Dominion's Proposed "Surry-Skiffes Creek Project" – Issues and Alternatives

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EXECUTIVE SUMMARY

This document summarizes the results of an evaluation of a Dominion Virginia Power (Dominion) proposal (Surry-Skiffes Creek Project) to install a 500 kV overhead transmission line across the James River east of the Surry Nuclear Power Plant near historic Jamestown and Colonial National Historical Park in Virginia. The report discusses shortcomings of the Dominion analysis, evaluates changing power market developments, and identifies practical measures to reduce, reconfigure or eliminate the need for the project.

In sum, the harm the proposed project would cause to nationally significant natural, historic and cultural resources requires that Dominion re-evaluate its proposal. Our analysis, using more recent growth projections and updated data as a basis, indicates that reasonable, practical strategies can meet the region's near-term electric power needs without degrading the region's historic character and environmental integrity.

Critical information was overlooked in the process of evaluating the proposed 500 kV overhead line and the alternatives analyzed by Dominion, and forecasted peak load growth has not materialized. Specifically, Dominion's analysis: (1) overstates peak demand growth by not incorporating the most recent demographic population shifts, military facility conservation and efficiency measures, and peak demand forecasts; (2) does not consider available demand side management (a.k.a., demand response, peak shaving) options commonly and effectively employed elsewhere; (3) does not account for growth of distributed generation such as rooftop solar photovoltaic and mandates for switching military bases to renewable energy; (4) does not properly consider options available to expand existing transmission resources, and understates the cost of the preferred option; (5) fails to quantify the damage the preferred option would cause to natural and historic resources, including, but not limited to potential adverse impacts on tourism, property values and to scenic resources; and (6) does not address the potential for increased use of reserve capacity at the oil-fired Yorktown Unit 3. These points are outlined below and discussed in detail in this report.

1. **Peak Load, Economic Growth <u>Overestimated</u>** – Demographic indicators including gross regional product and employment show that the Hampton Roads area has not experienced significant, sustained economic growth in recent years and there is no reason to believe this will change significantly in the near term. In addition, the nine major military installations in the area comprise a large portion of North Hampton Roads Load Area (NHRLA) energy demand, and have achieved a significant and accelerating decrease in energy consumption overall, cutting energy use by 10% in the past four years. Federal incentive programs are resulting in significant efficiency gains in overall commercial and residential energy with improvements in building insulation, industrial motors, smart controls, lighting and other technologies. Overall demand has leveled since 2010, with great potential for further efficiency improvements. The area's annual peak load growth between 2002-2011 averaged 1.1%, in contrast to the 1.9% average annual peak load growth factor used to support the need for the project. Recent trends and actual peak load data over the past decade show that the projection of 1.9% average annual peak load growth is too high.

2. **Demand Side Management <u>Underestimated</u>** – The Dominion analysis significantly underestimates the availability and growth potential of Demand Side Management, in which Dominion pays customers a small fee to allow the utility to reduce their power use during periods of peak demand or emergencies. System wide tests conducted by Dominion in 2014 showed potential for nearly three times the Demand Side Management capacity needed for

peak shaving to prevent blackouts. Consequently earlier forecasts used as a basis for the project underestimated available load management and this capacity can be easily and quickly expanded by Dominion by revising its policies and adopting proven programs commonly used throughout the industry.

3. **Growth of Distributed Solar PV <u>Underestimated</u>** – The shift to Distributed Generation - mostly solar photovoltaic panels (PV) - is occurring across the country. This trend, just beginning in the NHRLA, is conservatively projected to add 16 MW of residential and 64 MW of commercial installations of behind the meter or net metered solar systems in the area by 2030. Virginia ranks 42nd in both the number and installed capacity of solar power systems, with vast room for growth, as demonstrated by other states.

4. **Inadequate Evaluation of Alternatives and Project Costs** – The Dominion alternatives analysis fails to adequately consider two alternatives: 1) reinforcing or paralleling one of the existing lines into the Peninsula and 2) installing a single circuit line across the river under water and underground, thereby eliminating the need for tall towers that would have day and night lighting required by the Federal Aviation Administration. In addition, the costs analysis does not quantify added costs of overcoming permitting issues and possible litigation, nor the indirect costs of decreased property values and tourism. Detailed cost information on the Dominion preferred overhead line has not been provided, so cannot be properly evaluated.

5. **Inadequate Impact Assessment** – On a project of this magnitude in an environmentally and culturally sensitive area, an Environmental Impact Statement should be conducted to address the potentially significant adverse impacts to cultural resources, tourism, and recreation. The historic Carter's Grove Plantation is less than a mile from the proposed route of the towers, the Colonial Parkway is only 3.75 miles and the Jamestown Island Historic Site is only 3.36 miles from the proposed route. In addition, Dominion failed to evaluate properly the project's potential impacts on property values, threatened and endangered species, migratory birds, navigation, and riverine habitat loss.

6. **Failure to Evaluate the Potential for Yorktown Unit 3 to Temporarily Manage Greater Loads** – The Dominion forecast of reliability violations and load shedding is somewhat weakened by the fact that Yorktown Unit 3 is generating less than the annual capacity limit allowed by Environmental Protection Agency limited use provisions. Yorktown Unit 3 is not projected to close until 2022, and could likely manage peak loads in NHRLA until then since the region is not experiencing economic growth, and because efficiency, demand side management, and distributed generation will help reduce peak loads.

In the Public Interest, it is incumbent upon the U.S. Army Corps of Engineers to ensure that the alternatives analysis used to justify the need for the project includes an evaluation of the significant shifts in the power market and demand patterns over the last five years to determine: a) if the NHRLA is under threat of unscheduled load shedding, b) if options exist to mitigate or avoid power system violations, and c) if the new baseline conditions result in a different optimal alternative. If the Corps determines that an Environmental Impact Statement is required, this analysis shows that there would be adequate time to conduct the needed studies, and move forward on appropriate strategies, before any threatened overloading might occur. In light of new data, a re-examination of the project alternatives is needed, including a full and independent environmental impact study.

We therefore recommend that the Corps require a full Environmental Impact Statement, and the James City County Board of Supervisors reject Dominion's application.

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BACKGROUND AND PROJECT JUSTIFICATION

In October 2015, Princeton Energy Resources International (PERI) was retained by the National Parks Conservation Association (NPCA) to provide an independent technical review and assessment of a project proposed by Dominion Virginia Power (Dominion) known as the "Surry-Skiffes Creek -Whealton project", referenced in this document as "the Dominion Project". Dominion has applied to the U.S. Army Corps of Engineers (USACE) for permits to construct this transmission project to serve the North Hampton Roads Load Area (NHRLA). The North Hampton Roads Load Area (NHRLA)[1] is one of many designated "balancing areas" within Dominion territory. A balancing area is a geographic zone whose boundaries are defined by utilities in order to manage power flows in and out. NHRLA accounts for about 10 % of the total electric power demand (load) in Dominion service territory. As part of the same project, Dominion has also applied for a special use zoning designation in order to construct a new switching station near Skiffes Creek, in James City County. The county Planning Department recommended against the zoning change in August 2015 and the Board of Supervisors has scheduled a vote on the proposed zoning change in January 2016.

The Dominion project would add a new 500 kilo-Volt (kV) line on 44 new steel-lattice towers up to 300 feet tall that would cross the James River east of the Surry Nuclear Plant, connecting the switching station there to a new switching station at Skiffes Creek, on the Peninsula. It includes an additional 230 kV line to carry the power south from Skiffes Creek, along the right of way of the existing Peninsula line. There are four 230kv lines now providing power to the Peninsula; two coming from the north, through the Lanexa switching station and down the Peninsula into Newport News, and two from the south, on towers adjacent to the James River Bridge connecting to Norfolk (see Figure 1). NHRLA imports approximately 40% of its annual electricity demand through these lines. The southern two lines connect the NHRLA to the South Hampton Roads Load Area (SHRLA), which imports over half of its power (mostly from the west), so there are limits on the ability to increase the supply to NHRLA from SHRLA during peak loads. Other alternatives evaluated by Dominion include an additional high voltage line down the Peninsula from the Lanexa Station and an additional line from the south, across the James River adjacent to the existing line/towers/bridge.

Load Flow Studies – Load Flow modeling is used to forecast reliability violations so problems can be addressed before they occur. Dominion Load Flow studies conclude that if the proposed project is not in service before retirement of Yorktown Power Station Units 1 and 2, NHRLA will not meet the Reliability Standards of the North American Electric Reliability Corporation (NERC)[2] and load shedding will result (Dominion 2012). Dominion has applied for, and been granted, a one-year extension allowing Yorktown Units 1 and 2 to remain in service until April 2016[3]. An additional year extension may be granted at EPA's discretion. The need for the project is therefore predicated on Dominion's projections of peak loads within NHRLA producing instability (overloading) in the grid due to a lack of local generation and/or transmission capacity. This triggers "reliability violations" in the NHRLA as defined by NERC.

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[1] NHRLA consist of approximately 285,000 customers comprised of the Peninsula (Counties of Charles City, James City and York and the Cities of Williamsburg, Yorktown, Newport News, Poquoson, and Hampton), Middle Peninsula (Counties of Essex, King William, King and Queen, Middlesex, Mathews, Gloucester, and City of West Point), and Northern Neck (Counties of King George, Westmoreland, Northumberland, Richmond and Lancaster, and the City of Colonial Beach).

[2] NERC is a not-for-profit international regulatory authority whose mission is to assure the reliability of the bulk power system in North America.

[3] Source - http://www3.epa.gov/ozoneadvance/va2014/carolinectymatsextreq.pdf

Reliability Violations – Reliability violations are a useful metric to show how often the load in a particular balancing area exceeds a threshold that is set at a safe margin ("reserve margin") below the available power (transmission and generation capacities). In the northeast U.S., including Dominion service territory (DOM zone), reliability violations are triggered most often due to extreme summer heat, when air conditioning use peaks, and in recent years, they have also occurred due to anomalous extreme winter cold (polar vortex conditions), when electric heating peaks. The focus of this analysis is on summer peak loads, however, for reasons discussed later in this document.

Generation Capacity in NHRLA – The only large generator in NHRLA is the Yorktown Power Station, which is comprised of two coal fired plants (Yorktown 1 & 2) that produce approximately 323 MW and one oil fired plant (Yorktown Unit 3 – Y3) that has a rated capacity of 838 MW. Due to environmental restrictions Dominion can only operate Y3 intermittently (8% limit on annual capacity factor)[4] and the unit has an approximately 3 day start up time. Y3 is projected to run until 2022[5] under these restrictions. The Dominion analysis states that upon retirement of either Yorktown Unit 1 or 2, Dominion will be required to implement pre-contingency load shedding (i.e., rolling blackouts) in the NHRLA to prevent the possibility of cascading outages that could affect other connected balancing areas. Dominion estimates that rolling brown- and blackouts would initially occur 80 days a year and would continue to increase in number as load continues to grow in the area (Dominion 2012). The amount of load to be shed is estimated to be between 220 MW and 240 MW. This load shedding would theoretically occur only during extreme hot or cold weather, when loads are at their peak.

Figure 1 shows a regional map of high voltage lines and switching stations, with net energy flows indicated by arrows. Figure 2 shows a local map of the proposed James River crossing component of the proposed Dominion project.

[4] http://www3.epa.gov/ozoneadvance/va2014/carolinectymatsextreq.pdf
[5] http://wydailyarchives.com/2011/09/02/dominion-slates-yorktown-power-plant-for-closure-by-2022/

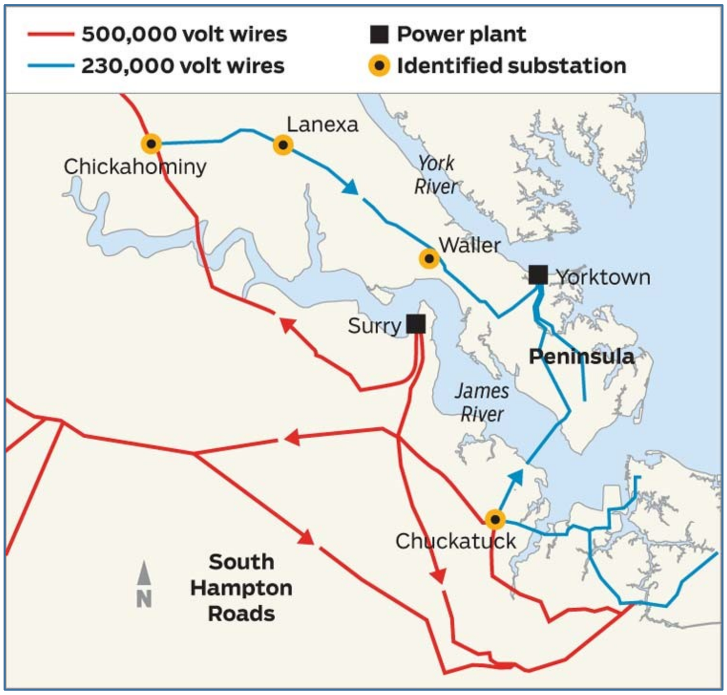

Figure 1 - Regional Map Showing Existing High Voltage Lines, Switching Stations in Hampton Roads. Source: PJM Regional Transmission Organization 2015

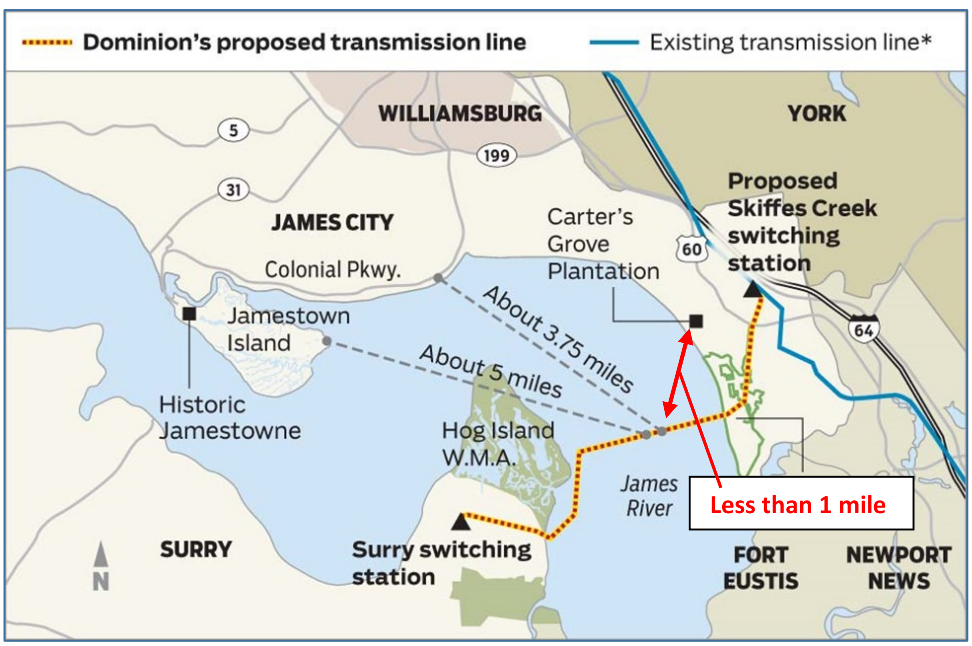

Figure 2 - Proposed Path of New 500kV Line and Towers Showing Distances to Nationally Significant Cultural Resources. Adapted from Daily Press 2015

Analysis of Project Impacts is Incomplete

The Corps (USACE) estimates that the proposed project would permanently impact 2,712 square feet (0.06 acres) of subaqueous river bottom and 281 square feet (0.01 acres) of non-tidal wetlands, and convert 0.56 acres of palustrine forested wetlands to scrub shrub non-tidal wetlands. The project could also impact locally-occurring endangered species including Atlantic Sturgeon, Northern Long Eared Bat, Small Whorled Pogonia, and Sensitive Joint Vetch, as well as the Bald Eagle, due to the project's impacts on the Hog Island Wildlife Management Area. The project would also have negative impacts on the view shed from important Historic and Cultural locations, including direct adverse effects to the Lower James River Historic District, and the Capt. John Smith Trail, and it would create indirect adverse impacts to Carter's Grove, Jamestown Island, and Colonial Parkway. Pursuant to §10.1-419 of the Code of Virginia, a twenty-five mile section of the James River is designated as a "Historic River". The Code provides that in the "*planning for the use and development of water and related land resources…full consideration and evaluation of the river as an historic, scenic and ecological resource should be given before such work is undertaken*." A portion of the project is within the designated area where the line begins to cross the river at the Surry Nuclear Power Station.

The Virginia Corporation Commission Hearing Examiner's Report states (August 2, 2013, p. 139):

"*…, I find that the portion of the Surry – Skiffes Creek Line crossing through the portion of the James River designated by §10.1-419 as an "Historic River" will be the least visually impacting portion of the James River crossing of the Surry – Skiffes Creek Line. Consequently, I find that the proposed project complies with §10.1-419 of the Code*."

This clearly is not the case, since the alternatives using an underwater cable do not include towers across the river, and so would create much less visual impact. This alternative was rejected by Dominion due to cost considerations and was not evaluated using the proper criteria.

In addition, potential significant impacts to property values, recreation, and navigation were not addressed in the alternatives analysis.

FOCUS ON SUMMER PEAK LOAD PROJECTIONS MAKES SENSE

Dominion service territory (hereafter referred to as "DOM zone") is part of PJM, the multi-state grid operator that controls bulk transmission systems across the Northeast. For reliability planning purposes, Dominion uses peak load forecast data from PJM. PJM, in turn, uses projections from the U.S. Energy Information Administration (EIA) and Moody's Analytics, and uses them to generate peak load forecasts for each of their 20 control zones (grid power management areas that comprise PJM). When Dominion first began doing load flow studies for this project, the 2012 Load Forecast Report (PJM 2012) was likely the most recent load forecast available. Those forecasts are based on historic data up to 2011.

Dominion reported record electricity usage in Virginia during the February 2014 polar vortex, and said an overload may have caused a blackout that affected several hundred customers in Hampton. The small number of customers affected indicates that the outage resulted from an overloaded distribution line within NHRLA, not a deficit of power coming in to NHRLA.

Despite recent winter peak loads, line overloading most often occurs during summer peaks, when lines sag and melt due to a combination of high air temperature and electrical resistance heating. System transmission capacity is higher in winter. As a result, the same peak load that could be easily managed during winter could easily cause line overheating during summer. Another consideration is that although the recent polar vortex triggered a winter peak load that exceeded the summer peak, this is highly unusual, and is not a suitable basis for long term reliability planning. In addition, upgrading building insulation is one of the most cost effective measures to reduce energy use, and cold snaps tend to inspire investments that reduce future costs of winter heating. Therefore, this analysis focuses on summer peak loading, since reliability violations and load shedding - if they occur - will be driven primarily by summer peaks, and not the anomalous winter peaks only recently observed.

Inflated Summer Peak Load Projections

The Dominion analysis is based on data from the PJM 2012 Load Forecast Report (PJM 2012), which projects a summer peak load growth rate of 1.9%. Inflated assumptions about growth can drastically affect peak load projections in a short time period. The summer peaks forecast for 2012-2014 in that report have not materialized in the DOM zone. Dominion based its justification for the project on NHRLA load growth of 8% between 2015 and 2020 (USACE 2015), but summer peak loads in the DOM zone dropped every year from 2011-2014 (PJM 2015a).

Figure 3 shows the results of a regression on the weather normalized summer peak historic data for the DOM zone based on the PJM 2014 Load Forecast Report, which includes actual summer peaks through 2013, shown in the black line. The red segments show weather normalized data, which is a "smoothed average" showing the last nine years of summer peaks had there been no anomalous weather events[6]. The green line shows forecast data from PJM 2014 (the 2014 Load Forecast Report) and the straight blue line shows a regression (numerical extrapolation) of the weather normalized data using the most recent 9 years of available data (2004-2013). By 2020, the difference between the two projections is over 2,000 MW. This translates to overestimating peak loads in the NHRLA by about 200 MW.

[6] More information on weather normalization is available at -http://www.pjm.com/~/media/committees-groups/subcommittees/las/20150902/20150902-item-03-weather-normalization.ashx

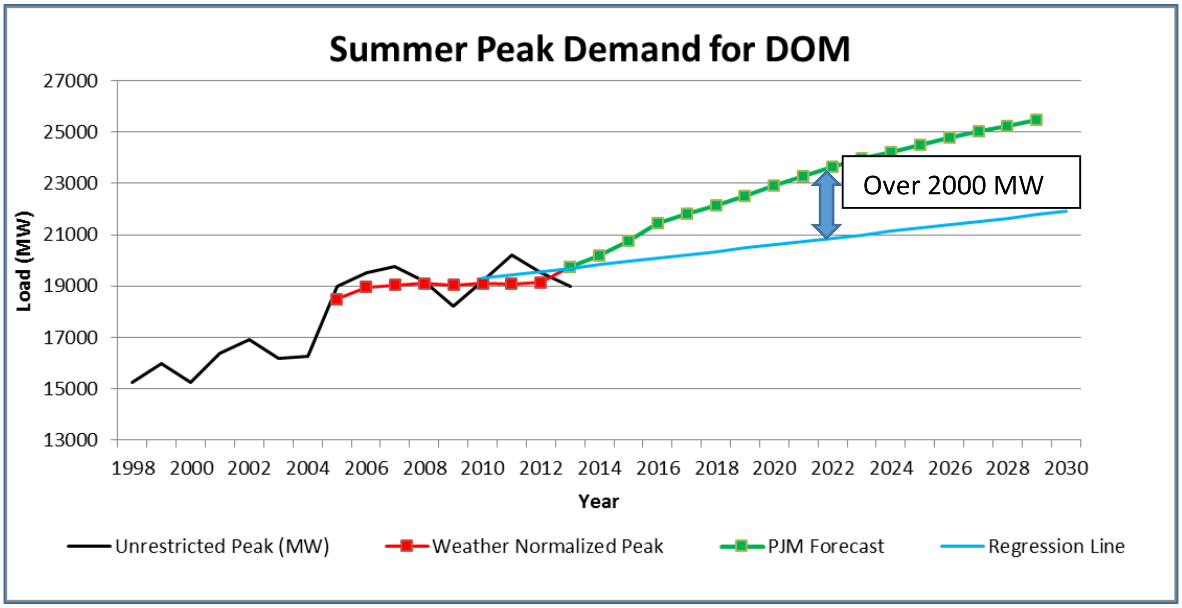

Figure 3 - Summer Peak Demand for DOM zone, Historic and Projected (Data Source-PJM 2014 load forecast report)

Figure 4 shows forecast data from two PJM Load Forecast Reports (2012 and 2016). There is a large difference between the forecasts in PJM 2012 (blue line) and the more recent forecasts (2016-orange line). The difference of about ten percent translates into about 200 MW of difference in NHRLA. This is nearly equal to the amount of load shedding predicted by Dominion upon closing of Yorktown units 1 and 2, and calls into question the project justification. It is worth noting that in 2012, 2013, and 2014 peak load actually dropped (PJM 2015a).

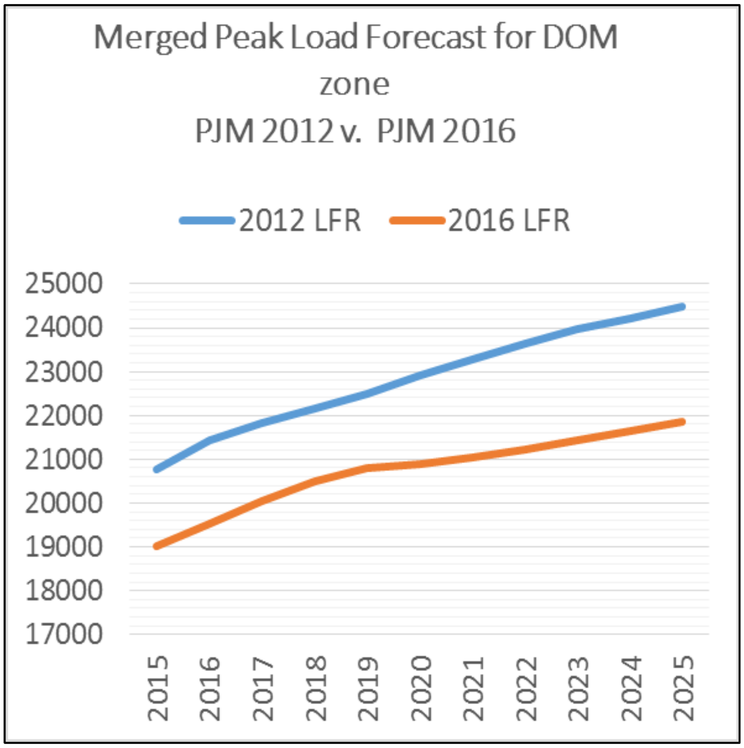

Figure 4 – Change in peak forecast between PJM 2012 and 2016, in DOM Zone

Overinflated Economic Growth Assumed in Hampton Roads

In May 2015, the Hampton Roads Planning Commission (HRPC 2015) published their "Little Book of Big Data", final version[7]. This volume provides valuable benchmark summaries and analyses of demographic trends in the region. During the recent recession Hampton Roads lost over 50,000 jobs and employment in the region remains 20,000 jobs below the pre-recession peak. As shown in Figure 5, the region's Gross Regional Product is barely above where it was pre-recession 8 years ago. Figure 6 shows total civilian employment, which peaked in 2007 at 781,200, but since then has barely managed to break 750,000, with the latest available (May 2015) figure standing at about 755,000. Figure 7 shows the total number of military personnel in Hampton Roads, with the levels going from a peak exceeding 140,000 in 1990 to barely 82,000 in 2013.

The area's annual peak load growth between 2002-2011 averaged 1.1% (Dominion 2012- data presented in Appendix I, attached), in contrast to the 1.9% average annual peak load growth factor used to support the need for the project. In light of the improvements in government and military facility insulation and significant efforts to improve efficiency and reduce energy use (discussed in a later section), the high peak load growth projections for the NHRLA clearly are no longer realistic.

[7] Available at https://hrpdcva.gov/uploads/docs/FinalPrinted_little-book-of-big-data.pdf

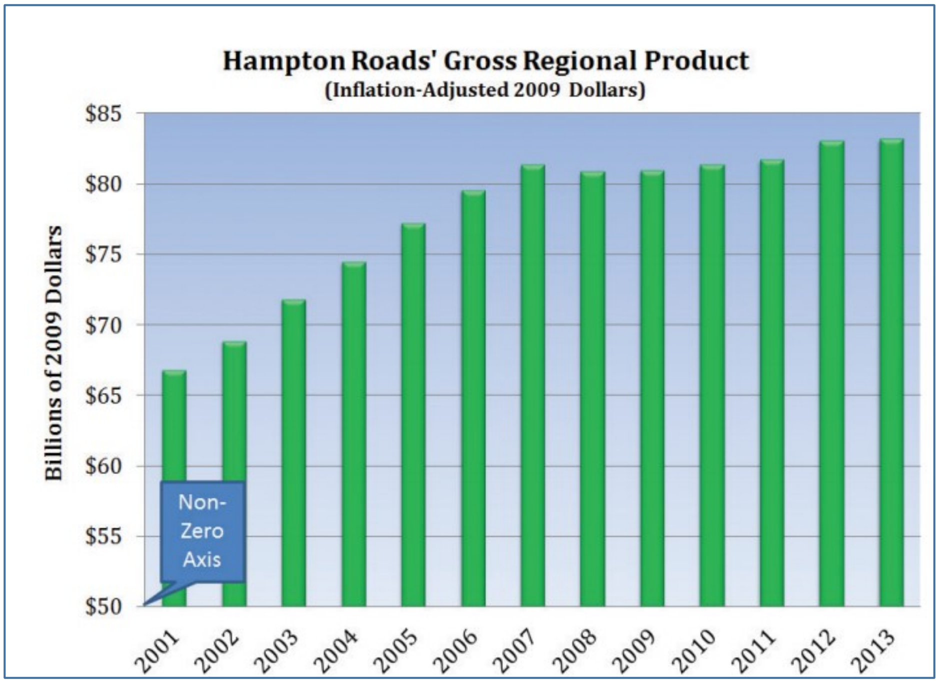

Figure 5 - Hampton Roads' Gross Regional Product, 2001-2013. Figure from HRPC2015, data from Bureau of Economic Analysis

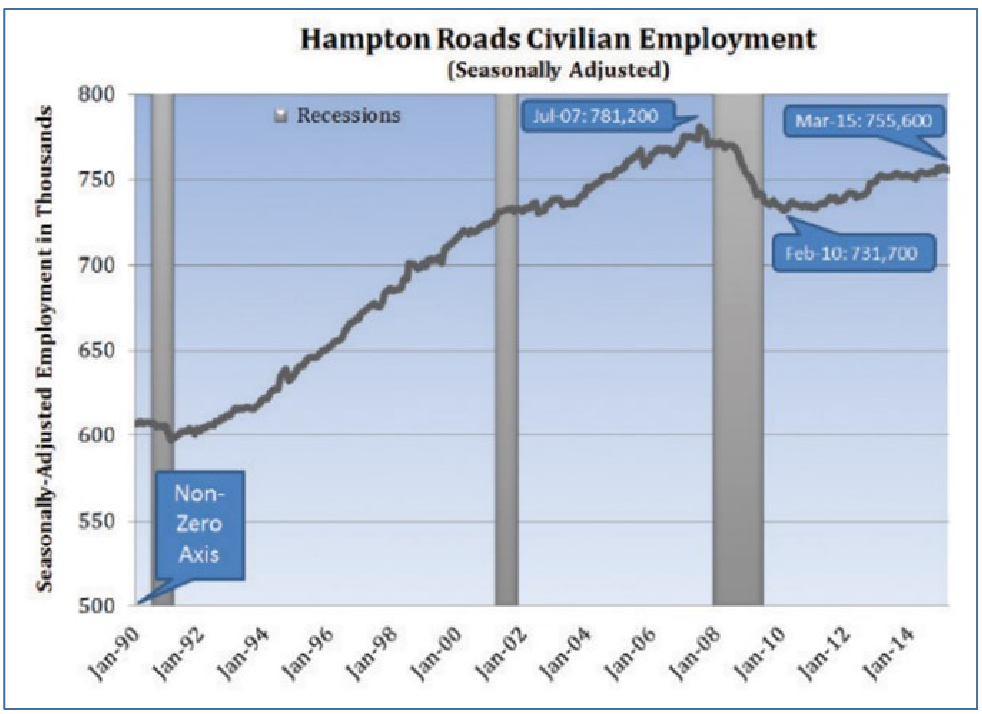

Figure 6 - Hampton Roads Civilian Employment, 1990 – 2014- Data from Bureau of Economic Analysis

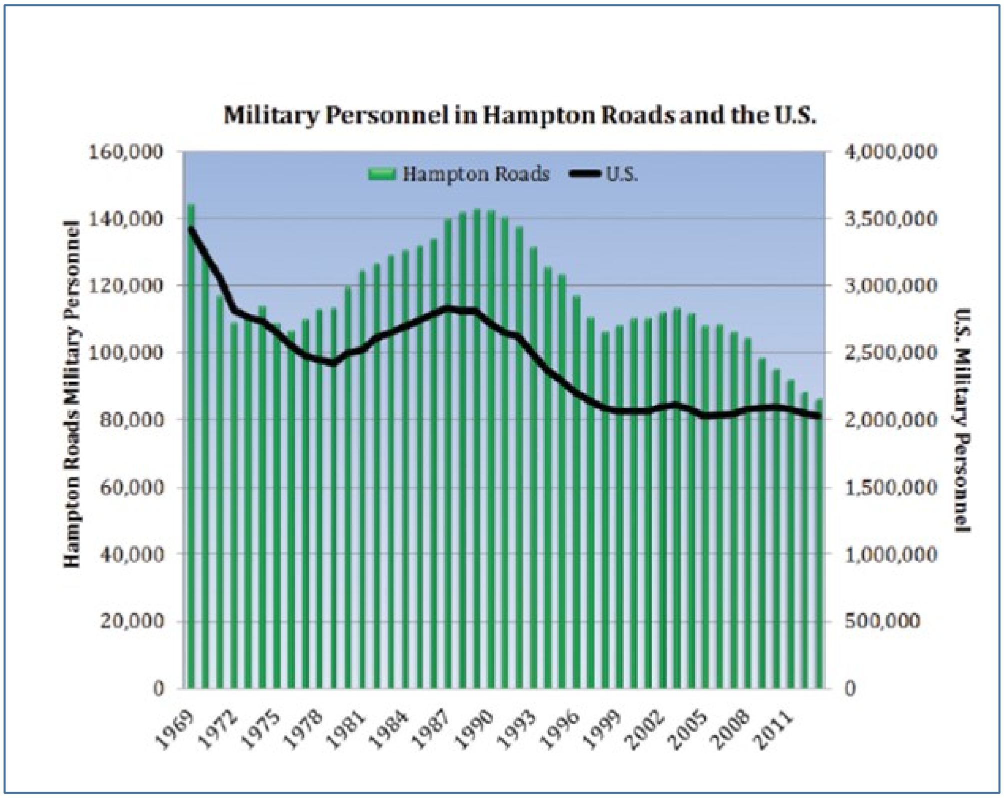

Figure 7 - Military Personnel Stationed in Hampton Roads and Overall US, 1969-2014. Data source- Bureau of Economic Analysis

System Wide Dominion Growth Rate Applied Improperly to NHRLA

In 2012, out of 20 control zones[8] in PJM, the DOM zone shows the highest forecast average growth rates, including the highest summer peak growth rate, at 1.9% (PJM 2012). This is nearly twice the overall forecast summer peak growth rate in PJM, and this is the rate used for forecasting load in NHRLA. However, the Hampton Roads area has not seen significant economic growth in almost a decade, and many key economic indicators are trending down, as discussed previously. Although the forecast algorithm details are not available, it appears that the growth rate for the entire Dominion region was applied to NHRLA without appropriate adjustment for local differences.

EIA Long Term Forecasts vs. Short Term Outlook

PJM uses data from the Energy Information Administration to generate projections. Until 2011, EIA was predicting growth in US electric sales through 2015 and beyond, yet sales have declined in four out of the last five years. Total electricity sales projections were overestimated by about 5 percent on average during the period 1994-2014.[9] EIA has since revised their projections downward significantly, but these revisions were not available for PJM 2012, and thus were not used in the Dominion analysis.

[8] Control zones are regions within PJM, such as DOM, that operate independently, but can buy and sell bulk power through the PJM markets with other control zones when needed
[9] Source data - http://www.eia.gov/forecasts/aeo/retrospective/pdf/table_15.pdf

In the near term, the EIA's annual Short Term Outlook is almost always more accurate than longer term projections. Table 1 shows retail sales for the Mid Atlantic (PJM) region, both residential and commercial sectors between 2011 and 2016. Actual data is shown through 2014, and of course the figures for 2015 and 2016 are projections. In almost every year, and over the five year span, sales actually dropped or are expected to drop. This matches the trends recently observed in the DOM zone and represents a more realistic view of the changes occurring in power markets nationwide.

Table 1 - Electricity Sales for Middle Atlantic Region - From EIA2015 Short Term Outlook, available at http://www.eia.gov/forecasts/steo/tables/?tableNumber=20#

Year	Retail Sales of Electricity in Residential Sector Middle Atlantic million kwh per day	Retail Sales of Electricity in Commercial Sector Middle Atlantic million kwh per day
2016	357	432
2015	371	434
2014	361	431
2013	366	432
2012	361	430
2011	371	436

PJM Making Major Adjustments to Load Forecast That Must Be Considered

The PJM 2015 Load Forecast Report (PJM 2015) includes historic data through 2014 and incorporates significant downward revisions of projections. PJM 2015 incorporates a newly developed algorithm ("new specifications") which models the effects of energy efficiency improvements based on the eventual widespread adoption of commercially available efficiency and energy use reduction technologies. This action acknowledges that prior models and methodologies consistently overestimated load growth, primarily due to underestimating efficiency gains and energy conservation programs. The forecasts for 2020, using the New Specification, are between 8% and 9% lower than the forecasts for 2020 published in PJM 2014[10], and are at least 10% lower than those published in PJM 2012 (and used in the Dominion project justification).

2015 Fewer Load Management Events and Emergency Events, Despite Increased Weather Alert Events

Table 2, below, was copied directly from PJM's 2015 State of the Market Report (PJM 2015d)[11] and shows the number of emergency and pre-emergency events in PJM for the first six months of 2015 compared to the first six months of 2014. The record of these events in any given year is a good indicator of how often and how close the PJM system comes to overloading a major circuit, including

[10] From PJM Load Analysis Subcommittee presentation of September 2, 2015 – source - http://www.pjm.com/~/media/committees-groups/subcommittees/las/20150902/20150902-item-03-weather-normalization.ashx

[11] Available at http://www.monitoringanalytics.com/reports/PJM_State_of_the_Market/2015/2015q2-som-pjm.pdf

those in the DOM zone. These are usually caused by unplanned events that result in system voltages, reserve capacities, or equipment temperatures deviating from safe operating ranges. The most common cause of these events, by far, is extreme weather resulting in peak loads. A more detailed definition of these events can be found in PJM 2015d.

Even though the total number of weather alert days is about 20 % higher in 2015 (35 v. 28) and, more importantly, the number of summer alert days has tripled in 2015 (from 3 to 9), the number of emergency events (excluding weather alerts) dropped from 44 to 16. This improvement is attributed to a combination of transmission infrastructure improvements, additional generation added in congested areas, and lower peak demands in problem zones. With the new Brunswick power plant coming online in 2016, the threat of rolling blackouts is receding throughout the system. Within NHRLA, there is every reason to believe this trend is more pronounced, and no reason to expect peak loads to grow every year through 2030, as Dominion forecasts.

Table 2- Summary of emergency and alert events declared in PJM: January- June, 2014 and 2015

	Number of days events declared	
Event Type	**Jan - Jun, 2014**	**Jan - Jun, 2015**
Cold Weather Alert	25	26
Hot Weather Alert	3	9
Maximum Emergency Generation Alert	6	0
Primary Reserve Alert	2	0
Voltage Reduction Alert	2	0
Primary Reserve Warning	1	0
Voltage Reduction Warning	4	0
Pre Emergency Mandatory Load Management Reduction Action	0	2
Emergency Load Management Long Lead Time	6	2
Emergency Load Management Short Lead Time	6	2
Maximum Emergency Action	8	1
Emergency Energy Bids Requested	3	0
Voltage Reduction Action	1	0
Shortage Pricing	2	0
Energy export recalls from PJM capacity resources	0	0

Source: PJM 2014a, available at http://www.monitoringanalytics.com/reports/PJM_State_of_the_Market/2014/2014q1-som-pjm-sec6.pdf

Several localized power outages were reported in the Newport News area in 2014/2015. The causes are identified as: a) electrical fires caused by rain and salt brine contamination of equipment[12], b) failure of a buried line[13], and c) a snake[14]. The small number of customers affected indicates that the problems were on distribution lines, not on transmission lines.

[12] http://wavy.com/2015/09/26/southside-power-outages-affect-more-than-2000-customers/
[13] http://wtkr.com/2015/06/22/power-outages-in-newport-news/
[14] http://www.dailypress.com/news/newport-news/dp-more-than-2-700-without-power-in-newport-news-20151103-story.html (approx. 2700 customers affected)

DSM Underestimated As Part of the Energy Mix

The Dominion analysis significantly underestimates the growth and potential for Demand Side Management (DSM), which contributes to an overestimation of future peak loads. The Dominion Integrated Resource Plan (IRP) of 2015 includes a baseline of DSM programs of about 300 MW, with zero growth, even though their own projections for the growth of DSM would roughly double that capacity within six years (Dominion 2015, Figure 5.5.6.2). Dominion policy is that only demand response capacity that has been approved can be counted in any future projections of load management capacity for reliability planning purposes. Since added DSM is a potentially available alternative to address peak demand issues, failure to evaluate potential options without a technical or economic justification leads to an inaccurate model of future conditions. More realistic estimates of the potential contribution from DSM are discussed in the PERI estimates below.

PERI REVISED ANALYSIS

Background

Even in areas showing sustained positive economic growth, there are both technical and human factors that are reducing electricity demand. Human factors include concern about air pollution and climate change, and desire to reduce the portion of household budgets paid to the electric utility company.

Technical factors relate primarily to three main areas outlined below: energy efficiency improvements, demand side management, and switching to distributed generation.

- Demand Side Management – reducing peak demand by allowing utilities to briefly turn off (cycle) appliances or equipment for groups of customers. This proven approach has been in common use for more than 40 years but is still in the pilot project stage in Dominion territory.

- Energy Efficiency Improvements – resulting from new electrical equipment and programs designed to conserve energy. Specific examples of efficiency improvements include: “Energy Star” appliances, compact florescent lights, light emitting diodes (LEDs), digital controls and high efficiency industrial motors, building thermal installation, and geoexchange heat pumps, among many others.

- Distributed Generation – mainly solar and a few wind, biomass hydro plants. This is largely an untapped resource in Virginia, where there are 1,318 individual plants registered and certified by PJM, compared to 18,381 in Maryland and 37,194 in New Jersey. Clearly, there is considerable potential for rooftop PV solar growth in the NHRLA.

For technical and business reasons, older forecast methodologies tend to overestimate the future demand for electricity. The reality is that, using the latest PJM Load Forecast Specifications (PJM 2015a), normalized summer peaks have been dropping for the last six years and that is likely to continue in the future. In light of these facts, and after reviewing more than 50 relevant documents, PERI developed an alternate peak load forecast for the NHRLA region that takes into account more realistic peak load projections, more accurate Demand Side Management projections, updated data on federal programs that are reducing energy use in NHRLA, and the growth of local solar PV.

Revised DSM Projections for NHRLA

Background – Methodologies and assumptions for forecasting DSM are changing to align with recent trends. The 2014 FERC Annual Staff Report on Demand Response and Advanced Metering (FERC 2014) is required by the Energy Policy Act of 2005 section 1252(e)(3). The report addresses the six requirements included in section 1252(e)(3) of EPAct 2005. It directs FERC to identify and review, with the goal of increasing DSM:

- *(A) saturation and penetration rate of advanced meters and communications technologies, devices and systems (Chapter 2);*
- *(B) existing demand response programs and time-based rate programs (Chapter 5);*
- *(C) the annual resource contribution of demand resources (Chapter 3);*
- *(D) the potential for demand response as a quantifiable, reliable resource for regional planning purposes (Chapter 4);*
- *(E) steps taken to ensure that, in regional transmission planning and operations, demand resources are provided equitable treatment as a quantifiable, reliable resource relative to the resource obligations of any load-serving entity, transmission provider, or transmitting party (Chapter 5); and*
- *(F) regulatory barriers to improved customer participation in demand response, peak reduction and critical period pricing programs (Chapter 6).*

Many utilities already are acting on these directives with effective and expanding DSM programs. About one third of all U.S. homes already have smart meters that can be used for DSM during peak loads. In the major U.S. power markets, DSM increased 9.3% from 2012 to 2013.

The Dominion Integrated Resource Plan (IRP) of 2015 (Dominion 2015) includes a baseline of DSM programs totaling 296 MW in the DOM zone by 2030. In contrast to this, PJM 2012 projects 1316 MW for DOM by 2016, and the PJM Load Management Report of January 2015 (PJM 2015) shows DSM of 938 MW was achieved during testing in 2014. Since this is a proven capacity, 938 MW is the value used in the revised projections, with a straight ramp to 1316 in 2020. A rough estimate can be generated based on weighted proportionality to estimate how much of this DSM is available to mitigate loads in NHRLA[15].

Weighted Proportionality – Historically, the summer peak of NHRLA has hovered very closely near 10% of the summer peak for the entire DOM region. Since DSM programs are most often associated with industrial and commercial users, and NHRLA has one of the highest proportions of these users, a reasonable estimate would give NHRLA a slightly higher share of the 938 MW of DSM allocated to the entire DOM region. Therefore, 12% was determined to be a suitable estimate of the portion of DOM DSM available to NHRLA. This yields about 112 MW.

[15] Dominion does not release disaggregated DSM data by Load Area.

Program
Non-Residential HVAC Tune-Up Program
Energy Management System Program
ENERGY STAR® New Homes Program
Geo-Thermal Heat Pump Program
Home Energy Comparison Program
Home Performance with ENERGY STAR® Program
In-Home Energy Display Program
Premium Efficiency Motors Program
Programmable Thermostat Program
Residential Refrigerator Turn-In Program
Residential Solar Water Heating Program
Residential Water Heater Cycling Program
Residential Comprehensive Energy Audit Program
Residential Radiant Barrier Program
Residential Lighting (Phase II) Program
Non-Residential Refrigeration Program
Cool Roof Program
Non-Residential Data Centers
Non-Residential Recommissioning
Non-Residential Curtailable Service
Qualifying Small Business Improvement Program*

Figure 8 - Energy Savings and Demand Side Management Measures Rejected by Dominion (source -Dominion 2015)

Potential for Expanding DSM -The potential for expanding DSM in the near term is extremely high since Dominion has installed over 320,000 smart meters as of May 2015. (Dominion IRP2015). These units are capable of cycling HVAC and/or water heater systems on and off during peak load periods, reducing the overall peak. Similar programs in other PJM balancing regions have met with great success in shaving peak summer loads. Compared to other utilities across the nation, however, Dominion has underutilized DSM as a strategy for managing peak load periods. Figure 8 is taken from Dominion 2015 (IRP) and shows the list of DSM programs that have been rejected by Dominion.

One of the most effective ways to reduce peak loads is to link retail rates, directly or indirectly, to wholesale or spot market prices. Equipment can be run at lower power when prices go up and appliances can be set to run only when prices drop below a threshold. Tiered pricing is a simplified variant of this market based strategy. The Quarterly State of the Market Report for PJM (PJM2014a) states the following; *"If retail markets reflected hourly wholesale prices and customers received direct savings associated with reducing consumption in response to real-time prices, there would not be a need for a PJM economic load response program*…"

There is clearly additional capacity available for DSM and energy efficiency gains if Dominion would support load management programs and power market reforms that have been proven to safely boost DSM capacity and reduce peak loads.

Renewable Energy Use Projections (Solar and Wind)

Solar – As part of Dominion's 2013 Integrated Resource Plan, both the Base Plan and the Fuel Diversity Plan include a small amount of solar photovoltaic electric systems. The plan shows about 200 MW of solar capacity to be provided by one or more Non-Utility Generators ("NUG") under long-term contract (Power Purchase Agreement) to the Company by 2016, as well as 13 MW from the first phase of the company's Solar Partnership Program ("SPP"). Under this program, company owned solar arrays are installed on rooftops and other spaces rented from customers at sites throughout the service area. As a result of a Stakeholder Review Process completed in 2013, the Fuel Diversity Plan of 2015 now includes additional solar resources with capacity of approximately 559 MW (nameplate) by 2029.

Compared to other states, this is merely a token use of solar energy. Virginia ranks 42nd in the U.S., in the use of solar energy, in the "Open Solar" data base maintained by the National Renewable Energy

Laboratory.[16] Currently Virginia has only 45 grid connected solar projects totaling less than 1 MW. For comparison, New Jersey ranks 3rd with 34,481 solar installations totaling 1,506 MW.

A review of land use conducted by PERI indicates that there are several suitable sites for commercial PV plants on the Peninsula, and there is also considerable potential for residential rooftop expansion, which has shown rapid growth elsewhere in recent years. This growth is attributed mainly to the precipitous drop (50% in five years) in the price of solar panels and to the 30% Investment Tax Credit (ITC). The ITC is set to expire at the end of 2016, but it is expected to be extended. There is also a large push for federal facilities to use more renewable energy. These developments/trends are contributing towards expansion of distributed generation, in the form of solar PV, across the nation.

To address these factors, PERI developed a revised forecast for rooftop solar PV in NHRLA. Table 3 summarizes the analysis and assumptions behind this forecast. The assumptions are based on the 2009 Climate Change study by the Virginia State Advisory Board on Air Pollution, and the information on homes and businesses is based on 2014 U.S. Census Data. The analysis projects a capacity of 60 MW of new residential and commercial solar installations in the NRHLA area by 2022, and 80 MW by 2030.

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[16] https://openpv.nrel.gov/rankings

Table 3 - Assumptions and Input to Solar PV Growth Projections for NHRLA

	Available Area (m^2)	Annual Energy (kWh)	Capacity (MW)	Assumptions; Input Data
Total Residential Floor space	40 million	--		206,437 homes; 192 m^2 (2067 ft^2) average floor space per home
Total Residential Interest Area	2.0 million	--		5% owner interest in retrofit
Total Residential Roof Area	400 Thousand	--		20% are near south facing (within +/- 20 degrees); ½ of roof; tilted at 35 degree slope
Exclusion for physical Integration Issues	320 Thousand	--		Additional 20% excluded (dormer windows, gutters, rafter location, etc.)
Exclusion for Shading	150 Thousand	--		50% excluded
Energy Potential from Residential Retrofits		47.3 million	14.25	4.8 $kWh/m^2/day$ resource with 14% load factor; 3.1 kW (AC) per 35 m^2 panel
New Residential only (sum 2015-2030)		6 million	1.8	47,704 building permits (2010); 4 kW PV per new home; if 10% accept solar option in 2020, increasing from 1% in 2015-20117, 3% 2018, 4% in 2019
Energy Potential from Business and Public Building Retrofits		213 million	64.15	Assume number of units is 1/10 of residential; with 10x available roof space, double (40%) flat or nearly south facing and only 25% loss due to shading
Total by 2030		266 million	80.2	880 Residential Installations (retrofits and new) and 90 Business and Public Installations

Wind – Dominion's projections and assumptions regarding development of renewable energy are constantly being revised. The Integrated Resource Plan of 2013 (Dominion 2013) is representative of the typical estimates. The "Base Plan" assumed by Dominion and detailed in the August 30, 2013 IRP document identifies and describes a "Fuel Diversity Plan" that includes about 250 MW of wind power capacity at identified sites in western VA.

The current estimates of the available offshore wind power available to the South Hampton Roads Load Area range from 1500 - 2000 MW, but that is at least five to ten years away, so is not included in Dominion's future assumptions of generation capacity. However the Dominion Fuel Diversity Plan does include the 12 MW offshore wind demonstration project planned for the federally designated Wind Energy Area off Virginia Beach. In addition, a new 208 MW onshore wind farm is being built near Elizabeth City, NC, 12 miles south of the VA-NC border, but in Dominion service area[17]. This plant will be connected to a local power purchaser, but could also feed into the SHRLA and will begin providing up to 208 MW of power in early 2016, and 300 MW upon complete build-out. This new generation, combined with the 12 MW offshore wind demonstration project, could be expanded to feed power into the SHRLA

[17] Iberdrola is building the facility near Elizabeth City, NC, about 45 miles south of the Hampton Roads, and Amazon has agreed to purchase the power. The groundbreaking occurred in July 2015 and the project is expected to be commissioned in 2016. The total project size after complete build-out will be 300 MW.

from the south and east, reducing the need to import power from the west, and freeing up capacity on those lines. Existing lines could allow the system to “pass through” additional power from the west to NHRLA when these wind plants are producing energy. Although individual solar and wind facilities cannot be counted as firm reserve power, they still reduce the likelihood of reliability violations within their own balancing area and adjacent balancing areas.

Federal Facilities Are Switching to Renewable Resources

The Energy Policy Act of 2005 set specific goals for renewable energy as a percentage of total federal facility electricity consumption. The target for FY 2014 was 7.5 percent, increasing annually to 25 percent by FY 2025. To comply, the Army and Air Force subsequently established a goal of deploying 1 GW of renewable energy on or near their installations. Following these announcements, in April 2012, the Executive Office made it official that the Department of Defense (DoD) had committed to having 3 GWs of renewable energy deployed on its installations by FY 2025. In March 2015 the bar was raised by a new Executive Order that requires agencies to: “ensure that the percentage of the total amount of building electric energy consumed by the agency that is renewable electric energy is: not less than 30 percent by fiscal year 2025 and each year thereafter.” In addition, the Clean Power Plan final rules were issued by EPA in July 2015 mandating each state to reduce carbon emissions from existing power plants by replacing them with cleaner generation. These initiatives are bearing fruit, and have even greater potential to increase distributed generation and reduce the need to import power, especially in Hampton Roads and other areas with numerous military and other federal installations.

Nationally, the Federal Energy Management Program (FEMP) reported that 8.8% of electricity used by federal facilities in 2014 came from renewable sources. In DoD, only 3.5% of the electricity came from renewables and likely far less in the Hampton Roads bases since the main supplier is Dominion. The ~400 MW of solar planned by Dominion and the 300 MW wind plant under construction near Elizabeth City, NC (in Dominion’s operating area) will help, but there is still a huge potential for much more solar PV development near or on military facilities, especially those in NRHLA. There are large areas on and nearby the many federal installations on the Peninsula that could be used to fulfill DoD mandates while reducing the peak loads in NHRLA.

DoD uses various authorities to increase the supply of renewable and other distributed (on-site) sources of energy on its installations. DoD often uses non-governmental, third-party developers and commercial financing to pursue renewable energy projects. Federal rules also allow developers to lease land on federal installations for renewable energy projects. The developer can pay for the lease in cash or by providing in-kind services (electric power). Taken together, these programs and trends are contributing to increasing use of renewable energy in NHRLA, which is reducing the need to import power.

Utility scale solar and wind power plants are also being actively pursued that should be factored into the local transmission system plan. Several solar energy pilot projects are underway that can be expanded. Dominion has applied for and been granted a lease for an offshore wind energy plant that can accommodate 1355 MW, reducing the need to import electricity from plants located west of Richmond.

Federal Facilities Are Using Less Electricity

Gains in energy conservation and efficiency within NHRLA are modeled in the PERI analysis using assumptions supported and detailed in the Climate Change study which was conducted by the Virginia State Advisory Board on Air Pollution. These gains are not accounted for in the Dominion analysis. The discussion below describes the well documented improvements at Department of Defense and Department of Energy installations nationally and in the NHRLA. It also outlines continuing reduction assumptions, why they are valid and reasonable, and how efforts to reduce energy use are paying off.

Federal facilities are using less energy. At the national level, DoD has shown significant progress in reducing installation energy use and in switching to renewable sources. This is clearly shown in reduced electricity consumption at military facilities nationwide as reported in the Department of Energy, Comprehensive Annual Energy Data and Sustainability Performance.[18] Figure 9 shows electricity usage combined for Defense Department installations for the last five years.

Government programs to conserve energy are rooted in Federal legislation and Presidential Executive

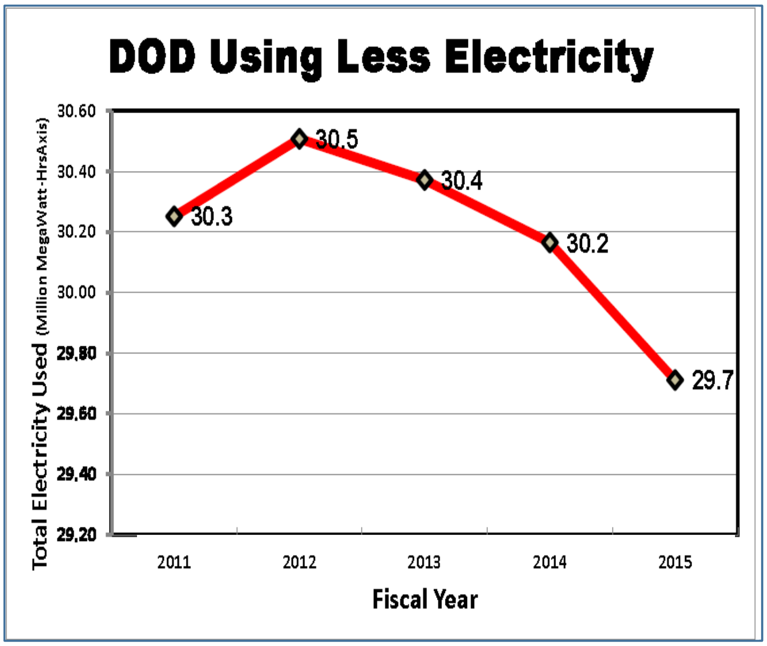

Figure 9 - Department of Defense Electricity Use Dropping Nationwide, FY 2011 – FY 2015. (Fiscal Year is Oct 1 – Sep. 30) tabulated by the Department of Energy, Federal Energy Management Program

[18] Federal Energy Management Program, Comprehensive Annual Energy Data and Sustainability Performance, Total electricity usage for Fiscal Years 2010 thru 2014.
http://ctsedwweb.ee.doe.gov/Annual/Report/FederalAgencyUseRenewableElectricAsPercentageOfElectricityUse.aspx

Orders, and they are working. Over 30 years ago, federal agencies were first directed to track and improve their energy management practices.[19] More recently (2007), the Bush administration issued a key Executive Order titled, "*Strengthening Federal Environmental, Energy, and Transportation Management.*" Subsequently goals were set by each federal agency to improve energy efficiency and reduce greenhouse gas emissions through reduction of energy intensity, and a progress tracking system was established. Energy usage trends are tracked for agencies by the Department of Energy, Federal Energy Management Program (FEMP).

While these goals have not all been fully met, they have had a significant impact in reducing demand for electricity since 2011. This trend is important in forecasting loads in the NHRLA given the area's numerous DoD facilities. Table 4 shows energy usage by military facilities in the Hampton Roads area. In some cases energy uses changed up or down due to shifting mission assignments, but generally the increasing emphasis on energy conservation and efficiency is reducing electricity use. Over the period from Fiscal Year 2011 thru Fiscal Year 2014 energy usage was reduced nearly 10 % - notably, during operations supporting intensive military activities overseas.[20]

Table 4 - Military Power Consumption Dropping in Hampton Roads

Department of Defense Facilities Annual Energy Usage (Bbtu)				
Source: DoD Annual Energy Management Reports for FY-2011 thru FY-2014 Hampton Roads Area				
Facility	**FY-2011**	**FY-2012**	**FY-2013**	**FY-2014**
Little Creek Amphibious Base	596	719	761	711
Oceana NAS	730	678	712	700
NAVSTA Norfolk	2179	2032	1980	1871
NOSC Midlant Norfolk	80	80	80	80
NSA Hampton Roads	572	984	964	949
NSS Ship Yard Norfolk	1128	1018	470	446
Weapons Station Yorktown	286	203	229	218
Joint Base Langley - Eustis	1363	1127	1284	1281
Total	6934	6841	6480	6256
Reduction				**9.8%**

There are many examples of major improvements in energy savings at bases in the Hampton Roads area. In 2014, Oceana Naval Air Station was one of 25 winners of the Federal Energy and Water Management awards sponsored by the Department of Energy. Oceana's energy program implemented a variety of projects, including: retrocommissioning of power systems, installation of ground-source heat pumps, and lighting upgrades. In addition, distributed energy teams were created as a key component of its awareness program to encourage energy conscious behaviors. The Navy's initiatives saved over 5200 MWh of energy in 2013 compared to the prior year. In addition, Joint Base Langley-Eustis has published

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[19] National Energy Conservation Policy Act (NECPA) of 1978, Section 548, in Title 42, U.S.C., Section 8258 [42 U.S.C. §8258], which requires Federal agencies to describe and improve their energy management activities

[20] Department of Defense Annual Energy Management Reports from Fiscal Years 2011 thru 2014, later dated May 2015, http://www.acq.osd.mil/ie/energy/energymgmt_report/main.shtml

a set of Sustainability Goals that aim to reduce energy intensity, by FY-2020, by 37.5% compared to FY-2003 levels, and to produce or procure 18.3% of energy for facilities from renewables by FY-2020[21].

Revised Peak Load Forecast

Based on the information discussed above, PERI developed a revised peak load forecast for NHRLA, shown as a "wedge graph" in Figure 10. The top line was first plotted using the NHRLA weather normalized summer peak loads from Dominion 2012, and the three colored wedges represent the yearly adjustments to that forecast resulting from the three trends discussed above that are driving down peak loads. These are, Distributed Generation (solar PV), Demand Side Management (load control), and Efficiency (energy use reductions). Each wedge represents measures that are additional to those assumed by Dominion in their 2012 estimate, so the amount that each measure contributes during a given year is represented by the thickness of the corresponding wedge in that year. The line between yellow and red represents the forecast after PV installations are included, the line between red and

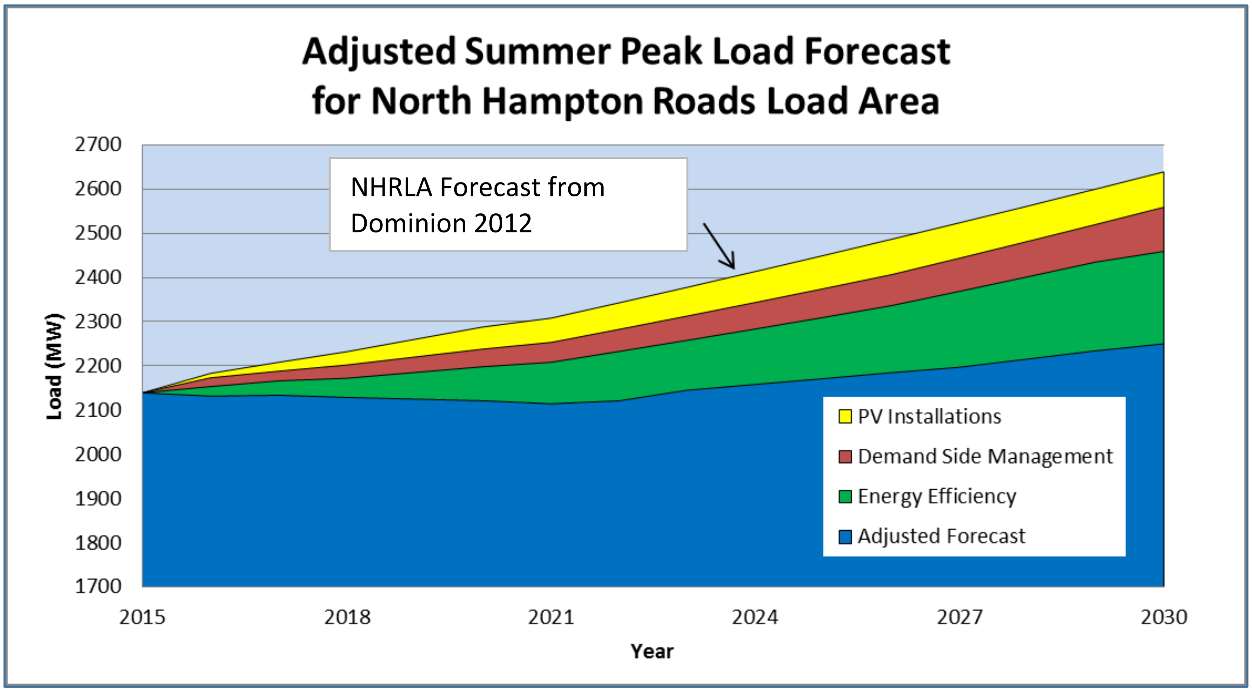

Figure 10- Wedge Graph Showing PERI-Revised Summer Peak Load Forecast for NHRLA

Sources for wedge data;
Dominion Forecast *Data from Dominion 2012, attachment I-B-2*
PV installations *from Assumptions based on SAB Climate Change Report, outlined above*
Demand Side Management *based on 12% of Dominions 938 MW proven resource over all DOM, ramping to 12% of 1316 MW by 2020 based on PJM 2012, and growing 1% per year thereafter.*
Energy Efficiency *Based on American ACEEE "Energizing Virginia: Efficiency First," October 2015*

[21] Available at https://www.wbdg.org/ccb/AF/AFDG/langley_isa.pdf

green represents the forecast after PV and DSM are included, and the bottom line, between the blue and green sections, represents the revised summer peak load in the NHRLA after all three measures are implemented. This analysis shows that there are easily obtainable pathways to achieving zero peak load growth in NHRLA until 2022. It should be noted that actual summer peaks are substantially below the starting point of 2139 MW projected for 2015 in the Dominion 2012 analysis (and used as the baseline for this graphical analysis).

Sufficient Resources Exist to Manage Predicted Summer Peak Loads Without Yorktown Units 1 and 2

The Dominion/Stantec Revised Alternatives Analysis of Jan. 2015 (Stantec 2015, section 3.1.3) states that under the No Action Alternative (Base Case – assumes Yorktown 1 and 2 offline), the amount of load to be shed in NHRLA, beginning in 2015, is between 220 and 240 MW. This was based on a projected 2015 summer peak of 2139 MW in NHRLA (Dominion 2012). Taking the higher value, 240 MW to be conservative, this indicates that Dominion expects to provide the balance (2139 – 240 = 1899MW) using Base Case infrastructure (without Yorktown Units 1 and 2). Therefore 1900 MW is Dominion's projection of how much load can be safely managed (without triggering emergency events) in NHRLA after closing Yorktown Units 1 and 2.

However, since this analysis, the forecasts for the 2015 DOM Zone summer peak load (used as the basis for the Dominion-NHRLA load forecast) have changed materially. In PJM 2012, it was 20,765 MW, but in PJM 2015a, this was revised downwards to 19,999 MW[22], a drop of about 4 %. Therefore it would be reasonable to assume proportionality - that the NHRLA peak loads should also be adjusted downward by 4%, since the DOM zone forecasts were reduced by this amount. Thus, the 2,139 MW forecast (peak summer load in NHRLA in 2015) is reduced by 85 MW to 2054 MW, and the estimated load shedding is also reduced by 85 MW to a revised value of (240 – 85 =) 155 MW. Table 5 lays out the calculations.

Table 5 - Updated Summer Peak Loads and Load Shed Estimate

Summer Peak Dom Load for 2015 (MW)	Summer Peak Dom Load for 2015 (MW)	Change	Peak NHRLA load 2015 (MW),	Updated NRHLA load 4% = 128 MW reduction	Updated load shedding (MW) = (240 - 85)
20,765	19,999	~-4%	2,139	2,054	155
forecast From PJM 2012	*forecast from PJM 2015a*	*change since PJM 2012*	*forecast from Dominion 2012*	*proportional reduction*	*revised load shedding*

Based on the analysis presented previously, the estimate of available summer DSM for NHRLA in 2016 is about 112 MW (12% of 938). The projected addition of 60 MW of solar PV within the area by 2022 will also reduce loads. Since peak loads occur in the afternoon on hot, sunny days, it is safe to assume an output of about 40 MW solar PV during peak summer loads by 2022. This results in total available DSM plus PV, during summer peaks, within NHRLA, of about (112 + 40 =) 152 MW by 2022.

[22] Table B-1 of PJM2015a

Based on the updated forecast and revised load shed requirement (135-155 MW instead of 220-240 MW forecast by Dominion), there is likely enough power to manage the threatened load shedding events that form the justification for the project; with 152 MW of DSM and PV available by 2022 to handle an estimated 135- 155 MW of load.

Yorktown Unit 3 May Have More Capacity for Summer Peak Generation – Another major factor which is not considered in the above load shedding analysis, and which could provide additional reserve capacity, is the availability of unused capacity at Yorktown 3. For emission limitation this oil-fired plant is only allowed to run at up to 8% annual capacity factor until 2022[23], but there are no restrictions on peak power output. This plant can produce 838 MW of power (up to 862 MW in certain conditions), but needs approximately 72 hours to "warm up".

Y3 has the highest costs of any thermal power plant in Dominion territory and the plant has not been operated anywhere near its EPA annual limit of 8% Capacity Factor. In 2013, Y3 generated about 98,000 MWhr, which represents an annual Capacity Factor of 1.3% (an operating Capacity Factor of 38%). In 2014, Y3 produced approximately 175,000 MWhr, for a CF of 2.4% (EPA 2015). There is still plenty of headroom to increase annual energy production at Y3, and this raises the distinct possibility that operations could be modified to better manage peak loads within NHRLA. An analysis of Y3 hourly output during the highest peak load events was performed to determine if unused capacity existed to help manage peak summer loads.

Overall Peak Produced no Load Shedding– The highest monthly output for Y3 over the period for which data are available (2009 -2014) was in January 2014, when it produced 131,298.3 MW-hrs of energy. The data for that peak event were extracted from EPA Air Markets Program Database on 10/31/2015 and are presented in Table 6 below. An examination of hourly output for that month reveals that the peak output of 862 MW occurred for 2 hours on 21 January from roughly 5:00 to 6:00 pm, as shown in Table 6. It also shows there were 12 hours of production above 850 MW, all occurring on 21 and 22 January, during a polar vortex. It is worth noting that this proven winter generation capacity of 862 MW is far above the rated capacity of 838 MW, and no load shedding was required.

Table 6 - Peak Output for Yorktown Unit 3 during January 21-22, 2014

Year	Date	Hour	Gross Load (MW)
2014	1/21/2014	17	862
2014	1/21/2014	18	862
2014	1/21/2014	23	859
2014	1/21/2014	16	858
2014	1/21/2014	21	858
2014	1/21/2014	20	857
2014	1/21/2014	22	857
2014	1/21/2014	19	855
2014	1/21/2014	15	854
2014	1/22/2014	0	852
2014	1/22/2014	3	849
2014	1/21/2014	14	830

[23] Source - http://www3.epa.gov/ozoneadvance/va2014/carolinectymatsextreq.pdf

Summer Peaks – A new record peak load in DOM occurred in February 2015 during a polar vortex, at 21,651 MW. Since this is considered an anomalous event, and since 2015 data are not yet available, the previous record peak event was examined, which occurred in July of 2011, at 20,061 MW. This event is more relevant since it represents the highest *summer* peak by a large margin, when lines are hot and system capacity is reduced. An analysis of the summer peak events of 2010 and 2011 showed only four hours of operation above 700 MW (Table 7, below). There is no evidence that Y3 operated anywhere near its rated capacity of 838 MW or its peak output of 862 MW during the last four summer peak events (2011-2014). The data indicate that somewhere between approximately 70 and 140 MW of unused generation capacity was available at Y3 during those events.

Table 7 - Yorktown Unit 3- Peak Output, July, 2011

Year	Date	Hour	Gross Load (MW)
2010	7/25/2010	19	771
2010	7/25/2010	18	763
2010	7/25/2010	17	719
2010	7/7/2010	12	705
2011	7/22/2011	11	691
2011	7/22/2011	14	689
2011	7/22/2011	12	687
2011	7/22/2011	13	687
2011	7/22/2011	15	678
2011	7/22/2011	10	670
2011	7/22/2011	16	639
2011	7/21/2011	17	607
2011	7/22/2011	9	607

Re-Evaluation of Submarine Cable Alternatives

Dominion and Stantec considered several underwater river crossing options and rejected them due to high cost and technical concerns. The estimated cost of over one billion dollars was not supported by any detailed break-down or independent analysis, so it is difficult to evaluate. However their Alternative C (Stantec 2015), described as an underground 230 kV double circuit (1,000 MVA) on James River crossing Variation 3 Hybrid Conceptual Route, was estimated to cost over a billion dollars. This estimate included $577 million to retrofit and repower the Yorktown plant - supposedly to resolve NERC issues related to project load growth in the post 2016 time frame. In effect, the billion dollar price is for two projects, the river crossing marine transmission line valued at $540.4 million and new generation at Yorktown. Later, in Section 3.3.1 of the Alternative Analysis, costs are compared as follows, "*This alternative [underwater double circuit 230 kV] also costs significantly more at $310 to $390 million versus the estimated $60 million for the overhead crossings.*" Alternative C would install cable below the riverbed for a distance of 3.5 km and then directional drill the cable beneath approximately 2 km of sensitive shoreline habitat. Although no direct rebuttal of Dominion costs is possible, they are clearly not supported by any hard evidence.

One feasible and cost effective alternative that was not considered was a 400 to 500 kV submarine cable. This type of high voltage alternating current cable has been in use in Europe and more recently in the US. See examples in Table 8. Many factors influence consideration of underground transmission lines but the technology is clearly available and virtually maintenance free. A 7.5 kilometer long 345 kV submarine cable carrying up to 602 MW has been installed under the Hudson River delivering power from New Jersey to New York City. That line was energized in 2011 and technology for even higher voltages is now in use. Another technology that is now available is directional drilling. This installation technique is used for shallow water and shoreline crossing and was used in river crossings projects in Jacksonville, Florida and Malden, Massachusetts. The option that Dominion evaluated was for a double circuit 230 kV submarine connection with six conductors. This two line approach appears unnecessary and would be much more expensive than a single, three phase, three conductor 400-500kV line.

Table 8 - Submarine cables are proven in use for many years

Submarine High Voltage Alternating Current Projects (HVAC)							
Location	**Country**	**Year**	**Technology**	**Voltage (kV)**	**Capacity (MW)**	**Distance (km)**	**Supplier**
Jutland to Funen	Denmark	2013	3 core cable	420	1,100	7.5 Submarine + 5.5 underground	ABB
Bayonne Energy Center, New York Harbor	USA	2011	3 XLPE with 10 m separation	345	602	10.4 Submarine + 1.1underground	ABB
Omen Lange Gas Field	Norway	2008	4 XLPE	420		3.2 in water depth 850 to 1100 m	Nexans

Our informal estimate is that the marine cable estimate at $310 million is reasonable but that the $60 million estimate for the proposed project is low and actual cost could be twice as high. Constructing 44 transmission towers, including 17 located in the river, involves excavating four leg footers for each tower so costs should include the extensive planning and permitting process. These costs can be considerable if litigation occurs, or if habitat baseline studies, archaeological surveys, or other additional studies are required.

Another cost consideration is the negative economic impact of the tower-based system. Property values in sight of the towers will decrease, especially near the shore line crossing. There are also potential negative impacts on tourism and fishing. The cost of litigation could also be significant, and so should be considered.

In other regions, surveys of local area residents show strong support for less visually or environmentally intrusive designs. Most residents would be willing to pay a nominal amount more for electricity if they did not have to look at tall transmission towers. The incremental cost would be small for each resident.

The security and reliability of underground infrastructure, along with regulatory issues and public demand are other important factors. In a recent case in California the CPUC approved a 3.5 mile long 500 kV underground line. The CPUC President Michael R. Peevey, said

"*It's the dawn of a new era in transmission line planning in this state. In urban and suburban areas, we have to look anew at how we site transmission lines, and carefully weigh their role in fulfilling the state's energy goals against their impact on community values. I know undergrounding costs more, but I believe in this instance the costs are manageable and relatively minor considering the overall well-being of the populace in doing so*."

Aside from cost, it is generally accepted that underground cable is more secure than overhead cable. Acts of nature can cause outages, and there is the possibility of a terrorist action. Aerial lines are exposed to hurricanes, ice and snow, wind and other natural disasters and overhead cables can be easily accessed for sabotage. Underground infrastructure is far less vulnerable to such risks and is considered more reliable. For infrastructure serving military bases and other institutions of national importance, this security is even more critical. The revised load forecast developed in this report indicates there would be enough time (before reliability violations would occur) to evaluate this alternative and obtain the necessary permits for a submarine cable link.

CONCLUSIONS AND RECOMMENDATIONS

The electrical load flow studies performed by Dominion and confirmed by PJM staff were performed using standard models and methods. However, several of the key operational and demographic assumptions going into the economic models regarding future loads and generation appear significantly out of date or inaccurate, and the model algorithms that were used to project peak loads are now considered flawed. In brief, the Dominion study significantly overestimates NHRLA load growth, including peak loads, and it underestimates: a) the availability of DSM capacity to reduce peak loads, b) the growth of distributed generation, and c) the increasing effectiveness of efficiency measures and energy reduction programs. These flaws result in exaggerated forecasts of rolling brown- or blackouts up to 80 events per year.

The PERI analysis and revised forecast strongly suggests that the summer peak loads Dominion is forecasting for 2016 and beyond will not materialize until at least 2022, and that more recent data shows that future peak loads can be managed with DSM and distributed solar resources. This removes the sense of urgency and would allow USACE adequate time to complete an Environmental Impact Statement for the project. We also conclude that there are potentially significant negative impacts associated with the 17 tower river crossing that have not been evaluated, or have been underplayed in the Dominion alternatives analysis, and that the cost estimates used for the proposed project do not include significant costs related to planning and permitting activities.

In the Public Interest, it is incumbent upon the Corps of Engineers to ensure that the alternatives analysis used to justify the need for the project includes an evaluation of the significant shifts in the power market and demand patterns over the last 5 years to determine a) if the North Hampton Roads Load Area is still under threat of unscheduled load shedding, b) if options exist to mitigate or avoid power system violations, and c) if the new baseline conditions result in a different optimal alternative. If the Corps determines that an EIS is required, this analysis shows that there would be adequate time to conduct the needed studies, and take appropriate action, before any threatened overloading might occur. Re-examination of the project alternatives should be done in the light of new data and along with a full and independent environmental study.

We therefore recommend that the Corps require an Environmental Impact Statement in order to provide an independent analysis of this proposed project, and that the James City County Board of Supervisors reject Dominion’s rezoning application for a new switching station associated with this project.

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LIST OF ACRONYMS

DoD – Department of Defense

DOM – Dominion Service Territory and Infrastructure

DSM – Demand Side Management

EIA – US Energy Information Administration

EIS – Environmental Impact Statement

IRP – Integrated Resource Plan

ITC – Investment Tax Credit

MW – megawatts

NERC - North American Electric Reliability Corporation

NHRLA – North Hampton Roads Load Area

NUG – non utility generator

PERI- Princeton Energy Resources International

PJM – (originally) Pennsylvania-Jersey-Maryland, (currently) PJM Interconnect is the regional transmission operator whose territory includes Dominion

PV – photovoltaic (solar panels)

SHRLA – South Hampton Roads Load Area

USACE – US Army Corps of Engineers

Y1, Y2, Y3 – Yorktown Power Plant Units 1, 2, 3

APPENDIX I - NHRLA HISTORIC AND PROJECTED PEAK LOADS (FROM DOMINION 2012)

Attachment I.B.1 Historical Loads (MW)

	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011
Northern Neck	387	399	392	357	439	445	483	457	431	471	501
Yorktown	1293	1,368	1,343	1,329	1,503	1,486	1,505	1,490	1,413	1,484	1,468
North Hampton Roads	**1,680**	**1,767**	**1,735**	**1,686**	**1,942**	**1,931**	**1,988**	**1,947**	**1,844**	**1,955**	**1,969**
Percent Growth	--	5.2%	(1.8%)	(2.8%)	**15.2%**	**(0.6%)**	**3.0%**	**(2.1%)**	**(5.3%)**	**6.0%**	**0.7%**
System Peak	**19,471**	19,077	**16,502**	**16,731**	18,897	19,375	**19,688**	**19,051**	18,137	**19,140**	**20,061**
Percent Growth	--	(2.0%)	(13.5%)	1.4%	14.4%	2.5%	1.6%	(3.2%)	(4.8%)	5.5%	4.8%
Date	8/09/2001	7/29/2002	8/29/2003	8/4/2004	7/27/2005	8/3/2006	8/8/2007	6/10/2008	8/10/2009	7/24/2010	7/22/2011

Attachment I.B.2 Projected Loads (MW) (2012 Load Forecast)

	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021
Northern Neck	480	490	505	539	565	575	585	596	607	616
Yorktown	1477	1531	1568	1600	1618	1633	1647	1664	1681	1692
North Hampton Roads	**1,957**	**2,021**	**2,073**	**2,139**	**2,183**	**2,208**	**2,232**	**2,260**	**2,288**	**2,308**
Percent Growth	--	**3.2%**	**2.6%**	**3.2%**	**2.1%**	**1.1%**	**1.1%**	**1.3%**	**1.2%**	**1.0%**
System Peak	**19,508**	**20,139**	**20,883**	**21,568**	**22,055**	**22,386**	**22,708**	**23,083**	**23,450**	**23,747**
Percent Growth		3.2%	3.7%	3.2%	2.3%	1.5%	1.4%	1.7%	1.6%	1.3%