Segmented Static Wires and Fault Location

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Abstract — Accurately locating faults on 500 kV lines using impedance-based methods has long been a challenge for Dominion Energy Virginia. Systems and methods were implemented to mitigate the fault location errors and worked well; however, single-ended, impedance-based methods kept returning inaccurate fault locations. In early 2020, we experienced an "ah-ha" event that changed the way we determine fault location for 500kV lines. While static wires are continuous on our 115 and 230 kV lines, for 500 kV lines they are segmented to reduce losses. A fault in a substation caused the remote end of a 500 kV line to trip on Zone 1, and DFRs incorrectly reported the fault location as being on the line. While analyzing the fault using the known location, we discovered that during certain faults segmented static wires will flash over at their segmentation points, causing the segments to appear as continuous. This resulted in a zero-sequence impedance vastly different than the system model. Based on this conclusion, Dominion is developing a process to calculate, for each of its 500 kV lines, the fault current levels required for flashover. This paper will describe the steps to our discovery, review fault location methods, and discuss other methods of determining fault location based on a known location.

Keywords— Fault Location, Static wire, Transmission Line impedance and Digital Fault Recorder (DFR)

I. Static Wire Segmentation at Dominion Energy

Transmission lines at Dominion include a static conductor that runs the length of the line. The static wire is grounded at each end of the line and at OPGW splice points. Otherwise, the static wire is insulated from the tower. They are usually continuous from one end of line to the other, except where it is not practical. This includes conditions where one line goes under another line, for example. The main purpose of the static wire is for lightning protection, but it also serves as a return path in the event of a phase to ground fault.

500kV transmission lines have their static wires segmented. This means that the wire is not continuous but is intentionally broken about every five miles. The wire is grounded to the tower closest to the center of the five-mile segment. This segmentation is done to reduce losses on the line. Without the segmentation, the losses on Dominion Energy's 500kV lines would be in the order of $17,000 to $45,000 per mile per year

Losses occur in the static wire due to the induced current from the transmission line conductors. Having the static wire grounded at each tower will create a looped path for circulating current through the static wire, down the tower, an adjacent tower through the ground. Shield wires are segmented by installing an insulator at the segment point, as shown in Figure 1.

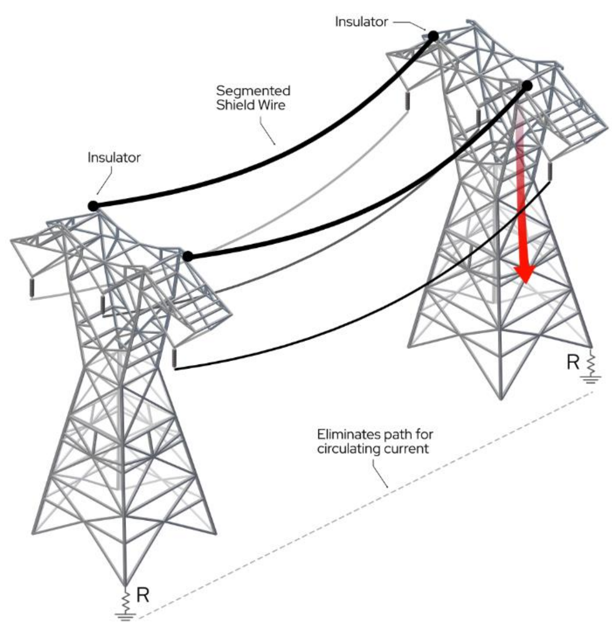

Figure 1 Segmented Static Wires

Isolating sections of the static and only grounding at one point eliminates the circulating current loop and reduces losses [1]. Lightning strikes to transmission structures, phase conductors, or shield wires can cause flashovers that force the line to trip [2]. Shield wires affect the zero-sequence impedance of a transmission line but have little impact on the positive or negative sequence impedances. The zero-sequence impedance of a transmission line impacts distance protection and fault location for phase to ground fault conditions.

This paper focuses on determining the fault location for 500 kV lines. Section II provides an overview of previous phase-ground faults that occurred on 500 kV transmission lines. Section III introduces a recent event which led to the realization that there was an error in the calculated impedance. Section IV presents the PSCAD simulation results of the recent event. A worst-case scenario study implemented using PSCAD and automated with Python is presented in Section V. Finally, Section VI discusses the conclusion, lessons learned and future work.

II. History of 500 kV Fault Location at Dominion Energy

Until the 2010s fault location methods at Dominion Energy consisted of:

- Vendor specific DFR software.
- Locations calculated by relays.
- Using DFR data in our system short circuit model (Aspen)
  - Direct match with recorded data.
  - "Ratio" method which involves finding the ratio of measured current or voltage and comparing it to the ratio in the system model until a reasonable match is found.
- Fault Analysis and Lightning Location System (FALLS)

A. Previous Lightning Strike Event Caused a P-G fault

On July 3rd, 2002, a lightning strike caused a P-G fault on a 76-mile long 500 kV line. While evidence of the fault was not found, we have high confidence in the location provided by FALLS. Regardless of the actual fault location the table below shows the large errors provided by the single-ended impedance-based fault location methods. Fault locations from opposite ends of the line should point to approximately the same location. In this case we had as much as a 16-mile gap between those locations. Table 1 shows the calculated distance from each end of the line for different methods. The *Gap* row shows how far apart the distances are from each other. Calculated locations from each end fell well short of the opposite end's location, creating the gap distance.

	FALLS	**Relay**	**DFR**	**ASPEN**	**ASPEN Ratio**
East Substation	26	19.7	18.95	19.2	24.5
West Substation	50	40.2	41.8	41.4	52.2
Gap	*0*	*16.1*	*15.25*	*15.4*	*0.7*

Table 1 - Calculated distances from substations

This event caused Dominion to reevaluate and analyze the zero-sequence modeling. Changes were made to the model but nothing that had a significant effect on fault location.

B. 500 kV Breaker Faulted Internally

On December 20th, 2004, a 500 kV breaker faulted internally. During the fault a 500 kV transmission line overtripped for the fault. A remote terminal of one of the lines out of the station tripped on zone 1. Using DFR data from the remote end the fault location was calculated to be about 77% of the line length. The line was 32 miles long and the estimated fault location was 24 miles. Since we knew the location of the fault to be 100% of the line length it was obvious that there was a problem. During the investigation of this event one of the action items was to verify if the line was segmented correctly. A field patrol found that the line was properly segmented.

These events highlighted a problem specific to our 500 kV system since our fault location estimates on 115 kV and 230 kV lines were accurate. We looked at all the steps involved in calculating line impedances, as well as things unique to our 500kV lines such as:

- Phases are not transposed on 500 kV.
- Our 500 kV system typically runs about 525 kV, yet our short circuit model uses a nominal voltage of 500 kV.
- 500 kV lines have segmented static wires.
- Soil resistivity, ρ, in our short circuit model

Based on the investigation, the soil resistivity was changed in our short circuit model. These changes only incrementally improved fault location accuracy but it did not solve the problem. Calculated locations are correct at other voltage levels indicating the fault location methods are adequate.

III. Mis-operation Event Description

In January 2020 there was another event involving a phase to ground fault. This time a metering CT failed inside a substation. One of the lines feeding that station over-tripped on Zone 1. Our DFRs and relays indicated that the fault was 5.7 miles from the remote station, however the fault was 7.8 miles away at the remote end of the line. This error in fault location points to a problem with the calculated line impedance. Positive sequence impedance is generally accurate since the biggest component of it is the conductor, thus the impacting component was the zero-sequence impedance. One of Dominions' fault location tools allows the user to manually enter the impedances used in the fault location calculation. This calculation uses the simple reactance method described in IEEE standard C37.114-2014 [3]. The team manually altered the impedance until the program gave the correct location. The zero-sequence impedance in the DFR was 17 ohms for this line. When 10.7 ohms was selected an accurate location was found.

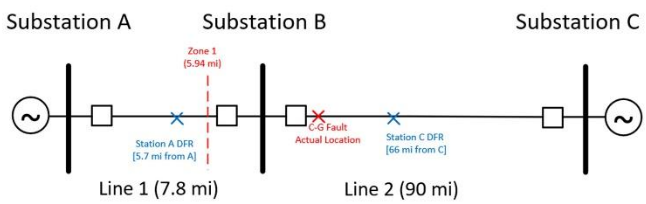

Figure 2 Mis-Operation Topology

It was suspected that the static wire was not segmented, therefore the calculations engineers re-calculated the zero-sequence impedance of the line as if the static wire was continuous. The results came back with a value of 10 ohms - very close to the empirical value of 10.7 ohms. At this point it was evident that the segmentation was not performing properly on this line. Field personnel patrolled the line and determined it was segmented as documented. While discussing the results with the lines department they decided they wanted to check the line again in case the static wire had flashed over at the segmentation location. An additional patrol revealed that there were flash marks.

During this same operation the other transmission line feeding this station tripped correctly, but the remote end of that line also tripped on zone 1. This was a much longer line that connected to another utility. Fault location from the remote end also came up short. The transmission lines crew wanted to check the segment locations on that line as well. They checked the first two segment locations and found them properly segmented, and both of those locations had flash marks as well.

At this point it was apparent that fault current could induce enough voltage on the static wires to the point that the arc would jump the gap at the segmented locations and the static wire then appears as electrically continuous rather than segmented.

Methods in [4] are used to calculate the zero-sequence impedance based on measured data from a relay or DFR. The fault analytics team developed a small computer program based on one of the equations in the paper. Table 2 lists the various impedances and the calculation method used. **Error! Reference source not found.** shows the math associated with calculating the new impedance.

Z0 Calculation Method	Impedance	Calculated Location
Traditional, with segmented static	17.583∠82.418°	5.78
Empirical	10.7∠82.418°	7.83
Calculated using DFR data	11.1412∠72.2718°	7.83
Traditional, with continuous static	10.1198∠76.2718°	8.05

Table 2 - Comparison of impedances

$$Z_{L0} = \frac{V_G - mZ_{L1}(I_{G1}+I_{G2})}{mI_{G0}} \tag{1}$$

Where terminal G is the end of the line from which the measurements are taken
V_G= faulted phase voltage at terminal G
m = per unit fault location
Z_{L1} = positive sequence line impedance
I_{G1}, I_{G2}, and I_{G0}= Positive, negative, and zero sequence currents at terminal G.

This equation requires that the actual fault location be known and entered in per unit distance.

IV. 500 kV Static Wire Segmentation Simulations

After the fault current was recorded by the DFR at Substation A, it became evident fault currents of large magnitude can cause an induce voltage substantial enough to flash over the segmentation points. A replica of the event was modeled in PSCAD to analyze the simulated induced voltage. The porcelain insulators on the 500 kV transmission line are rated for 10 kV for a wet flashover and 20 kV for a dry flashover. When the fault occurred it was snowing, therefore a 10 kV threshold was assumed. Figure 3 shows the left and right locations of the four porcelain insulators at the segmentation points and where an induced voltage was produced.

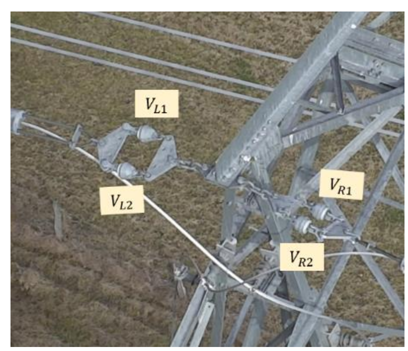

Figure 3 Insulators on the 500 kV Transmission Line [5]

The DFR at Substation A recorded a fault current of 16.35 kA. The C Phase-ground fault event is recreated in the PSCAD model, and the Simulated fault current illustrated in Figure 4 matches the DFR-recorded fault current value. An average sag height is incorporated between sections when conducting the model. The soil resistivity, ρ, is 200.0 Ω-m in the model. The bundle conductor separation, d = 18”.

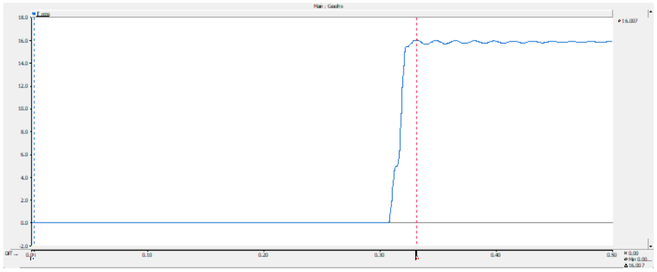

Figure 4 Simulated Fault Current from Substation A in PSCAD

The simulation results, waveforms of induced voltage across the four insulators, are depicted in Figure 5. The induced voltages across the insulators of 27.11 kV, (V_{L_1}), 28.66 kV (V_{R_1}), 27.11 kV (V_{L_2}) and 28.66 kV (V_{R_2}) all exceed the dry rating of 20kV of the insulator.

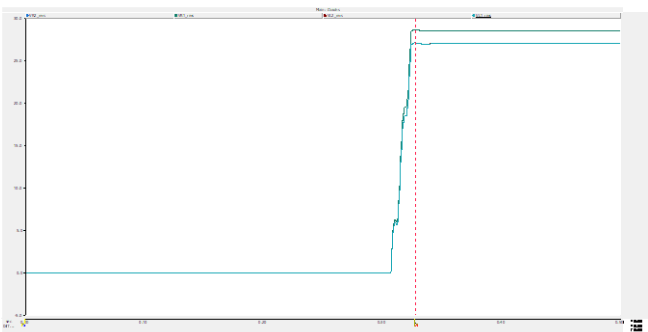

Figure 5 Simulated Induced Voltage on the Insulators

These simulations prove that a significant amount of induced voltage across the insulator can be generated from a fault condition. This can cause sufficient induced voltage to be created that exceeds the threshold and result in a flashover.

V. WORST CASE SCENRIO

To ensure the insulators are rated for the appropriate voltage for all the 500 kV structures, a worst-case scenario is conducted. The voltage equation in [1] sums the mutual impedances between the shield wire, phase conductors and current flow in the phase conductors,

$$\bar{V}_{ind} = \bar{Z}_{sw1a} I_a + \bar{Z}_{sw1b} I_b + \bar{Z}_{sw1c} I_c \qquad (2)$$

Contributions to the magnitude of the induced voltage are the following:

- Conductor impedances
- Fault Current Magnitude
- System Thevenin equivalent
- Shield Wire Impedances
- Fault Type

In this worst-case scenario, the transmission conductor, 1351.5-45/7 DIPPER ACSR and the fiber optic shield wire, FOSW DNO-10100 25C are used. Figure 6 and Table 4 provide the shield wire and conductor placement information.

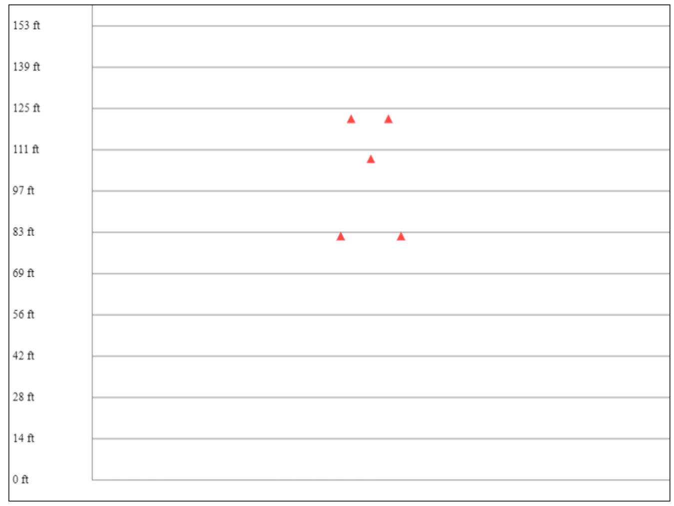

Figure 6 Structure 2D View

Phase	A	B	C	SW1	SW2
H (ft)	200.7	225	249.3	209.08	239.17
V (ft)	82.04	108	82.04	121.5	121.5

Table 3 Structure Data

Because the B-phase conductor was located closest to the shield wire, we theorized that it would produce the highest fault current. So, for this worst-case study, a B-phase-to-ground fault was applied to each structure to evaluate the induced voltage.

The worst case was modeled in PSCAD with all the grounding structures and segmentation points explicitly modeled as well as two additional structures in each interval between a grounded structure and a segmentation point. These additional structures provide additional measurement locations thus providing more data granularity, allowing for smoother graphing. A Python script was then developed to interface with the model. The Python script was used to control the fault type and fault location (transmission structure at which the fault is applied).

For most faults, the induced voltage was larger than the wet rating of the insulators, confirming the assertion from the engineers, based on historical events, about the induced voltage being larger than the insulator rating for virtually all faults.

The induced voltage profile for a phase B to ground fault at structure 118 is illustrated in Figure 7. Structures 106 and 132 are 8 miles apart with Structure 118 being about halfway. The lowest induced voltage is at the two ends of this segment of the line as structures 106 and 132 are grounded. The highest induced voltage of 29kV is across the insulators at structure 118. This maximum induced voltage was also higher than any other induced voltage for all fault locations on the line.

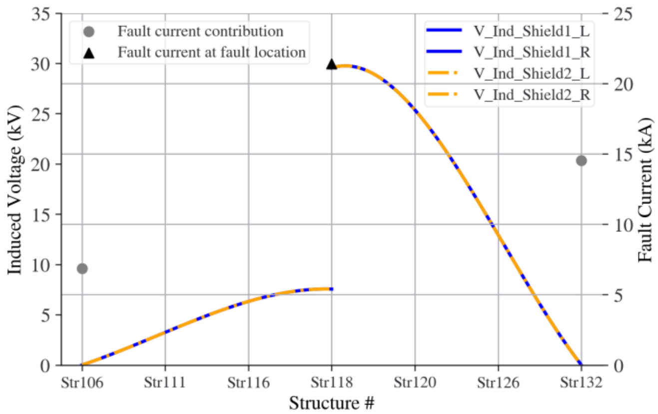

Figure 7 Induced Voltage and Fault Current Profile for a Fault at Structure 118

VI. Lessons Learned and Future Action Items

The challenge of accurately locating faults on 500 kV lines using impedance-based methods at Dominion Energy Virginia began in the early 2000s. Early investigations explored the factors that affect the accuracy of impedance-based fault location methods. These are ground resistivity value, phase transposition and modeling of the static wire (segmented vs. continuous). Investigators suspected that the static wire could be continuous, as opposed to segmented as documented in the engineering drawing, but inspection confirmed that the static was indeed segmented. Investigations also lead to the update of the soil resistivity value in the short circuit model which only slightly improved the fault location on 500kV lines but did not provide a solution to the fault location method.

The investigations also proved that the impedance based single ended fault location algorithms were adequate as they were returning accurate results at all voltage levels other than 500kV. As a solution to the challenge of accurately locating faults on 500 kV lines using impedance-based methods had not been found, other calculation methods such as double ended location calculations as well as the use of traveling wave locators, have been used for fault location at Dominion.

A recent 500kV relay mis-operation was investigated, and the investigation led to the discovery of flashover marks on static segmentation points. Engineers suspected that when lighting strikes, the induced voltage could be large enough to cause a flashover, which in turn causes the static wire to become continuous. A PSCAD study was conducted to determine the values of induced voltages and found that the insulator rating needed to be increased from 10 kV for a wet flashover and 20 kV for dry flashover to higher values. The current insulator ratings contribute to the issue of fault location as the engineers compute the zero-sequence impedance with the assumption that the static wire is segmented while during a flashover, the static wire acts as if it is continuous. This event and the follow up investigation highlighted that the fidelity of the static wire model is very important for fault location.

Future work include: (1) A study of the induced voltage profile on other lines to determine how to upgrade insulators on existing 500kV line and inform on the selection of insulator ratings for new lines and (2) automation of fault location algorithms for Double Line-to-Ground Faults and other types of faults as automation allow to speed up the analysis and the ability to make decisions.

VII. Reference

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VIII. Biographes

Robert M. Orndorff has been at Dominion Energy since 1984. He spent 11 years as a field relay technician and moved to the Fault Analysis department in 1997 where he still works. His interests include fault location, grid frequency events, and analyzing unusual operations. Robert graduated from J Sargeant Reynolds Community College in 1986 with an AAS degree in Electricity and Electronics. He is a member of IEEE and has been a member of the TRUC planning committee since 2003.

Genesis B. Alverez received her B.S (2016) in Electrical Engineering from Florida Atlantic University, Boca Raton, FL and the M.S. (2019) in Electrical Engineering from Virginia Tech. She is an Engineer III in the Electric Transmission Operation Engineering Team. Her research interests include power systems analysis, system protection and renewable energy integration in distribution systems.

Gad M. Ilunga received his B.S., M.S. and Ph.D. degrees in electrical engineering from Georgia Institute of Technology in 2017, 2019 and 2022. Since 2022, he has worked at Dominion Energy the Special Studies team in Electric Transmission. His research interest include power systems operations and control

Micah J. Till received his PhD from the University of Tennessee, Knoxville in 2017. He is the supervisor of Electrical Transmission System Protection Automation & Analysis at Dominion Energy in Richmond, Virginia. His work history includes time in Dominion Energy's Special Studies, Reliability Engineering, System Protection Engineering, Electric Transmission Planning, and Operations Engineering groups, as well as previous positions at Tennessee Valley Authority in Chattanooga and ABB Group in Baden, Switzerland.

Katelynn Vance received her M.S. and Ph.D. degrees in electrical engineering from Virginia Polytechnic Institute and State University in 2011 and 2017. She earned her B.S. in Electrical and Computer Engineering from the University of Virginia in 2009. Since 2014, she has worked at Dominion Energy in Electric Transmission in the System Operations Center and in Special Studies. Her interests include real-time stability applications of power systems.