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February 1, 2016

Pamela Goddard
Director, Chesapeake & Virginia Program
National Parks Conservation Association
777 6th Street, N.W., Suite 700
Washington D.C. 200001-3723

Re: Proposed Surry-Skiffes-Whealton Transmission Line

Dear Ms. Goddard:

I am writing to respond on behalf of Dominion Virginia Power ("DVP" or "Dominion") to the follow-up questions presented in your letters of December 18, 2015 and January 12, 2016.

Before responding to your follow-up questions, it is important to put the information you seek in the context of its relevancy to the purpose of the proposed Surry-Skiffes Creek-Whealton Line. Most of your questions relate to the "demand profile," "peak load" or "changes in demand." While the projected load on a transmission system is a required input for the NERC-prescribed computer modeling that identifies projected violations of the NERC Reliability Standards, it is only one of many inputs to the modeling that are required by those Standards. Focusing only on projected loading ignores the fact that Federal law requires that the reliability of the interconnected transmission grid be determined through compliance with the FERC-approved NERC Reliability Standards, which require compliance with specific criteria for transmission planning. The NERC Reliability Standards require that no operating system element overheats, and that prescribed voltage levels be maintained, throughout the system during various contingencies or scenarios when any system component is not in service. The **only** way to comply with NERC Reliability Standards is by performing computerized modeling simulations of future system operations under prescribed operating conditions to identify violations mandating the need for transmission system improvements. This analysis is critical because the NERC Standards ensure the reliability of the transmission system under study, since the stability of the system in an area can adversely affect the larger grid. Given the reliance of society on electricity in providing basic needs, reliability of the system in any event imposes severe and unacceptable risks to public health and safety.

The required power-flow modeling is far more complex, in at least three ways, than a simple comparison of load versus generating capacity. First, the modeling must look not at a single variable such as peak load but rather at the relevant components of the system. This means that the model takes into account multiple variables, such as whether each component that is part of the entire grid system will be able to operate within its operating limits. Moreover the way an equipment component reacts may have an effect on other equipment in the system, so they are interdependent. The model has to evaluate each variable at each location and the solutions for each location must be consistent for the system as a whole.

Second, the relationships among some of those variables are nonlinear. For example, the power flow into load impedances is a function of the square of the applied voltages. Due to the nonlinear, interdependent nature of this problem, numerical methods – a form of mathematical analysis that uses a computer to solve a series of multiple variable non-linear equations in an iterative manner – are employed to solve it. The iterations continue until each equation is solved at each location in a manner that is consistent with operations across the system as a whole. Even with the computing power available today it can take hours and even days to run a single model run.

Third, the power flow model evaluates the system under various contingencies. The NERC Reliability Standards are designed to show whether the system is sufficiently robust to be reliable not only on the peak day or an average day but under a range of foreseeable operating conditions. The most critical contingency may not occur on peak load winter or summer days when all equipment is operating, but rather on relatively mild spring or fall days when power stations or transmission lines are down for maintenance. The power-flow models project up to fifteen years out and take into account equipment additions, planned retirements, and contingency conditions for the system under study. Moreover, the loading input for use in such modeling on the PJM system is the PJM Load Forecast, developed in accordance with the NERC Standards and PJM's FERC-approved transmission tariff. The final result is a full picture of the power flows at multiple points throughout the entire power grid that accounts for a wide variety of circumstances that affects reliability. Only this NERC-compliant power flow modeling can be used to evaluate whether an alternative meets NERC Reliability Standards at all points in the system.

In January 2016, Dominion conducted NERC-compliant power flow studies using the recently released 2016 PJM Load Forecast. These studies continue to indicate NERC criteria violations following the retirement of Yorktown Units 1 and 2 and verify the need for the proposed project as the solution to fully address those identified reliability violations. On December 2, 2015, FERC issued comments on Dominion's request to EPA for an additional year to comply with the Mercury and Air Toxics Standards (MATS) rule under an EPA Administrative Order, which comments verify the reliability violations expected from the Yorktown unit retirements (see Attachment 1 hereto). Moreover, see Attachment 2 hereto for a January 26, 2016 letter to the Corps from Steven R. Herling, Vice President – Planning, PJM, validating the continued need for the Skiffes project "even considering the updated load forecasts in the recently released 2016 PJM Load Forecast Report," and confirming the proposed project as "the most effective and efficient solution to address the reliability criteria violations."

Turning now to your questions, your letters of December 18, 2015 and January 12, 2016, raised similar issues in different ways. Rather than trying to parse through the difference in the wording of the similar questions in your two letters, we are providing response information on the topics raised.

Topic 1. How the system provided reliable service with Surry off line. (Question 1 of Dec 18 letter)

Response: The simple answer is that Surry being out of service is just one of the contingencies that are modeled in the power flow models to demonstrate compliance with NERC Reliability Standards. Other contingencies have to be addressed, and improving the existing lines serving NHRLA will not suffice. More specifically, this question was addressed in our December 15, 2015 response to Question No. 1 of your November 5, 2015 letter. Our response explained why a new 500 kV transmission source into the Peninsula is needed to resolve the large number of identified violations of NERC's thermal and voltage planning criteria.

Topic 2. Why "upgrading or reinforcing the transmission lines in the two existing corridors" is not sufficient. (Question 1 of Dec 18 letter)

Response: The 230 kV system in the NHRLA is fed from two existing 230 kV transmission corridors. One contains two 230 kV lines (and two 115 kV lines) running down the Peninsula from Chickahominy and Lanexa Stations in the west to Yorktown Station and the other containing two 230 kV lines running from the South Hampton Roads Load Area ("SHRLA"), specifically Chuckatuck Station in Isle of Wight County, across the James River onto the Peninsula at Newport News.

The excerpt from the SCC Hearing Examiner's Report provided as Attachment 2 to our December 15 letter reviews the SCC case evidence showing that increasing the capacity of the existing 230 kV crossing at Newport News (referred to as "Alternative C" suggested by James City County's witness Whittier) would not resolve all of the identified NERC violations, and construction of additional new 230 kV and 115 kV lines in the NHRLA, with attendant cost and impacts, would be required for Alternative C to be electrically equivalent to the proposed project. Evidence provided by DVP witness Elizabeth Harper, provided as Attachment 3 to this letter, showed further that Alternative C also would have significant adverse impacts on existing uses in Isle of Wight County and would require crossing a public park in Newport News, assuming that city's approval could be obtained, and extensive use of underground construction in Newport News due to the density of existing development that would be crossed. The prefiled rebuttal testimony of DVP witness Mark Allen, provided as Attachment 4 to this letter, shows that construction of the additional new facilities would increase the total cost of Alternative C to $408.8 million and would take ten years to complete. Thus, this alternative does not meet project needs and is not practicable.

The evidence also showed that using the existing developed corridor from the west through Lanexa Station for a new 500 kV overhead line to Skiffes Creek Switching Station would solve the identified NERC violations but would create a new violation of NERC Reliability Category D by creating the potential for cascading outages within a common right-of-way and would require widening the existing right-of-way by 115-125 feet (representing 310-312 acres) and the taking of 15-17 homes. DVP's 500 kV Chickahominy Alternative would avoid that portion of the existing developed right-of-way of-way by constructing the new line in 24.9 miles of existing undeveloped right-of-way from Chickahominy Station to the existing developed right-of-way at a point east of Lanexa. However, the Chickahominy Alternative with this route would cross a truly evocative section of the Chickahominy River and extensive wetlands. The SCC did not approve the Chickahominy Alternative because of its much greater overall impacts and significantly higher cost compared to the proposed project.

You also may have been suggesting that the conductors of the existing 230 kV and 115 kV lines in the NHRLA might be replaced with new, higher capacity conductors. However, such reconductoring would also require replacement of the existing structures with new, taller structures to achieve the ground clearances required by the currently effective National Electrical Safety Code. As noted, Attachment 4 hereto shows the construction of the additional transmission facilities required to make Alternative C electrically equivalent to the proposed project would cost $264 million, bringing the total cost of that Alternative to $408.8 million, and require ten years to complete. This is because construction would be limited to off-peak periods of the year when service can be maintained while lines in proximity to construction are taken out of service to assure compliance with applicable safety standards (assuming PJM approvals can be obtained for such outages). Reconductoring and rebuilding the existing 230 kV and 115 kV systems in the NHRLA would cost even more and take at least as long. Thus, these alternatives do not meet project needs.

For these reasons, reinforcement of 230 kV lines in NHRLA is not a practicable alternative to the proposed project.

Topic 3. Costs of Alternatives. (Question 2 of Dec 18 letter; Question 3 of the January 12, 2016 letter)

Response: As required by SCC guidelines, DVP's application to the SCC identified a double circuit 230 kV line from Surry to Skiffes Creek as an alternative to the proposed project and explained that it was rejected because it would not resolve all of the identified violations of the NERC Reliability Standards and would cost approximately $382.6 million to construct. This estimate was for a hybrid line (overhead on land/underground river crossing).

In the SCC proceeding, DVP was directed by the SCC Hearing Examiner to provide conceptual design and cost estimates for two hybrid (overhead above ground/underground river crossing) Surry-Skiffes Creek lines; a single circuit line with 1000 MVA capacity ("Alternative "A") and double circuit line with 1000 MVA per circuit ("Alternative B"). A copy of the prefiled rebuttal testimony of DVP witness Trey Thomasson submitting that evidence, based in DVP's recent experience in the construction of a 230 kV underwater single circuit line (600 MVA) across the York

River, is provided as Attachment 5 to this letter. Alternative A was not viable because power flow studies showed it would overload under a number of NERC contingencies. Mr. Thomasson testified that the estimated cost of the Alternative B double circuit 230 kV line would be $440.4 million; however, it would not resolve the identified NERC violations and would require, as presented by Mr. Allen in Attachment 4 hereto, the construction of $48.2 million of additional new transmission facilities to resolve the identified 2015 NERC violations and $26.7 million of additional facilities to resolve the identified 2021 violations (for a total project cost of $515.3 million) and thereby be electrically equivalent to the proposed project. He also explained the need to construct three reactor banks that were omitted from the estimate provided in the SCC Application. Moreover, Mr. Allen testified that the double circuit 230 kV would take five (5) years to build after obtaining all necessary permits, so it could not meet the need date. Mr. Allen's testimony also showed that the overall reliability of an underground transmission line is less than for an overhead line because a problem on an overhead is easier to locate, and repairs to underground lines take much longer to complete.

Mr. Thomasson explained the differences between the two prevailing technologies for underwater transmission lines: high-pressure fluid-filled ("HPFF") (also called "pipe-type") and cross-linked polyethylene ("XLPE") and his selection of the HPFF technology because of its longer life expectancy, lower cost, shorter time for repairs and replacements, and less disturbance of the river bottom compared to XLPE, which has less extensive operating history in the United States. For the river crossing of approximately 4 miles, the 2000 MW HPFF cable system would include six pipes, each containing three cables (one per phase), which would be directionally drilled at least 15 feet below the river bed for 4 miles across the river, with three sets of intermediate splicing platforms in three locations (total of nine splicing platforms). The pipes would need to be separated by 20 feet, with 150 feet between each pipe pair, requiring a minimum right-of-way width of 400 feet. A fenced 1-acre transition station, resembling a conventional electric substation, would be required on the shore at each end of the river crossing to transition the line from overhead to underground and back to overhead.

The testimonies of Mr. Thomasson and Mr. Allen also showed that the double circuit underground line would have significant adverse impacts on the James River. For overhead construction, pipe pile foundations are vibrated into the ground approximately every 1,400 feet, which produces minimal disturbance of the bottom. In contrast, the Alternative B underground line would need to be excavated for the entire length, resulting in approximately 47,000 cubic yards of soil excavation, plus three trenches would be required at each of three splice points, resulting in excavation of an additional 36,000 cubic yards of sediment and riverbed. Significant trenching also would be required on each shore to bring the underground lines to the transition stations.

We have previously explained to the Corps, and the SCC found, that 500 kV underwater technology is not feasible for the Surry-Skiffes Creek line, so we have not designed such a project. Even if technically feasible, which it is not, the cost of a 500 kV underwater line would be greater than the cost of the double circuit 230 kV designed for the SCC case. As we have explained to the Corps, "Constructing a 500 kV line underwater at the distances needed to cross the James River and at a capacity needed to resolve the NERC Reliability Violations has never been done before and would carry too much risk to be a project supported by [DVP]." Dominion is not aware of any applications of 500 kV underwater that have the thermal capacity needed for this project. These statements include the only 500 kV underwater line in North America, located in Vancouver, Canada, which has a capacity of less than half of the proposed project's capacity.

As to cost, the 500 kV underground line which is a land based installation now under construction in California is estimated to cost approximately $100 million per mile. However, the construction requirements for, and capabilities and impacts of, submarine transmission lines are very different from those of underground lines, and the costs are necessarily higher. Among other things, the submarine environment is less able to dissipate heat from a submarine cable as compared to underground construction, which reduces the capacity of underwater lines and requires wider rights-of-way. For example, the Vancouver line spaces the two cables that comprise that line 1640 feet apart, requiring a right-of-way 1.5 miles wide. This difference in heat dissipation also reduces the transmission capacity of an underwater line. This is critical for the Surry-Skiffes Creek line, which will operate under consistently higher loading due to its interconnection with the 500 kV bulk transmission system at Surry Power Station.

HPFF technology would not be utilized at 500 kV, so installation of self contained oil cables would require trenching and recovering for the entire river crossing and far more excavation and disruption of the river bottom than for the double circuit 230 kV line. In addition, no splicing techniques currently exist for such an underwater application. The type of vessels and contractors required to install the Vancouver line are highly specialized, not generally available and draw too much water to navigate the James River. In the event of an outage, repairs could require months to obtain a vessel and associated specialized equipment to make repairs and restore service.

Voltage control of any underground line, let alone a 500 kV line underwater, is extremely difficult in real time operations. Because one terminus of this line would be a nuclear power station, if system voltage were to become unmanageable it would be necessary to remove the underground line from service to avoid impacting the operation of the power station.

The forgoing discussion addresses AC technology, but the same conclusions apply to HVDC. None of the HD projects mentioned by NPCA and/or PERI provide sufficient capacity to address all of the identified violations of the NERC Standards. In addition to many of the same issues presented by AC technology, DC requires massive converter stations at each end of the line, each of which would be large multi-story warehouse type structures that would dwarf Skiffes Station. A 2014 study by Black & Veatch for the Western Electricity Coordinating Council estimated the cost of a 500 kV converter station to be over $460 million.

Topic 4. Demand reductions from solar, DSM and efficiency programs. (Question 3 of Dec 18, 2015 letter; Question 4 of January 12, 2016 letter)

Response: We are not able to provide such an assessment based on the experience in other states that would be reliably accurate. DVP's service area and potential market for DSM in Virginia are unique. Experience has shown over the years that what has happened with respect to DSM programs in other states will not necessarily reflect with accuracy what will happen in Virginia. DVP must obtain approval from the SCC before bringing DSM programs to customers and must also obtain SCC approval for rate recovery of the costs of approved programs. The SCC's regulations require it to determine that a proposed program is cost-effective and in the public interest based on prescribed methodologies, and a number of DVP's proposed programs have been rejected by the SCC for not being cost-effective or been made subject to spending caps below those proposed by DVP. Thus, action by the SCC can cause the results of DVP's DSM programs to be different from the results in other states.

The results of DSM and solar PV resources are already accounted for in the PJM load forecasts, including the 2016 PJM Load Forecast; therefore, their impacts are presently considered in the NERC-compliant power flow models that identified and continue to confirm the need for the proposed project. In addition, DSM for DVP and other utilities at the PJM level has been decreasing, rather than increasing, in recent years. Attachment 6 to this letter shows that the amount of DSM capacity on the DVP system that has cleared the PJM RPM auction since 2014/2015 has decreased by 39.8 % and the combined total for the DVP, BGE, PEPCO and DPL systems has decreased by 39% over that period.

Topic 5. Peak Load data since 2011. (Question 4 of Dec 18, 2015 letter; Questions 1 and 2 of the January 12, 2016 letter)

Response: Reference Attachment 7 hereto. However, peak load is not particularly relevant without understanding where that load is located and the capacity of the system at that location. That evaluation is made by power flow modeling as described above. In any event, claims that the 2013 PJM load forecast used in the NERC-compliant computer modeling overstated the 2015 peak load in NHRLA are refuted by the fact that the actual base system load in the NHRLA in 2015 already exceeds the capability of the transmission system without Yorktown Units 1 and 2.

Topic 6. Updated estimate for peak load shedding needed in NHRLA. (Question 5 of Dec 18, 2015 letter; Question 5 of the January 12, 2016 letter)

Response: Federal law requires compliance with the NERC Reliability Standards for transmission planning based on the results of the computer simulations required by the NERC Reliability Standards for modeling the performance of each element of a transmission system to determine whether the system will meet the NERC criteria 5 years and 10 years in the future. Such compliance is not, and cannot lawfully be, determined by simple comparisons of retired generation capacity with peak load or reductions in load shedding or by ignoring the PJM load forecast methodology required by the PJM tariff for development of the Regional Transmission Expansion Plan.

As noted in the Stantec Report Section 3.1.3 (page 3.10) "pre-contingency" load shedding was estimated to be in the range of 220-240 MW with an additional 30% of customer demand needing to be dropped post contingency. This preliminary analysis done in the Fall of 2014 was based on current load profiles known at the time, including expected Summer 2015 loading conditions resulting from retirement of Yorktown Units #1 and #2 in April of 2015. While such pre-contingency load shedding estimates can be an acceptable tool for real time system operators to prepare for implementing solutions to avoid cascading outages when faced with unforeseen operational scenarios, they are not acceptable for transmission planning purposes under NERC Reliability Criteria.

Since that time, the Company's and PJM's system operations groups have been forced to plan in detail for operating scenarios where pre-contingency load shedding is necessitated by the proposed project not being in-service prior to the retirement of Yorktown Units 1 and 2. For several of these expected operating conditions the system operations groups have determined that up to 375 MW of load on a pre-contingency basis may need to be dropped to maintain the operation of the NHRLA transmission grid within a stable operating point. The Company understands that this may have come as a surprise to NPCA at our January 8, 2016, meeting but the reality is that the Company is now approaching a real time operating condition in the NHRLA where the transmission system is no longer able to meet the NHRLA's basic demand and energy requirements absent load shedding, which is unprecedented in the Company's history.

In summary, the need for the proposed project was determined and has been verified again using transmission planning protocols and inputs required by NERC Reliability Standards, including NERC-prescribed power-flow modeling. The proposed project resolves the identified NERC reliability violations and continues to be the most practicable alternative available to maintain continued reliable electric service in the NHRLA and Commonwealth of Virginia, thereby supporting continued economic development, including tourism in the Historic Triangle.

Sincerely,

J. Kevin Curtis

Kevin Curtis
Vice President
Dominion Technical Solutions

cc: Mr. Randy Steffey

ATTACHMENT 1

153 FERC ¶ 61,265
UNITED STATES OF AMERICA
FEDERAL ENERGY REGULATORY COMMISSION

City of Ames	Docket Nos. AD16-9-000
Tennessee Valley Authority	AD16-10-000
Virginia Electric and Power Company	AD16-11-000

COMMISSION COMMENTS ON REQUESTS FOR
EPA ADMINISTRATIVE ORDERS

(Issued December 2, 2015)

1. On October 15, 2015, City of Ames (Ames), Tennessee Valley Authority (TVA) and Virginia Electric and Power Company (Dominion) submitted separate requests to the Environmental Protection Agency (EPA) seeking administrative orders, pursuant to Section 113(a) of the Clean Air Act (CAA), to allow each entity additional time to comply with EPA's Mercury and Air Toxics Standards (MATS) final rule.[1] Ames, TVA and Dominion also submitted copies of their requests to the Commission.[2]

2. The MATS final rule limits mercury, acid gases and other toxic emissions from power plants. Pursuant to Section 112(i)(3)(A) of the CAA, affected sources are required to comply within three years of the MATS effective date. Pursuant to CAA Section 112(i)(3)(B), some affected sources are eligible for a one-year extension of the compliance deadline (i.e., for a total of four years). In a policy memorandum dated December 16, 2011, EPA's Office of Enforcement and Compliance Assurance described its intended approach regarding the use of administrative orders under CAA Section 113(a) with respect to sources that must operate in noncompliance with

[1] EPA issued the MATS final rule pursuant to its authority under Section 112 of the CAA. *See* 42 U.S.C. § 7412(i)(3)(A) (2012).

[2] Ames, TVA and Dominion submitted their petitions to the Commission, and the Commission is providing comments to EPA, pursuant to the Commission's May 17, 2012 policy statement. *See Policy Statement of the Commission's Role Regarding the Environmental Protection Agency's Mercury and Air Toxics Standards*, 139 FERC ¶ 61,131 (2012) (Policy Statement).

MATS for up to one year to address a specific and documented reliability concern (i.e., for a total of five years).[3]

3. EPA states that the analysis provided in an administrative order request should demonstrate "that operation of the unit after the MATS Compliance Date is critical to maintaining electric reliability, and that failure to operate the unit would: (a) result in the violation of at least one of the reliability criteria required to be filed with the Commission, and, in the case of the Electric Reliability Council of Texas, with the Texas Public Utility Commission; or (b) cause reserves to fall below the required system reserve margin."[4] The EPA Policy Memorandum indicates that the EPA intends to seek advice, as necessary and on a case-by-case basis from the Commission, among others, as the EPA decides whether it will grant an administrative order to an owner/operator. The EPA Policy Memorandum makes clear that the EPA decision as to whether to grant an administrative order to an owner/operator is solely the decision of the EPA and that the concurrence or approval of any entity is not a condition for approval or denial of an administrative order request.[5]

4. On May 17, 2012, the Commission issued a Policy Statement explaining how it will provide advice to the EPA for it to rule on requests for an administrative order to operate in noncompliance with EPA's MATS rule. The Commission's Policy Statement provided that the Commission will advise the EPA by submitting written Commission comments to the EPA based on the Commission's review of the information provided in an informational filing containing the request for the administrative order provided to the Commission in an AD docket.[6] The Commission's comments would provide advice to the EPA on whether, based on the Commission's review of the informational filing, there might be a violation of a Commission-approved Reliability Standard, and may also identify issues within its jurisdiction other than a potential violation of a Commission-approved Reliability Standard.

[3] 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 (Dec. 16, 2011), *available at* http://www.epa.gov/mats/pdfs/EnforcementResponsePolicyforCAA113.pdf (EPA Policy Memorandum).

[4] EPA Policy Memorandum at 7.

[5] *Id.*

[6] Policy Statement, 139 FERC ¶ 61,131 at P 21.

A. Ames

1. Request for EPA Administrative Order

5. Ames owns and operates the Steam Electric Plant Unit Nos. 7 and 8 electric generating units. Located in Ames, Iowa, Unit No. 7 is a 33 megawatt (MW) coal-fired steam turbine unit and Unit No. 8 is a 65 MW coal-fired steam turbine unit. Ames requests an EPA administrative order to continue operating Unit No. 7 for a four month period, from April 16, 2016 to August 16, 2016.[7] Ames explains that the administrative order will allow Ames to continue running Unit No. 7 while Unit No. 8 is converted to natural gas and, subsequently, will allow Unit No. 7 to be converted to natural gas.[8] Ames states that the conversion of Unit No. 7 is scheduled to be completed by August 16, 2016.[9]

6. Ames, a municipal electric system within the Midcontinent Independent System Operator, Inc. (MISO) region, contends that it will be unable to avoid violations of Reliability Standards developed by the North American Electric Reliability Corporation (NERC) without load shedding if Unit Nos. 7 and 8 are deactivated before Unit No. 8 is converted to natural gas.[10] Specifically, Ames asserts that the simultaneous removal from service of Unit Nos. 7 and 8 for conversion to natural gas would result in potential violations of Transmission Planning (TPL) Reliability Standard for Category B and C contingencies without load shedding.[11] Ames also claims that Unit Nos. 7 and 8 provide service to a number of major facilities in the City of Ames.[12] Ames explains that, without

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[7] Ames Submission at 1.

[8] *Id.* at 1. Ames explains that it is converting Unit Nos. 7 and 8 to natural gas, but because "the two units are considered reliability critical units in the Central Iowa transmission region, construction on the units could not be undertaken simultaneously for conversion to natural gas." *Id.* at 2.

[9] *Id.* at 16.

[10] *Id.* at 4.

[11] *Id.* A Category B contingency refers to an event resulting in the loss of a single element while a Category C contingency refers to event(s) resulting in the loss of two or more (multiple) elements. *See* Reliability Standard TPL-002-0b (System Performance Following Loss of a Single BES Element), Table 1 (Transmission System Standards — Normal and Emergency Conditions).

[12] *Id.* at 2 (identifying the Iowa Department of Transportation, Mary Greeley Medical Center and U.S. Department of Agriculture's National Animal Disease Center).

an administrative order, the loss of Unit Nos. 7 and 8 "exposes both the City [of Ames] and the transmission region to serious consequences, including voltage collapse and blackout."[13]

7. In a memorandum attached to Ames's submission, MISO concurs with Ames's reliability assessment.[14] MISO states that without Unit Nos. 7 and 8 "outage of the two 161kV interconnection circuits to the City of Ames system or outage of both Ames area 161/69kV transformers results in voltage collapse during peak load conditions."[15] MISO also explains that "[d]uring shoulder load periods severe thermal and voltage violations are observed for outage of both 161kV interconnection circuits or both 161/69kV transformers which prevents the ability to perform planned maintenance on these facilitates without the availability of the Ames Unit 7 & 8."[16]

2. Commission Comment

8. Based on our review of Ames's submission, we find that the loss of Unit Nos. 7 and 8 might result in Ames violating NERC Reliability Standards without the use of load shedding.[17] Accordingly, we believe that Ames's Unit No. 7 is needed during the requested four-month period to maintain electric reliability and to avoid possible NERC Reliability Standard violations.

B. TVA

1. Request for EPA Administrative Order

9. TVA requests an EPA administrative order to allow the continued operation of TVA's Paradise Fossil Plant Unit Nos. 1 and 2 electric generator units for a one-year period, from April 16, 2016 to April 16, 2017.[18] Unit Nos. 1 and 2 are 704 MW coal-

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[13] *Id.* at 9.

[14] *Id.*, Attachment 4 (City of Ames Import Limit Assessment Study Report) at 2. MISO is the planning coordinator for Unit Nos. 7 and 8.

[15] *Id.* at 6.

[16] *Id.*

[17] Policy Statement, 139 FERC ¶ 61,131 at P 17 ("The review will examine whether, based on the circumstances presented, there might be a violation of a Commission-approved Reliability Standard.").

[18] TVA Submission at 2.

fired steam turbine units located near Bowling Green, Kentucky.[19] TVA explains that the administrative order will allow TVA to complete construction of a natural gas combined cycle (NGCC) facility at the Paradise Fossil Plant, which will not be operational until just prior to April 16, 2017.[20]

10. TVA, an agency of the United States government and public power provider, contends that deactivating Unit Nos. 1 and 2 before the new NGCC facility is completed would result in violations of NERC Reliability Standards.[21] Specifically, TVA maintains that the retirement of Unit Nos. 1 and 2 before the NGCC facility becomes operational would result in violations of Reliability Standards TPL-002-1 and TPL-001-4 (i.e., Category B contingency).[22] TVA explains that with the loss of Unit Nos. 1 and 2, "to operate within established system limits and maintain the stability of the transmission system, local area mitigation would include curtailment of firm load and firm transmission service to customers."[23] TVA also claims that without Unit Nos. 1 and 2, TVA "loses a primary source of reactive power in the western Kentucky area," which could create conditions where "voltage could drop below required criteria."[24] TVA explains that in order to meet required voltage criteria at least one unit is required "every month, except for the 'shoulder' months of April and October."[25]

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[19] TVA states that Unit Nos. 1 and 2 also provide the steam necessary for the start-up of Unit No. 3, which provides approximately 1,000 MW to TVA's 500 kV transmission system. *Id.* at 11.

[20] *Id.* at 8.

[21] *Id.* at 11.

[22] *Id.* Reliability Standard TPL-001-4 is the successor to Reliability Standard TPL-002-0b. *See Transmission Planning Reliability Standards*, Order No. 786, 145 FERC ¶ 61,051 (2013).

[23] *Id.* ("The dropping of firm load is not allowed for single contingency events under TPL-002-1 or TPL-001-4 and correlates to loss of power for TVA customers in the affected areas.").

[24] *Id.* at 12 (stating that the loss of reactive power support from Unit Nos. 1 and 2 "puts several cities, including Hopkinsville and Bowling Green, as well as the military base at Fort Campbell, at risk for increased exposure to low voltage issues resulting in load curtailment and ultimately customer power outages").

[25] *Id.* at 13.

11. In a letter attached to TVA's submission, TVA Planning Coordinator states that it "concurs with TVA's analysis of the reliability and reserve margin issues in the [administrative order] request."[26]

2. Commission Comment

12. Based on our review of TVA's submission and attachments, we find that the loss of Unit Nos. 1 and 2 prior to the completion of the new NGCC facility might result in violations of NERC Reliability Standards. Accordingly, we believe that Unit Nos. 1 and 2 are needed during the administrative order period, as requested by TVA, to maintain electric reliability and to avoid possible NERC Reliability Standard violations.

C. Dominion

1. Request for EPA Administrative Order

13. Dominion requests an EPA administrative order to allow the continued operation of its Yorktown Power Station Unit Nos. 1 and 2 electric generator units for a one-year period, from April 16, 2016 to April 16, 2017.[27] Unit No. 1 is a 159 MW coal-fired steam turbine unit and Unit No. 2 is a 164 MW coal-fired steam turbine unit located near Yorktown, Virginia. Dominion explains that an administrative order will allow the completion of transmission upgrades known as the "Skiffes Creek Project," which will not be operational until the second quarter of 2017, prior to the deactivation of Unit Nos. 1 and 2.[28]

14. Dominion, a load serving member of PJM, contends that an administrative order is justified to minimize the risk of losing reliable electric service to the North Hampton Roads area and to avoid violations of NERC Reliability Standards.[29] Dominion states that deactivation of Unit Nos. 1 and 2 prior to completion of the Skiffes Creek Project could lead to loss of service (i.e., require load shedding in the North Hampton Roads area under certain grid operating conditions) and could potentially damage Dominion's

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[26] *Id.*, Attachment C (Written Concurrence of Planning Coordinator) at 2. TVA Planning Coordinator is the planning coordinator for Unit Nos. 1 and 2. *Id.* at 10.

[27] Dominion Submission at 1.

[28] *Id.* at 21. Dominion describes the Skiffes Creek Project as a new high-voltage electric transmission line across the James River near Williamsburg, Virginia and related project components. *Id.* at 1.

[29] *Id.* at 17.

electrical facilities in this area.[30] Dominion also maintains that an administrative order is necessary to avoid violations of NERC Reliability Standards unless Dominion resorts to load shedding.[31] Dominion cites power flow studies indicating that its transmission facilities will not satisfy NERC Reliability Standards if the Skiffes Creek Project is not in service by the time Unit Nos. 1 and 2 are deactivated.[32] Specifically, Dominion maintains that the retirement of Unit Nos. 1 and 2 before completion of the Skiffes Creek Project would result in Category B, C and D violations under the NERC Transmission Planning Reliability Standards without load shedding.[33] Dominion contends that the Skiffes Creek Project will address each of these potential NERC Reliability Standard violations.[34]

15. In a letter attached to Dominion's submission, PJM concurs that "the Deactivation of both Yorktown Unit Nos. 1 and 2 will adversely affect the reliability of the PJM Transmission System, and that updates to the system were required."[35]

2. <u>Commission Comment</u>

16. Based on our review of Dominion's submission and attachments, we find that the loss of Dominion's Yorktown Unit Nos. 1 and 2 prior to the completion of the Skiffes

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[30] *Id.*

[31] *Id.* North Hampton Roads includes Charles City County, James City County, York County, Williamsburg, Yorktown, Newport News, Poquoson, Hampton, Essex County, King William County, King and Queen County, Middlesex County, Mathews County, Gloucester County, the City of West Point, King George County, Westmoreland County, Northumberland County, Richmond County, Lancaster County, and the City of Colonial Beach. *Id.* at 7.

[32] *Id.* at 17; *see also id.*, Attachment O (Skiffes Creek Project and Yorktown Generation Retirement Studies).

[33] *Id.* at 18-19; *see also supra* note 11. A Category D contingency refers to an extreme event resulting in two or more (multiple) elements removed or cascading out of service. *See* Reliability Standard TPL-002-0b (System Performance Following Loss of a Single BES Element), Table 1 (Transmission System Standards — Normal and Emergency Conditions).

[34] *Id.* at 20.

[35] *Id.*, Attachment K (PJM April 11, 2014 Letter) at 1. PJM is the planning coordinator for Unit Nos. 1 and 2. *Id.* at 6.

Creek Project might result in violations of NERC Reliability Standards in the absence of load shedding. Accordingly, in our view, Dominion's 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.

By the Commission.

(S E A L)

Nathaniel J. Davis, Sr.,
Deputy Secretary.

ATTACHMENT 2

2750 Monroe Blvd
Audubon, PA 19403-2497

Steven R, Herling
Vice President, Planning

January 25, 2016

Colonel Jason E. Kelly
District Commander, Army Corps of Engineers
803 Front Street
Norfolk, Va. 23510

Subject: Skiffes Creek Project

Dear Colonel Kelly,

PJM is a regional transmission organization ("RTO") that ensures the reliability of the electric transmission system under its functional control. PJM coordinates the movement of wholesale electricity in the PJM Region, which consists of all or parts of Delaware, Illinois, Indiana, Kentucky, Maryland, Michigan, New Jersey, North Carolina, Ohio, Pennsylvania, Tennessee, Virginia, West Virginia and the District of Columbia. In its role as an RTO, PJM is responsible for planning and operating the bulk electric transmission system and administering the wholesale electricity market in the PJM region. As part of its ongoing responsibilities as an RTO, PJM prepares a Regional Transmission Expansion Plan ("RTEP") to analyze the electric supply needs of the customers in the PJM region.

During the development of the 2012 RTEP, PJM identified numerous grid reliability criteria violations in the Virginia Electric and Power transmission system. The reliability criteria violations were driven by the scheduled deactivation of generators at the Dominion Yorktown facility in York County Virginia. PJM identified the Skiffes Creek project as the preferred and most effective solution to address the expected reliability problems. PJM's subsequent RTEP restudies continue to validate the need for the project. Based on recently updated analysis, the reliability criteria violations are expected to occur immediately following the retirement of the Yorktown generators. The project continues to be needed even considering the updated load forecasts in the recently released 2016 PJM Load Forecast Report. Mandatory reliability standards, approved by the Federal Energy Regulatory Commission require PJM to implement a solution to address the reliability criteria violations. The current Skiffes Creek 500 kV project is the most effective and efficient solution to address the reliability criteria violations.

Sincerely,

Steven R. Herling

Cc: Ronnie Bailey - Dominion
Steve Chafin - Dominion
Scott Miller – Dominion
Randy Steffey – USACE
William Walker – USCE

8476335

ATTACHMENT 3

up, and those sediments could be redistributed downriver.

So it's not -- so there is impact to -- from construction of an underground line across the James River.

Q. Did you also examine Mr. Whittier's variation that he presented in his Exhibit 71?

A. Yes.

MS. LINK: Your Honor, we have an exhibit to hand out.

Your Honor, we've just handed out a series of maps. It's entitled, "Whittier Variations to Alternative C, Exhibit 71." May we have an exhibit number for this?

HEARING EXAMINER SKIRPAN: I'll mark this as Exhibit Number 119.

(Exhibit Number 119 is placed in the record.)

BY MS. LINK:

Q. Ms. Harper, can you please walk us through this exhibit and what it shows?

A. This --

Q. And I'm sorry to interrupt. I have hand numbered very quickly on the bottom right to help us along with this process, but other folks may want to also do the same, the page numbers.

A. This is 13 pages of aerial maps showing the route from Chuckatuck across the river to the Whealton substation.

Mr. Allen testified that if an additional 230 kV line were built in this corridor, that the right-of-way would need to be expanded.

The route starts at Chuckatuck, which is in Isle of Wight County, and really the first -- almost all of the first five pages show a somewhat rural area where the right-of-way could be expanded and an easement could -- may be able to be obtained.

But then you get to Page 5, and going on into Page 6, where you see we're beginning to get constraints along the right-of-way. You have homes and perhaps some business there, too. A little further north from Eagle Harbor Parkway, I believe that might be a residential area, because I see a pool, so they might be apartments.

Q. Is that on Page 6, Ms. Harper?

A. Yes, that's on Page 6.

So expanding the right-of-way through this area would be very difficult. It would require, possibly, that homes would be taken.

An option to expanding the right-of-way in this area would be really to create a whole new corridor for a new 230 that would simply go around this area of constraint.

Then, on Page 7, you would come back to the existing river crossing, and you see there, there's a wide expanse of wetlands there on the south side of the river.

Now, the next several pages are the river crossing itself, and a 230 kV line would be parallel to the existing lines and require the appropriate permits for that.

Coming up on the north side of the river, you enter into the City of Newport News.

Q. And I'm sorry, Ms. Harper, to interrupt, but Page 11 we're on now?

A. That is Page 11.

Right there at the shore is what they call Huntington Beach. It appears to be a public beach. You can see that there is parking. There's some piers or perhaps boat docks there. A little further inland, there are tennis courts.

So this area is an area that is owned by the City of Newport News, and of course to get additional easement there, again, we would have to hope that the City of Newport News would work with us, since we would not have the power of condemnation.

From this point forward, as noted by Whittier, the right-of-way becomes constrained, and even he had said that it might -- such a line proposal might need to be underground.

So somewhere in this area around Huntington Beach, we would need to find a terminal location to take the line underground.

Q. Ms. Harper, we're back on Page 11 and still talking about the terminal location?

A. Right. And that terminal location would need to be somewhere soon after we cross the river because, on Page 12 and 13, you will see that again the right-of-way becomes very constrained, and an overhead line probably would not work there. And I think 12 and 13 basically speak for themselves.

Then coming -- on Page 13, coming to the Whealton substation, if the line is underground, of course then you need another terminal station to bring the line overhead.

The Whealton substation, as you can

see, is itself a very small station without room for expansion, because it is in a residential neighborhood. So, again, that terminal station could not be within the Whealton substation and would need to be at some point on this line prior to coming into the Whealton substation.

In addition to the constraints, of course this is basically a new route, we would need to come back to the Commission with an application. And prior to that application being made, we would have to go through the process of open houses, of talking to state agencies about impacts, in order to prepare the application.

Then, of course, we'd have to go through the whole approval process again through the Commission. So it really would be starting over completely with a new project.

Q. And since this was just presented to you on Monday, have you been able to do even a preliminary assessment of environmental impacts of this Alternative C?

A. Not really. Not really. We know that we have the wetlands and we have the river crossing, and it would be just a matter of figuring out those lengths and what those are compared to perhaps other opportunities.

Q. All right.

A. One more thing. If we had to purchase the new easement, of course that in itself takes a tremendous amount of time for this much easement. It's a long process. That's all.

MS. LINK: Your Honor, we'd move the admission of Exhibit 119.

HEARING EXAMINER SKIRPAN: It's in.

BY MS. LINK:

Q. Turning to another topic, Ms. Harper, do you recall being asked, on the second day of the hearing, April 10th, about a zoning letter that you -- that was dated April 4th, sent to you and you received on April 8th?

A. Yes. I'm sorry. I'm searching for it now.

Q. That's all right. I'll give you a moment.

A. This is the zoning letter?

Q. The zoning letter --

A. Okay.

Q. -- that was dated April 4th --

A. Yes.

Q. -- and you received on April 8th.

Ex. 119

Dominion

Whittier Variation to Alternative C

Exhibit 71

Whittier Variation to Alternative C

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DRAWN BY: Randy McGregor

Dominion

Whittier Variation to Alternative C

Exhibit 71

Whittier Variation to Alternative C

Whealton Substation

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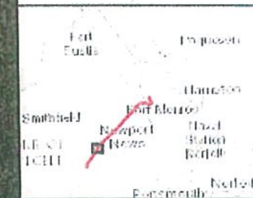

Whittier Variation to Alternative C

Exhibit 71

Whittier Variation to Alternative C

Whealton Substation

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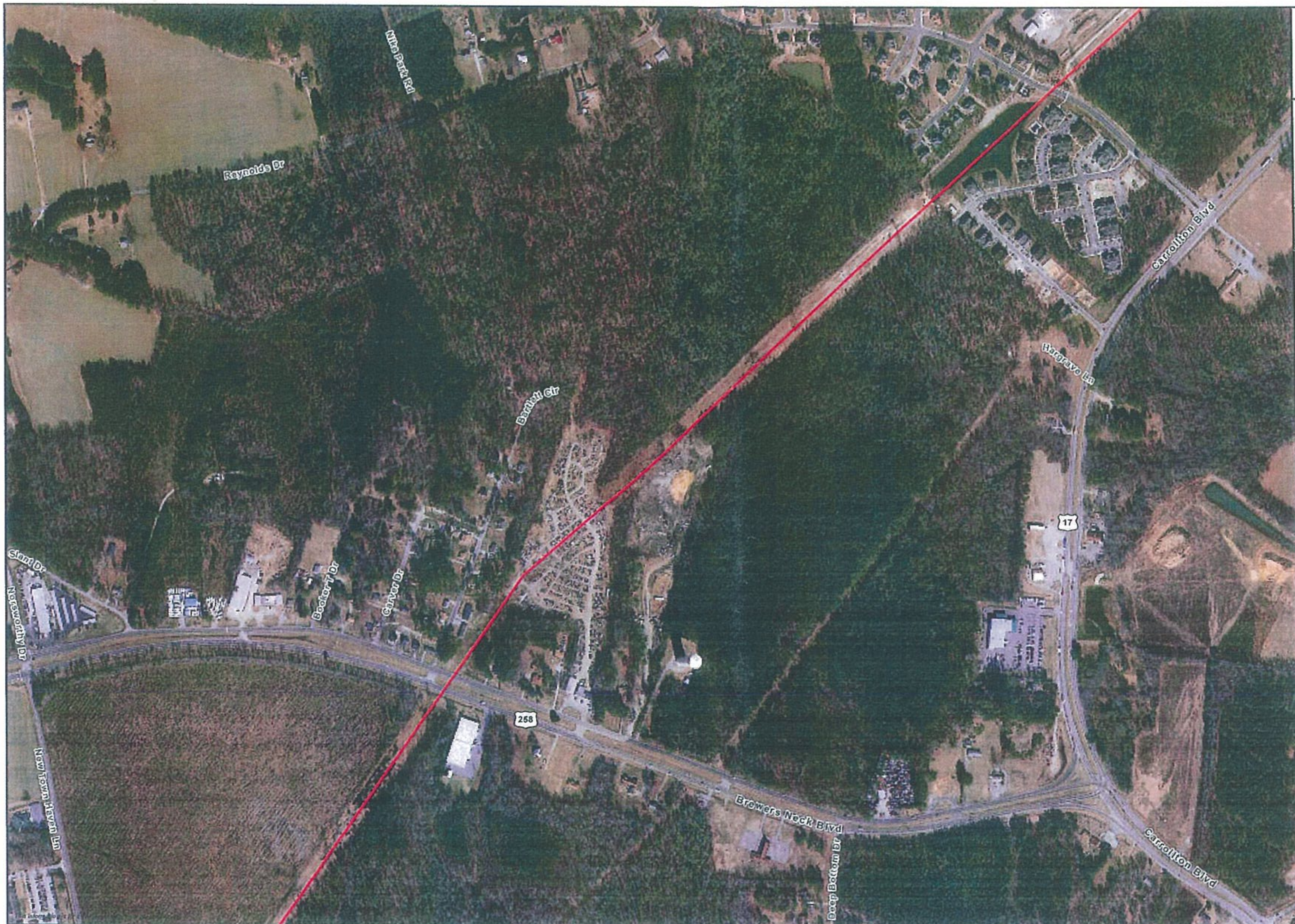

Dominion

Fort Eustis
Poquoson
Hampton
Fort Monroe
Smithfield
Newport News
Naval Station Norfolk
Norfolk
Portsmouth

Whittier Variation to Alternative C

Exhibit 71

Whittier Variation to Alternative C

Whealton Substation

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Whittier Variation to Alternative C

Exhibit 71

Whittier Variation to Alternative C

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DRAWN BY: Randy McGregor

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Dominion

Whittier Variation to Alternative C

Exhibit 71

Whittier Variation to Alternative C

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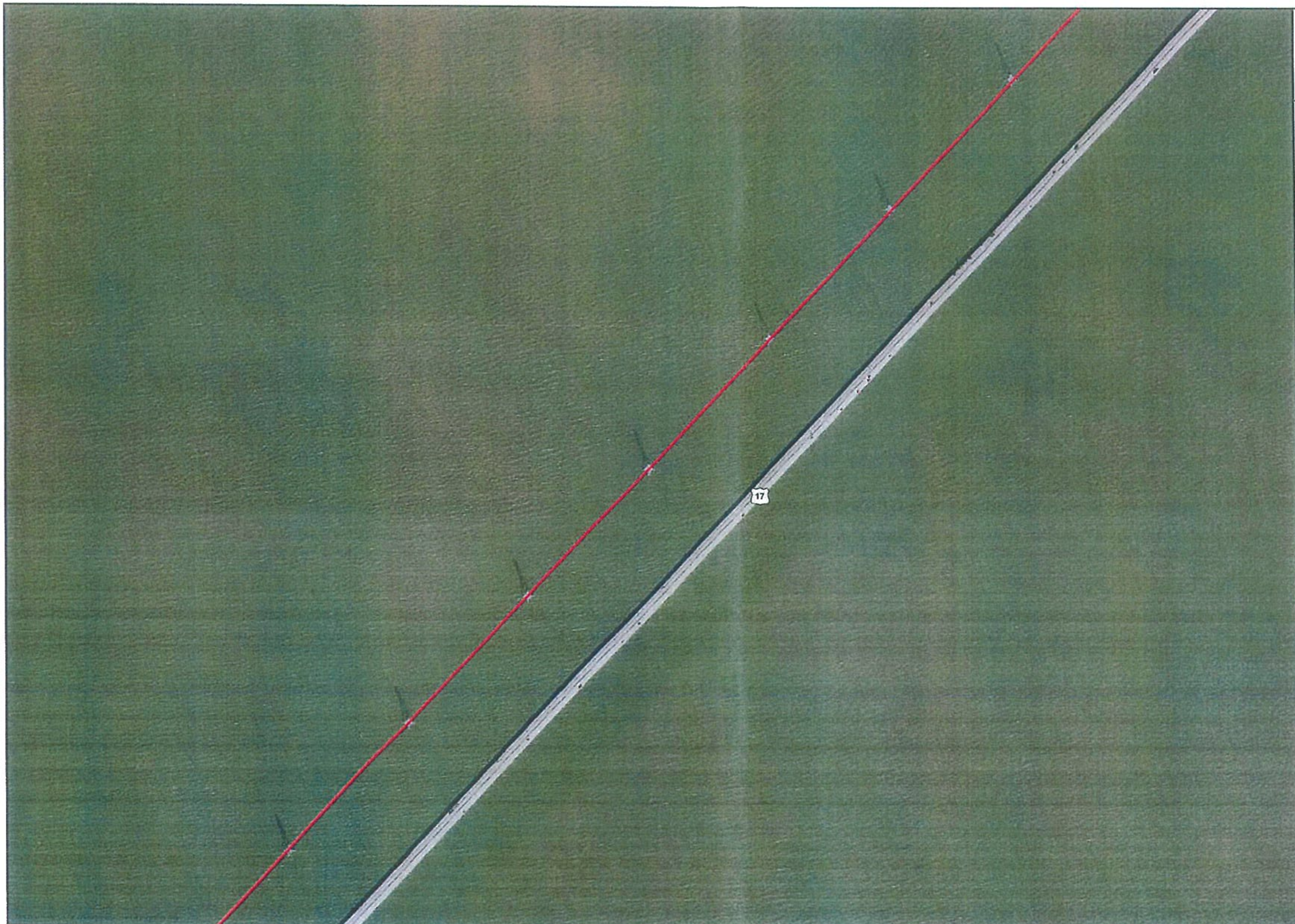

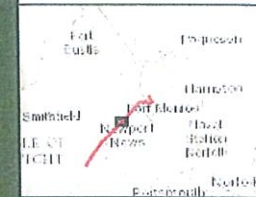

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Whittier Variation to Alternative C

Exhibit 71

Whittier Variation to Alternative C

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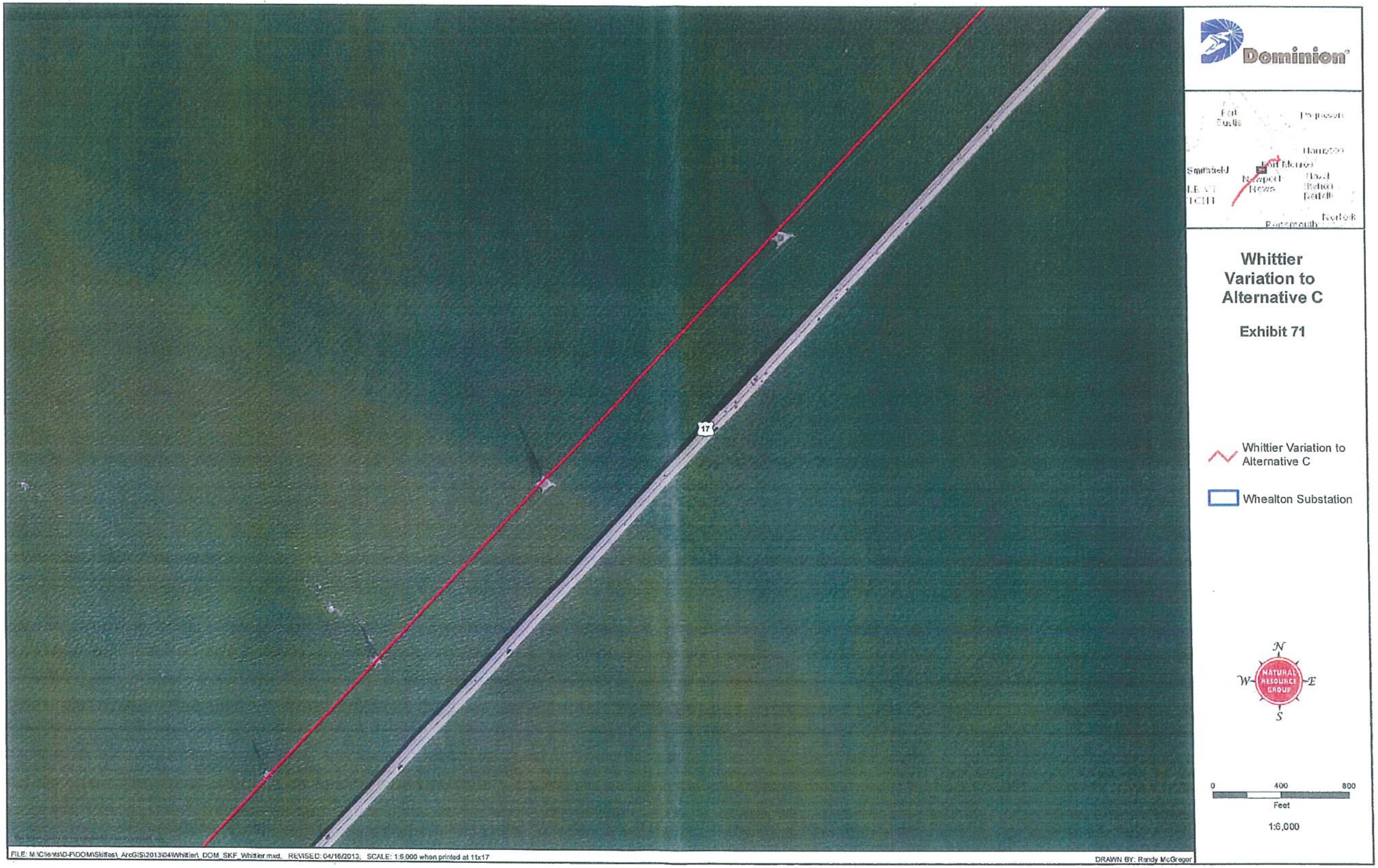

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Whittier Variation to Alternative C
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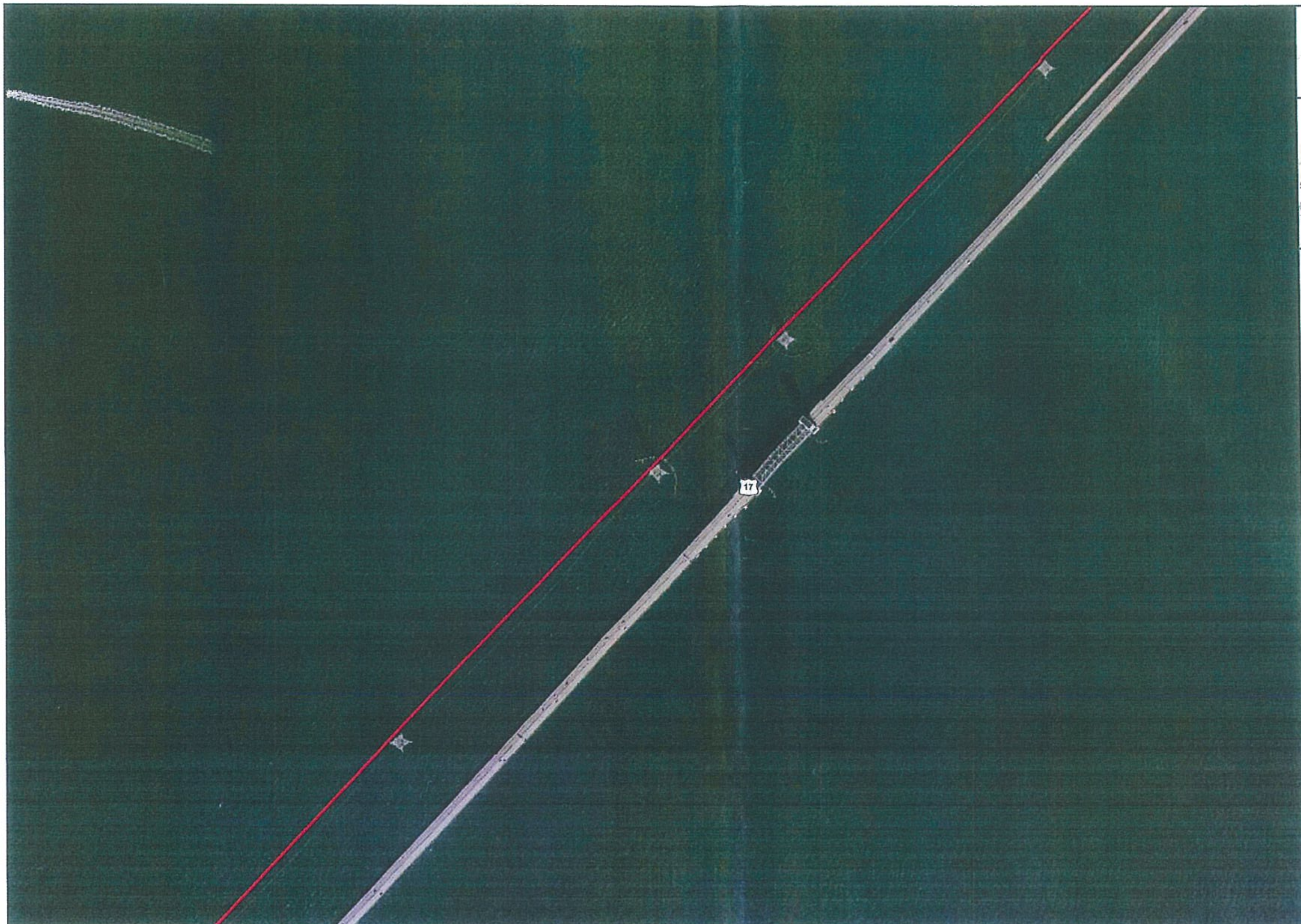

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DRAWN BY: Randy McGregor

Dominion

Whittier Variation to Alternative C

Exhibit 71

Whittier Variation to Alternative C

Whealton Substation

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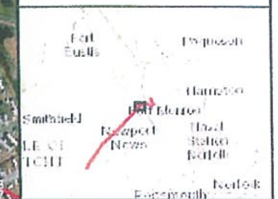
Dominion



Whittier Variation to Alternative C

Exhibit 71

Whittier Variation to Alternative C

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Dominion®

Whittier Variation to Alternative C

Exhibit 71

Whittier Variation to Alternative C

Wheaton Substation

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Variation to
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ATTACHMENT 4

REBUTTAL TESTIMONY
OF
MARK S. ALLEN
ON BEHALF OF
VIRGINIA ELECTRIC AND POWER COMPANY
BEFORE THE
STATE CORPORATION COMMISSION OF VIRGINIA
CASE NO. PUE-2012-00029

Q. Please state your name, business address and position with Virginia Electric and Power Company ("Dominion Virginia Power" or "Company").

A. My name is Mark S. Allen and I am Manager, Electric Transmission Line Engineering for the Company. My business address is 701 East Cary Street, Richmond, Virginia 23219.

Q. What is your educational and professional background?

A. I received a Bachelor of Science degree in Civil Engineering (*magna cum laude*) from West Virginia University of Technology in 1981. I am a Registered Professional Engineer in Connecticut, Kentucky, Michigan, Ohio, Pennsylvania, Virginia, Utah and West Virginia. I have 31 years of experience with the Company in both Transmission and Distribution. I started my career with the Company as a Project Engineer in Transmission Engineering in 1981. In 1985, I moved to Distribution Planning as a Planning Engineer in the Eastern Division and then returned to Transmission Engineering in 1989. I have experience in both overhead and underground transmission design.

Q. What are your responsibilities as Manager, Electric Transmission Line Engineering?

A. I am responsible for the coordination of all high voltage transmission designs (overhead and underground) on the Dominion Virginia Power system. This includes all new designs as well as upgrades and relocations. I manage the engineering activities for each project to ensure completion of construction specifications by the established target date. I am responsible for assuring that all such designs/specifications meet the established criteria for safety, reliability, and cost-effectiveness.

Q. Have you previously submitted testimony in support of the Company's Application in this proceeding?

A. I did not originally submit pre-filed direct testimony, but, as the Company advised the Virginia State Corporation Commission (the "Commission") and participants on February 4, 2013, I am adopting the pre-filed Direct Testimony of Company Witness James Cox, who has taken another position in the Company.

Q. What is the purpose of your rebuttal testimony?

A. The Company proposes to construct an overhead 500 kV transmission line from Surry Switching Station ("Surry Station") at the Company's Surry Power Station in Surry County across the James River to the proposed Skiffes Creek Switching Station ("Skiffes Station") in James City County (or "JCC"). For the reasons expressed in the Appendix filed in support of the Application and in the direct testimony that I am sponsoring, the Company did not propose, as an alternative to its 500 kV overhead line, that all or part of the 500 kV line be constructed underground, or by using a hybrid combination of underground and overhead construction. Certain of the Respondents, as well as public witnesses, have recommended in this proceeding, however, that the Commission require that any transmission line crossing the James River to Skiffes Station be constructed underground at 230 kV. My testimony will address these recommendations.

In addition, during the January 10, 2013 public hearing in this proceeding and in a subsequent pre-hearing conference on January 30, 2013, the Hearing Examiner directed the Company to present evidence regarding the feasibility, cost and advisability of constructing an underground 230 kV hybrid single circuit (1000 MVA) ("Alternative A") or an underground 230 kV hybrid double circuit (1000 MVA/circuit) ("Alternative B") both from Surry Station to Skiffes Station along the route of James River Crossing Variation 3, both of which I will call together the "Variation 3 Hybrid" conceptual route.[1] In responding to the Hearing Examiner's direction, I will describe the Company's approach to undergrounding of transmission lines, based on our use of and experience with underground construction and operation of such lines; compare the construction, reliability, and operation impacts of underground with overhead construction; address the questions raised by the Hearing Examiner regarding the 230 kV Alternatives A and B; and recommend that no part of the Surry-Skiffes Creek line be constructed underground. Rebuttal testimony regarding underground construction costs will be provided by Company Witness Walter R. "Trey" Thomasson, III. I also will provide the estimated construction costs for constructing the additional overhead transmission facilities necessary to resolve all of the violations of mandatory NERC Reliability Standards ("NERC Reliability Violations") not resolved by Alternatives A and B, as identified by Company Witness Peter Nedwick, as well as for JCC Witness Waine P. Whittier's suggested rebuild of the existing James River crossing of 230 kV Lines #214 and #263 between Isle of Wight County and the City of Newport News ("Alternative C"). Finally, I will comment on the pre-filed testimony of BASF Corporation ("BASF") Witness

[1] As directed by the Hearing Examiner, Alternatives A and B are to come ashore underground on the BASF property at the James River Crossing Variation 3 and then continue underground on that route to an underground-overhead transition station at BASF Drive and then continue overhead on that route along BASF Drive to Skiffes Station.

Vernon C. Burrows concerning certain aspects of the construction of the proposed overhead line.

Q. Are you sponsoring an exhibit in this proceeding?

A. Yes. Company Exhibit No. __, MSA, consisting of Rebuttal Schedules 1-5, was prepared under my supervision and direction and is accurate and complete to the best of my knowledge and belief.

Q. Before you begin, can you please summarize your rebuttal testimony and explain how it is organized?

A. In fulfilling its obligation to provide reliable electric service at reasonable rates, the Company utilizes overhead transmission facilities to meet customers' load demands in the most economical manner whenever possible. When determining whether to build overhead or underground transmission lines, the Company considers such factors as reliability, time to construct, operability and cost. Based on these considerations, currently only about 1.27% of the Company's total transmission system operating at 69 kV or above is underground, and of that percentage, none operates above 230 kV. As supported by the evidence presented by the Company in its direct, supplemental and rebuttal filings in this proceeding, the Company continues to recommend its proposed Project, including the 500 kV overhead Surry-Skiffes Creek line, as the most robust and cost-effective transmission planning solution to meet the identified need in the North Hampton Roads Load Area.

First, the overall reliability of an underground transmission line is not considered as good as an equivalent overhead line due to the time it takes to locate and repair an underground fault. Since customer reliability is a major concern in determining whether to build overhead or underground transmission lines, an overhead line should be constructed whenever a viable overhead route exists, as it does in this case.

Second, as stated in the Company's Appendix and explained later in my rebuttal testimony, the Company does not consider 500 kV to be a viable underground alternative. Further, as explained by Company Witness Nedwick in his rebuttal testimony, neither a single circuit nor a double circuit 230 kV line from Surry Station to Skiffes Station, whether underground or overhead, will resolve all of the NERC Reliability Violations identified by Mr. Nedwick for 2015 and would increase the load on the already stressed 230 kV transmission system in the South Hampton Roads Load Area.

Third, the Company has a responsibility to build a reliable system in as cost-effective a manner as possible. As further supported by Company Witness Thomasson in his rebuttal testimony, the cost for a 230 kV hybrid underground/overhead Surry-Skiffes Creek line, including Skiffes Station and work at Surry Station, would be significantly more than the cost of corresponding facilities for the Company's overhead 500 kV line.

Finally, unlike the Company's proposed Project, the length of time to construct either an underground line or the Alternative C proposed by JCC Witness Whittier far exceeds the required target date for this Project.

As Company Witness Nedwick in his rebuttal testimony and Staff Witness John W. Chiles have testified, it is not viable to construct the new 500 kV line underground, and a 230 kV line without additional transmission upgrades, whether constructed overhead or underground, does not meet the identified electrical need. Further, the much higher cost for an underground line, including the additional transmission facilities required to resolve the identified NERC Reliability Violations, would not meet the 2.5 times criterion for the Project to qualify for treatment as a pilot program under House Bill ("HB") 1319 and does not address the need in this case. For these reasons, and as supported by the Company's evidence presented in this case, the Company continues to recommend that no part of the Surry-Skiffes Creek line be constructed underground.

Finally, construction of the Surry-Skiffes Creek overhead line using the Updated Proposed Route will not compromise the current environmental remediation on the BASF property.

My rebuttal testimony is organized as follows:

I. Background on Company's Underground Transmission
II. Effects of Underground Transmission
III. HB 1319
IV. 230 kV Alternative Estimates
V. Issues Related to the BASF Property

I. BACKGROUND ON COMPANY'S UNDERGROUND TRANSMISSION

Q. What portion of the Company's transmission system is underground, and how does that compare to the portion that is overhead?

A. The Company's transmission system is comprised of approximately 6,406 miles of lines operating at voltages of 69 kV and above. Of this total, there are 23.5 miles of 69 kV underground lines, 0.075 mile of 115 kV underground lines and 57.8 miles of 230 kV underground lines, for a total of 81.4 miles. The underground facilities represent 1.27% percent of the total transmission system. Underground transmission facilities are rare on most utility systems with service areas comparable to the Company's area in Virginia and North Carolina.

Q. How has the Company approached the installation of underground transmission lines?

A. The Company is obligated to provide reliable electric service at reasonable rates to the public. We discharge this obligation by utilizing overhead transmission facilities to meet the load demands of customers in the most economical manner whenever possible. Underground installation has only been used in very limited circumstances. Examples include the Company's underground facilities in northern Virginia inside the "Beltway," where the congested urban nature of these areas prohibited an overhead corridor from being established. A more recent example is our Hayes-Yorktown project for which the portion of a new 230 kV line across the York River was installed underground, using an existing river bottom encroachment permit, to avoid conflicts with operations of U.S. military elements.

Q. Are there examples of lines in the Company's transmission system that were installed underground for specific reasons?

A. Yes. My Rebuttal Schedule 1, a spreadsheet entitled "Dominion Virginia Power 230 kV Underground Transmission Facilities," shows each 230 kV underground circuit in the system and lists the primary reasons each was installed underground. In summary, these underground circuits were required because (1) no feasible, cost-effective overhead alternative was available; (2) the line was built as a radial configuration for direct delivery to the customer, who requested underground service and paid for the construction; (3) underground construction was required by Virginia law; or

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(4) underground construction was approved by the Commission as a pilot project.

Q. Has the issue of underground construction been raised in prior transmission line cases?

A. Yes, for many years. In most cases, putting transmission lines underground appears to be an easy or obvious answer to some, but that is simply not the case. It is no coincidence that utilities with service territories similar to that of Dominion Virginia Power have constructed most, if not all, of their transmission lines overhead. Undergrounding is also a frequent response from local governments when members of the public express concerns about a proposed overhead route. It should be noted, however, that in no case has the Commission required underground construction against the Company's best engineering judgment.

Between 2001 and 2008, underground construction was proposed by opponents of overhead construction, and rejected by the Commission in a series of four cases, three of which involved 230 kV projects in Loudoun County: Beaumeade-Beco and Beaumeade-Greenway, Case No. PUE-2001-00154; Brambleton-Greenway, Case No. PUE-2002-00702; and Pleasant View-Hamilton, Case No. PUE-2005-00018. The Commission's rejection of underground construction in the Brambleton-Greenway case was upheld by the Supreme Court of Virginia on appeal. The Pleasant View-Hamilton line ultimately fell under HB 1319, and a two-mile section of this line was installed underground. The fourth case, the Garrisonville project, Case No. PUE-2006-00091, involved a proposed five-mile double circuit overhead line in Stafford County. In that case, the Company proposed an overhead line but also had filed testimony stating it was not opposed to undergrounding the double circuit line as a pilot project for the purpose of gaining experience with a new underground technology, if the Commission found that to be in the public interest. The Commission approved underground construction of the line as a pilot project to permit the Company to gain that experience.

II. EFFECTS OF UNDERGROUND TRANSMISSION

Q. What are the Company's concerns about installing transmission lines underground?

A. As stated above, the Company has 6,406 miles of transmission lines, but only 81.4 miles are underground, or about 1.27% of the total system amount. When determining whether to build overhead or underground transmission power lines, the Company considers four main issues: reliability, time to construct, operability, and cost.

Reliability is a major concern in determining whether to build overhead or underground transmission lines. Overhead and underground lines each have reliability challenges, but it is obvious that a problem on an overhead line is easier to locate than on an underground line, and underground line outages are significantly longer than those on overhead lines. On average, most repairs on an overhead line can be completed within hours, but repairs to underground lines take days to weeks. The Company clearly understands the expectation that lengthy power outages are unacceptable. As a result, when we consider customer reliability, overhead lines are preferred.

The second issue, equally critical, is the time to construct. None of the transmission alternatives to the proposed Project can be completed by the June 2015 need date for the Project. Based on a previous 230 kV project of this nature, the minimum estimated construction time for 230 kV transmission Alternatives A or B to fully resolve 2015 NERC Reliability Violations is 60 months from issuance of a Commission order. This is based on the time required for the activities described in the Company's response to Question No. 22 of the Staff's Second Set of Interrogatories, a copy of which is provided as my Rebuttal Schedule 2. This 60-month construction timeframe is based on the availability of multiple contractors to attack this aggressive schedule. It is unlikely that this number of contractor crews can be obtained due to the limited resources that exist in the transmission underground construction industry. In addition, it would require the postponement of the retirement of Yorktown Units 1 and 2 during this construction period. Therefore, those undergrounding alternatives are not technically feasible from an electrical or need date standpoint. JCC Witness Whittier's proposed Alternative C rebuild of existing 230 kV Lines #214 and #263 requires rebuilding so much of the Company's 230 kV facilities in the area that it would take an estimated 10 years just to complete the facilities needed to address the 2015 NERC Reliability Violations. Since it takes 10 years to construct Alternative C and the additional compliance facilities to address the 2015 NERC Reliability Violations, the construction group did not address the additional time it would take to build the additional facilities needed to address the 2021 Reliability Violations caused by Alternative C.

By contrast, the length of time required to construct the overhead 500 kV line proposed in this Project is 15 months and is projected to be completed by December 31, 2014. With a timely order from this Commission, the entire Project, including the 230 kV Skiffes Creek-Whealton line, is projected to be completed by the May 31, 2015 need date.

Another issue is operability. Underground transmission lines add operating restrictions to the electric system. When power usage is low, normally in spring and fall, underground lines can raise the voltage on the grid to unacceptable levels. In order to avoid damaging equipment, both of the Company and its customers, these lines must be temporarily taken out of service, or sufficient reactive compensation facilities must be added to the system. So operability concerns also lead us to prefer overhead transmission lines. Underground lines present significant issues for "reclosing" after faults and also can present transmission operating issues from the effects of weather.

The fourth issue considered when determining whether to build overhead or underground is cost. Dominion Virginia Power has a responsibility to build a reliable system in as cost-effective a manner as possible. As explained in detail below, both of 230 kV underground Alternatives A and B not only cannot be constructed by the need date, but would cost $333.2 million more than the $155.4 million cost of the proposed Project.

Q. **What factors would cause the underground installation of a transmission line to have a detrimental effect on the reliability of electric service?**

A. Outages of transmission lines, both overhead and underground, are not common but when they occur it is very important to restore the line to service as quickly as possible because of the amount of power they carry within our system and the significant numbers of customers that can be impacted.

As stated above, an outage of an overhead transmission line can usually be repaired within a matter of hours. Location of the problem is easy to identify. Our system operator will know that the outage is on a certain line between two substations, and a visual inspection of the line via air or land will quickly disclose the location where repairs are needed. We can gain access to the site promptly by road and along the right-of-way itself. We maintain our own skilled personnel, equipment and materials to make such repairs promptly, and qualified contractors are readily available, if necessary. The line can usually be restored quickly. In most outage cases, such as those caused by a broken insulator or conductor, repairs take only a few hours. In very rare cases of a structure failure, restoration can be, on average, one to three days. Based on the Company's experience with repairs required for overhead lines over water, restoration may take slightly longer depending on the nature of the problem, but still much faster than an underground repair.

In contrast, location of a failure of an underground transmission line is more difficult and time-consuming. First, each cable must be tested to identify the failed cable. Complex fault location equipment is used to calculate a distance to the fault. When the damaged section of a land-based cable is identified, the site must be excavated sufficiently to provide access to the failed cable. Depending on the nature of the damage, the cables must either be repaired with a splice, or the entire section between existing splices must be removed from its protective pipe casing and replaced. Splicing a 230 kV transmission cable is highly specialized. We must rely on the very few contractors in the United States that can do this work. After such a contractor is on-site and the damaged area has been excavated, it may take several weeks to over a month to complete the entire repair operation. If the damaged cable must be removed and a new cable installed, the process takes even longer. In the case of the Northern Virginia failure in 2004, the fault was the result of steel h-pile being driven through the steel pipe and cable. Consequently, we knew exactly where the failure was so assessment and repairs began immediately. A temporary repair had to be installed around the failed/ruptured pipe to prevent additional leakage of the dielectric fluid. The fluid that did spill had to be cleaned up in accordance with environmental regulations. One of the specialized contractors referenced above was brought in to facilitate and complete the repair. An oil freeze had to be installed on each side of the failed section so the pipe could be reopened to make the splice. A temporary splice pit had to be installed at the splice location to maintain proper atmospheric conditions while making the repair. The end result was a five-week repair of this 230 kV cable and pipe.

However, if the damaged section is deep underneath the bed of the river, in a directionally drilled pipe-type cable system, as would be the case for either of 230 kV Alternatives A or B, the repair becomes much more difficult and time-consuming. This is due to the fact that the pipe can be as much as 60 feet below the bottom of the river bed. Specialized marine construction contractors, as well as cable installation contractors, would be required to locate and fully evaluate the damage, devise a repair plan, and execute the plan.

Q. Are there additional reliability differences between underground and overhead transmission facilities?

A. Yes, with respect to "reclosing" of circuit breakers after a fault occurs. When a fault occurs on an overhead transmission line, the line may not have been damaged and can be restored to service immediately. When our overhead transmission system experiences a fault, breakers open to protect the line but automatically and immediately "reclose" so that, if the line has not been damaged, the power flow in the line is interrupted only for a fraction of a second. This can be done safely because a fault event is usually a temporary condition for an overhead line. Arcing associated with a fault of an overhead line does not usually do significant damage to the equipment.

Automatic "reclosing" is not permitted on underground transmission lines because the fault will likely result in damage to the cable and its insulation and immediate reclosing would cause more extensive damage. The resulting damage would require the lengthy repair process that I described above. Therefore, when a fault occurs on an underground transmission line, we keep the line out of service until tests can be performed to determine the cause of the fault and ascertain the extent of damage to the cable. Typically such testing would take several days to mobilize personnel and complete.

Q. What are the voltage control problems associated with underground cables and how do they affect the operation of the Company's transmission system?

A. Due to the electrical characteristics of underground cables, namely the capacitance, voltages on such cables can rise to unacceptable levels during periods of light load. These excessive voltage levels can damage equipment and create situations where devices can no longer function as required under all operating conditions.

Q. Are underground lines immune from the adverse effects of weather?

A. No. In fact, one of the 230 kV lines under the Elizabeth River locked out in 2009 for a fault during Hurricane Ida. The storm sprayed salt water into the transition station and caused the cable terminations to flashover from the salt contamination. The circuit locked out as designed and was out of service until the termination could be repaired and cleaned. It is actually standard practice now to de-energize this line during a major storm preparation to prevent flashover damage.

Q. How do the construction impacts of underground transmission lines compare to those of overhead transmission lines?

A. On land, there are significantly more impacts with underground construction compared with overhead line construction. For overhead construction, pipe pile foundations will be vibrated into the ground approximately every 1,000 feet. This results in minimal land disturbance. In contrast, for the double circuit underground alternative, two trenches, each approximately six feet wide and five feet deep will need to be excavated for the entire length of the circuit. This will result in an estimated 11,733 cubic yards of soil excavation for every mile of underground construction.

For the river crossing, the overhead construction would be similar to the land construction, with pipe pile foundations installed approximately every 1,400 feet, resulting in minimal riverbed disturbance. For the underground construction, most of the river crossing would not be disturbed, as the cable pipes would be directionally drilled underneath the riverbed. However, at every splice point for the cable, a trench approximately 900 feet long, four feet wide, and 15 feet deep would be excavated in the riverbed in order to properly "overboard" and bury the cable splices. Due to the length of the river crossing, this would have to be done three times for each individual pipe. This results in a riverbed excavation of 36,000 cubic yards of sediment and riverbed for six pipes with three splices each.

Q. Should the Commission require any portion of a Surry-Skiffes Creek line to be constructed underground?

A. No. The proposed Surry-Skiffes Creek transmission line should not be constructed underground for the following reasons:

1. As stated in the discussion above, the overall reliability of an underground transmission line is less than an equivalent overhead line due to the time it takes to locate and repair an underground fault. The duration of an underground outage has been validated by the Company's own experience with underground transmission, as in the case of the Northern Virginia project discussed above. Since customer reliability is a major concern in determining whether to build overhead or underground transmission lines, an overhead line should be constructed whenever a viable overhead route exists.

2. The Company does not consider 500 kV to be a viable underground alternative. The only 500 kV underground cables in the United States are at the Grand Coulee Dam in the state of Washington, which are short generator connections from the dam to the adjacent switchyard, and these circuits are currently in the process of being replaced due to reliability concerns. As explained by Company Witness Nedwick, neither 230 kV Alternative A nor B can, without significant further additions to the transmission system, resolve all of the identified NERC Reliability Violations, and either of these alternatives would only increase the load on the already stressed 230 kV transmission system in South Hampton Roads.

3. The Company has a responsibility to build a reliable system in as cost-effective manner as possible. My Rebuttal Schedule 4 provides the estimated overhead transmission costs for Alternatives A, B and C. As shown there, the estimated

cost for the proposed 500 kV Surry-Skiffes Creek overhead line, including Skiffes Station and work at Surry Station, is $155.4 million, while the cost for a corresponding hybrid underground/overhead double circuit 230 kV line from Surry to Skiffes Station (Alternative B) is $440.4 million, representing a 2.83 times cost differential for comparison purposes. However, this does not account for the $48.2 million of additions to the transmission system that would be required to resolve the NERC Reliability Violations for 2015 not addressed by Alternative B. When those costs are considered, the cost of Alternative B for 2015 increases to 3.14 times that of the Company's proposed overhead Surry-Skiffes Creek line. And with the additional $26.7 million of additional compliance facilities required for 2021, the cost of Alternative B is 2.98 times that for the proposed Project. The cost to construct single circuit 230 kV Alternative A would be $273.8 million, but the additions to the transmission system that would be required for that alternative to resolve the identified NERC Reliability Violations for 2015 and 2021 would be those required to build Alternative B plus the same compliance facilities as for Alternative B to resolve NERC Reliability Violations in those years. Accordingly, the total cost is the same for both Alternatives A and B.

4. The length of time to construct either transmission Alternative A or B is a minimum of 60 months after issuance of the Commission's Final Order, which would mean completion in mid to late 2018, far exceeding the required summer 2015 need date for this Project. The overhead construction of the proposed 500 kV line is projected to be completed by December 31, 2014, while the total

Project, including the 230 kV line from Skiffes Creek-Whealton, will be completed by May 31, 2015.

III. HB 1319

Q. Has the General Assembly enacted legislation that affects the choice of undergrounding versus overhead construction?

A. In 2008, the General Assembly enacted HB 1319 establishing a limited pilot program requiring the Commission to approve undergrounding of a two-mile portion of the Pleasant View-Hamilton project (for which the Commission previously had rejected undergrounding), plus all or part of three more transmission lines of 230 kV or less by July 1, 2012. In 2011, the expiration date for this program was extended to July 1, 2014. The legislation establishes three criteria for a project to be eligible for approval as a qualifying pilot project: (1) undergrounding all or a part of a line must be technically feasible; (2) the estimated additional cost of undergrounding may not exceed 2.5 times the cost of placing the same line overhead (unless the public utility, affected localities and the Commission agree that a project not meeting this criterion may be accepted into the pilot program); and (3) the governing body of each locality in which a portion of the proposed line indicates, by general resolution, general community support for the line to be placed underground.

Q. What has been the Company's response to HB 1319?

A. The Garrisonville project was submitted prior to HB 1319 and was not eligible for inclusion in the HB 1319 program. The Commission approved undergrounding of the two-mile portion of the Pleasant View-Hamilton line, as required by HB 1319, in Case No. PUE-2008-00042. The Company filed applications, which were approved by the

Commission, to construct two additional underground transmission lines as pilot projects under HB 1319. The 0.71-mile Beaumeade-NIVO underground line was approved in Case No. PUE-2008-00063, and the 3.7-mile Ballston-Radnor Heights underground line was approved in Case No. PUE-2010-00004.

Q. Were these projects comparable to the proposed 500 kV Surry-Skiffes Creek line?

A. No. This case concerns the need to provide a new source of 500 kV bulk power to support reliable service within an extensive load area that includes the Peninsula, Middle Peninsula and Northern Neck. Each of these pilot projects addressed a much more localized need and affected a much smaller area. Moreover, the Company does not consider undergrounding to be a viable alternative for a 500 kV line. As stated in Appendix I.C.4 on page 58, the only 500 kV underground cables in the United States are short generator connections from the Grand Coulee Dam to the adjacent switchyard. These cables are actually in the process of being replaced with 500 kV overhead lines due to reliability concerns, as discussed in my Rebuttal Schedule 3.

Q. Would undergrounding the proposed 500 kV Surry-Skiffes Creek line qualify for treatment as a pilot program under HB 1319?

A. No. As Company Witness Nedwick in his rebuttal testimony and Staff Witness Chiles have testified, it is not viable to construct the new 500 kV line underground, and a 230 kV line without additional transmission upgrades, whether constructed overhead or underground, does not meet the identified electrical need. Further, as shown in my Rebuttal Schedule 4, the much higher estimated cost for either a single circuit or double circuit underground line, including the additional 230 kV facilities required to resolve the identified NERC Reliability Violations, would exceed the 2.5 times criterion for a project to qualify under HB 1319. As I have explained, the total Project cost of Alternative A for 2015 ($488.6 million) is the same as for Alternative B. Of this total cost, the cost attributable to a Surry-Skiffes Creek line is $439.8 million ($488.6 million total minus $46.4 million for the Skiffes Creek-Whealton line and $2.4 million for work at Whealton and other substations). The comparable costs for the proposed 500 kV line total $106.6 million ($155.4 million total minus the same $46.4 million and $2.4 million figures related to the Skiffes Creek-Whealton line). Comparison of the costs for these comparable facilities shows that the cost of facilities associated with the underground/overhead alternative 230 kV line to Skiffes Station is 3.13 times for HB 1319 comparison purposes for the proposed 500 kV overhead line for 2015. Adding the $26.7 million of additional facilities required for either 230 kV alternative to achieve full compliance for 2021 produces a total of $515.3 million for the 230 kV alternative. Of this total, the cost attributable to a Surry – Skiffes Creek line is $466.5 million ($515.3 minus $46.4 million for the Skiffes Creek-Whealton line and $2.4 million for work at Whealton and other substations). The comparable cost for the proposed 500 kV line for 2021 compliance is $123.9 million ($172.7 million total minus the same $46.4 million and $2.4 million figures related to the Skiffes Creek-Whealton line). This is 2.77 times the $ 123.9 million cost of the proposed 500 kV overhead line for HB 1319 purposes.

IV. 230 KV ALTERNATIVE ESTIMATES

Q. Please provide the Company's estimated cost of the additional transmission facilities that would be required for each of Alternatives A and B to resolve identified NERC Reliability Violations that are not resolved by those 230 kV alternatives.

A. These additional facilities are identified in Company Witness Nedwick's Rebuttal

Schedule 4, and the estimated costs of these facilities for Alternative A are shown on page 1 of my Rebuttal Schedule 4. The corresponding costs for Alternative B are shown on page 2 of that schedule.

Q. Please provide the Company's estimated cost for 230 kV Alternative C.

A. Currently, existing 230 kV Line #214 (Surry-Winchester) and Line #263 (Chuckatuck-Newport News), each with a transfer capability of approximately 500 MVA, cross the James River on common double circuit structures between Isle of Wight County and the City of Newport News. As described in the rebuttal testimony of Mr. Nedwick, Alternative C, suggested by JCC Witness Whittier, would tie the river crossing portions of these two circuits together to create one six-wire circuit between Chuckatuck and Newport News Stations, designated Line #263, with a combined transfer capability of approximately 1000 MVA. The river crossing portion of Surry-Winchester Line #214 would be replaced with a new single circuit river crossing with new 1000 MVA conductors.

Of course, the transfer capability of these rebuilt river crossings would be limited by the transfer capability of the onshore portions of these circuits unless they are rebuilt to provide approximately 1000 MVA. In the case of Line #214, this would mean rebuilding from the Isle of Wight side of the James River 30.29 miles back to Surry Power Station, and from the Newport News side 2.65 miles back to Winchester Station. In the case of Line #263, 6.25 miles would need to be rebuilt from the Isle of Wight side of the river back to Chuckatuck Station and 4.52 miles from the Newport News side back to Newport News Station. But this work only covers the facilities that are directly affected by this increase in transfer capability of these two circuits. Significant improvements also would be required to additional interconnecting facilities to prevent them from overloading due to the increased power flows on Line #214 and Line #263. As shown on page 3 of my Rebuttal Schedule 4, the total cost of improvements to rebuild Line #214 and Line #263 and address the resulting impacts on other facilities is $144.8 million.

Mr. Nedwick's rebuttal testimony also identifies a number of NERC Reliability Violations that are not resolved by Alternative C, lists the additional improvements to the transmission system that would be required to resolve those deficiencies and explains that the cost of these additional transmission system improvements must be included in the total cost of Alternative C. As shown on page 3 of my Rebuttal Schedule 4, we estimate the cost of these additional improvements to transmission facilities to be $82.1 for 2015 compliance and $181.9 million for 2021 compliance, bringing the total cost of Alternative C to $ 408.8 million. In addition, this work would require the postponement of the retirement of Yorktown Units 1 and 2 during the construction period of the 2015 compliance work, resulting in an additional $ 652 million for 2015 compliance. This would bring the total project costs to $1,060.8 million for 2015 compliance, which exceeds the $155.4 million of the Company's proposed Project by 6.83 times. Because the time to construct the transmission facilities for 2015 NERC Reliability Standards compliance (10 years) far exceeds the Project need date, no generation costs were prepared for 2021 compliance.

Q. Do you have any further comments regarding the constructability of Alternative C?

A. Yes. We have analyzed the feasibility of constructing Alternative C, which would require rebuilding most of the existing 230 kV system in the area. That analysis, which focused on the sequence for rebuilding the various components of the system and the feasibility of scheduling the outages of existing lines that would be required, shows that it would take a minimum of 10 years to complete just the construction required for 2015 NERC Reliability Standards compliance for Alternative C. Obviously, this is not a feasible solution to meet the identified electrical need date of June 1, 2015.

V. ISSUES RELATED TO THE BASF PROPERTY

Q. Do you agree with BASF Witness Vernon C. Burrows's comments on pages 9-12 of his testimony, regarding his assessment of the impact of the construction of the transmission line using the Updated Proposed Route?

A. No. Mr. Burrows has made several incorrect assumptions about our engineering and construction methods to support his position on page 2 of his testimony that the construction of the line using the "Variation 1 route would be a disaster." First, Dominion Virginia Power plans to use a pipe pile foundation design to support the transmission towers on BASF property, not Drilled Foundations as noted by Mr. Burrows on page 10 of his testimony. These pipe pile foundations will be approximately 42 inches in diameter and will be driven with a vibratory hammer to a depth of approximately 40-60 feet. This type of foundation design is minimally invasive and is generally considered to have little, if any, impact when used in sensitive areas such as wetlands as discussed by Company Witness Cathy Taylor. Additionally, Mr. Burrows's statement on page 10 of his testimony that it will be difficult to span the bluff at the river is not correct. The BASF Property already has a 115 kV line that transverses the property for over one mile to the Dow Substation located on the property, which supplies electricity to the property. The extension of this corridor to the River is another approximately 2,500 feet and in that expansion our preliminary design calls for four towers. As is also discussed by Company

Witness Taylor, Dominion Virginia Power will not locate any towers in the capped landfill in Area 4C of the BASF property as shown in BASF Witness Burrows's Exhibits VCB-2 and VCB-3, nor will any construction activities occur on this capped landfill. In fact our preliminary designs indicate we can easily span the majority of this area and will have only one tower in Area 4C. While the Company has not yet determined the precise location for this tower, and will not be able to determine this until the final engineering following approval of the route, preliminary plans indicate that the tower would be located in the southern portion of Area 4C, between the capped landfill and the unnamed tributary. In any case, the tower will not be located on the capped landfill. See Rebuttal Schedule 5 for a map showing Area 4C and preliminary tower location.

Q. **What concerns does Dominion Virginia Power have regarding the Policies and Procedures that Mr. Burrows asks to be required for the construction of an overhead route on BASF Property?**

A. Dominion Virginia Power complies with all Federal, State, and Local laws and established construction practices for the utility industry in the construction of transmission lines and associated facilities. Below I quote the relevant portion and respond individually to each of the requirements Mr. Burrows sets out on Pages 14 and 15 of his testimony.

1. "Clearing of roadways or access points for construction purposes should be avoided when possible . . . ." Dominion Virginia Power will use existing roadways for access to the construction locations, unless use of such roadways is not practical. Based on preliminary route review, all right-of-way and structure locations can be accessed from an existing roadway, driveway, or by using a short

ingress and egress route.

2. "Construction traffic and equipment should be minimized so that only the vehicles and machinery necessary are used." Dominion Virginia Power is in agreement with this statement.

3. "Construction activities should be coordinated with BASF . . . ." Dominion Virginia Power will work with BASF in developing construction practices within appropriate bounds provided that BASF's requirements do not impede Dominion Virginia Power's construction schedule, do not cause the Company to absorb excessive cost to the project, and do not conflict with the established safety and construction methods used by Dominion Virginia Power and its contractors.

4. "Construction practices that minimize disturbance of vegetation should be used to the extent possible." Dominion Virginia Power maintains and utilizes experienced and qualified construction firms in the construction of transmission lines. Additionally we assign to each project a Dominion Virginia Power representative experienced in transmission line construction to oversee all construction activities. Construction of the line will be done within the confines of the right-of-way except where we have to ingress and egress to the tower locations or for set up locations for the wire pulling activity.

5. "Construction activity in proximity to rivers and creeks should be avoided if possible, and otherwise undertaken with utmost care." Dominion Virginia Power is in agreement with this statement.

6. "Construction activity in proximity to remediation areas or areas identified as environmentally sensitive should be carefully coordinated with BASF, VDEQ, and USEPA." Dominion Virginia Power is in agreement with this statement.

7. "Tower locations should be determined with the objective of minimizing visibility and point of sight screening by retention of existing vegetation . . . ." Company Witness Mike Brucato discusses the Company's vegetation management practices in further detail; however, where possible, Dominion Virginia Power will make every effort to retain existing vegetation that will not interfere with the usage and reliable operation of the transmission line.

8. "Tower design and materials and conductor type should be selected to mitigate visibility." Dominion Virginia Power has filed with the Commission the structure type and route that will be used for this Project. These items will come under the provisions of the Certificate. The design, structure location, foundations, conductors, hardware, and so forth will be as the Company outlined in its Application.

Q. **Mr. Allen, does this conclude your pre-filed rebuttal testimony?**

A. Yes, it does.

Company Exhibit No. __
Witness: MSA
Rebuttal Schedule 1
Page 1 of 1

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Dominion Virginia Power 230 kV Underground Transmission Facilities

Line No.	Installation Date	Substation (Transition)	Substation (Transition)	Area	Voltage	Mileage	Cable Type	Number of Circuits	Cables Per Phase	MVA Capacity	Network/ Radial	Local Factors Influencing Underground Installation Requirements
248	1997	Ox (Carlyle South)	Glebe (Potomac Yards North)	Potomac Yards	230 KV	3.10	HPFF	1	2	637	Network	Relocation Condition of Railroad R/W agreement-no OH route available
2023	1997	Jefferson St (Carlyle South)	Glebe (Potomac Yards North)	Potomac Yards	230 KV	3.10	HPFF	1	2	637	Network	Relocation Condition of Railroad R/W agreement-no OH route available
257	1970	Churchland (Craney Island)	Sewells Pt. (Tanners Pt.)	Norfolk	230 KV	1.54	HPFF	1	2	531	Network	Underwater segment of OH Line-no viable OH route available
270	1988	Sideburn	Burke	Fairfax	230 KV	2.18	HPFF	1	1	338	Network	Dense suburban area-no viable OH route available
275	1970	Glebe	Crystal	Arlington	230 KV	1.23	HPFF	1	1	338/293	Radial	Urban area-no viable OH route available
276	1970	Glebe	Crystal	Arlington	230 KV	1.20	HPFF	1	1	338/293	Radial	Urban area-no viable OH route available
277	1983	Glen Carlyn	Clarendon	Arlington	230 KV	1.05	HPFF	1	1	338/293	Radial	Urban area-no viable OH route available
278	1983	Glen Carlyn	Clarendon	Arlington	230 KV	1.85	HPFF	1	1	338/293	Radial	Urban area-no viable OH route available
294	1985	Braddock	Annandale	Annandale	230 KV	3.58	HPFF	1	1	400/340	Radial	Urban area-no viable OH route available
297	1985	Braddock	Annandale	Annandale	230 KV	3.58	HPFF	1	1	400/340	Radial	Urban area-no viable OH route available
2036	1991/2012	Glebe	Radnor Heights	Arlington	230 KV	4.93	HPFF	1	1	338/293	Network	Urban area-no viable OH route available
2037	1991	Glebe	Davis	Arlington	230 KV	2.37	HPFF	1	1	338/293	Network	Urban area-no viable OH route available
2082	2003	Sewells Pt.	Navy South	Norfolk	230 KV	0.58	HPFF	1	1	412/355	Radial	Norfolk Naval Base-customer requested & paid for UG
2093	2003	Sewells Pt.	Navy South	Norfolk	230 KV	0.58	HPFF	1	1	412/355	Radial	Norfolk Naval Base-customer requested & paid for UG
2062	2005	Navy South	Navy North	Norfolk	230 KV	1.5	HPFF	1	1	412/355	Radial	Norfolk Naval Base-customer requested & paid for UG
2093	2005	Navy South	Navy North	Norfolk	230 KV	1.5	HPFF	1	1	412/355	Radial	Norfolk Naval Base-customer requested & paid for UG
2096	2008	Clarendon	Ballston	Arlington	230 KV	0.43	XLPE	1	1	240	Radial	Urban area-no viable OH route available
2098	2010	Pleasant View (Dry Mill South)	Hamilton (Breezy Knoll)	Loudon	230 KV	2.2	XLPE	1	2	1048	Radial	Suburban area-HB1319 Pilot Project & required by VA law
2099	2007	Churchland (Craney Island)	Sewells Pt. (Tanners Pt.)	Norfolk	230 KV	1.54	HPFF	1	2	600	Network	Underwater segment of OH Line-no viable OH route available
2116	2010	Beaumeade	Nivo	Ashburn	230 KV	0.71	XLPE	1	1	524	Radial	Suburban area-HB1319 Pilot Project
2118	2011	Garrisonville	Aquia	Stafford	230 KV	5.5	XLPE	1	2	1048	Network	Suburban area-UG construction as pilot project
2120	2010/2012	Garrisonville	Aquia	Stafford	230 KV	5.5	XLPE	1	2	1048	Network	Suburban area-UG construction as pilot project
2121	2012	Davis	Radnor Heights	Arlington	230 KV	2.56	HPFF	1	1	319	Network	Urban area-no viable OH route available
2122	2012	Hayes (Gaines Pt.)	Yorktown	Yorktown	230 KV	3.8	HPFF	1	2	600	Network	Underwater segment of OH Line-no viable OH route available
2130	2010	Beaumeade	Nivo	Ashburn	230 KV	0.71	XLPE	1	1	524	Radial	Suburban area-HB1319 Pilot Project
					Total Miles	57.8						

130320225

Virginia Electric and Power Company
Case No. PUE-2012-00029
Virginia State Corporation Commission Staff
Second Set

The following response to Question No. 22 of the Second Set of Interrogatories and Requests for Production of Documents Propounded by the State Corporation Commission Staff received on October 23, 2012 has been prepared under my supervision.

Walter R. "Trey" Thomasson, III, PE
Engineer III, Transmission Line Engineering
Dominion Technical Solutions, Inc.

Question No. 22:

For each underground alternative to the Surry-Skiffes Creek line that was evaluated by the Company, describe in detail the identified potential impediments to timely construction of that alternative.

Response:

Two underground alternatives to the Surry-Skiffes Creek line were evaluated by the Company, both double circuit 230 kV high pressure fluid filled transmission lines. The first was a hybrid line underground from Surry Power Station to the shore of James City County, where the line would transition to overhead construction to the Skiffes Creek Switching Station. The second was for underground line the entire distance from Surry Power Station to Skiffes Creek Switching Station. Both alternatives involve similar impediments to timely construction.

Lead time for material to build underground transmission lines is much longer than traditional overhead construction. High pressure fluid filled cable has an approximate lead time of 18 months from order date. A cable order of this magnitude (92 miles or 133 miles of single-phase cable) may be even longer. Other items such as cable terminations and pressurization plants have approximate lead times of nine months or longer.

Detailed engineering surveys would need to be performed on the river crossing as well as any land portion of an underground transmission line. Items such as geology of the riverbed, dredging activities, utility crossings, and nearby military activities could have an impact on routing options for an underground alternative. The right-of-way for a six-pipe river crossing will be a minimum of 400 feet wide in order to properly overboard the cable splices. In addition, a complete thermal route survey would need to be performed in order to ensure the transfer capacity of the underground alternative could be met with the assumed circuit configuration of three (3) three-phase sets of cable for each 1000MVA 230 kV circuit.

There are three known buried pipelines that cross the James River from the Surry Power Station property to James City County. These pipelines limit the optimal routing options across the river. These pipelines may have to be crossed with the transmission lines in the river, depending on the route selected. There will also likely be interference from any parallel pipeline's cathodic protection systems which would need to be studied and remedied if necessary. Also, the intake canal for the Surry Power Station would possibly need to be crossed.

There are limited contractor resources for the installation of high pressure fluid filled cable systems. In the area of the proposed crossing, the James River is shallower than the Company's previous crossing of the York River. Specialized vessels may be required to safely and efficiently work in the river.

An underwater crossing of the James River would require development by a qualified engineering and construction firm to determine the scope of issues and obstacles involved, and to develop a project activity schedule. Routing, right-of-way acquisition, environmental considerations, marine construction, civil engineering, electrical engineering, horizontal directional drilling construction, material acquisition, permitting, time-of-year restrictions, and weather are among the disciplines that would need to be considered to develop a detailed scope of work, cost estimates and a schedule for this type of project.

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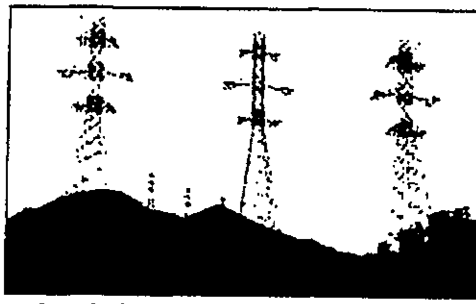
Grand Coulee Dam: Third Powerplant Overhaul Project

back>>

Projects to be Completed Prior to the Overhauls

Replacing 500 kV Cables with Overhead Lines



Underground, oil-filled cables currently transmit all power from the six TPP generating units to the 500kV switchyard.

In 1981, a single phase of an oil filled cable faulted, destroying all circuits in the tunnel that house the transmission lines for generating units G-22, G-23 and G-24. This fire instantly removed 2,415MW of power from the grid. It took approximately two years to plan, design and construct temporary overhead lines and another three years to replace the oil-filled cables. Once the oil-filled cables were replaced, the temporary overhead lines were abandoned in place. It has recently become apparent that the condition of underground oil-filled high voltage cables is degrading.

Replacing these oil-filled cables with overhead transmission lines solves several problems: Overhead transmission lines can be inspected and maintained more safely than oil filled cables; the new lines can support an up-rating of the TPP generators; and the replacement using an overhead route does not require long periods without generation to safely remove old cables and install new cables. Switching from the oil filled cables to overhead lines only constitutes a two week outage per generating unit while replacing the oil filled cables would take at least one year and cost over $250M in lost generation revenue. In order to remove the risk of another tunnel fire, support an uprate of units G-19, G-20 and G-21 and reduce operation and maintenance costs, USBR made the decision to remove the oil-filled cables install and install overhead transmission lines (Photo shows a simulation of the new towers and overhead lines).

The USBR approached Bonneville Power Administration (BPA) to assist in planning, designing and constructing the new 500kV overhead lines. The $18.5M construction phased of the project was awarded to Wilson Construction (Canby, OR). The new overhead lines will be energized in December 2012 and the oil-filled cables will be removed by December 2013.

Modifying the Fixed-wheel Gate Repair Chamber for Blasting and Painting

Each unit in the TPP has a single Fixed Wheel Gate (FWG), aka head gate. These gates need to be routinely inspected and overhauled, but this takes substantial manpower and unit outages. The unit outages required for each TPP generating units' mechanical overhaul are

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an ideal time to inspect and overhaul the gates.

However, the FWG chamber is no longer in compliance with current life safety and electrical codes. At present, the wiring is not explosion-proof, ventilation is inadequate, separation from dam galleries is insufficient, and lighting is poor. Compounded, each of these factors lead USBR to the decision to extensively modify the FWG Chamber to ensure it is fully compliant with all applicable codes and regulations.

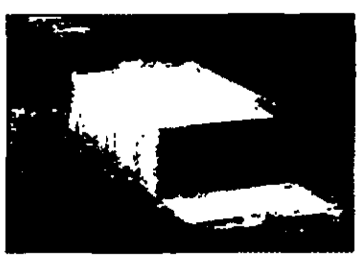
The $4M project was designed by the USBR and is being constructed by Knight Construction (Spokane, WA). The project is scheduled to be complete by February 2013.

Rehabilitating TPP Cranes

There are six cranes in the TPP, which will all be usec heavily use during the TPP unit overhauls. The TPP has two 275 ton upper bridge cranes, one 50 ton uppei bridge crane, one 2,000-ton lower bridge crane, one 70 ton draft tube gantry crane, and one 275 ton forebay gantry crane. It is imperative that they all be in excellent working order prior to the overhaul work in order to prevent unplanned crane outages that coulc result in costly delays in the schedule.

Repairs and upgrades of these cranes in preparation for mechanical overhaul was the subject of an A/E crane consultants' inspection and report that was completed in September 2008. The A/E's report stated that the cranes were all in good condition and recommended, in lieu of a complete overhaul of the cranes, to the limit the scope of the project to crane controls. The $17M crane controls project was designed by CH2MHill, Inc. and the construction work is being performed by Dix, Inc (Spokane, WA). The project is scheduled to be complete by December 2012.

New Material Storage Building

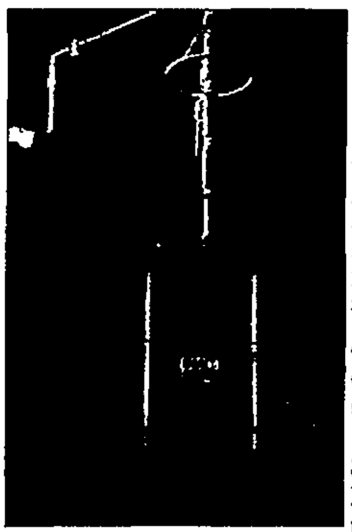


Overhaul of the TPP turbines and generators requires lay-down space for all turbine and generator parts as they are removed. These and other incidental parts will occupy nearly all of the TPP floor space. There are a variety of spare parts and pieces presently being stored in the TPP that need to be removed in order to provide the needed overhaul lay-down space. These valuable and easily damaged spare parts need to be kept in a secure, climate and temperature controlled storage space. The new storage building was built adjacent to the TPP, providing a convenient location for movement of materials to and from the TPP. The building includes a 100-foot by 200-foot floor area with 30-foot walls, 30-foot by 28-foot door (same opening as the north TPP door), insulated walls and ceiling, heating and cooling, forced ventilation, power, compressed air, and a life safety system with fire suppression. The building is also certified LEED Silver.

The GCPO facilities are considered part of a historically significant area. As such, this new storage building cannot detract from the overall appearance of the area. The storage building is significantly smaller than the TPP, but retains the historical perspective of the site.

A design/build contract was awarded to Graham Construction (Spokane, WA) for $5M. The project is scheduled to be substantially complete in October 2012. Once the building is commissioned, Grand Coulee forces will begin moving material from the TPP into the Material Storage Building, freeing up lay down space for the TPP mechanical overhaul project.

TPP 236 MVA Transformer Replacement



The generator step-up transformer banks for generators G-19 and G-20 have been in continuous use since 1975. Identical transformers for G-21 were replaced in 2002 because of deteriorating conditions, and it was recently noted that the transformers for G-19 and G-20 are also beginning to show signs of deterioration. When these types of transformers deteriorate they produce flammable gases within the cooling oil. Close monitoring is required to prevent gas build up and the potential for explosion. Due to potential for explosion, access to this transformer area has been restricted. An explosive failure could damage cable circuit terminations and adjacent transformers which would compound immediate power loss and lengthen recovery time.

Spares for these transformers are not available in the Northwest. An additional motive for replacing these transformers is the forthcoming uprate of generating units G-19 and G-20. In order to uprate G-19 and G-20 from 690 MW to 770 MW, the single phase step up transformers required an uprate from 236 MVA to 276 MVA. The $28M project was designed by the USBR and the construction phase was awarded to Gardner Zemke (Albuquerque, NM) for $26M. The project was substantially complete in December 2011.

Rehabilitation of Two TPP Elevators

There are two freight/personnel elevators which will be in continual use during the TPP mechanical overhauls. One elevator is in the Turbine Erection Bay at the southern end of the TPP and the other in the Generator Erection Bay at the northern end of the TPP. It is imperative that both are in excellent working order prior to the overhaul work in order to reduce potential for elevator outages and costly delays in the overhaul schedule. The $2.3M project was designed by CH2MHill, Inc. and the construction phase was awarded to

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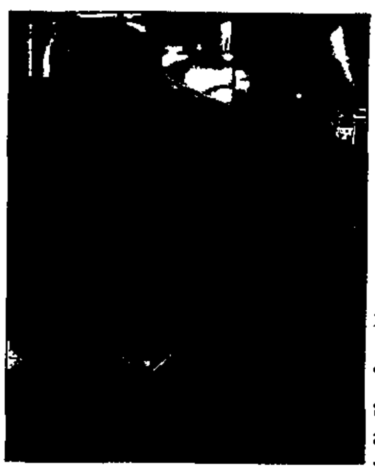
ThyssenKrupp, Inc (Spokane, WA). This project is scheduled to be complete by January 2013.

TPP Governor Replacement

The TPP generators have a major role in reacting to normal load swings but also in reacting to power system transient conditions such as loss of critical transmission paths or varying load. However, the units have been experiencing failures and erratic behavior, therefore not responding as quickly as possible. The electric-hydraulic governors are also showing problems with obsolete electronic components. The printed circuit cards used epoxy-based operational amplifiers which are no longer being manufactured.

The six TPP governor control systems are currently being replaced with new digital governor controls. The new, faster responding governors allow for a more stable response to load rejection. The TPP governor hydraulic systems are in good condition and have not experienced major problems, so the scope of the governor replacement project is limited to replacement of the electronic components and pilot valve. Four of the new governor systems are currently online, one is being installed and the final unit is scheduled to be installed in January 2013. The construction phase of the $3M project was awarded to American Governor, Inc. (Amherst, WI) and is scheduled to be complete in May 2013.

TPP Exciter Replacement



The TPP generators have a major role in reacting to both normal load swings and to power system transient conditions such as loss of critical transmission paths. Generation dropping opens generator breakers and is usec to decrease supplied power to compensate for loss of a similar quantity of load. In addition, the new modern, faster responding exciters have contemporary power system stabilizers which will enhance the overall stability of the units and the power system. Between generation drop and the power system stabilizers, the stability of the northwest power grid will be enhanced.

The excitation systems and associated equipment for the six TPP generators are being replaced with more robust and modern equipment. The previous excitation systems were state-of-the-art when first supplied in the late 1970s but the components have become obsolete and are difficult to replace. In addition, failures associated with the older excitation systems have created frequent unscheduled, forced outages of the TPP generators. Recently, one of the 805MW generators was forced out of

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service for several days by the failure of a small choke coil in the exciter regulator circuitry. Lost revenue is dependent upon time of year and availability of other TPP generators. However, an average one week forced outage of one TPP generator costs about $250,000 in lost revenue and approximately $800,000 if an additional unit is also forced out of service.

Four TPP units are currently operating with the new excitation system, one is currently being installed and the last unit is scheduled to be installed in January 2013. The construction phase of the $22M project was awarded to ABB., Inc (Montreal, Quebec) and is scheduled to be complete in May 2013.

Asbestos and Lead Paint Abatement

The Contractors performing work on existing equipment need may encounter asbestos or lead paint on some of the existing components. This is typically not an issue for components manufactured after 1980, however, these units were completed prior to 1980. Tests have confirmed that lead and asbestos do exist. The units will be cleaned prior to the overhauls by USBR and contractors who specialize in this field. The overhaul Contractors must be prepared with appropriate safety equipment, procedures, and trained staff to test for, handle and dispose of hazardous materials should they be encountered.

Permitting and Coordinating Activities

National Environmental Protection Agency (NEPA) compliance must be considered for all activities associated with the TPP overalls. Impacts to the environment need to be defined and addressed appropriately. Additionally, the GCPO facilities are considered part of a historically significant area. As such, any activity that could impact the overall appearance of the area could have an adverse effect and should be avoided if possible, and mitigation for the action applied if the action is unavoidable. The NEPA process has been completed for all of the TPP associated projects.

New Draft Tube Platform

The TPP unit overhauls will provide an opportunity to inspect and, if necessary, to repair the draft tubes. A specialize work platform is needed to complete the repairs, and the contractor performing the overhaul work will be responsible for fabricating it. The platform will be suitable for use on all three units undergoing overhauls.

On-Going Maintenance Programs in TPP

Throughout the execution of the overhaul program there will be operation and maintenance (O&M) work being performed by Reclamation staff. Units will be taken out of service for routine maintenance needs. Some of this work requires the use of the cranes and requires room for parts and equipment. Cavitation repair of turbine runners will be performed as a part of the routine maintenance and electrical testing of various components and will also be performed with repair work done as needed. These O&M activities may conflict with

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overhaul work, but will scheduled such that there are no delays to either O&M or the contractor.

TPP Operational Constraints

There are operational constraints regarding outages for the six units in the TPP. Typically, five of the six units need to be operational during the spring months to pass inflows to prevent total dissolved gas in excess of allowable amounts from being generated by spills. There are additional outage limitations during times of high power demand in July and August and during the winter months between mid-November through mid-February.

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230 kV Alternative A Costs for 2015 and 2021
(Millions in 2012 Dollars)

Single Circuit 230kV U.G. Hybrid

Surry - Skiffes Creek Line	$187.5
Skiffes Creek - Whealton Line	$46.4
Skiffes Creek Switching Station	$23.5
Surry Switching Station	$14.0
Whealton Substation	$2.0
Lanexa & Yorktown Substations	$0.4
Total	$273.8

Full Compliance Cost for 2015

Wreck & Rebuild 209 Line (Waller - C&O)	$27.5
Temporary Line (285/209)	$0.7
Add 3rd 500/230 Transformer at Suffolk Sub	$20.0
Build 2nd 230kV Surry - Skiffes Creek Line	$166.6
Total	$214.8

Additional Full Compliance Cost for 2021

Add 230/115 Transformer at Whealton	$8.0
Wreck & Rebuild 34 Line (Skiffes Creek – Yorktown)	$18.7
Total	$26.7

Total Cost	**$515.3**

230 kV Alternative B Costs for 2015 and 2021
(Millions in 2012 Dollars)

Double Circuit 230kV U.G. Hybrid

Surry - Skiffes Creek Line	$343.8
Skiffes Creek - Whealton Line	$46.4
Skiffes Creek Switching Station	$24.8
Surry Switching Station	$23.0
Whealton Substation	$2.0
Lanexa & Yorktown Substations	$0.4
Total	$440.4

Full Compliance Cost for 2015

Wreck & Rebuild 209 Line (Waller - C&O)	$27.5
Temporary Line (285/209)	$0.7
Add 3rd 500/230 Transformer at Suffolk Sub	$20.0
Total	$48.2

Additional Full Compliance Cost for 2021

Add 230/115 Transformer at Whealton	$8.0
Wreck & Rebuild 34 Line (Skiffes Creek - Yorktown)	$18.7
Total	$26.7

Total Cost	**$515.3**

230 kV Alternative C Costs for 2015 and 2021
(Millions in 2012 Dollars)

Line 214, 263, & 261 Rebuild

Wreck & Rebuild 263 Line (Chuckatuck – Newport News) (land)	$26.8
Wreck & Rebuild 214 Line (Surry – Winchester) (land)	$61.3
New Single Circuit River Crossing for 214 Line	$37.5
Wreck & Rebuild 261 Line	$11.2
Temporary Line (263 Wreck & Rebuild)	$6.4
Add Capacitor Bank at Peninsula Sub	$1.6
Total	$144.8

Full Compliance Cost for 2015

Wreck & Rebuild 2113 Line (Lanexa-Waller)	$36.3
Wreck & Rebuild 34 Line (Skiffes - Grafton)	$17.3
Wreck & Rebuild 234 Line (Winchester - Whealton)	$0.5
Add 3rd 500/230 Transformer at Suffolk Sub	$20.0
R/P Transformer at Lanexa	$8.0
Total	$82.1

Additional Full Compliance Cost for 2021

Wreck & Rebuild 209 Line (Waller - C&O)	$35.6
Wreck & Rebuild 209 & 285 (C&O - Yorktown)	$11.4
Wreck & Rebuild 2102 (Tower Section) - Chickahominy - Waller	$59.7
Reconductor 2102 (Steel Pole) - Chickahominy - Waller	$1.9
Wreck & Rebuild 99 Line (Peninsula - Whealton)	$17.3
Add Shellbank 230/115 Transformer	$8.0
Add Whealton 230/115 Transformer	$8.0
Add SVC at Skiffes Creek location	$40.0
Total	$181.9

Total Cost	**$408.8**

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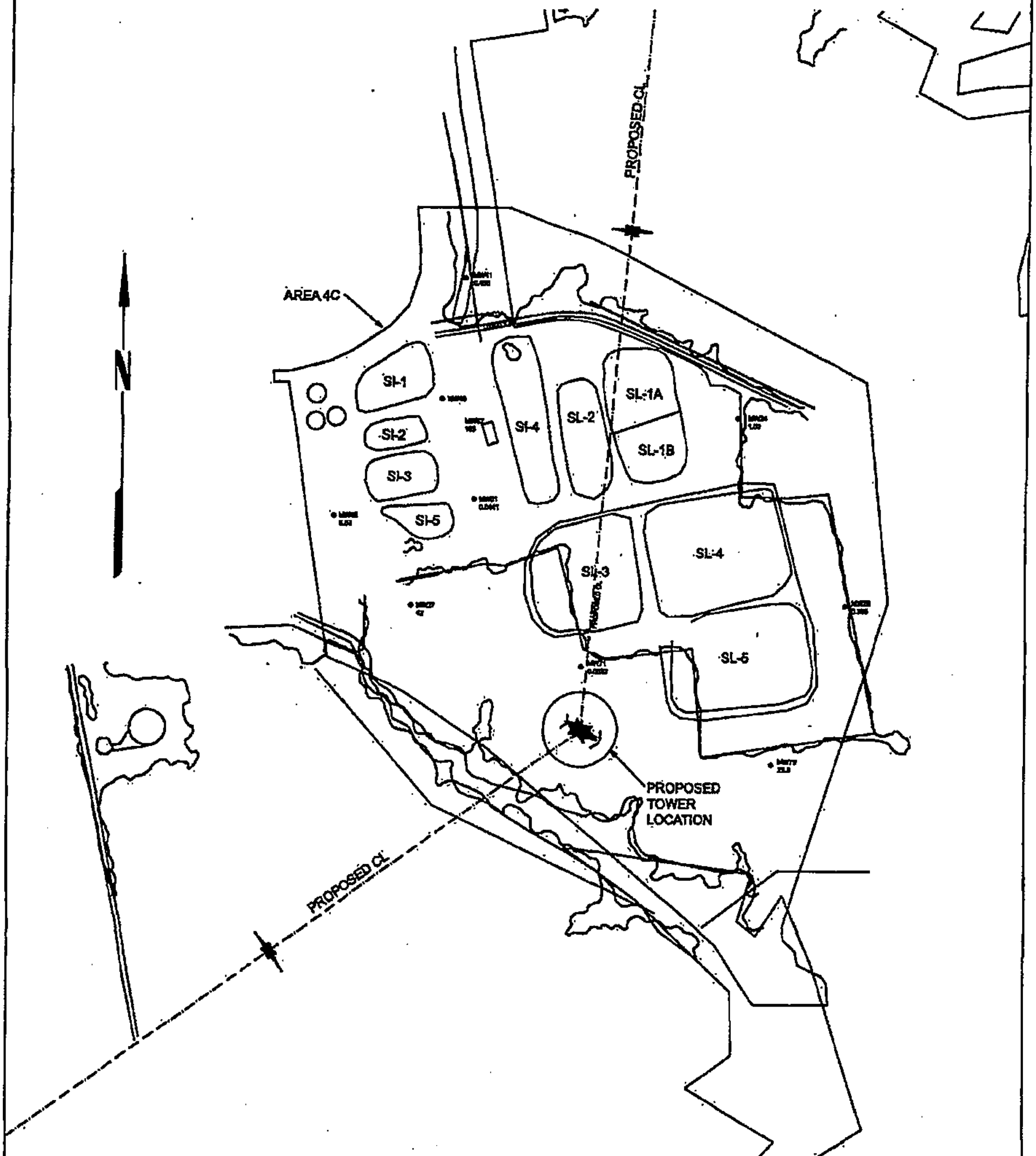

Standard Transmission Construction	SURRY - SKIFFES CREEK AREA 4C APPROXIMATE TOWER LOCATION MAP				
Dominion 701 E. Cary Street Richmond, VA 23219		DRAWN	CHECKED	APPROVED	DATE	DRAWING NO.
	ORIGINAL	MWS	03/04/13		03/04/13	
	REVISION					CAD NO.

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y-skiffes creek alt 1 skiffes creek layout kak.dxf 3/4/2013 12:28:58 PM

ATTACHMENT 5

REBUTTAL TESTIMONY
OF
WALTER R. THOMASSON, III
ON BEHALF OF
VIRGINIA ELECTRIC AND POWER COMPANY
BEFORE THE
STATE CORPORATION COMMISSION OF VIRGINIA
CASE NO. PUE-2012-00029

Q. Please state your name, business address and position with Virginia Electric and Power Company ("Dominion Virginia Power" or the "Company").

A. My name is Walter R. "Trey" Thomasson, III, and I am an Engineer III, Electric Transmission Line Engineering for Dominion Technical Solutions, Inc. My business address is 701 East Cary Street, Richmond, Virginia 23219.

Q. What is your educational and professional background?

A. I received a Bachelor of Science degree in Electrical Engineering from Virginia Tech in 2003. I received a Master of Engineering Management degree from Old Dominion University in 2007. I am a Registered Professional Engineer in the Commonwealth of Virginia. I started my career with the Company as an Engineer II in Electric Transmission Operations Engineering in 2008. In 2011, I moved to Electric Transmission Line Engineering and was promoted to Engineer III in 2012. From 2004 to 2008, I was employed by the U. S. Department of Defense.

Q. What are your responsibilities as Engineer III, Electric Transmission Line Engineering?

A. My responsibilities are to design, engineer, and provide operational and maintenance support for underground high voltage transmission lines.

Q. What is the purpose of your rebuttal testimony?

A. The purpose of my rebuttal testimony is to provide conceptual design and cost estimates for an underground 230 kV hybrid single circuit (1000 MVA) ("Alternative A") and an underground 230 kV hybrid double circuit (1000 MVA/circuit) ("Alternative B"), as directed by the Hearing Examiner in this proceeding. I also will address statements of James City County (or "JCC") Witness Waine P. Whittier, PE, comparing the Company's estimated cost to construct a 230 kV hybrid underground line from Surry Switching Station ("Surry Station") to Skiffes Creek Switching Station ("Skiffes Station") provided in Section I.C.4 of the Appendix ("Appendix Hybrid Estimate") with the estimates provided by LS Power to PJM Interconnection, LLC ("PJM") in support of LS Power's proposal to PJM for a hybrid single circuit line from Surry to Skiffes Creek.

Q. Are you sponsoring an exhibit in your rebuttal testimony?

A. Yes. Company Exhibit No. __, WRT, consisting of Rebuttal Schedules 1-10, was prepared under my supervision and direction and is accurate and complete to the best of my knowledge and belief.

Q. Before you begin, can you please summarize your rebuttal testimony and explain how it is organized?

A. My rebuttal testimony explains the routing, construction, equipment, and costs associated with the underground 230 kV hybrid single and double circuit lines (Alternatives A and B) investigated by the Company at the direction of the Hearing Examiner. I also provide a proper cost comparison between the Company's Appendix Hybrid Estimate and the LS Power estimate for its 230 kV hybrid line proposal.

My rebuttal testimony is organized as follows:

I. 230 kV ALTERNATIVES A AND B

Q. Please describe the 230 kV hybrid lines covered by the Hearing Examiner.

A. At the January 10, 2013 public hearing, the Hearing Examiner directed the Company to investigate whether a single circuit or double circuit 230 kV hybrid line could, or should, be constructed, and, if not, why not, to run overhead from Surry Station to an overhead-to-underground transition station at the shore of the James River in Surry County, then cross the James River underwater and, upon coming ashore on the BASF property along the Company's James River Crossing Variation 3 route, continue underground along that route until reaching the intersection of the James River Crossing Variation 3 route and BASF Drive, where an underground-overhead transition would be constructed. The line would then continue overhead from the transition station north with the Updated Proposed Route along BASF Drive and across U.S. Route 60 into Skiffes Station. The Hearing Examiner further directed that the overhead portions of the Variation 3 Hybrid would utilize galvanized steel monopoles. At the prehearing conference held on January 30, 2013, the Hearing Examiner directed the Company to conduct certain power flow studies of these single and double circuit hybrid lines, which he referred to as 230 kV Alternatives A and B. I will use his terminology.

Q. Please describe the conceptual design of 230 kV Alternatives A and B.

A. The Company does not propose, and in fact opposes, undergrounding for any portion of the Surry-Skiffes Creek line. However, in response to the Hearing Examiner's direction, the following is a conceptual description of Alternatives A and B. For both alternatives involved, the line would need to start the river crossing south of the existing pipelines in Surry County so that they would not need to be crossed in the river. Also, the river crossing would not follow the overhead James River Crossing Variation 3 route across the river, but instead be a straight line across. For both alternatives, the straight line river crossing portion is approximately 4.0 miles, and the land portion in James City County is approximately 0.78 mile. The land portion in Surry County is approximately 1.5 miles for both an overhead and an underground route. Both alternatives were evaluated using a high-pressure fluid-filled ("HPFF") cable system for the underground portion and single shaft monopoles for the overhead portions.

II. CONCEPTUAL DESIGNS

Q. Please describe the conceptual design of 230 kV Alternative A.

A. The route of Alternative A, the single circuit hybrid line, is shown in my Rebuttal Schedule 1. Alternative A would leave the north side of the 230 kV switchyard at the Surry Station and run overhead on double circuit 500 kV monopoles (to accommodate a future 500kV line) and cross the intake canal for Surry Power Station before turning east to run along the northern bank of the canal for approximately a mile before turning south, crossing the canal and the three pipelines (two natural gas transmission and one petroleum products) and then leaving the Surry Power Station site into adjoining property where an overhead-to-underground transition station would have to be built on the Surry

230 kV switchyard at Surry Station as underground lines and would parallel the existing transmission corridor in a south-easterly direction and would cross the existing natural gas and petroleum products pipelines before leaving the Surry Power Station property and continuing to a temporary workspace site on the adjoining property where the drill rig would be located to commence directional drilling for the underground river crossing. Just before getting to the James River, the pipes would spread before crossing the river. In the portion of Alternative B from the 230 kV switching station and where it enters the water, the cable system would consist of two parallel trenches, each with three steel pipes containing three cables (a total of 18 cables), as shown in my Rebuttal Schedule 5. The two trenches would be separated by 20 feet to reduce mutual heating effects in order to maximize the ampacity of the circuit, requiring a minimum right-of-way width of 50 feet. For the river crossing, the HPFF cable system would consist of six horizontal directional drills for an equal number of pipes, with three sets of intermediate splicing platforms in three locations (nine total platforms), as shown in my Rebuttal Schedule 6. The pipes would need to be separated by 20 feet, with 120 feet between each pipe pair, requiring a minimum right-of-way width of 400 feet. This extra distance is needed for when the cables are spliced together and the pipe is overboarded into the river on each side of the splicing platform. Once ashore on the James City County side, the underground cable system from the shore to the transition station on BASF Drive would be the same as shown in my Rebuttal Schedule 5. After leaving the transition station, the two 230 kV circuits would continue overhead to Skiffes Creek on double circuit monopoles, which would parallel and adjoin the existing 115 kV line all the way to the Skiffes Station site and would require expansion of the existing right-of-way to 150 feet.

Q. Will the adjoining property south of Surry Power Station be available to serve as the site for the transition station on the Surry side and/or the temporary construction workspace for the drilling rig?

A. In addition to a site of approximately 1 acre for a transition station, we also would need approximately 2.2 acres (single circuit – a 240 feet by 400 feet area) or 3.7 acres (double circuit – a 400 feet by 400 feet area) of additional land for temporary work space for the drilling rig. We don't know the availability of that adjoining land for these purposes. We also would need a permanent right-of-way through that land for the line itself.

Q. Please describe the equipment that would be needed to transition from the overhead line construction to underground cables.

A. For a single circuit underground transition station with 3 pipes, there would be a graveled, fenced area approximately 150 feet by 100 feet that would contain the following pieces of equipment:

- One overhead line backbone structure (75-foot steel H-frame)
- Multiple pipe stands for underground cable terminations, current transformers and surge arresters
- Control house for protective relays, communications equipment, batteries and battery charger
- A prefabricated enclosure approximately 12 feet high by 12 feet wide by 45 feet long also would be required for pressurization equipment for the HPFF cable system (located at one of the transition stations, with a corresponding hydraulic crossover cabinet at the other transition station)

Each of the underground cables must be terminated in a large porcelain bushing-type insulator that is approximately two feet in diameter and 10 feet tall. These cable terminations are necessary to transition from the cable insulation to air insulation for the outdoor overhead components. To the average person, this facility would look like a conventional electric substation.

For a double circuit underground transition station with 3 pipes per circuit, there would be a graveled, fenced area approximately 200 feet by 200 feet that would contain the following pieces of equipment:

- Two overhead line backbone structures (75-foot steel H-frame)
- Multiple pipe stands for underground cable terminations, current transformers and surge arresters
- Control house for protective relays, communications equipment, batteries and battery charger
- A prefabricated enclosure approximately 12 feet high by 12 feet wide by 45 feet long also would be required for pressurization equipment for the HPFF cable systems (one at each transition station)

Each of the underground cables must be terminated in a large porcelain bushing-type insulator that is approximately two feet in diameter and ten feet tall. These cable terminations are necessary to transition from the cable insulation to air insulation for the outdoor overhead components. To the average person, this facility would look like a conventional electric substation.

Q. **As mentioned by the Hearing Examiner during the public hearing and pre-hearing conference, please explain the Company's preference for a HPFF cable system.**

A. The Company has experience and success with three river crossing installations using

HPFF cable technology at 230 kV. The first such installation was in 1970/1971 across the Elizabeth River between Portsmouth, Virginia and Norfolk, Virginia. This circuit has been in continuous operation for 40+ years with no major problems. Another parallel Elizabeth River crossing circuit was installed in 2007, and the third is the recently completed Hayes to Yorktown circuit.

HPFF and cross-linked polyethylene ("XLPE") cables age in different manners. HPFF cables are paper insulated, for which the primary aging mechanism is well known and is very temperature dependant (current flow dependant). This means that cables that are lower loaded will last longer than cables that are higher loaded. XLPE cables have polymeric insulation, and the aging mechanism is much more complex. Many aging factors influence the life of an XLPE cable system, including physical, chemical, physico-chemical, and electrical effects. Numerous specifications, qualification testing and strict quality control are required to obtain an industry expected design life of 40 years for XLPE cable.

While the industry standard for a cable system life expectancy is 40 years for XLPE, HPFF is expected to last much longer. This has been demonstrated for HPFF technology on the Dominion transmission system as noted above. In fact, many of the earliest HPFF installations that were installed in the 1930s in the United States are still in operation today (75+ years). XLPE cable at 230 kV has limited operating history in the United States, especially in submarine applications; therefore, its actual life expectancy is unclear. For a cable system of this magnitude and importance, such risk of uncertainty cannot be taken.

Riverbed disturbance would be much greater using an XLPE submarine cable system than a directionally drilled HPFF cable system. As discussed in the rebuttal testimony of Company Witness Mark S. Allen, the riverbed disturbance for the HPFF system would be at the drill entry/exit points and the area to be trenched after the splicing operations are completed. While this would be greater than required for the proposed 500 kV overhead line, it is much less than would be required for an equivalent capacity XLPE submarine installation. For the XLPE submarine cable system, a cable laying barge would tow a jetting sled that would be used to embed the cable upwards of 10-15 feet below the river bed. For a double circuit cable system with three cables per phase, this would result in 18 cable laying operations across the river.

If the need ever did arise to replace cable due to end of life concerns, it would be much easier and cheaper to replace the HPFF cable than the XLPE cable. HPFF cable could be installed in the same pipes as the existing circuits, which would only require excavation at the splicing locations in the river. New pipe would not need to be directionally drilled across the river. With the case of XLPE cable, since it would be directly buried across the river, the whole entire jetting operation from shore to shore would need to take place again. This operation would be much more expensive and disruptive to the riverbed.

It should also be noted that the Company hired independent consultants to help identify the best cable system for both the Elizabeth River and York River crossing projects. In both cases, HPFF technology was ultimately chosen based on its proven reliability and less environmental disturbance.

III. COST ESTIMATES

Q. Have you prepared cost estimates for 230 kV Alternatives A and B?

A. Yes, I have. For each of these alternatives, a single circuit was defined as having a capacity of 1000 MVA. These estimates were completed using the same basic parameters (e.g., material costs, labor costs, contingency factor), used to develop the Appendix Hybrid Estimate.

Q. Please provide the cost estimate for Alternative A.

A. The line portion of Alternative A is estimated to be $187.5 million, including $154.6 million for the underground portions, $30.3 million for the overhead portions, and $2.6 million for two transition stations. The estimated cost of Alternative A would also include $14.0 million for work at Surry Station (which includes $12.0 million for two reactor banks and $2.0 million for 230 kV breakers and equipment) and $23.5 million for the construction of Skiffes Station (which includes $6.0 million for one reactor bank), bringing the total estimated cost of Alternative A to $225.0 million.

Q. Please provide the cost estimate for Alternative B.

A. The line portion of Alternative B is estimated to be $343.8 million, including $323.9 million for the underground portions, $18.2 million for the overhead portions, and $1.7 million for the transition station. The estimated cost of Alternative B would also include $23.0 million for work at Surry Station (which includes $18.0 million for three reactor banks and $5.0 million for 230 kV breakers and equipment) and $24.8 million for the construction of Skiffes Station (which includes $6.0 million for one reactor bank), bringing the total estimated cost of Alternative B to $391.6 million.

Q. What would be the estimated total cost of the Project with Alternatives A and B, excluding the cost of any additional overhead transmission or generation facilities that may be required to resolve all reliability deficiencies identified by Company Witness Nedwick?

A. By adding the cost of the 230 kV Skiffes Creek-Whealton line ($46.4 million) and the costs for work at Whealton Substation ($2.0 million) and Lanexa and Yorktown Substations ($0.4 million), the cost of the total Project with Alternative A would be $273.8 million and the cost of the total Project with Alternative B would be $440.4 million, plus any such additional costs.

IV. APPENDIX HYBRID ESTIMATE

Q. How do Alternatives A and B compare to the Appendix Hybrid Estimate?

A. The Company's Appendix Hybrid Estimate reflects a conceptual route leaving underground from Surry Station to a location south of the existing gas pipelines at the shore of the James River in Surry County, then crosses the James River underwater to an underground-overhead transition station shortly after reaching shore on the BASF property along the James River Crossing Variation 1 route. From the transition station, this route continues overhead north along the James River Crossing Variation 1 route along BASF Drive and across U.S. Route 60 to Skiffes Station, as shown on my Rebuttal Schedule 7. Alternative B has a slightly longer (0.3 mile) crossing of the James River, as well as additional underground construction on the James City County side (0.78 mile), compared to the Appendix Hybrid Estimate, which results in a $33.8 million ($343.8 million vs. $310.0 million) higher line cost for Alternative B than the Appendix Hybrid Estimate.

As noted above, the total project cost for Alternative B (exclusive of full compliance costs) is $440.4 million. This includes $18.0 million (of the $23.0 million) at Surry Station for three reactor banks and $6.0 million (of the $24.8 million) at Skiffes Station for one reactor bank. These reactor banks are needed for voltage control during periods of light load due to the highly capacitive underground cable circuits. These reactor banks were identified during the recent planning studies and, therefore, were not included in the original Appendix Hybrid Estimate. By including the costs of these reactor banks, the total project cost for the Appendix Hybrid Estimate becomes $406.6 million. It should be noted that these additional reactor bank costs were not identified at the time the Company submitted its response to No. 21 of the Staff's Second Set of Interrogatories, as the additional planning studies had not been completed at that time. The Company's updated response to No. 21 of the Staff's Second Set of Interrogatories is provided as my Rebuttal Schedule 8.

V. RESPONSE TO WHITTIER COST COMPARISON

Q. On pages 9-10 of his direct testimony, JCC Witness Whittier claims that the Company's estimated costs for 230 kV underground construction of the Surry-Skiffes Creek line appear "extremely high" and that the LS Power estimate provided to PJM is "comparable to industry expectation." Is this an "apples to apples" comparison?

A. No. The LS Power estimate was for a single circuit 230 kV hybrid underground line at a capacity of 500 MVA. Dominion Virginia Power's estimate is for double circuit 230 kV underground lines at a capacity of 1000 MVA per circuit for a total of 2000 MVA. This is four times the capacity of the LS Power proposal. Each circuit of the Company's

Appendix Hybrid Estimate reflects three individual pipes with three cables each to achieve this capacity. For two circuits, this equates to six pipes or six different directional drills across the James River, each with three separate splice locations in the river. In addition to the James River crossing of 3.7 miles (landing at the James River Crossing Variation 1 location), Dominion Virginia Power's estimate includes 1.5 miles of underground construction on land from Surry Station to the river. This cost estimate was performed as a desktop study using actual material costs and estimates for labor and material based on Dominion Virginia Power's just-completed Hayes-Yorktown 230 kV single circuit crossing of the York River. Based on the Hayes-Yorktown project costs and the additional complexities at the James River, which are discussed in detail in the Company's responses to Nos. 22 and 45 of the Staff's Second and Fourth Sets of Interrogatories, the Company's cost estimates are justified as submitted. My Rebuttal Schedules 9 and 10, respectively, contain copies of these responses.

Furthermore, as explained in paragraph 3 on page 17 of Exhibit WDM-1, Appendix IX, to the testimony of Staff Witness Wayne D. McCoy, comparing underground transmission costs between projects on a cost-per-mile basis is very difficult:

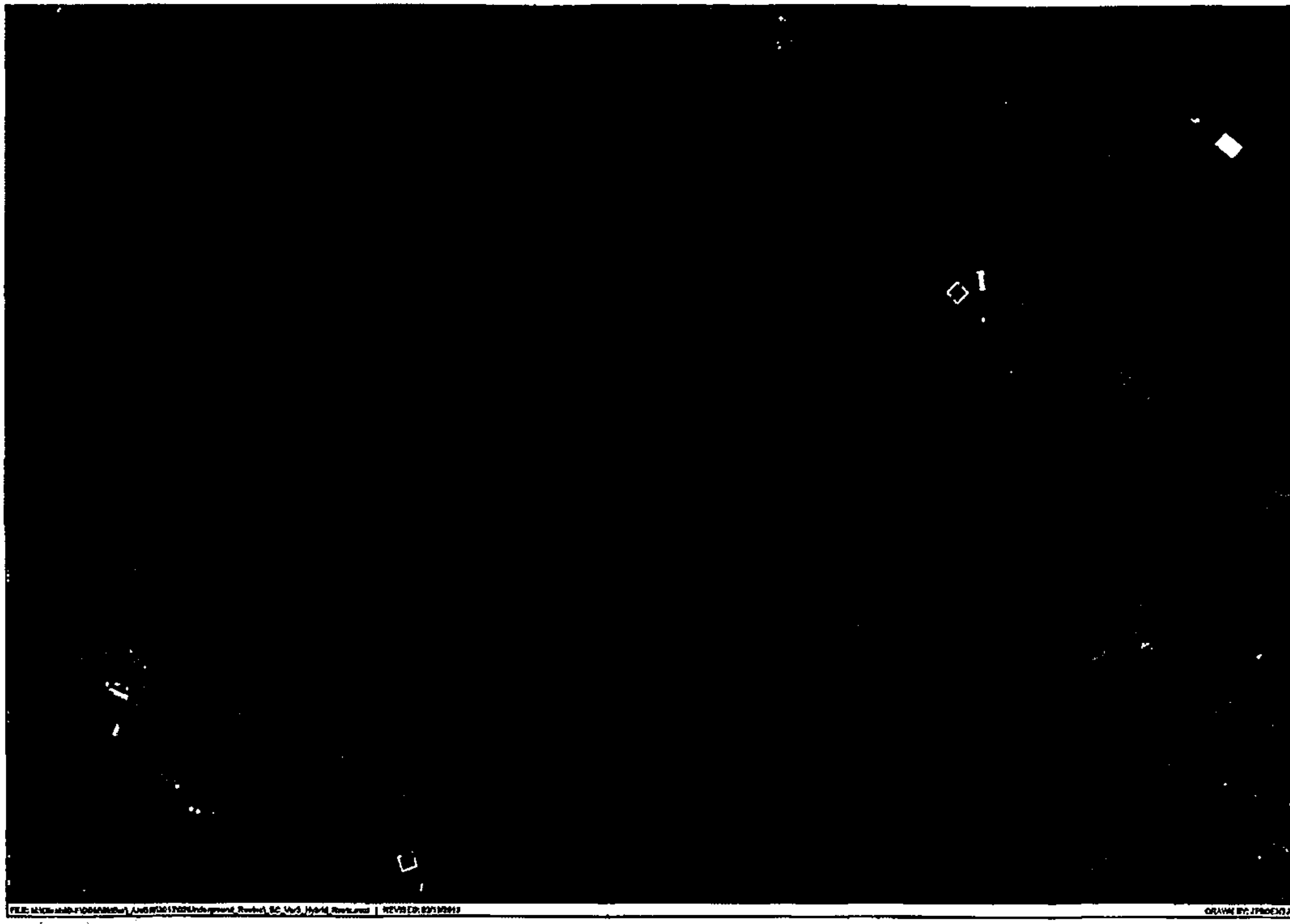
> While it may be useful to sometimes compare the general cost differences between overhead and underground construction, the actual costs for underground may be quite different. Underground transmission construction can be very site-specific, especially for higher voltage lines. Components of underground transmission are often not interchangeable as they are for overhead. A complete in-depth study and characterization of the subsurface and electrical environment is necessary in order to get an accurate cost estimate for undergrounding a specific section of transmission. **This can make the cost of underground transmission extremely variable when calculated on a per-mile basis.**

(Emphasis added.)

To compare estimated project costs more accurately, the amount of transfer capability should be factored into the calculation. For the Company's estimate of $310 million for the double circuit 230 kV hybrid line, the cost per MVA of transfer capability is $155,000 ($310 million / 2000 MVA). For the LS Power estimate of $84 million for a single circuit 230kV hybrid line, the cost per MVA of transfer capability is $168,000 ($84 million / 500 MVA). Based on a comparison of transfer capability, the Company's estimate for the double circuit 230 kV hybrid line is actually lower than the LS Power proposal ($155,000 vs. $168,000). Also, for comparison sake, the Company's estimated $61.1 million for the proposed 500 kV overhead line using the Company's Updated Proposed Route, the cost per MVA of transfer capability is $14,127 ($61.1 million / 4325 MVA).

Q. Mr. Thomasson, does this conclude your pre-filed rebuttal testimony?

A. Yes, it does.



Dominion

Surry-Skiffes Creek 500 kV Transmission Line

James River 230 kV Underground Crossing Alternatives

Alternative A

Single Circuit
Variation 3 Hybrid

Overhead Route
Underground Route
Drill-Rig Temporary Workspace
Transition Station

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REBUTTAL SCHEDULE WRT-2

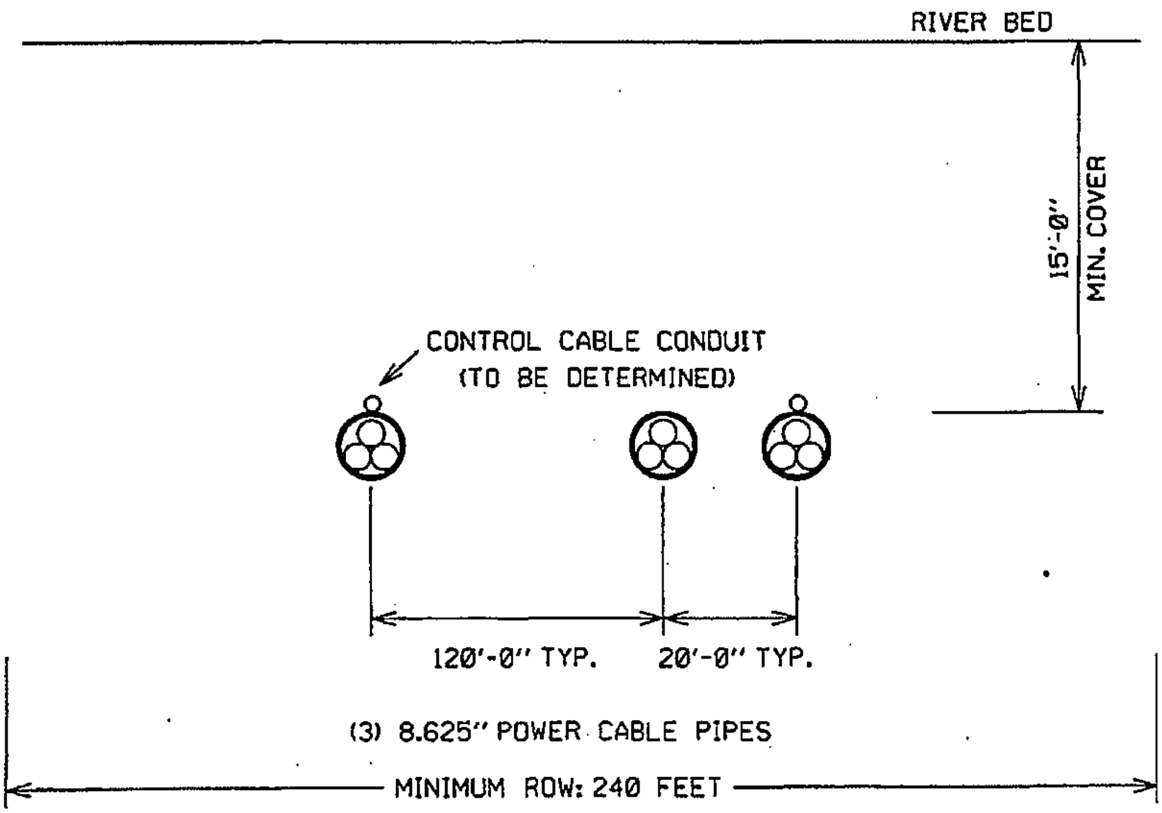
230 kV Alternative A

Surry - Skiffes Creek

Single Circuit HPFF Cable System (1000 MVA)

Underground River Crossing

Typical Horizontal Directional Drill Configuration



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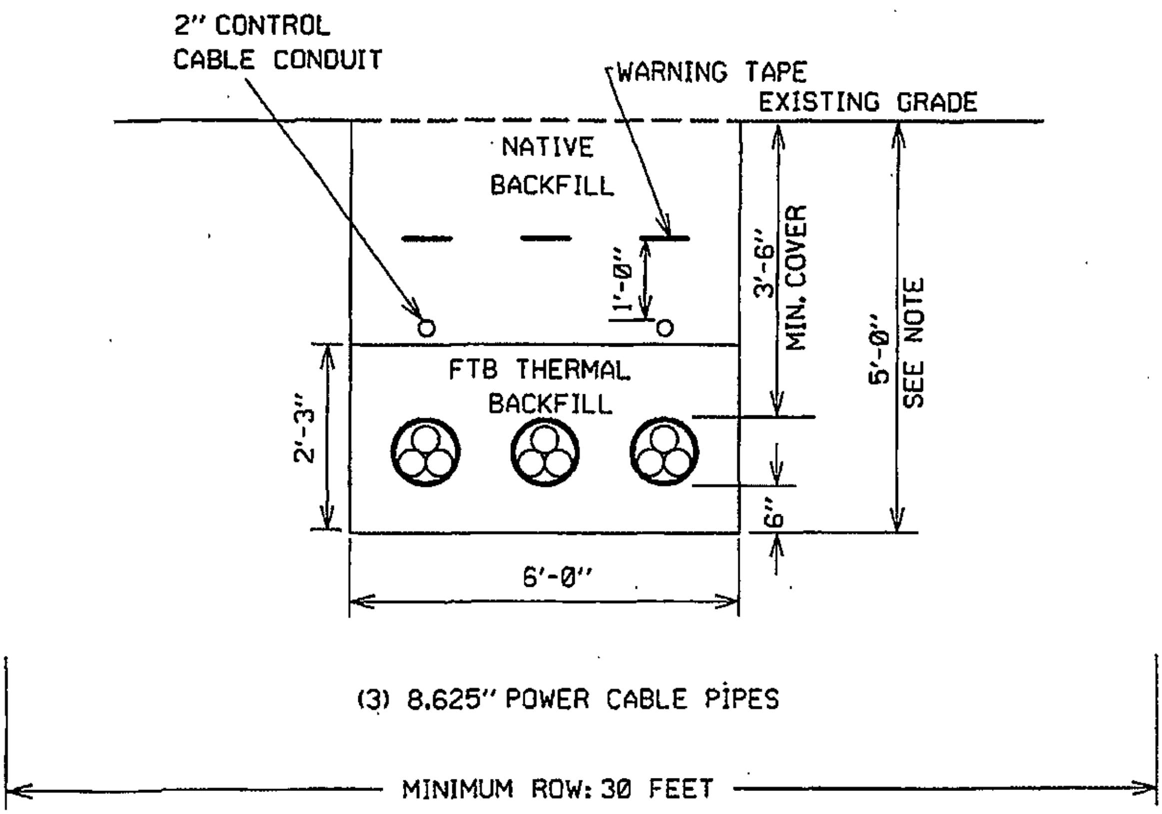
REBUTTAL SCHEDULE WRT-3

230 kV Alterative A
Surry - Skiffes Creek
Single Circuit HPFF Cable System (1000 MVA)
On-Shore
Typical Open Trench Configuration



NOTE:
THIS DIMENSION WILL VARY DEPENDING ON CLEARANCES
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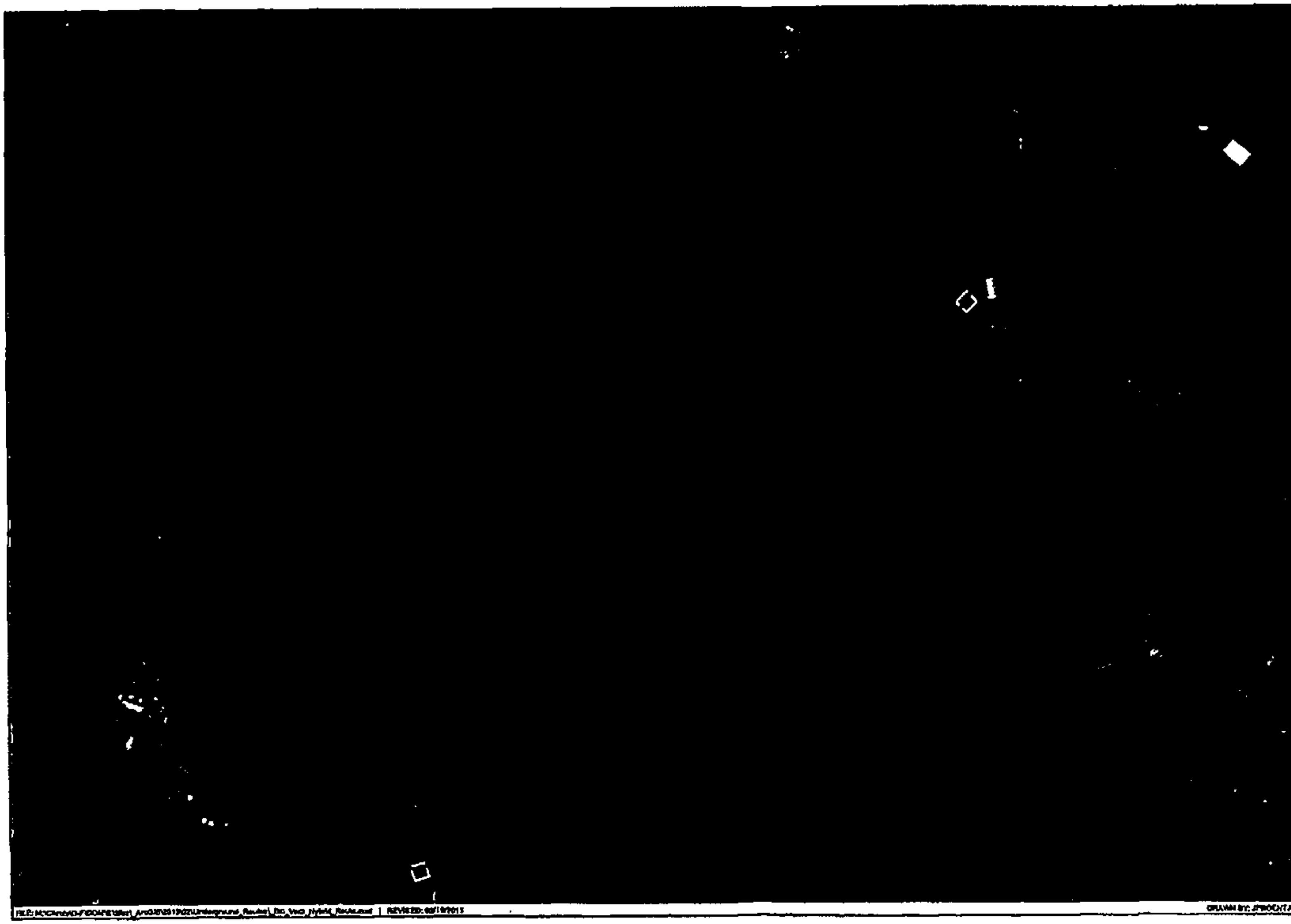

Dominion

Surry-Skiffes Creek 500 kV Transmission Line

James River 230 kV Underground Crossing Alternatives

Alternative B

Double Circuit
Variation 3 Hybrid

Overhead Route
Underground Route
Drill Rig Temporary Workspace
Transition Station

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Feet

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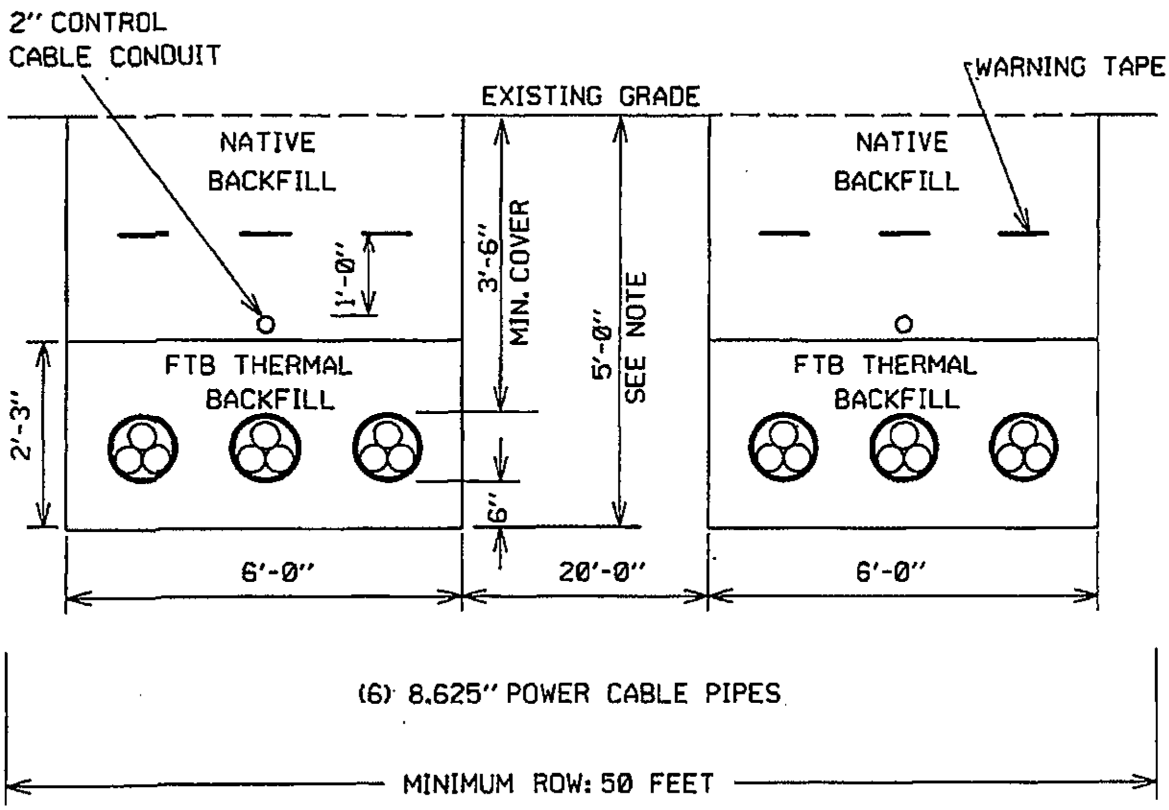
REBUTTAL SCHEDULE WRT-5

230 kV Alternative B
Surry - Skiffes Creek
Double Circuit HPFF Cable System (2 x 1000 MVA)
On-Shore
Typical Open Trench Configuration



NOTE:
THIS DIMENSION WILL VARY DEPENDING ON CLEARANCES
NEEDED WHEN CROSSING OTHER FACILITIES

Company Exhibit No. __
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REBUTTAL SCHEDULE WRT-6

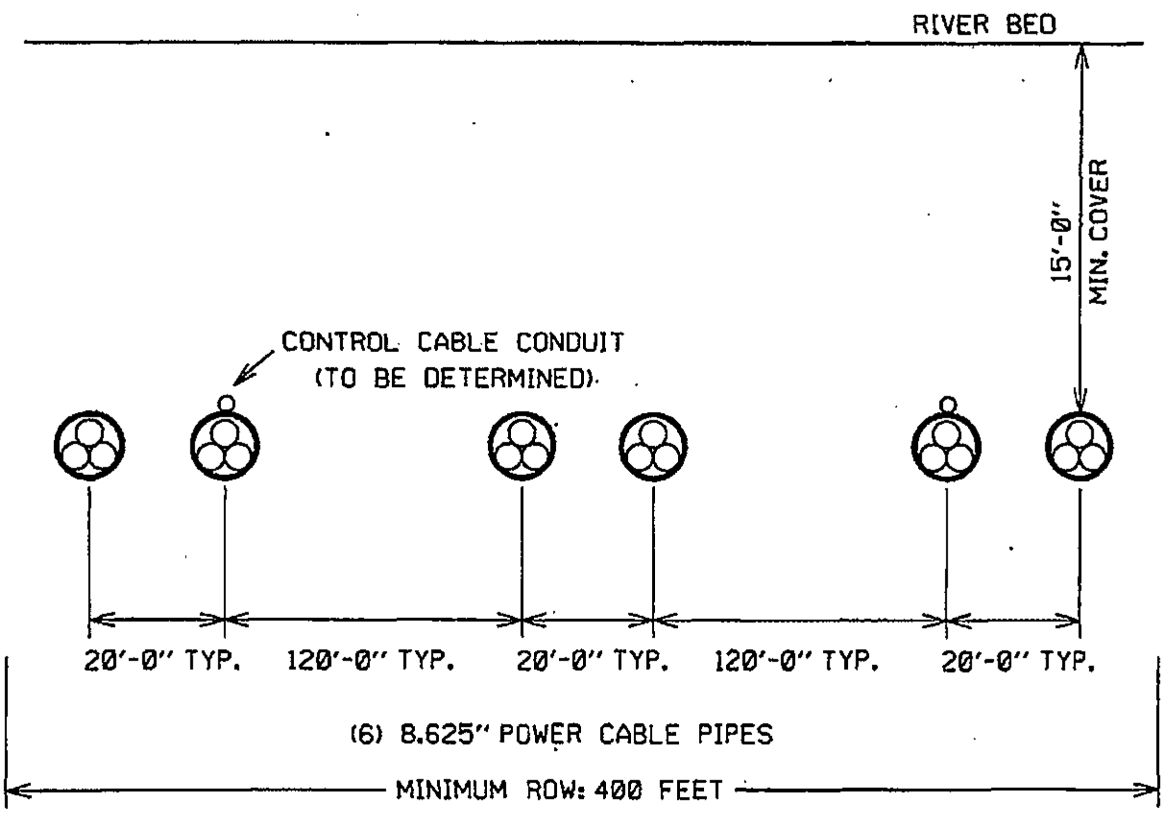
230 kV Alternative B

Surry - Skiffes Creek

Double Circuit HPFF Cable System (2 x 1000 MVA)

Underground River Crossing

Typical Horizontal Directional Drill Configuration



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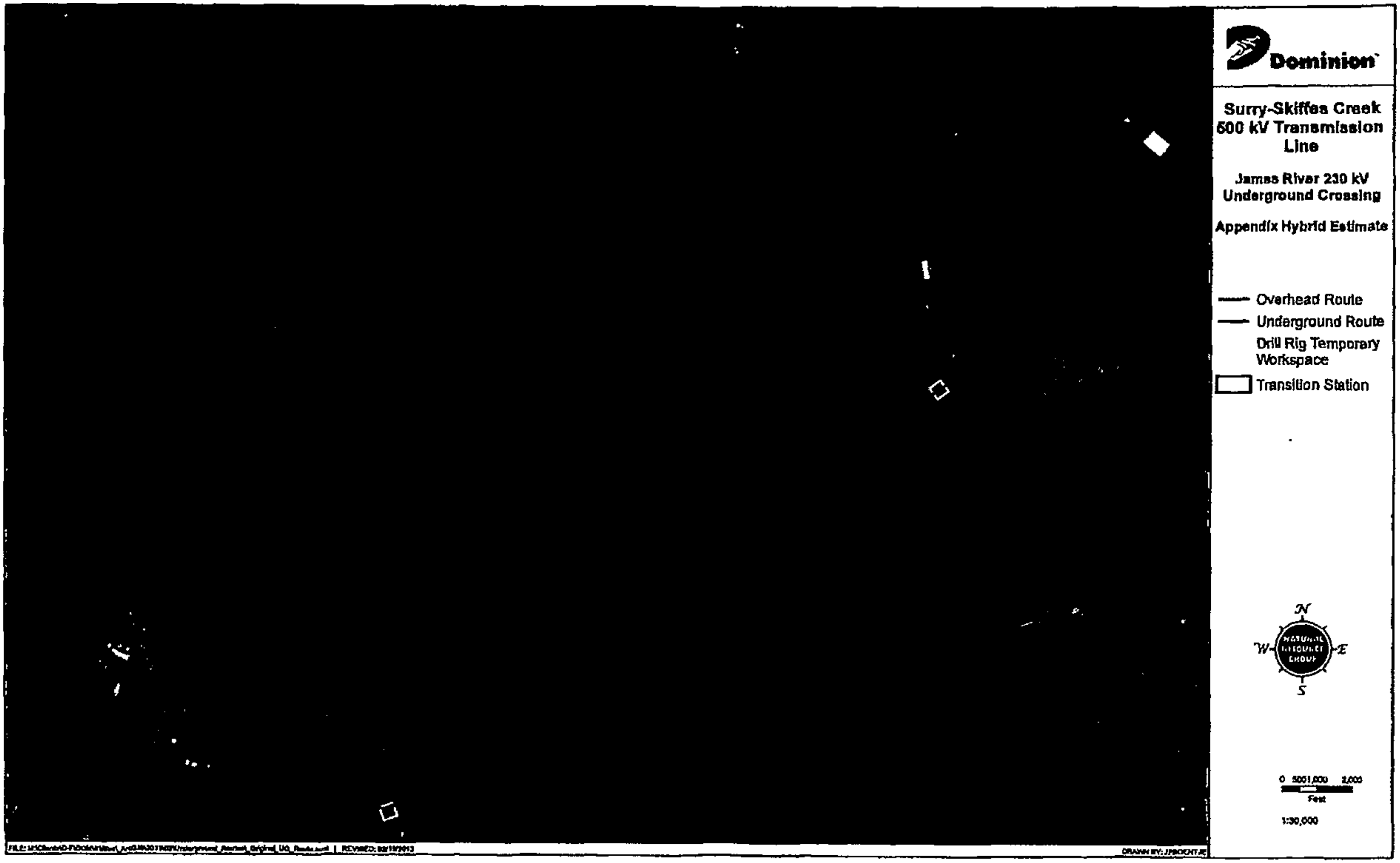

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Virginia Electric and Power Company
Case No. PUE-2012-00029
Virginia State Corporation Commission Staff
Second Set

The following REVISED response to Question No. 21 of the Second Set of Interrogatories and Requests for Production of Documents Propounded by the State Corporation Commission Staff received on October 23, 2012 has been prepared under my supervision.

Walter R. "Trey" Thomasson, III, PE
Engineer III, Transmission Line Engineering
Dominion Technical Solutions, Inc.

Question No. 21:
Reference page 20 of Company witness Nedwick's testimony, where it states that:

> Moreover, based on the Company's recent experience constructing 8-mile 230 kV Hayes-Yorktown Line #2122, including a 3.8-mile submarine crossing of the Rappahannock [sic] River, the estimated cost of the project, if this alternative were included, would be approximately $382.6 million for a hybrid line underground from Surry Power Station to the shore of James City County, where a transition, or terminal, station would be required to go from underground to overhead construction, and overhead from there to Skiffes Creek Switching Station. The estimated cost would be approximately $462.6 million for an underground line all the way to Skiffes Creek Switching Station.

Please elaborate on the "recent experience constructing ... Line #2122" and the estimates referenced by Mr. Nedwick. Include in this discussion the following:

(a) Provide the estimated cost of such construction at the time that the Company requested approval of Line #2122 from the Commission. Break down the total cost into the project's major components, including land and right-of-way acquisition, underground line, overhead line, transition station, and substation work.

(b) Provide the current estimated cost for construction of Line #2122. Break down the total cost into the project's major components, including land and right-of-way acquisition, underground line, overhead line, transition station, and substation work.

(c) To the extent the estimated cost provided by the Company in subsection (a) of this request differs from the cost in its response to subsection (b), provide an explanation of the reasons for the difference(s).

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(d) Provide the current construction or operational status of Line #2122. Include the design capacity (MVA) of its underground portion, its overhead portion, and the total line.

(e) Describe in detail how the Company's recent experience constructing Line #2122 served as a basis for the $382.6 million and $462.6 million estimates included in this portion of Mr. Nedwick's testimony.

(f) Provide a detailed breakdown of the $382.6 million and $462.6 million estimates, including the project's major components, including land and right-of-way acquisition, underground line, overhead line, substation work, switching station, and transition station.

(g) Clarify whether the estimated costs included in the referenced portion of Mr. Nedwick's testimony are for a single-circuit or a double-circuit 230 kV alternative to the Company's proposed 500 kV Surry-Skiffes Creek line, including the number of three-phase cable sets and the capacity (MVA).

Revised Response:

(a) The original estimated cost for the Hayes-Yorktown project was $62.7M. All fee property was previously acquired, so no costs were allocated for land and right-of-way acquisition. The costs were broken down as follows:

- $47.5M for underground line work
- $8.4M for overhead line work
- $1.3M for transition station work
- $5.5M for substation work

(b) The current estimated cost for the Hayes-Yorktown project is $79.0M. All fee property was previously acquired, so no costs were allocated for land and right-of-way acquisition. The costs were broken down as follows:

- $62.2M for underground line work
- $8.7M for overhead line work
- $1.3M for transition station work
- $6.8M for substation work

(c) The major difference between the estimates provided in subsections (a) and (b) is the underground line work. The original estimate for the underground line was produced by an outside consultant. The cost of construction was considerably higher than originally anticipated. This became apparent during the construction bidding process. Also, there have been some unforeseen circumstances that have driven the construction costs higher. These circumstances include multiple construction delays involving cable installation, fiber optic installation, and splice over-boarding, as well as Hurricane Irene preparations and recovery and now Hurricane Sandy.

(d) As of this writing, Line #2122 is still under construction. Estimated energization date is December 2012. The underground portion of the line is designed for a 600MVA capacity at 0.95 load factor. The overhead portion of the line is designed for 604MVA. The total Line #2122 capacity will be set at 600MVA.

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(e) Due to the Company's recent experience constructing Line #2122, material and construction costs from that project were utilized in the estimates provided by Mr. Nedwick's testimony. In addition as stated in subsection (c) of this response, there are multiple factors that can escalate construction costs. To accommodate for unknowns such as these that cannot be identified before hand a large underwater construction job, a contingency factor was included in the estimates.

(f) The estimated cost for a double circuit 230kV hybrid line underground from Surry Power Station to the shore of James City County and overhead from there to Skiffes Creek Switching Station is $406.6M. The costs were broken down as follows:

- $290.9M for underground line work and transition station
- $65.5M for overhead line work
  - $19.1M for UG Transition Station – Skiffes Creek
    - Including $0.8M for overhead line easements
  - $46.4M for Skiffes Creek – Whealton Line
    - Including $150k for overhead line easements
- $50.2M for substation work
  - $24.8M for Skiffes Creek Switching Station
  - $23.0M for Surry Switching Station
  - $2.0M for Whealton Substation
  - $0.4M for Lanexa and Yorktown Substations

The estimated cost for a double circuit completely underground from Surry Power Station to Skiffes Creek Switching Station is $486.6M. The costs were broken down as follows:

- $390.0M for underground line work
  - Including $0.8M for underground line easements
- $46.4M for overhead line work - Skiffes Creek-Whealton Line
  - Including $150k for overhead line easements
- $50.2M for substation work
  - $24.8M for Skiffes Creek Switching Station
  - $23.0M for Surry Switching Station
  - $2.0M for Whealton Substation
  - $0.4M for Lanexa and Yorktown Substations

(g) Both estimated costs ($406.6M & $486.6M) referenced were for double-circuit 230kV underground alternatives. Each circuit is estimated to have three (3) sets of three-phase cables for a 1000MVA transfer capacity. Combined, the double-circuit capacity would be 2000MVA utilizing six (6) sets of three-phase cables.

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Virginia Electric and Power Company
Case No. PUE-2012-00029
Virginia State Corporation Commission Staff
Second Set

The following response to Question No. 22 of the Second Set of Interrogatories and Requests for Production of Documents Propounded by the State Corporation Commission Staff received on October 23, 2012 has been prepared under my supervision.

Walter R. "Trey" Thomasson, III, PE
Engineer III, Transmission Line Engineering
Dominion Technical Solutions, Inc.

Question No. 22:

For each underground alternative to the Surry-Skiffes Creek line that was evaluated by the Company, describe in detail the identified potential impediments to timely construction of that alternative.

Response:

Two underground alternatives to the Surry-Skiffes Creek line were evaluated by the Company, both double circuit 230 kV high pressure fluid filled transmission lines. The first was a hybrid line underground from Surry Power Station to the shore of James City County, where the line would transition to overhead construction to the Skiffes Creek Switching Station. The second was for underground line the entire distance from Surry Power Station to Skiffes Creek Switching Station. Both alternatives involve similar impediments to timely construction.

Lead time for material to build underground transmission lines is much longer than traditional overhead construction. High pressure fluid filled cable has an approximate lead time of 18 months from order date. A cable order of this magnitude (92 miles or 133 miles of single-phase cable) may be even longer. Other items such as cable terminations and pressurization plants have approximate lead times of nine months or longer.

Detailed engineering surveys would need to be performed on the river crossing as well as any land portion of an underground transmission line. Items such as geology of the riverbed, dredging activities, utility crossings, and nearby military activities could have an impact on routing options for an underground alternative. The right-of-way for a six-pipe river crossing will be a minimum of 400 feet wide in order to properly overboard the cable splices. In addition, a complete thermal route survey would need to be performed in order to ensure the transfer capacity of the underground alternative could be met with the assumed circuit configuration of three (3) three-phase sets of cable for each 1000MVA 230 kV circuit.

There are three known buried pipelines that cross the James River from the Surry Power Station property to James City County. These pipelines limit the optimal routing options across the river. These pipelines may have to be crossed with the transmission lines in the river, depending on the route selected. There will also likely be interference from any parallel pipeline's cathodic protection systems which would need to be studied and remedied if necessary. Also, the intake canal for the Surry Power Station would possibly need to be crossed.

There are limited contractor resources for the installation of high pressure fluid filled cable systems. In the area of the proposed crossing, the James River is shallower than the Company's previous crossing of the York River. Specialized vessels may be required to safely and efficiently work in the river.

An underwater crossing of the James River would require development by a qualified engineering and construction firm to determine the scope of issues and obstacles involved, and to develop a project activity schedule. Routing, right-of-way acquisition, environmental considerations, marine construction, civil engineering, electrical engineering, horizontal directional drilling construction, material acquisition, permitting, time-of-year restrictions, and weather are among the disciplines that would need to be considered to develop a detailed scope of work, cost estimates and a schedule for this type of project.

Company Exhibit No. __
Witness: WRT
Rebuttal Schedule 10
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Virginia Electric and Power Company
Case No. PUE-2012-00029
Virginia State Corporation Commission Staff
Fourth Set

The following response to Question No. 45 of the Fourth Set of Interrogatories and Requests for Production of Documents Propounded by the State Corporation Commission Staff received on December 7, 2012 has been prepared under my supervision.

Ward L. Allen for
Walter R. "Trey" Thomasson, III, PE
Engineer III, Transmission Line Engineering
Dominion Technical Solutions, Inc.

Question No. 45:

Referencing the information below, please explain in detail the higher per-pipe-mile cost of underground construction in the Company's estimate for a hybrid 230 kV Surry-Skiffes Creek line versus the Hayes-Yorktown hybrid 230 kV line (Case No. PUE-2009-00049). Include an analysis of how the different fractions of directional-drilling (71% for Surry-Skiffes Creek and 79% for Hayes-Yorktown) affect the cost comparison.

Hayes-Yorktown

The following data is derived from the Company's response to Staff discovery request no. 2-21, and Case No. PUE-2009-00049:

- $62.2M for underground line work
- 2 pipes (1 circuit composed of 2 paralleled sets of 3-phase cables)
- 3.0 miles directionally-drilled (79% of the total 3.8-mile length)
- 0.8 mile trenched

(The drill pits are a short distance back on land from each shoreline. Thus, a small amount of the trenched distance may actually be directionally-drilled.)

The Staff calculates the per-pipe-mile cost for the underground portion of Hayes-Yorktown to be:

- $62.2M / 2 pipes / 3.8 miles = $8.2M per pipe-mile

Surry-Skiffes Creek

The following data is derived from the Company's responses to Staff discovery request nos. 2-21, 3-28, and 3-29:

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- \$290.9M for underground line work (includes the \$1.7M transition station)
- 6 pipes (2 circuits, each composed of 3 paralleled sets of 3-phase cables)
- 3.7 miles directionally-drilled (71 % of the total 5.2-mile length)
- 1.5 miles trenched

The Staff calculates the per-pipe-mile cost for the underground portion of Surry-Skiffes Creek to be:

- \$(290.9 - 1.7)M / 6 pipes / (3.7 + 1.5) miles = \$289.2M /6 pipes / 5.2 miles = \$9.3M per pipe-mile

Response:

The Company's estimate for a hybrid 230 kV Surry-Skiffes Creek line is higher on a per-pipe-mile basis than the Hayes-Yorktown hybrid 230 kV line for several reasons. First, the costs of project materials have increased over the last few years. For example, the price of cable – including raw materials such as copper – has increased over the last three years since the filing for Hayes-Yorktown.

Secondly, it is expected that three intermediate river platforms [per pipe pair] would be needed in the James River for the directional drilling instead of the two on the Hayes-Yorktown project. The additional platform would be needed for the following two reasons: (1) the James River has two distinct dredged shipping channels in the area of the Project route; and (2) the existing gas pipelines would need to be crossed with a directional drilling operation. An additional platform and the associated marine work significantly increase the cost on a per-pipe-mile basis.

Finally, as stated in the Company's response to Staff Set 2-21 (c) and (e), and Staff Set 2-22, the Surry-Skiffes Creek hybrid 230 kV line cost estimates include a contingency for unknowns and as a result of the issues associated with the Hayes-Yorktown project.

The cost estimates for the Surry-Skiffes Creek Project underground alternatives were not performed on a "fractional" basis of the Hayes-Yorktown project. The cost estimate for the hybrid Surry-Skiffes Creek line was performed as a desktop study using actual material costs and estimates for labor and directional drilling. For the reasons stated above, the per-pipe-mile costs are higher than the Hayes-Yorktown project.

ATTACHMENT 6

MW DSM CLEARED PJM RPM AUCTION

	2014/15	2015/16	2016/17	2017/18	2018/19	% Decrease
Dominion	1360	1381	1120	1020	817	39.9%
PEPCO	893	867	663	608	523	
BG&E	1341	1142	937	791	660	
DPL	391	433	440	370	417	
Sub Total	2625	2442	2040	1769	1600	39.0%

* pjm Market Monitor Report indicated PJM may be over relying on DSM only 74% is actually occuring doing to remaining 26% buying out of their obligation.

ATTACHMENT 7

Total Customers	2012	2013	2014	2015
Total NHRLA	285,461	286,495	288,254	290,985

New Customers	2013	2014	2015	Total
Total NHRLA	1,033	1,758	2,730	8,836

% Growth	2013	2014	2015	Annual
Total NHRLA	0.36%	0.61%	0.95%	0.61%

NHRLA Loads

	Summer 2012	Summer 2013	Summer 2014	Summer 2015*
Northern Neck	475	449	466	463
Yorktown	1367	1350	1300	1430
Actual	1842	1799	1766	1893

*2015 Preliminary Assessment