013	–	–	–	–	–	–	–	–	4	–	–	–	4	–	–	–
	EAP	3/11/2013	–	–	–	–	–	–	–	–	4	–	–	–	4	–	–	–
Chesapeake Energy Center	Landfill	12/20/1983	–	–	10	–	–	–	12	–	–	–	23	–	–	–	23	–
	BAP (w/ Historic Pond)	6/4/2018	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–
Chesterfield Power Station	FFCPMF	8/6/2015	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–
	LAP	1/22/1986	4	–	–	–	4	–	–	–	4	–	–	–	4	–	–	–
	UAP	11/20/1985	7	–	–	–	10	–	–	–	10	–	–	–	10	–	–	–
Clover Power Station	Stage I&II LF	12/21/1993	–	–	9	–	–	–	8	–	–	–	8	–	–	–	8	–
	Stage III LF	3/15/2000	–	–	9	–	–	–	8	–	–	–	8	–	–	–	8	–
	Sludge Basins	3/23/1994	4	–	–	–	4	–	–	–	4	–	–	–	4	–	–	–
Mt. Storm Power Station	Phase A LF	9/2/1987	7	–	–	–	9	–	–	–	9	–	–	–	9	–	–	–
	Phase B LF	9/2/1987	6	–	–	–	8	–	–	–	8	–	–	–	8	–	–	–
	LVWSP	11/3/2015	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–
Possum Point Power Station	Ponds ABC	11/4/2016	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–
	Pond D	12/31/1985	14	–	–	–	12	–	–	–	12	–	–	–	12	–	–	–
	Pond E	12/5/1990	3	–	–	–	3	–	–	–	3	–	–	–	3	–	–	–
VCHEC	Landfill	6/3/2010	–	–	–	–	–	–	8	–	–	–	8	–	–	–	8	–
Yorktown Power	Landfill	12/5/1985	–	25	11	–	–	21	11		–	21	11	–	–	21	11	–
		SUBTOTAL	47	25	59	0	52	21	47	0	62	21	58	0	62	21	58	0
		TOTAL	111				120				141				141			

Station	Unit	Number of Monitoring Wells Per Unit and Monitoring Program															
		2015				2016				2017				2018			
		NPDES	CUP	Solid Waste	CCR	NPDES	CUP	Solid Waste	CCR	NPDES	CUP	Solid Waste	CCR	NPDES	CUP	Solid Waste	CCR
Bremo Power Station	NAP	4	–	–	–	4	–	–	8	4	–	–	8	4	–	–	8
	WAP	4	–	–	–	4	–	–	–	4	–	–	5	4	–	–	5
	EAP	7	–	–	–	4	–	–	–	4	–	–	9	4	–	–	9
Chesapeake Energy Center	Landfill	–	–	23	–	–	–	23	–	–	–	23	–	–	–	23	–
	BAP (w/ Historic Pond)	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	27
Chesterfield Power Station	FFCPMF	–	–	10	10	–	–	10	10	–	–	10	10	–	–	10	10
	LAP	4	–	–	–	4	–	–	–	4	–	–	16	4	–	–	16
	UAP	10	–	–	–	10	–	–	27	10	–	–	27	10	–	–	27
Clover Power Station	Stage I&II LF	–	–	8	–	–	–	8	–	–	–	8	–	–	–	8	–
	Stage III LF	–	–	8	–	–	–	8	8	–	–	8	8	–	–	8	8
	Sludge Basins	4	–	–	6	4	–	–	6	4	–	6	6	4	–	6	6
Mt. Storm Power Station	Phase A LF	9	–	–	–	9	–	–	6	9	–	–	6	9	–	–	6
	Phase B LF	8	–	–	–	8	–	–	8	8	–	–	8	8	–	–	8
	LVWSP	–	–	–	7	–	–	–	7	–	–	–	7	–	–	–	7
Possum Point Power Station	Ponds ABC	–	–	–	–	–	–	–	4	–	–	–	4	–	–	–	4
	Pond D	12	–	–	–	12	–	–	6	12	–	–	6	12	–	–	6
	Pond E	3	–	–	–	4	–	–	5	3	–	–	5	3	–	–	5
VCHEC	Landfill	–	–	8	–	–	–	8	7	–	–	8	7	–	–	8	7
Yorktown Power	Landfill	–	21	11	–	–	21	11	11	–	21	11	11	–	21	11	11
	SUBTOTAL	65	21	68	23	63	21	68	119	62	21	74	143	62	21	74	170
	TOTAL	177				265				300				327			

Greyed The Public Staff totaled the monitoring wells by program and year, in the greyed fields, as provided by the Company in response to DR 3-10.

DOMININON ENERGY NORTH CAROLINA
Docket No. E-22, Sub 562
North Carolina Retail Operations
REVENUE IMPACT OF SETTLED AND UNRESOLVED ADJUSTMENTS
AT 8.75% ROE
For the Test Year Ended December 31, 2018
(in Thousands)

8.75% ROE
Schedule 1

DATA RESPONSE TO AGO - ROE of 8.75%
NOT PUBLIC STAFF RECOMMENDATION

Line No.	Item	Revenue Requirement (a)
1	Non-fuel revenue requirement increase per Company application	$ 26,958
2	Revenue impact of Company update in first supplemental filing	(2,079)
3	**Non-fuel revenue requirement increase per Company after updates**	**24,879**
4	Revenue impact of adjustments:	
5	**Settled Issues (To the extent there is an ROE impact, not settled at that amount):**	
6	Change in equity ratio from 53.65% to 52.00% equity	(1,903)
7	Change in debt cost rate from 4.442% to 4.442%	-
8	Change in return on equity from 10.75% to 8.75%	(16,126)
9	Change in retention factor - uncollectibles	(17)
10	Adjust uncollectibles	(238)
11	Adjust allocation of state accumulated deferred income taxes	-
12	Remove Mt Storm Impairment costs	(470)
13	Adjust NUG Contract Termination Expense - Regulatory Asset	(33)
14	Adjust outside services	(177)
15	Eliminate certain ADIT balances	-
16	Remove Skiffes Creek mitigation costs	(144)
17	Remove executive compensation costs	(92)
18	Remove Chesterfield Units 3 & 4 wet-to-dry conversion costs	-
19	Adjustment to remove federal unprotected EDIT treatment as a rider	(264)
20	Adjust lobbying expense	(42)
21	Adjust storm costs	(81)
22	Remove employee severance program costs	(304)
23	Remove advertising costs	(12)
24	Adjust annual incentive plan costs	(358)
25	Adjust employee VRP Backfill costs	-
26	Adjust expenses for customer growth, usage, and weather normalization	(90)
27	Adjust variable non-fuel O&M expenses for displacement	(142)
28	Adjust inflation adjustment	(9)
29	Adjust uncollectibles for decrease in base fuel rate	(7)
30	Adjust cash working capital under present rates	(76)
31	Adjust cash working capital under proposed rates	(413)
32	Adjustment to reflect kWh change in revenue annualization	49
33	Adjustment for New Office Building	(720)
34	Rounding	(2)
35	**Total Settled Issues**	**(21,671)**
36	**Unsettled Issues:**	
37	Adjust coal combustion residual (CCR) costs	(7,081)
38	Adjust cash working capital for CCR adjustment	(68)
39	**Total Unsettled Issues**	**(7,149)**
40	**Decrease in non-fuel revenue requirement**	**$ (3,941)**
41	**Decrease in base fuel revenue requirement**	**$ (2,155)**
42	Annual EDIT Rider for 2 year period	**$ 647**

Attorney General's Office - __________ Cross Exhibit ___

CUSTOMER IMPACT OF 8.75% ROE

	ROE	Annual Revenue	
Revenue Impact of Settled Adjustments	9.75% ROE	$ (13,517,000)	Note 1
Same Settled adjustments except ROE	8.75% ROE	$ (21,671,000)	Note 2
Difference		$ 8,154,000	

Note 1: See Johnson Settlement Exhibit 1 Schedule 1 Line 35
Note 2: See AGO 8.75% ROE Line 35

DOMININON ENERGY NORTH CAROLINA
Docket No. E-22, Sub 562
North Carolina Retail Operations
REVENUE IMPACT OF SETTLED AND UNRESOLVED ADJUSTMENTS
AT 9.00% ROE
For the Test Year Ended December 31, 2018
(in Thousands)

9.00% ROE
Schedule 1

DATA RESPONSE TO AGO - ROE of 9.00%
NOT PUBLIC STAFF RECOMMENDATION

Line No.	Item	Revenue Requirement (a)
1	Non-fuel revenue requirement increase per Company application	$ 26,958
2	Revenue impact of Company update in first supplemental filing	(2,079)
3	**Non-fuel revenue requirement increase per Company after updates**	**24,879**
4	Revenue impact of adjustments:	
5	**Settled Issues (To the extent there is an ROE impact, not settled at that amount):**	
6	Change in equity ratio from 53.65% to 52.00% equity	(1,903)
7	Change in debt cost rate from 4.442% to 4.442%	-
8	Change in return on equity from 10.75% to 9.00%	(14,111)
9	Change in retention factor - uncollectibles	(17)
10	Adjust uncollectibles	(238)
11	Adjust allocation of state accumulated deferred income taxes	-
12	Remove Mt Storm Impairment costs	(470)
13	Adjust NUG Contract Termination Expense - Regulatory Asset	(34)
14	Adjust outside services	(177)
15	Eliminate certain ADIT balances	-
16	Remove Skiffes Creek mitigation costs	(146)
17	Remove executive compensation costs	(92)
18	Remove Chesterfield Units 3 & 4 wet-to-dry conversion costs	-
19	Adjustment to remove federal unprotected EDIT treatment as a rider	(270)
20	Adjust lobbying expense	(42)
21	Adjust storm costs	(81)
22	Remove employee severance program costs	(304)
23	Remove advertising costs	(12)
24	Adjust annual incentive plan costs	(358)
25	Adjust employee VRP Backfill costs	-
26	Adjust expenses for customer growth, usage, and weather normalization	(90)
27	Adjust variable non-fuel O&M expenses for displacement	(142)
28	Adjust inflation adjustment	(9)
29	Adjust uncollectibles for decrease in base fuel rate	(7)
30	Adjust cash working capital under present rates	(78)
31	Adjust cash working capital under proposed rates	(382)
32	Adjustment to reflect kWh change in revenue annualization	49
33	Adjustment for New Office Building	(720)
34	Rounding	-
35	**Total Settled Issues**	**(19,634)**
36	**Unsettled Issues:**	
37	Adjust coal combustion residual (CCR) costs	(7,100)
38	Adjust cash working capital for CCR adjustment	(69)
39	**Total Unsettled Issues**	**(7,169)**
40	**Decrease in non-fuel revenue requirement**	**$ (1,924)**
41	**Decrease in base fuel revenue requirement**	**$ (2,155)**
42	**Annual EDIT Rider for 2 year period**	**$ 647**

Attorney General's Office - __________ Cross Exhibit ___

CUSTOMER IMPACT OF 9.0% ROE

	ROE	Annual Revenue	
Revenue Impact of Settled Adjustments	9.75% ROE	$ (13,517,000)	Note 1
Same Settled adjustments except ROE	9.0% ROE	$ (19,634,000)	Note 2
Difference		$ 6,117,000	

Note 1: See Johnson Settlement Exhibit 1 Schedule 1 Line 35

Note 2: See AGO 9.0% ROE Line 35

DOMINION ENERGY NORTH CAROLINA
Docket No. E-22, Sub 562
CALCULATION OF LEVELIZED FEDERAL
UNPROTECTED EDIT RIDER CREDIT
For the Test Year Ended December 31, 2018

Johnson Settlement Exhibit II
Schedule 2

I/A

Line No.	Item	Year 1 Revenue Requirement (a)	Year 2 Revenue Requirement (b)	Total Revenue Requirement (c)
	Annuity Factor			
1	Number of years	2 1/		
2	Payment per period	1		
3	After tax rate of return	6.654% 2/		
4	Present value of 1 dollar over number of years with			
5	with 1 payment per year	1.8167		
6	1 plus (interest rate divided by two)	1.0333		
7	Annuity factor (L4 x L5)	1.8772		
8	Total NC retail regulatory liability to be amortized	($1,214,000) 3/	($1,214,000) 3/	
9	Annuity factor (L7)	1.8772	1.8772	
10	Levelized rider federal EDIT regulatory liability (L8 / L9)	(646,708)	(646,708)	(1,293,416) 6/
11	One minus composite income tax rate	74.377% 4/	74.377% 4/	74.377% 4/
12	Net operating income effect (L10 x L11)	(481,003)	(481,003)	(962,007)
13	Retention factor	0.740365 5/	0.740365 5/	0.740365 5/
14	Levelized rider federal EDIT credit (L5 / L6)	($649,684)	($649,684)	($1,299,369)

1/ Rider period per Settlement Agreement.
2/ Johnson Settlement Exhibit II, Schedule 2(a), Line 3.
3/ Company Supplemental Exhibit PMM-2, Schedule 1, page 3, lines 86 plus 87, plus one year EDIT Rideer amount originally proposed by the Company.
4/ One minus the composite income tax rate of 25.6228%.
5/ Johnson Settlement Exhibit 1, Schedule 1-2, Column (d), Line 14.
6/ Sum of Columns (a) through Column (e).

DOMINION ENERGY NORTH CAROLINA
Docket No. E-22, Sub 562
CALCULATION OF ANNUITY FACTOR FOR EDIT LIABILITY RIDER
For the Test Year Ended December 31, 2018

Johnson Settlement Exhibit II
Schedule 2(a)

Line No.	Item	Amount	
	Annuity Factor		
1	Number of years	2	1/
2	Payment per period	1	
3	After tax rate of return (L9)	6.654%	
4	Present value of 1 dollar over number of years with with 1 payment per year	1.8167	
5	1 plus (interest rate divided by two)	1.0333	
6	Annuity factor (L4 x L5)	1.8771	

Line No.		Capital Structure (a)		Cost Rates (b)		Overall Rate of Return (c)		Net of Tax Rate (d)	
	After Tax Rate of Return						6/		
7	Long-term debt	48.00%	2/	4.442%	4/	2.13%		1.58%	7/
8	Common equity	52.00%	3/	9.75%	5/	5.07%		5.070%	8/
9	Total	100.00%				7.20%		6.654%	

1/ Rider period per Settlement Agreement.
2/ Johnson Settlement Exhibit 1, Schedule 1-2, Column (a), Line 2.
3/ Johnson Settlement Exhibit 1, Schedule 1-2, Column (a), Line 3.
4/ Johnson Settlement Exhibit 1, Schedule 1-2, Column (b), Line 2.
5/ Johnson Settlement Exhibit 1, Schedule 1-2, Column (b), Line 3.
6/ Column (a) times Column (b).
7/ Column (c) times 1 minus the composite income tax rate of 25.6228%.
8/ Amount from Column (c).

I / A

DOMININON ENERGY NORTH CAROLINA
Docket No. E-22, Sub 562
North Carolina Retail Operations
REVENUE IMPACT OF SETTLED AND UNRESOLVED ADJUSTMENTS
For the Test Year Ended December 31, 2018
(In Thousands)

Johnson Settlement Exhibit 1
Schedule 1

Line No.	Item	Per Public Staff (a)		Per Company (b)		Difference 9/ (c)
1	Non-fuel revenue requirement increase per Company application	$ 26,958	1/	$ 26,958		$ -
2	Revenue impact of Company update in first supplemental filing	(2,079)	2/	(2,079)		-
3	**Non-fuel revenue requirement increase per Company after updates**	24,879		24,879		$ -
4	Revenue impact of Public Staff adjustments: 3/					
5	**Settled Issues:**					
6	Change in equity ratio from 53.65% to 52.00% equity	(1,903)		(1,903)		-
7	Change in debt cost rate from 4.442% to 4.442%	-		-		-
8	Change in return on equity from 10.75% to 9.75%	(8,064)		(8,064)		-
9	Change in retention factor - uncollectibles	(17)		(17)		-
10	Adjust uncollectibles	(238)		(238)		-
11	Adjust allocation of state accumulated deferred income taxes	-		-		-
12	Remove Mt Storm Impairment costs	(470)		(470)		-
13	Adjust NUG Contract Termination Expense - Regulatory Asset	(36)		(36)		-
14	Adjust outside services	(177)		(177)		-
15	Eliminate certain ADIT balances	-		-		-
16	Remove Skiffes Creek mitigation costs	(153)		(153)		-
17	Remove executive compensation costs	(92)		(92)		-
18	Remove Chesterfield Units 3 & 4 wet-to-dry conversion costs	-		-		-
19	Adjustment to remove federal unprotected EDIT treatment as a rider	(287)		(287)		-
20	Adjust lobbying expense	(42)		(42)		-
21	Adjust storm costs	(81)		(81)		-
22	Remove employee severance program costs	(304)		(304)		-
23	Remove advertising costs	(12)		(12)		-
24	Adjust annual incentive plan costs	(358)		(358)		-
25	Adjust employee VRP Backfill costs	-		-		-
26	Adjust expenses for customer growth, usage, and weather normalization	(90)		(90)		-
27	Adjust variable non-fuel O&M expenses for displacement	(142)		(142)		-
28	Adjust inflation adjustment	(9)		(9)		-
29	Adjust uncollectibles for decrease in base fuel rate	(7)		(7)		-
30	Adjust cash working capital under present rates	(83)	8/	(83)	8/	-
31	Adjust cash working capital under proposed rates	(282)	8/	(282)	8/	-
32	Adjustment to reflect kWh change in revenue annualization	49		49		-
33	Adjustment for New Office Building	(720)		(720)		-
34	Rounding	1		1		-
35	**Total Settled Issues**	(13,517)		(13,517)		-
36	**Unsettled Issues:**					
37	Adjust coal combustion residual (CCR) costs	(7,096)	7/	(2,750)	7/	(4,346)
38	Adjust cash working capital for CCR adjustment	(74)	8/	(29)	8/	(45)
39	**Total Unsettled Issues**	(7,170)		(2,779)		(4,391)
40	**Recommended increase in non-fuel revenue requirement**	$ 4,192	4/	$ 8,583		$ (4,391)
41	**Public Staff recommended decrease in base fuel revenue requirement**	$ (2,155)	5/	$ (2,155)		$ -
42	**Annual EDIT Rider recommended by Public Staff for 5 year period**	$ 649	6/	$ 649		$ -

1/ Company Exhibit PMM-1, Page 1, Line 6, Column (6).
2/ Company Supplemental Exhibit PMM-1, Page 10.
3/ Calculated based on Johnson Settlement Exhibit 1, Schedules 2, 3, 4, 5, and backup schedules.
4/ Johnson Settlement Exhibit 1, Schedule 5, Line 7.
5/ Johnson Settlement Exhibit 1, Schedule 5, Line 6.
6/ Johnson Settlement Exhibit 2, Schedule 1, Line 14.
7/ DENC and the Public Staff have agreed on a small portion of this issue involving compounding of financing costs.
8/ Calculated based on including and excluding Public Staff and Company CCR adjustments in spreadsheet calculation.
9/ Column (a) - Column (b).

DOMININON ENERGY NORTH CAROLINA
Docket No. E-22, Sub 562
North Carolina Retail Operations
SUPPORT FOR RECONCILIATION SCHEDULE
For the Test Year Ended December 31, 2018
(In Thousands)

Johnson Settlement Exhibit 1
Schedule 1(a)

Line No.	Item	Rate Base Impact 1/ (a)	Income Statement Impact 2/ (b)	Total Revenue Impact 3/ (c)
1	Remove Mt Storm Impairment costs	$0	($470)	($470)
2	Remove Skiffes Creek mitigation costs	(108)	(45)	(153)
3	Remove Chesterfield Units 3 & 4 wet-to-dry conversion costs	-	-	-
4	Adjust CCR costs	(977)	(6,119)	(7,096)

1/ Johnson Settlement Exhibit 1, Schedule 2-1, Line 11.
2/ Johnson Settlement Exhibit 1, Schedule 3-1, Line 20.
3/ Column (a) plus Column (b).

DOMININON ENERGY NORTH CAROLINA
Docket No. E-22, Sub 562
North Carolina Retail Operations
CALCULATION OF GROSS REVENUE EFFECT FACTORS
For the Test Year Ended December 31, 2018
(In Thousands)

Johnson Settlement Exhibit 1
Schedule 1-2

Line No.	Item		Capital Structure (a)		Cost Rates (b)		Retention Factor (c)		Gross Revenue Effect (d)	
1	Rate Base Factor									
2	Long-term debt		48.000%	1/	4.442%	1/	0.9954193	2/	0.0214217	4/
3	Common equity		52.000%	1/	9.75%	1/	0.7403645	3/	0.0684798	4/
4	Total (Sum of Lines 2 and 3)		100.000%						0.0899015	

Line No.	Item		Amount	
5	Net Income Factor			
6	Total revenue		1.0000000	
7	Uncollectibles		0.0032850	5/
8	Balance (L6 - L7)		0.9967150	
9	Regulatory fee (L8 x 0.130%)	6/	0.0012957	
10	Balance (L8 - L9)		0.9954193	
11	State income tax (L10 x 5.8517%)	7/	0.0582490	
12	Balance (L10 - L11)		0.9371703	
13	Federal income tax (L12 x 21%)	8/	0.1968058	
14	Retention factor (L12 - L13)		0.7403645	

1/ Per Settlement Agreement.
2/ Line 10.
3/ Line 14.
4/ Column (a) times Column (b) divided by Column (c).
5/ Johnson Settlement Exhibit 1, Schedule 3-1(b), Line 5.

DOMININON ENERGY NORTH CAROLINA
Docket No. E-22, Sub 562
North Carolina Retail Operations
CALCULATION OF WEIGHTED
STATE INCOME TAX RATE
For the Test Year Ended December 31, 2018
(In Thousands)

Johnson Settlement Exhibit 1
Schedule 1-3

Line No.	Item	Total System	Virginia	North Carolina	Washington DC	West Virginia
		(a)	(b)	(c)	(d)	(e)
1	Weighted state income tax rate					
2	Apportionment factor		93.5230% 2/	3.6873% 4/	0.0000% 2/	2.2788% 2/
3	State income tax rate		6.00% 2/	2.50% 5/	8.25% 2/	6.50% 2/
4	Weighted state income tax rate	5.8517% 1/	5.61138% 3/	0.09218% 3/	0.00000% 3/	0.14812% 3/
5	Composite income tax rate					
6	Weighted state income tax rate (L4)	5.8517%				
7	Federal income tax rate	21% 6/				
8	Composite income tax rate	25.6228% 7/				

1/ Sum of Columns (b) through (e).
2/ NCUC Form E-1, Item No. 13a6(2)va_new.
3/ Line 1 times Line 2.
4/ NCUC Form E-1, Item No. 10 - Supplemental Filing, Page 286, Line 3.
5/ Based on North Carolina Department of Revenue Notice dated December 2018.
6/ Statutory rate.
7/ 1 minus ((1 minus Line 6) times (1 minus Line 7)).

DOMININON ENERGY NORTH CAROLINA
Docket No. E-22, Sub 562
North Carolina Retail Operations
ORIGINAL COST RATE BASE
For the Test Year Ended December 31, 2018
(In Thousands)

Johnson Settlement Exhibit 1
Schedule 2

Line No.	Item	Under Present Rates: NC Retail Adjusted Per Company 1/ (a)	Public Staff Adjustments 2/ (b)	After Public Staff Adjustments 3/ (c)	After Public Staff Recommended Increase: Rate Increase (d)	After Rate Increase 5/ (e)
1	Electric plant in service	$2,142,169	($1,671)	$2,140,498	$0	$2,140,498
2	Accumulated depreciation and amortization	(777,432)	(352)	(777,784)	-	(777,784)
3	Net electric plant in service (L1 + L2)	1,364,737	(2,024)	1,362,713	-	1,362,713
4	Materials and supplies	40,755	-	40,755	-	40,755
5	Cash working capital	14,451	(547)	13,904	456 4/	14,360
6	Other additions	37,149	(14,607)	22,542	-	22,542
7	Other deductions	(26,130)	-	(26,130)	-	(26,130)
8	Customer deposits	(4,615)	-	(4,615)	-	(4,615)
9	Accumulated deferred income taxes	(278,395)	984	(277,411)	-	(277,411)
10	Total original cost rate base (Sum of L3 thru L9)	$1,147,952	($16,194)	$1,131,758	$456	$1,132,214

1/ Company Supplemental Exhibit PMM-1, Page 2, Column 5.
2/ Johnson Settlement Exhibit 1, Schedule 2-1, Column (h).
3/ Column (a) plus Column (b).
4/ Johnson Settlement Exhibit 1, Schedule 2-1(g), Line 44, Column (k).
5/ Column (c) plus Column (d).

DOMINION ENERGY NORTH CAROLINA
Docket No. E-22, Sub 562
North Carolina Retail Operations
SUMMARY OF PUBLIC STAFF RATE BASE ADJUSTMENTS
For the Test Year Ended December 31, 2018
(In Thousands)

Johnson Settlement Exhibi
Schedule 2-1

Line No.	Item	Adjust ADIT for Certain Balances 1/ (a)	Remove Mt Storm Impairment Costs 2/ (b)	Adjust NUG Contract Terminations Expense 3/ (c)	Remove Skiffes Creek Mitigation Costs (d)	Remove Chesterfield Units 3 & 4 Conversion Costs (e)	Adjustment to Remove Federal Unprotected EDIT	Adjust CCR Costs 10/ (f)	Adjust Cash Working Capital 11/ (g)	Total Rate Base Adjustments 12/ (h)
1	Electric plant in service	$0	$0	$0	$ (1,671) 4/	$ -	$ - 7/	$0	$0	($1,671)
2	Accumulated depreciation and amortization	-	-	(397)	45 5/	-	- 8/	-	-	(352)
3	Net electric plant in service (L1 + L2)	-	-	(397)	(1,627)	-	-	-	-	(2,024)
4	Materials and supplies	-	-	-	-	-	-	-	-	-
5	Cash working capital	-	-	-	-	-	-	-	($547)	(547)
6	Other additions	-	-	-	-	-	-	(14,607) 14/	-	(14,607)
7	Other deductions	-	-	-	-	-	-	-	-	-
8	Customer deposits	-	-	-	-	-	-	-	-	-
9	Accumulated deferred income taxes	-	-	-	428 6/	-	($3,187) 9/	3,743 15/	-	984
10	Total original cost rate base (Sum of L3 thru L9)	$0	$0	($397)	($1,199)	$0	($3,187)	($10,864)	($547)	($16,194)
11	Revenue requirement impact 13/	$0	$0	($36)	($108)	$0	($287)	($977)	($49)	($1,456)

1/ Johnson Settlement Exhibit 1, Schedule 2-1(a), Line .
2/ Johnson Settlement Exhibit 1, Schedule 2-1(c), Column .
3/ Johnson Settlement Exhibit 1, Schedule 2-1(d), Line 11.
4/ Johnson Settlement Exhibit 1, Schedule 2-1(b), Line 3.
5/ Johnson Settlement Exhibit 1, Schedule 2-1(b), Line 5.
6/ Johnson SettlementExhibit 1, Schedule 2-1(b), Line 4.
7/ Johnson Settlement Exhibit 1, Schedule 2-1(e), Line 3.
8/ Johnson Settlement Exhibit 1, Schedule 2-1(e), Line 5.
9/ Johnson Settlement Exhibit 1, Schedule 2-1(h), Line 4.
10/ Per Public Staff witness Maness.
11/ Johnson Settlement Exhibit 1, Schedule 2-1(f), Line 45.
12/ Sum of Column (a) through Column (g).
13/ Line 10 times rate base retention factor of 0.0899015 from Johnson Settlement Exhibit 1, Schedule 1-2.
14/ Maness Supplemental Exhibit I, Schedule 1, Line 14.
15/ Maness Supplemental Exhibit I, Schedule 1, Line 15.

DOMININON ENERGY NORTH CAROLINA
Docket No. E-22, Sub 562
North Carolina Retail Operations
ADJUSTMENT TO ELIMINATE CERTAIN ADIT BALANCES
For the Test Year Ended December 31, 2018
(in Thousands)

Johnson Settlement Exhibit 1
Schedule 2-1(a)

Line No.	Item	Amount
	ADJUSTMENT NO LONGER REQUIRED	

DOMININON ENERGY NORTH CAROLINA
Docket No. E-22, Sub 562
North Carolina Retail Operations
ADJUSTMENT TO REMOVE SKIFFES CREEK MITIGATION COSTS
For the Test Year Ended December 31, 2018
(in Thousands)

Johnson Settlement Exhibit 1
Schedule 2-1(b)

Line No.	Item	Amount	
1	Skiffes Creek Mitigation Costs - System	$ 39,787	1/
2	NC Power Supply Transmission Factor 2	4.2009%	2/
3	Public Staff adjustment to Skiffes Creek mitigation costs from rate base (L3 x L4)	$ (1,671)	
4	Adjustment to ADIT associated with Skiffes Creek	$ 428	3/
5	Accumulated Depreciation associated with Skiffes Creek	$ 45	4/
6	Depreciation expense associated with Skiffes Creek	$ (45)	5/

1/ Per Settlement Agreement.
2/ Factor 2 from NCUC Form E-1, Item No. 45a, Schedule 15, Line 14.
3/ Negative of Line 3 amount times composite income tax rate.
4/ Negative of Line 3 amount per Settlement Agreement.
5/ Per Settlement Agreement.

DOMININON ENERGY NORTH CAROLINA
Docket No. E-22, Sub 562
North Carolina Retail Operations
ADJUSTMENT TO REMOVE IMPAIRMENT COSTS FOR MT STORM
For the Test Year Ended December 31, 2018
(in Thousands)

Johnson Settlement Exhibit 1
Schedule 2-1(c)

Line No.	Item	Amount	
1	Mt Storm Fuel Flexibility Project Impairment - System	$ 62,364	1/
2	Adjustment per Public Staff	(31,182)	2/
3	Revised Mt Storm Impairment Expense (L1 - L2)	31,182	
4	NC Retail Factor 1	4.9507%	
5	NC Retail Regulatory Asset (L3 x L4)	$ 1,544	
6	Amortization Period	2.75	3/
7	Regulatory Asset Amortization per Public Staff (L5/L6)	561	
8	Regulatory Asset Amortization per Company	1,029	1/
9	Public Staff Adjustment to Mt Storm Impairment Expense (L7 - L8)	$ (468)	

1/ Company Adjustment SUPP-5.
2/ Per Settlement Agreement.
3/ Per Settlement Agreement.

DOMININON ENERGY NORTH CAROLINA
Docket No. E-22, Sub 562
North Carolina Retail Operations
ADJUSTMENT TO NUG CONTRACT TERMINATION EXPENSE
REGULATORY ASSET
For the Test Year Ended December 31, 2018
(In Thousands)

Johnson Settlement Exhibit 1
Schedule 2-1(d)

Line No.	Description	Amount (a)	
1	NUG Contract Termination Expense - System	$ 135,000	1/
2	Less: Net Capacity Revenue/Replacement Cost	21,400	2/
3	Revised NUG Contract Termination Expense (L1 - L2)	$ 113,600	
4	NC Retail Factor 1	4.9507%	
5	NUG Contract Termination Expense per Public Staff (L3 x L4)	$ 5,624	
6	Remaining Months in Contract (April 2019 - November 2021)	32	
7	Monthly Amortization	$ 176	
8	Times: Twelve Months	12	
9	Annual Amortization per Public Staff (L7 x L8)	$ 2,109	
10	Annual Amoritzation per Company	2,506	1/
11	Public Staff Adjustment to NUG Contract Termination Expense Reg Asset	$ (397)	

1/ Company Adjustment SUPP-2.
2/ Based on information provided by the Company. (Email 8/15/19)

DOMININON ENERGY NORTH CAROLINA
Docket No. E-22, Sub 562
North Carolina Retail Operations
ADJUSTMENT TO REMOVE COSTS FOR CHESTERFIELD UNITS 3 & 4
For the Test Year Ended December 31, 2018
(in Thousands)

Johnson Settlement Exhibit 1
Schedule 2-1(e)

ADJUSTMENT NO LONGER REQUIRED

DOMININON ENERGY NORTH CAROLINA
Docket No. E-22, Sub 562
North Carolina Retail Operations
CALCULATION OF WORKING CAPITAL FROM
LEAD / LAG STUDY UNDER PRESENT RATES
For the Test Year Ended December 31, 2018
(In Thousands)

Johnson Settlement Exhibi
Schedule 2-1(f)

Line No.	Item	Per Books Amounts 1/ (a)	Company Ratemaking Adjustments 5/ (b)	After Company Adjustments 7/ (c)	Public Staff Adjustments 8/ (d)	After Public Staff Adjustments 9/ (e)	(Lead) / Lag Days 10/ (f)	Working Capital From Lead/ Lag Study 14/ (g)
1	Electric operating revenues:							
2	Rate revenues	$353,978 2/	($5,393) 6/	$348,585	($48)	$348,537	43.36 11/	$41,404
3	Sales for resale revenues	1,126 2/	-	1,126	-	1,126	38.91 11/	120
4	Other operating revenues	5,941 2/	(823) 6/	5,118	-	5,118	25.19 11/	353
5	Electric operating revenues	361,045	(6,216)	354,829	(48)	$354,781	43.08	41,877
6	Account 501 - Fuel	24,682	(3,709)	20,973	(382)	20,591	(33.27) 12/	(1,877)
7	Account 518 - Nuclear Fuel	8,487	(1,275)	7,212	(131)	7,080	(3.21) 12/	(62)
8	Account 547 - Other Fuel	55,934	(8,405)	47,529	(866)	46,664	(33.27) 12/	(4,253)
9	Account 555 - Purchased Power	49,912	(25,884)	24,028	(773)	23,255	(28.21)	(1,797)
10	Account 557 - Deferred Fuel	(27,204)	27,204	-	-	-	- 13/	-
11	Payroll expense	34,032	(2,339)	31,693	(356)	31,337	(26.90) 12/	(2,309)
12	Benefits and pension expense	8,485	(293)	8,192	-	8,191	(31.81) 12/	(714)
13	OPEB expense	(1,721)	-	(1,721)	-	(1,721)	(20.64) 12/	97
14	Uncollectibles expense	1,109	272	1,381	(236)	1,144	(254.79)	(799)
15	Stores expense	9,243	-	9,243	-	9,243	(43.92)	(1,112)
16	Accrued vacation expense	81	-	81	-	81	- 13/	-
17	Worker's compensation expense	73	-	73	-	73	-	-
18	Prepaid insurance amortization expense	412	-	412	-	412	-	-
19	Director's deferred compensation expense	-	-	-	-	-	-	-
20	Miscellaneous prepaid expense	503	-	503	-	503	-	-
21	Other O&M expense	34,997	7,805	42,802	(1,660)	41,142	(43.65) 12/	(4,920)
22	Total O&M expenses	199,025	(6,624)	192,401	(4,404)	187,995		(17,746)
23	Depreciation and amortization expense	60,066 3/	4,521	64,587	(6,602)	57,985	-	-
24	Current state and federal income taxes	(2,846)	723	(2,123)	2,599	476	87.90 12/	115
25	Deferred state and federal income taxes	13,456	138	13,594	-	13,594	-	-
26	Deferred ITC	(74)	-	(74)	-	(74)	-	-
27	Total income taxes	10,536	861	11,397	2,599	13,996		115
28	North Carolina franchise tax	486	-	486	-	486	(523.00)	(696)
29	Property tax expense	10,642	(84)	10,558	-	10,558	(111.96)	(3,239)
30	West Virginia B&O tax expense	1,045	-	1,045	-	1,045	(39.54)	(113)
31	Payroll taxes	2,307	(179)	2,128	-	2,128	(27.26)	(159)
32	Other taxes	102	-	102	-	102	(31.06)	(9)
33	Total taxes other than income	14,582	(263)	14,319	-	14,319		(4,216)
34	Gain / loss on disposition of property	238	(13)	225	-	225	-	-

DOMININON ENERGY NORTH CAROLINA
Docket No. E-22, Sub 562
North Carolina Retail Operations
CALCULATION OF WORKING CAPITAL FROM
LEAD / LAG STUDY UNDER PRESENT RATES
For the Test Year Ended December 31, 2018
(In Thousands)

Johnson Settlement Exhib
Schedule 2-1(f)

Line No.	Item	Per Books Amounts 1/ (a)	Company Ratemaking Adjustments 5/ (b)	After Company Adjustments 7/ (c)	Public Staff Adjustments 8/ (d)	After Public Staff Adjustments 9/ (e)	(Lead) / Lag Days 10/ (f)	Working Capital From Lead/ Lag Study 14/ (g)
35	Total electric operating expenses	284,447	(1,518)	282,929	(8,408)	274,519		(21,847)
36	AFUDC	235	(235)	-	-	-	-	-
37	Charitable contributions	330	(330)	-	-	-	-	-
38	Interest on customer deposits	72	-	72	-	72	(182.50)	(36)
39	Interest on tax deficiencies	76	-	76	-	76	- 13/	-
40	Interest expense	24,539	(902)	23,637	807	24,444	(90.93)	(6,090)
41	Income available for common equity	51,816 4/	(3,701) 4/	48,115	7,552	55,667	-	-
42	Total requirement	$ 361,045	$ (6,216)	$ 354,829	$ (48)	$ 354,779		$ (27,973)
43	Cash working capital per Public Staff (L5 + L41)							$13,904
44	Amount per Company application							14,451 15/
45	Adjustment to cash working capital							($547)

1/ NCUC Form E-1, Item No. 10 - Supplemental Filing, Page 308, Column (1), unless footnoted otherwise.
2/ NCUC Form E-1, Item No. 45a, Schedule 2.
3/ Company Supplemental Exhibit PMM-1, Page 1, Line 9, Column (3).
4/ Line 5 minus (Sum of Lines 35 through 39).
5/ NCUC Form E-1, Item No. 10 - Supplemental Filing, Page 308, Column (2), unless footnoted otherwise.
6/ Company Supplemental Exhibit PMM-1, Page 1, Lines 2 through 5, Column (4).
7/ Column (a) plus Column (b).
8/ Johnson Settlement Exhibit 1, Schedule 2-1(f)(1), Column (z).
9/ Column (c) plus Column (d).
10/ NCUC Form E-1, Item No. 10 - Supplemental Filing, Page 308, Column (6), unless footnoted otherwise.
11/ Calculated based on the Company's lead-lag workpapers, and the per books amounts for 2015.
12/ Calculated by Public Staff.
13/ Updated composite revenue lag from Column (f), Line 5.
14/ Column (e) divided by 365 days times Column (f).
15/ NCUC Form E-1, Item No. 10 - Supplemental Filing, Page 308, Column (8).

DOMININON ENERGY NORTH CAROLINA
Docket No. E-22, Sub 562
North Carolina Retail Operations
PUBLIC STAFF ADJUSTMENTS TO BE
REFLECTED IN LEAD LAG CALCULATION
For the Test Year Ended December 31, 2018
(in Thousands)

Line No.	Item	Adjust ADIT for Certain Balances 1/	Reflect Decrease in State Income Tax Rate 1/	Adjust Uncollectibles 1/	Adjust Storm Costs 1/	Adjust Nuclear Outage Costs 1/	Remove Mt Storm Impairment Costs 1/	Adjust Allocation of Revenues from Sale of RECs 1/	Remove Employee Severance Costs 1/	Remove Skiffes Creek Mitigation Costs 1/
		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)
1	Electric operating revenues:									
2	Rate revenues	$0	$0	$0	$0	$0	$0	$0	$0	$0
3	Sales for resale revenues	-	-	-	-	-	-	-	-	-
4	Other operating revenues	-	-	-	-	-	-	-	-	-
5	Electric operating revenues	-	-	-	-	-	-	-	-	-
6	Account 501 - Fuel	-	-	-	-	-	-	-	-	-
7	Account 518 - Nuclear Fuel	-	-	-	-	-	-	-	-	-
8	Account 547 - Other Fuel	-	-	-	-	-	-	-	-	-
9	Account 555 - Purchased Power	-	-	-	-	-	-	-	-	-
10	Account 557 - Deferred Fuel	-	-	-	-	-	-	-	-	-
11	Payroll expense	-	-	-		-	-	-	-	-
12	Benefits and pension expense	-	-	-	-	-	-	-	-	-
13	OPEB expense	-	-	-	-	-	-	-	-	-
14	Uncollectibles expense	-	-	(236)	-	-	-	-	-	-
15	Stores expense	-	-	-	-	-	-	-	-	-
16	Accrued vacation expense	-	-	-	-	-	-	-	-	-
17	Worker's compensation expense	-	-	-	-	-	-	-	-	-
18	Prepaid insurance amortization expense	-	-	-	-	-	-	-	-	-
19	Director's deferred compensation expense	-	-	-	-	-	-	-	-	-
20	Miscellaneous prepaid expense	-	-	-	-	-	-	-	-	-
21	Other O&M expense	(42)	-	-	(81)	-	-	-	(302)	-
22	Total O&M expenses	(42)	-	(236)	(81)	-	-	-	(302)	-
23	Depreciation and amortization expense	-	-	-	-	-	(468)	-	-	(45)
24	Current state and federal income taxes	11	-	60	21	-	120	-	77	11
25	Deferred state and federal income taxes	-	-	-	-	-	-	-	-	-
26	Deferred ITC	-	-	-	-	-	-	-	-	-
27	Total income taxes	11	-	60	21	-	120	-	77	11
28	North Carolina franchise tax	-	-	-	-	-	-	-	-	-
29	Property tax expense	-	-	-	-	-	-	-	-	-
30	West Virginia B&O tax expense	-	-	-	-	-	-	-	-	-
31	Payroll taxes	-	-	-	-	-	-	-	-	-
32	Other taxes	-	-	-	-	-	-	-	-	-
33	Total taxes other than income	-	-	-	-	-	-	-	-	-
34	Gain / loss on disposition of property	-	-	-	-	-	-	-	-	-
35	Total electric operating expenses	(31)	-	(176)	(60)	-	(348)	-	(225)	(34)
36	Charitable contributions	-	-	-	-	-	-	-	-	-
37	Interest on customer deposits	-	-	-	-	-	-	-	-	-
38	Interest on tax deficiencies	-	-	-	-	-	-	-	-	-
39	Interest expense	-	-	-	-	-	-	-	-	-
40	Income available for common equity	31	-	176	60	-	348	-	225	34
41	Total requirement	$0	$0	$0	$0	$0	$0	$0	$0	$0

1/ Based on adjustments made by Public Staff in Johnson Exhibit 1, Schedule 3-1.

DOMININON ENERGY NORTH CAROLINA
Docket No. E-22, Sub 562
North Carolina Retail Operations
PUBLIC STAFF ADJUSTMENTS TO BE
REFLECTED IN LEAD LAG CALCULATION
For the Test Year Ended December 31, 2018
(In Thousands)

Line No.	Item	Adjust Chesapeake Retired Plant Levelized Amortization 1/ (j)	Remove Executive Compensation Costs 1/ (k)	Adjust CCR Costs 1/ (l)	Remove Chesterfield Units 3 & 4 Conversion Costs 1/ (m)	Adjust Annual Incentive Plan Costs 1/ (n)	Adjust O&M VRP Costs 1/ (o)	Remove Advertising Expense 1/ (p)	Adjust Outside Services 1/ (q)	Inflation Adjustment (r)
1	Electric operating revenues:									
2	Rate revenues	$0	$0	$0	$0	$0	$0	$0	$0	$0
3	Sales for resale revenues	-	-	-	-	-	-	-	-	-
4	Other operating revenues	-	-	-	-	-	-	-	-	-
5	Electric operating revenues	-	-	-	-	-	-	-	-	-
6	Account 501 - Fuel	-	-	-	-	-	-	-	-	-
7	Account 518 - Nuclear Fuel	-	-	-	-	-	-	-	-	-
8	Account 547 - Other Fuel	-	-	-	-	-	-	-	-	-
9	Account 555 - Purchased Power	-	-	-	-	-	-	-	-	-
10	Account 557 - Deferred Fuel	-	-	-	-	-	-	-	-	-
11	Payroll expense	-	-	-	-	(356)	-	-	-	-
12	Benefits and pension expense	-	-	-	-	-	-	-	-	-
13	OPEB expense	-	-	-	-	-	-	-	-	-
14	Uncollectibles expense	-	-	-	-	-	-	-	-	-
15	Stores expense	-	-	-	-	-	-	-	-	-
16	Accrued vacation expense	-	-	-	-	-	-	-	-	-
17	Worker's compensation expense	-	-	-	-	-	-	-	-	-
18	Prepaid insurance amortization expense	-	-	-	-	-	-	-	-	-
19	Director's deferred compensation expense	-	-	-	-	-	-	-	-	-
20	Miscellaneous prepaid expense	-	-	-	-	-	-	-	-	-
21	Other O&M expense	-	(91)	-	-	-	-	(12)	(176)	(10)
22	Total O&M expenses	-	(91)	-	-	(356)	-	(12)	(176)	(10)
23	Depreciation and amortization expense	-	-	(6,090)	-	-	-	-	-	-
24	Current state and federal income taxes	-	23	1,560	-	91	-	3	45	3
25	Deferred state and federal income taxes	-	-	-	-	-	-	-	-	-
26	Deferred ITC	-	-	-	-	-	-	-	-	-
27	Total income taxes	-	23	1,560	-	91	-	3	45	3
28	North Carolina franchise tax	-	-	-	-	-	-	-	-	-
29	Property tax expense	-	-	-	-	-	-	-	-	-
30	West Virginia B&O tax expense	-	-	-	-	-	-	-	-	-
31	Payroll taxes	-	-	-	-	-	-	-	-	-
32	Other taxes	-	-	-	-	-	-	-	-	-
33	Total taxes other than income	-	-	-	-	-	-	-	-	-
34	Gain / loss on disposition of property	-	-	-	-	-	-	-	-	-
35	Total electric operating expenses	-	(68)	(4,530)	-	(265)	-	(9)	(131)	(7)
36	Charitable contributions	-	-	-	-	-	-	-	-	-
37	Interest on customer deposits	-	-	-	-	-	-	-	-	-
38	Interest on tax deficiencies	-	-	-	-	-	-	-	-	-
39	Interest expense	-	-	-	-	-	-	-	-	-
40	Income available for common equity	-	68	4,530	-	265	-	9	131	7
41	Total requirement	$0	$0	$0	$0	$0	$0	$0	$0	$0

DOMININON ENERGY NORTH CAROLINA
Docket No. E-22, Sub 562
North Carolina Retail Operations
PUBLIC STAFF ADJUSTMENTS TO BE REFLECTED IN LEAD LAG CALCULATION
For the Test Year Ended December 31, 2018
(in Thousands)

Line No.	Item	Adjust for Customer Growth, Usage and Weather Normalization 1/ (s)	Non-Fuel Variable O&M Expense Displacement Adjustment 1/ (t)	Annualize Fuel Revenue and Expense at Current Fuel Revenue Rate 1/ (u)	Set Expense to Reflect Recommended Base Fuel Factor (v)	Set Revenue to Reflect Recommended Base Fuel Factor 1/	Adjust New Office Building	Adjust PJM Capacity Rate 1/ (w)	Adjust Marketer Percentage 1/ (x)	Interest Synchronization 1/ (y)	Total Public Staff Adjustments 1/ (z)
1	Electric operating revenues:										
2	Rate revenues	$0	$0	$0	$0	($48)	$0	$0	$0	$0	($48)
3	Sales for resale revenues	-	-	-	-	-	-	-	-	-	-
4	Other operating revenues	-	-	-	-	-	-	-	-	-	-
5	Electric operating revenues	-	-	$0	-	(48)	-	-	-	-	(48)
6	Account 501 - Fuel	-	-	-	(382)	-	-	-	-	-	(382)
7	Account 518 - Nuclear Fuel	-	-	-	(131)	-	-	-	-	-	(131)
8	Account 547 - Other Fuel	-	-	-	(866)	-	-	-	-	-	(866)
9	Account 555 - Purchased Power	-	-	-	(773)	-	-	-	-	-	(773)
10	Account 557 - Deferred Fuel	-	-	-	-	-	-	-	-	-	-
11	Payroll expense	-	-	-	-	-	-	-	-	-	(356)
12	Benefits and pension expense	-	-	-	-	-	-	-	-	-	-
13	OPEB expense	-	-	-	-	-	-	-	-	-	-
14	Uncollectibles expense	-	-	-	-	-	-	-	-	-	(236)
15	Stores expense	-	-	-	-	-	-	-	-	-	-
16	Accrued vacation expense	-	-	-	-	-	-	-	-	-	-
17	Worker's compensation expense	-	-	-	-	-	-	-	-	-	-
18	Prepaid insurance amortization expense	-	-	-	-	-	-	-	-	-	-
19	Director's deferred compensation expense	-	-	-	-	-	-	-	-	-	-
20	Miscellaneous prepaid expense	-	-	-	-	-	-	-	-	-	-
21	Other O&M expense	(89)	(141)	-	-	-	(716)	-	-	-	(1,660)
22	Total O&M expenses	(89)	(141)	-	(2,152)	-	(716)	-	-	-	(4,404)
23	Depreciation and amortization expense	-	-	-	-	-	-	-	-	-	(6,602)
24	Current state and federal income taxes	23	36	-	551	(12)	183	-	-	(207)	2,599
25	Deferred state and federal income taxes	-	-	-	-	-	-	-	-	-	-
26	Deferred ITC	-	-	-	-	-	-	-	-	-	-
27	Total income taxes	23	36	-	551	(12)	183	-	-	(207)	2,599
28	North Carolina franchise tax	-	-	-	-	-	-	-	-	-	-
29	Property tax expense	-	-	-	-	-	-	-	-	-	-
30	West Virginia B&O tax expense	-	-	-	-	-	-	-	-	-	-
31	Payroll taxes	-	-	-	-	-	-	-	-	-	-
32	Other taxes	-	-	-	-	-	-	-	-	-	-
33	Total taxes other than income	-	-	-	-	-	-	-	-	-	-
34	Gain / loss on disposition of property	-	-	-	-	-	-	-	-	-	-
35	Total electric operating expenses	(66)	(105)	-	(1,601)	(12)	(533)	-	-	(207)	(8,408)
36	Charitable contributions	-	-	-	-	-	-	-	-	-	-
37	Interest on customer deposits	-	-	-	-	-	-	-	-	-	-
38	Interest on tax deficiencies	-	-	-	-	-	-	-	-	-	-
39	Interest expense	-	-	-	-	-	-	-	-	807	807
40	Income available for common equity	66	105	-	1,601	(36)	533	-	-	(601)	7,552
41	Total requirement	$0	$0	$0	$0	($48)	$0	$0	$0	$0	($48)

DOMINION ENERGY NORTH CAROLINA
Docket No. E-22, Sub 562
North Carolina Retail Operations

Johnson Settlement Exhibit 1
Schedule 2-1(g)
Page 1 of 2

CALCULATION OF WORKING CAPITAL FROM LEAD / LAG STUDY AFTER RATE INCREASE

For the Test Year Ended December 31, 2019
(In Thousands)

Line No.	Item	Under Present Rates After Adjustments 1/ (a)	(Lead) Lag Days 4/ (b)	Iteration 1: Increase (c)	Iteration 1: With Increase 11/ (d)	Iteration 1: CWC Change 13/ (e)
1	Electric operating revenues:					
2	Rate revenues	$348,537	43.36	$2,307 5/	$350,844	$274
3	Sales for resale revenues	1,126	38.91	-	1,126	-
4	Other operating revenues	5,118	25.19	7 6/	5,125	-
5	Electric operating revenues	354,781	43.08	2,314	357,095	274
6	Account 501 - Fuel	20,591	(33.27)	-	20,591	-
7	Account 518 - Nuclear Fuel	7,080	(3.21)	-	7,080	-
8	Account 547 - Other Fuel	46,664	(33.27)	-	46,664	-
9	Account 555 - Purchased Power	23,255	(28.21)	-	23,255	-
10	Account 557 - Deferred Fuel	-	-	-	-	-
11	Payroll expense	31,337	(26.90)	-	31,337	-
12	Benefits and pension expense	8,191	(31.81)	-	8,191	-
13	OPEB expense	(1,721)	(20.64)	-	(1,721)	-
14	Uncollectibles expense	1,144	(254.79)	8 7/	1,152	(5)
15	Stores expense	9,243	(43.92)	-	9,243	-
16	Accrued vacation expense	81	-	-	81	-
17	Worker's compensation expense	73	-	-	73	-
18	Prepaid insurance amortization exp.	412	-	-	412	-
19	Director's deferred compensation exp.	-	-	-	-	-
20	Miscellaneous prepaid expense	503	-	-	503	-
21	Other O&M expense	41,142	(43.65)	3 8/	41,145	-
22	Total O&M expenses	187,995		11	188,005	(5)
23	Depreciation and amortization exp.	57,985	-	-	57,985	-
24	Net current income taxes	476	87.90	590 9/	1,066	142
25	Deferred state and federal income taxes	13,594	-	-	13,594	-
26	Deferred ITC	(74)	-	-	(74)	-
27	Total income taxes	13,996		590	14,586	142
28	North Carolina franchise tax	486	(523.00)	-	486	-
29	Property tax expense	10,558	(111.96)	-	10,558	-
30	West Virginia B&O tax expense	1,045	(39.54)	-	1,045	-
31	Payroll taxes	2,129	(27.26)	-	2,129	-
32	Other taxes	102	(31.06)	-	102	-
33	Total taxes other than income	14,319		-	14,319	-
34	Gain / loss on disposition of property	225	-	-	225	-
35	Total electric operating expenses	274,519		601	275,120	137
36	Charitable contributions	-	-	-	-	-
37	Interest on customer deposits	72	(182.50)	-	72	-
38	Interest on tax deficiencies	76	-	-	76	-
39	Other expenses / (income)	148		-	148	-
40	Interest expense	24,444	(90.93)	-	24,444	-
41	Income available for common equity	55,667	-	1,713 10/	57,380 12/	-
42	Net operating income for return	80,112		1,713	81,824	-
43	Total requirement	$354,779		$2,314	$357,093	$137
44	Cumulative change in working capital					$411
45	Rate base under present rates					1,131,758
46	Rate base after rate increase	$1,131,758 2/				$1,132,169
47	Overall rate of return (L42 / L46)	7.08%				7.23%
48	Target rate of return	7.20% 3/				7.20% 3/

1/ Johnson Settlement Exhibit 1, Schedule 2-1(f), Column (e).
2/ Johnson Settlement Exhibit 1, Schedule 2, Line 10, Column (c).
3/ Johnson Settlement Exhibit 1, Schedule 4, Line 3, Column (h).
4/ Johnson Settlement Exhibit 1, Schedule 2-1(f), Column (f).
5/ Line 5 minus Line 4 minus Line 3.
6/ ((Line 5 minus $330,000) divided by (1 minus 0.00319951911162212)) minus (Line 5 minus $330,000) plus $330,000.
7/ Line 5 times 0.3285%.
8/ Line 5 times 0.130%.
9/ (Line 41 divided by (1 minus 25.6228%)) minus Line 41.
10/ Column (d) minus Column (a).
11/ Column (a) plus Column (c), unless footnoted otherwise.
12/ Line 46, Column (e) times 52.000% times 9.750%.
13/ Column (c) divided by 365 days times Column (b).

DOMININON ENERGY NORTH CAROLINA
Docket No. E-22, Sub 562
North Carolina Retail Operations
CALCULATION OF WORKING CAPITAL
FROM LEAD / LAG STUDY AFTER RATE
INCREASE
For the Test Year Ended December 31, 2018
(In Thousands)

Johnson Settlement Exhibit 1
Schedule 2-1(g)
Page 2 of 2

Line No.	Item	Iteration 2 Increase	Iteration 2 With Increase 16/	Iteration 2 CWC Change 19/	Iteration 3 Increase	Iteration 3 With Increase 21/	Iteration 3 CWC Change 24/	After Increase Cumulative Increase	After Increase After Increase
		(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)
1	Electric operating revenues:								
2	Rate revenues	($276) 5/	$350,567	($33)	$4 5/	$350,571	$0	$2,034	$350,571
3	Sales for resale revenues	-	1,126	-	-	1,126	-	-	1,126
4	Other operating revenues	(1) 14/	5,124	-	- 14/	5,124	-	6	5,124
5	Electric operating revenues	(277)	356,817	(33)	4	356,821	-	2,040	356,821
6	Account 501 - Fuel	-	20,591	-	-	20,591	-	-	20,591
7	Account 518 - Nuclear Fuel	-	7,080	-	-	7,080	-	-	7,080
8	Account 547 - Other Fuel	-	46,664	-	-	46,664	-	-	46,664
9	Account 555 - Purchased Power	-	23,255	-	-	23,255	-	-	23,255
10	Account 557 - Deferred Fuel	-	-	-	-	-	-	-	-
11	Payroll expense	-	31,337	-	-	31,337	-	-	31,337
12	Benefits and pension expense	-	8,191	-	-	8,191	-	-	8,191
13	OPEB expense	-	(1,721)	-	-	(1,721)	-	-	(1,721)
14	Uncollectibles expense	(1) 7/	1,151	1	0 7/	1,151	-	7	1,151
15	Stores expense	-	9,243	-	-	9,243	-	-	9,243
16	Accrued vacation expense	-	81	-	-	81	-	-	81
17	Worker's compensation expense	-	73	-	-	73	-	-	73
18	Prepaid insurance amortization exp.	-	412	-	-	412	-	-	412
19	Director's deferred compensation exp.	-	-	-	-	-	-	-	-
20	Miscellaneous prepaid expense	-	503	-	-	503	-	-	503
21	Other O&M expense	- 6/	41,145	-	0 6/	41,145	-	3	41,145
22	Total O&M expenses	(1)	188,004	1	0	188,004	-	10	188,004
23	Depreciation and amortization exp.	-	57,985	-	-	57,985	-	-	57,985
24	Net current income taxes	7 9/	1,073	2	1 9/	1,074	-	598	1,074
25	Deferred state and federal income taxes	-	13,594	-	-	13,594	-	-	13,594
26	Deferred ITC	-	(74)	-	-	(74)	-	-	(74)
27	Total income taxes	7	14,593	2	1	14,594	-	598	14,594
28	North Carolina franchise tax	-	486	-	-	486	-	-	486
29	Property tax expense	-	10,558	-	-	10,558	-	-	10,558
30	West Virginia B&O tax expense	-	1,045	-	-	1,045	-	-	1,045
31	Payroll taxes	-	2,128	-	-	2,128	-	-	2,128
32	Other taxes	-	102	-	-	102	-	-	102
33	Total taxes other than income	-	14,319	-	-	14,319	-	-	14,319
34	Gain / loss on disposition of property	-	225	-	-	225	-	-	225
35	Total electric operating expenses	6	275,126	3	1	275,127	-	608	275,127
36	Charitable contributions	-	-	-	-	-	-	-	-
37	Interest on customer deposits	-	72	-	-	72	-	-	72
38	Interest on tax deficiencies	-	76	-	-	76	-	-	76
39	Other expenses / (income)	-	148	-	-	148	-	-	148
40	Interest expense	(302) 15/	24,142 17/	75	1 20/	24,143 22/	-	(301)	24,143
41	Income available for common equity	21 15/	57,401 18/	-	2 20/	57,403 23/	-	1,736	57,403
42	Net operating income for return	(281)	81,543	75	3	81,546	-	1,434	81,546
43	Total requirement	($275)	$356,817	$78	$4	$356,821	$0	$2,042	$356,821
44	Cumulative change in working capital			$456			$456		$456
45	Rate base under present rates			1,131,758			1,131,758		1,131,758
46	Rate base after rate increase			$1,132,214			$1,132,214		$1,132,214
47	Overall rate of return (L42 / L46)			7.20%			7.20%		7.20%
48	Target rate of return			7.20% 3/			7.20% 3/		7.20%

14/ (Line 5 divided by (1 minus 0.00319951911162212)) minus Line 5.
15/ Column (g) minus Column (d).
16/ Column (d) plus Column (f), unless footnoted otherwise.
17/ Line 46, Column (e) times 48.000% times 4.442%.
18/ Line 46, Column (e) times 52.000% times 9.750%.
19/ Column (f) divided by 365 days times Column (b).
20/ Column (j) minus Column (g).
21/ Column (g) plus Column (i), unless footnoted otherwise.
22/ Line 46, Column (h) times 48.000% times 4.442%.
23/ Line 46, Column (h) times 52.000% times 9.750%.
24/ Column (i) divided by 365 days times Column (b).

DOMINION ENERGY NORTH CAROLINA
Docket No. E-22, Sub 562
North Carolina Retail Operations
ADJUSTMENT TO REMOVE FEDERAL UNPROTECTED EDIT FOR TREATMENT AS A RIDER
For the Test Year Ended December 31, 2018
(in Thousands)

Johnson Settlement Exhibit 1
Schedule 2-1 (h)

Line No.	Item	Amount
1	Federal unprotected EDIT to be flowed back to customers through a rider	$3,187 1/
2	Adjustment to remove federal unprotected EDIT from rate base (-L1 minus L2)	($3,187)

1/ Company Supplemental Exhibit PMM-2, Schedule 1, page 3, Lines 86 plus 87.

DOMININON ENERGY NORTH CAROLINA
Docket No. E-22, Sub 562
North Carolina Retail Operations
SUMMARY OF OTHER ADDITIONS
For the Test Year Ended December 31, 2018
(In Thousands)

Johnson Settlement Exhibit 1
Schedule 2-2

Line No.	Item	NC Retail Adjusted Per Company 1/ (a)	Public Staff Adjustments 2/ (b)	NC Retail Adjusted Per Public Staff 3/ (c)	
1	1132030 - SAP A/R EE Purchase Program	$0	$0	$0	Total Plant
2	1134010 - Joint Owner Receivable	-	-	-	Total Plant
3	1137050 - Account Receivable - ARM-Public	-	-	-	Total Plant
4	1137055 - Accounts Receivable - Other	-	-	-	Total Plant
5	1191210 - Prepaid Insurance - Executive Protection	-	-	-	Tot sal&wages
6	1191220 - Prepaid Insurance - Excess Liability	-	-	-	Tot sal&wages
7	1191240 - Prepaid Insurance - Nuclear Property	-	-	-	Tot sal&wages
8	1191250 - Prepaid Insurance - NEIL	-	-	-	Tot sal&wages
9	1191260 - Prepaid Insurance - General Property	-	-	-	Tot sal&wages
10	1191270 - Prepaid Insurance - Executive Life	-	-	-	Tot sal&wages
11	1191290 - Prepaid Insurance - Workers Comp.	-	-	-	Tot sal&wages
12	1191310 - Prepaid Auto Licenses	-	-	-	Tot sal&wages
13	1191330 - Prepaid Fees & Assessments	-	-	-	Tot sal&wages
14	1191900 - Prepaid - Miscellaneous	-	-	-	Tot sal&wages
15	1199010 - Temporary Facilities	-	-	-	Tot Dist Plant
16	1220910 - Other Non-Current Receivables	-	-	-	Factor 3
17	1242020 - Unamort. Loss on Reacquired Debt - Mrtg Bnd	-	-	-	Total net plant
18	1242022 - Reg Asset - Unamort. Loss - Reacquired Debt	-	-	-	
19	1242030 - Unamort. Loss on Reacquired Debt - Poll Cntrl	-	-	-	
20	1242045 - Unamort. Loss on Reacquired Debt - Write Off	-	-	-	Total net plant
21	1242062 - Reg Asset - NRC Requirements - North Anna	-	-	-	Factor1
22	1242063 - Reg Asset - NRC Requirements - Surry	-	-	-	
23	1250010 - Preliminary Survey and Investigations	-	-	-	Factor1
24	1251010 - Other Work in Progress	-	-	-	Total Dist Plant
25	1251020 - Other Work in Progress - Direct Post	-	-	-	Total Dist Plant
26	1292860 - Misc. Prepayments - Non Current	-	-	-	Total Sal&Wage
27	2220120 - Reg Liab - Deferred Gain on Reacquired Debt	-	-	-	
28	1242060 - Reg Asset - Unrecov. Design Basis Costs - NA	-	-	-	Factor 1D
29	1242061 - Reg Asset - Unrecov. Design Basis Costs - Surry	-	-	-	Factor 1D
30	1242070 - Reg Asset - Unrecov. Tech. Spec. Update	-	-	-	Factor 1D
31	1242205 & 1171205 - Reg Asset - NUG Buyout Costs	-	-	-	Factor 1D
32	1242265 & 1171265 - Reg Asset - Bear Garden Sub 479	-	-	-	Factor 1D
33	1242270 - Reg Asset - Emission Allowances - Non Current	-	-	-	
34	1171270 - Reg Asset - Emission Allowances - Current	-	-	-	
35	1171245 - Reg Asset - Nuclear Outage Deferral	-	-	-	Factor 1NUC
36	Reg Asset - Chesapeake Closure Costs	-	-	-	
37	1171280&1242280&1242285 Reg Asset - CCR Rule Expenditu	-	(14,607)	(14,607)	Factor3D
38	Reg Asset - Warren County Deferral	-	-	-	
39	Reg Asset - Brunswick County Deferral	-	-	-	
40	1171255 & 1242255 Reg Asset - North Branch Net Proceeds	-	-	-	
41	Rounding	37,149	-	37,149	
42	Total Other Additions	$37,149	($14,607)	$22,542	

1/ Based on review of Company Item 10 workpapers.
2/ Based on adjustments recommended by Public Staff.
3/ Column (a) plus Column (b).

DOMININON ENERGY NORTH CAROLINA
Docket No. E-22, Sub 562
North Carolina Retail Operations
SUMMARY OF OTHER DEDUCTIONS
For the Test Year Ended December 31, 2018
(in Thousands)

Johnson Settlement Exhibit 1
Schedule 2-3

Line No.	Item	NC Retail Adjusted Per Company 1/ (a)	Public Staff Adjustments 2/ (b)	NC Retail Adjusted Per Public Staff 3/ (c)
1	2171138 - Reg. Liab. - Other - NCUC Order (DOE Settlement)	$0	$0	$0
2	2141100 - Accrued Vacation	-	-	-
3	2190010 - Capital Lease Obligation - Current	-	-	-
4	2290010 - Capital Lease Obligation - Noncurrent	-	-	-
5	2191000 - Appropriated Funds - Customer Accounts	-	-	-
6	2191800 - Centralized Appropriations	-	-	-
7	2192030 - Supplemental Pensions - Current	-	-	-
8	2192060 - Reserve for IBNR/FBNP Hospitalization	-	-	-
9	2192070 - Reserve for IBNR/FBNP Dental/Vision	-	-	-
10	2299025 - Accum. Provisions for Injuries and Damages	-	-	-
11	2141400 - Accr. Severance Pay	-	-	-
12	2199040 - Customer Advances for Construction	-	-	-
13	1292840 - FAS 112 - Deferred Post Employment Benefit	-	-	-
14	1292870 - ME Pension Asset / Oblig. - FAS 158 - Non Current	-	-	-
15	1291810 - Non Current Asset - Worker's Compensation	-	-	-
16	2291010 - Non Current Liability - Workers Compensation	-	-	-
17	2291030 - Non Current Liability - Long Term Disability	-	-	-
18	2291510 - OPEB ME 158 Benefit Obligation - Non Cur.	-	-	-
19	2291050 - Non Current Liability - Supplemental Post Empl	-	-	-
20	2291080 - Deferred Compensation - Executives	-	-	-
21	2299910 - Other Non Current Liabilities	-	-	-
22	6199010 - Other Income CIAC Tax Recovery	-	-	-
23	Company adjustment to eliminate nuclear outage deferral balance	(26,130)	-	(26,130)
24	Total Other Deductions	($26,130)	$0	($26,130)

1/ Based on review of Company Item 10 workpapers.
2/ Based on adjustments recommended by Public Staff.
3/ Column (a) plus Column (b).

DOMININON ENERGY NORTH CAROLINA
Docket No. E-22, Sub 562
North Carolina Retail Operations
NET OPERATING INCOME FOR RETURN
For the Test Year Ended December 31, 2018
(In Thousands)

Johnson Settlement Exhibit 1
Schedule 3

Line No.	Item	Under Present Rates: NC Retail Adjusted Per Company 1/ (a)	Public Staff Adjustments 2/ (b)	After Public Staff Adjustments 3/ (c)	After Public Staff Recommended Increase: Rate Increase (d)		After Rate Increase 10/ (e)	Base Fuel Only
1	Electric operating revenues:							
2	Base non-fuel rate revenues	$256,741	($48)	$256,693	$4,185	4/	$260,878	
3	Base fuel revenues	91,845	-	91,845	(2,155)	5/	89,690	89,690
4	Late payment fees	1,187	-	1,187	7	6/	1,194	
5	Other revenues	5,057	-	5,057	-	7/	5,057	
6	Electric operating revenues (Sum of L2 thru L5)	354,830	(48)	354,782	$2,037		356,819	89,690
7	Electric operating expenses:							
8	Operations and maintenance:							
9	Fuel clause expenses	91,725	(2,153)	89,572	-		89,572	89,572
10	Other operations and maintenance expenses	100,674	(2,252)	98,422	9	8/	98,431	117
11	Depreciation and amortization	64,586	(6,602)	57,984	-		57,984	
12	Gain / loss on disposition of property	225	-	225	-		225	
13	Taxes other than income taxes	14,319	-	14,319	-		14,319	
14	Income taxes	11,397	2,680	14,077	517	9/	14,594	
15	Total electric operating expenses (Sum of L8 thru L14)	282,926	(8,328)	274,598	526		275,125	89,689
16	Net operating income before adjustments (L6 - L15)	71,904	8,280	80,184	1,511		81,694	1
17	Interest on customer deposits	(72)	-	(72)	-		(72)	
18	Interest on tax deficiencies	(76)	-	(76)	-		(76)	
19	Net operating income for return (Sum of L16 thru L18)	$71,756	$8,280	$80,036	$1,511		$81,546	$1

1/ Company Supplemental Exhibit PMM-1, Page 1, Column 5, unless footnoted otherwise.
2/ Johnson Settlement Exhibit 1, Schedule 3-1, Column (u).
3/ Column (a) plus Column (b).
4/ Johnson Settlement Exhibit 1, Schedule 5, Line 7 minus other revenues on Line 5 minus late payment fees on Line 4.
5/ Johnson Settlement Exhibit 1, Schedule 5, Line 6.
6/ ((Line 6 minus Line 5) divided by (1 minus late payment fee rate of 0.320%)) minus (Line 6 minus Line 5).
7/ Based on testimony of Company witness Paul Haynes.
8/ Line 6 times (1 minus retention factor after uncollectibles and regulatory fee from Johnson Settlement Exhibit 1, Schedule 1-2, Line 10).
9/ Line 6 minus sum of Lines 8 thru 13 minus Johnson Settlement Exhibit 1, Schedule 5, Line 3, Column (a), times composite income tax rate of 25.6228%.
10/ Column (c) plus Column (d).

DOMININON ENERGY NORTH CAROLINA
Docket No. E-22, Sub 562
North Carolina Retail Operations
SUMMARY OF PUBLIC STAFF NET OPERATING INCOME ADJUSTMENTS
For the Test Year Ended December 31, 2018
(In Thousands)

Line No.	Item	Adjust Lobbying Expense (a)	Adjust Uncollectibles (b)	Adjust Storm Costs (c)	Remove Executive Compensation Costs (d)	Remove Employee Severance Costs (e)	Adjust Incentive Plan Costs (f)	Adjust O&M VRP Costs (g)
1	Electric operating revenues:							
2	Base non-fuel rate revenues	$0	$0	$0	$0	$0	$0	$0
3	Base fuel revenues	-	-	-	-	-	-	-
4	Late payment fees	-	-	-	-	-	-	-
5	Other revenues	-	-	-	-	- 10/	-	-
6	Electric operating revenues (Sum of L2 thru L5)	-	-	-	-	-	-	-
7	Electric operating expenses:							
8	Operations and maintenance:							
9	Fuel clause expenses	-	-	-	-	-	-	-
10	Other operations and maintenance expenses	(42) 1/	(236) 2/	(81) 4/	($91) 5/	($302) 6/	(356) 7/	$0 9/
11	Depreciation and amortization	-	-	-	-	-	-	-
12	Gain / loss on disposition of property	-	-	-	-	-	-	-
13	Taxes other than income taxes	-	-	-	-	-	-	-
14	Income taxes	11 3/	60 3/	21 3/	23 3/	77 3/	91 3/	- 3/
15	Total electric operating expenses (Sum of L8 thru L14)	(31)	(176)	(60)	(68)	(225)	(265)	-
16	Net operating income before adjustments (L6 - L15)	31	176	60	68	225	265	-
17	Interest on customer deposits	-	-	-	-	-	-	-
18	Interest on tax deficiencies	-	-	-	-	-	-	-
19	Net operating income for return (Sum of L16 thru L18)	$31	$176	$60	$68	$225	$265	$0
20	Calculated revenue requirement impact 8/	($42)	($238)	($81)	($92)	($304)	($358)	$0

1/ Johnson Settlement Exhibit 1, Schedule 3-1(a), Line 5.
2/ Johnson Settlement Exhibit 1, Schedule 3-1(b), Line 9.
3/ Line 6 minus Sum of Lines 9 through 13 times composite income tax rate of 25.6228%.
4/ Johnson Settlement Exhibit 1, Schedule 3-1(c), Line 19.
5/ Johnson Settlement Exhibit 1, Schedule 3-1(d), Line 7.
6/ Johnson Exhibit 1, Schedule 3-1(e), Line 9.
7/ Johnson Exhibit 1, Schedule 3-1(f), Line 10.
8/ Negative of Line 19 divided by net income retention factor from Johnson Settlement Exhibit 1, Schedule 1-2, Line 14.
9/ Johnson Settlement Exhibit 1, Schedule 3-1(g), Line .

DOMINNION ENERGY NORTH CAROLINA
Docket No. E-22, Sub 562
North Carolina Retail Operations
SUMMARY OF PUBLIC STAFF NET OPERATING INCOME ADJUSTMENTS
For the Test Year Ended December 31, 2018
(in Thousands)

Johnson Settlement Exhibit 1
Schedule 3-1
Page 2 of 3

Line No.	Item	Remove Advertising Expense (h)	Customer Growth, Usage and Weather Normalization (i)	Non-Fuel Variable O&M Expense Displacement Adjustment (j)	Adjust Outside Service (k)	Remove Skiffes Creek Mitigation Costs (l)	Remove Chesterfield Units 3 & 4 Conversion Costs (m)	Remove Mt Storm Impairment Costs (n)
1	Electric operating revenues:							
2	Base non-fuel rate revenues	$0	$0	$0	$0	$0	$0	$0
3	Base fuel revenues	-	-	-	-	-	-	-
4	Late payment fees	-	-	-	-	-	-	-
5	Other revenues	-	-	-	-	-	-	-
6	Electric operating revenues (Sum of L2 thru L5)	-	-	-	-	-	-	-
7	Electric operating expenses:							
8	Operations and maintenance:							
9	Fuel clause expenses	-	-	-	-	-	-	-
10	Other operations and maintenance expenses	$ (12) 10/	(89) 11/	(141) 12/	(176) 13/	-	-	-
11	Depreciation and amortization	-	-	-	-	(45) 14/	- 15/	(468) 16/
12	Gain / loss on disposition of property	-	-	-	-	-	-	-
13	Taxes other than income taxes	-	-	-	-	-	-	-
14	Income taxes	3 3/	23 3/	36 3/	45 3/	11 3/	- 3/	120 3/
15	Total electric operating expenses (Sum of L8 thru L14)	(9)	(66)	(105)	(131)	(34)	-	(348)
16	Net operating income before adjustments (L6 - L15)	9	66	105	131	34	-	348
17	Interest on customer deposits	-	-	-	-	-	-	-
18	Interest on tax deficiencies	-	-	-	-	-	-	-
19	Net operating income for return (Sum of L16 thru L18)	$9	$66	$105	$131	$34	$0	$348
20	Calculated revenue requirement impact 8/	($12)	($90)	($142)	($177)	($45)	$0	($470)

10/ Johnson Settlement Exhibit 1, Schedule 3-1(h), Line 5.
11/ Johnson Settlement Exhibit 1, Schedule 3-1(i), Line 11.
12/ Johnson Settlement Exhibit 1, Schedule 3-1(j), Line 10.
13/ Johsnon Settlement Exhibit 1, Schedule 3-1(m), Line 6.
14/ Johnson Settlement Exhibit 1, Schedule 2-1(b), Line 6.
15/ Johnson Settlement Exhibit 1, Schedule 2-1(e), Line 6.
16/ Johnson Settlement Exhibit 1, Schedule 2-1(c), Line 9.

DOMINNON ENERGY NORTH CAROLINA
Docket No. E-22, Sub 562
North Carolina Retail Operations
SUMMARY OF PUBLIC STAFF NET OPERATING
INCOME ADJUSTMENTS
For the Test Year Ended December 31, 2018
(in Thousands)

Johnson Settlement Exhibit 1
Schedule 3-1
Page 3 of 3

Line No.	Item	Inflation Adjustment	Adjust CCR Costs	Set Expense to Reflect Recommended Base Fuel Factor	Set Revenue to Reflect Recommended Base Fuel Factor	Adjust New Office Building	Interest Synchronization Adjustment	Total NOI Adjustments 22/
		(o)	(p)	(q)	(r)	(s)	(t)	(u)
1	Electric operating revenues:							
2	Base non-fuel rate revenues	$0	$0	$0	($48) 19/	$0	$0	($48)
3	Base fuel revenues	-	-	-	-	-	-	-
4	Late payment fees	-	-	-	-	-	-	-
5	Other revenues	-	-	-	-	-	-	-
6	Electric operating revenues (Sum of L2 thru L5)	-	-	-	(48)	-	-	(48)
7	Electric operating expenses:							
8	Operations and maintenance:							
9	Fuel clause expenses	-	-	(2,153) 19/	-	-	-	(2,153)
10	Other operations and maintenance expenses	(10) 17/	-	-	-	(716) 20/	-	(2,252)
11	Depreciation and amortization	-	(6,090) 18/	-	-	-	-	(6,602)
12	Gain / loss on disposition of property	-	-	-	-	-	-	-
13	Taxes other than income taxes	-	-	-	-	-	-	-
14	Income taxes	3 3/	1,560 3/	552 3/	(12) 3/	183 3/	(127) 21/	2,680
15	Total electric operating expenses (Sum of L8 thru L14)	(7)	(4,530)	(1,601)	(12)	(533)	(127)	(8,328)
16	Net operating income before adjustments (L6 - L15)	7	4,530	1,601	(36)	533	127	8,280
17	Interest on customer deposits	-	-	-	-	-	-	-
18	Interest on tax deficiencies	-	-	-	-	-	-	-
19	Net operating income for return (Sum of L16 thru L18)	$7	$4,530	$1,601	($36)	$533	$127	$8,280
20	Calculated revenue requirement impact 8/	($9)	($6,119)	($2,162)	$49	($720)	($172)	($11,183)

17/ Johnson Settlement Exhibit 1, Schedule 3-1(k), Line 12.
18/ Maness Supplemental Exhibit I, Schedule 1, Line 5.
19/ Per Settlement Agreement
20/ Per Settlement Agreement
21/ Johnson Settlement Exhibit 1 Schedule 3-1(n), Line 8.
22/ Sum of Column (a) through Column (t).

DOMININON ENERGY NORTH CAROLINA
Docket No. E-22, Sub 562
North Carolina Retail Operations
ADJUSTMENT TO LOBBYING EXPENSE
For the Test Year Ended December 31, 2018
(in Thousands)

Johnson Settlement Exhibit 1
Schedule 3-1(a)

Line No.	Item	Amount	
1	Internal Lobbying Costs to be removed per Public Staff	$844	1/
2	External Lobbing Costs to be removed per Public Staff	-	2/
3	Total Lobbying Costs to be Excluded (L1 + L2)	844	
4	NC Retail Allocation Factor	4.9507%	3/
5	NC Retail Lobbying Costs to be Excluded per Public Staff (-L3 x L4)	($42)	

1/ E-1, Item 18(a) & Company responses to DR49 and DR119.
2/ Corrected amount per Settlement Agreement.
3/ NC Jurisdictional Factor 1.

DOMININON ENERGY NORTH CAROLINA
Docket No. E-22, Sub 562
North Carolina Retail Operations

Johnson Settlement Exhibit 1
Schedule 3-1(b)

ADJUSTMENT TO UNCOLLECTIBLES EXPENSE
For the Test Year Ended December 31, 2018
(in Thousands)

Line No.	Item	Amount	
1	Average bad debt expense attributed to retail customers	$24,084	1/
2	Percentage to North Carolina retail	4.8779%	2/
3	Average bad debt expense for North Carolina retail (L1 x L2)	1,175	
4	Average North Carolina retail revenues	357,717	3/
5	Uncollectibles percentage per Public Staff (L3 / L4)	0.3285%	
6	North Carolina retail revenues (including fuel) adjusted for weather and customer growth per Company	348,586	4/
7	Uncollectibles expense per Public Staff (L5 x L6)	1,145	
8	Amount per Company	1,381	5/
9	Adjustment to uncollectibles expense (L7 - L8)	($236)	

1/ NCUC Form E-1, Item No. 10 - Supplemental Filing, Page 151, Line 3 thru Line 6, divided by 4.
2/ NCUC Form E-1, Item No. 45a, Schedule 15, Line 399.
3/ NCUC Form E-1, Item No. 10 - Supplemental Filing, Page 155. The average for the last 4 years; not 5.
4/ Company Exhibit PMM-1, Scheduel 1, Col. 5, Line 2 + Line 3.
5/ NCUC Form E-1, Item No. 10 - Supplemental Filing, Page 150, Line 3.

DOMININON ENERGY NORTH CAROLINA
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North Carolina Retail Operations
ADJUSTMENT TO NORMALIZED LEVEL OF
STORM O&M EXPENSE
For the Test Year Ended December 31, 2018
(in Thousands)

Johnson Settlement Exhibit 1
Schedule 3-1(c)

Line No.	Item	Amount	
	Overtime hours		
1	2009	105,084	1/
2	2010	128,942	2/
3	2011	263,752	2/
4	2012	190,679	2/
5	2013	85,741	2/
6	2014	13,865	2/
7	2015	30,692	2/
8	2016	134,616	2/
9	2017	35,720	2/
10	2018	184,801	2/
11	Ten year average overtime wages ((Sum of L1 thru L10) / 10)	117,389	
12	Hourly rate (in thousands)	0.0659	3/
13	Average overtime wages per Public Staff (L11 x L12)	7,736	
14	Average overtime wages per Company	7,828	4/
15	Adjustment to overtime wages (L13 - L14)	(92)	
16	NC retail percentage	4.9841%	5/
17	Adjustment to overtime wages - NC retail (L15 x L16)	(5)	
18	Adjustment to other storm expenses - NC retail	(157)	6/
19	Public Staff adjustment - NC retail (L17 + L18)	(162)	
20		50%	
21	Public Staff adjustment - NC retail (L17 + L18)	$ (81)	

1/ DNCP Sub 532 Fernald Exhibit 1, Schedule 3-1 Storm Adj, Line 4.
2/ NCUC Form E-1, Item No. 10 - Supplemental Filing, Page 128, Lines 10 thru 18.
3/ divided by Line 18, Column (2), times (1 plus Line 4). - Zero placement corrected as part of Settlement Agreement.
4/ NCUC Form E-1, Item No. 10 - Supplemental Filing, Page 128, Line 5.
5/ Salaries and wages factor from NCUC Form E-1, Item No. 10 - Supplemental Filing, Page 73.
6/ Johnson Settlement Exhibit 1, Schedule 3-1(c)(1), Line 17, Column (e).

DOMININON ENERGY NORTH CAROLINA
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North Carolina Retail Operations
ADJUSTMENT TO NORMALIZED LEVEL OF
STORM O&M EXPENSE EXCLUDING LABOR
For the Test Year Ended December 31, 2018
(In Thousands)

Johnson Settlement Exhibit 1
Schedule 3-1(c)(1)

Line No.	Item	Normalized Amount per Public Staff 1/	Normalized Amount per Company 2/	Public Staff Adjustment 3/	NC Retail Allocation Factor 4/	Public Staff Adjustment - NC Retail 5/
		(a)	(b)	(c)	(d)	(e)
1	Acct 562 - Trans Op - Station Exp	$0	$0	$0	4.2841%	$0
2	Acct 563 - Trans Op - Ovrhd Lines	0	-	-	4.2071%	-
3	Acct 566 - Trans Op - Misc Exp	87	96	(9)	4.4492%	-
4	Acct 582 - Dist Op - Station Exp	7	8	(1)	5.7804%	-
5	Acct 583 - Dist Op - Ovhd Lines	2,332	2,354	(22)	7.5771%	(2)
6	Acct 584 - Dist Op - Ungrd Lines	272	297	(25)	3.7154%	(1)
7	Acct 585 - Dist Op - St Lt/Sig Lines	0	-	-	5.4307%	-
8	Acct 586 - Dist Op - Meters	24	25	(1)	2.5127%	-
9	Acct 587 - Dist Op - Cust Install	130	137	(7)	5.4413%	-
10	Acct 588 - Dist Op - Misc Exp	4,832	5,253	(421)	6.1822%	(26)
11	Acct 593 - Dist Maint - Ovrhd Ln	25,738	27,355	(1,617)	7.5771%	(123)
12	Acct 594 - Dist Maint - Ungrd Ln	1,061	1,139	(78)	3.7154%	(3)
13	Acct 595 - Dist Maint - Ln Trnsfm	727	783	(56)	4.4475%	(2)
14	Acct 596 - Dist Maint - St Lt/Sig	17	19	(2)	5.4307%	-
15	Acct 597 - Dist Maint - Meters	54	55	(1)	2.5127%	-
16	Acct 935 - Admin & Gen - Electric	15	17	(2)	6.1618%	-
17	Total	$35,296	$37,538	($2,242)		($157)

1/ Johnson Settlement Exhibit 1, Schedule 3-1(c)(2), Line 20, Column (k) divided by ten times distribution percentage for account from Johnson Settlement Exhibit 1, Schedule 3-1(c)(2), Column (l).
2/ NCUC Form E-1, Item No. 10 - Supplemental Filing, Page 129, Column (4).
3/ Column (a) minus Column (b).
4/ NCUC Form E-1, Item No. 45a - Supplemental Filing, Schedule 3.
5/ Column (c) times Column (d).

DOMININON ENERGY NORTH CAROLINA
Docket No. E-22, Sub 562
North Carolina Retail Operations
STORM O&M EXPENSES
EXCLUDING LABOR ADJUSTED
FOR INFLATION
For the Test Year Ended December 31, 2018
(in Thousands)

Johnson Settlement Exhibit 1
Schedule 3-1(c)(2)

Line No.	Item	2009 1/	2010 1/	2011 1/	2012 1/	2013 1/	2014 2/	2015 3/	2016 4/	2017 5/	2018 6/	Total for Ten Years 7/	Distribution Percent 8/
		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)
1	Acct 184 - Clearing Accounts	$0	$0	$84	$0	$0	$0	$0	$0	$0	$0	84	
2	Acct 562 - Trans Op - Station Exp	-	-	1	-	-	-	-	-	-	-	1	0.000%
3	Acct 563 - Trans Op - Ovrhd Lines	-	-	-	-	-	-	-	-	-	-	-	0.000%
4	Acct 566 - Trans Op - Misc Exp	-	-	808	-	-	-	-	-	-	-	808	0.246%
5	Acct 582 - Dist Op - Station Exp	-	7	25	15	5	1	1	6	1	5	66	0.020%
6	Acct 583 - Dist Op - Ovhd Lines	1,911	2,196	7,603	2,094	809	173	229	2,117	570	4,025	21,727	6.607%
7	Acct 584 - Dist Op - Ungrd Lines	35	205	799	376	110	23	30	302	82	578	2,540	0.772%
8	Acct 585 - Dist Op - St Lt/Sig Lines	-	-	-	-	-	-	-	-	-	-	-	0.000%
9	Acct 586 - Dist Op - Meters	11	10	40	88	15	3	4	21	3	25	220	0.067%
10	Acct 587 - Dist Op - Cust Install	55	86	299	93	23	5	6	163	59	420	1,209	0.368%
11	Acct 588 - Dist Op - Misc Exp	804	2,752	13,197	18,180	2,789	528	694	3,162	352	2,560	45,018	13.690%
12	Acct 593 - Dist Maint - Ovrhd Ln	9,548	14,138	49,717	41,772	17,348	4,113	5,967	34,872	9,547	52,776	239,798	72.922%
13	Acct 594 - Dist Maint - Ungrd Ln	303	616	2,221	1,349	424	89	118	1,394	418	2,953	9,885	3.006%
14	Acct 595 - Dist Maint - Ln Trnsfm	180	545	1,885	1,545	212	42	56	670	203	1,432	6,770	2.059%
15	Acct 596 - Dist Maint - St Lt/Sig	-	-	11	96	20	4	5	19	1	5	161	0.049%
16	Acct 597 - Dist Maint - Meters	38	28	98	1	20	4	6	84	27	193	499	0.152%
17	Acct 935 - Admin & Gen - Electric	-	10	29	60	1	-	-	5	-	35	140	0.043%
18	Total historical cost	12,885	20,593	76,817	65,669	21,776	4,985	7,116	42,815	11,283	65,007	328,926	100.001%
19	Inflation factor for year 9/	1.1725	1.1473	1.1059	1.0870	1.0736	1.0580	1.0603	1.0531	1.0286	1.0000		
20	Total adjusted for inflation (L18 x L19)	$ 15,108	$ 23,626	$ 84,952	$ 71,382	$ 23,379	$ 5,274	$ 7,545	$ 45,088	$ 11,585	$ 65,007	$ 352,947	

1/ Based on Company response to Public Staff Data Request No. 54, Item 4.
2/ Amounts from NCUC Form E-1, Item No. 10 - Supplemental Filing, Page 139 adjusted to remove labor component of service company charges based on Public Staff Data Request No. 113, Item 1.
3/ Amounts from NCUC Form E-1, Item No. 10 - Supplemental Filing, Page 138 adjusted to remove labor component of service company charges based on Public Staff Data Request No. 113, Item 1.
4/ NCUC Form E-1, Item No. 10 - Supplemental Filing, Page 137.
5/ NCUC Form E-1, Item No. 10 - Supplemental Filing, Page 136.
6/ NCUC Form E-1, Item No. 10 - Supplemental Filing, Page 135.
7/ Sum of Columns (a) thru (j).
8/ Amount for account in Column (k) divided by total excluding clearing account from Column (k).
9/ One plus amount for year from Johnson Settlement Exhibit 1, Schedule 3-1(c)(3) Column (g).

DOMININON ENERGY NORTH CAROLINA
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North Carolina Retail Operations

Johnson Settlement Exhibit 1
Schedule 3-1(c)(3)

CALCULATION OF INFLATION FACTORS TO BE APPLIED TO HISTORICAL STORM COSTS
For the Test Year Ended December 31, 2018
(in Thousands)

Line No.	Year	Consumer Price Index (CPI) CPI 1/	CPI % 2/	Producer Price Index (PPI) Finished Goods less Food & Energy 1/	Intermediate Materials less Food & Energy 1/	Average PPI 3/	Average PPI % 4/	Average CPI / PPI % 5/
		(a)	(b)	(c)	(d)	(e)	(f)	(g)
1	2009	214.56	17.03%	171.48	173.38	172.43	17.47%	17.25%
2	2010	218.08	15.14%	173.58	180.80	177.19	14.31%	14.73%
3	2011	224.93	11.63%	177.79	191.99	184.89	9.55%	10.59%
4	2012	229.60	9.36%	182.38	192.61	187.50	8.03%	8.70%
5	2013	232.96	7.79%	185.10	193.78	189.44	6.92%	7.36%
6	2014	236.71	6.08%	188.64	195.25	191.95	5.52%	5.80%
7	2015	237.00	5.95%	192.36	189.46	190.91	6.10%	6.03%
8	2016	240.01	4.62%	195.28	186.89	191.09	6.00%	5.31%
9	2017	245.13	2.44%	198.88	193.34	196.11	3.28%	2.86%
10	2018	251.10		203.33	201.77	202.55		

1/ Based on Company response to Public Staff Data Request No. 54, Item 10.
2/ Percentage of increase / (decrease) in average index in Column (a) from base year through test year.
3/ Average of index amounts in Columns (c) and (d).
4/ Percentage of increase / (decrease) in average index in Column (e) from base year through test year.
5/ Average of percentages in Columns (b) and (f).

DOMININON ENERGY NORTH CAROLINA
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North Carolina Retail Operations
ADJUSTMENT TO REMOVE EXECUTIVE COMPENSATION AND BENEFITS
For the Test Year Ended December 31, 2018
(in Thousands)

Johnson Settlement Exhibit 1
Schedule 3-1(d)

Line No.	Item	Amount	
1	System Amount of Total Compensation of Top 4 Executive Positions Per Public Staff	$ 9,168	1/
2	Eliminate 50%	(4,584)	2/
3	Amount of Executive Compensation to be Allocated to DENC	$ 4,584	
4	NC Retail Allocation Factor	4.9841%	
5	NC Retail Amount of Executive Compensation to be Eliminated per Public Staff	(228)	
6	NC retail amount of Executive Compensation to be Eliminated per Company	(137)	3/
7	Public Staff Adjustment to Executive Compensation	$ (91)	

1/ Based on Company response to Public Staff Data Request No. 23.
2/ Public Staff position.
3/ NCUC Form E-1, Item No. 10 - Supplemental Filing, Page 117.

DOMININON ENERGY NORTH CAROLINA
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North Carolina Retail Operations
ADJUSTMENT TO REMOVE EMPLOYEE SEVERANCE PROGRAM COSTS
For the Test Year Ended December 31, 2018
(in Thousands)

Johnson Settlement Exhibit 1
Schedule 3-1(e)

Line No.	Item	Amount	
1	Average Major Corporate-Wide Employee Severance Program Costs	$ 120,376	1/
2	Normalization Period	4.17	2/
3	Normalized Severance Expense - System (Line 1/Line 2)	$28,890	
4	Test Year Major Corporate-Wide Severance Program Costs	(1,078)	3/
5	System Adjustment (Line 3 - Line 4)	$29,968	
6	North Carolina Jurisdictional Allocation Factor	4.9841%	4/
7	North Carolina Jurisdictional Adjustment Per Company (Line 3 x Line 6)	1,440	
8	Normalized level per Public Staff	$1,138	5/
9	Public Staff Adjustment to Employee Severance Program Costs	$ (302)	

1/ NCUC Form E-1, Item No. 10 - Supplemental Filing, Page 107, Line 7.
2/ NCUC Form E-1, Item No. 10 - Supplemental Filing, Page 107, Line 11.
3/ Based on response to Public Staff Data Request No. 51, Item 3.
4/ Salaries and wages factor from NCUC Form E-1, Item No. 10 - Supplemental Filing, Page 73.
5/ Based on 50% of the 2019 VRP costs normalized over 4.5 years per Settlement Agreement.

DOMININON ENERGY NORTH CAROLINA
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North Carolina Retail Operations
ADJUSTMENT TO ANNUAL INCENTIVE PLAN EXPENSE
For the Test Year Ended December 31, 2018
(in Thousands)

Johnson Settlement Exhibit 1
Schedule 3-1(f)

Line No.	Item	Amount	
	Annual Incentive Plan (AIP)		
1	VA Power Executive AIP expense associated with earnings	$ 2,560	1/
2	NC jurisdicational allocation	4.9841%	2/
3	Adjustment to remove AIP related to EPS outcomes - NC (-L1 x L2)	(128)	
4	Executive AIP already removed in executive compensation adjustment	83	3/
5	Adjustment to AIP (L3 + L4)	$ (45)	
	Long Term Incentive Plan (LTI)		
6	LTI associated with ROIC and TSR at target	$ 401	4/
7	Adjustment to remove LTI associated with ROIC and TSR - NC jurisdictional (-L6)	(401)	
8	Executive LTI already removed in executive compensation adjustment	90	3/
9	Adjustment to LTI (L7 + L8)	$ (311)	
10	Adjustment to incentive plan expense (L5 + L9)	$ (356)	

1/ Per Settlement Agreement
2/ NC S&W Allocation factor.
3/ Based on executive compensation adjustment.
4/ Per Settlement Agreement

DOMININON ENERGY NORTH CAROLINA
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North Carolina Retail Operations
ADJUSTMENT TO O&M VOLUNTARY
RETIREMENT PLAN (VRP) BACKFILL
For the Test Year Ended December 31, 2018
(in Thousands)

Johnson Settlement Exhibit 1
Schedule 3-1(g)

ADJUSTMENT NO LONGER REQUIRED

DOMININON ENERGY NORTH CAROLINA
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ADJUSTMENT TO REMOVE ADVERTISING EXPENSE
For the Test Year Ended December 31, 2018
(in Thousands)

Johnson Settlement Exhibit 1
Schedule 3-1(h)

Line No.	Item	Amount	
1	Advertising Expense included per Company	$ 1,293	1/
2	Less: Advertising not related to NC Jurisdiction	(610)	2/
3	Advertising Expense related to VA Jurisdiction to be removed (L1 + L2)	683	
4	NC Jurisdictional Allocation Factor	5.0484%	
5	Adjustment to remove advertising before direct adjustment	(34)	
6	NC direct advertising	11	3/
7	Adjustment to Remove Advertising Expense Per Public Staff (L5 + L6)	(23)	
8		50%	
9		$ (12)	

1/ NCUC Form E-1 Supplemental Item No. 10, page 149, Line 5.
2/ PS DR21-2(a).
3/ Per Settlement Agreement.

DOMININON ENERGY NORTH CAROLINA
Docket No. E-22, Sub 562
North Carolina Retail Operations
ADJUSTMENT TO EXPENSES FOR WEATHER NORMALIZATION, CUSTOMER USAGE, AND GROWTH IN CUSTOMERS
For the Test Year Ended December 31, 2018
(in Thousands)

Johnson Settlement Exhibit 1
Schedule 3-1(i)

Line No.	Item	Amount	
1	Total energy-related expenses not adjusted elsewhere for growth	$3,587	1/
2	Test year per books MWH sales	4,400,784	2/
3	Rate per MWH (L1 / L2)	0.000815	
4	Change in MWH sales related to normalization, usage and growth	(113,669)	3/
5	Adjustment to energy-related expenses (L3 x L4)	(93)	
6	Total customer-related expenses not adjusted elsewhere for growth	1,271	4/
7	Test year billings, excluding duplicate bills	121,436	5/
8	Expense per bill (L6 / L7)	0.010466	
9	Increase in billings due to customer growth	341	6/
10	Adjustment to customer related expenses (L8 x L9)	4	
11	Total adjustment to O&M expenses (L5 + L10)	($89)	

1/ Calculated by Public Staff utilizing cost of service study and other data provided by Company.
2/ Based on review of Company workpapers - Corrected from original filing.
3/ Company Supplemental Exhibit PBH-1, Schedule 2, Column (2), Line 54 less test year amount on Line 2.
4/ Calculated by Public Staff utilizing cost of service study and other data provided by Company.
5/ Based on review of Company workpapers.
6/ Company Supplemental Exhibit PBH-1, Schedule 2, Column (1), Line 54 less test year amount on Line 7.

DOMININON ENERGY NORTH CAROLINA
Docket No. E-22, Sub 562
North Carolina Retail Operations
ADJUSTMENT FOR NON-FUEL VARIABLE O&M EXPENSE DISPLACEMENT
For the Test Year Ended December 31, 2018
(in Thousands)

Johnson Settlement Exhibit 1
Schedule 3-1(j)

Line No.	Item	Amount	
1	Greensville County CC commercial MWH generation monthly average	371,000	1/
2	Number of months	12	
3	Annualized Greensville County CC generation (L1 x L2)	4,452,000	
4	Actual for twelve months ended December 31, 2018	917,306	2/
5	Implicit adjustment to MWH generation	3,534,694	
6	NC retail allocation factor	5.0924%	3/
7	Line loss factor	95.8229%	4/
8	Additional MWH generation added (L5 x L6 x L7)	172,482	
9	Non-fuel energy-related expense factor used by Public Staff	0.000815	5/
10	NC retail displacement adjustment (L8 x -L9)	($141)	

1/ Per Settlement Agreement.
2/ Per Settlement Agreement.
3/ Factor 3 from NCUC Form E-1, Item No. 45a, Schedule 15, Line 95.
4/ Annual MWH sales of 4,377,561 divided by Annual MWH at transmission level of 4,568,385 based on North Carolina jurisdictional amounts on NCUC Form E-1, Item No. 45f, Page 117.
5/ Johnson Settlement Exhibit 1, Schedule 3-1(i), Line 3.

DOMININON ENERGY NORTH CAROLINA
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Johnson Settlement Exhibit 1
Schedule 3-1(k)

ADJUSTMENT TO COMPANY'S INFLATION ADJUSTMENT
For the Test Year Ended December 31, 2018
(in Thousands)

Line No.	Item	Amount	
1	Remove Chesapeake closure costs from test year O&M expenses	$0	1/
2	Remove Brunswick CC O&M expenses already at 2018 level	-	2/
3	Remove portion of Company storm adjustment already at 2018 level	-	3/
4	Reflect Public Staff adjustment for outside services	(209)	4/
5	Reflect Public Staff adjustment to storm costs	(157)	5/
6	Reflect Public Staff adjustment to remove Mt. Storm costs	-	6/
7	Reflect Public Staff adjustment to O&M expenses for changes in customer growth and usage	(89)	7/
8	Reflect Public Staff adjustment for O&M expense displacement	-	8/
9	Reflect Public Staff adjustment to remove Chesterfield Units 3 & 4 costs	-	9/
10	Total adjustment to O&M subject to inflation (Sum of L1 thru L9)	(455)	
11	Inflation percentage	2.264%	10/
12	Public Staff adjustment (L10 x L11)	($10)	

1/ NCUC Form E-1, Item No. 10 - Supplemental Filing, Page 111, Line 12.
2/ Corrected amount per Settlemtnt Agreement.
Item No. 10 - Supplemental Filing, Page 143, Line 2 times Line 4.
3/ Corrected amount per Settlemtnt Agreement.
4/ Johnson Settlement Exhibit 1, Schedule 3-1(m), Line 6.
5/ Johnson Settlement Exhibit 1, Schedule 3-1(c), Line 18.
6/ Corrected amount per Settlemtnt Agreement.
7/ Johnson Settlement Exhibit 1, Schedule 3-1(i), Line 11.
8/ Johnson Settlement Exhibit 1, Schedule 3-1(j), Line 10 times Johnson Settlement Exhibit 1, Schedule 3-1(i)(1), Line 2 divided by Line 3.
9/ Corrected amount per Settlement Agreement.
10/ NCUC Form E-1, Item No. 10 - Supplemental Filing, Page 166, Line 17.

DOMININON ENERGY NORTH CAROLINA
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North Carolina Retail Operations

Johnson Settlement Exhibit 1
Schedule 3-1(l)

ADJUSTMENT TO FUEL EXPENSE TO REFLECT
RECOMMENDED JURISDICTIONAL BASE FUEL FACTOR
For the Test Year Ended December 31, 2018
(in Thousands)

Line No.	Item	Amount	
1	Annualized and normalized NC retail kWh sales	4,287,115,148	1/
2	Base fuel rate, excluding regulatory fee	$0.02089	2/
3	Adjusted fuel clause expense (L1 x L2 / 1000)	89,558	
4	Annualized pro forma fuel expense under present rates, per Company	91,711	3/
5	Public Staff adjustment to fuel clause expense (L3 - L4)	($2,153)	

1/ NCUC Form E-1, Item No. 10 - Supplemental Filing, Page 15, Line 3.
2/ Haynes Second Supplemental
3/ Company Second Supplemental Exhibit PMM-1, Schedule 7, Line 4.

Dominion Energy North Carolina
Docket No. E-22, Sub 562
ADJUSTMENT TO OUTSIDES SERVICES
For the Test Year Ended December 31, 2018

Johnson Exhibit 1
Schedule 3-1(m)

Line No.	Item		Amount	
1	Legal invoices allocated from DES to be excluded	$	505	1/
2	Other allocations from DES to DENC to be excluded		758	1/
3	Legal Invoices - Direct DENC		2,949	2/
4	Total Outside Services to be excluded		(4,212)	
5	NC Retail Allocation Factor		4.9507%	
6	Public Staff Adjustment to Outside Services		(209)	
			0.158	
		$	(176)	

1/ Company response to DR14-2(b).
2/ Per Settlement Agreement.

DOMININON ENERGY NORTH CAROLINA
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North Carolina Retail Operations
INTEREST SYNCHRONIZATION ADJUSTMENT
For the Test Year Ended December 31, 2018
(in Thousands)

Johnson Settlement Exhibit 1
Schedule 3-1(n)

Line No.	Item	Amount	
1	Public Staff original cost rate base	$1,131,758	1/
2	Public Staff long term debt ratio	48.000%	2/
3	Public Staff embedded cost of debt	4.442%	3/
4	Public Staff interest expense income tax deduction (L1 x L2 x L3)	24,133	
5	Company interest expense income tax deduction	23,638	4/
6	Adjustment to interest expense (L4 - L5)	495	
7	Composite tax rate	25.6228%	5/
8	Adjustment to income taxes (-L6 x L7)	($127)	

1/ Johnson Settlement Exhibit 1, Schedule 2, Line 10, Column (c).
2/ Johnson Settlement Exhibit 1, Schedule 4, Line 1, Column (a).
3/ Johnson Settlement Exhibit 1, Schedule 4, Line 1, Column (c).
4/ Johnson Settlement Exhibit 1, Schedule 3-1(n)(1), Line 4.
5/ Johnson Settlement Exhibit 1, Schedule 1-3. Line 8.

DOMININON ENERGY NORTH CAROLINA
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North Carolina Retail Operations
CALCULATION OF COMPANY'S INTEREST
SYNCHRONIZATION ADJUSTMENT
For the Test Year Ended December 31, 2018
(in Thousands)

Johnson Settlement Exhibit 1
Schedule 3-1(n)(1)

Line No.	Item	Amount	
1	NC retail rate base per Company	$1,147,952	1/
2	Long tern debt ratio per Company	46.351%	2/
3	Long term debt cost rate per Company	4.442%	3/
4	Interest tax deduction per Company (L1 x L2 x L3)	$23,638	

1/ Johnson Settlement Exhibit 1, Schedule 2, Line 10, Column (a).
2/ Company Supplemental Exhibit PMM-2, Page 8, Line 1, Column (1).
3/ Company Supplemental Exhibit PMM-2, Page 8, Line 1, Column (2).

DOMININON ENERGY NORTH CAROLINA
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North Carolina Retail Operations
RETURN ON EQUITY AND ORIGINAL COST RATE BASE
BEFORE AND AFTER PUBLIC STAFF PROPOSED INCREASE
For the Test Year Ended December 31, 2018
(In Thousands)

Johnson Settlement Exhibit 1
Schedule 4

			Before Public Staff Proposed Increase				After Public Staff Proposed Increase			
Line No.	Item	Capitalization Ratio	NC Retail Rate Base	Embedded Cost or Return	Weighted Cost or Return	Net Operating Income	NC Retail Rate Base	Embedded Cost or Return	Weighted Cost or Return	Net Operating Income
		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)
1	Long-term debt	48.000% 1/	$543,244 2/	4.442% 1/	2.13% 5/	$24,133 6/	$543,463 9/	4.442% 1/	2.13% 11/	$24,143 12/
2	Common equity	52.000% 1/	588,514 2/	9.50% 4/	4.94% 5/	55,903 7/	588,751 9/	9.75% 1/	5.07% 11/	57,403 12/
3	Total (L1 + L2)	100.000%	$1,131,758 3/		7.07%	$80,036 8/	$1,132,214 10/		7.200%	$81,546

1/ Per Public Staff witness Woolridge.
2/ Column (b), Line 3 times Column (a)
3/ Johnson Settlement Exhibit 1, Schedule 2, Line 10, Column (c).
4/ Column (e) divided by Column (b).
5/ Column (a) times Column (c).
6/ Column (b) times Column (c).
7/ Line 3, Column (e) minus Line 1, Column (e).
8/ Johnson Settlement Exhibit 1, Schedule 3, Line 19, Column (c).
9/ Column (f), Line 3 times Column (a)
10/ Johnson Settlement Exhibit 1, Schedule 2, Line 10, Column (e).
11/ Column (a) times Column (g).
12/ Column (f) times Column (g).

DOMININON ENERGY NORTH CAROLINA
Docket No. E-22, Sub 562
North Carolina Retail Operations
CALCULATION OF PUBLIC STAFF'S ADDITIONAL GROSS REVENUE REQUIREMENT
For the Test Year Ended December 31, 2018
(In Thousands)

Line No.	Item	Debt (a)		Equity (b)		Total 7/ (c)
	Calculation of additional gross revenue requirement					
1	Required net operating income	$24,143	1/	$57,403	4/	$81,546
2	Net operating income before proposed increase	24,133	2/	55,903	5/	80,036
3	Additional net operating income requirement (L1 - L2)	10		1,500		1,510
4	Retention factor	0.9954193	3/	0.7403645	6/	
5	Additional revenue requirement (L3 / L4)	$10		$2,027		$2,037
	Breakdown of additional revenue requirement					
6	Public Staff recommended decrease in base fuel revenue requirement					($2,155)
7	Additional gross base non-fuel revenue requirement (L5 - L6)					$4,192

1/ Johnson Settlement Exhibit 1, Schedule 4, Line 1, Column (i).
2/ Johnson Settlement Exhibit 1, Schedule 4, Line 1, Column (e).
3/ Johnson Settlement Exhibit 1, Schedule 1-2, Line 10.
4/ Johnson Settlement Exhibit 1, Schedule 4, Line 2, Column (i).
5/ Johnson Settlement Exhibit 1, Schedule 4, Line 2, Column (e).
6/ Johnson Settlement Exhibit 1, Schedule 1-2, Line 14.
7/ Column (a) plus Column (b).

DOMININON ENERGY NORTH CAROLINA
Docket No. E-22, Sub 562
North Carolina Retail Operations
CALCULATION OF GROSS REVENUE EFFECT FACTORS
For the Test Year Ended December 31, 2018
(in Thousands)

Johnson Exhibit 1
Schedule 1-2

Line No.	Item		Capital Structure (a)	Cost Rates (b)	Retention Factor (c)	Gross Revenue Effect (d)
1	Rate Base Factor					
2	Long-term debt		50.000% 1/	4.442% 1/	0.9954193 2/	0.0223143 4/
3	Common equity		50.000% 1/	9.00% 1/	0.7403645 3/	0.0607809 4/
4	Total (Sum of Lines 2 and 3)		100.000%			0.0830952
						Amount
5	Net Income Factor					
6	Total revenue					1.0000000
7	Uncollectibles					0.0032850 5/
8	Balance (L6 - L7)					0.9967150
9	Regulatory fee (L8 x 0.130%)	6/				0.0012957
10	Balance (L8 - L9)					0.9954193
11	State income tax (L10 x 5.8517%)	7/				0.0582490
12	Balance (L10 - L11)					0.9371703
13	Federal income tax (L12 x 21%)	8/				0.1968058
14	Retention factor (L12 - L13)					0.7403645

1/ Per Public Staff witness Woolridge.
2/ Line 10.
3/ Line 14.
4/ Column (a) times Column (b) divided by Column (c).
5/ Johnson Exhibit 1, Schedule 3-1(b), Line 5.

DOMININON ENERGY NORTH CAROLINA
Docket No. E-22, Sub 562
North Carolina Retail Operations
CALCULATION OF WEIGHTED
STATE INCOME TAX RATE
For the Test Year Ended December 31, 2018
(in Thousands)

Johnson Exhibit 1
Schedule 1-3

Line No.	Item	Total System (a)	Virginia (b)	North Carolina (c)	Washington DC (d)	West Virginia (e)
1	Weighted state income tax rate					
2	Apportionment factor		93.5230% 2/	3.6873% 4/	0.0000% 2/	2.2788% 2/
3	State income tax rate		6.00% 2/	2.50% 5/	8.25% 2/	6.50% 2/
4	Weighted state income tax rate	5.8517% 1/	5.61138% 3/	0.09218% 3/	0.00000% 3/	0.14812% 3/
5	Composite income tax rate					
6	Weighted state income tax rate (L4)	5.8517%				
7	Federal income tax rate	21% 6/				
8	Composite income tax rate	25.6228% 7/				

1/ Sum of Columns (b) through (e).
2/ NCUC Form E-1, Item No. 13a6(2)va_new.
3/ Line 1 times Line 2.
4/ NCUC Form E-1, Item No. 10 - Supplemental Filing, Page 286, Line 3.
5/ Based on North Carolina Department of Revenue Notice dated December 2018.
6/ Statutory rate.
7/ 1 minus ((1 minus Line 6) times (1 minus Line 7)).

DOMININON ENERGY NORTH CAROLINA
Docket No. E-22, Sub 562
North Carolina Retail Operations
ORIGINAL COST RATE BASE
For the Test Year Ended December 31, 2018
(In Thousands)

Johnson Exhibit 1
Schedule 2

		Under Present Rates			After Public Staff Recommended Increase	
Line No.	Item	NC Retail Adjusted Per Company 1/	Public Staff Adjustments 2/	After Public Staff Adjustments 3/	Rate Increase	After Rate Increase 5/
		(a)	(b)	(c)	(d)	(e)
1	Electric plant in service	$2,142,169	($5,709)	$2,136,460	$0	$2,136,460
2	Accumulated depreciation and amortization	(777,432)	(1,223)	(778,655)	-	(778,655)
3	Net electric plant in service (L1 + L2)	1,364,737	(6,932)	1,357,805	-	1,357,805
4	Materials and supplies	40,755	-	40,755	-	40,755
5	Cash working capital	14,451	(169)	14,282	(1,728) 4/	12,554
6	Other additions	37,149	(14,607)	22,542	-	22,542
7	Other deductions	(26,130)	-	(26,130)	-	(26,130)
8	Customer deposits	(4,615)	-	(4,615)	-	(4,615)
9	Accumulated deferred income taxes	(278,395)	5,214	(273,181)	-	(273,181)
10	Total original cost rate base (Sum of L3 thru L9)	$1,147,952	($16,494)	$1,131,458	($1,728)	$1,129,730

1/ Company Supplemental Exhibit PMM-1, Page 2, Column 5.
2/ Johnson Exhibit 1, Schedule 2-1, Column (h).
3/ Column (a) plus Column (b).
4/ Johnson Exhibit 1, Schedule 2-1(g), Line 44, Column (k).
5/ Column (c) plus Column (d).

DOMININON ENERGY NORTH CAROLINA
Docket No. E-22, Sub 562
North Carolina Retail Operations
SUMMARY OF PUBLIC STAFF RATE BASE ADJUSTMENTS
For the Test Year Ended December 31, 2018
(In Thousands)

Johnson Exhibit 1
Schedule 2-1

Line No.	Item	Adjust ADIT for Certain Balances 1/ (a)	Remove MI Storm Impairment Costs 2/ (b)	Adjust NUG Contract Terminations Expense 3/ (c)	Remove Skiffes Creek Mitigation Costs (d)	Remove Chesterfield Units 3 & 4 Conversion Costs (e)	Adjust CCR Costs 10/ (f)	Adjust Cash Working Capital 11/ (g)	Total Rate Base Adjustments 12/ (h)
1	Electric plant in service	$0	$0	$0	$ (4,437) 4/	$ (1,272) 7/	$0	$0	($5,709)
2	Accumulated depreciation and amortization	-	(993)	(397)	118 5/	48 8/	-	-	(1,223)
3	Net electric plant in service (L1 + L2)	-	(993)	(397)	(4,318)	(1,224)	-	-	(6,932)
4	Materials and supplies	-	-	-	-	-	-	-	-
5	Cash working capital	-	-	-	-	-	-	($169)	(169)
6	Other additions	-	-	-	-	-	(14,607)	-	(14,607)
7	Other deductions	-	-	-	-	-	-	-	-
8	Customer deposits	-	-	-	-	-	-	-	-
9	Accumulated deferred income taxes	8	-	-	1,137 6/	$ 326 9/	3,743	-	5,214
10	Total original cost rate base (Sum of L3 thru L9)	$8	($993)	($397)	($3,181)	($898)	($10,864)	($169)	($16,494)
11	Revenue requirement impact 13/	$1	($83)	($33)	($264)	($75)	($903)	($14)	($1,371)

1/ Johnson Exhibit 1, Schedule 2-1(a), Line 10.
2/ Johnson Exhibit 1, Schedule 2-1(c), Column .
3/ Johnson Exhibit 1, Schedule 2-1(d), Line 11.
4/ Johnson Exhibit 1, Schedule 2-1(b), Line 3.
5/ Johnson Exhibit 1, Schedule 2-1(b), Line 5.
6/ Johnson Exhibit 1, Schedule 2-1(b), Line 4.
7/ Johnson Exhibit 1, Schedule 2-1(e), Line 3.
8/ Johnson Exhibit 1, Schedule 2-1(e), Line 5.
9/ Johnson Exhibit 1, Schedule 2-1(e), Line 4.
10/ Per Public Staff witness Maness.
11/ Johnson Exhibit 1, Schedule 2-1(f), Line 45.
12/ Sum of Column (a) through Column (g).
13/ Line 10 times rate base retention factor of 0.0830952 from Johnson Exhibit 1, Schedule 1-2.

DOMININON ENERGY NORTH CAROLINA
Docket No. E-22, Sub 562
North Carolina Retail Operations
ADJUSTMENT TO ELIMINATE CERTAIN ADIT BALANCES
For the Test Year Ended December 31, 2018
(in Thousands)

Johnson Exhibit 1
Schedule 2-1(a)

Line No.	Item	Amount	
	Eliminate ADIT related to TCJA Regulatory Liabilities		
1	Reg Liability - COS Tax Gross Up	$ (8,196)	1/
2	Reg Liability - COS Tax Gross Up Current	(20,029)	1/
3	Reg Liability - EDIT Amort - Fed Tax Reform	(12,856)	1/
4	Deferred State Taxes	(11,447)	2/
5	Federal Effect of State	2,404	1/
6	Total System Tax Reform Reserves ADIT (sum of L 1 thru 5)	$ 50,124	
7	NC Retail allocation factor	5.0484%	3/
8	Total NC Tax Reform Reserves ADIT per the Public Staff (L6 x L7)	$ 2,530	
9	Tax NC Reform Reserves Balance ADIT per Company	2,522	4/
10	Adjustment Eliminate ADIT related to TCJA Regulattory Liabilities (L8 - L9)	$ 8	

1/ NCUC Form E-1, Item No. 10, page 284, lines 16 through 20.
2/ Company response to Public Staff data request 27-2.
3/ NCUC Form E-1, Item No. 45a, Schedule 15, Line 393.
4/ NCUC Form E-1, Item No. 10, page 283, line 8.

DOMININON ENERGY NORTH CAROLINA
Docket No. E-22, Sub 562
North Carolina Retail Operations
ADJUSTMENT TO REMOVE SKIFFES CREEK MITIGATION COSTS
For the Test Year Ended December 31, 2018
(in Thousands)

Johnson Exhibit 1
Schedule 2-1(b)

Line No.	Item	Amount	
1	Skiffes Creek Mitigation Costs - System	$ 105,612	1/
2	NC Power Supply Transmission Factor 2	4.2009%	2/
3	Public Staff adjustment to remove Skiffes Creek mitigation costs from rate base (L3 x L4)	$ (4,437)	
4	Adjustment to remove ADIT associated with Skiffes Creek	$ 1,137	3/
5	Accumulated Depreciation associated with Skiffes Creek	$ 118	4/
6	Depreciation expense associated with Skiffes Creek	$ (118)	5/

1/ Based on recommendation of Public Staff witness David Williamson.
2/ Factor 2 from NCUC Form E-1, Item No. 45a, Schedule 15, Line 14.
3/ Negative of Line 3 amount times composite income tax rate.
4/ Negative of Line 3 amount times depreciation rate recommended by Public Staff witness Lucas.
5/ Line 3 amount times depreciation rate recommended by Public Staff witness Lucas.

DOMININON ENERGY NORTH CAROLINA
Docket No. E-22, Sub 562
North Carolina Retail Operations
ADJUSTMENT TO REMOVE IMPAIRMENT COSTS FOR MT STORM
For the Test Year Ended December 31, 2018
(In Thousands)

Johnson Exhibit 1
Schedule 2-1(c)

Line No.	Item	Amount	
1	Mt Storm Fuel Flexibility Project Impairment - System	$ 62,364	1/
2	Disallowance per Public Staff	(60,179)	2/
3	Revised Mt Storm Impairment Expense (L1 - L2)	2,185	
4	NC Retail Factor 1	4.9507%	
5	NC Retail Regulatory Asset (L3 x L4)	$ 108	
6	Amortization Period (3 Years)	3	
7	Regulatory Asset Amortization per Public Staff (L5/L6)	36	
8	Regulatory Asset Amortization per Company	1,029	1/
9	Public Staff Adjustment to remove Mt Storm Impairment Expense (L7 - L8)	$ (993)	

1/ Company Adjustment SUPP-5.
2/ Based on recommendation of Public Staff witness Thomas.

DOMININON ENERGY NORTH CAROLINA
Docket No. E-22, Sub 562
North Carolina Retail Operations
ADJUSTMENT TO NUG CONTRACT TERMINATION EXPENSE
REGULATORY ASSET
For the Test Year Ended December 31, 2018
(In Thousands)

Johnson Exhibit 1
Schedule 2-1(d)

Line No.	Description	Amount (a)	
1	NUG Contract Termination Expense - System	$ 135,000	1/
2	Less: Net Capacity Revenue/Replacement Cost	21,400	2/
3	Revised NUG Contract Termination Expense (L1 - L2)	$ 113,600	
4	NC Retail Factor 1	4.9507%	
5	NUG Contract Termination Expense per Public Staff (L3 x L4)	$ 5,624	
6	Remaining Months in Contract (April 2019 - November 2021)	32	
7	Monthly Amortization	$ 176	
8	Times: Twelve Months	12	
9	Annual Amortization per Public Staff (L7 x L8)	$ 2,109	
10	Annual Amortization per Company	2,506	1/
11	Public Staff Adjustment to NUG Contract Termination Expense Reg Asset	$ (397)	

1/ Company Adjustment SUPP-2.
2/ Based on information provided by the Company. (Email 8/15/19)

DOMININON ENERGY NORTH CAROLINA
Docket No. E-22, Sub 562
North Carolina Retail Operations
ADJUSTMENT TO REMOVE COSTS FOR CHESTERFIELD UNITS 3 & 4
For the Test Year Ended December 31, 2018
(in Thousands)

Johnson Exhibit 1
Schedule 2-1(e)

Line No.	Item		Amount	
1	Chesterfield Units 3 & 4 Total System Common Costs	$	25,700	1/
2	NC Retail Factor		4.9507%	2/
3	Public Staff adjustment to remove Chesterfield Units 3 & 4 conversion costs (L1 x L2)	$	(1,272)	
4	Adjustment to remove ADIT associated with Chesterfield Units 3 & 4	$	326	3/
5	Accumulated Depreciation associated with Chesterfield Units 3 & 4	$	48	4/
6	Depreciation expense associated with Chesterfield Units 3 & 4	$	(48)	5/

1/ Based on reccomendation of Public Staff witness Lucas
2/ NCUC Form E-1, Item No. 10 - Supplemental Filing, Page 310, Account 1242063.
3/ Negative of Line 3 amount times composite income tax rate.
4/ Negative of Line 3 amount times depreciation rate recommended by Public Staff witness Lucas.
5/ Line 3 amount times depreciation rate recommended by Public Staff witness Lucas.

DOMININON ENERGY NORTH CAROLINA
Docket No. E-22, Sub 562
North Carolina Retail Operations
CALCULATION OF WORKING CAPITAL FROM
LEAD / LAG STUDY UNDER PRESENT RATES
For the Test Year Ended December 31, 2018
(In Thousands)

Johnson Exhibit 1
Schedule 2-1(f)

Line No.	Item	Per Books Amounts 1/	Company Ratemaking Adjustments 5/	After Company Adjustments 7/	Public Staff Adjustments 8/	After Public Staff Adjustments 9/	(Lead) / Lag Days 10/	Working Capital From Lead/ Lag Study 14/
		(a)	(b)	(c)	(d)	(e)	(f)	(g)
1	Electric operating revenues:							
2	Rate revenues	$353,978 2/	($5,393) 6/	$348,585	$0	$348,585	43.38 11/	$41,410
3	Sales for resale revenues	1,126 2/	-	1,126	-	1,126	38.91 11/	120
4	Other operating revenues	5,941 2/	(823) 6/	5,118	-	5,118	25.19 11/	353
5	Electric operating revenues	361,045	(6,216)	354,829	-	$354,829	43.08	41,883
6	Account 501 - Fuel	24,682	(3,709)	20,973	(382)	20,591	(33.27) 12/	(1,877)
7	Account 518 - Nuclear Fuel	8,487	(1,275)	7,212	(131)	7,080	(3.21) 12/	(62)
8	Account 547 - Other Fuel	55,934	(8,405)	47,529	(866)	46,664	(33.27) 12/	(4,253)
9	Account 555 - Purchased Power	49,912	(25,884)	24,028	(773)	23,255	(28.21)	(1,797)
10	Account 557 - Deferred Fuel	(27,204)	27,204	-	-	-	- 13/	-
11	Payroll expense	34,032	(2,339)	31,693	(1,064)	30,629	(26.90) 12/	(2,257)
12	Benefits and pension expense	8,485	(293)	8,192	-	8,191	(31.81) 12/	(714)
13	OPEB expense	(1,721)	-	(1,721)	-	(1,721)	(20.64) 12/	97
14	Uncollectibles expense	1,109	272	1,381	(236)	1,144	(254.79)	(799)
15	Stores expense	9,243	-	9,243	-	9,243	(43.92)	(1,112)
16	Accrued vacation expense	81	-	81	-	81	- 13/	-
17	Worker's compensation expense	73	-	73	-	73	-	-
18	Prepaid insurance amortization expense	412	-	412	-	412	-	-
19	Director's deferred compensation expense	-	-	-	-	-	-	-
20	Miscellaneous prepaid expense	503	-	503	-	503	-	-
21	Other O&M expense	34,997	7,805	42,802	(4,563)	38,239	(43.65) 12/	(4,573)
22	Total O&M expenses	199,025	(6,624)	192,401	(8,015)	184,384		(17,347)
23	Depreciation and amortization expense	60,066 3/	4,521	64,587	(7,312)	57,275	-	-
24	Current state and federal income taxes	(2,846)	723	(2,123)	3,473	1,350	87.90 12/	325
25	Deferred state and federal income taxes	13,456	138	13,594	-	13,594	-	-
26	Deferred ITC	(74)	-	(74)	-	(74)	-	-
27	Total income taxes	10,536	861	11,397	3,473	14,870		325
28	North Carolina franchise tax	486	-	486	-	486	(523.00)	(696)
29	Property tax expense	10,642	(84)	10,558	-	10,558	(111.96)	(3,239)
30	West Virginia B&O tax expense	1,045	-	1,045	-	1,045	(39.54)	(113)
31	Payroll taxes	2,307	(179)	2,128	-	2,128	(27.26)	(159)
32	Other taxes	102	-	102	-	102	(31.06)	(9)
33	Total taxes other than income	14,582	(263)	14,319	-	14,319		(4,216)
34	Gain / loss on disposition of property	238	(13)	225	-	225	-	-

DOMININON ENERGY NORTH CAROLINA
Docket No. E-22, Sub 562
North Carolina Retail Operations
CALCULATION OF WORKING CAPITAL FROM
LEAD / LAG STUDY UNDER PRESENT RATES
For the Test Year Ended December 31, 2018
(In Thousands)

Johnson Exhibit 1
Schedule 2-1(f)

Line No.	Item	Per Books Amounts 1/ (a)	Company Ratemaking Adjustments 5/ (b)	After Company Adjustments 7/ (c)	Public Staff Adjustments 8/ (d)	After Public Staff Adjustments 9/ (e)	(Lead) / Lag Days 10/ (f)	Working Capital From Lead/ Lag Study 14/ (g)
35	Total electric operating expenses	284,447	(1,518)	282,929	(11,855)	271,072		(21,238)
36	AFUDC	235	(235)	-	-	-	-	-
37	Charitable contributions	330	(330)	-	-	-	-	-
38	Interest on customer deposits	72	-	72	-	72	(182.50)	(36)
39	Interest on tax deficiencies	76	-	76	-	76	- 13/	-
40	Interest expense	24,539	(902)	23,637	1,760	25,397	(90.93)	(6,327)
41	Income available for common equity	51,816 4/	(3,701) 4/	48,115	10,095	58,210	-	-
42	Total requirement	$ 361,045	$ (6,218)	$ 354,829	$ -	$ 354,627		$ (27,601)
43	Cash working capital per Public Staff (L5 + L41)							$14,282
44	Amount per Company application							14,451 15/
45	Adjustment to cash working capital							($169)

1/ NCUC Form E-1, Item No. 10 - Supplemental Filing, Page 308, Column (1), unless footnoted otherwise.
2/ NCUC Form E-1, Item No. 45a, Schedule 2.
3/ Company Supplemental Exhibit PMM-1, Page 1, Line 9, Column (3).
4/ Line 5 minus (Sum of Lines 35 through 39).
6/ NCUC Form E-1, Item No. 10 - Supplemental Filing, Page 308, Column (2), unless footnoted otherwise.
6/ Company Supplemental Exhibit PMM-1, Page 1, Lines 2 through 5, Column (4).
7/ Column (a) plus Column (b).
8/ Johnson Exhibit 1, Schedule 2-1(f)(1), Column (z).
9/ Column (c) plus Column (d).
10/ NCUC Form E-1, Item No. 10 - Supplemental Filing, Page 308, Column (6), unless footnoted otherwise.
11/ Calculated based on the Company's lead-lag workpapers, and the per books amounts for 2015.
12/ Calculated by Public Staff.
13/ Updated composite revenue lag from Column (f), Line 5.
14/ Column (e) divided by 365 days times Column (f).
15/ NCUC Form E-1, Item No. 10 - Supplemental Filing, Page 308, Column (8).

DOMINION ENERGY NORTH CAROLINA
Docket No. E-22, Sub 562
North Carolina Retail Operations
PUBLIC STAFF ADJUSTMENTS TO BE
REFLECTED IN LEAD LAG CALCULATION
For the Test Year Ended December 31, 2018
(In Thousands)

Johnson Exhibit 1
Schedule 3-1(a)
Page 1 of 3

Line No.	Item	Adjust ADIT for Certain Balances 1/ (a)	Reflect Decrease in State Income Tax Rate 1/ (b)	Adjust Uncollectibles 1/ (c)	Adjust Storm Costs 1/ (d)	Adjust Nuclear Outage Costs 1/ (e)	Remove Mt Storm Impairment Costs 1/ (f)	Adjust Allocation of Revenues from Sale of RECs 1/ (g)	Remove Employee Severance Costs 1/ (h)	Remove [illegible] Mitigation Costs 1/ (i)
1	Electric operating revenues:									
2	Rate revenues	$0	$0	$0	$0	$0	$0	$0	$0	$0
3	Sales for resale revenues	-	-	-	-	-	-	-	-	-
4	Other operating revenues	-	-	-	-	-	-	-	-	-
5	Electric operating revenues	-	-	-	-	-	-	-	-	-
6	Account 501 - Fuel	-	-	-	-	-	-	-	-	-
7	Account 518 - Nuclear Fuel	-	-	-	-	-	-	-	-	-
8	Account 547 - Other Fuel	-	-	-	-	-	-	-	-	-
9	Account 555 - Purchased Power	-	-	-	-	-	-	-	-	-
10	Account 557 - Deferred Fuel	-	-	-	-	-	-	-	-	-
11	Payroll expense	-	-	-	(382)	-	-	-	-	-
12	Benefits and pension expense	-	-	-	-	-	-	-	-	-
13	OPEB expense	-	-	-	-	-	-	-	-	-
14	Uncollectibles expense	-	-	(238)	-	-	-	-	-	-
15	Stores expense	-	-	-	-	-	-	-	-	-
16	Accrued vacation expense	-	-	-	-	-	-	-	-	-
17	Worker's compensation expense	-	-	-	-	-	-	-	-	-
18	Prepaid insurance amortization expense	-	-	-	-	-	-	-	-	-
19	Director's deferred compensation expense	-	-	-	-	-	-	-	-	-
20	Miscellaneous prepaid expense	-	-	-	-	-	-	-	-	-
21	Other O&M expense	(37)	-	-	(157)	-	-	-	(1,129)	-
22	Total O&M expense	(37)	-	(238)	(539)	-	-	-	(1,129)	-
23	Depreciation and amortization expense	-	-	-	-	-	(993)	-	-	(118)
24	Current state and federal income taxes	13	-	60	130	-	254	-	290	30
25	Deferred state and federal income taxes	-	-	-	-	-	-	-	-	-
26	Deferred ITC	-	-	-	-	-	-	-	-	-
27	Total income taxes	13	-	60	130	-	254	-	290	30
28	North Carolina franchise tax	-	-	-	-	-	-	-	-	-
29	Property tax expense	-	-	-	-	-	-	-	-	-
30	West Virginia B&O tax expense	-	-	-	-	-	-	-	-	-
31	Payroll taxes	-	-	-	-	-	-	-	-	-
32	Other taxes	-	-	-	-	-	-	-	-	-
33	Total taxes other than income	-	-	-	-	-	-	-	-	-
34	Gain / loss on disposition of property	-	-	-	-	-	-	-	-	-
35	Total electric operating expenses	(24)	-	(178)	(379)	-	(739)	-	(839)	(88)
36	Charitable contributions	-	-	-	-	-	-	-	-	-
37	Interest on customer deposits	-	-	-	-	-	-	-	-	-
38	Interest on tax deficiencies	-	-	-	-	-	-	-	-	-
39	Interest expense	-	-	-	-	-	-	-	-	-
40	Income available for common equity	24	-	178	379	-	739	-	839	88
41	Total requirement	$0	$0	$0	$0	$0	$0	$0	$0	$0

1/ Based on adjustments made by Public Staff in Johnson Exhibit 1, Schedule 3-1.

DOMINION ENERGY NORTH CAROLINA
Docket No. E-22, Sub 562
North Carolina Retail Operations
PUBLIC STAFF ADJUSTMENTS TO BE
REFLECTED IN LEAD LAG CALCULATION
For the Test Year Ending December 31, 2019
(In Thousands)

Johnson Exhibit 1
Schedule 3-1(f)(1)
Page 1 of 3

Line No.	Item	Adjust Chesapeake Retired Plant Levelized Amortization	Remove Executive Compensation Costs	Adjust CCR Costs	Remove Chesterfield Units 3 & 4 Conversion Costs	Adjust Annual Incentive Plan Costs	Adjust O&M VRF Costs	Remove Advertising Expense	Adjust Outside Services
		(j)	(k)	(l)	(m)	(n)	(o)	(p)	(q)
1	Electric operating revenues								
2	Rate revenues	$0	$0	$0	$0	$0	$0	$0	$0
3	Sales for resale revenues	-	-	-	-	-	-	-	-
4	Other operating revenues	-	-	-	-	-	-	-	-
5	Electric operating revenues	-	-	-	-	-	-	-	-
6	Account 501 - Fuel	-	-	-	-	-	-	-	-
7	Account 518 - Nuclear Fuel	-	-	-	-	-	-	-	-
8	Account 547 - Other Fuel	-	-	-	-	-	-	-	-
9	Account 555 - Purchased Power	-	-	-	-	-	-	-	-
10	Account 557 - Deferred Fuel	-	-	-	-	-	-	-	-
11	Payroll expense	-	-	-	-	(712)	-	-	-
12	Benefits and pension expense	-	-	-	-	-	-	-	-
13	OPEB expense	-	-	-	-	-	-	-	-
14	Uncollectibles expense	-	-	-	-	-	-	-	-
15	Stores expense	-	-	-	-	-	-	-	-
16	Accrued vacation expense	-	-	-	-	-	-	-	-
17	Worker's compensation expense	-	-	-	-	-	-	-	-
18	Prepaid insurance amortization expense	-	-	-	-	-	-	-	-
19	Director's deferred compensation expense	-	-	-	-	-	-	-	-
20	Miscellaneous prepaid expense	-	-	-	-	-	-	-	-
21	Other O&M expenses	-	(91)	-	-	-	(1,667)	(34)	(252)
22	Total O&M expenses	-	(91)	-	-	(717)	(1,667)	(34)	(252)
23	Depreciation and amortization expense	-	-	(6,153)	(48)	-	-	-	-
24	Current state and federal income taxes	-	23	1,577	12	183	426	9	62
25	Deferred state and federal income taxes	-	-	-	-	-	-	-	-
26	Deferred ITC	-	-	-	-	-	-	-	-
27	Total income taxes	-	23	1,577	12	183	426	9	62
28	North Carolina franchise tax	-	-	-	-	-	-	-	-
29	Property tax expense	-	-	-	-	-	-	-	-
30	West Virginia B&O tax expense	-	-	-	-	-	-	-	-
31	Payroll taxes	-	-	-	-	-	-	-	-
32	Other taxes	-	-	-	-	-	-	-	-
33	Total taxes other than income	-	-	-	-	-	-	-	-
34	Gain / loss on disposition of property	-	-	-	-	-	-	-	-
35	Total electric operating expenses	-	(68)	(4,576)	(36)	(530)	(1,238)	(25)	(187)
36	Charitable contributions	-	-	-	-	-	-	-	-
37	Interest on customer deposits	-	-	-	-	-	-	-	-
38	Interest on tax deficiency	-	-	-	-	-	-	-	-
39	Interest expense	-	-	-	-	-	-	-	-
40	Income available for common equity	-	68	4,576	36	530	1,238	25	191
41	Total requirement	$0	$0	$0	$0	$0	$0	$0	$0

DOMINION ENERGY NORTH CAROLINA
Docket No. E-22, Sub 562
North Carolina Retail Operations
PUBLIC STAFF ADJUSTMENTS TO BE
REFLECTED IN LEAD LAG CALCULATION
For the Test Year Ended December 31, 2018
(In Thousands)

Johnson Exhibit I
Schedule 3-4(f)(1)
Page 1 of 3

Line No.	Item	Inflation Adjustment (a)	Adjust for Customer Growth, Usage and Weather Normalization (b)	Non-Fuel Variable O&M Expense Adjustment (c)	Annualize Fuel Revenue and Expense at Current Fuel Revenue Rate (d)	Set Expense to Reflect Recommended Base Fuel Factor (e)	Adjust PJM Capacity Rate (f)	Adjust Allocation Percentages (g)	Interest Synchronization (h)	Total Public Staff Adjustments (i)
1	Electric operating revenues:									
2	Rate revenues	$0	$0	$0	$0	$0	$0	$0	$0	$0
3	Sales for resale revenues	-	-	-	-	-	-	-	-	-
4	Other operating revenues	-	-	-	-	-	-	-	-	-
5	Electric operating revenues	-	-	-	-	-	-	-	-	-
6	Account 501 - Fuel	-	-	-	-	(342)	-	-	-	(342)
7	Account 518 - Nuclear Fuel	-	-	-	-	(131)	-	-	-	(131)
8	Account 547 - Other Fuel	-	-	-	-	(906)	-	-	-	(906)
9	Account 555 - Purchased Power	-	-	-	-	(773)	-	-	-	(773)
10	Account 557 - Deferred Fuel	-	-	-	-	-	-	-	-	-
11	Payroll expense	-	-	-	-	-	-	-	-	(1,084)
12	Benefits and pension expense	-	-	-	-	-	-	-	-	-
13	OPEB expense	-	-	-	-	-	-	-	-	-
14	Uncollectibles expense	-	-	-	-	-	-	-	-	(238)
15	Stores expense	-	-	-	-	-	-	-	-	-
16	Accrued vacation expense	-	-	-	-	-	-	-	-	-
17	Worker's compensation expense	-	-	-	-	-	-	-	-	-
18	Prepaid insurance amortization expense	-	-	-	-	-	-	-	-	-
19	Director's deferred compensation expense	-	-	-	-	-	-	-	-	-
20	Miscellaneous prepaid expense	-	-	-	-	-	-	-	-	-
21	Other O&M expenses	(47)	(251)	(902)	-	-	-	-	-	(1,567)
22	Total O&M expenses	(47)	(251)	(902)	-	(2,152)	-	-	-	(6,315)
23	Depreciation and amortization expense	-	-	-	-	-	-	-	-	(7,312)
24	Current state and federal income taxes	11	84	231	-	551	-	-	(451)	3,673
25	Deferred state and federal income taxes	-	-	-	-	-	-	-	-	-
26	Deferred ITC	-	-	-	-	-	-	-	-	-
27	Total income taxes	11	84	231	-	551	-	-	(417)	3,473
28	North Carolina franchise tax	-	-	-	-	-	-	-	-	-
29	Property tax expense	-	-	-	-	-	-	-	-	-
30	West Virginia B&O tax expense	-	-	-	-	-	-	-	-	-
31	Payroll taxes	-	-	-	-	-	-	-	-	-
32	Other taxes	-	-	-	-	-	-	-	-	-
33	Total taxes other than income	-	-	-	-	-	-	-	-	-
34	Gain / loss on disposition of property	-	-	-	-	-	-	-	-	-
35	Total electric operating expenses	(36)	(167)	(671)	-	(1,601)	-	-	(451)	(11,856)
36	Charitable contributions	-	-	-	-	-	-	-	-	-
37	Interest on customer deposits	-	-	-	-	-	-	-	-	-
38	Interest on tax deficiencies	-	-	-	-	-	-	-	-	-
39	Interest expense	-	-	-	-	-	-	-	1,760	1,760
40	Income available for common equity	36	167	671	-	1,601	-	-	(1,309)	10,0[illegible]
41	Total requirement	$0	$0	$0	$0	$0	$0	$0	$0	$0

DOMINION ENERGY NORTH CAROLINA
Docket No. E-22, Sub 562
North Carolina Retail Operations

Johnson Exhibit 1
Schedule 2-1(g)
Page 1 of 2

CALCULATION OF WORKING CAPITAL FROM LEAD / LAG STUDY AFTER RATE INCREASE

For the Test Year Ended December 31, 2018
(In Thousands)

Line No.	Item	Under Present Rates After Adjustments 1/	(Lead) Lag Days 4/	Iteration 1 Increase	Iteration 1 With Increase 11/	Iteration 1 CWC Change 13/
		(a)	(b)	(c)	(d)	(e)
1	Electric operating revenues:					
2	Rate revenues	$348,585	43.36	($9,820) 5/	$338,765	($1,167)
3	Sales for resale revenues	1,126	38.91	-	1,126	-
4	Other operating revenues	5,118	25.19	(32) 6/	5,086	(2)
5	Electric operating revenues	354,829	43.06	(9,852)	344,977	(1,169)
6	Account 501 - Fuel	20,591	(33.27)	-	20,591	-
7	Account 518 - Nuclear Fuel	7,080	(3.21)	-	7,080	-
8	Account 547 - Other Fuel	46,664	(33.27)	-	46,664	-
9	Account 555 - Purchased Power	23,255	(28.21)	-	23,255	-
10	Account 557 - Deferred Fuel	-	-	-	-	-
11	Payroll expense	30,629	(26.90)	-	30,629	-
12	Benefits and pension expense	8,191	(31.61)	-	8,191	-
13	OPEB expense	(1,721)	(20.64)	-	(1,721)	-
14	Uncollectibles expense	1,144	(254.79)	(32) 7/	1,112	23
15	Stores expense	9,243	(43.92)	-	9,243	-
16	Accrued vacation expense	61	-	-	61	-
17	Worker's compensation expense	73	-	-	73	-
18	Prepaid insurance amortization exp.	412	-	-	412	-
19	Director's deferred compensation exp.	-	-	-	-	-
20	Miscellaneous prepaid expense	503	-	-	503	-
21	Other O&M expense	38,239	(43.65)	(13) 8/	38,226	2
22	Total O&M expenses	184,384		(45)	184,339	25
23	Depreciation and amortization exp.	57,275	-	-	57,275	-
24	Net current income taxes	1,350	87.90	(2,513) 9/	(1,163)	(605)
25	Deferred state and federal income taxes	13,594	-	-	13,594	-
26	Deferred ITC	(74)	-	-	(74)	-
27	Total income taxes	14,870		(2,513)	12,357	(605)
28	North Carolina franchise tax	486	(523.00)	-	486	-
29	Property tax expense	10,558	(111.96)	-	10,558	-
30	West Virginia B&O tax expense	1,045	(39.54)	-	1,045	-
31	Payroll taxes	2,128	(27.26)	-	2,128	-
32	Other taxes	102	(31.06)	-	102	-
33	Total taxes other than income	14,319		-	14,319	-
34	Gain / loss on disposition of property	225	-	-	225	-
35	Total electric operating expenses	271,072		(2,558)	268,514	(580)
36	Charitable contributions	-	-	-	-	-
37	Interest on customer deposits	72	(182.50)	-	72	-
38	Interest on tax deficiencies	76	-	-	76	-
39	Other expenses / (income)	148		-	148	-
40	Interest expense	25,397	(90.93)	-	25,397	-
41	Income available for common equity	58,210	-	(7,294) 10/	50,916 12/	-
42	Net operating income for return	83,607		(7,294)	76,313	-
43	Total requirement	$354,827		($9,852)	$344,975	($580)
44	Cumulative change in working capital					($1,749)
45	Rate base under present rates					1,131,458
46	Rate base after rate increase	$1,131,458 2/				$1,129,709
47	Overall rate of return (L42 / L46)	7.39%				6.76%
48	Target rate of return	6.72% 3/				6.72% 3/

1/ Johnson Exhibit 1, Schedule 2-1(f), Column (e).
2/ Johnson Exhibit 1, Schedule 2, Line 10, Column (c).
3/ Johnson Exhibit 1, Schedule 4, Line 3, Column (h).
4/ Johnson Exhibit 1, Schedule 2-1(f), Column (f).
5/ Line 5 minus Line 4 minus Line 3.
6/ ((Line 5 minus $330,000) divided by (1 minus 0.00319951911162212)) minus (Line 5 minus $330,000) plus $330,000.
7/ Line 5 times 0.3285%.
8/ Line 5 times 0.130%.
9/ (Line 41 divided by (1 minus 25.6228%)) minus Line 41.
10/ Column (d) minus Column (a).
11/ Column (a) plus Column (c), unless footnoted otherwise.
12/ Line 46, Column (a) times 50.000% times 9.000%.
13/ Column (c) divided by 365 days times Column (b).

DOMINION ENERGY NORTH CAROLINA
Docket No. E-22, Sub 562
North Carolina Retail Operations
CALCULATION OF WORKING CAPITAL
FROM LEAD / LAG STUDY AFTER RATE
INCREASE
For the Test Year Ended December 31, 2018
(In Thousands)

Johnson Exhibit 1
Schedule 2-1(g)

		Iteration 2			Iteration 3			After Increase	
Line No.	Item	Increase	With Increase 18/	CWC Change 19/	Increase	With Increase 21/	CWC Change 24/	Cumulative Increase	After Increase
		(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)
1	Electric operating revenues:								
2	Rate revenues	($413) 6/	$338,352	($49)	$2 6/	$338,354	$0	($10,231)	$338,354
3	Sales for resale revenues	-	1,126	-	-	1,126	-	-	1,126
4	Other operating revenues '	(1) 14/	5,085	-	- 14/	5,085	-	(33)	5,085
5	Electric operating revenues	(414)	344,563	(49)	2	344,565	-	(10,264)	344,565
6	Account 501 - Fuel	-	20,591	-	-	20,591	-	-	20,591
7	Account 518 - Nuclear Fuel	-	7,080	-	-	7,080	-	-	7,080
8	Account 547 - Other Fuel	-	46,664	-	-	46,664	-	-	46,664
9	Account 555 - Purchased Power	-	23,255	-	-	23,255	-	-	23,255
10	Account 557 - Deferred Fuel	-	-	-	-	-	-	-	-
11	Payroll expense	-	30,629	-	-	30,629	-	-	30,629
12	Benefits and pension expense	-	8,191	-	-	8,191	-	-	8,191
13	OPEB expense	-	(1,721)	-	-	(1,721)	-	-	(1,721)
14	Uncollectibles expense	(1) 7/	1,111	1	0 7/	1,111	-	(33)	1,111
15	Stores expense	-	9,243	-	-	9,243	-	-	9,243
16	Accrued vacation expense	-	61	-	-	61	-	-	61
17	Worker's compensation expense	-	73	-	-	73	-	-	73
18	Prepaid insurance amortization exp.	-	412	-	-	412	-	-	412
19	Director's deferred compensation exp.	-	-	-	-	-	-	-	-
20	Miscellaneous prepaid expense	-	603	-	-	603	-	-	603
21	Other O&M expense	(1) 8/	38,225	-	0 8/	38,225	-	(14)	38,225
22	Total O&M expenses	(2)	184,337	1	0	184,337	-	(47)	184,337
23	Depreciation and amortization exp.	-	57,275	-	-	57,275	-	-	57,275
24	Net current income taxes	(27) 9/	(1,190)	(7)	0 9/	(1,190)	-	(2,540)	(1,190)
25	Deferred state and federal income taxes	-	13,594	-	-	13,594	-	-	13,594
26	Deferred ITC	-	(74)	-	-	(74)	-	-	(74)
27	Total income taxes	(27)	12,330	(7)	0	12,330	-	(2,540)	12,330
28	North Carolina franchise tax	-	486	-	-	486	-	-	486
29	Property tax expense	-	10,558	-	-	10,558	-	-	10,558
30	West Virginia B&O tax expense	-	1,045	-	-	1,045	-	-	1,045
31	Payroll taxes	-	2,128	-	-	2,128	-	-	2,128
32	Other taxes	-	102	-	-	102	-	-	102
33	Total taxes other than income	-	14,319	-	-	14,319	-	-	14,319
34	Gain / loss on disposition of property	-	225	-	-	225	-	-	225
35	Total electric operating expenses	(29)	268,485	(6)	0	268,485	-	(2,587)	268,485
36	Charitable contributions	-	-	-	-	-	-	-	-
37	Interest on customer deposits	-	72	-	-	72	-	-	72
38	Interest on tax deficiencies	-	76	-	-	76	-	-	76
39	Other expenses / (income)	-	148	-	-	148	-	-	148
40	Interest expense	(304) 15/	25,093 17/	76	1 20/	25,094 22/	-	(303)	25,094
41	Income available for common equity	(79) 15/	50,837 18/	-	1 20/	50,838 23/	-	(7,372)	50,838
42	Net operating income for return	(383)	75,930	76	2	75,932	-	(7,675)	75,932
43	Total requirement	($412)	$344,563	$70	$2	$344,565	$0	($10,262)	$344,565
44	Cumulative change in working capital			($1,728)			($1,728)		($1,728)
45	Rate base under present rates			1,131,458			1,131,458		1,131,458
46	Rate base after rate increase			$1,129,730			$1,129,730		$1,129,730
47	Overall rate of return (L42 / L46)			6.72%			6.72%		6.72%
48	Target rate of return			6.72% 3/			6.72% 3/		6.72%

14/ (Line 5 divided by (1 minus 0.00319951911162212)) minus Line 5.
15/ Column (g) minus Column (d).
16/ Column (d) plus Column (f), unless footnoted otherwise.
17/ Line 46, Column (e) times 50.000% times 4.442%.
18/ Line 46, Column (e) times 50.000% times 9.000%.
19/ Column (f) divided by 365 days times Column (b).
20/ Column (j) minus Column (g).
21/ Column (g) plus Column (i), unless footnoted otherwise.
22/ Line 46, Column (h) times 50.000% times 4.442%.
23/ Line 46, Column (h) times 50.000% times 9.000%.
24/ Column (i) divided by 365 days times Column (b).

DOMININON ENERGY NORTH CAROLINA
Docket No. E-22, Sub 562
North Carolina Retail Operations
SUMMARY OF OTHER ADDITIONS
For the Test Year Ended December 31, 2018
(in Thousands)

Johnson Exhibit 1
Schedule 2-2

Line No.	Item	NC Retail Adjusted Per Company 1/ (a)	Public Staff Adjustments 2/ (b)	NC Retail Adjusted Per Public Staff 3/ (c)
1	1132030 - SAP A/R EE Purchase Program	$0	$0	$0
2	1134010 - Joint Owner Receivable	-	-	-
3	1137050 - Account Receivable - ARM-Public	-	-	-
4	1137055 - Accounts Receivable - Other	-	-	-
5	1191210 - Prepaid Insurance - Executive Protection	-	-	-
6	1191220 - Prepaid Insurance - Excess Liability	-	-	-
7	1191240 - Prepaid Insurance - Nuclear Property	-	-	-
8	1191250 - Prepaid Insurance - NEIL	-	-	-
9	1191260 - Prepaid Insurance - General Property	-	-	-
10	1191270 - Prepaid Insurance - Executive Life	-	-	-
11	1191290 - Prepaid Insurance - Workers Comp.	-	-	-
12	1191310 - Prepaid Auto Licenses	-	-	-
13	1191330 - Prepaid Fees & Assessments	-	-	-
14	1191900 - Prepaid - Miscellaneous	-	-	-
15	1199010 - Temporary Facilities	-	-	-
16	1220910 - Other Non-Current Receivables	-	-	-
17	1242020 - Unamort. Loss on Reacquired Debt - Mrtg Bnd	-	-	-
18	1242022 - Reg Asset - Unamort. Loss - Reacquired Debt	-	-	-
19	1242030 - Unamort. Loss on Reacquired Debt - Poll Cntrl	-	-	-
20	1242045 - Unamort. Loss on Reacquired Debt - Write Off	-	-	-
21	1242062 - Reg Asset - NRC Requirements - North Anna	-	-	-
22	1242063 - Reg Asset - NRC Requirements - Surry	-	-	-
23	1250010 - Preliminary Survey and Investigations	-	-	-
24	1251010 - Other Work in Progress	-	-	-
25	1251020 - Other Work in Progress - Direct Post	-	-	-
26	1292860 - Misc. Prepayments - Non Current	-	-	-
27	2220120 - Reg Liab - Deferred Gain on Reacquired Debt	-	-	-
28	1242060 - Reg Asset - Unrecov. Design Basis Costs - NA	-	-	-
29	1242061 - Reg Asset - Unrecov. Design Basis Costs - Surry	-	-	-
30	1242070 - Reg Asset - Unrecov. Tech. Spec. Update	-	-	-
31	1242205 & 1171205 - Reg Asset - NUG Buyout Costs	-	-	-
32	1242265 & 1171265 - Reg Asset - Bear Garden Sub 479	-	-	-
33	1242270 - Reg Asset - Emission Allowances - Non Current	-	-	-
34	1171270 - Reg Asset - Emission Allowances - Current	-	-	-
35	1171245 - Reg Asset - Nuclear Outage Deferral	-	-	-
36	Reg Asset - Chesapeake Closure Costs	-	-	-
37	1171280&1242280&1242285 Reg Asset - CCR Rule Expenditu	-	(14,607)	(14,607)
38	Reg Asset - Warren County Deferral	-	-	-
39	Reg Asset - Brunswick County Deferral	-	-	-
40	1171255 & 1242255 Reg Asset - North Branch Net Proceeds	-	-	-
41	Rounding	37,149	-	37,149
42	Total Other Additions	$37,149	($14,607)	$22,542

1/ Based on review of Company Item 10 workpapers.
2/ Based on adjustments recommended by Public Staff.
3/ Column (a) plus Column (b).

DOMININON ENERGY NORTH CAROLINA
Docket No. E-22, Sub 562
North Carolina Retail Operations
SUMMARY OF OTHER DEDUCTIONS
For the Test Year Ended December 31, 2018
(In Thousands)

Johnson Exhibit 1
Schedule 2-3

Line No.	Item	NC Retail Adjusted Per Company 1/ (a)	Public Staff Adjustments 2/ (b)	NC Retail Adjusted Per Public Staff 3/ (c)
1	2171138 - Reg. Liab. - Other - NCUC Order (DOE Settlement)	$0	$0	$0
2	2141100 - Accrued Vacation	-	-	-
3	2190010 - Capital Lease Obligation - Current	-	-	-
4	2290010 - Capital Lease Obligation - Noncurrent	-	-	-
5	2191000 - Appropriated Funds - Customer Accounts	-	-	-
6	2191800 - Centralized Appropriations	-	-	-
7	2192030 - Supplemental Pensions - Current	-	-	-
8	2192060 - Reserve for IBNR/FBNP Hospitalization	-	-	-
9	2192070 - Reserve for IBNR/FBNP Dental/Vision	-	-	-
10	2299025 - Accum. Provisions for Injuries and Damages	-	-	-
11	2141400 - Accr. Severance Pay	-	-	-
12	2199040 - Customer Advances for Construction	-	-	-
13	1292840 - FAS 112 - Deferred Post Employment Benefit	-	-	-
14	1292870 - ME Pension Asset / Oblig. - FAS 158 - Non Current	-	-	-
15	1291810 - Non Current Asset - Worker's Compensation	-	-	-
16	2291010 - Non Current Liability - Workers Compensation	-	-	-
17	2291030 - Non Current Liability - Long Term Disability	-	-	-
18	2291510 - OPEB ME 158 Benefit Obligation - Non Cur.	-	-	-
19	2291050 - Non Current Liability - Supplemental Post Empl	-	-	-
20	2291080 - Deferred Compensation - Executives	-	-	-
21	2299910 - Other Non Current Liabilities	-	-	-
22	6199010 - Other Income CIAC Tax Recovery	-	-	-
23	Company adjustment to eliminate nuclear outage deferral balance	(26,130)	-	(26,130)
24	Total Other Deductions	($26,130)	$0	($26,130)

1/ Based on review of Company Item 10 workpapers.
2/ Based on adjustments recommended by Public Staff.
3/ Column (a) plus Column (b).

DOMININON ENERGY NORTH CAROLINA
Docket No. E-22, Sub 562
North Carolina Retail Operations
NET OPERATING INCOME FOR RETURN
For the Test Year Ended December 31, 2018
(In Thousands)

Johnson Exhibit 1
Schedule 3

		Under Present Rates			After Public Staff Recommended Increase	
Line No.	Item	NC Retail Adjusted Per Company 1/	Public Staff Adjustments 2/	After Public Staff Adjustments 3/	Rate Increase	After Rate Increase 10/
		(a)	(b)	(c)	(d)	(e)
1	Electric operating revenues:					
2	Base non-fuel rate revenues	$256,741	$0	$256,741	($8,079) 4/	$248,662
3	Base fuel revenues	91,845	-	91,845	(2,155) 5/	89,690
4	Late payment fees	1,187	-	1,187	(33) 6/	1,154
5	Other revenues	5,057	-	5,057	- 7/	5,057
6	Electric operating revenues (Sum of L2 thru L5)	354,830	-	354,830	($10,267)	344,563
7	Electric operating expenses:					
8	Operations and maintenance:					
9	Fuel clause expenses	91,725	(2,153)	89,572	-	89,572
10	Other operations and maintenance expenses	100,674	(5,863)	94,811	(47) 8/	94,764
11	Depreciation and amortization	64,586	(7,312)	57,274	-	57,274
12	Gain / loss on disposition of property	225	-	225	-	225
13	Taxes other than income taxes	14,319	-	14,319	-	14,319
14	Income taxes	11,397	3,542	14,939	(2,609) 9/	12,330
15	Total electric operating expenses (Sum of L8 thru L14)	282,926	(11,787)	271,139	(2,656)	268,483
16	Net operating income before adjustments (L6 - L15)	71,904	11,787	83,691	(7,611)	76,080
17	Interest on customer deposits	(72)	-	(72)	-	(72)
18	Interest on tax deficiencies	(76)	-	(76)	-	(76)
19	Net operating income for return (Sum of L16 thru L18)	$71,756	$11,787	$83,543	($7,611)	$75,932

1/ Company Supplemental Exhibit PMM-1, Page 1, Column 5, unless footnoted otherwise.
2/ Johnson Exhibit 1, Schedule 3-1, Column (u).
3/ Column (a) plus Column (b).
4/ Johnson Exhibit 1, Schedule 5, Line 7 minus other revenues on Line 5 minus late payment fees on Line 4.
5/ Johnson Exhibit 1, Schedule 5, Line 6.
6/ ((Line 6 minus Line 5) divided by (1 minus late payment fee rate of 0.320%)) minus (Line 6 minus Line 5).
7/ Based on testimony of Company witness Paul Haynes.
8/ Line 6 times (1 minus retention factor after uncollectibles and regulatory fee from Johnson Exhibit 1, Schedule 1-2, Line 10).
9/ Line 6 minus sum of Lines 8 thru 13 minus Johnson Exhibit 1, Schedule 5, Line 3, Column (a), times composite income tax rate of 25.6228%.
10/ Column (c) plus Column (d).

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North Carolina Retail Operations
SUMMARY OF PUBLIC STAFF NET OPERATING
INCOME ADJUSTMENTS
For the Test Year Ended December 31, 2018
(In Thousands)

Line No.	Item	Adjust Lobbying Expense (a)	Adjust Uncollectibles (b)	Adjust Storm Costs (c)	Remove Executive Compensation Costs (d)	Remove Employee Severance Costs (e)	Adjust Incentive Plan Costs (f)	Adjust O&M VRP Costs (g)	Remove Advertising Expense (h)
1	Electric operating revenues:								
2	Base non-fuel rate revenues	$0	$0	$0	$0	$0	$0	$0	$0
3	Base fuel revenues	-	-	-	-	-	-	-	-
4	Late payment fees	-	-	-	-	-	-	-	-
5	Other revenues	-	-	-	-	- 10/	-	-	-
6	Electric operating revenues (Sum of L2 thru L5)	-	-	-	-	-	-	-	-
7	Electric operating expenses:								
8	Operations and maintenance:								
9	Fuel clause expenses	-	-	-	-	-	-	-	-
10	Other operations and maintenance expenses	(51) 1/	(236) 2/	(509) 4/	($91) 5/	($1,128) 6/	(712) 7/	($1,662) 9/	($34) 10/
11	Depreciation and amortization	-	-	-	-	-	-	-	-
12	Gain / loss on disposition of property	-	-	-	-	-	-	-	-
13	Taxes other than income taxes	-	-	-	-	-	-	-	-
14	Income taxes	13 3/	60 3/	130 3/	23 3/	289 3/	182 3/	426 3/	9 3/
15	Total electric operating expenses (Sum of L6 thru L14)	(38)	(176)	(379)	(68)	(839)	(530)	(1,236)	(25)
16	Net operating income before adjustments (L6 - L15)	38	176	379	68	839	530	1,236	25
17	Interest on customer deposits	-	-	-	-	-	-	-	-
18	Interest on tax deficiencies	-	-	-	-	-	-	-	-
19	Net operating income for return (Sum of L16 thru L18)	$38	$176	$379	$68	$839	$530	$1,236	$25
20	Calculated revenue requirement impact 8/	($52)	($238)	($512)	($92)	($1,133)	($716)	($1,669)	($34)

1/ Johnson Exhibit 1, Schedule 3-1(a), Line 5.
2/ Johnson Exhibit 1, Schedule 3-1(b), Line 9.
3/ Line 6 minus Sum of Lines 9 through 13 times composite income tax rate of 25.6226%.
4/ Johnson Exhibit 1, Schedule 3-1(c), Line 19.
5/ Johnson Exhibit 1, Schedule 3-1(d), Line 7.
6/ Johnson Exhibit 1, Schedule 3-1(e), Line 9.
7/ Johnson Exhibit 1, Schedule 3-1(f), Line 10.
8/ Negative of Line 19 divided by net income retention factor from Johnson Exhibit 1, Schedule 1-2, Line 14.
9/ Johnson Exhibit 1, Schedule 3-1(g), Line 7.

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North Carolina Retail Operations
SUMMARY OF PUBLIC STAFF NET OPERATING
INCOME ADJUSTMENTS
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Johnson Exhibit 1
Schedule 3-1
Page 2 of 3

Line No.	Item	Customer Growth, Usage and Weather Normalization	Non-Fuel Variable O&M Expense Displacement Adjustment	Adjust Outside Service	Remove Skiffes Creek Mitigation Costs	Remove Chesterfield Units 3 & 4 Conversion Costs	Remove Mt Storm Impairment Costs	Inflation Adjustment	Adjust CCR Costs
		(i)	(j)	(k)	(l)	(m)	(n)	(o)	(p)
1	Electric operating revenues:								
2	Base non-fuel rate revenues	$0	$0	$0	$0	$0	$0	$0	$0
3	Base fuel revenues	-	-	-	-	-	-	-	-
4	Late payment fees	-	-	-	-	-	-	-	-
5	Other revenues	-	-	-	-	-	-	-	-
6	Electric operating revenues (Sum of L2 thru L5)	-	-	-	-	-	-	-	-
7	Electric operating expenses:								
8	Operations and maintenance:								
9	Fuel clause expenses	-	-	-	-	-	-	-	-
10	Other operations and maintenance expenses	(251) 11/	(902) 12/	(243) 13/	-	-	-	(43) 17/	-
11	Depreciation and amortization	-	-	-	(118) 14/	(48) 15/	(993) 16/	-	(6,153) 16/
12	Gain / loss on disposition of property	-	-	-	-	-	-	-	-
13	Taxes other than income taxes	-	-	-	-	-	-	-	-
14	Income taxes	64 3/	231 3/	62 3/	30 3/	12 3/	254 3/	11 3/	1,577 3/
15	Total electric operating expenses (Sum of L8 thru L14)	(187)	(671)	(181)	(88)	(36)	(739)	(32)	(4,576)
16	Net operating income before adjustments (L6 - L15)	(187	671	181	88	36	739	32	4,576
17	Interest on customer deposits	-	-	-	-	-	-	-	-
18	Interest on tax deficiencies	-	-	-	-	-	-	-	-
19	Net operating income for return (Sum of L16 thru L18)	$187	$671	$181	$88	$36	$739	$32	$4,576
20	Calculated revenue requirement impact 8/	($252)	($906)	($245)	($119)	($49)	($998)	($43)	($6,181)

10/ Johnson Exhibit 1, Schedule 3-1(h), Line 6.
11/ Johnson Exhibit 1, Schedule 3-1(i), Line 11.
12/ Johnson Exhibit 1, Schedule 3-1(j), Line 10.
13/ Johnson Exhibit 1, Schedule 3-1(m), Line 6.
14/ Johnson Exhibit 1, Schedule 2-1(b), Line 6.
15/ Johnson Exhibit 1, Schedule 2-1(e), Line 6.
16/ Johnson Exhibit 1, Schedule 2-1(c), Line 9.

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North Carolina Retail Operations
SUMMARY OF PUBLIC STAFF NET OPERATING
INCOME ADJUSTMENTS
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(In Thousands)

Johnson Exhibit 1
Schedule 3-1
Page 3 of 3

Line No.	Item	Set Expense to Reflect Recommended Base Fuel Factor (r)	Interest Synchronization Adjustment (t)	Total NOI Adjustments 21/ (u)
1	Electric operating revenues:			
2	Base non-fuel rate revenues	$0	$0	$0
3	Base fuel revenues	-	-	-
4	Late payment fees	-	-	-
5	Other revenues	-	-	-
6	Electric operating revenues (Sum of L2 thru L5)	-	-	-
7	Electric operating expenses:			
8	Operations and maintenance:			
9	Fuel clause expenses	(2,153) 19/	-	(2,153)
10	Other operations and maintenance expenses	-	-	(5,683)
11	Depreciation and amortization	-	-	(7,312)
12	Gain / loss on disposition of property	-	-	-
13	Taxes other than income taxes	-	-	-
14	Income taxes	552 3/	(383) 20/	3,542
15	Total electric operating expenses (Sum of L8 thru L14)	(1,601)	(383)	(11,787)
16	Net operating income before adjustments (L6 - L15)	1,601	383	11,787
17	Interest on customer deposits	-	-	-
18	Interest on tax deficiencies	-	-	-
19	Net operating income for return (Sum of L16 thru L18)	$1,601	$383	$11,787
20	Calculated revenue requirement impact 6/	($2,162)	($517)	($15,920)

17/ Johnson Exhibit 1, Schedule 3-1(k), Line 12.
18/ Per Public Staff witness Maness.
19/ Johnson Exhibit 1, Schedule 3-1(l), Line 5.
20/ Johnson Exhibit 1, Schedule 3-1(n), Line 8.
21/ Sum of Column (a) through Column (t).

DOMININON ENERGY NORTH CAROLINA
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North Carolina Retail Operations
ADJUSTMENT TO LOBBYING EXPENSE
For the Test Year Ended December 31, 2018
(In Thousands)

Johnson Exhibit 1
Schedule 3-1(a)

Line No.	Item	Amount	
1	Internal Lobbying Costs to be removed per Public Staff	$844	1/
2	External Lobbing Costs to be removed per Public Staff	196	1/
3	Total Lobbying Costs to be Excluded (L1 + L2)	1,040	
4	NC Retail Allocation Factor	4.9507%	2/
5	NC Retail Lobbying Costs to be Excluded per Public Staff (-L3 x L4)	($51)	

1/ E-1, Item 18(a) & Company responses to DR49 and DR119.
2/ NC Jurisdictional Factor 1.

DOMININON ENERGY NORTH CAROLINA
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North Carolina Retail Operations

Johnson Exhibit 1
Schedule 3-1(b)

ADJUSTMENT TO UNCOLLECTIBLES EXPENSE
For the Test Year Ended December 31, 2018
(in Thousands)

Line No.	Item	Amount	
1	Average bad debt expense attributed to retail customers	$24,084	1/
2	Percentage to North Carolina retail	4.8779%	2/
3	Average bad debt expense for North Carolina retail (L1 x L2)	1,175	
4	Average North Carolina retail revenues	357,717	3/
5	Uncollectibles percentage per Public Staff (L3 / L4)	0.3285%	
6	North Carolina retail revenues (including fuel) adjusted for weather and customer growth per Company	348,586	4/
7	Uncollectibles expense per Public Staff (L5 x L6)	1,145	
8	Amount per Company	1,381	5/
9	Adjustment to uncollectibles expense (L7 - L8)	($236)	

1/ NCUC Form E-1, Item No. 10 - Supplemental Filing, Page 151, Line 3 thru Line 6, divided by 4.
2/ NCUC Form E-1, Item No. 45a, Schedule 15, Line 399.
3/ NCUC Form E-1, Item No. 10 - Supplemental Filing, Page 155. The average for the last 4 years; not 5.
4/ Company Exhibit PMM-1, Scheduel 1, Col. 5, Line 2 + Line 3.
5/ NCUC Form E-1, Item No. 10 - Supplemental Filing, Page 150, Line 3.

DOMININON ENERGY NORTH CAROLINA
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North Carolina Retail Operations
ADJUSTMENT TO NORMALIZED LEVEL OF
STORM O&M EXPENSE
For the Test Year Ended December 31, 2018
(in Thousands)

Johnson Exhibit 1
Schedule 3-1(c)

Line No.	Item	Amount	
	Overtime hours		
1	2009	105,084	1/
2	2010	128,942	2/
3	2011	263,752	2/
4	2012	190,679	2/
5	2013	85,741	2/
6	2014	13,865	2/
7	2015	30,692	2/
8	2016	134,616	2/
9	2017	35,720	2/
10	2018	184,801	2/
11	Ten year average overtime wages ((Sum of L1 thru L10) / 10)	117,389	
12	Hourly rate (in thousands)	0.0066	3/
13	Average overtime wages per Public Staff (L11 x L12)	775	
14	Average overtime wages per Company	7,828	4/
15	Adjustment to overtime wages (L13 - L14)	(7,053)	
16	NC retail percentage	4.9841%	5/
17	Adjustment to overtime wages - NC retail (L15 x L16)	(352)	
18	Adjustment to other storm expenses - NC retail	(157)	6/
19	Public Staff adjustment - NC retail (L17 + L18)	($509)	

1/ DNCP Sub 532 Fernald Exhibit 1, Schedule 3-1 Storm Adj, Line 4.
2/ NCUC Form E-1, Item No. 10 - Supplemental Filing, Page 128, Lines 10 thru 18.
3/ NCUC Form E-1, Item No. 10 - Supplemental Filing, Page 128, Line 18, Column (3) divided by Line 18, Column (2), times (1 plus Line 4).
4/ NCUC Form E-1, Item No. 10 - Supplemental Filing, Page 128, Line 5.
5/ Salaries and wages factor from NCUC Form E-1, Item No. 10 - Supplemental Filing, Page 73.
6/ Johnson Exhibit 1, Schedule 3-1(c)(1), Line 17, Column (e).

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North Carolina Retail Operations
ADJUSTMENT TO NORMALIZED LEVEL OF
STORM O&M EXPENSE EXCLUDING LABOR
For the Test Year Ended December 31, 2018
(In Thousands)

Johnson Exhibit 1
Schedule 3-1(c)(1)

Line No.	Item	Normalized Amount per Public Staff 1/ (a)	Normalized Amount per Company 2/ (b)	Public Staff Adjustment 3/ (c)	NC Retail Allocation Factor 4/ (d)	Public Staff Adjustment - NC Retail 5/ (e)
1	Acct 562 - Trans Op - Station Exp	$0	$0	$0	4.2841%	$0
2	Acct 563 - Trans Op - Ovrhd Lines	0	-	-	4.2071%	-
3	Acct 566 - Trans Op - Misc Exp	87	96	(9)	4.4492%	-
4	Acct 582 - Dist Op - Station Exp	7	8	(1)	5.7804%	-
5	Acct 583 - Dist Op - Ovhd Lines	2,332	2,354	(22)	7.5771%	(2)
6	Acct 584 - Dist Op - Ungrd Lines	272	297	(25)	3.7154%	(1)
7	Acct 585 - Dist Op - St Lt/Sig Lines	0	-	-	5.4307%	-
8	Acct 586 - Dist Op - Meters	24	25	(1)	2.5127%	-
9	Acct 587 - Dist Op - Cust Install	130	137	(7)	5.4413%	-
10	Acct 588 - Dist Op - Misc Exp	4,832	5,253	(421)	6.1822%	(26)
11	Acct 593 - Dist Maint - Ovrhd Ln	25,738	27,355	(1,617)	7.5771%	(123)
12	Acct 594 - Dist Maint - Ungrd Ln	1,061	1,139	(78)	3.7154%	(3)
13	Acct 595 - Dist Maint - Ln Trnsfm	727	783	(56)	4.4475%	(2)
14	Acct 596 - Dist Maint - St Lt/Sig	17	19	(2)	5.4307%	-
15	Acct 597 - Dist Maint - Meters	54	55	(1)	2.5127%	-
16	Acct 935 - Admin & Gen - Electric	15	17	(2)	6.1618%	-
17	Total	$35,296	$37,538	($2,242)		($157)

1/ Johnson Exhibit 1, Schedule 3-1(c)(2), Line 20, Column (k) divided by ten times distribution percentage for account from Johnson Exhibit 1, Schedule 3-1(c)(2), Column (l).
2/ NCUC Form E-1, Item No. 10 - Supplemental Filing, Page 129, Column (4).
3/ Column (a) minus Column (b).
4/ NCUC Form E-1, Item No. 45a - Supplemental Filing, Schedule 3.
5/ Column (c) times Column (d).

DOMININON ENERGY NORTH CAROLINA
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North Carolina Retail Operations
STORM O&M EXPENSES
EXCLUDING LABOR ADJUSTED
FOR INFLATION
For the Test Year Ended December 31, 2018
(in Thousands)

Johnson Exhibit 1
Schedule 3-1(c)(2)

Line No.	Item	2009 1/ (a)	2010 1/ (b)	2011 1/ (c)	2012 1/ (d)	2013 1/ (e)	2014 2/ (f)	2015 3/ (g)	2016 4/ (h)	2017 5/ (i)	2018 6/ (j)	Total for Ten Years 7/ (k)	Distribution Percent 8/ (l)
1	Acct 184 - Clearing Accounts	$0	$0	584	$0	$0	$0	$0	$0	$0	$0	84	
2	Acct 562 - Trans Op - Station Exp	-	-	1	-	-	-	-	-	-	-	1	0.000%
3	Acct 563 - Trans Op - Ovrhd Lines	-	-	-	-	-	-	-	-	-	-	-	0.000%
4	Acct 566 - Trans Op - Misc Exp	-	-	808	-	-	-	-	-	-	-	808	0.246%
5	Acct 582 - Dist Op - Station Exp	-	7	25	15	5	1	1	6	1	5	66	0.020%
6	Acct 583 - Dist Op - Ovhd Lines	1,911	2,196	7,603	2,094	809	173	229	2,117	570	4,025	21,727	6.607%
7	Acct 584 - Dist Op - Ungrd Lines	35	205	799	376	110	23	30	302	82	578	2,540	0.772%
8	Acct 585 - Dist Op - St Lt/Sig Lines	-	-	-	-	-	-	-	-	-	-	-	0.000%
9	Acct 586 - Dist Op - Meters	11	10	40	88	15	3	4	21	3	25	220	0.067%
10	Acct 587 - Dist Op - Cust Install	55	66	209	93	23	5	6	183	69	420	1,209	0.368%
11	Acct 588 - Dist Op - Misc Exp	804	2,752	13,197	18,180	2,789	528	694	3,182	352	2,560	45,018	13.690%
12	Acct 593 - Dist Maint - Ovrhd Ln	9,548	14,138	49,717	41,772	17,348	4,113	5,967	34,872	9,547	52,776	239,798	72.922%
13	Acct 594 - Dist Maint - Ungrd Ln	303	616	2,221	1,349	424	89	118	1,394	418	2,953	9,885	3.006%
14	Acct 595 - Dist Maint - Ln Trnsfm	160	545	1,885	1,545	212	42	56	670	203	1,432	6,770	2.059%
15	Acct 596 - Dist Maint - St Lt/Sig	-	-	11	96	20	4	5	19	1	6	161	0.049%
16	Acct 597 - Dist Maint - Meters	38	28	98	1	20	4	6	84	27	193	499	0.152%
17	Acct 935 - Admin & Gen - Electric	-	10	29	60	1	-	-	5	-	35	140	0.043%
18	Total historical cost	12,665	20,593	76,817	65,669	21,776	4,985	7,116	42,815	11,263	65,007	328,926	100.001%
19	Inflation factor for year 9/	1.1725	1.1473	1.1059	1.0870	1.0736	1.0580	1.0603	1.0531	1.0286	1.0000		
20	Total adjusted for inflation (L18 x L19)	$ 15,108	$ 23,626	$84,952	$ 71,382	$23,379	$ 5,274	$ 7,546	$45,088	$ 11,585	$65,007	$ 352,947	

1/ Based on Company response to Public Staff Data Request No. 54, Item 4.
2/ Amounts from NCUC Form E-1, Item No. 10 - Supplemental Filing, Page 139 adjusted to remove labor component of service company charges based on Public Staff Data Request No. 113, Item 1.
3/ Amounts from NCUC Form E-1, Item No. 10 - Supplemental Filing, Page 138 adjusted to remove labor component of service company charges based on Public Staff Data Request No. 113, Item 1.
4/ NCUC Form E-1, Item No. 10 - Supplemental Filing, Page 137.
5/ NCUC Form E-1, Item No. 10 - Supplemental Filing, Page 136.
6/ NCUC Form E-1, Item No. 10 - Supplemental Filing, Page 135.
7/ Sum of Columns (a) thru (j).
8/ Amount for account in Column (k) divided by total excluding clearing account from Column (k).
9/ One plus amount for year from Johnson Exhibit 1, Schedule 3-1(c)(3) Column (g).

DOMININON ENERGY NORTH CAROLINA
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North Carolina Retail Operations

Johnson Exhibit 1
Schedule 3-1(c)(3)

CALCULATION OF INFLATION
FACTORS TO BE APPLIED TO
HISTORICAL STORM COSTS
For the Test Year Ended December 31, 2018
(In Thousands)

Line No.	Year	Consumer Price Index (CPI): CPI 1/	Consumer Price Index (CPI): CPI % 2/	Producer Price Index (PPI): Finished Goods less Food & Energy 1/	Producer Price Index (PPI): Intermediate Materials less Food & Energy 1/	Producer Price Index (PPI): Average PPI 3/	Producer Price Index (PPI): Average PPI % 4/	Average CPI / PPI % 5/
		(a)	(b)	(c)	(d)	(e)	(f)	(g)
1	2009	214.56	17.03%	171.48	173.38	172.43	17.47%	17.25%
2	2010	218.08	15.14%	173.58	180.80	177.19	14.31%	14.73%
3	2011	224.93	11.63%	177.79	191.99	184.89	9.55%	10.59%
4	2012	229.60	9.36%	182.38	192.61	187.50	8.03%	8.70%
5	2013	232.96	7.79%	185.10	193.78	189.44	6.92%	7.36%
6	2014	236.71	6.08%	188.64	195.25	191.95	5.52%	5.80%
7	2015	237.00	5.95%	192.36	189.46	190.91	6.10%	6.03%
8	2016	240.01	4.62%	195.28	186.89	191.09	6.00%	5.31%
9	2017	245.13	2.44%	198.88	193.34	196.11	3.28%	2.86%
10	2018	251.10		203.33	201.77	202.55		

1/ Based on Company response to Public Staff Data Request No. 54, Item 10.
2/ Percentage of increase / (decrease) in average index in Column (a) from base year through test year.
3/ Average of index amounts in Columns (c) and (d).
4/ Percentage of increase / (decrease) in average index in Column (e) from base year through test year.
5/ Average of percentages in Columns (b) and (f).

DOMININON ENERGY NORTH CAROLINA
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North Carolina Retail Operations
ADJUSTMENT TO REMOVE EXECUTIVE COMPENSATION AND BENEFITS
For the Test Year Ended December 31, 2018
(in Thousands)

Johnson Exhibit 1
Schedule 3-1(d)

Line No.	Item	Amount
1	System Amount of Total Compensation of Top 4 Executive Positions Per Public Staff	$ 9,168 1/
2	Eliminate 50%	(4,584)
3	Amount of Executive Compensation to be Allocated to DENC	$ 4,584
4	NC Retail Allocation Factor	4.9841%
5	NC Retail Amount of Executive Compensation to be Eliminated per Public Staff	(228)
6	NC retail amount of Executive Compensation to be Eliminated per Company	(137)
7	Public Staff Adjustment to Executive Compensation	$ (91)

1/ Based on Company response to Public Staff Data Request No. 23.

Johnson Exhibit 1
Schedule 3-1(e)

DOMININON ENERGY NORTH CAROLINA
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North Carolina Retail Operations
ADJUSTMENT TO REMOVE EMPLOYEE SEVERANCE PROGRAM COSTS
For the Test Year Ended December 31, 2018
(In Thousands)

Line No.	Item	Amount	
1	Average Major Corporate-Wide Employee Severance Program Costs	$ 120,376	1/
2	Normalization Period	4.17	2/
3	Normalized Severance Expense - System (Line 1/Line 2)	$28,890	
4	Test Year Major Corporate-Wide Severance Program Costs	(1,078)	3/
5	System Adjustment (Line 3 - Line 4)	$29,968	
6	North Carolina Jurisdictional Allocation Factor	4.9841%	4/
7	North Carolina Jurisdictional Adjustment Per Company (Line 3 x Line 6)	1,440	
8	Normalized level per Public Staff from 2016 rate case	$312	5/
9	Public Staff Adjustment to Employee Severance Program Costs	$ (1,128)	

1/ NCUC Form E-1, Item No. 10 - Supplemental Filing, Page 107, Line 7.
2/ NCUC Form E-1, Item No. 10 - Supplemental Filing, Page 107, Line 11.
3/ Based on response to Public Staff Data Request No. 51, Item 3.
4/ Salaries and wages factor from NCUC Form E-1, Item No. 10 - Supplemental Filing, Page 73.
5/ Based on Docket No. E-22, Sub 532 rate case.

DOMININON ENERGY NORTH CAROLINA
Docket No. E-22, Sub 562
North Carolina Retail Operations
ADJUSTMENT TO ANNUAL INCENTIVE PLAN EXPENSE
For the Test Year Ended December 31, 2018
(in Thousands)

Johnson Exhibit 1
Schedule 3-1(f)

Line No.	Item	Amount	
	Annual Incentive Plan (AIP)		
1	VA Power Executive AIP expense associated with earnings	$ 4,281	1/
2	NC jurisdicational allocation	4.9841%	2/
3	Adjustment to remove AIP related to EPS outcomes - NC (-L1 x L2)	(213)	
4	Executive AIP already removed in executive compensation adjustment	83	3/
5	Adjustment to AIP (L3 + L4)	$ (130)	
	Long Term Incentive Plan (LTI)		
6	LTI associated with ROIC and TSR at target	$ 671	4/
7	Adjustment to remove LTI associated with ROIC and TSR - NC jurisdictional (-L6)	(671)	
8	Executive LTI already removed in executive compensation adjustment	90	3/
9	Adjustment to LTI (L7 + L8)	$ (581)	
10	Adjustment to incentive plan expense (L5 + L9)	$ (712)	

1/ From Company Response to Public Staff Data Request No. 163, Item 4.
2/ NC S&W Allocation factor.
3/ Based on executive compensation adjustment.
4/ From Company Response to Public Staff Data Request No. 163, Item 5.

DOMININON ENERGY NORTH CAROLINA
Docket No. E-22, Sub 562
North Carolina Retail Operations
ADJUSTMENT TO O&M VOLUNTARY
RETIREMENT PLAN (VRP) BACKFILL
For the Test Year Ended December 31, 2018
(in Thousands)

Johnson Exhibit 1
Schedule 3-1(g)

Line No.	Item	Amount	
1	DENC Backfill Labor Costs (Non Union)	$ 28,179	1/
2	DENC Backfill Labor Costs (Union)	9,718	1/
3	DES Backfill Labor Costs	11,207	1/
4	Total Backfill Labor Costs (sun of Lines 1 thru 3)	$ 49,104	
5	Expense Factor	67.91%	2/
6	Total Backfill Labor Costs - O&M (Line 4 x Line 5)	33,347	
7	North Carolina Jurisdictional Allocation Factor	4.9841%	3/
8	North Carolina Jurisdictional Adjustment Per Company (Line 6 x 7)	$1,662	
9	North Carolina Jurisdictional Adjustment Per Public Staff	$0	4/
10	Public Staff Adjustment to O&M VRP Backfill	($1,662)	

1/ NCUC Form E-1, Item No. 10 - Supplemental Filing, Page 217.
2/ NCUC Form E-1, Item No. 10 - Supplemental Filing, Page 226.
3/ NCUC Form E-1, Item No. 45a., Line 255.
4/ Based on Company response to Public Staff Data Request No. 159.

DOMININON ENERGY NORTH CAROLINA
Docket No. E-22, Sub 562
North Carolina Retail Operations
ADJUSTMENT TO REMOVE ADVERTISING EXPENSE
For the Test Year Ended December 31, 2018
(In Thousands)

Johnson Exhibit 1
Schedule 3-1(h)

Line No.	Item	Amount
1	Advertising Expense included per Company	$1,293 1/
2	Less: Advertising related to NC Jurisdiction	(610) 2/
3	Advertising Expense related to VA Jurisdiction to be removed (L1 + L2)	683
4	NC Jurisdictional Allocation Factor	5.0484%
5	Adjustment to Remove Advertising Expense Per Public Staff (L3 x L4)	$ (34)

1/ NCUC Form E-1 Supplemental Item No. 10, page 149, Line 5.
2/ PS DR21-2(a).

DOMININON ENERGY NORTH CAROLINA
Docket No. E-22, Sub 562
North Carolina Retail Operations
ADJUSTMENT TO EXPENSES FOR WEATHER NORMALIZATION, CUSTOMER USAGE, AND GROWTH IN CUSTOMERS
For the Test Year Ended December 31, 2018
(In Thousands)

Johnson Exhibit 1
Schedule 3-1(i)

Line No.	Item	Amount	
1	Total energy-related expenses not adjusted elsewhere for growth	$9,764	1/
2	Test year per books MWH sales	4,400,784	2/
3	Rate per MWH (L1 / L2)	0.002219	
4	Change in MWH sales related to normalization, usage and growth	(112,983)	3/
5	Adjustment to energy-related expenses (L3 x L4)	(251)	
6	Total customer-related expenses not adjusted elsewhere for growth	1,271	4/
7	Test year billings, excluding duplicate bills	121,777	5/
8	Expense per bill (L6 / L7)	0.010437	
9	Increase in billings due to customer growth	19	6/
10	Adjustment to customer related expenses (L8 x L9)	0	
11	Total adjustment to O&M expenses (L5 + L10)	($251)	

1/ Calculated by Public Staff utilizing cost of service study and other data provided by Company.
2/ Based on review of Company workpapers.
3/ Company Supplemental Exhibit PBH-1, Schedule 2, Column (2), Line 54 less test year amount on Line 2.
4/ Calculated by Public Staff utilizing cost of service study and other data provided by Company.
5/ Based on review of Company workpapers.
6/ Company Supplemental Exhibit PBH-1, Schedule 2, Column (1), Line 54 less test year amount on Line 7.

DOMININON ENERGY NORTH CAROLINA
Docket No. E-22, Sub 562
North Carolina Retail Operations
ADJUSTMENT FOR NON-FUEL VARIABLE O&M EXPENSE DISPLACEMENT
For the Test Year Ended December 31, 2018
(in Thousands)

Johnson Exhibit 1
Schedule 3-1(j)

Line No.	Item	Amount	
1	Greensville County CC commercial MWH generation monthly average	770,900	1/
2	Number of months	12	
3	Annualized Greensville County CC generation (L1 x L2)	9,250,802	
4	Actual for twelve months ended December 31, 2018	917,306	2/
5	Implicit adjustment to MWH generation	8,333,496	
6	NC retail allocation factor	5.0924%	3/
7	Line loss factor	95.8229%	4/
8	Additional MWH generation added (L5 x L6 x L7)	406,648	
9	Non-fuel energy-related expense factor used by Public Staff	0.002219	5/
10	NC retail displacement adjustment (L8 x -L9)	($902)	

Nameplate Rating of Plant x 75% Annual Capacity Factor x 8760 / 12 months.
1/ Based on recommendation of Public Staff Engineer Metz.
2/ Based on information from S&P Global Marketplace and recommendation of Public Staff Engineer Metz
3/ Factor 3 from NCUC Form E-1, Item No. 45a, Schedule 15, Line 95.
4/ Annual MWH sales of 4,377,561 divided by Annual MWH at transmission level of 4,568,385
based on North Carolina jurisdictional amounts on NCUC Form E-1, Item No. 45f, Page 117.
5/ Johnson Exhibit 1, Schedule 3-1(i), Line 3.

DOMININON ENERGY NORTH CAROLINA
Docket No. E-22, Sub 562
North Carolina Retail Operations

Johnson Exhibit 1
Schedule 3-1(k)

ADJUSTMENT TO COMPANY'S INFLATION ADJUSTMENT
For the Test Year Ended December 31, 2018
(In Thousands)

Line No.	Item	Amount	
1	Remove Chesapeake closure costs from test year O&M expenses	$0	1/
2	Remove Brunswick CC O&M expenses already at 2018 level	-	2/
3	Remove portion of Company storm adjustment already at 2018 level	(201)	3/
4	Reflect Public Staff adjustment for outside services	(243)	4/
5	Reflect Public Staff adjustment to storm costs	(157)	5/
6	Reflect Public Staff adjustment to remove Mt. Storm costs	(993)	6/
7	Reflect Public Staff adjustment to O&M expenses for changes in customer growth and usage	(251)	7/
8	Reflect Public Staff adjustment for O&M expense displacement	-	8/
9	Reflect Public Staff adjustment to remove Chesterfield Units 3 & 4 costs	(48)	9/
10	Total adjustment to O&M subject to inflation (Sum of L1 thru L9)	(1,893)	
11	Inflation percentage	2.264%	10/
12	Public Staff adjustment (L10 x L11)	($43)	

1/ NCUC Form E-1, Item No. 10 - Supplemental Filing, Page 111, Line 12.
2/ NCUC Form E-1, Item No. 10 - Supplemental Filing, Page 158, Line 18 plus NCUC Form E-1, Item No. 10 - Supplemental Filing, Page 143, Line 2 times Line 4.
3/ NCUC Form E-1, Item No. 10 - Supplemental Filing, Page 127, Line 1.
4/ Johnson Exhibit 1, Schedule 3-1(m), Line 6.
5/ Johnson Exhibit 1, Schedule 3-1(c), Line 18.
6/ Johnson Exhibit 1, Schedule 2-1(c), Line 6.
7/ Johnson Exhibit 1, Schedule 3-1(i), Line 11.
8/ Johnson Exhibit 1, Schedule 3-1(j), Line 10 times Johnson Exhibit 1, Schedule 3-1(i)(1), Line 2 divided by Line 3.
9/ Johnson Exhibit 1, Schedule 2-1(e), Line 6.
10/ NCUC Form E-1, Item No. 10 - Supplemental Filing, Page 166, Line 17.

DOMININON ENERGY NORTH CAROLINA
Docket No. E-22, Sub 562
North Carolina Retail Operations

Johnson Exhibit 1
Schedule 3-1(l)

ADJUSTMENT TO FUEL EXPENSE TO REFLECT
RECOMMENDED JURISDICTIONAL BASE FUEL FACTOR
For the Test Year Ended December 31, 2018
(in Thousands)

Line No.	Item	Amount	
1	Annualized and normalized NC retail kWh sales	4,287,801,016	1/
2	Base fuel rate, excluding regulatory fee	$0.02089	2/
3	Adjusted fuel clause expense (L1 x L2 / 1000)	89,572	
4	Annualized pro forma fuel expense under present rates, per Company	91,725	3/
5	Public Staff adjustment to fuel clause expense (L3 - L4)	($2,153)	

1/ NCUC Form E-1, Item No. 10 - Supplemental Filing, Page 15, Line 3.
2/ Haynes Second Supplemental
3/ NCUC Form E-1, Item No. 10 - Supplemental Filing, Page 15.

Dominion Energy North Carolina
Docket No. E-22, Sub 562
ADJUSTMENT TO OUTSIDES SERVICES
For the Test Year Ended December 31, 2018

Johnson Exhibit 1
Schedule 3-1(m)

Line No.	Item		Amount	
1	Legal invoices allocated from DES to be excluded	$	505	1/
2	Other allocations from DES to DENC to be excluded		758	1/
3	Legal Invoices - Direct DENC		3,619	2/
4	Total Outside Services to be excluded		(4,882)	
5	NC Retail Allocation Factor		4.9810%	
6	Public Staff Adjustment to Outside Services	$	(243)	

1/ Company response to DR14-2(b).
2/ Company response to DR5,DR73 and information provided by the Company.

DOMININON ENERGY NORTH CAROLINA
Docket No. E-22, Sub 562
North Carolina Retail Operations
INTEREST SYNCHRONIZATION ADJUSTMENT
For the Test Year Ended December 31, 2018
(in Thousands)

Johnson Exhibit 1
Schedule 3-1(n)

Line No.	Item	Amount	
1	Public Staff original cost rate base	$1,131,458	1/
2	Public Staff long term debt ratio	50.000%	2/
3	Public Staff embedded cost of debt	4.442%	3/
4	Public Staff interest expense income tax deduction (L1 x L2 x L3)	25,132	
5	Company interest expense income tax deduction	23,638	4/
6	Adjustment to interest expense (L4 - L5)	1,494	
7	Composite tax rate	25.6228%	5/
8	Adjustment to income taxes (-L6 x L7)	($383)	

1/ Johnson Exhibit 1, Schedule 2, Line 10, Column (c).
2/ Johnson Exhibit 1, Schedule 4, Line 1, Column (a).
3/ Johnson Exhibit 1, Schedule 4, Line 1, Column (c).
4/ Johnson Exhibit 1, Schedule 3-1(n)(1), Line 4.
5/ Johnson Exhibit 1, Schedule 1-3. Line 8.

DOMININON ENERGY NORTH CAROLINA
Docket No. E-22, Sub 562
North Carolina Retail Operations
CALCULATION OF COMPANY'S INTEREST
SYNCHRONIZATION ADJUSTMENT
For the Test Year Ended December 31, 2018
(in Thousands)

Johnson Exhibit 1
Schedule 3-1(n)(1)

Line No.	Item	Amount
1	NC retail rate base per Company	$1,147,952 1/
2	Long tern debt ratio per Company	46.351% 2/
3	Long term debt cost rate per Company	4.442% 3/
4	Interest tax deduction per Company (L1 x L2 x L3)	$23,638

1/ Johnson Exhibit 1, Schedule 2, Line 10, Column (a).
2/ Company Supplemental Exhibit PMM-2, Page 8, Line 1, Column (1).
3/ Company Supplemental Exhibit PMM-2, Page 8, Line 1, Column (2).

DOMININON ENERGY NORTH CAROLINA
Docket No. E-22, Sub 562
North Carolina Retail Operations
RETURN ON EQUITY AND ORIGINAL COST RATE BASE
BEFORE AND AFTER PUBLIC STAFF PROPOSED INCREASE
For the Test Year Ended December 31, 2018
(in Thousands)

Johnson Exhibit 1
Schedule 4

			Before Public Staff Proposed Increase				After Public Staff Proposed Increase			
Line No.	Item	Capitalization Ratio	NC Retail Rate Base	Embedded Cost or Return	Weighted Cost or Return	Net Operating Income	NC Retail Rate Base	Embedded Cost or Return	Weighted Cost or Return	Net Operating Income
		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)
1	Long-term debt	50.000% 1/	$565,729 2/	4.442% 1/	2.22% 5/	$25,132 6/	$564,865 9/	4.442% 1/	2.22% 11/	$25,094 12/
2	Common equity	50.000% 1/	565,729 2/	10.32% 4/	5.16% 5/	58,411 7/	564,865 9/	9.00% 1/	4.50% 11/	50,838 12/
3	Total (L1 + L2)	100.000%	$1,131,458 3/		7.38%	$83,543 8/	$1,129,730 10/		6.72%	$75,932

1/ Per Public Staff witness Woolridge.
2/ Column (b), Line 3 times Column (a)
3/ Johnson Exhibit 1, Schedule 2, Line 10, Column (c).
4/ Column (e) divided by Column (b).
5/ Column (a) times Column (c).
6/ Column (b) times Column (c).
7/ Line 3, Column (e) minus Line 1, Column (e).
8/ Johnson Exhibit 1, Schedule 3, Line 19, Column (c).
9/ Column (f), Line 3 times Column (a)
10/ Johnson Exhibit 1, Schedule 2, Line 10, Column (e).
11/ Column (a) times Column (g).
12/ Column (f) times Column (g).

DOMININON ENERGY NORTH CAROLINA
Docket No. E-22, Sub 562
North Carolina Retail Operations
CALCULATION OF PUBLIC STAFF'S ADDITIONAL GROSS REVENUE REQUIREMENT
For the Test Year Ended December 31, 2018
(In Thousands)

Johnson Exhibit 1
Schedule 5

Line No.	Item	Debt (a)	Equity (b)	Total 7/ (c)
	Calculation of additional gross revenue requirement			
1	Required net operating income	$25,094 1/	$50,838 4/	$75,932
2	Net operating income before proposed increase	25,132 2/	58,411 5/	83,543
3	Additional net operating income requirement (L1 - L2)	(38)	(7,573)	(7,611)
4	Retention factor	0.9954193 3/	0.7403645 6/	
5	Additional revenue requirement (L3 / L4)	($38)	($10,229)	($10,267)
	Breakdown of additional revenue requirement			
6	Public Staff recommended decrease in base fuel revenue requirement			($2,155)
7	Additional gross base non-fuel revenue requirement (L5 - L6)			($8,112)

1/ Johnson Exhibit 1, Schedule 4, Line 1, Column (i).
2/ Johnson Exhibit 1, Schedule 4, Line 1, Column (e).
3/ Johnson Exhibit 1, Schedule 1-2, Line 10.
4/ Johnson Exhibit 1, Schedule 4, Line 2, Column (i).
5/ Johnson Exhibit 1, Schedule 4, Line 2, Column (e).
6/ Johnson Exhibit 1, Schedule 1-2, Line 14.
7/ Column (a) plus Column (b).

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COPIES ORDERED BY: Drooz, Edmondson, Fennell, Cummings and Holt, Harrod, Force, Townsend, Grigg, Kells, and Eason

REPORTED BY: Patricia Elliott

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DATE: Tuesday, September 24, 2019

TIME: 1:30 p.m. - 5:27 p.m.

DOCKET NO: E-22, Sub 562 and E-22, Sub 566

BEFORE: Chair Charlotte A. Mitchell, Presiding

Commissioner ToNola D. Brown-Bland

Commissioner Lyons Gray

Commissioner Daniel G. Clodfelter

IN THE MATTER OF:

Application of Virginia Electric and Power Company,
d/b/a Dominion Energy North Carolina,
for Adjustment of Rates and Charges Applicable to
Electric Service in North Carolina

And

Petition of Virginia Electric and Power Company,
d/b/a Dominion Energy North Carolina,
for an Accounting Order to Defer Certain Capital and
Operating Costs Associated with Greensville County
Combined Cycle Addition

VOLUME 6

Noteworthy Reporting Services, LLC

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EXAMINATIONS

E X H I B I T S

E X H I B I T S Cont'd.

I/A

DOMININON ENERGY NORTH CAROLINA
Docket No. E-22, Sub 562
North Carolina Retail Operations
REVENUE IMPACT OF PUBLIC STAFF ADJUSTMENTS
For the Test Year Ended December 31, 2018
(in Thousands)

Johnson Exhibit 1
Schedule 1

Line No.	Item	Amount	
1	Non-fuel revenue requirement increase per Company application	$26,958	1/
2	Revenue impact of Company update	(2,079)	2/
3	**Non-fuel revenue requirement increase per Company after updates**	**24,879**	
4	Revenue impact of Public Staff adjustments: 3/		
5	Change in equity ratio from 53.65% to 50.00% equity	(4,214)	
6	Change in debt cost rate from 4.442% to 4.442%	-	
7	Change in return on equity from 10.75% to 9.00%	(13,566)	
8	Change in retention factor - uncollectibles and state tax rate change	(17)	
9	Adjust uncollectibles	(238)	
10	Adjust allocation of state accumulated deferred income taxes	1	
11	Remove Mt Storm Impairment costs	(1,081)	
12	Adjust NUG Contract Termination Expense - Regulatory Asset	(33)	
13	Adjust outside services	(245)	
14	Eliminate certain ADIT balances	1	
15	Remove Skiffes Creek mitigation costs	(383)	
16	Remove executive compensation costs	(92)	
17	Remove Chesterfield Units 3 & 4 wet-to-dry conversion costs	(124)	
18	Adjust allocation of per books income tax expense	(52)	
19	Adjust storm costs	(512)	
20	Remove employee severance program costs	(1,133)	
21	Remove advertising costs	(34)	
22	Adjust annual incentive plan costs	(716)	
23	Adjust employee VRP Backfill costs	(1,669)	
24	Adjust expenses for customer growth, usage, and weather normalization	(252)	
25	Adjust variable non-fuel O&M expenses for displacement	(906)	
26	Adjust inflation adjustment	(43)	
27	Adjust coal combustion residual (CCR) costs	(7,084)	
28	Adjust uncollectibles for decrease in base fuel rate	(7)	
29	Adjust cash working capital under present rates	(14)	
30	Adjust cash working capital under proposed rates	(574)	
31	Rounding	(4)	
32	Total revenue impact of Public Staff adjustments	(32,991)	
33	**Public Staff recommended decrease in non-fuel revenue requirement**	**(8,112)**	4/
34	Public Staff recommended decrease in base fuel revenue requirement	(2,155)	5/
35	Annual EDIT Rider recommended by Public Staff for 5 year period	1,378	6/
36	**Public Staff recommended decrease in revenue requirement**	**($8,889)**	

1/ Company Exhibit PMM-1, Page 1, Line 6, Column (6).
2/ Company Supplemental Exhibit PMM-1, Page 10.
3/ Calculated based on Johnson Exhibit 1, Schedules 2, 3, 4, 5, and backup schedules.
4/ Johnson Exhibit 1, Schedule 5, Line 7.
5/ Johnson Exhibit 1, Schedule 5, Line 6.