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US Army Corps of Engineers
Norfolk District
Regulatory Office
Received by: RLS
Date: Sept. 12, 2016

September 12, 2016

William T. (Tom) Walker
Chief, Regulatory Branch
USACE Norfolk District
803 Front Street
Norfolk, Virginia 23510

Re: Response to the U.S. Army Corps of Engineers' June 29, 2016, Email and National Park Conservation Association's June 30, 2016, letter to the Corps Re: *Proposed Dominion Power Surry-Skiffes Creek-Whealton Transmission Line Project - Corps Permit Application NAO-2012-00080 / 13-V0408 (James River) James City County, Virginia*

Dear Mr. Walker:

Dominion Virginia Power ("Dominion") is pleased to provide this response to the U.S. Army Corps of Engineers' email to Dominion dated June 29, 2016 ("Corps Email") and the National Park Conservation Association's June 30, 2016, letter to the Corps ("NPCA Letter").

The Corps Email follows a June 15, 2016, meeting it had with NPCA and Princeton Energy Resources International ("PERI") regarding the Yorktown Power Station, which Dominion attended. That meeting involved NPCA's claims that Dominion's Proposed Surry-Skiffes Creek-Whealton Transmission Line project ("Project") is unnecessary because, among other things, (i) the loss of Yorktown to closure will not have the impacts to electrical reliability Dominion claims, (ii) Yorktown can run on gas in any event, (iii) the Project is oversized, and (iv) there are "unanswered questions" regarding Dominion's power flow models related to compliance with North American Electric Reliability Corporation's ("NERC") reliability standards. NPCA Letter at 1-4. According to the NPCA Letter, at that meeting NPCA/PERI presented data and information that "clearly show[s] that there are better alternatives than" the Project. *Id.* at 1. As such, the questions in the Corps Email are aimed at ground-truthing NPCA's claims, as well as confirming the Corps' prior conclusion that "there is a need for this project from both Dominion's and the general public's perspective." Letter from Col. J.E. Kelly, Corps, to C. Vaughn, Advisory Council on Historic Preservation ("ACHP"), at 3 (Apr. 5, 2016) ("April 2016 Ltr."). The Corps' conclusion was based on its independent review, and re-review, of information regarding over twenty alternatives, including, repowering Yorktown with gas, as well as its consideration of other issues raised by NPCA/PERI, which are similar to those raised at the June 15, 2016, meeting. *Id.* ("[B]ased on analysis of all information made available to date, the USACE finds nothing to indicate that Dominion's information regarding practicability of alternatives is flawed or incorrect. Additionally, Dominion has explored all feasible alternatives, including those identified by the consulting parties and the public to date.")

Introduction and Summary

As the Corps is aware, since proposing the Project to the Corps, and in proceedings before the Virginia State Corporation Commission ("SCC"), Dominion has addressed issues related to the retirement and/or repowering of the Yorktown units, and the impending NERC Reliability Standard violations in the North Hampton Roads Load Area ("NHRLA") without the Project. The SCC's review was comprehensive, and concluded that the Project was necessary. In turn, the Corps' review also has been comprehensive, as well as searching. *See* April 26 Ltr. at 2-3 (citing the Corps' Preliminary Alternatives Conclusions White Paper (Oct. 1, 2015) ("White Paper")). In particular, the Corps has held numerous meetings with Dominion and NPCA/PERI to consider in detail the operational and regulatory realities that compel the need for the Project. These meetings have specifically addressed most, if not all, of the issues NPCA/PERI raised at the June 15, 2016, meeting. For example, late last year NPCA/PERI questioned the validity of the Dominion's power load flow analyses. Dominion provided the Corps and NPCA with a new, updated 2016 power load flow analysis based on the current system and user trends. This analysis continued to demonstrate an immediate need for the Project. The regional transmission organization,[1] PJM Interconnection, independently reviewed the updated power load flow analysis and confirmed the continued need for the Project. *Id.* at 3; Letter from S. Herling, PJM Interconnection, to Col. J.E. Kelly, Corps (Jan. 25, 2016) ("Based on recently updated analysis, the [NERC] 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 [Project] . . . is the most effective and efficient solution to address the reliability criteria violations."). Despite NPCA's claims in its letter of changed circumstances, as discussed below, nothing has changed, the analyses remain valid and correct, and the urgency of the Project has increased as the mandatory retirement date of Yorktown Units 1 and 2 draws nearer.

For nearly a year, Dominion and the Corps have patiently and diligently responded to NPCA/PERI's questions and assertions regarding the need for the Project, and alternatives thereto.[2] While NPCA/PERI have repackaged their assertions and conclusions a number of times, the thrust of their position has not changed.[3] Dominion's responses to those assertions

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[1] Regional transmission organizations ("RTOs") were created by the Federal Energy Regulatory Commission (FERC) to be responsible for moving electricity over large interstate areas. RTOs coordinate, control, and monitor electric transmission grids. PJM Interconnection is responsible for the transmission grid that serves Pennsylvania, Ohio, West Virginia, Virginia, Maryland, Delaware, New Jersey, and parts of Illinois, Indiana, Kentucky, and North Carolina. *See* FERC, Regional Transmission Organizations (RTO)/Independent System Operators (ISO), at http://www.ferc.gov/industries/electric/indus-act/rto.asp (last visited July 8, 2016).

[2] Dominion also has responded to similar assertions from other consulting parties over the past three years. For example, it recently responded to a June 7, 2016, letter from the National Park Service ("NPS") in which the agency questioned the role of the Yorktown Power Station and how that impacts the need for the Project, including compliance with NERC Reliability Standards. Letter from S. Miller, Dominion, to T. Walker, Corps, at 1-5 (June 23, 2016) ("June 2016 Ltr.").

[3] The NPCA Letter as well as a June 22, 2016, email from B. Williams, PERI, to the Corps claims that Dominion has withheld power load flow information from them. Dominion provided NPCA/PERI with the requested information in the June 2016 Ltr. To aid in assisting NPCA and Mr. Williams in understanding the power flow information provided, Dominion is providing a chart explaining the computer output. See Attachment 1.

have demonstrated that the facts, assumptions, and analyses upon which the Corps has relied to determine the need for the Project, and to reject the other alternatives, are accurate and comprehensive. Dominion's responses also have demonstrated that NPCA/PERI's assertions are unfounded and contrary to the basics of electric power generation and transmission, as well as to the regulatory and operational realities that govern those endeavors, including at Yorktown.

Before proceeding to the responses, it is appropriate to provide additional explanation regarding the context in which Dominion operates. We do so because many of the issues raised, and assertions made, by NPCA/PERI in the NPCA Letter (and in prior comments and discussions) reflect a disconnect in understanding the types of operational constraints and requirements involved, and how those constraints and requirements impact, or do not impact, the need for the Project. For ease, we will refer to the constraints and requirements as short-term and long-term. Dominion's short-term constraints and requirements consist of meeting its obligations to provide reliable electricity to its customers in the most efficient manner, and cost effective basis, possible. It also must meet NERC Reliability Standards governing its current operations. These short-term constraints and requirements impact, for example, how Dominion operates its generation assets on a daily basis to produce the amount of electricity necessary to meet immediate demand. Thus, in addition to being short-term, these types of constraints and requirements may require more localized action by Dominion, for example regarding how and when to operate Yorktown (as discussed in the responses below). The short-term constraints and requirements, however, also require Dominion to have sufficient generation and transmission assets available to meet NERC Reliability Standards, even if those assets are not used on a daily basis to address the scenarios contained within the NERC Reliability Standards because they have not occurred. These types of constraints and requirements also may require localized action by Dominion, but for completely different reasons; the NERC Reliability Standards ensure the integrity of all of the components of an entire transmission system (here, the PJM Interconnection system) that work together. Thus, certain actions may be required locally due to NERC Reliability Standards that do not appear to be necessary to, for example, provide reliable electricity on a daily basis under normal operating conditions.

The long-term constraints and requirements work similarly to the short-term constraints and requirements, but are aimed at predicting future compliance with NERC Reliability Standards based on projected changes in, for example, generating and transmission components, as well as projected changes in demand. From these projections and predictions, operators can plan necessary projects to meet reliability standards, as well as to meet projected needs to perform its essential service. As suggested above, actions that may be required locally to meet future NERC Reliability Standards may not appear to be necessary to, for example, provide for the projected need for reliable electricity on a daily basis under normal operating conditions. This is because, among other things, the NERC Reliability Standards are designed to protect the entire transmission system, not to simply ensure one local area has power. The generation and transmission systems are integrated so completely that system protection on a regional basis necessarily drives local activities.

Here, NPCA/PERI's assertions and positions fail to recognize these realities and distinguish between them appropriately. As such, they assert that, for example, Dominion's daily decisions to provide reliable, efficient, and cost-effective electricity to the NHRLA (which, as discussed below, recently have relied upon relatively less generation from the Yorktown

Power Station), demonstrate that the Project is not needed, and that the *status quo* is acceptable. It might be possible to validate this view if Dominion operated Yorktown and provided power for the NHRLA in a vacuum. But, it does not. As discussed, Yorktown and the NHRLA are just parts in an otherwise large, complex integrated generation and transmission system that is subject to a set of governing rules that test that system, and any changes to it, against numerous scenarios, including worst-case scenarios. Maintaining a larger, reliable system often requires local actions that appear unnecessary when compared to what might be thought to be the minimum necessary to address local needs. Those actions are, however, very necessary.

In summary, the assertions made and issues raised by NPCA/PERI at the June 15, 2016, meeting are not new. The Corps and Dominion have responded to the assertions previously, and they do nothing to change the Corps' conclusions based on those responses. In short, NPCA /PERI is not in the business of generating and transmitting electricity; its continued assertion of the same points (with various nuances each time) rest on fundamental misunderstandings regarding planning and operating an integrated electrical generation and transmission system, and how it is undertaken and governed. Nevertheless, below Dominion provides complete and comprehensive responses to the Corps questions, which confirm the Corps' prior conclusions regarding these issues and should put these issues to rest.

In so doing, Dominion has reordered and grouped the Corps' questions into subject matter areas for ease of explanation and understanding. For some of the questions, Dominion's response addresses incorrect or imprecise assumptions imbedded in the questions, which likely are due to the incorrect assumptions contained in NPCA/PERI's assertions at the June 15, 2016, meeting, and the accompanying presentation materials. After its responses to the Corps' questions, in brackets Dominion references the assertions in the NPCA Letter that the response covers. The Corps' questions are italicized and Dominion's responses are in standard font, prefaced with the term "DOMINION RESPONSE:".

Responses to Questions Regarding Power Generation at Yorktown Related to Projected NERC Violations

Question 10 - Please clarify and help us better understand specific NERC Criteria Violations, specifically which standard (with reference to citation) is violated for the various scenarios and alternatives considered.

DOMINION RESPONSE: Federal law requires that the reliability of the interconnected transmission grid be determined through compliance with the FERC-approved NERC Reliability Standards. The NERC standards require compliance with specific criteria for transmission planning. As the Corps requested, a summary of the NERC Reliability Standards, TPL-04-001, (under the old and new nomenclature) and what they mean in concrete terms is provided in Attachment 2.[4] Rather than focusing on, for example, what is the peak load on the hottest or coldest day, the NERC Reliability Standards require that sufficient voltage be maintained at each component in the system without overheating, and it must do so under various contingencies or

[4] NERC, United States Mandatory Standards Subject to Enforcement at http://www.nerc.com/pa/stand/Pages/ReliabilityStandardsUnitedStates.aspx?jurisdiction=United States (see "(TPL) Transmission Planning") (last visited July 18, 2016)).

scenarios when system components are not in service. The only way to evaluate this compliance is by performing computerized modeling simulations of future system operations under specific contingencies to identify the need for construction of new transmission facilities.[5] This analysis is critical because NERC reliability criteria do not reflect fiction. They are tied to ensuring the safety and reliability of the electrical system in the area under study and take into account reasonably likely system stress conditions. The stability of the system in one area can affect the larger grid and have far reaching consequences, as the examples in the chart below demonstrate.

Major North American Blackouts

Year	Location	Cause	Customers	Duration
1965	NY/NE/ Canada	Faulty relay	30 million	13 hours
1977	New York/ Midwest	Lightning	9 million	26 hours
1996	Western US/Canada	Heat, low voltage	2 million	Up to 4 hours
1996	Western US/Canada	Tree contact	7.5 million	9 hours
2003	NY/NE/ Midwest	Tree contact	17 million	2 hours to 2 weeks
2008	Florida	Human error	1 million	4 hours
2011	San Diego	Human error / situational awareness	1.4 million	12 hours

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Instability of the system in any event imposes severe and unacceptable risks to public health and safety. The NERC Reliability Standards are designed to prevent these risks to the greatest extent possible.

The NERC-required computer modeling is known as an alternating current power-flow model. A power-flow model provides a representation of a particular power transmission scenario under a specific scenario. Each model only represents a single scenario and several models are created to analyze the power-flow under different circumstances. As a result, this power-flow computer modeling is far more complex than a simple comparison of load versus generating capacity in at least three ways. 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 transformer or bus that is part of the entire grid system will be able to operate within its operating limits. These operating limits are typically calculated

[5] As required by Virginia law, Dominion is a transmission owning member of PJM, a FERC-regulated RTO that must plan the PJM system, in concert with Dominion and the other PJM members, all of whom must develop PJM's annual Regional Transmission Plan ("RTEP") under the RTEP protocols and processes in PJM's FERC-approved Open Access Transmission Tariff. The federal regulatory requirements for the performance of these functions by Dominion and PJM are described in Attachment 1 to our December 15, 2015 response to the NPCA's November 5, 2015 letter.

on a per unit basis, rather than an actual kV or MVA basis. Second, the relationship between some of the variables is nonlinear. For example, the power flow into load impedances is a function of the square of the applied voltages. Due to the nonlinear nature of this problem, numerical methods are employed to solve it. Numerical methods are a form of mathematical analysis that uses a computer to solve a series of multi-variable, non-linear equations in an iterative manner. Third, the power-flow model evaluates the system under various contingencies. NERC Reliability Standards have to be met not on the best day or an average day, but under all identified contingencies. Therefore, many power-flow models are projected up to ten years out and take into account planned equipment additions, planned retirements, planned and unplanned outages (potentially due to weather events), and expected repairs and enhancements. The most critical contingency may not be 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. Thus, forecasted peak load, while relevant, is not the sole criteria that must be evaluated and met. Only power-flow modeling can evaluate whether an alternative meets NERC Reliability Standards at all points in the system under all contingencies.

[NPCA Issues Addressed: Assertion that Dominion is conflating its policies and/or preferences with NERC requirements (including quote from SCC proceeding); assertions regarding that NERC Reliability Standards require. NPCA Letter at 3]

Question 1 - Dominion's forecast projections have shown, that with Yorktown in place and fully functional, the NHRLA would remain NERC compliant until 2019. NPCA & PERI have provided Annual Energy Production Trends for Yorktown for the period of 2009 - 2015. This data shows that Yorktown collectively has decreased its generation output nearly 50% and Yorktown Units 1 -3 have only operated at less than a 1/3rd of their full capacity potential in 2014 and 2015.

a. Please validate the length of time the NHRLA remains compliant with NERC if Yorktown were to remain fully available.

DOMINION RESPONSE: Hypothetically, based on present system conditions, and assuming Dominion had the ability and timely regulatory approvals to construct and spend $859 million to $1.873 billion to retrofit Yorktown Units 1, 2, and 3 with air emissions and other environmental controls so they would be fully available (*i.e.*, without the 8% capacity operating limit on Unit 3), the NHRLA load area would remain compliant with NERC Reliability Criteria until 2021. The assumptions used in the hypothetical to answer the question are, of course, incorrect.

b. Please explain why the NHRLA has been able to become less dependent on generation from Yorktown.

DOMINION RESPONSE: NPCA/PERI are operating under a false premise that the only time the generating units at Yorktown Power Station operate is for area security needs (*i.e.*, to ensure compliance with reliability standards). In the real world, generating units are operated in real time under two basic scenarios: (a) system efficiency and economics; and, (b) area security requirements. Recently, natural gas commodity costs continue to decrease relative to coal commodity costs which, in turn, makes coal-fired units more expensive to operate for customers.

The timeframe mentioned in Question 1 encompasses a period where natural gas prices dropped significantly, thereby allowing natural gas-fired units to displace coal and oil units in economic merit dispatch.

More specifically, the Yorktown units recently are operating less than they have historically because natural gas commodity costs have decreased relative to coal commodity which in turn, makes coal-fired units more expensive to operate for customers. In addition, the small size coal-fired units at Yorktown operate less efficiently (higher heat rate) than larger coal units, such as those at Dominion's Clover, Chesterfield, and Mt. Storm facilities. Natural gas-fired generating resources are being dispatched more frequently due to economics, which are displacing higher cost coal-fired units such as Yorktown Units 1 and 2.

In addition to the unfavorable economics of these coal-fired resources, EPA's Mercury & Air Toxics Standards ("MATS") applies additional emission constraints to coal (Yorktown Units 1 & 2) and oil (Yorktown Unit 3) facilities.[6] This rule does not allow trading, allowances, or averaging between facilities. The MATS compliance date commenced on April 16, 2015; thereby limiting operating flexibility at Yorktown. Under an Administrative Order issued by EPA, Yorktown can operate until April 16, 2017 only in emergency situations. After that date it must be retired. These operational, economic and regulatory realities explain why it appears that the NHRLA has become less dependent on generation from Yorktown, which it has not.

Notwithstanding the forgoing, data from the time period from May 1, 2015, to April 30, 2016, (when current environmental regulations took effect) nevertheless highlights how critical the operation of the Yorktown units are for continued, reliable service to Dominion's customers in the NHRLA on a daily basis. During this timeframe, Yorktown Unit 1 was on-line 16 days, Yorktown Unit 2 was on-line 84 days, and Yorktown Unit 3 was on-line 26 days. *See* Attachment 3. The actual run-time of these units is very much in line with the estimated 60-80 days of risk that Dominion previously identified to the Corps and NPCA in meetings that exists in the NHRLA absent the Project being in-service. This data only further highlights the criticality of completing the Project as soon as possible for Dominion's customers in the NHRLA.

More recently, PJM called upon Yorktown Unit 2 to operate a number of times since July 14 to meet reliability needs.

[NPCA Issues Addressed: Yorktown units have been effectively shut down since 2015 and there is unused capacity; NPCA Letter at 1; maintaining the *status quo* at Yorktown, while using gas for emergencies, is a viable alternative; NPCA Letter at 3].

Question 2 - Dominion has asserted that continued power generation, via coal, at Yorktown will be eliminated due to MATS requirements; therefore creating or accelerating violations with NERC.

a. In the absence of other improvements, what level of power generation capacity would have to be maintained at Yorktown to remain compliant with NERC?

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[6] *See* Dominion SCC Rebuttal Witness G. Kelly, Rebuttal Schedule 1, at 3.

DOMINION RESPONSE: The updated analysis that the USACE requested based on PJM's current 2016 Load Forecast and current system topology has determined that 656 MW of generation capacity is required in the NHRLA (all located at Yorktown 230 kV bus) with at least 276 MW of generation remaining on-line after the outage of the largest single generating unit in the NHRLA. *See* Attachment 4. These generating numbers are consistent with the study results conducted during the Virginia SCC Hearing which determined that, 620 MW of generating capacity is required with the smallest unit that remains in-service being no less than 295 MW.[7] Additional generation would be required after Summer 2021, for the NHRLA Transmission System to remain compliant with NERC Reliability Criteria.

b. What combination of Units must remain in service to maintain the level of generation capacity needed for compliance?

DOMINION RESPONSE: As noted above in response to Question 2.a, to maintain compliance with NERC Reliability Standards, Yorktown is required to have 656 MW of generation located with at least 276 MW remaining in service after the outage of the largest generating unit; therefore, all three units at Yorktown Power Station would be required to remain in service to maintain compliance with NERC Reliability Standards. Even assuming Units 1 and 3 (the two largest units) were repowered for natural gas, they would be capable of producing 157 MW and 430 MW of capacity, respectively.[8] This equates to a total generating capacity of 587 MW, which is 69 MW <u>less than</u> the required minimum generating capacity. Therefore, it would still be necessary to have and operate Unit 2, which would need to be retrofitted or repowered to meet the minimum amount of generation required to maintain compliance with NERC Reliability Standards.

[NPCA Issues Addressed: Yorktown has unused capacity that will meet demand; Unit 3 should be sufficient for peak periods, particularly in light of flexibility provided by ability to use gas; NPCA Letter at 1]

Responses to Questions Related to Powering Yorktown with Natural Gas or Other Non-Coal Fuels

Before providing its responses to the Corps' questions below regarding powering the Yorktown units with natural gas or other non-coal fuels, Dominion first provides an explanation regarding how two of the three Yorktown units can and do use natural gas and other non-coal fuels at the facility. As discussed below in greater detail, based on their physical and mechanical design, and thus, how they operate, none of the three Yorktown units can generate minimum load power on natural gas alone. Minimum load is the lowest level of power that can be sustained for any period; because the equipment and combustion system are not stable until they reach minimum load, boiler operations cannot be maintained below minimum load.[9] For sustained operation, the

[7] Dominion SCC Rebuttal Testimony of S. Hathaway at 12 and P. Nedwick at 10-11 (Mar. 14, 2013).

[8] Note that repowering Unit 3 with natural gas does not equate to a similar capacity as Unit 3 powered by #6 Fuel Oil, due to the inability of natural gas to produce the same level of heat as oil firing.

[9] As a loose analogy, consider running a car engine on only one cylinder. While you may be able to get the engine to start, it operation is unstable and unreliable, likely will shut off soon, and certainly cannot be used to propel the vehicle.

boiler must operate above minimum load and that cannot occur in Units 1 and 3 on natural gas alone. Instead, Yorktown Units 1 and 3 either can or must use natural gas as fuel in one of two ways. First, natural gas can or must be used as fuel for the unit startup process. The natural gas is fired to heat the unit up to operating temperature and to begin generating power at low output, but below minimum load. Second, natural gas can be used as a supplemental fuel to coal and oil. This also is referred to as co-firing. Co-firing with natural gas typically is done for flame stabilization during a low load, or when poor coal quality conditions require supplemental natural gas. Yorktown Unit 2 cannot use natural gas as currently configured.

To generate steam for the production of electricity, as discussed in detail below, all three Yorktown units must operate and be maintained at a minimum load. Units 1 and 3 cannot achieve their minimum load when fired on natural gas alone. In order to achieve and maintain their minimum loads, or more, the units must be operated on their primary fuels (*i.e.*, coal for Unit 1 and fuel oil for Unit 3). While these two units can be co-fired with natural gas, co-firing is not required for them to operate and generate electricity. Although, as noted, co-firing sometimes is employed to make operations more stable.

In light of the forgoing, NPCA/PERI's assertion that Yorktown has the capability in place to generate power using natural gas is incorrect (*see* Question 3). Similarly, NPCA/PERI's assertion (which forms the basis for Question 4) that all Yorktown units previously have run on natural gas is misleading (and simply wrong for Unit 2). On the one hand, Units 1 and 3 can be started and co-fired with natural gas, and thus, these units can loosely be said to "run" on natural gas. Natural gas can be used to heat up the boilers and generate power at low levels below minimum load, and once coal and oil are added to reach minimum load, natural gas can be added as a supplement, for example for flame stabilization. On the other hand, neither Unit 1 nor Unit 3, when fueled by natural gas alone, can operate at minimum load and reliability generate electricity. Likewise, NPCA/PERI's assertion that Unit 3 could lift its 8% capacity operating limit if it operated on natural gas (the basis for Question 5), is misleading for the same reason. Thus, while Dominion provides answers to the Corps' questions regarding the use of natural gas at Yorktown below, any discussion about the possibility for the Yorktown units as currently configured to run on natural gas alone and generate electricity above minimum load is a purely hypothetical exercise. As discussed elsewhere, the Yorktown units would only be able to operate as intended (*i.e.*, to generate electricity) using only natural gas as fuel if they were repowered, the costs of which are discussed in the response to question 3.e below.

Question 3 - NPCA & PERI have asserted that Yorktown currently has the capabilities in place to generate power on alternative fuel sources that currently exist at Yorktown, absent coal. Specifically, Units 1 & 3 via LNG.

a. Please confirm the type(s) of fuel currently available at Yorktown, including the types that may not be on-site but can be delivered via existing infrastructure.

DOMINION RESPONSE: Oil (#2 Fuel Oil and #6 Fuel Oil), coal, and natural gas are the fuels currently available to the Yorktown Power Station.

b. Please confirm the amount of each fuel type described in response to item 3.a.

DOMINION RESPONSE:

#2 Fuel Oil

- Units 2 and 3 typically use approximately 30,000-60,000 gallons each for startup purposes.
- Resupplied via 7,500 gallon truck load per hour and stored in a 434,994 gallon max capacity on-site tank.

#6 Fuel Oil

- Unit 3 uses approximately 30,857 barrels per day at maximum winter claimed capacity.
- Stored on-site in a 233,057 barrel Day tank, which provides approximately 5 days of fuel at maximum winter claimed capacity.
- The Day tank is resupplied via tank to tank transfer from adjacent Phase 1 storage tanks A or B.
- Adjacent Phase 1 storage tanks A and B each have a maximum storage capacity of 475,000 barrels.
- Phase 1 storage tanks A and B are resupplied by ocean going vessels in various sizes at approximately 10,000 barrels per hour.
- 2-3 weeks' lead time needed for resupply.

Coal

- Units 1 and 2 burn Central Appalachian (CAPP) bituminous coal that originates from mines located in West Virginia and Kentucky.
- Yorktown Power Station can hold approximately 180,000 tons (maximum) of coal inventory on site.
- Units 1 and 2 have a combined coal burn of approximately 3,200 tons (maximum) per day.
- Coal is delivered to the Yorktown Power Station by rail with CSX Transportation as the rail carrier.
- Each train shipment is delivered in 102 rail cars having a combined total tonnage of 11,750 tons.

Natural Gas

- Unit 1 must be started using natural gas. It uses roughly 800 DTH/Day for startup purposes. As discussed above, a low level of electricity (approximately 25 MW) below minimum load can be generated during startup.

- Once started, Unit 1 can be co-fired with natural gas for flame stabilization during a low load, or when poor coal quality conditions require supplemental gas. Historically, when Unit 1 uses natural gas to provide supplemental fueling support to its coal-fired operations, it uses roughly 5,000 DTH/Day. As discussed above, however, Unit 1 cannot run at its minimum operating load on natural gas alone. As such, Unit 1 cannot reliably generate electricity at necessary levels when using only natural gas as its fuel; its primary fuel coal is required to do so.

- Yorktown Unit 3 is capable of using natural gas for startup purposes. When natural gas is used for startup, Unit 3 uses roughly 8,000 DTH/Day. As discussed above, a low level of electricity (approximately 100 MW) below minimum load can be generated during startup.

- Unit 2 cannot use natural gas for startup or co-firing. It uses #2 Fuel Oil for startup.

- After startup, Unit #2 must use coal as it primary fuel, and Unit #3 must use #6 Fuel Oil for its primary fuel. Like Unit 1, Unit 3 can use natural gas as a fuel supplement to provide support for flame stabilization for their primary fuel operations. When Unit #3 is co-fired with natural gas it uses roughly 30,000 DTH/Day.

- Like Unit 1, and as discussed above, Unit 3 cannot run at its minimum operating load on natural gas alone. As such, it cannot reliably generate electricity at necessary levels when using only natural gas as its fuel; its primary fuel (#6 Fuel Oil) must be used to do so.

- Natural gas is supplied to the Yorktown Power Station site via a Virginia Natural Gas ("VNG") pipeline lateral, which currently only is served with supply at the Dominion Transmission Inc./Quantico interconnection on the northern end of VNG's system. The current contractual arrangements for natural gas transportation to the site provides only for interruptible service, not firm; therefore, natural gas supply to the site is dependent upon VNG pipeline availability conditions. Generally, VNG pipeline capacity is unavailable during times of high demand (*i.e.*, winter peak demands, and occasionally in peak summer demands). Natural gas typically is available and supplied from spring through fall as temperatures and pipeline conditions allow. While the amount of natural gas available from spring through fall varies, historically roughly

35,000 DTH/day is the most VNG is able to deliver.[10] Currently, there is no firm transport capacity available on the VNG's system to serve the Yorktown Power Station for year round operations. Acquiring firm transport capacity for the Yorktown Power Station would require new pipeline infrastructure (such as compressors and pipeline looping) on the VNG's system. Time would be required to permit, design and construct such facilities.

c. *Please confirm the type(s) of fuel all three Units are currently capable of burning to generate power without modifications. Please confirm the type(s) of fuel all three Units are currently capable of burning to generate power without modifications.*

DOMINION RESPONSE:

Yorktown Unit 1

Unit 1 is a 159 MW (summer)/162 MW (winter) coal-fired unit capable of being fueled by coal or by a combination of coal and natural gas, but is not configured to operate on natural gas alone. Unit 1 must use natural gas for startup purposes, and may use natural gas to provide supplemental fueling support to its coal-fired operations, for unit stabilization under adverse conditions for example (*e.g.*, poor coal quality). Unit 1 has a minimum load requirement of approximately 80 MW to run, and a maximum of approximately 30-40 MW of its load can be fueled by natural gas; therefore, even when running at its 80 MW minimum load requirement on coal and natural gas, Unit 1 must utilize coal to run.

Yorktown Unit 2

Unit 2 is a 164 MW (summer)/165 MW (winter) coal-fired unit capable of being fueled by coal or by a combination of coal and #2 Fuel Oil, with #2 Fuel Oil only being used for startup purposes. Unit 2 cannot use natural gas for startup or co-firing purposes.

Yorktown Unit 3

Unit 3 is a 790 MW (summer)/792 MW (winter) oil-fired unit capable of being fueled by #6 Fuel Oil or by a combination of #2 and #6 Fuel Oil and natural gas, but is not currently configured to operate on natural gas alone. Unit 3 may only utilize natural gas for startup purposes and to provide supplemental fueling support to its oil-fired operations. Unit 3 has a minimum load requirement of approximately 310 MW to run, and a maximum of approximately 100 MW of its load can be fueled by natural gas; therefore, even when running at its 310 MW minimum load requirement on #Fuel Oil and natural gas, Unit 3 must utilize #6 Fuel Oil to run.

d. *Explain the current generating capability of each unit, with each fuel type.*

DOMINION RESPONSE: See response to question 3.c.

[10] Without firm transportation arrangements, Yorktown is and will continue to be limited in its ability to function reliably during high natural gas demand periods.

e. Please clarify Dominion's interpretation of "repowering". What specific modifications must take place at Yorktown based on its current infrastructure and capabilities?

f. Costs to "Repower Yorktown Power Station to Natural Gas" have been unreported, please provide cost estimates broken down into the need for additional supply lines and cost to convert a specific Unit to burn natural gas if necessary?

DOMINION RESPONSE (to both 3.e. and f.): As an initial matter, it would not be practicable to repower because it would require time to permit and construct far beyond the time available to address the retirement at Yorktown Units 1 and 2 and to avoid NERC reliability deficiencies. In response to your question, repowering means to convert a generating resource's ability to produce electricity from one primary fuel to another primary fuel. For the Yorktown facility, coal is the primary fuel for Units 1 and 2, while #6 Fuel Oil is the primary fuel for Unit 3. To "repower" the entire facility with natural gas with the capability to operate anytime through the year would require securing firm transport gas pipeline capacity, as well as additional capital expenditures ("CAPX") for necessary equipment to operate in full compliance with applicable laws.[11]

More specifically, several environmental regulations would require additional control equipment requiring incremental additional CAPX for years 2012-2022. These costs may increase if additional NOx controls are required during permitting or to address the ozone NAAQS implementation rule currently under development.[12] Similarly, section 316(b) of the Clean Water Act would require installation of variable speed drives on the cooling water intake pumps and screens or closed cycle cooling towers.[13] Adding in the cost of replacement equipment and ongoing maintenance measures, and depending on whether variable speed drives or cooling towers would be required, the CAPX required for Unit 1 ranges from $102 million to $226 million, for Unit 2 the CAPX ranges from $100 million to $224 million, and for Unit 3 the CAPX ranges from $189 million to $542 million. Overall the CAPX cost for all three units ranges from $391 million to $992 million.[14] In addition, payment of an annual charge would be required for the firm transport gas pipeline capacity contract, estimated at $72 million per year for the entire Yorktown facility (levelized cost).[15] Even with these CAPX and firm contract

[11] LNG was not considered as a viable alternative fuel source due to, among other things, extremely high fuel cost, high fixed costs, residential area not conducive to trucks, permitting issues, the shipment dock would need to be extremely long due to water depth. *See, e.g.*, SCC, Order at 25 n.50 (Nov. 2013) (citing G. Kelly testimony); SCC, Senior Hearing Officer's Report at 146-47 (Aug. 2, 2013) (same).

[12] Conversion of Units 1 and 2 from coal to natural gas could also trigger Best Available Control Technology (BACT) review for carbon monoxide ("CO"), which may require a CO catalyst and additional cost.

[13] In order to repower Units 1, 2, and 3 to be fully available, CWA § 316(b) would require conducting biological and technology studies at Yorktown Power Station, since the station's annual average cooling water flow would be above 125 million gallons per day. Under this scenario compliance with the impingement standard (e.g., intake screen and fish return upgrades) would be required and it is probable that either variable speed drives for the intake pumps or cooling towers will be required.

[14] The cost information is taken from the 2012 IRP or estimated if not included in the IRP for its basis.

expenditures, there would be a reduction of 398 MW combined when all units are repowered to natural gas (most of the reduction (aka, derate) occurs on Unit 3).

Question 5 - When referencing Unit 3's 8% use restriction, does this only apply if Dominion burns oil? What availability restrictions exist for Unit #3 if run on natural gas should the 8% be exceeded?

DOMINION'S RESPONSE: For purposes of compliance with MATS, the 8% capacity factor restriction applies only when Unit 3 burns oil. Nevertheless, the 8% restriction applies regardless of fuel under the requirements of the Clean Water Act Section 316(b).[16] Under the 316(b) Rule, Yorktown can request less stringent impingement standards if Unit 3 can stay under the 8% capacity factor. For Yorktown to exceed the 8% capacity factor, the station would have to meet one of the impingement standard options, which would include the retrofit of the cooling water intake screens to meet the modified travelling screen standard. In addition, the station also would likely exceed the 125 million gallons per day withdrawal threshold which would require the full suite of entrainment studies including biology (2 years) and engineering/cost studies. These studies impose a significant cost. Additionally, the increase in intake flow likely will require installation of costly entrainment protection technologies or operational restrictions required by Virginia Department of Environmental Quality.

Question 6 - Dominion has reported costs in excess of one billion dollars to "Retrofit Yorktown Power Station with Anti-pollution Control Equipment". Please provide clarification on which units were factored into the billion dollars. If multiple units were included, please provide the cost per Unit to retrofit.

DOMINION RESPONSE: Retrofitting means installing new equipment to allow the units to comply with applicable laws using their current primary fuel. As with repowering, it would not be practicable to retrofit because it would require time to permit and construct far beyond the time available to address the retirement at Yorktown Units 1 and 2 and to otherwise avoid NERC reliability deficiencies.

Assuming the retrofitting of the three Yorktown units were possible, the CAPX analysis for a retrofit is similar to that described in response to Question 3.f. for repowering except the environmental compliance equipment for a retrofit to handle each unit's primary fuels is more substantial and costlier to meet environmental regulations for years 2012-2022.[17] Thus, to comply with MATS and the NAAQS for Sulfur Dioxide, Units 1 and 2 would require SO2 scrubbers and fabric filters (baghouses). Selective Catalytic reduction would be required on

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[15] Dominion SCC Rebuttal Witness G. Kelly, Rebuttal Schedule 2, at 3.

[16] Clean Water Act Section 316(b) regulates cooling water intake structures. EPA, Cooling Water Intakes, at https://www.epa.gov/cooling-water-intakes (last visited July 10, 2016). In 2014, EPA promulgated Section 316(b) requirements for existing electric generating plants, such as Yorktown. EPA, Cooling Water Intakes - Final 2014 Rule for Existing Electric Generating Plants and Factories, at https://www.epa.gov/cooling-water-intakes/cooling-water-intakes-final-2014-rule-existing-electric-generating-plants-and (last visited July 10, 2016) (the "316(b) Rule"). Under the 316(b) Rule, a facility must take certain actions to reduce fish impingement and entrainment, depending on the amount of water a facility withdrawals for its operations. *Id.*

[17] The cost information is taken from the 2012 IRP or estimated where not included in IRP for its basis.

Units 1 and 2 to meet NOx emission requirements and protect the ozone NAAQS.[18] Similarly, section 316(b) of the Clean Water Act would likely require installation of variable speed drives on the cooling water intake pumps and screens or closed cycle cooling towers on Units 1 and 2.[19] Unit 3 would need dry-sorbent injection (DSI) and a baghouse, and would likely need variable speed drives and screens or closed cycle cooling in 2022.[20] Further equipment would likely be required to satisfy other emission and effluent limitations. Adding in the cost of replacement equipment and ongoing maintenance measures, and depending on whether variable speed drives or cooling towers would likely be required, the CAPX required for Unit 1 is estimated at $284 million to $408 million, for Unit 2 the CAPX is estimated at $265 million to $389 million, and for Unit 3 the CAPX is estimated at $310 million to $1.076 billion in 2022. Overall the CAPX cost for all three is estimated at $859 million to $1.873 billion.

Response to Questions Regarding the Supply/Availability of Natural Gas to Yorktown

Question 4 - NPCA & PERI have asserted that Dominion has previously run Yorktown Units 1 & 3 on natural gas. Dominion has indicated an insufficient supply of natural gas for year around operations at Yorktown.

a. How many months out the year would natural gas be available based on the current supply?

DOMINION RESPONSE: As explained above, the Yorktown units are not configured to run on natural gas alone. In order to run the units on natural gas alone, the repowering measures identified in the response to 3.e would be required. *See* response to 3.b. above concerning current gas supply to the site.

b. Would the available gas supply have been sufficient to operate Yorktown during the 2009 - 2015 timeframe as reported by NPCA/PERI?

DOMINION RESPONSE : No. As discussed above, even if natural gas were available, the units cannot run on natural gas alone. See also response to question 4.a.

c. If deficiencies in supply volume would have occurred please indicate which year(s) and by what amount.

DOMINION RESPONSE : Even assuming the Yorktown units could run on natural gas alone, the supply of natural gas to Yorktown is not firm transport, and is subject to availability. As

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[18] There are no SCR costs for Unit 3 because it is not a coal-fired unit.

[19] In order to retrofit Units 1, 2, and 3 to be fully available, CWA § 316(b) would require conducting biological and technology studies at Yorktown Power Station, since the station's annual average cooling water flow would be above 125 million gallons per day. Under this scenario compliance with the impingement standard (e.g., intake screen and fish return upgrades) would be required and it is probable that either variable speed drives and screens for the intake pumps or cooling towers will be required.

[20] The closed cycle cooling CAPX for Unit 3 is more expensive than the gas repower closed cycle cooling because there is no reduction (aka, derate) of unit megawatts.

discussed above, natural gas historically has been available from spring until fall at about 35,000 DTH/day. Natural gas generally is not available in the winter, and certainly not during peak demands. It also has been unavailable during some peak summer demands. In any event, as discussed, deficiencies in natural gas supply would only have made operating in co-firing circumstances more difficult or impossible, and also would have been the startup of Unit 1 or Unit 3 more difficult or impossible. Deficiencies in natural gas would not impact the Yorktown units' ability to operate on their primary fuels. See also response to question 4.a.

d. Would the supply have been enough to power Unit 1 and/or 3 for a full year?

DOMINION RESPONSE: No. As discussed, even if natural gas were available, the units cannot run on natural gas alone. See also responses to Questions 4.a. and 4.c.

e. Assuming Units 1 & 3 are powered by natural gas, would Dominion still need Unit #2 to remain compliant with NERC?

DOMINION RESPONSE: Yes. Based on present system conditions, all three generating units are required to remain in operation to maintain compliance with NERC Reliability Standards. As explained above, based on PJM 2016 Load Forecast and the 2016 updated power flow models performed at the Corps' request, the NHRLA is required to have a minimum of 656 MW of generation located in it, with at least 276 MW remaining in service after the outage of the largest generating unit. Assuming Yorktown Units 1 and 3 (the two largest units) were repowered for natural gas, they would be capable of producing 157 MW and 430 MW of capacity, respectively. This equates to a total generating capacity of 587 MW, which is 69 MW less than the required minimum generating capacity. Therefore, it would still be necessary to have and operate Unit 2, which would need to be retrofitted or repowered to meet the minimum amount of generation required to maintain compliance with NERC Reliability Standards.

f. Assuming a Unit has the capabilities in place to burn natural gas and the fact that some level of natural gas is presently available into Yorktown, why does Unit 1 and/or 2 have to be fully decommissioned from further service? Are there regulatory requirements that would drive decommissioning these units if they can burn fuel other than coal? Would the presence of these units, running on natural gas, help Dominion meet NERC requirements in the NHRLA?

DOMINION RESPONSE: As discussed above, while Units 1 and 3 have the capability to burn natural gas for purposes of startup and supplemental co-firing, neither has the ability to generate electricity when running on natural gas alone. Unit 2 currently does not have the capability to use natural gas in any capacity. Because Units 1 and 2 cannot produce electricity running solely on gas, and because environmental regulations (namely MATS) will preclude their ability to run on coal, the units have no generation value unless retrofitted or repowered. Because retrofitting and repowering these units is cost- and time- prohibitive, particularly given that there are other alternatives (namely the Project) to supply the power needed in the NHRLA, they must be retired.

Even if Units 1 and 2 could run on natural gas (and produce electricity), as noted elsewhere, there are other regulatory requirements that otherwise likely would drive their retirement.

For example, to continue operating on natural gas the units would have to comply with requirements of the Clean Water Act Section 316(b), the costs associated with those requirements are described above. In addition, the proposed Clean Power Plan would likely limit, if not prohibit, the ability to dispatch older, less inefficient gas plants.

Taking the analysis one step further, even if all three units at Yorktown had the appropriate capacity sizes and could operate on natural gas, they only would meet the NERC Reliability Standards for the NHRLA until Summer (commencing June 1) 2021. After that time, they are no longer sufficient to meet the NERC Reliability Standards. *See* Response to Question 1.a. Thereafter, to be able to meet those standards, Unit 3 would have to operate above its 8% capacity limit, thereby triggering its compliance with Clean Water Act Section 316(b), the costs of compliance with which (noted above) are substantial and likely prohibitive, particularly in light of other alternatives (namely, the Project).

[NPCA Issues Addressed: Dominion has not documented physical properties of natural gas delivery system for Yorktown or contracts that would be needed to ensure firm gas supplied; gas is available to supplement Unit 3's oil capacity; Virginia Natural Gas's recently announced open season (which includes the Yorktown area); NPCA Letter at 2.]

Responses to Questions Regarding Underwater Transmission

Question 8 - NPCA & PERI have reported the industry standard for submarine 230kV transmission lines installed via horizontal directional drill is $35 million dollars per mile.

a. We request Dominion validate the accuracy of its reported project cost per mile for submarine installation. To the extent Dominion's cost per mile estimates exceed those provided by NPCA/PERI, please explain why the cost for this project would be higher than reported costs for other HDD projects.

DOMINION RESPONSE: NPCA/PERI start with an incorrect premise because they initially calculated Dominion's underground cost to be equal to $130 million per mile at the June 15, 2016, meeting. NPCA/PERI subsequently updated this cost to be equal to $80.5 million per mile in their June 30, 2016 letter to the USACE. As explained below, Dominion's actual per mile estimate for the underground lines is approximately $ 25.80 million per mile. While actual underground transmission costs are going to vary depending on the exact nature of the project being constructed, with one of the main drivers of project cost being number of cables per phase needed to reach the ampacity required, NPCA/PERI reference an industry standard cost via horizontal direction drilling ("HDD") as a benchmark number referenced by a consultant who was helping PJM evaluate several different underground options related to a project. Dominion's Alternative B consists of two approximately 7.4 mile long 230 kV transmission lines, each with a rating of 1000 MVA. Of this distance, each transmission line was estimated to consist of an underground portion of approximately 6.3 miles, for a total of approximately 12.6 miles of underground construction. The underground route is longer than the approximately 4.2 miles across the river due to land availability for the placement of the transition stations and space for a drilling rig for HDD construction. Transition stations are needed on each end of the underground portion of the line to transition from overhead to underground construction. In total, approximately 3 to 5 acres of land would be required at each end of the underground portion of the line in order to accommodate both the transition station and the temporary work space for the drilling rig. An initial review identified constructible sites that could potentially be used for transition stations and drilling work, while minimizing the length of underground construction. The underground route length reflects the use of these identified sites. Trey Thomasson's Rebuttal Testimony before the SCC provides the basis for the underground cost estimates, and construction practices used to construct underground transmission lines. On page 11 of his Rebuttal Testimony, he explains that the estimated total cost for the two transmission lines from Surry to Skiffes Creek Substation is $343.8 million, of which $1.7 million is for a transition station for overhead to underground and $18.2 million is for the overhead portion of these two 230 kV transmission lines. This cost excludes the construction of Skiffes Creek Substation, required work at Surry Substation, and the Skiffes Creek to Whealton 230 kV Line. Adding these components to the $343.8 million brings the total cost of the Alternatives A and B to $488.6 million as indicated in Attachment 5. This leaves the underground portion of this estimate to be equal to $323.9 million or approximately $25.80 million per mile of underground construction. This estimate per mile is less than the industry average referenced by NPCA/PERI. Dominion does not understand how NPCA/PERI calculated $130 million per mile, or the $80.5 million per mile figure, given that the information Dominion notes above is available publically, and the actual information also was provided to NPCA/PERI in Dominion's February 1, 2016, letter from J. Kevin Curtis to Pamela Goddard.

b. We request Dominion verify that its consideration of a submarine crossing evaluated possible use of HDD construction methods, versus trenching along the river's entire span.

DOMINION RESPONSE: The river portion of the underground estimates was based on HDD construction methods, and the land portion was based on trenching. Trenching was estimated for the land portion of the project due to its lower cost of installation.

c. If the cost per mile previously used was found in error and/or outdated, please provide updated project costs for those alternatives which involved use of a submarine crossing.

DOMINION RESPONSE: *See* response to Question 8.a above.

[NPCA Issues Addressed: underwater lines have become the option of choice (as illustrated by a number of projects NPCA referenced) and improvements in HDD reduces environmental impacts, costs, and risk; NPCA Letter at 2.]

Question 9 - Dominion has previously reported an alternative involving an underwater double circuit 230kV crossing with additional facilities to resolve identified 2015 & 2021 NERC violations; however the cost was reported at $515 million dollars. Based on the revised "Summer 2016 Load Forecast Alternative B Double-Circuit 230kV UG" this alternative now results in only one violation. Therefore, it appears that the cost associated with the "additional facilities" required to meet NERC standards through Alternative B may have changed.

a. Please recalculate and provide us the updated cost of this alternative, as well as make any adjustments to the cost associated with submarine installation.

DOMINION RESPONSE: See chart at Attachment 5.

b. Please verify and provide any cost updates for any other alternatives affected by the results of the Revised Forecasts.

DOMINION RESPONSE: See chart at Attachment 5.

Question 12 - Dominion's 500kV system uses lines of 5000 MWA capacity, which Dominion has explained limits the feasibility of a submarine crossing. Dominion has shown alternatives that considered use of 500kV and 230kV circuits, however what consideration was given to an alternative that uses 345kV at a capacity proven to be used in submarine crossings?

DOMINION RESPONSE: As set forth in Dominion's November 13, 2015, letter to the Corps, the use of underwater transmission lines was studied and rejected in the SCC proceeding. It also was studied and addressed in the Corps' Preliminary Alternatives Analysis White Paper, as well as the Stantec Report. An underwater 345 kV line would have several practical hurdles that could not reasonably be overcome. Such lines would not be practicable because they would require time to permit and construct far beyond the time available to address the retirement at Yorktown Units 1 and 2 and to otherwise avoid NERC reliability deficiencies. This timeframe would be elongated because there are no 345 kV lines in the Dominion Virginia Power system. This poses problems in terms of how to integrate such lines into the system, as well as maintenance and operation of such lines. The lines would also pose the same problems of any underwater line in terms of identifying and repairing any defects. Installation of such a line would cause the same environmental impacts as those for construction a 230 kV underground crossing of the James River as described in section 3.3.1 of the Dominion's Stantec-produced revised Alternatives Analysis Report.

And, even assuming such a voltage was added here to Dominion's system, it would result in an inefficient solution to meet the capacity and energy requirements of the NHRLA. First, a new substation would have to be developed and located south of the existing Surry 230 kV and 500 kV Substation, due to space considerations. Second, at this new site, transformers would need to be installed to convert the delivery voltage (most likely 500 kV) to 345 kV, and then at the proposed Skiffes Creek Substation additional transformers would need to be installed to interconnect the 345 kV line with the 230 kV system located on the Peninsula (*i.e.*, Skiffes Creek to Whealton line). This double transformation of system voltage is an inefficient means of transmitting electricity. It also is expensive. The installation of a new 345 kV switchyard and two 500-345 kV transformer banks plus associated facilities and equipment, a 345 kV underground alternative is estimated to cost $508.6 million.

NPCA/PERI made reference to the $1.2 billion 345 kV project that PSE&G currently is undertaking on their system to resolve fault current issues. The proposed 345 kV underground lines associated with that project have a transfer capability that is approximately 65% <u>less</u> than the rejected alternative to construct a 230 kV underground line. Therefore, Dominion would need to construct more underground transmission lines if it were to pursue a 345 kV option than if it pursued the 230 kV underground options, the latter of which already has been demonstrated to not be practicable. In summary the Company's proposed Project is the most practicable and least environmentally impacting option available to meet the NERC Reliability Standards in the NHRLA.

Response to Question Regarding Project Cost Information

Question 7 - We have found inconsistencies in the reported cost information Dominion has provided specific to the proposed project. Please clarify by providing project costs on a per segment basis (i.e., (1)Surry - Skiffes, (2) Switching Station, and (3) Skiffes – Whealton).

DOMINION RESPONSE:

Surry to Skiffes 500kV line	-	$66.5M
Skiffes Switching Station and Line Rearrangement	-	$56.5M
Skiffes to Whealton 230kV line	-	$55.7M
Mitigation	-	$85.0M
Total		$263.7M

Excluding the estimated $85 million cost for mitigation the updated project cost for the proposed project is $178.7 million. Project cost increases from the originally proposed project include additional cost for the fender system, SCC ordered structure modification on BASF property, project delay cost and general cost escalation from 2012 anticipated construction cost. Other alternatives have not undergone more detailed engineering so those costs have not been changed. It is anticipated that these costs have also escalated but no escalation has been applied.

Response to the Question Regarding Switching Station Citing

Question 11 - What consideration has Dominion given to constructing the proposed Switching Station on the Surry Co side of the river crossing, rather than in James City County as proposed?

DOMINION RESPONSE: Dominion considered this alternative in its feasibility phase of the project. This alternative would require a total of eight transmission lines (five 230 kV and three 115 kV) to cross the James River in the same vicinity as the proposed Project. This is because the NHRLA requires a new injection point to allow existing capacity and energy to be able to be reliably transported from generation resources into the NHRLA in a manner consistent with NERC Reliability Standards. Hence, it would be necessary to route the existing transmission lines in the NHRLA located at the proposed Skiffes Creek Site across the river to a new switching station site just south of Surry Power Station. Based on the routing impacts associated with trying to route eight transmission lines across the James River, as compared to the proposed Project, Dominion did not consider this a viable option in light of the significant increase in costs and environmental and visual impacts, among other impacts. Even if this were a practicable alternative, it would have a greater impact on aquatic resources and the environmental generally than the Project, and therefore would not be acceptable under the applicable CWA § 404(b)(1) guidelines, which require the Corps to select the least environmentally damaging practicable alternative.

Sincerely,

Scott C. Miller
Vice President - Transmission

Attachment 1

Chart Explaining Power-Flow Output

Legend For Reading Power Flow Output

Note: Be sure to print power flows 11" x 17" landscape

- Seventeen (17) key columns contain specific information for each power flow output
- Example (pages 2-3) is an N-1-1 test, other tests such as N-1, N-2(tower line), breaker failure may not have all the same number of columns, however, this legend can be used in a similar way to assist interpreting those printouts

Column Label		Explanation
1	First Level Scenario Index	This is a programming index to help the program as it computes the information. For example the first line index is 47. It is the 47th contingency taken in the test.
2	First Level Scenario	This is the first N-1 facility outage for this N-1-1 test. For example using the first line, the Dahlgren to Arnolds 230 kV line is taken out of service (outaged).
3	Monitored Facility	This is the facility being monitored for the N-1-1 test. For the first line on this sheet, the monitored facility is Harmony to White S 115 kV line.
4	Areas	Reference the Transmission Owner area which in this case is Dominion, area 345
5	Zones	Zones within Dominion area. For the first line it is located in zone 354.
6	Rate Base (MVA)	This is the base normal or continuous rating of the Monitored Facility (Column 3) in MVA. For example the Harmony to White S 115 kV line has a base thermal rating of 147 MVA.
7	Rate Cont (MVA)	This is the short term (8 hour for Dominion) emergency rating of the Monitored Facility (Column 3) in MVA. For example the Harmony to White S 115 kV line has a short term emergency thermal rating of 169 MVA.
8	Contingency Name	This is the second N-1 contingency to complete the N-1-1 test. For example the first N-1 in column 2 is the outage of Dahlgren to Arnolds 230 kV line. Then a second N-1 is taken on the Dunnsville to Lanexa 230 kV line completing the N-1-1 test.
9	Base Flow (MVA)	This is the base power flow on the Monitored facility before any contingencies are taken. For example the Harmony to White S 115 kV line has a base flow of 48.2 MVA.
10	Cont Flow (MVA)	This is the base power flow after the first N-1 test has been applied and before the second N-1 test has been applied.
11	Original Case Cont AC %Loading	This is the AC power flow on the monitored line before any contingency expressed in percentage of Base Rating.
12	Final DC % Loading	This is the Final DC loading in percentage on the monitored facility after the N-1-1 is taken. This is a DC test which does not take into account reactive loading.
13	Final AC % Loading	This is the Final AC loading in percentage on the monitored facility after the N-1-1 is taken. This is a AC test which does take into account reactive loading.
14	Base MW Flow	Base pre-contingency MW flow on the monitored facility.
15	Cont MW Flow	Contingency MW flow on the monitored facility after the N-1-1 contingencies are taken.
16	Base MVAR Flow	Base pre-contingency MVAR flow on the monitored facility.
17	Cont MVAR Flow	Contingency MVAR flow on the monitored facility after the N-1-1 contingencies are taken.

Example:

N-1-1 test of the North Hampton Roads area. N-1-1 is a mandatory NERC TPL test to ensure the system can withstand two element outages.

DOMINION N-1-1 AC Monitored Facility Loadings[TARA Ver 8.20 64-bit - Thu Jan 14 12:31:32 2016]

Loadflow Case: Z:\Peter Nedwick\USACE 2016 Study\2016 As-Is NonDiversified-No Skiffes.raw
Study Data File: Z:\Peter Nedwick\USACE 2016 Study\dvp.sub
Contingency File: Z:\Peter Nedwick\USACE 2016 Study\Vapsys.con (total 1378 contingencies)/ First-Level Contingency File: Z:\Peter Nedwick\USACE 2016 Study\Vapsys.con (total 1378 contingencies)
Monitor File: Z:\Peter Nedwick\USACE 2016 Study\vapsys.mon (99.5% loading cutoff)
Exclude File: not provided
Solution Options (Pre/Post Contingency): Shunts[All Enabled/All Enabled] PAR[Adjusted/Fixed] XFMR Tap[Adjusted/Adjusted] Area Interchange [Disabled/Disabled]

1 First Level Scenario Index	2 First Level Scenario							3 Monitored Facility							4 Areas	5 Zones	6 Rate Base (MVA)
47	313810	6DAHLGREN	230	314131	6ARNOLDS	230	1	314174	3HARMONY	115	314191	3WHITE S	115	1	34	354	147
47	313810	6DAHLGREN	230	314131	6ARNOLDS	230	1	314174	3HARMONY	115	314191	3WHITE S	115	1	34	354	147
4[illegible]	313810	6DAHLGREN	230	314139	6OAKGROV	230	1	314174	3HARMONY	115	314191	3WHITE S	115	1	34	354	147
5[illegible]	313812	6ROCKLANDING	230	314416	6WARWICK	230	1	314407	6SHELBNK	230	314406	3SHELBNK	115	1	34	356	244.9
5[illegible]	313812	6ROCKLANDING	230	314416	6WARWICK	230	1	314407	6SHELBNK	230	314406	3SHELBNK	115	1	34	356	244.9
[illegible]	313812	6ROCKLANDING	230	314416	6WARWICK	230	1	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	34	[illegible]	251.1
51	313812	6ROCKLANDING	230	314416	6WARWICK	230	1	314407	6SHELBNK	230	314406	3SHELBNK	115	1	345	356	244.9
51	313812	6ROCKLANDING	230	314416	6WARWICK	230	1	314402	6PENINSL	230	314401	3PENINSL	115	1	345	356	251.1
52	313812	6ROCKLANDING	230	314423	6YORKTWN	230	1	314407	6SHELBNK	230	314406	3SHELBNK	115	1	345	356	244.9
52	313812	6ROCKLANDING	230	314423	6YORKTWN	230	1	314407	6SHELBNK	230	314406	3SHELBNK	115	1	345	356	244.9
52	313812	6ROCKLANDING	230	314423	6YORKTWN	230	1	314407	6SHELBNK	230	314406	3SHELBNK	115	1	345	356	244.9
52	313812	6ROCKLANDING	230	314423	6YORKTWN	230	1	314402	6PENINSL	230	314401	3PENINSL	115	1	345	356	251.1
52	313812	6ROCKLANDING	230	314423	6YORKTWN	230	1	314402	6PENINSL	230	314401	3PENINSL	115	1	345	356	251.1
52	313812	6ROCKLANDING	230	314423	6YORKTWN	230	1	314412	3U CARBD	115	314417	3WHEALTN	115	1	345	356	118
52	313812	6ROCKLANDING	230	314423	6YORKTWN	230	1	314401	3PENINSL	115	314412	3U CARBD	115	1	345	356	118
52	313812	6ROCKLANDING	230	314423	6YORKTWN	230	1	314412	3U CARBD	115	314417	3WHEALTN	115	1	345	356	118
52	313812	6ROCKLANDING	230	314423	6YORKTWN	230	1	314401	3PENINSL	115	314412	3U CARBD	115	1	345	356	118

Example:

N-1-1 test of the North Hampton Roads area. N-1-1 is a mandatory NERC TPL test to ensure the system can withstand two element outages.

DOMINION N-1-1 AC Monitored Facility Loadings[TARA Ver 8.20 64-bit - Thu Jan 14 12:31:32 2016]

Loadflow Case: Z:\Peter Nedwick\USACE 2016 Study\2016 As-Is NonDiversified-No Skiffes.raw
Study Data File: Z:\Peter Nedwick\USACE 2016 Study\dvp.sub
Contingency File: Z:\Peter Nedwick\USACE 2016 Study\Vapsys.con (total 1378 contingencies)/ First-Level Contingency File: Z:\Peter Nedwick\USACE 2016 Study\Vapsys.con (total 1378 contingencies)
Monitor File: Z:\Peter Nedwick\USACE 2016 Study\vapsys.mon (99.5% loading cutoff)
Exclude File: not provided
Solution Options (Pre/Post Contingency): Shunts[All Enabled/All Enabled] PAR[Adjusted/Fixed] XFMR Tap[Adjusted/Adjusted] Area Interchange [Disabled/Disabled]

7 Rate Cont (MVA)	8 Cont Name							9 Base Flow (MVA)	10 Cont Flow (MVA)	11 Orig Case Cont AC %Loading	12 Final DC %Loading	13 Final AC %Loading	14 Base MW Flow	15 Cont MW Flow	16 Base MVAR Flow	17 Cont MVAR Flow
169	314172	6DUNNSVL	230	314388	6LANEXA	230	1	48.2	262.[illegible]	24.3[illegible]	137.[illegible]3	155.[illegible]4	4[illegible].8	20[illegible].3	-10.[illegible]	149.5
169	314172	6DUNNSVL	230	314182	6NORNECK	230	1	48.2	244.[illegible]	19.9[illegible]	121.[illegible]5	144.[illegible]1	4[illegible].8	20[illegible].3	-10.[illegible]	129.7
169	314172	6DUNNSVL	230	314388	6LANEXA	230	1	36	180.[illegible]	24.3[illegible]	96.[illegible]2	107.[illegible]2	[illegible]4.6	17[illegible].4	-9.[illegible]	54.7
268.7	314538	6SURRY	230	314540	6POOLSVL	230	1	172.9	33[illegible]	78.3[illegible]	107.[illegible]5	125.[illegible]1	14[illegible].2	[illegible]94	89.[illegible]	166.8
268.7	314421	6WINCHST	230	314540	6POOLSVL	230	1	172.9	333.[illegible]	78.7[illegible]	104.[illegible]2	124.[illegible]2	14[illegible].2	28[illegible].9	89.[illegible]	168.4
278.4	314538	6SURRY	230	314540	6POOLSVL	230	1	140.1	29[illegible]	60.[illegible]	88.[illegible]4	10[illegible].[illegible]6	1[illegible].5	25[illegible].1	5[illegible]	149.6
[illegible]	314418	6WHEALTN	230	314421	6WINCHST	230	1	[illegible]	283.[illegible]	[illegible]	92.[illegible]	[illegible]	14[illegible]	[illegible].9	89.[illegible]	[illegible]
278.4	314421	6WINCHST	230	314540	6POOLSVL	230	1	140.1	290.6	60.91	85.68	104.37	130.5	248.1	51	151.2
268.7	314538	6SURRY	230	314540	6POOLSVL	230	1	177.1	350.2	78.31	110.83	130.32	152.9	302.4	89.4	176.5
268.7	314421	6WINCHST	230	314540	6POOLSVL	230	1	177.1	345.5	78.76	107.63	128.58	152.9	296.3	89.4	177.7
268.7	314418	6WHEALTN	230	314421	6WINCHST	230	1	177.1	296.1	71.27	95.26	110.19	152.9	262.1	89.4	137.7
278.4	314538	6SURRY	230	314540	6POOLSVL	230	1	144.5	304.6	60.3	90.99	109.41	135.1	261	51.2	157
278.4	314421	6WINCHST	230	314540	6POOLSVL	230	1	144.5	301.1	60.91	88.47	108.14	135.1	256.1	51.2	158.3
136	314538	6SURRY	230	314540	6POOLSVL	230	1	22.6	140.5	9.11	95.86	103.29	-3.3	129.9	21.9	41.6
136	314538	6SURRY	230	314540	6POOLSVL	230	1	22	140.4	9.04	95.84	103.22	-3.4	130	21.8	41.9
136	314421	6WINCHST	230	314540	6POOLSVL	230	1	22.6	136.3	9.11	90.01	100.24	-3.3	124.7	21.9	44.4
136	314421	6WINCHST	230	314540	6POOLSVL	230	1	22	136.2	8.92	89.99	100.16	-3.4	124.7	21.8	44.6

Attachment 2

Summary of NERC Reliability Standards

Category	Contingencies Initiating Event(s) and Contingency Element(s)	Standard TPL – 001 – 4 Transmission System Planning Performance Requirements
A No Contingencies	All Facilities in Service	**PO**
B Event resulting in the loss of a single element.	Single Line Ground (SLG) or 3-Phase (3Ø) Fault, with Normal Clearing: 1. Generator 2. Transmission Circuit 3. Transformer Loss of an Element without a Fault.	**P1 & P3** 1. Generator 2. Transmission Circuit 3. Transformer 4. Shunt Device
	Single Pole Block, Normal Clearing[e]: 4. Single Pole (dc) Line	**P3** 5. Single Pole of a DC line
C Event(s) resulting in the loss of two or more (multiple) elements.	SLG Fault, with Normal Clearing[e]: 1. Bus Section 2. Breaker (failure or internal Fault)	**P2 & P4**
	SLG or 3Ø Fault, with Normal Clearing[e], Manual System Adjustments, followed by another SLG or 3Ø Fault, with Normal Clearing[e]: 3. Category B (B1, B2, B3, or B4) contingency, manual system adjustments, followed by another Category B (B1, B2, B3, or B4) contingency	**P6**
	Bipolar Block, with Normal Clearing[e]: 4. Bipolar (dc) Line Fault (non 3Ø), with Normal Clearing[e]:	**P1** 5. Single Pole of a DC line
	5. Any two circuits of a multiple circuit towerline[f]	**P7**
	SLG Fault, with Delayed Clearing[e] (stuck breaker or protection system failure): 6. Generator 7. Transformer 8. Transmission Circuit 9. Bus Section	**P5**
D[d] Extreme event resulting in two or more (multiple) elements removed or Cascading out of service	3Ø Fault, with Delayed Clearing[e] (stuck breaker or protection system failure): 1. Generator 3. Transformer 2. Transmission Circuit 4. Bus Section 3Ø Fault, with Normal Clearing[e]: 5. Breaker (failure or internal Fault) 6. Loss of towerline with three or more circuits 7. All transmission lines on a common right-of way 8. Loss of a substation (one voltage level plus transformers) 9. Loss of a switching station (one voltage level plus transformers) 10. Loss of all generating units at a station 11. Loss of a large Load or major Load center 12. Failure of a fully redundant Special Protection System (or remedial action scheme) to operate when required 13. Operation, partial operation, or misoperation of a fully redundant Special Protection System (or Remedial Action Scheme) in response to an event or abnormal system condition for which it was not intended to operate 14. Impact of severe power swings or oscillations from Disturbances in another Regional Reliability Organization.	**See Table 1**

Table 1 – Steady State & Stability Performance Planning Events

Steady State & Stability:

a. The System shall remain stable. Cascading and uncontrolled islanding shall not occur.

b. Consequential Load Loss as well as generation loss is acceptable as a consequence of any event excluding P0.

c. Simulate the removal of all elements that Protection Systems and other controls are expected to automatically disconnect for each event.

d. Simulate Normal Clearing unless otherwise specified.

e. Planned System adjustments such as Transmission configuration changes and re-dispatch of generation are allowed if such adjustments are executable within the time duration applicable to the Facility Ratings.

Steady State Only:

f. Applicable Facility Ratings shall not be exceeded.

g. System steady state voltages and post-Contingency voltage deviations shall be within acceptable limits as established by the Planning Coordinator and the Transmission Planner.

h. Planning event P0 is applicable to steady state only.

i. The response of voltage sensitive Load that is disconnected from the System by end-user equipment associated with an event shall not be used to meet steady state performance requirements.

Stability Only:

j. Transient voltage response shall be within acceptable limits established by the Planning Coordinator and the Transmission Planner.

Category	Initial Condition	Event[1]	Fault Type[2]	BES Level[3]	Interruption of Firm Transmission Service Allowed[4]	Non-Consequential Load Loss Allowed
P0 No Contingency	Normal System	None	N/A	EHV, HV	No	No
P1 Single Contingency	Normal System	Loss of one of the following: 1. Generator 2. Transmission Circuit 3. Transformer[5] 4. Shunt Device[6]	3Ø	EHV, HV	No[9]	No[12]
		5. Single Pole of a DC line	SLG			
P2 Single Contingency	Normal System	1. Opening of a line section w/o a fault[7]	N/A	EHV, HV	No[9]	No[12]
		2. Bus Section Fault	SLG	EHV	No[9]	No
				HV	Yes	Yes
		3. Internal Breaker Fault[8] (non-Bus-tie Breaker)	SLG	EHV	No[9]	No
				HV	Yes	Yes
		4. Internal Breaker Fault (Bus-tie Breaker)[8]	SLG	EHV, HV	Yes	Yes

Category	Initial Condition	Event [1]	Fault Type [2]	BES Level [3]	Interruption of Firm Transmission Service Allowed [4]	Non-Consequential Load Loss Allowed
P3 Multiple Contingency	Loss of generator unit followed by System adjustments[9]	Loss of one of the following: 1. Generator 2. Transmission Circuit 3. Transformer [5] 4. Shunt Device [6]	3Ø	EHV, HV	No[9]	No[12]
		5. Single pole of a DC line	SLG			
P4 Multiple Contingency *(Fault plus stuck breaker[10])*	Normal System	Loss of multiple elements caused by a stuck breaker [10](non-Bus-tie Breaker) attempting to clear a Fault on one of the following: 1. Generator 2. Transmission Circuit 3. Transformer [5] 4. Shunt Device [6] 5. Bus Section	SLG	EHV	No[9]	No
				HV	Yes	Yes
		6. Loss of multiple elements caused by a stuck breaker[10] (Bus-tie Breaker) attempting to clear a Fault on the associated bus	SLG	EHV, HV	Yes	Yes
P5 Multiple Contingency *(Fault plus relay failure to operate)*	Normal System	Delayed Fault Clearing due to the failure of a non-redundant relay[13] protecting the Faulted element to operate as designed, for one of the following: 1. Generator 2. Transmission Circuit 3. Transformer [5] 4. Shunt Device [6] 5. Bus Section	SLG	EHV	No[9]	No
				HV	Yes	Yes
P6 Multiple Contingency *(Two overlapping singles)*	Loss of one of the following followed by System adjustments.[9] 1. Transmission Circuit 2. Transformer [5] 3. Shunt Device[6] 4. Single pole of a DC line	Loss of one of the following: 1. Transmission Circuit 2. Transformer [5] 3. Shunt Device [6]	3Ø	EHV, HV	Yes	Yes
		4. Single pole of a DC line	SLG	EHV, HV	Yes	Yes

Category	Initial Condition	Event [1]	Fault Type [2]	BES Level [3]	Interruption of Firm Transmission Service Allowed [4]	Non-Consequential Load Loss Allowed
P7 Multiple Contingency *(Common Structure)*	Normal System	The loss of: 1. Any two adjacent (vertically or horizontally) circuits on common structure [11] 2. Loss of a bipolar DC line	SLG	EHV, HV	Yes	Yes

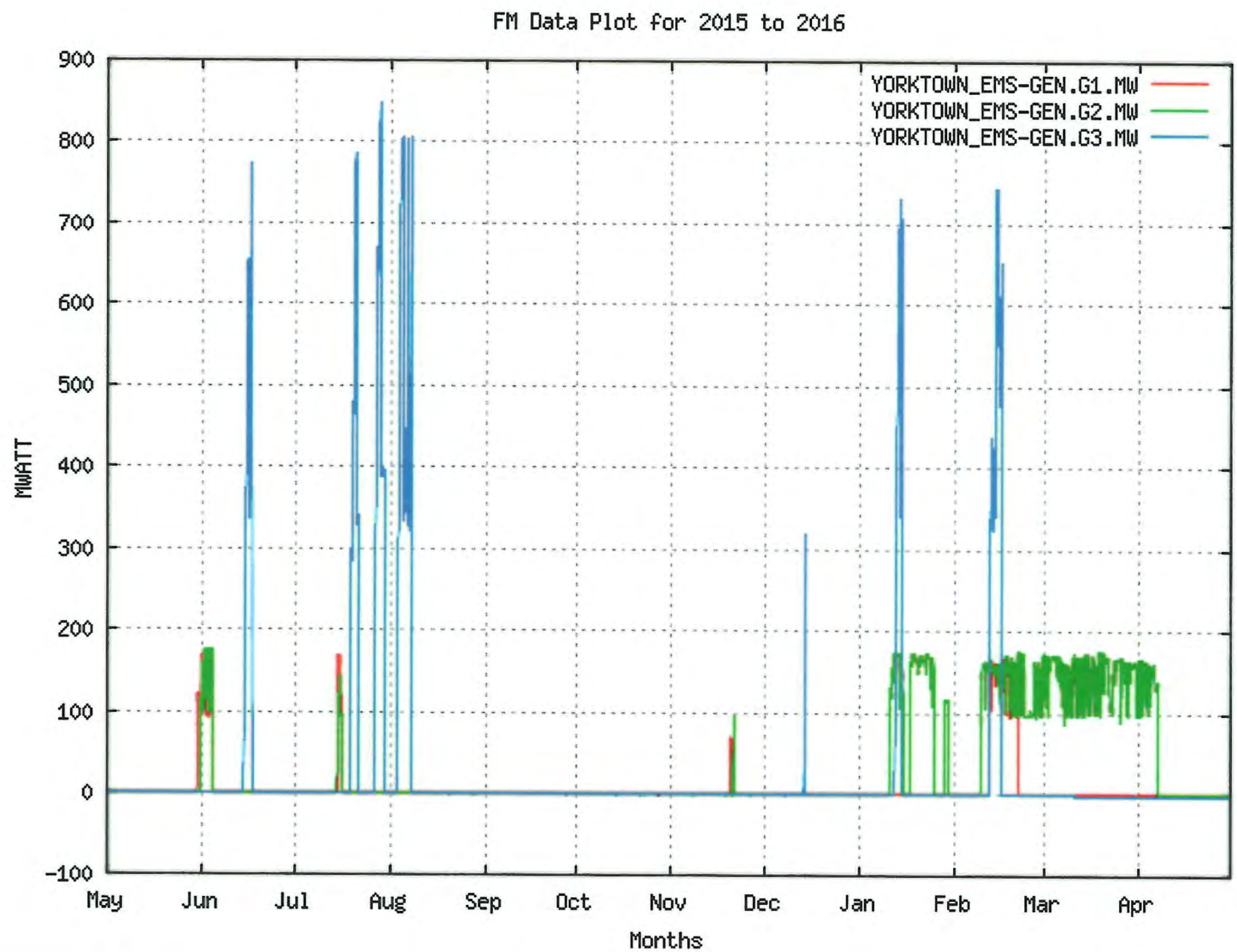
<table>
<tr><th colspan="2">Table 1 – Steady State & Stability Performance Extreme Events</th></tr>
<tr><td colspan="2">Steady State & Stability
For all extreme events evaluated:
a. Simulate the removal of all elements that Protection Systems and automatic controls are expected to disconnect for each Contingency.
b. Simulate Normal Clearing unless otherwise specified.</td></tr>
<tr><td>Steady State
1. Loss of a single generator, Transmission Circuit, single pole of a DC Line, shunt device, or transformer forced out of service followed by another single generator, Transmission Circuit, single pole of a different DC Line, shunt device, or transformer forced out of service prior to System adjustments.
2. Local area events affecting the Transmission System such as:
a. Loss of a tower line with three or more circuits.[11]
b. Loss of all Transmission lines on a common Right-of-Way[11].
c. Loss of a switching station or substation (loss of one voltage level plus transformers).
d. Loss of all generating units at a generating station.
e. Loss of a large Load or major Load center.
3. Wide area events affecting the Transmission System based on System topology such as:
a. Loss of two generating stations resulting from conditions such as:
i. Loss of a large gas pipeline into a region or multiple regions that have significant gas-fired generation.
ii. Loss of the use of a large body of water as the cooling source for generation.
iii. Wildfires.
iv. Severe weather, e.g., hurricanes, tornadoes, etc.
v. A successful cyber attack.
vi. Shutdown of a nuclear power plant(s) and related facilities for a day or more for common causes such as problems with similarly designed plants.
b. Other events based upon operating experience that may result in wide area disturbances.</td>
<td>Stability
1. With an initial condition of a single generator, Transmission circuit, single pole of a DC line, shunt device, or transformer forced out of service, apply a 3Ø fault on another single generator, Transmission circuit, single pole of a different DC line, shunt device, or transformer prior to System adjustments.
2. Local or wide area events affecting the Transmission System such as:
a. 3Ø fault on generator with stuck breaker[10] or a relay failure[13] resulting in Delayed Fault Clearing.
b. 3Ø fault on Transmission circuit with stuck breaker[10] or a relay failure[13] resulting in Delayed Fault Clearing.
c. 3Ø fault on transformer with stuck breaker[10] or a relay failure[13] resulting in Delayed Fault Clearing.
d. 3Ø fault on bus section with stuck breaker[10] or a relay failure[13] resulting in Delayed Fault Clearing.
e. 3Ø internal breaker fault.
f. Other events based upon operating experience, such as consideration of initiating events that experience suggests may result in wide area disturbances</td></tr>
</table>

Table 1 – Steady State & Stability Performance Footnotes (Planning Events and Extreme Events)
1. If the event analyzed involves BES elements at multiple System voltage levels, the lowest System voltage level of the element(s) removed for the analyzed event determines the stated performance criteria regarding allowances for interruptions of Firm Transmission Service and Non-Consequential Load Loss.
2. Unless specified otherwise, simulate Normal Clearing of faults. Single line to ground (SLG) or three-phase (3Ø) are the fault types that must be evaluated in Stability simulations for the event described. A 3Ø or a double line to ground fault study indicating the criteria are being met is sufficient evidence that a SLG condition would also meet the criteria.
3. Bulk Electric System (BES) level references include extra-high voltage (EHV) Facilities defined as greater than 300kV and high voltage (HV) Facilities defined as the 300kV and lower voltage Systems. The designation of EHV and HV is used to distinguish between stated performance criteria allowances for interruption of Firm Transmission Service and Non-Consequential Load Loss.
4. Curtailment of Conditional Firm Transmission Service is allowed when the conditions and/or events being studied formed the basis for the Conditional Firm Transmission Service.
5. For non-generator step up transformer outage events, the reference voltage, as used in footnote 1, applies to the low-side winding (excluding tertiary windings). For generator and Generator Step Up transformer outage events, the reference voltage applies to the BES connected voltage (high-side of the Generator Step Up transformer). Requirements which are applicable to transformers also apply to variable frequency transformers and phase shifting transformers.
6. Requirements which are applicable to shunt devices also apply to FACTS devices that are connected to ground.
7. Opening one end of a line section without a fault on a normally networked Transmission circuit such that the line is possibly serving Load radial from a single source point.
8. An internal breaker fault means a breaker failing internally, thus creating a System fault which must be cleared by protection on both sides of the breaker.
9. An objective of the planning process should be to minimize the likelihood and magnitude of interruption of Firm Transmission Service following Contingency events. Curtailment of Firm Transmission Service is allowed both as a System adjustment (as identified in the column entitled 'Initial Condition') and a corrective action when achieved through the appropriate re-dispatch of resources obligated to re-dispatch, where it can be demonstrated that Facilities, internal and external to the Transmission Planner's planning region, remain within applicable Facility Ratings and the re-dispatch does not result in any Non-Consequential Load Loss. Where limited options for re-dispatch exist, sensitivities associated with the availability of those resources should be considered.
10. A stuck breaker means that for a gang-operated breaker, all three phases of the breaker have remained closed. For an independent pole operated (IPO) or an independent pole tripping (IPT) breaker, only one pole is assumed to remain closed. A stuck breaker results in Delayed Fault Clearing.
11. Excludes circuits that share a common structure (Planning event P7, Extreme event steady state 2a) or common Right-of-Way (Extreme event, steady state 2b) for 1 mile or less.
12. An objective of the planning process is to minimize the likelihood and magnitude of Non-Consequential Load Loss following planning events. In limited circumstances, Non-Consequential Load Loss may be needed throughout the planning horizon to ensure that BES performance requirements are met. However, when Non-Consequential Load Loss is utilized under footnote 12 within the Near-Term Transmission Planning Horizon to address BES performance requirements, such interruption is limited to circumstances where the Non-Consequential Load Loss meets the conditions shown in Attachment 1. In no case can the planned Non-Consequential Load Loss under footnote 12 exceed 75 MW for US registered entities. The amount of planned Non-Consequential Load Loss for a non-US Registered Entity should be implemented in a manner that is consistent with, or under the direction of, the applicable governmental authority or its agency in the non-US jurisdiction.
13. Applies to the following relay functions or types: pilot (#85), distance (#21), differential (#87), current (#50, 51, and 67), voltage (#27 & 59), directional (#32, &

Table 1 – Steady State & Stability Performance Footnotes (Planning Events and Extreme Events)
67), and tripping (#86, & 94).

Attachment 3

Chart Showing Operations at Yorktown from May 1, 2015, to April 30, 2016


FM Data Plot for 2015 to 2016
YORKTOWN_EMS-GEN.G1.MW
YORKTOWN_EMS-GEN.G2.MW
YORKTOWN_EMS-GEN.G3.MW
900
800
700
600
500
400
300
200
100
0
-100
MWATT
May
Jun
Jul
Aug
Sep
Oct
Nov
Dec
Jan
Feb
Mar
Apr
Months

Attachment 4

2016 Yorktown Stand Alone Generation Options

2016
Stand Alone Generation Option

	NERC Contingency Test				
	Category B	Category B CSC	Category C Tower Line	Category C N-1-1	Category D
Summer 2016					
Start Gen	788	788	788	788	788
- FCITC	512	275	185	292	247
Required Gen	**276**	**513**	603	496	541

Summer 2016 Total Generation needed 603 **MW**
Outage of largest unit must leave **276 MW** on-line (CSC)

	NERC Contingency Test				
	Category B	Category B CSC	Category C Tower Line	Category C N-1-1	Category D
Summer 2021					
Start Gen	788	788	788	788	788
- FCITC	691	132	288	267	266
Required Gen	**97**	**656**	500	521	522

Summer 2021 Total Generation needed **656 MW**
Outage of largest unit must leave 97 **MW** on-line (CSC)

2016 Load Forecast Analysis Results
Total Generation needed **656 MW**
Outage of largest unit must leave 276 **MW** on-line (CSC)

Attachment 5

Response to Questions 9a and 9b

Attachment 5 - Alternatives that will address 2021 NERC Reliability Violations

		Surry -Skiffes 500 kV (proposed project)	Chickahominy-Skiffes Creek 500 kV	Alternative A Underground 230 kV Single Circuit + Other Transmission[6]	Alternative A Underground 230 kV Single Circuit + Generation (1449 MW)[7]	Alternative B Underground 230 kV Double Circuit + Other Transmission[6]	Alternative B Underground 230 kV Double Circuit + Generation (551 MW)[8]	Alternative C Line 214/263 230 kV Rebuild (James River Bridge Crossing) [Whittier Hybrid] + Other Transmission	Alternative C Line 214/263 230 kV Rebuild (James River Bridge Crossing) [Whittier Hybrid] + Generation (552 MW)[9]	New Generation (656 MW)	Retrofit Yorktown Units 1, 2 & 3	Repower Units 1, 2 & 3	Surry - Whealton 500kV	Surry - Skiffes Creek 500 kV Underground (HVDC)
Alternative Available and Capable to Meet Overall Project Purpose[1]	Total 2021 Project Compliance Cost[2]	**$178.7 M**	**$213.2 M**	**$488.6 M**	**$1200.8 M**	**$488.6 M**	**$1117.4 M**	**$391.5 M**	**$1071.8 M**	**$1345.0 M**	**$859 M - $1.873 B**	**$391 M - $992 M + $72 M yr. gas FT**	Not evaluated because not constructible	**$1,000 M[5]**
	Mitigation Cost	$85 M	Unknown	Unknown	Unknown	Unknown	Unknown	Unknown	Unknown	Unknown	Unknown	Unknown	Unknown	Unknown
	NERC Compliance Good Through	2042	2042	2032	2021	2032	2021	2038	2021	2021	2021	2021	Not evaluated because not constructible	2042
	Logistics State regulatory approval estimated at 24 months for each alternative other than the Proposed Project which already has approval	Y - 18-20 months for construction	N - 27 months for construction	N - 60 months for construction	N - 48 months for construction	N -60 months for construction	N - 60 months for construction	N - 120 months for construction	N - 96 months for construction	N - 48 months for construction 2. Fuel supply issues for natural gas, 3. Potential Siting Issues	N - 48 months for construction	N - 48 months for construction 2. Fuel supply issues for natural gas	N - Not constructible due to route alignment and the inability to obtain the necessary ROW to Whealton Substation.	N - 1. 96 months for construction, 2. Space availability issues for converter station
	Section in Alternatives Analysis	4.0	3.2.3.5	3.3.1	3.3.1 and 3.2.1	3.3.1	3.3.1 and 3.2.1	3.2.3.2	3.2.3.1 and 3.2.1	3.2.1	n/a	n/a	3.2.3.3	3.3.3
Practicable?		**Y**	**Y**	**N**	**N**	**N**	**N**	**N**	**N**	**N**	**N**	**N**	**N**	**N**
Environmental Impacts[3]	Tidal Wetlands	1.20 ac crossed 0 ac impact	8.64 ac crossed <0.1 ac impact	1.20 ac crossed 0 ac impact	1.20 ac crossed 0 ac impact	1.20 ac crossed 0 ac impact	1.20 ac crossed 0 ac impact	Temp impact	Temp impact	None likely	None likely	None likely	5 ac crossed <0.1 ac impact	Potential impact
	PFO Wetland Conversion	0.41 ac	62.00 ac	0.73 ac	0.73 ac	0.73 ac	0.73 ac	Likely 0 ac	Likely 0 ac	None likely	None likely	None likely	Potential impact	Potential impact
	River Crossing	New James River aerial	New Chickahominy River aerial	New James River underground	New James River underground	New James River underground	New James River underground	Existing James River aerial rebuild	Existing James River aerial rebuild	None likely	None likely	None likely	New James River aerial at existing aerial	New James River underground
	Subaqueous Bottom Encroachment	0.63 ac	<0.1 ac	Direct impacts required	Direct impacts required	Direct impacts required	Direct impacts required	Impacts unlikely	Impacts unlikely	Minimum impact	Impacts Unlikely	Impacts Unlikely	Minimal impacts similar to Proposed	Considerable impacts
	Direct Oyster Lease Impacts	<0.25 ac	0 ac	Direct impacts likely	Direct impacts likely	Direct impacts likely	Direct impacts likely	Impacts unlikely	Impacts unlikely	None likely	None likely	None likely	10 leases present, similar impacts to Proposed Project	Considerable impact
	Water Quality Impacts	Minimal w/ E&S controls	Minimal w/ E&S controls	Turbidity, release of contaminants	Turbidity, release of contaminants	Turbidity, release of contaminants	Turbidity, release of contaminants	Minimal w/ E&S controls	Minimal w/ E&S controls	Minimal w/ E&S controls	Minimal w/ E&S controls	Minimal w/ E&S controls	Minimal w/ E&S controls	Turbidity, release of contaminants
	Protected Species Impacts	Not likely to adversely affect	Potential impacts to SWP, SJV, bald eagle[4]	Potential impacts to Atlantic sturgeon	Potential impacts to Atlantic sturgeon	Potential impacts to Atlantic sturgeon	Potential impacts to Atlantic sturgeon	Not likely to adversely affect	Not likely to adversely affect	Unknown	Unknown	Unknown	Not likely to adversely affect	Potential impacts to Atlantic sturgeon
	Potential for Visual Effects to Architectural Resources	Effects to resources on James River	Potential effects to resources along new ROW	Potential visual effects from onshore towers (0.8 mi from Carters Grove)	Potential visual effects from onshore towers (0.8 mi from Carters Grove)	Potential visual effects from onshore towers (0.8 mi from Carters Grove)	Potential visual effects from onshore towers (0.8 mi from Carters Grove)	Little change to existing visual effects	Little change to existing visual effects	Potential effects	Potential effects	Potential effects	Little change to existing visual effects	Large (5-8 story) converter stations on both sides of James River
	Archaeological Sites w/in ROW	7	68	Similar to proposed project	Similar to proposed project	Similar to proposed project	Similar to proposed project	Unknown but existing ROW	Unknown but existing ROW	Unknown	Unknown	Unknown	Unknown	Unknown for converter station
	Underwater Archaeological Sites w/in ROW	6 all avoided by towers	Unknown	Similar to proposed project but may be directly impacted	Similar to proposed project but may be directly impacted	Similar to proposed project but may be directly impacted	Similar to proposed project but may be directly impacted	Unknown but existing crossing	Unknown but existing crossing	Unlikely to affect	Unlikely to affect	Unlikely to affect	Unknown but existing crossing	Similar to proposed project but may be directly impacted
	Homes w/in 500' of ROW	160	1,129	160	160	160	160	No new ROW required	No new ROW required	Unknown - New generation and pipeline would likely affect some homes	Unknown	Unknown - pipeline would likely affect some homes	Many homes within ROW/switching station expansion	160

1. Overall Purpose: To provide reliable, cost-effective bulk electric power delivery to the NHRLA to maintain compliance with NERC reliability standards. All alternatives presented here deemed to be technically available and capable of being implemented without regard to schedule.
2. Except for the Proposed Project, all costs are in 2012 dollars
3. Environmental impacts only need be evaluated for alternatives deemed practicable; however, environmental impacts are provided for all alternatives for comparison.
4. SWP = small whorled pogonia, SJV = sensitive joint vetch. Effects to federally threatened or endangered species or disturbance to bald eagles has not been evaluated by the USFWS or NOAA for any alternatives except the proposed project.
5. The estimates for HVDC alternative were derived from data on other completed HVDC projects that are vaguely similar of scope. We have taken a conservative approach in estimating the cost and duration for this alternative such not to over state the cost or duration. However, because of projects of these type are unique in their complexity, the only true and accurate estimation for cost and duration can only be done through a thorough engineering scoping design which would take 12-18 months to complete.
6. A single circuit underground line is deficient hence a second underground line is needed at the same time; therefore, Alternative A + Other Transmission is equivalent to Alternative B + Other Transmission.
7. The least cost analysis of generation identified in 2012 for this alternative included repowering Unit 2, retrofitting Unit 3 and relocating a planned new combined cycle unit to the NHRLA, the estimated cost for which only included firm gas transportation costs, all as described in Glenn Kelly's rebuttal testimony in SCC Case No. PUE-2012-00029. These costs are conservative because they do not include the substantial construction costs of the new generating facilities.
8. The least cost analysis of generation identified in 2012 for this alternative included repowering Unit 2 and relocating a planned new combined cycle unit to the NHRLA, the estimated cost for which only included firm gas transportation costs, all as described in Glenn Kelly's rebuttal testimony in SCC Case No. PUE-2012-00029. These costs are conservative because they do not include the substantial construction costs of the new generating facilities.
9. The least cost analysis of generation identified in 2012 for this alternative included repowering Unit 2, retrofitting Unit 3 and relocating a planned new combined cycle unit to the NHRLA, the estimated cost for which only included firm gas transportation costs, all as described in Glenn Kelly's rebuttal testimony in SCC Case No. PUE-2012-00029. These costs are conservative because they do not include the substantial construction costs of the new generating facilities.