Parking Lot Questions & Answers

Below, we have captured the questions and remaining issues from the second CAG meeting. We have inserted responses from Dominion and NOVEC below each question.

1. *What about other alternatives to solve the reliability problems at Warrenton (Remington? Solar/Renewables? Shifting load?)*

DVP/NOVEC: Additional generation -- from Remington, solar panels, or any other source – doesn't have any way of reaching the customers who need it if the existing transmission line is out of service. It may help to think of the existing transmission line as a bridge that goes to an island. Today, that bridge is the only way to get to the island. If the bridge is knocked out – by a hurricane, tornado, plane crash, or just failure due to age – there is no other way to get to the island. Producing more cars on the mainland won't help. You need another bridge to the island. The electricity that is produced at Remington or anywhere else on the system has to have a way to get to the Warrenton Substation to be delivered to the customers throughout Fauquier County. It is the job of the utility to ensure that when the main "bridge" or line to the Warrenton "island" is in jeopardy, that we have a plan in place to provide backup.

Shifting load is sometimes necessary in emergency scenarios. It is also sometimes possible when the neighboring facilities are not as heavily loaded. Unfortunately, shifting load from the Warrenton line is not an opportunity to avoid the need for the project. Dominion is obligated to be prepared to satisfy the load requirements as they occur.

When preparing the application to be filed with the Virginia State Corporation Commission (SCC), Dominion typically considers many alternatives including non-transmission solutions, such as generation. Viable alternatives, their merits and shortcomings, will be described in detail in the application to the Commission.

2. *Since the Gainesville substation needs more power, why not tap into the 500 kV line?*

DVP/NOVEC: The Gainesville Substation does not need more power. The issue isn't about voltage or capacity. The concern is the amount of customer load that would be without power if an event caused the loss of an entire voltage level at the station. While the risk of this type of event is relatively low, the consequences are unacceptable – for Dominion, NOVEC, PJM, and the federal agencies that regulate our business. Tapping into the 500 kV system would not eliminate this concern, or provide any relief. In this scenario, shifting load away from Gainesville does help resolve the issue.

3. *Is Dominion currently shifting load away from the substation?*

DVP/NOVEC: Yes. Dominion and NOVEC have other active projects in Prince William County. One of Dominion's projects will create a new Liberty Substation just north of Prince William County Parkway and Sudley Manor Road. This station is scheduled to be energized in 2015, and will briefly help alleviate some of the growing demand currently served by Gainesville. However, due to the projected growth in this area, this will not provide a long term solution.

4. *What is the historical and projected growth for the Gainesville substation?*

DVP/NOVEC: Between 2002 and 2012, the demand for electricity served by the Gainesville substation grew by approximately 54%. Dominion and NOVEC have had a watchful eye on this situation for decades – carefully monitoring and making adjustments to the system. Dominion and NOVEC anticipate continued, steady growth in this area making this project a vital step in maintaining reliable facilities to serve the area.

5. *Can you build another substation or add transformers at the Gainesville site?*

DVP/NOVEC: While these steps would not reduce the amount of customer load that could be lost in a single event, these, and other options will continue to be explored over time. Many similar steps have already been undertaken in the last few years to help us manage the ever-increasing demand up to this point.

6. *Are there other lines (or the substation at Vint Hill Road) that can create redundancy for Wheeler?*

DVP/NOVEC: Dominion and NOVEC explored an option of building new facilities off Vint Hill Road at the location where NOVEC already has an approved distribution substation. At this location, two stations would be required to create a new transmission line (on new right-of-way) to serve the Wheeler substation. This scenario was initially ruled out because of the estimated cost, which was substantially higher than Option A or Option B.

7. *Underground vs. Overhead – what is the rate of failure for each? What technology is available to help with emergency response?*

DVP/NOVEC: Underground transmission lines are designed such that if a fault occurs, it will remain de-energized until the problem is found and corrected. This can take anywhere from over a week to over a month, depending on the problem.

In general, underground transmission lines have a lower rate of failure than an equivalent overhead transmission line. The biggest difference in reliability is the amount of time required to repair and return the line to service. The vast majority of faults on overhead lines are temporary (lightning, etc) and the system will automatically return the line to service. For permanent faults, most repairs can be completed in a few hours. In very rare cases of a structure failure, restoration can be, on average, one to three days.

For failures on overhead transmission lines, the location of the problem is easy to identify. Our system operator will know that the outage is on a certain line between two substations and a fault recorder predicts the approximate location. A visual inspection of the line will quickly identify the exact location and where repairs are needed. Dominion maintains its own qualified personnel, equipment, and material to make such repairs promptly. Contractor crews and equipment are also readily available, if needed.

For failures on underground transmission lines, each cable must be tested to indentify the failed cable. Dominion must call contractors with complex fault location equipment to aid in locating the fault, unless it is obvious as in the case of a dig-in. Once the fault is located, other highly specialized contractors, of which there are only a handful in the country, must perform the necessary repairs. Depending on the situation, these resources may need to come from abroad. The site of the failure must be excavated sufficiently to provide access to the failed cable to verify the fault location. There is no fault location equipment available that provides enough confidence to begin excavation without doing further fault location testing as described above. Depending on the nature of the damage, the cables must either be repaired with a splice or the entire section between existing splices must be removed from its protective pipe casing and replaced. For a splice repair, the construction of a temporary splice vault for atmospheric control of the splice area is required.

8. *Provide comparative data for underground/overhead to include maintenance (life of the line) costs.*

DVP/NOVEC: A 2006 JLARC (Joint Legislative Audit and Review Commission) report for the General Assembly of Virginia included a study of a hypothetical five-mile 230 kV transmission line for the purposes of comparing life cycle costs (including maintenance) of overhead and underground transmission lines. The results of this study showed that the cost of the underground line was approximately 7.4 times the cost of the overhead line [Table 7, next page]. This study also included full cable replacement after year 40 (underground line design life) to adequately compare to the 70 year design life of an overhead line. Estimated project costs for overhead and underground can vary depending on the location, route, rock encountered, length, etc.

According to this JLARC report, underground transmission lines can cost 3 to 12 times as much as overhead lines.

Table 7: In Four Life Cycle Cost Estimates, Underground Line Costs Are Three to 11.8 Times More Than Overhead Line Costs

Type of Cost	Source 1: 1996, 2001 Acres International Corp. (115 kV)	Source 2: 2005 Highland Council, Jacobs Babtie	Source 3: 2006 Updated Cost, Dominion (230 kV)	Source 4: 1996 CIGRE Working Group (1,700 MVA circuit)
Starting point: Capital cost ratio only	5 to 6	6.4 XLPE 9.5 HPFF	7.1 XLPE 9.7 HPFF	15.3
Revised ratio with differential lifetimes assumed in figures	--	--	7.6 XLPE 9.7 HPFF	--
With maintenance / decommissioning costs included	--	6.1 to 6.3 XLPE 9.1 to 9.3 HPFF	7.4 XLPE 9.5 HPFF	--
With load losses taken into account	--	4.0 to 4.8 XLPE 5.8 to 7.1 HPFF	--	6.9 to 11.8
With outage repair costs considered	--	7.2 to 7.6 XLPE 9.1 to 9.3 HPFF	--	--
Final ratio	**3 to 5**	**7.2 to 7.6 XLPE 9.1 to 9.3 HPFF**	**7.4 XLPE 9.5 HPFF**	**6.9 to 11.8**

Notes: "—" indicates that this factor was not a factor in the particular analysis shown.
Dominion assumes that overhead lines and HPFF lines can last 70 years, but assumed replacement of XLPE at 40 years. Still, the cost Dominion estimates for XLPE replacement is only about $2.6 million, assuming that an investment of that amount could, with a real return of about five percent, produce funds to cover the cost of the replacement 40 years from now.
The 2005 Highland Council report indicated that the analysis assumed decommissioning of lines at the end of 40 years, which, it noted, "in the context of OHLs, is unduly conservative" with current practice "suggesting an asset life of 80 years for OHLs."

Sources: (1) Information on the 1996 and 2001 work by Acres International Corporation is based on a document of the Institute for Sustainable Energy at Eastern Connecticut State University entitled "Comprehensive Assessment and Report, Part I: Energy Resources and Infrastructure of Southwest Connecticut (January 2003). (2) Information based on Table 5 from the Highland Council report "Undergrounding of Extra High Voltage Transmission Lines" (2005). (3) Information on Dominion's updated (2006) life cycle costs were provided by Dominion staff to JLARC staff during the review. (4) Information on CIGRE findings is based on ICF Consulting's "Overview of the Potential for Undergrounding the Electricity Networks in Europe" (February 2003).

9. *Since Dominion only has one percent of transmission lines installed underground, would it be possible to reach out to other companies to compare statistics?*

DVP/NOVEC: The 2006 JLARC report indicates that Dominion has a higher percentage of underground transmission lines than the U.S. average:

Underground Lines Are a Small Percentage of All Transmission Lines

- In U.S., about 0.5 to 0.6% of 230 kV and above
- In Europe, about 2% for 220 to 300 kV and 0.5 % for 380 to 400 kV (2003 data)
- In Virginia, 1.3% of 230 kV lines are underground
  - Alexandria: 6.2 miles
  - Arlington: 11.1 miles (and 18.3 miles of 69 kV)
  - Fairfax: 9.3 miles
  - Norfolk: 5.6 miles

Underground transmission facilities are rare on most utility systems with service areas comparable to Dominion's area in Virginia and North Carolina. Other utilities located in highly populated areas (New York, Los Angeles, etc) may have a higher percentage of transmission lines underground due to their highly urbanized environments. Underground transmission lines have only been constructed in Dominion's territory for one of four reasons:

1) No feasible, cost-effective overhead alternative was available (examples include Dominion's facilities in northern Virginia inside the "Capital Beltway" and river crossings)

2) The transmission line was built as a radial configuration for direct delivery to the customer, who requested underground service and paid for the construction

3) Underground construction was required by Virginia law

4) Underground construction was approved by the State Corporation Commission as a pilot project