UNITED STATES DEPARTMENT OF ENERGY

PJM Interconnection, L.L.C.	)	Order No. 202-17-4
Request for Emergency Order	)	
Pursuant to Section 202(c) of the	)	
Federal Power Act	)	
________________________________	)	

SIERRA CLUB'S MOTION TO INTERVENE AND PETITION FOR REHEARING

Comments of
Ariel Horowitz, PhD

October 5, 2017

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IDENTIFICATION

My name is Ariel Horowitz, PhD. I am a Senior Associate at Synapse Energy Economics, located at 485 Massachusetts Avenue, Cambridge, MA 02139.

Synapse Energy Economics is a research and consulting firm specializing in electricity and gas industry regulation, planning, and analysis. Our work covers a range of issues, including economic and technical assessments of demand-side and supply-side energy resources; energy efficiency policies and programs; integrated resource planning; electricity market modeling and assessment; renewable resource technologies and policies; and climate change strategies. Synapse works for a wide range of clients, including state attorneys general, offices of consumer advocates, trade associations, public utility commissions, environmental advocates, the U.S. Environmental Protection Agency (EPA), U.S. Department of Energy (DOE), U.S. Department of Justice, the Federal Trade Commission, and the National Association of Regulatory Utility Commissioners. Synapse has over 25 professional staff with extensive experience in the electricity industry.

At Synapse, I have worked extensively on issues related to energy system planning, data analysis, and the use of new technologies. My work has included comments on integrated resource plans, as well as reports on and modeling of policy-driven changes to the energy sector pertaining to Oregon, Michigan, Puerto Rico, Connecticut, and the Regional Greenhouse Gas Initiative member state region. I have provided consulting services for clients including: the Energy Commission of Puerto Rico, U. S. EPA, the District of Columbia Office of the People’s Counsel, the Michigan Public Service Commission and Department of Environmental Quality, multiple renewable energy developers, and the Sierra Club.

I have provided expert analysis and testimony on issues related to utility planning, revenue requirement, forecasting, and operations on behalf of the Energy Commission of Puerto Rico. I have also testified on grid modernization issues before the Massachusetts Department of Public Utilities and on wind resource economics before the Wisconsin Public Service Commission, and submitted formal comments on utility resource and compliance plans before the Washington Utilities and Transportation Commission and the Oregon Public Utility Commission.

I hold a Doctorate in Chemical Engineering from Tufts University as well as a BS in Engineering from Swarthmore College. My research focused on design and use of electrochemical energy storage technologies.

In preparing the comments herein, I reviewed publicly-available information concerning the Yorktown Plant, the Skiffes Creek transmission project, and load and transmission conditions in the North Hampton Roads area and the Dominion zone generally. I have not reviewed any competitively-sensitive information or critical energy infrastructure information as part of the analysis presented below, but have submitted a request for access to critical energy infrastructure information and may update my analysis once I have had an opportunity to evaluate those data.

1. INTRODUCTION

In 2012, Dominion Electric Power Company ("Dominion" or "the Company"), the owner of the Yorktown power plant, announced it would be ceasing the operation of two of the plant's units, effective 2015, as part of its strategy to comply with the United States Environmental Protection Agency's Mercury and Air Toxics (MATS) rule. In June of 2017, PJM Interconnection, the local regional transmission operator, appealed to the United States Department of Energy (DOE) for an emergency authorization to maintain operation of those two coal-fired units. In the intervening years, Dominion and PJM repeatedly failed to take into account reasonable alternatives to continued operation of the Yorktown coal units, negligently allowing the plant's allowable life under MATS to run out without implementing either their preferred plan—a new transmission line—or any other "Plan B" alternative.

DOE granted PJM's request in June of this year, allowing PJM and Dominion to maintain operations at the Yorktown units for a period of 90 days (lasting until September 14, 2017). DOE has renewed its Order through December 13, 2017 (Order 202-17-04). PJM's initial application included a request that DOE grant continued 90-day extensions until it has been conclusively demonstrated that the circumstances prompting the first application are no longer relevant—for example, because the preferred transmission project has come online, currently anticipated for 2019. This prolonged period of allowed operations would come with high costs for ratepayers and emissions that undermine the aims of the MATS rule.

Below, I discuss the history of the current application, including PJM and Dominion's respective roles, responsibilities, and actions (or lack thereof). I describe why the Yorktown coal units are unlikely to be needed for load-based reliability purposes in the near term and, moreover, why they are ill-suited to provide reliability services in the first place. Finally, I describe a range of reasonable alternatives that PJM and Dominion should examine as a means of avoiding continued operation of one or both of the Yorktown coal units even during the construction of the preferred transmission alternative. I recommend that DOE require such an analysis from PJM and Dominion, as well as a clear plan to implement the findings of the analysis, prior to reauthorizing continued operations of the Yorktown coal units.

2. Background of PJM's Request and DOE's Order in Response

2.1. The Yorktown Plant and its Role in the Hampton Roads Area

The North Hampton Roads Load Area (NHRLA) is located on a peninsula in the state of Virginia. This peninsula is occupied by the Newport News/Hampton metropolitan area and is home to the Langley Air Force Base, William and Mary College, and some 600,000 residents. The peninsula's electricity need is served by Dominion Electric Power Company. Dominion and the regional transmission operator, PJM, share the responsibility of providing reliable electric service to the residents of the NHRLA.

Although PJM and Dominion both have adequate generating capacity to serve load on a system-wide basis, they must also ensure reliability in areas subject to significant transmission constraints (sometimes referred to as "load pockets"). The NHRLA is itself one such load pocket. At present, the NHRLA's electricity needs are served almost entirely by power imported to the area from other parts of PJM. In decades past, however, much of the NHRLA's need was supported by the peninsula's only power generating campus of note, the Yorktown plant. Yorktown consists of three electric generating units: two identical 188 MW coal-fired units, which had been slated for retirement earlier this year, and a third 882 MW oil-fired unit.[1] All three Yorktown units are owned and operated by Dominion through its subsidiary, Virginia Electric and Power Company.

Yorktown's two coal units began operations in 1957 and 1959, respectively. At 60 years old, these units are ten years older than the average coal unit in the United States—and likely 20 to 30 years older than their original design lives. Yorktown's coal units were originally designed to operate as "base load" generators, meaning that they were engineered to withstand near-constant operations. In recent years, however, the Yorktown units' economic viability has collapsed as prices for alternative resources (such as natural gas and renewable energy) have fallen and coal prices have risen. Subject to transmission

[1] The third oil-fired unit, constructed in 1974, has not been announced for retirement.

constraints, PJM is obligated to dispatch the cheapest units on the system first, and therefore it has chosen to dispatch the Yorktown units less and less over time. Over the past decade, dispatch of the Yorktown coal units has gradually diminished, falling from a 47 percent capacity factor in 2007, to a 25 percent capacity factor in 2013, to a capacity factor of only 10 percent in 2016.

The Yorktown coal units have operated primarily as capacity resources in recent years, meaning that they are dispatched only at times of unusually high load in the NHRLA or in the Dominion load zone more broadly. Although load data for the NHRLA is not public and I have not yet been afforded the opportunity to review it, historical load data for the Dominion zone is available from PJM[2] and the Yorktown units' generation data by month is publicly available from the DOE's Energy Information Administration through May of 2017[3] as well as having been reported by PJM for June and July of 2017 for compliance purposes.[4] In 2016, the Yorktown units were not dispatched at any time after early September.[5]

[2] Hourly metered loads are available in PJM's DataMiner2 tool.
[3] EIA Form 923.
[4] PJM, Report on Yorktown Units 1 and 2 Operations Pursuant to Order No. 202-17-2. 24 August, 2017.
[5] Based on a review of hourly generation data from EPA's AMPD database.

According to PJM, the Yorktown coal units are not needed for capacity purposes until Dominion zone load exceeds 18,400 MW, [6] which generally occurs only in the summer months and in January at the height of the winter peak (Figure 1). While it is possible that Dominion will have a significant winter peak, as it did in January of 2017, Dominion will be able to access capacity from outside of its territory to serve this peak, due to the fact that PJM is a summer-peaking system. Because Dominion's overall capacity need is less constrained in the winter than for the summer peak, its need of the Yorktown units is likely less during the winter peak than during the summer peak.

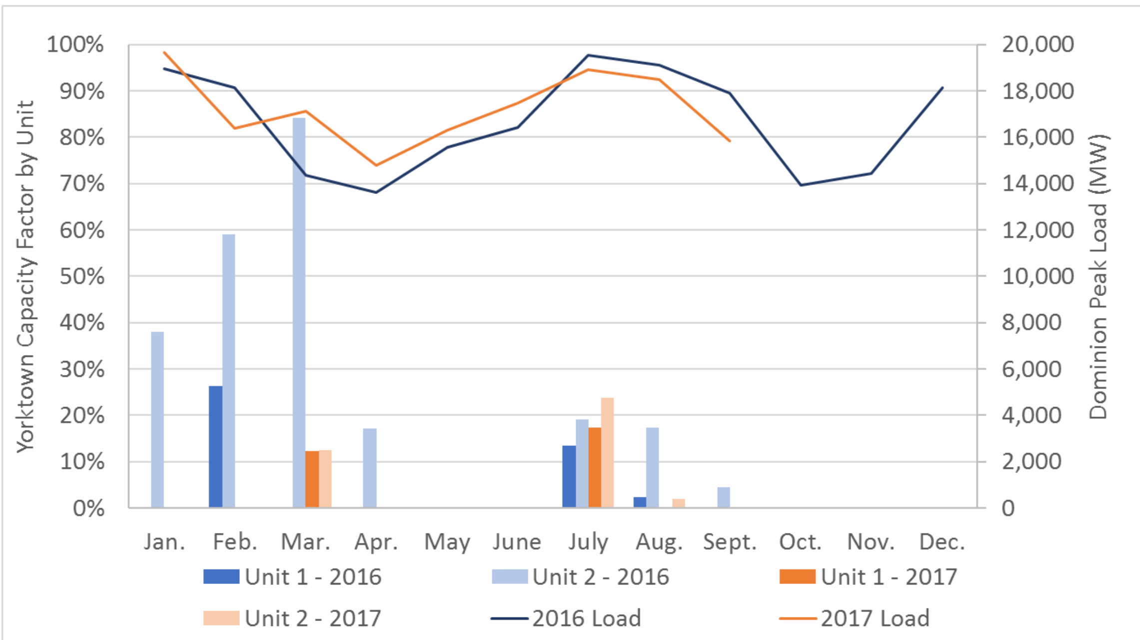

Figure 1. Dominion monthly peak load and Yorktown Units 1 and 2 Operations, 2016-2017.

PJM recently submitted a compliance report to DOE recording generation from the Yorktown coal units in June through August of 2017. My review of this data shows that, as expected, the Yorktown coal units were dispatched more in July than in August (Figure 1), indicating that capacity needs were likely a primary contributor to dispatching the units. As above, Dominion's peak hour for 2017 has almost certainly passed. Neither PJM nor Dominion have described load patterns in the NHRLA that differ materially

[6] PJM Application for Renewal, p2.

from those in the Dominion zone as a whole, suggesting that the NHRLA is also at the beginning of its fall shoulder season. It is reasonable to expect, based on this evidence, that the Yorktown units would not need to be dispatched at the same time on the basis of high load conditions alone between now and mid-December.

Like many thermal plants of its vintage, Yorktown was not compliant with EPA's Mercury and Air Toxics Standard (MATS) when the rule was finalized in 2011. Faced with the requirements of this rule, Dominion engaged in a multi-year decision-making process to consider how to comply. Yorktown unit 3, which burns heavy fuel oil, can comply with MATS by simply operating at an 8 percent capacity factor or less over the course of the year. Because Yorktown 3 has not run at more than a single-digit capacity factor for at least the past decade,[7] essentially no changes to the unit's operations were needed to bring it into compliance. In order to bring the Yorktown coal units into compliance with MATS, however, Dominion would have had to either install expensive emissions-control retrofits, convert the units to run on natural gas instead of coal, or retire them. There is not sufficient gas delivery infrastructure on the peninsula to support the second option. In consideration of the coal units' dim economic future, Dominion decided to retire the units as of its 2012 Integrated Resource Plan (IRP). At the time, Dominion anticipated taking the Yorktown units offline in 2015.[8]

2.2. THE SKIFFES CREEK PROJECT: SUMMARY AND CURRENT STATUS

PJM was made aware of Dominion's intent to retire the Yorktown units as part of its 2012 Regional Transmission Expansion Plan (RTEP) process. In its RTEP studies, PJM found that retirement of the units would lead to multiple violations of North American Electric Reliability Corporation (NERC) reliability standards, which are heuristics, rules, and best practices meant to ensure reliable operation of the electric grid. PJM and Dominion proposed construction of additional transmission links between the NHRLA and the rest of Dominion's territory as the primary means of addressing these NERC violations. These links consist of three components: a new 500 kV line from the area of

[7] Data published by the Energy Information Administration only provides per-unit generation information back through 2008.
[8] Dominion 2012 IRP, Figure 7.2.5.

Skiffes Creek (a tributary to the James River) on the peninsula to the Surry switching station across the James River; a 230 kV line along the peninsula between Skiffes Creek and Whealton; and a new switching station at Skiffes Creek itself. Collectively, these components are referred to as the Skiffes Creek project.

Dominion and PJM first proposed the Skiffes Creek project in 2012. During the planning process for the Skiffes Creek project, Dominion and the Army Corps of Engineers conducted multiple alternative analyses assessing other means of solving potential reliability problems in the NHRLA. These analyses were supplemented by an additional review of alternatives, conducted by Tabors Caramanis Rudkevich on behalf of the National Trust for Historic Preservation[9] and by Princeton Energy Research International on behalf of the National Parks Conservation Association.[10] Most of these alternatives consisted of either other transmission routes or installation of new conventional natural gas-fired generation on the peninsula.[11] Dominion discarded both options. The Army Corps of Engineers' environmental impact statement for the Skiffes Creek project concluded that alternative transmission routes (for example, going up the peninsula instead of across the James River) would cause greater environmental disturbances than the Skiffes Creek route. Dominion also determined that installation of a new gas-fired combustion turbine (CT) would be infeasible due to the development timeline necessary for such a project and to the lack of fuel delivery infrastructure on the peninsula. Although stakeholders proposed other, more minor transmission upgrades as an alternative to Skiffes Creek, PJM and Dominion argued that these options would be insufficient to address the full suite of potential violations.[12]

[9] https://nthp-savingplaces.s3.amazonaws.com/2017/02/14/10/27/11/381/NTHP-TCR%20Alternatives%20Report%20(002).pdf

[10] https://npca.s3.amazonaws.com/documents/3323/a084fea6-60eb-4c7c-81b0-9af1b4cd5594.pdf?1453909860

[11] The analysis conducted by Princeton Energy Research International did discuss likely trends in peak load, demand-side management potential, and adoption of rooftop photovoltaics. However, this analysis relied on 2015-vintage forecasts to predict peak load in 2022. These values are informative but cannot be treated as decisive given the current context.

[12] http://www.nao.usace.army.mil/Portals/31/docs/regulatory/Skiffes/Alternatives/2016.11.17_Dom_response%20to%20NTHP_Tabors%20analysis.pdf?ver=2016-11-18-124548-357

Dominion and PJM originally planned that the 18-to-20 month construction term of the Skiffes Creek project would be completed in time for the project to come online prior to the retirement of the Yorktown coal units.[13] However, the project has been held up in permitting and only recently received the final approvals necessary to begin construction. In response to these delays, Dominion sought and received an extension of the MATS compliance deadline and a one-year compliance order following the expiry of that extension. The order required the Yorktown units to comply with MATS or retire by April 15, 2017. As of that date, the new 500 kV line that forms the heart of the Skiffes Creek project had not even begun construction, much less come online.

2.3. DOE'S EMERGENCY ORDERS

PJM sent a request for emergency action under the Federal Power Act on June 13, 2017, approximately two months after the planned retirement date for the Yorktown units. PJM cited internal power flow studies that indicated a potential need for rolling blackouts (otherwise known as "shedding load") under certain load and transmission system conditions, given the lack of both the Yorktown units and the intended replacement (the Skiffes Creek project). PJM identified two particular scenarios in which it anticipated needing to either operate the Yorktown units or shed load in the NHRLA:

a) During times of peak load under normal transmission conditions

b) During transmission outages anticipated to occur as part of the construction of the Skiffes Creek project

In addition, PJM submitted a proposed dispatch methodology to DOE, laying out how PJM would decide whether and when to call on the Yorktown coal units. This methodology implies a need to operate one or both of the Yorktown units in the event of certain transmission system contingencies, such as an unsolved N-2 contingency (i.e., a situation in which two elements of the transmission are unexpectedly out of service at the same time), although such situations are not listed as a formal "scenario" in the Request.

[13] PJM Application, p13.

PJM requested wide latitude to operate one or both of the Yorktown units under any of these three situations. The application does not extensively describe the specific conditions under which PJM anticipated calling upon both of the Yorktown units rather than only one. However, PJM did state that the transmission outages associated with construction of the Skiffes Creek project could require at least one of the Yorktown units to operate for some portion of the construction period.[14] PJM went on to say that "the second unit will need to be ready if the first unit is not available" or in the event of unusually high local loads. I understand this statement to imply that one of the units is clearly preferable to the other in terms of ongoing operability or cost.

Given the dependency of PJM and Dominion's plans to retire the Yorktown units on completion of the Skiffes Creek project, PJM's application implies that its current state of apparent emergency will last until the project is completed. PJM proposed in its application that DOE issue an order and then allow that order to automatically "roll over" for additional 90-day periods. PJM suggested that this state of default continued approval last until it has provided "a demonstration of changed circumstances."[15] It is not clear what circumstances those might be apart from completion of the Skiffes Creek project, as PJM did not describe any other efforts on its part or Dominion's part to materially change the circumstances leading to PJM's request. Indeed, PJM's mitigation plan, as described within its application, refers primarily to development of the Skiffes Creek project and to PJM's ability to shed load if necessary.

DOE granted PJM's request on June 16, 2017, allowing PJM to dispatch the Yorktown units "in the event that [it] determines that generation from Yorktown Units 1 and 2 is needed to maintain reliability."[16] DOE's initial order operated through September 14, 2017. In issuing its order, DOE required PJM and Dominion to develop a dispatch methodology "to operate Yorktown Units 1 and 2 *only* when called upon to address reliability needs."[17] Moreover, DOE declined to allow the order to renew automatically,

[14] PJM Request at p14; value redacted.
[15] PJM Request at p13.
[16] DOE Order, p2.
[17] DOE Order, p2, emphasis added.

stating that renewal "should it be needed, must be requested prior to [the] expiration" of the original order.

PJM submitted a Renewal Application on August 24, 2017, requesting a 90-day extension to DOE's first order. DOE granted that request, issuing a renewed 90-day order on September 15, 2017.[18] Unlike DOE's initial order, the renewal order expressly permits the Yorktown units to run as PJM deems necessary to support grid reliability during transmission outages associated with construction of the Skiffes Creek project. The renewal also requires, as the original order did not, that PJM and Dominion "shall exhaust all reasonably and practicably available resources, including demand response and behind-the-meter generation resources, prior to operating Yorktown Unit 1 or Yorktown Unit 2."[19] This directive recognizes that the public interest is served by Dominion and PJM seeking alternatives to continued reliance on the Yorktown coal units.

3. NEED FOR AND ALTERNATIVES TO CONTINUED OPERATION OF ONE OR BOTH YORKTOWN UNITS

3.1. PJM AND DOMINION'S RELIANCE ON THE YORKTOWN UNITS EXPOSES THE PUBLIC TO RELIABILITY RISKS AND HIGH COSTS

As mentioned above, PJM anticipates an 18-to-20-month construction period for the Skiffes Creek project. In order for the project to have come online prior to the anticipated retirement date of the Yorktown units, construction would have had to commence by the middle of October 2015. Dominion and PJM were, of course, aware that the project was held up in permitting and that some means of compensatory action would therefore be required to ensure stable grid operations in the NHRLA.

Dominion's proposal was to employ a "Remedial Action Scheme" (RAS), which would lead to load-shedding in the NHLRA under high-load conditions. As early as mid-October of 2015, Dominion notified the Virginia State Corporation Commission (SCC) that it intended to conduct an inspection program to "ensure reliability for the Peninsula

[18] Order 202-17-04
[19] *Id.* at 2.

while the Surry-Skiffes Creek Line is being constructed in anticipation of the Yorktown Unit 1 and 2 retirements."[20] Dominion then continued:

> If the Certificated Project is not in-service by the time that Yorktown Units 1 and 2 must retire to be in compliance with effective environmental regulations, then the plan for maintaining system reliability for the Peninsula will include careful planning of transmission outages and minimum work on assets on the Peninsula while the planned outages to support the construction of the Certificated Project outages are underway. Under some unplanned event scenarios, the reliability plan must include shedding of load in the amounts necessary to reduce stress on the system below critical demand levels.[21]

Dominion did not cite continued operation of the Yorktown units as a potential option for avoiding this load shedding. Nor did Dominion discuss any other feasible alternatives, despite referencing the potential loss of load and despite having over a year to pursue a mitigation plan more extensive than a line inspection program. Indeed, this same text appears in Dominion's most recent update to the SCC,[22] along with a brief description of the exact load shedding scheme Dominion plans to employ in the event that the Yorktown units are not available and contingency conditions occur (the aforementioned RAS). However, Dominion has been clear with PJM and other stakeholders that the RAS is only a "stopgap measure" and cannot provide a long-term solution to the reliability issues posed by retirement of the Yorktown coal units under certain load conditions.[23]

PJM's proposal was and continues to be limited to continued operation of the Yorktown units themselves. However, this path is hardly preferable to Dominion's RAS from the public's point of view. In addition to the harmful emissions associated with operation of Yorktown 1 and 2, these units come with high costs and are poorly-suited to provide reliability benefits. The Yorktown units are old and inflexible, requiring 10 to 12 hours to ramp from a cold state to full capacity.[24] As described above, the units have been dispatched infrequently and primarily for capacity-related purposes in recent years.

[20] Dominion Update on Status of Certificated Project, 23 October 2015, docket PUE-2012-00029.
[21] *Id.*, p10.
[22] Dominion Update on Status of Certificated Project, 19 September 2017, docket PUE-2012-00029.
[23] Dominion North Hampton RAS Presentation to PJM, p8.
[24] Lazarro Att., p4.

Dominion's head of generation himself acknowledges that when these units are rarely used, "it is more difficult for [them] to quickly and reliably start up."[25] The reliability of the units will get even worse over time, as the Yorktown units experience "general degradation."[26]

The inflexibility, long startup times, and decreasing availability of the Yorktown units make them ill-suited to provide a reliability benefit even under conditions of need that are forecastable to a reasonable degree of certainty, such as peaks in demand and construction-related transmission outages. In such cases, Dominion may have enough advance notice to begin operations at Yorktown early so that the units are ready in time for a critical event. It is worth noting, however, that deploying the units under these circumstances necessarily causes additional emissions during the units' lengthy ramp-up/ramp-down periods.

However, PJM has also made clear its view that the Yorktown units may be needed in the case of contingencies or other unexpected events that impair the operability of the transmission network. These events can often pose a substantial threat to the reliability of electric service, although most contingencies do not cause a loss of service to end-users. Indeed, the transmission system is designed exactly to withstand most foreseeable contingencies without interrupting service.[27] Even so, the unpredictable nature of contingency conditions is in large part what allows them to pose a threat to grid reliability—sudden and unexpected losses of transmission facilities are challenging to adequately plan for and respond to on a real-time basis.

The Yorktown units are particularly ill-suited to provide a reliability benefit in response to such conditions. Contingencies are by definition unexpected, meaning that no notice can be given to allow Dominion to prepare for contingency conditions. Continued degradation of the units—for example, the development of corrosion, leaks, and other

[25] Declaration of Kenneth Lazzaro ("Lazarro Att."), attached, at p. 3.
[26] Lazzaro Att., p. 4.
[27] J. D. Kueck et al., "Measurement Practices for Reliability and Power Quality: a Toolkit of Reliability Measurement Practices." 2004. Oak Ridge National Laboratory. http://www.science.smith.edu/~jcardell/Courses/EGR325/Readings/ornl_tm_2004_91.pdf. P6.

faults—may prevent a rapid and reliable startup during a contingency event.[28] Even without considering forced outages, Yorktown 1 and 2 are sufficiently inflexible that they cannot be relied upon to provide generation or reactive power support in a short enough timeframe to be materially useful during an unforeseen contingency event.[29] PJM and Dominion's claim that the Yorktown units will provide a substantial reliability benefit is therefore a dubious one. Over time, this degradation may even reduce the Yorktown units' ability to provide services during foreseen peak load or planned transmission outage events.

Maintaining the Yorktown units to provide reliability services places a notable burden on the public. In addition to the variable cost of operating the plant when called upon to do so (which consists primarily of fuel), Dominion must spend about $500,000 per month[30] to keep the units in a ready-to-operate state. Each three-month emergency order contemplated by DOE will therefore incur a cost of at least $1.5 million, for a reliability benefit that will decrease over time. Fuel, as well as startup- and shutdown-related operational and other variable maintenance costs, will only increase the costs associated with dispatch of Yorktown units 1 and 2. Dominion may have already spent more than an additional $1.7 million[31] on fuel costs alone simply to run the Yorktown coal units during June and July of 2017.

Given the long lead time between when Dominion foresaw its present conditions and when PJM appealed to DOE for emergency relief, it is not clear to me why neither Dominion nor PJM sought a more aggressive mitigation plan that included reliance on resources other than load-shedding. However, this decision to neglect pursuit of reasonable alternatives has committed the public in PJM to payment of the substantial costs associated with maintaining Yorktown 1 and 2 without providing the reliability benefits associated with modern resources in good operational condition. The substantial costs associated with maintaining and operating the Yorktown coal units and the minimal

[28] Lazzaro Att., p4.
[29] Lazarro Att., p4.
[30] Lazzaro Att., p5.
[31] Based on coal consumption data from Attachment 2 to PJM's Application for Renewal and coal cost data from the EIA's Form 923 and 923M publications for 2016 and 2017.

reliability benefits provided by these units underscore the importance of a mitigation plan to allow Dominion and PJM to cease or reduce their reliance on one or both Yorktown units as rapidly as possible. The public's interest is best be served by avoiding unnecessary usage of the Yorktown units, regardless of when the Skiffes Creek project comes online.

3.2. Dominion and PJM should Pursue All Reasonable Alternatives to Continued Operation of the Yorktown Units

As described above, several alternatives analyses examining options other than the Skiffes Creek project were conducted by Dominion and other stakeholders as part of the project's planning process. The most recent update to these analyses was performed by the Army Corps of Engineers (USACE) in March 2017. This analysis concluded with certainty that the Skiffes Creek project is the preferred path to resolving reliability issues posed by the retirement of the Yorktown units. However, the fact is that the Skiffes Creek project is not presently available and will not be available within the next 18 months at a minimum. In the meantime, Dominion and PJM can and should seek to mitigate or resolve their current needs using reasonable non-wires alternatives (NWAs).

When PJM, Dominion, and USACE approached their consideration of alternatives to the Skiffes Creek project initially in 2012, the concept of using distributed energy resources (DERs) and NWAs to meet reliability and other system needs was in its infancy. Over the past five years, increased sophistication and decreased costs associated with DERs have allowed NWAs to become one of the top-line means of addressing grid issues.[32] These strategies were not considered with adequate depth or, in some cases, considered at all in USACE's alternatives analysis process. For example, both PJM's application and the USACE's review of alternatives discard the possibility of demand-side management (including both energy efficiency and demand response) as a means of controlling load levels on the peninsula. PJM states that the existing demand response levels are limited-

[32] A similar example is Bonneville Power Administration's I-5 Corridor Reinforcement Project, which was proposed in 2009 as a billion dollar transmission expansion project, and whose need was deferred entirely by a combination in NWAs and changes to their system. See U.S. DOE, BPA I-5 Decision Letter: https://www.bpa.gov/Projects/Projects/I-5/Documents/letter_I-5_decision_final_web.pdf

use in nature and therefore it cannot rely upon those resources indefinitely.[33] The USACE states that "additional amounts [of DSM] cannot be assumed to be available."[34] Other regulators, however, have taken a different tack—for example, the California Public Utilities Commission directed Southern California Edison (SCE) to "take immediate steps to enhance their demand response efforts" in response to emergency capacity needs in the wake of the Aliso Canyon Gas Storage Facility leak.[35] In response, SCE proposed to reach an additional 1 million customers[36] and accomplish at least an additional 8 to 14 MW[37] of load reduction in the space of approximately six months.

Even a much more modest demand response or energy efficiency deployment effort in the NHRLA may yield notable benefits in terms of local peak reductions. Dominion achieved a total of almost 50 MW of peak reduction in Virginia between 2012 and 2015 using energy efficiency measures, with 25 MW saved in 2015 alone.[38] Given the existence of several large institutions in the NHRLA, it is possible that Dominion could enter additional demand response arrangements quickly and at a meaningful scale. Large organizations have increasingly invested in microgrids and other resiliency-focused technologies that can also provide demand response-type services. Indeed, the United States Department of Defense has itself installed several microgrid and/or demand response projects at sites close to the NHRLA.[39] Dominion can also seek to enroll additional residential and small commercial customers in existing demand response programs. Rapid deployment of demand response may reduce the occurrence of situations in which PJM calls upon the Yorktown units.[40] Dominion's 2017 Integrated

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[33] PJM Request, p21.
[34] USACE, p3. http://www.nao.usace.army.mil/Portals/31/docs/regulatory/Skiffes/Alternatives/Updated_Alt_White_Paper_3.30.17.pdf?ver=2017-04-04-105404-793
[35] California Public Utilities Commission, Decision 16-06-029, p16.
[36] *Id.,* p20.
[37] *Id.*, p19.
[38] EIA 861 data for years 2012–2015.
[39] http://map.serdp-estcp.org/index.html?ProgramArea=EW#; see in particular: https://www.serdp-estcp.org/Program-Areas/Energy-and-Water/Energy/Microgrids-and-Storage/EW-201600, https://www.serdp-estcp.org/Program-Areas/Energy-and-Water/Energy/Microgrids-and-Storage/EW-201343.
[40] The oft-cited Brooklyn-Queens Demand Management program managed to defer a substation upgrade project for a fifth of the upgrade cost by investing in local demand response. See: https://conedbqdmauction.com/

Resource Plan points out that the achievable market potential (as per a 2013 potential study) is three times higher than the Company is currently planning to achieve, indicating that under the appropriate incentive regime, much more load reduction—both from an energy and capacity standpoint—is possible across Dominion's territory.[41]

Distributed generation is another potential contributor to a rapid-deployment, non-wires strategy to approaching reliability needs on the peninsula. Dominion's comments on a stakeholder-proposed alternative generation option make it clear generation must be located in the NHRLA in order to provide a reasonable alternative to the Yorktown units and the Skiffes Creek project, simply because of potential energy deficiencies in the NHRLA itself during summer peak periods.[42] Distributed rooftop solar generation is one of the most rapidly-deployable of all generation resources; a study by DOE's National Renewable Energy Laboratory recently found that distributed solar systems of up to 50 kW can be deployed within 1.5-2 months.[43] Although many individual installations may be needed to meet the NHRLA's needs, the deployment time of such systems is far shorter than that required of a conventional resource such as a gas-fired CT. Because solar installations provide their maximum generation during summer peak hours, they can help alleviate the specific constraint from which the NHRLA suffers. If it obtained regulatory approval to do so, it is highly likely that Dominion could prompt substantial installations of distributed generation in the NHRLA—many years of industry experience have shown that customers readily respond with installations when given clear price signals in favor of distributed generation from their utility.[44] For example, Hawaii experienced annual increases in rooftop solar capacity on the order of 75–100 MW per

[41] Dominion 2017 IRP, p 95-96.

[42] Dominion response to NTHP, June 2, 2017. http://www.nao.usace.army.mil/Portals/31/docs/regulatory/Skiffes/Alternatives/2017.06.02_2017.05.26%20Dom_Resps_NTHP.pdf?ver=2017-07-05-130502-077

[43] NREL, Table 1. https://www.nrel.gov/docs/fy15osti/63556.pdf

[44] An analysis of a map of EIA-reported solar installations – such as the one available on Synapse's website at http://www.synapse-energy.com/tools/interactive-map-us-power-plants – in the United States demonstrates the efficacy of state policy and incentives in promoting solar growth. Note that installations are almost perfectly aligned with state borders in North Carolina, Maryland, Massachusetts, and New Jersey as a result of favorable policies, incentives, and pricing signals.

year for the period 2011–2015, based in large part on the strong economics of net-metered distributed generation in that state.[45]

Finally, neither Dominion, nor PJM, nor the USACE appear to have considered the use of advanced energy storage systems as a means of providing both capacity and reactive support on the peninsula. Battery energy storage is perhaps the most promising of all potential near-term options for addressing the issues cited by PJM in its Request. Advanced batteries have rapid ramp rates and response times[46] and are able to provide capacity, energy, and reactive power on an as-needed basis,[47] especially for short periods of need. The plummeting costs of battery systems in recent years have made this technology feasible and cost-effective for more applications than in the past, and other utilities have responded appropriately. Three recent examples show the potential of rapidly-deployed battery energy storage systems to address conditions similar to that in the NHRLA:

- SCE relied on battery storage to address its emergency capacity shortfall in the wake of the Aliso Canyon gas leak. SCE procured a 20 MW, four-hour battery storage system, with a total procurement time of approximately five months.[48]
- Arizona Public Service (APS) chose to install two four-megawatt-hour batteries to address local transmission constraints rather than construct a new line in rural Arizona.[49] APS is installing these batteries explicitly to provide grid services rather than load shifting or firming renewable energy. The utility expects these systems to come on line in early 2018, and to be the first steps towards adding 500 MW of battery capacity system-wide over the next fifteen years.

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[45] http://energy.hawaii.gov/wp-content/uploads/2011/10/FF_May2016_FINAL_5.13.16.pdf, p23; Hawaii has since altered its net metering policy.
[46] https://www.nrel.gov/docs/fy14osti/59003.pdf, Table 7.
[47] http://www.sandia.gov/ess/publications/SAND2010-0815.pdf
[48] https://www.sce.com/NR/sc3/tm2/pdf/3455-E.pdf
[49] https://www.aps.com/en/ourcompany/news/latestnews/Pages/aps-brings-battery-storage-to-rural-arizona.aspx

- Tesla has committed to supplying a 100 MW storage system to address local reliability problems in South Australia with a total procurement time of 100 days after the signing of an interconnection agreement.[50]

Because I was not able to review the confidential values of Dominion and NHRLA load levels at which PJM anticipates requiring grid services from the Yorktown units, I was not able to perform an analysis of the capacity and generation required from alternative resources to provide local capacity and reliability services at the levels PJM found to be necessary to avoid load-shedding in the NHRLA. However, a strong possibility exists that Dominion can implement one or more of these alternatives at a sufficient scale and with sufficient rapidity to allow for the final retirement of one or both of the Yorktown coal units or, at a minimum, reduce the number of hours that these units are operated.

As a particular example, Dominion's presentations on the design of the Skiffes Creek project point to the limited transfer capabilities of the two currently-existing transmission paths into the peninsula as the primary motivator of reliability concerns in the absence of the Yorktown coal units.[51] One such path runs in parallel lines from the Chickahominy and Lanexa substations down to the peninsula, through the Lightfoot and Waller substations and towards Yorktown.[52] The other connects the Whealton and Winchester substations to the Chuckatuck substation across the James River.[53] The hypothetical posed by Dominion is that in the event that one of these transmission paths became unavailable, the other path would be insufficient to satisfy demand in the NHRLA, and that therefore either NHRLA-sited generation (i.e., the Yorktown coal units) or an additional transmission path (i.e., the Skiffes Creek project) is needed to ensure reliable electric service on the peninsula. Neither Dominion nor PJM has seriously studied the option of deploying local distributed generation and demand-side management strategies with the aim of substantially lowering local peak requirements. However, it may be the

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[50] https://www.premier.sa.gov.au/index.php/jay-weatherill-news-releases/7736-tesla-to-pair-world-s-largest-lithium-ion-battery-with-neoen-wind-farm-in-sa

[51] http://www.nao.usace.army.mil/Portals/31/docs/regulatory/Skiffes/Section%20106/11_02.10.2016_Dom_Skiffes_Modeling_Alternatives.pdf?ver=2016-06-28-124053-013

[52] *Id.*

[53] *Id.*

case that these strategies could control the NHRLA's needs sufficiently that battery systems of moderate size (10-100 MW) located at the NHRLA end of the two major existing transmission paths, for example at the Waller and Whealton substations, would cost-effectively address these reliability concerns during the Skiffes Creek construction period.

Dominion and PJM should investigate the feasibility and cost-effectiveness of such alternative options. Battery system capital costs have been declining sharply in recent years. Recent estimates place the all-in capital cost of a 4-hour battery storage system at approximately $3,000/kW.[54] Distributed solar generation has capital costs on the order of $2,000-$2,800/kW,[55] much of which is borne by the system owners themselves. Dominion itself has recently been able to acquire energy efficiency for well under 3 cents per kWh on a lifetime basis.[56] While the cost of fully replacing the Yorktown coal units on a MW-for-MW basis would likely exceed the cost of keeping the units online, these alternative resources have lifetimes that would that would last far beyond the scope of the current conditions. DERs can generally provide other types of system benefits in addition to addressing the immediate need posed by the retirement of the Yorktown units, and would continue to provide these benefits for many years to come. The public's interest would be best served by PJM and Dominion conducting a thorough analysis of these options and formulating a mitigation plan that would allow them to reduce operations at the Yorktown units, and potentially to retire one or both of the Yorktown units on a near-immediate basis, regardless of the development path of the Skiffes Creek project.

4. CONCLUSIONS AND RECOMMENDATIONS

Dominion and PJM should be actively pursuing all reasonable alternatives to continued operation of the Yorktown units. The Yorktown units themselves are poorly-suited to reliably provide generation or reactive power support (given the units' operational inflexibility and long startup times). Continued reliance on Yorktown 1 and 2 therefore

[54] https://www.wecc.biz/Administrative/2017-01-31%20E3%20WECC%20Capital%20Costs%20v1.pdf, p48.
[55] https://www.lazard.com/media/438038/levelized-cost-of-energy-v100.pdf, p18.
[56] Savings-weighted average of total lifetime savings for years 2012–2015, based on EIA Form 861 data for Dominion.

places the reliability of electric service for residents of the NHRLA in a precarious position, while exposing the public to burdensome costs. Conversely, implementation of reasonable non-wires alternatives may render one or both units unnecessary even during transmission system outages associated with the construction of the Skiffes Creek project—and such alternative resources would continue to provide benefits even after the resolution of the current emergency.

At present, neither Dominion nor PJM has seriously assessed options like local distributed generation and demand-side management strategies as a means to substantially lower local peak requirements. PJM and Dominion have neglected to explore these options despite having adequate notice of the delay in the construction of the Skiffes Creek Project. Recent rapid deployment of demand response, renewables, and storage in other jurisdictions has proven that alternatives to units like Yorktown 1 and 2 can be used to provide reliability support quickly and cost-effectively.

In light of these findings, I recommend that DOE enforce its directive that PJM and Dominion "exhaust all reasonably and practicably available resources… prior to operating" the Yorktown coal units. DOE should require PJM and Dominion to investigate the economic and technical viability of resources that may provide alternatives to continued reliance on the Yorktown coal units, rather than continuing to automatically renew its decision to allow continued operations at the two Yorktown coal units. I recommend that DOE require PJM and Dominion to submit a rigorous and thorough study of the extent to which implementation of demand-side management, distributed generation, and battery storage can be cost-effective as a means of avoiding further reliance on the Yorktown units as soon as practically possible, ideally within 60 days of the issuance of DOE's extension order. This study should be accompanied by a plan to implement those measures which Dominion and PJM find would allow final retirement of one or both of the Yorktown coal units prior to the online date of the Skiffes Creek project.

Attachment

IN THE UNITED STATES DISTRICT COURT
FOR THE DISTRICT OF COLUMBIA

NATIONAL PARKS CONSERVATION ASSOCIATION 777 6th Street, NW Suite 700 Washington, DC 20001, Plaintiff, v. TODD T. SEMONITE, Lieutenant General U.S. Army Corps of Engineers 441 G Street, NW Washington, DC 20314, and ROBERT M. SPEER Secretary of the Army 101 Army Pentagon Washington, DC 20310, Defendants, and VIRGINIA ELECTRIC AND POWER COMPANY, c/o HUNTON & WILLIAMS LLP 951 E Byrd Street Richmond, VA 23219, Defendant-Intervenor.	)	Civil Action No. 1:17-cv-01361

DECLARATION OF KENNETH LAZZARO

I, Kenneth Lazzaro, hereby state as follows:

1. I am over the age of twenty-one and have personal knowledge of the facts set forth herein. I have knowledge of, and I am competent to testify regarding, all of the matters set forth herein.

2. I am the Director of Power Generation Operations at Virginia Electric and Power Company dba Dominion Energy Virginia ("Dominion Energy").

Operation Of Yorktown 1 & 2 During Emergencies

3. Dominion Energy owns and operates the Yorktown Power Station. Two coal-fired units at this facility, Units 1 and 2, originally placed into service in 1957 and 1958, respectively, were scheduled to cease operations as of April 15, 2015, in response to mandatory regulations issued by U.S. Environmental Protection Agency ("EPA") in 2011, known as the "Mercury and Air Toxics Rule" (or "MATS Rule"), which imposed new restrictions on emissions of air pollutant that these older Yorktown units could not meet.

4. In order to meet reliability standards of the North American Reliability Corporation ("NERC") and avoid load shedding throughout the North Hampton Roads Load Area ("NHRLA"), and as permitted by federal environmental regulations, the Virginia Department of Environmental Quality ("DEQ") granted Dominion Energy the maximum one-year extension of the April 16, 2015 MATS compliance deadline, to April 15, 2016. A copy of this extension is provided as Exhibit 41.[1]

5. Prior to the expiration of the DEQ extension, EPA issued an Administrative Order to Dominion Energy extending the MATS deadline for another year through April 15, 2017, to operate the Yorktown Units on an as-needed basis to meet the NERC Reliability Standards. A copy of this Order is provided as Exhibit 42. By law, no further extensions of MATS were allowed, and therefore the Yorktown Units ceased operations on April 15, 2017.

6. Dominion Energy is constructing the Surry–Skiffes Creek–Whealton Project ("Project") to increase transmission capacity into the NHRLA. Due to the extended time

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[1] Exhibits referenced herein are attached to Dominion Energy's Memorandum in Opposition to Plaintiff's Motion for Preliminary Injunction.

required to obtain the necessary permit from the U.S. Army Corps of Engineers, it was not possible for the Project to be completed and in service before the Yorktown Units ceased operating due to the MATS rule. As a result, PJM Interconnection L.L.C. ("PJM"), the regional transmission organization, filed for an emergency order under § 202(c) of the Federal Power Act from the Department of Energy ("DOE"). A copy of the application is provided as Exhibit 43. On June 16, 2017, DOE issued Order No. 202-16-2, finding that an emergency exists under the Federal Power Act and requiring Dominion Energy to operate the Yorktown Units to meet that emergency. A copy of the emergency order is provided as Exhibit 7. The Sierra Club recently filed with DOE a Motion to Intervene and Petition for Reconsideration of the emergency order. A copy of that motion is provided as Exhibit 8. On August 11, 2017, DOE granted Sierra Club's request for rehearing to allow time to consider the issues, but did not stay the effectiveness of the DOE Emergency order. A copy of the DOE Order granting rehearing is provided as Exhibit 44.

7. Both of the Yorktown Units were directed by PJM, under authority of the DOE emergency order, to operate during the extremely hot weather last month which resulted in high electricity demand. During July of 2017, Unit 1 was required to operate on seven days and Unit 2 was required to operate on 10 days. Both units were required to operate on July 24, 2017.

8. Relying on the emergency operation of the Yorktown Units under the DOE order is at best a stopgap measure. Due to the legal constraints since April 2015, the Yorktown Units have been called on less frequently, and only when needed during extreme heat or extreme cold conditions when electricity demands increase or when transmission line maintenance constrains normal transmission flow. It is more difficult for units to quickly and reliably start up in these conditions.

9. Units of this type also experience general degradation as a result of limited operation. This may take the form of corrosion to electronic switches, moisture build-up in various electric motors, leaks in cooling water lines, or faults in pressurized vessels and duct work. Any of these problems can delay start up or cause a unit to be shut down.

10. Problems of this kind generally can be identified, and thus corrected, only when the unit is operating. The limited operating authorization under the DOE order provides for more limited opportunities to detect and remedy such problems at the Yorktown Units, increasing the likelihood that the units will experience a problem upon startup or during operation on any given occasion.

11. When the Yorktown Units are needed to meet peak demand, PJM will typically give notice less than 24 hours before the units are needed. If there are no equipment malfunctions, the Yorktown Units take approximately 10-12 hours to come on-line.

12. The Yorktown Units typically will be needed only for a short periods of time—sometimes a day or two. Delays in starting up these units or the need to shut down due to an operating problem could cause the units to be unavailable during the short time period they are needed.

13. The Yorktown Units can, if started up successfully and running reliably, address known or anticipated demand (*i.e.*, extreme weather conditions, maintenance elsewhere in the power grid). Because of the time required to start up, the Yorktown Units cannot be relied on to address service disruption due to unforeseen immediate service outages (*i.e.*, a tree falling on transmission line currently bringing power into the NHRLA).

Costs of Operating Yorktown Units 1 and 2

14. Until the Project is completed and placed into service, Dominion Energy must be in a position to run the Yorktown Units when directed to do so.

15. The fixed cost of maintaining the Yorktown Units in an operational state, even when not running, is approximately $500,000 per month.

[signature appears on following page]

I declare under penalty of perjury that the foregoing is true and correct.

Date: August 16, 2017

Kenneth Lazzaro