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US Army Corps of Engineers
Norfolk District
Regulatory Office
Received by: RLS
Date: November 17, 2016

VIA Electronic Mail

November 17, 2016

Col. Jason E. Kelly
Commander
U.S. Army Corps of Engineers
Norfolk District
803 Front Street
Norfolk, Virginia 23510

Re: Dominion's Surry-Skiffes Creek 500 kV Line: Response to National Trust for Historic Preservation's October 28, 2016, Presentation Regarding Load Flow Analyses and Project Alternatives

Dear Col. Kelly:

This letter responds to the National Trust for Historic Preservation's ("NTHP") presentation, provided by its consultant Tabors Caramanis Rudkevich ("Tabors"), titled "Alternatives to Surry-Skiffes Creek 500 kV Overhead Project: Identification and Power Flow Analysis" ("Presentation"). The Presentation was provided on October 28, 2016, to the U.S. Army Corps of Engineers ("Corps") and Dominion Virginia Power ("Dominion") at the Corps' offices. NTHP provided copies of the Presentation on October 31, 2016.

Tabors was retained by NTHP to identify alternatives to Dominion's Surry-Skiffes Creek 500 kV line ("Project") and evaluate them using power flow simulations to determine if they meet NERC Reliability Standards. Presentation at 3. Before performing its analysis, Tabors evaluated and confirmed Dominion's conclusions that violations of the NERC standards would occur in the absence of the Project.[1] *Id.* at 10. That is, the Project is necessary. With that conclusion, Tabors becomes the third independent entity, along with the Virginia State Corporation Commission ("SCC") and PJM Interconnection ("PJM"), to evaluate and confirm Dominion's load flow modeling and its conclusions regarding the need for the Project.

Tabors presented four alternatives to the Project that it claimed were compliant with NERC standards. *Id.* at 4, 13-20. While Tabors provided what it verbally described as "back of

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[1] Tabors used power flow analysis and information Dominion previously provided to the National Parks Conservation Association ("NPCA") in a March 21, 2016, letter when that group was evaluating and questioning Dominion's load flow analyses and conclusions regarding the need for the Project.

the envelope" cost estimates and implementation time frames for each of the alternatives, *id.* at 20, it did not consider or provide fully fleshed out estimates or otherwise consider all the variables related to implementing its alternatives, including required permitting, constructability, or otherwise how its concept-level ideas fit within and meshed with Dominion's larger system. In this sense, Tabors' analysis was conducted in a vacuum without any real-world considerations, a point Tabors conceded during the parties' discussion after the presentation.

Dominion comprehensively evaluated all four alternatives (labeled A through D) proffered by Tabors. Specifically, Dominion's transmission planning experts took each alternative as proposed by Tabors and evaluated it using the PJM-approved power flow model with all of the necessary inputs Dominion used when performing its evaluations in compliance with NERC Reliability Planning Criteria.[2] We note, however, that when a Tabors alternative required the use of Yorktown Unit 3, we used it as Tabors proposed, even though NERC criteria would require Dominion to remove Yorktown Unit 3 from the model. The rationale for and impacts of this are discussed in further detail below in response to Alternatives B and C. In any event, contrary to Tabors assertions, none of its alternatives are NERC compliant. Notwithstanding this, Dominion evaluated the real-world costs and time to implement those alternatives, including related to implementing them in a NERC-compliant manner,[3] consistent with Dominion's entire system, and certain legal requirements. The result is that, like all of the other alternatives evaluated and rejected, not only are the Tabors alternatives not NERC-compliant, they also are prohibitively expensive and take far too long to permit and construct. They also present serious constructability issues, and one of the alternatives would involve significant impacts to wetlands and other aquatic resources located in a pristine area important to American Indian tribes. The Tabors alternatives do not meet the project purpose and need, and otherwise are not reasonable or practicable. A summary of Dominion's review and analysis is set out below.

General Comments Regarding Tabors' Non-NERC and PJM Compliant Modeling

As the Corps is aware, on September 28, 2016, NTHP sent a letter informing the Corps of its intent to have Tabors perform the work discussed herein, and sought certain load flow modeling information from Dominion to do so. In an October 13, 2016, letter, Dominion offered to provide Tabors with the information it sought, with the condition that Tabors and Dominion work together to ensure that NERC and PJM requirements were followed, and Dominion's model inputs and parameters were used. Letter from S. Miller, Dominion, to Col. J. E. Kelly, Corps, at 2-3 (Oct. 13, 2016). NTHP rejected Dominion's offer. Letter from S. Williamson,

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[2] Dominion used the same process it used to evaluate all of the alternatives to the Project. The updated results of those analyses are shown in Dominion's Modeling and Alternatives Summary (Sept. 12, 2016) ("Modeling Summary"). Dominion provides a similar summary of the Tabors alternatives in Attachment B hereto.

[3] *See* Modeling Summary and Attachment 5 to the Letter from S. Miller, Dominion, to Col. J. E. Kelly, Corps (Sept. 12, 2016) ("Yorktown Response"). As the Corps is aware, that chart is the updated version of the same chart presented as Revised Chart 3-1 to Dominion's Revised Alternatives Analysis (Jan. 8, 2015). In Attachment 5, alternatives are shown as NERC compliant, even though, for example, Dominion had to add generation or transmission not originally part of the proffered alternative, in order to evaluate it on-par with the proposed Project and other alternatives. *See, e.g.*, Yorktown Response, Attachment 5 (see Underground 230 kV Alternatives A & B and Whittier Hybrid Alternative C).

NTHP, to Col. J. E. Kelly, Corps, and S. Miller, Dominion at 1 (Oct 18, 2016). In so doing, it asserted that the information from Dominion was not necessary for Tabors to complete its work, and instead, Tabors would use transmission planning information Dominion submitted to FERC on its annual Form 715 submission. *Id.* at 2. Tabors did so, and claimed that it combined that with information Dominion previously provided to NPCA to complete its work. Presentation at 10.

As a member of the PJM Regional Transmission Organization, Dominion is required to use the appropriate Regional Transmission Expansion Plan ("RTEP") models in its transmission planning studies. The power flow cases submitted with Dominion's Form 715 submission are not RTEP compliant.[4] This is because, among other things, the power flow cases in the Form 715 filing do not contain the most current system topology, use of the current 2016 Load Forecast, or the most recent generation profiles and dispatches like a RTEP power flow case will. That is, a NERC-compliant solution assessment using a model must include, but is not limited to, proper transmission system topology assumptions (*e.g.*, whether lines are normally open or closed, load profiles), contingency files that properly simulate how the transmission system actually operates, generation changes both internally and externally from the study area, as well as an understanding of the various criteria assessments, including the use of the correct facility rating.[5] In addition, these load flow modeling assumptions are vetted through PJM's RTEP protocol, including required concurrence from the Southern sub-regional stake holders.[6] Excluding any, some, or all of this information, as happened with Tabors' work, will lead to incorrect results and a non-compliant simulation of the North Hampton Roads Load Area ("NHRLA"). This necessary and specific information cannot be obtained from Form 715 filings. The plain language of Part 2 of Form 715 is consistent with that conclusion, and goes further by providing a disclaimer warning persons reviewing filing that "*the cases provided are not detailed models of individual systems and they may not be appropriate for individual system studies*." Attachment A (a copy of Dominion's Form 715 (without the power flow cases) (emphasis added). In layman's terms, the information and data provided in a Form 715 filing provides a general, 50,000 foot level view of the system, while a NERC-PJM-compliant power flow case analysis addresses the required details in order to determine whether a system is NERC-compliant. Tabors performed the former, not the latter.

The fact that Tabors claims to have obtained and employed PJM's RTEP contingency definitions in its work does not remedy the short-coming of relying on Dominion's Form 715 submissions. Dominion spoke with PJM, and, according to PJM, Tabors did not obtain the requisite information from PJM because PJM does not have a critical energy infrastructure information agreement on file for Tabors. So, at most, Tabors likely had access to PJM's 2012

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[4] This is because the Form 715 filing is an annual submission requirement that is part of FERC's collection of critical energy infrastructure information, and is not geared toward providing the necessary information for accurate load flow modeling. *See* FERC Form No. 715 Overview, *at* https://www.ferc.gov/docs-filing/forms/form-715/overview.asp (last visited Nov. 9, 2016).

[5] For example, while certain tests are done on a load dump rating, other tests require emergency or normal ratings to be met. It appears here that Tabors incorrectly relied on load dump ratings.

[6] FERC's open process requirements mandates that stakeholders review and concur with Dominion's planning assumptions.

document that provides brief, three-line textual summaries of all PJM-approved RTEP projects. That document does not provide the specific contingency files applicable to the NHRLA, and relevant to Dominion's system in that area (and related to that area) in 2016.

That conclusion is borne out by a review of the Presentation. The Presentation and Tabors' methodology described therein suggests that Tabors did not conduct a full contingency analysis, which would involve thousands of contingencies. Instead, it appears that Tabors looked at a limited set of seven contingencies. Presentation at 11-12. Two of these do not appear even to be correct. Specifically, the Presentation lists one contingency as "Chickahominy – Skiffes Creek 230 kV" and another as "Lanexa – Skiffes Creek 230 kV." *Id.* at 12. No such lines exist. Instead, there are Chickahominy to Waller, and Waller to Skiffes Creek, as well as Lanexa to Waller and Waller to Skiffes Creek. Instead of using the correct contingency files, it appears that Tabors looked at a discrete area within the NHRLA and modeled what it could with limited time and information. That is not NERC or PJM compliant.[7]

Tabors also claims to have used the power flow summary tables Dominion provided to NPCA in the March 21, 2016, letter. This also does not remedy the short-comings of relying on the Form 715 filing. At NPCA's request, the March letter provided a print out of the output data files from Dominion's power flow model runs. As that letter explained, the data set on its own "does not include a power flow model utilizing the appropriate software modeling tools and PJM's federally approved modeling procedures" and "is not relevant in assessing actual risk/consequences on the transmission grid."[8] As such, while this data may have been helpful to Tabors in some senses to help make somewhat educated guesses, it does not remedy the data and informational short-coming of relying solely on the Form 715 filing, and does not render its work NERC or PJM compliant. As with the PJM contingency file information discussed above, NTHP's September 28, 2016, letter requesting information from Dominion bears out that Tabors knew this, and proceeded without the requisite information anyway. *See supra* note 6.

Dominion's NERC- and PJM-Compliant Analysis of the Tabors Alternatives

To ensure that the four alternatives proposed and presented by Tabors were analyzed in a manner consistent with previous power flow analyses, Dominion modeled the four Tabors alternatives using the same Summer 2016 RTEP As-Is power flow case that was used earlier this year to update the power load flow modeling for the Project and previously evaluated alternatives, the results of which are presented in the Modeling Summary and Attachment 5 to the Yorktown Response. This will allow the Corps to perform an apples-to-apples comparison of the Project and all alternatives, to the greatest extent possible.

[7] This conclusion is supported by the fact that in NTHP's September 28, 2016, letter requesting information from Dominion necessary to conduct its own analysis, Tabors specifically sought the "set of contingencies used with the power flow cases, in .con format." Letter from S. Williamson, NTHP, to Col. J. E. Kelly, Corps, at 2 (Sept. 28, 2016). That is, Tabors clearly knew what information it needed, but nevertheless proceeded without it after NTHP rejected Dominion's offer to work with Tabors.

[8] Letter from J. K. Curtis, Dominion, to Pamela Goddard, NPCA, at 1-2 (Mar. 21, 2016).

1. Alternative A – Re-conductor and Reconfigure

Dominion modeled the changes to the Summer 2016 RTEP As-Is Case based on the information provided on page 15 of the Presentation. The study results indicated that the system as proposed in Alternative A – Re-conductor and Reconfigure is not NERC-compliant. Many of the modifications proposed in this alternative are still transmission deficiencies after they are modified. For example, Tabors Alternative A calls for the existing 230 kV line from Lightfoot to Kingsmill to be re-conductored to increase its summer Load Dump Rating by 20% to 650 MVA. Even after being re-conductored, this line still has NERC Reliability Standards violations because it continues to be thermally overloaded for certain contingencies. Attachment B highlights and depicts on a system map the transmission deficiencies that result in NERC violations.

Even if this alternative was NERC-compliant (which it is not) as described by Tabors, it would take, at a minimum, approximately 3 years' worth of outage windows to complete the re-conductor work. At least three of the lines proposed to be re-conductored (Line #58 (Lanexa-Toano), Line #2113(Lightfoot – Waller), and Line #2154(Waller-Kingsmill)) would need to be rebuilt as part of this alternative because the existing transmission towers cannot structurally support the larger and heavier conductors and other equipment required to achieve the higher rating Tabors seeks. That rebuilding work would require an additional approximately 2 years' worth of outages to complete construction. The total time to construct Alternative A excluding regulatory approvals is shown below:

	3 years to re-conductor
	+ 2 years for additional rebuild work
Total Time to Construct	= 5 years (or 9.5 construction windows)

Regarding regulatory approvals, this work would require SCC approval, which would take an additional 15-18 months to obtain, at a minimum. Further, at least an additional 6-12 months would be needed to obtain permits from the Corps and the Virginia Marine Resource Commission ("VMRC") prior to construction beginning. Based on Dominion's experiences, under a minimum/best case scenario it would take 2 years to obtain these regulatory approvals. Adding that time to the 5 years to construct results in at least 7 years to permit and construct this alternative, even assuming it resolved the NERC Criteria violations, which it does not. Should any additional transmission lines identified in this alternative as proposed by Tabors be required to be rebuilt, the estimated time line to construct would only increase.

The transmission portion of this alternative would cost approximately $146 million. This option, however, relies on the use of Yorktown Unit 3 as a synchronous condenser. The estimated cost to convert Yorktown Unit 3 to a synchronous condenser operation is an estimated $425 million, plus an additional $5 million per year in ongoing operations and maintenance ("O&M") costs. This $425 million is broken down as follows: $15 million in capital cost to convert the unit to a synchronous condenser; $410 million for the lost capacity replacement through the purchase and installation of a new combustion turbine at $510/KW. The total cost of this alternative is $571 million ($146M + $425M).

In summary, this alternative failed to resolve all the identified NERC Criteria violations, is far more expensive then the proposed Project, and cannot be constructed in a timely manner. The resolution of all the deficiencies with this alternative would require additional transmission or generation projects, which would essentially equate this alternative to the Alternative C (the Whittier Hybrid) previously analyzed. *See* Yorktown Response, Attachment 5. That alternative has been discussed in great detail since August of 2012 in the SCC and Corps permit processes, and has been found not to meet the Project's purpose and need, or otherwise be reasonable or practicable.

2. Alternative B – Yorktown 3 On Summer Peak

Dominion modeled the changes to the Summer 2016 RTEP As-Is Case based on the information provided on page 16 of the Presentation. The study results indicated that the system as proposed in the Alternative B -- Yorktown 3 On Summer Peak is not NERC compliant. Attachment B highlights and depicts on a system map the transmission deficiencies that result in NERC violations.

In addition, Tabors calculated a 6.4% capacity factor for Yorktown Unit 3 if operated at 5 days/week for 12 weeks per year.[9] That is incorrect. The actual capacity factor would be right at the unit's 8% limit, and that assumes the unit operates perfectly (an unreasonable assumption because large, aging, heavy oil-fired units like Yorktown Unit 3 have high forced outage rates). The calculation of this capacity factor based on the environmental constraints is not linear. The regulation is based on "heat-input" and operating the unit as proposed by Tabors (310 MW minimum load value) requires the unit to operate in a very inefficient manner. The heat input calculation is higher because the efficiency is poor, and startup Btus are included as the unit takes additional energy to ramp up from 0 MW to 310 MW (minimum load). This inefficiency is increased under the Tabors alternative because it calls for the unit to shut down on weekends, but actually ends up resulting in less than a day of shutdown before startup procedures would begin again.[10] Therefore, the unit can only operate for approximately 11 weeks in the manner proposed by Tabors. This would not leave any operating hours available for any other time of the year, creating serious operational and reliability issues. These operations also would require that the circulating water system operate for approximately 3 months out of the 12 months in a year, or 25% of the time. This would trigger additional environmental compliance costs under the Clean Water Act § 316(b) regulatory requirements.

[9] Operationally speaking, neither Dominion nor any other operator would actually operate a generation unit in this manner due to start risk. Start risk is the risk of a unit failing to come online, or come online in a timely manner, after shutdown. To minimize start risk, Dominion and any other operator simply would operate the unit at minimum load over the weekends when it knew it would need to operate the unit the following weekdays. In addition, it also is worth noting that while typically load is higher during the week, planning not to have Yorktown Unit 3 online or available on summertime weekends creates the risk of serious reliability issues. Therefore, while Dominion modeled this alternative as presented, it assumes a manner of operation that is contrary to industry standards and reality. It also demonstrates that Tabors' calculations are low regarding the amount of annual capacity the unit would consume operating over the summer as proposed by Tabors.

[10] For cold startup, Yorktown Unit 3 has a 3 hour notification requirement, and then a 20 hour startup period before getting to 310 MW. For hot startup, the unit also has a 3 hour notification requirement, and a 13 hour startup period before getting to 310 MW.

Further, this alternative's proposed exhaustion of capacity at Yorktown Unit 3 would necessitate that additional capacity be added in order to ensure the minimum generation requirements (656 MW) in the NHRLA are met. *See* Yorktown Response at 8.

Operating the unit in this manner is expected to cost between $867M to $1,635M, which is broken down as:

Increased fuel expense	$399M (15 years NPV)
Capacity replacement CT	$410M
316(b) Capital Cost	$58M - $826M
Total Cost Generation	$867M-$1,635M

The estimated time to construct the combustion turbine for additional capacity and to obtain necessary regulatory approvals is 4 years.

Alternative B also suffers from additional NERC issues. As noted in the introduction, Dominion modeled the Tabors alternatives exactly as proposed against its model, and consistent with NERC Reliability Criteria. Requirement R1 of NERC TPL-001-4, however, requires that "[k]nown outages(s) of generation or Transmission Facility(ies) with a duration of at least six months" be modeled out as outages. Because of Yorktown Unit 3's 8% runtime limitation, it always must be modeled as an outage. Thus, the use of Yorktown Unit 3 as a solution from a planning perspective violates NERC standards from the start. Notwithstanding this fact, Alternative B still failed to resolve all NERC violations. If Tabors had modeled Yorktown Unit 3 as an outage consistent with NERC Reliability Standards, Alternative B would have shown an even greater number of NERC violations, which in turn would further increase the costs, resources, and time necessary to make Alternative B NERC-compliant.

In summary, this alternative failed to resolve all the identified NERC violations, is vastly more expensive then the proposed Project, and cannot be done in a timely manner.

3. Alternative C – Yorktown 3 Stand-by

For this alternative, Dominion modeled the changes to the 2016 RTEP As-Is Case based on the information provided on page 17 of the Presentation. The study results indicated that the system as proposed in the Alternative C -- Yorktown 3 Stand-by is not NERC-compliant. Like Alternative A, many of the proposed modifications proposed in this alternative are still transmission deficiencies after they are modified. *See supra* discussion regarding the 230 kV line from Lightfoot to Kingmill. Attachment B highlights and depicts on a system map the transmission deficiencies that result in NERC violations.

To operate any turbine generator unit (such as Yorktown Unit 3) also as a synchronous condenser would require the installation and use of a synchronous power clutch. The highest power clutch produced to date is 300 MW at 3,000 rpm.[11] Since Yorktown Unit 3 operates at 790 MW at 3,600 rpm, a customized solution would have to be engineered and manufactured.

[11] These clutches typically are used on simple-cycle combustion turbine generators ranging from 10 MW to 140 MWs, which have been favored to operate as synchronous condensers as opposed to large generating units such as Yorktown Unit 3.

The installation of a clutch would require at least 40 feet of additional space between the generator and steam turbine, which would require extensive modifications and retrofitting. The costs associated with configuring Yorktown Unit 3 with a clutch would include:

- engineering costs associated with the clutch, clutch component, and modifications to the turbine support system to support clutch operations;
- additional foundations required for the clutch and components;
- purchase of the clutch and components; and,
- installation and maintenance of the clutch and components.

The estimated cost to accomplish all the modifications to Yorktown Unit 3 related to this alternative and operate it as proposed is between \$768M to \$1,935M, which is broken down as:

Increased fuel expense	\$200M - \$399M (15 years -NPV)
Yorktown Unit 3 Clutch	\$100M - \$300M
Capacity replacement CT	\$410M
316(b) Capital Cost	\$58M - \$826M
Total Cost Generation	\$768M-\$1,935M

The estimated time to modify Yorktown Unit 3, construct the additional capacity, and obtain necessary regulatory approvals is 4 years.

In summary, this alternative failed to resolve all the identified NERC violations, is vastly more expensive then the proposed Project, and cannot be constructed in a timely manner.

4. NTHP/Tabors Alternative D – Bypassing Critical ROWs

Dominion modeled the changes to the 2016 RTEP As-Is Case based on the information provided on page 19 of the Presentation. The study results indicated that the system as proposed in Alternative D - Bypassing Critical ROWs is not NERC-compliant. Attachment B highlights and depicts on a system map the transmission deficiencies that result in NERC violations.

This alternative has several significant impacts that the proposed Project does not, which are listed below.

- Brookwoods – Slaterville 230 kV Line requires the acquisition, development, and clearing of 18 miles of new 120-foot wide right-of-way ("ROW").
    - The 120-foot 18-mile new ROW will impact approximately 300 acres;
    - The new ROW would run through the Chickahominy Swamp and its tributaries and would result in significant impacts to at least 20 acres of forested wetlands;
    - It would result in a new crossing of the Chickahominy River in an area consider sacred by the Chickahominy Tribe, and that has been described during the SCC proceedings as "pristine";
    - The ROW also would be located approximately 2.5 miles from the Pamunkey Indian Reservation; and,

- The proposed ROW route would cut through a number of residential, agricultural and commercial areas, which raises significant doubts about its feasibility, and introduces significant, but currently unknown, costs.[12]

- Hayes-Harmony Village 230 kV Line requires the acquisition, development, and clearing of an additional 20-foot expansion of the 25-mile ROW
  - 20-foot expansion of existing 25- mile ROW will impact approximately 61 acres; and,
  - Additional wetland impacts plus river and stream crossings and related impacts.

While this proposed alternative may be considered a new alternative from a theoretical viewpoint, it has far greater impacts when compared to the proposed Project. As proposed, this alternative would cost $140M, but it does not resolve all the identified NERC Criteria violations. That cost does not include 1) the costs of wetland, historical, and cultural mitigation; 2) costs related to the acquisition or condemnation of numerous homes, farms, and business (or parts thereof); or, 3) additional transmission or generation necessary to make this alternative NERC-compliant. As proposed (and not taking into account the other needed work), this alternative would take a minimum of 40 months to permit and 30 months to construct, for a total of approximately 6 years. That timeline, however, assumes that Dominion could timely acquire the necessary property for the ROW, which is doubtful.

It also is noteworthy that this alternative impacts some of the same areas as the currently evaluated Chickahominy – Skiffes Creek Alternative. The SCC's and Virginia Department of Environmental Quality's ("VDEQ") independent evaluation of that alternative found that would result in major and significant impacts to wetlands, open waters, and the environment. *See* Mid Atlantic Environmental LLC ("MAE"), Report to SCC on the Routing and Environmental Aspects of the Project at 5-6, 22-23 (Jan. 11, 2013); Letter from R. Weeks, VDEQ, to J. Peck, Virginia SCC, at 7, 10-13 (Aug. 31, 2012) (submitting VDEQ's comments regarding the Chickahominy Alternative and stating that the Chickahominy – Skiffes Creek Alternative would have impacts "several orders of magnitude higher" on aquatic resources than the Project) ("VDEQ Report"). In particular, the SCC's consultant MAE observed that a power line crossing the Chickahominy River would have significant impacts, as that area was in "pristine" condition. Because of the significant impacts to aquatic resources and the environment, both VDEQ and MAE recommended the SCC select the Project and not the Chickahominy – Skiffes Creek Alternative. MAE, Report to SCC on the Routing and Environmental Aspects of the Project at 5-6, 22-23 (Jan. 11, 2013); VDEQ Report at 7, 10-13.

While the Tabors Alternative D is not identical to the Chickahominy – Skiffes Creek Alternative, it is located in the same area and has similar impacts. These impacts, including to aquatic resources, are significant and are much greater than the minimal impacts to aquatic resources of the Project. These facts implicate the Corps' duty to select the least environmentally damaging practicable alternative, which generally forbids the Corps from selecting and permitting an alternative that has greater impacts to aquatic resources if another

[12] While we have analyzed this alterative as proposed, it may be possible to route around the homes, farms, and businesses. This, however, would substantially raise the costs of this alternative, as the route length would increase, and it likely also would increase the environmental and cultural impacts of it.

practicable alternative is available. Thus, even assuming Tabors Alternative D resolved all NERC violations and otherwise was cost effective and could be constructed in a timely manner, and thus met the project purpose and need and could be considered reasonable and practicable (which it cannot), it is unlikely that the Corps could authorize it.

Conclusion

None of the alternatives proposed by Tabors resolved all the identified NERC Criteria violations. None of Tabors alternatives can be constructed in timely manner, and thus needlessly jeopardize reliable service to the hundreds of thousands of people, institutions, and companies in the NHRLA. Finally, none of the Tabors alternatives are cost efficient, and all cost substantially more than the Project.[13] The alternatives do not meet the Project purpose and need, and otherwise are not reasonable or practicable alternatives.

This analysis provides additional evidence that the Project continues to be the least environmentally impactful and most cost efficient alternative that can be constructed quickly, and that resolves all the identified NERC Criteria violations.

Please contact us if you have any questions about this response or Dominion's analysis or conclusions.

Sincerely,

Scott C. Miller
Vice President – Transmission
Dominion Virginia Power

cc: William T. Walker, Corps
Randy Steffey, Corps
Sharee Williamson, National Trust for Historic Preservation
John Fowler, Reid Nelson, Charlene Vaughn, and John Eddins
Advisory Council on Historic Preservation

[13] Tabors provided cost and construction time estimates, which it admitted during its presentation were based on limited information. As this response bears out, Tabors' estimates were significantly off.

Attachment A

Dominion's Form 715

Federal Energy Regulatory Commission
Form FERC-715 (2015)

Annual Transmission Planning and Evaluation Report
For the Year Ending December 31, 2015

Utility Code: 19876
Utility Name: Virginia Electric & Power Co

Part 1: Identification and Certification

1. Respondent Identification:

Code: 19876 **Name:** Virginia Electric & Power Co

2. Responses Provided:

[✓] **Parts 2, 5 and 6:**

Submitted by: SERC Reliability Corporation

Contact Person: Rebecca Poulsen

Title: Legal Counsel

Telephone: (704) 414-4230

Facsimile: (704) 357-7914

e-mail: rpoulsen@serc1.org

[✓] **Parts 3 and 4 :**

Transmitting Utility: Virginia Electric & Power Company
One James River Plaza
701 E. Cary St
Richmond, Virginia 23219

3. Respondent Mailing Address:

Mehdi Shakibafar
Virginia Electric & Power Company
701 East Cary Street
Richmond, Virginia 23219

4. Contact Person:

Name: Mehdi Shakibafar, P.E.

Title: Consulting Engineer

Telephone: (804) 771-4861

Facsimile: (804) 771-4548

e-mail: Mehdi.shakibafar@dom.com

5. Certifying Official:

Name: Steve Chafin

Title: Dir. Electric Transmission Planning

Signature:

Date: **03/24/16**

Return Completed Form to: **Federal Energy Regulatory Commission**
Secretary of the Commission
Form No. 715
888 First Street N.E.
Washington, D.C. 20426

Part 2: Power Flow Base Cases

Virginia Electric & Power Company (the Company) is a member of the SERC Reliability Corporation (SERC) and participates in its regional process for consolidating and sharing of power flow information. As such, the Company authorizes the SERC to release, without conditions, to FERC the most current regional power flow models.

The following cases are available and are filed electronically with FERC:

ERAG-MMWG Base Cases

1. 2016 Spring Light Load
2. 2016 Summer
3. 2016/17 Winter
4. 2017 Spring Light Load
5. 2017 Summer Shoulder
6. 2017 Summer
7. 2017/18 Winter
8. 2021 Spring Light Load
9. 2021 Summer
10. 2021/22 Winter
11. 2026 Summer
12. 2026/27 Winter

SERC Long-Term Study Group (LTSG) Base Cases

1. 2016 Fall
2. 2017 Spring
3. 2020 Summer
4. 2021 Summer Shoulder

These cases contain the following information: Input data in Siemens PTI PSS/E Raw Data File (.RAW) format; corresponding output data files in ASCII format showing solved real and reactive power flows and other relevant output information; and a SERC Data Dictionary that cross-references bus names. Areas outside SERC contain equivalent representations not intended for study of the transmission systems in those areas. In addition, some future transmission and generation facilities in these cases are for planning purposes only and have not been authorized for the individual systems. The cases provided are not detailed models of individual systems and may not be appropriate for individual system studies.

Annual Transmission Planning and Evaluation Report
For the Year Ending December 31, 2015

Utility Code: 19876
Utility Name: Virginia Electric & Power Co

Part 3: Transmitting Utility Maps and Diagrams

Map identifying Items A, B, C, D, and E are attached.

A. Generating Plants
B. Switching Stations
C. Substations
D. Service Areas, and
E. Interconnections with other utilities.

Included (and attached separately) are most recent single-line schematic diagrams identifying:

A. AC and DC transmission lines and facilities, including their nominal operating and design voltages,
B. Electrical connections
C. Generating plants
D. Transformation facilities,
E. Phase angle transformers, and
F. VAR control equipment, i.e., shunt and series capacitors and inductors, etc.

Annual Transmission Planning and Evaluation Report
For the Year Ending December 31, 2015

Utility Code: 19876
Utility Name: Virginia Electric & Power Co

Part 4: Transmission Planning Reliability Criteria

Attached PDF document titled: “CEII 2015 Form 715 for DVP part IV – Transmission Planning Criteria”

Federal Energy Regulatory Commission
Form FERC-715 (2015)

Annual Transmission Planning and Evaluation Report
For the Year Ending December 31, 2015

Utility Code: 19876
Utility Name: Virginia Electric & Power Co

Part 5: Transmission Planning Assessment Practices

General procedures to assess the transmission system:

1. Base case parameters for the conditions under study are established. The most common situation studied is the projected peak load for a particular year, although studies at other than peak loads are also conducted. Loads, generation dispatch, power interchange, and system improvements are modeled in the base case for the year and conditions under study.

2. A list of outaged and monitored facilities is developed. For internal studies, all of the transmission facilities in the area under study are usually outaged and monitored. For regional/subregional studies, certain selected facilities are outaged and all bulk power facilities are monitored.

3. When power transfers with other entities are being studied, generation dispatches and scheduled power interchange for the involved parties are modeled.

4. A linear power flow program ("DC" power flow) is used as a screening tool to determine line flows for the modeled transfers and/or simulated facility outages. The program currently being used is the Power Technologies, Inc. (PTI) PSSE/E Power Flow Program and MUST.

5. The output of the linear power flow is analyzed for overloaded facilities. Transfer capabilities between entities are calculated in accordance with the NERC document, "Transmission Transfer Capability" dated May 1995.

6. If a more detailed analysis is required, AC power flow studies are conducted using the PTI PSS/E Power Flow Program.

7. The results of the above studies are compared with the planning criteria. In some instances, a formal report is written documenting the study results.

Special studies are required to analyze particular situations. Some examples are transient stability, voltage and reactive control, steady state stability, and inertial power flow studies.

Virginia Power participates in SERC Intra-Regional Near-Term Study Group (NTSG)), and SERC Intra-Regional Long-Term Study Group (LTSG). The NTSG and LTSG study groups have procedural manuals that detail work procedures and practices. These manuals are being submitted by the office of the SERC Reliability Corporation (SERC) and are to be considered a part of Virginia Power's response to Part 5.

Part 5: Transmission Planning Assessment Practices (Cont.)

The following documents were filed in hard copy and electronically by SERC in past years and have been on file at FERC and in the regional reliability organization office. The current revisions of the first two documents (Adobe Acrobat Format) are included in the SERC present filing.

1. Current SERC NTSG Procedural Manual
2. Current SERC LTSG Procedural Manual
3. Current ERAG Study Procedural Manual

SERC has adopted NERC's reliability standards and Rules of Procedure. SERC guidelines and regional criteria have been written to clarify and augment the requirements of the NERC reliability standards as they are applied to the SERC Region and its members. These guidelines and regional criteria are posted on the SERC website.

Annual Transmission Planning and Evaluation Report
For the Year Ending December 31, 2015

Utility Code: 19876
Utility Name: Virginia Electric & Power Co

Part 6: Evaluation of Transmission System Performance

Virginia Power participates in the following regional/subregional study groups with other utilities: SERC Intra-Regional Long-Term Study Group (LTSG), and SERC Intra-Regional Near-Term Study Group (NTSG)

Reports on the evaluation of transmission system performance for future time periods, including the upcoming summer and winter peak load seasons, are issued by the above groups. The most recent reports of these study groups are being submitted by the SERC Reliability Corporation (SERC) office and are considered to be part of Virginia Power's response to Part 6:

1. 2015 ERAG Summer Transmission System Reliability Assessment (December 2015)
2. SERC Engineering Committee Near-term Study Group (NTSG) 2015 Summer Reliability Study of Projected Operating Conditions (June 2015)
3. SERC NTSG 2015/2016 Winter Reliability Study of Projected Operating Conditions (December 2015)
4. SERC Engineering Committee Long-term Study Group (LTSG) 2020 Summer Future Year Study (December 2015)

Federal Energy Regulatory Commission Form FERC-715 (2015)	**Annual Transmission Planning and Evaluation Report For the Year Ending December 31, 2015**	**Utility Code: 19876 Utility Name: Virginia Electric & Power Co**

Checklist

__√___ One electronic copy of Parts 1, 3, 4, 5 and 6 of the FERC Form No. 715.

______ One electronic copy of Part 2, 5 and 6 of the FERC Form No. 715 - **Supplied by SERC Reliability Corporation (SERC)**

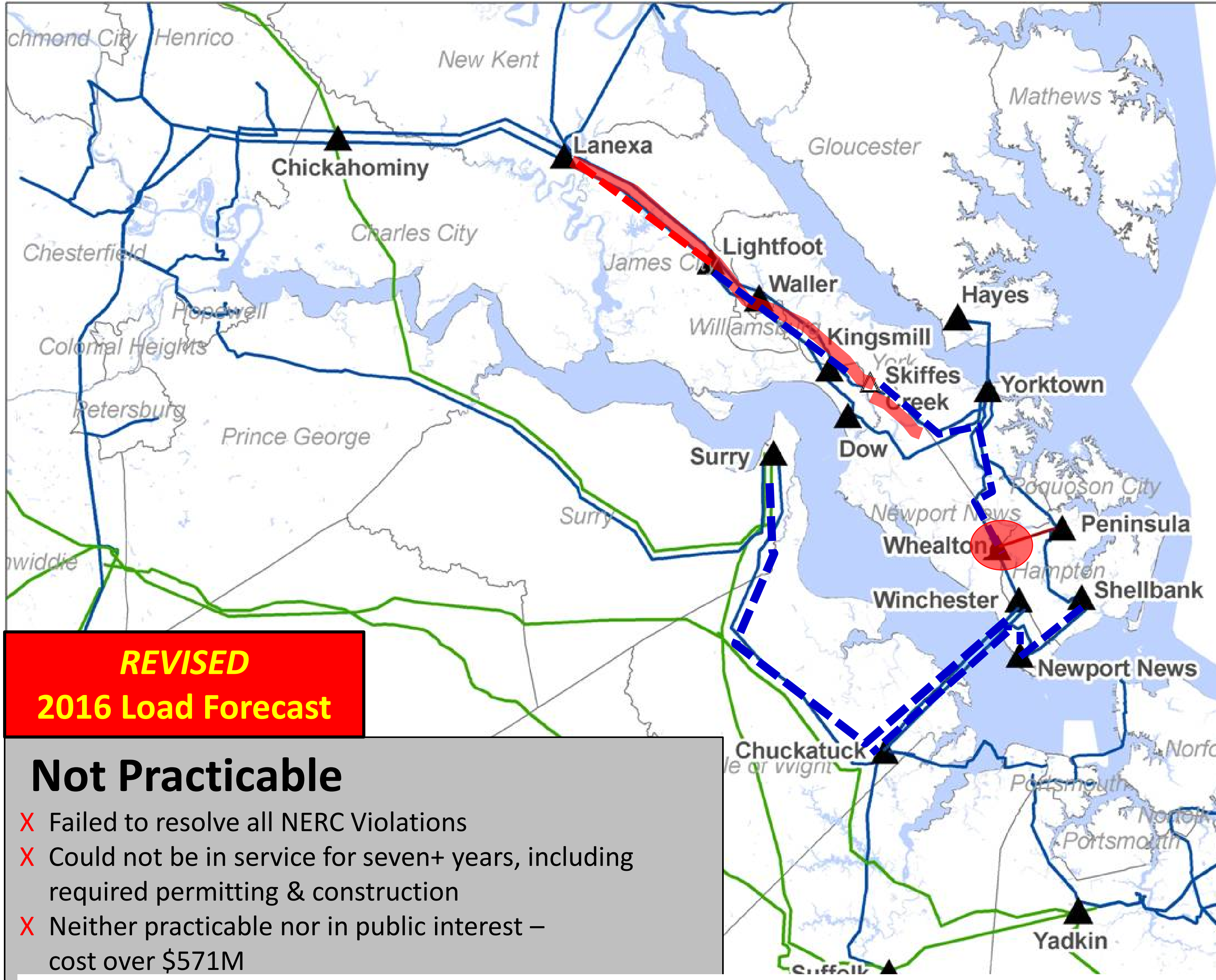
Attachment B

Dominion, Modeling Review of NTHP/Tabors Alternatives (Nov. 14, 2016)

Surry – Skiffes Creek – Whealton

Modeling Review of NTHP/Tabors Alternatives

November 17, 2016



Tabors Alt. A (Reconductor and Reconfigure) Summer 2016

- Line # 2113 *(Lightfoot-Waller)*
- Line # 2154 *(Waller-Skiffes Creek)*
- Line # 34 *(Skiffes-Ft Eustis)*
- Line # 58 *(Lanexa-Skiffes)*
- Whealton 230-115 kV Tx

REVISED
2016 Load Forecast

Not Practicable

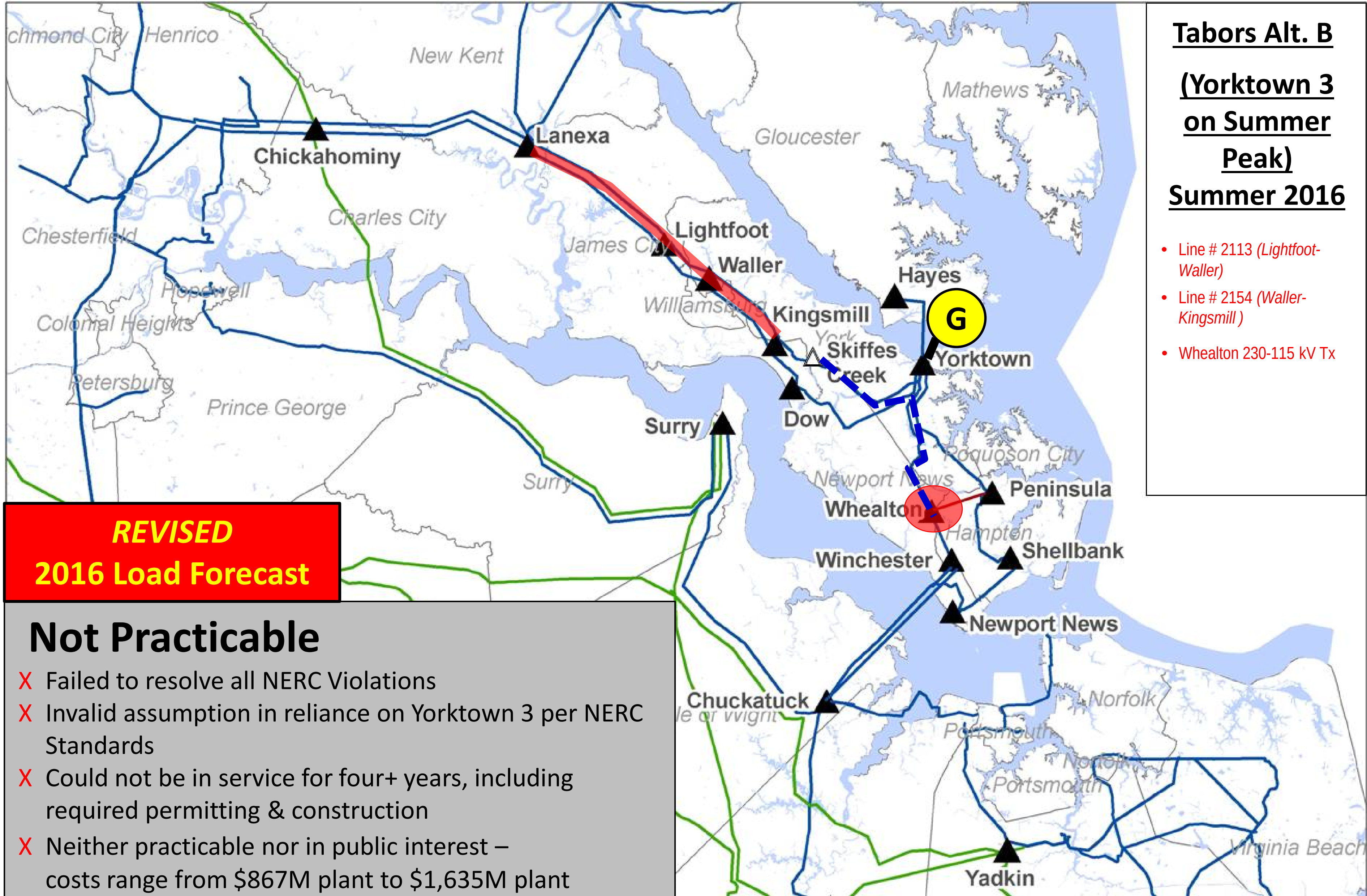
X Failed to resolve all NERC Violations
X Could not be in service for seven+ years, including required permitting & construction
X Neither practicable nor in public interest – cost over $571M

	2017	2018	2019	2020	2021	2022	2023+
Tabors Alternative A	**Permitting & Construction** (7+ Years)						
	Risk for Rotating Blackouts						

Tabors Alt. B

(Yorktown 3 on Summer Peak) Summer 2016

- Line # 2113 *(Lightfoot-Waller)*
- Line # 2154 *(Waller-Kingsmill)*
- Whealton 230-115 kV Tx



REVISED
2016 Load Forecast

Not Practicable

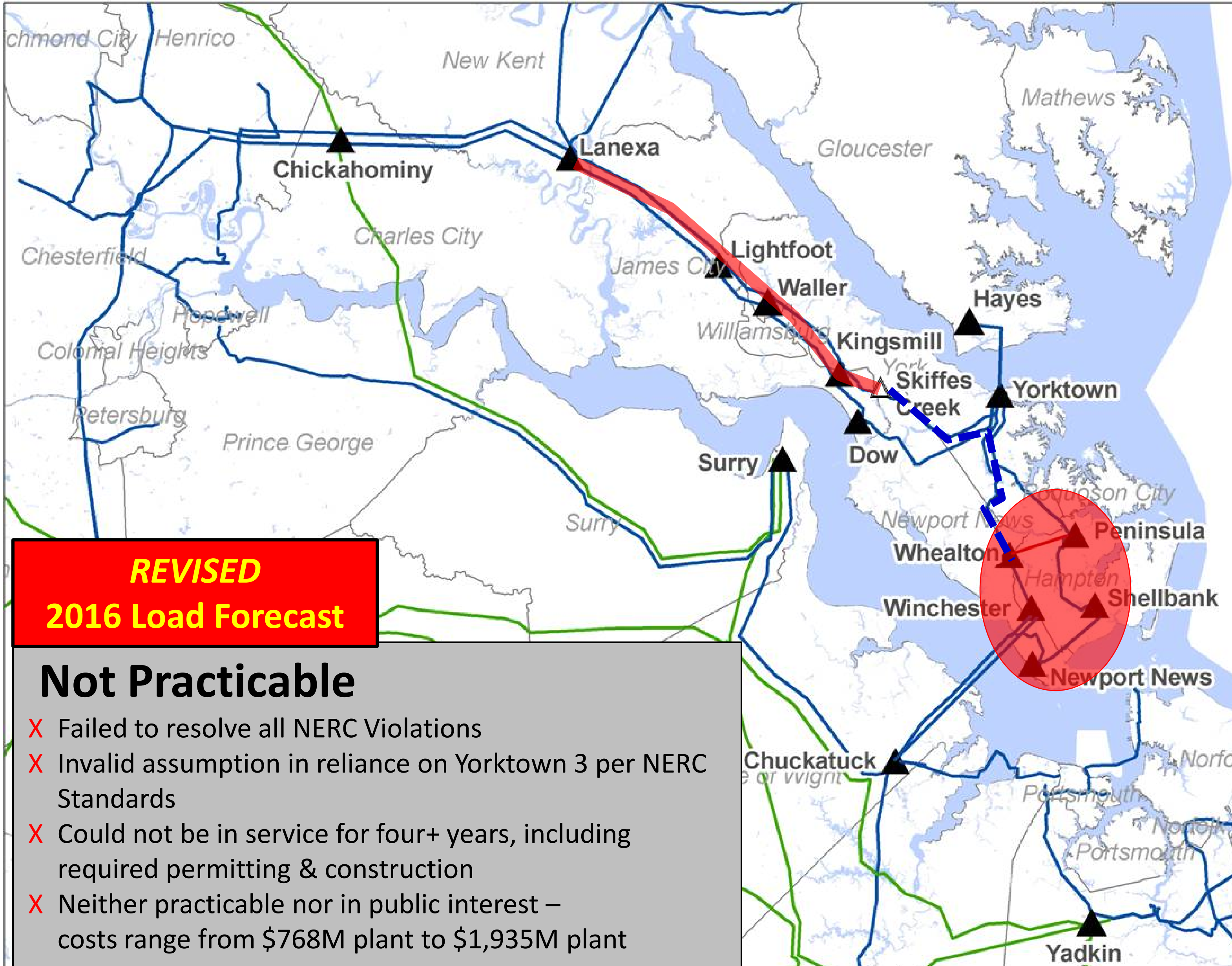
- X Failed to resolve all NERC Violations
- X Invalid assumption in reliance on Yorktown 3 per NERC Standards
- X Could not be in service for four+ years, including required permitting & construction
- X Neither practicable nor in public interest – costs range from $867M plant to $1,635M plant

	2017	2018	2019	2020	2021	2022	2023
Tabors Alternative B	**Permitting & Construction** (4+ Years)						
	Risk for Rotating Blackouts						

Tabors Alt. C

(Yorktown 3 Stand-by) Summer 2016

- Line # 2113 *(Lightfoot-Waller)*
- Line # 2154 *(Waller-Skiffes Creek)*
- Line # 34 *(Lanexa-Ft Eustis)*
- 225 MW SPS



REVISED
2016 Load Forecast

Not Practicable

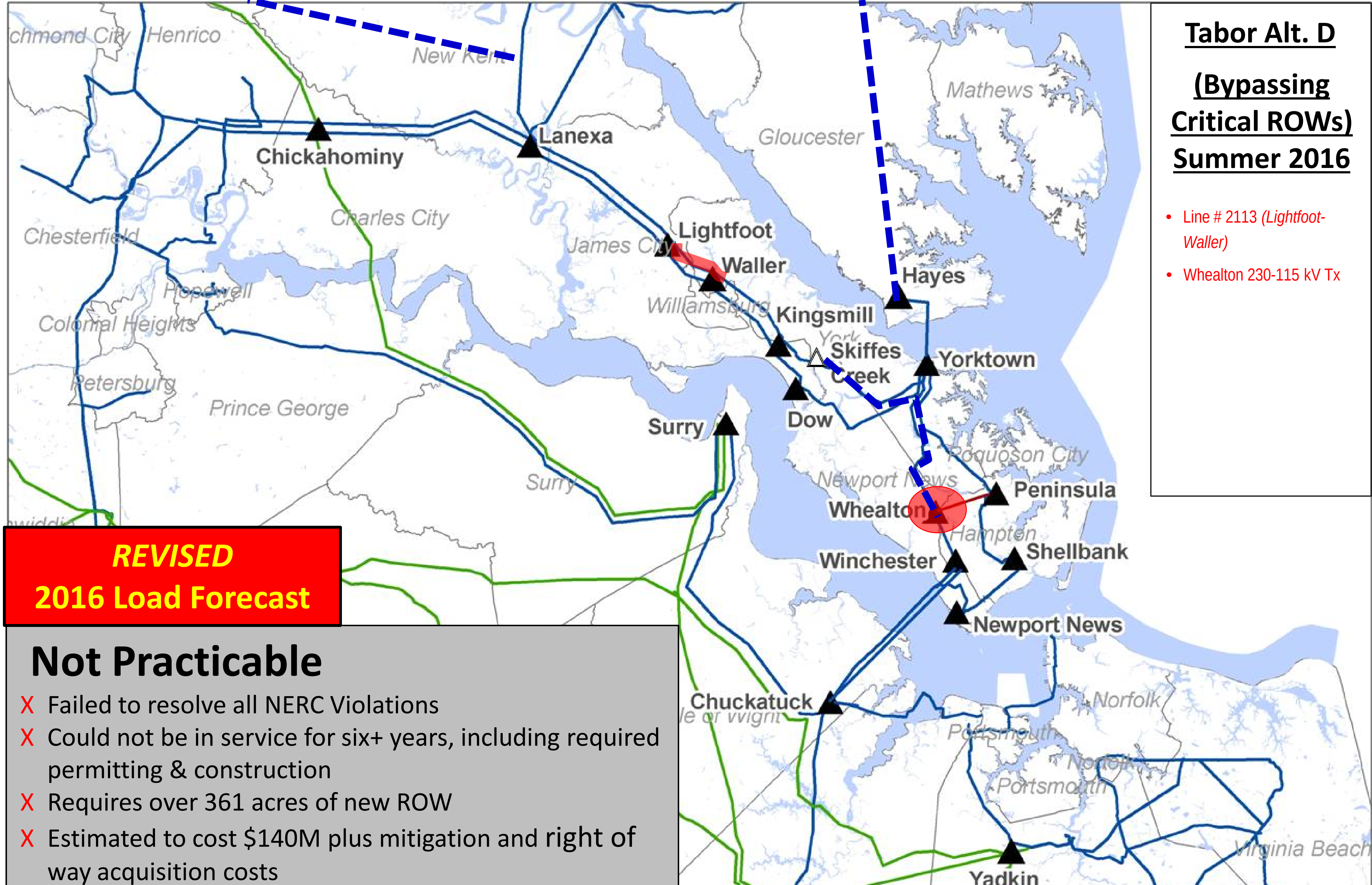
- X Failed to resolve all NERC Violations
- X Invalid assumption in reliance on Yorktown 3 per NERC Standards
- X Could not be in service for four+ years, including required permitting & construction
- X Neither practicable nor in public interest – costs range from $768M plant to $1,935M plant

	2017	2018	2019	2020	2021	2022	2023+
Tabors Alternative D	**Permitting & Construction** (4+ Years)						
	Risk for Rotating Blackouts						

Tabor Alt. D

(Bypassing Critical ROWs) Summer 2016

- Line # 2113 *(Lightfoot-Waller)*
- Whealton 230-115 kV Tx



REVISED
2016 Load Forecast

Not Practicable

- X Failed to resolve all NERC Violations
- X Could not be in service for six+ years, including required permitting & construction
- X Requires over 361 acres of new ROW
- X Estimated to cost $140M plus mitigation and right of way acquisition costs

	2017	2018	2019	2020	2021	2022	2023+
Tabors Alternative C	**Permitting & Construction** (6+ Years)						
	Risk for Rotating Blackouts						

<u>Proposed Project Summer 2016</u>

Surry - Skiffes Creek 500 kV
&
Skiffes Creek - Whealton 230kV
&
Skiffes Creek Switching Station

<u>No Violations</u>

SCC Rebuttal Testimony 2013

REVISED
2016 Load Forecast

- ✓ **Practicable**
- ✓ **Reasonable**
- ✓ **Prudent & Feasible**

	2017	2018	2019	2020	2021	2022	2023
Proposed Project	Permitting & Construction / Risk		Reliable Power on the Peninsula				