Impact of Geomagnetic Induced Current Neutral Blocking Devices in sub-transmission network on Distance relays in the presence of IBRs

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***Abstract*—Geomagnetically induced currents (GICs) can flow through transmission lines during geomagnetic disturbances, such as solar flares or coronal mass ejections. These currents can cause problems like transformer saturation and equipment damage. The most common method of mitigating GICs involves installing GIC neutral blocking devices (NBDs) in transformer neutrals. However, the wide application of capacitive GIC blocking devices may have unintended adverse effects on other devices, such as distance protection relays. As the number of inverter-based re- sources being connected to the transmission and sub-transmission systems increases, the likelihood of a sub-transmission line protected by a distance relay connected to a transformer with NBDs is increasing. Therefore, distance relays fed by IBRs and transmission lines with GIC-NBDs must be studied. This paper studies the effect of GIC-NBDs on a 69kV sub-transmission line of various lengths fed by a 25 MVA IBR and synchronous source. This work focused on the behaviour of the GIC-NBDs using the measured apparent phase-to-ground and phase-to-phase impedance calculated by the relay and the source impedance ratio (SIR) during various electrical faults.**

***Index Terms*—Neutral blocking devices, Inverter-based re- sources, Distance relay, source impedance ratio.**

I. Introduction

Geomagnetically induced currents (GICs) are currents that are induced in power systems during a geomagnetic disturbance, such as solar flares, coronal mass ejections, and other geomagnetic events [1]. GICs have the potential to damage transformers, transmission lines, and other critical components of the bulk transmission system and cause a large outage [2], [3]. An example of the effects of GICs on the power system is the failure of the Hydro Quebec power transmission system in March 1989, which led to widespread blackouts [3]. Several different mitigation methods have been developed to limit GICs. The most common neutral blocking devices (NBDs) are capacitor banks connected at the neutral ground point of the transformer [3], [4].

The impact of GICs on transmission lines and transformers has been studied in [5]–[7]. In [8]–[10], the impact of GIC-NBDs on protection relay operations was studied. All [10], [8], and [9] concluded that GIC-NBDs did not significantly impact the operation of distance relays. However, these studies did not consider the presence of Inverter-Based Resources (IBRs).

No analysis of the impact of NBDs on distance protection in the presence of IBRs has been published. In this analysis, the impact of NBDs on distance relays monitoring a sub- transmission line fed by IBRs was analyzed. The impact of IBRs that only output positive sequence fault currents and IBRs that output positive and negative sequence fault currents was studied by measuring the apparent impedance calculated by a distance relay model. Several electrical fault types were tested along power lines with different lengths. Additionally, the single line-to-ground source impedance ratios (SLG-SIRs) and three-phase source impedance ratios (3PH-SIRs) were measured and compared with the protection communication schemes suggested by IEEE Standard C37.113-2015 [11], which classifies transmission line lengths.

II. Test System

A test system consisting of two sources, three 13.8 to 69kV delta-wye transformers, a 25+3j MVA load, and the 69kV sub-transmission line was created in MATLAB Simulink. The load is modeled as a balanced constant impedance load using the ”three-phase RLC load” model in MATLAB Simulink [12]. The power lines were modeled as three-phase PI sections. The power line parameters are shown in Table I. The power line parameters were sourced from [13] and represent a typical 69 kV sub- transmission line. The ”three-phase PI section” available in MATLAB Simulink was used to implement the balanced three-phase power line [12].

The three transformers are modeled using the ”Three-Phase Transformer (Two Windings)” model in MATLAB Simulink [12]. The neutral of the transformers can be connected to

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TABLE I
LINE PARAMETERS FOR TYPICAL 69KV LINE [13]

Positive sequence resistance, R1	$0.34\Omega/mile$
Positive sequence reactance, X1	$0.78\Omega/mile$
Zero sequence reistance, R0	$1.22\Omega/mile$
Zero sequence reactance, X0	$2.37\Omega/mile$
Positive sequence susceptance, B1	$5.43uMho/mile$
Zero sequence susceptance, B0	$3.38uMho/mile$

ground directly or switched to be connected through a capacitor representing the GIC-NBD. A 2650 μF capacitor is used to represent a typical 1Ω GIC-NBD [10], [14], [15]. A distance relay model and associated to the measured phase voltages and currents is located at the sending end of the power line near bus 2, as shown in Figure 1. The details of the distance elements calculation for the relay are provided in Section III-A.

A total of 6 cases were created to observe the impact of GIC-NBDs in various conditions. In cases 1 and 2, the distance relay is fed by a synchronous generator, as shown in Figure 1. In case 1, the system does not have NBDs present, and in case 2, NBDs are connected to the neutral of the transformers in the system. In cases 3 and 4, the distance relay is fed by a 25 MVA IBR, which only supplies positive sequence fault currents, as shown in Figure 2. In case 3, the system does not have NBDs present, and in case 4, NBDs are connected to the neutral of the transformers in the system. In cases 5 and 6, the distance relay is fed by a 25 MVA IBR, which supplies both positive and negative sequence fault currents, as shown in Figure 3. In case 5, the system does not have NBDs present, and in case 6, NBDs are connected to the neutral of the transformers in the system. The power line length was varied for all cases from 25 miles to 100 miles. The phase A, B and C to ground (ABCG), phase A and B to ground (ABG), phase A to ground (AG), and phase A to B (AB) electrical faults at bus 1 were tested for each case and power line length.

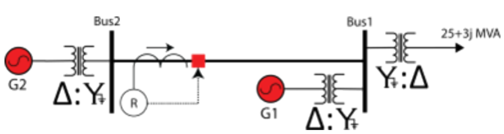

Fig. 1. Test system for case 1 and Case 2.

Fig. 2. Test system for case 3 and Case 4.

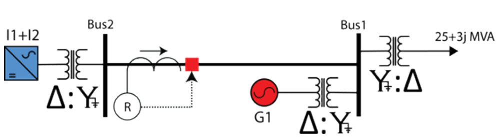

Fig. 3. Test system for case 5 and Case 6.

A. Grid Following IBR model

Fig. 4 shows the control diagram of the IBR used in this study. The IBR operates as a current source, providing real and reactive power based on a setpoint. The grid-following control comprises droop, LVRT mode, and the current control loop. The GFL droop control adjusts the real power setpoint based on the frequency measured at the inverter terminal and the reactive power setpoint based on the voltage measured at the inverter terminal. This droop behavior enables voltage regulation and automatic load sharing among multiple inverters [16]. The power references are converted to dq current references Id^* and Iq^*. During a fault or other disturbances, the inverter terminal voltage drops below the LVRT threshold. According to the IEEE 2800-2022 standard for interconnection and interoperability of IBRs with transmission systems, an IBR should prioritize reactive current (Q-priority) mode during an LVRT event [17].

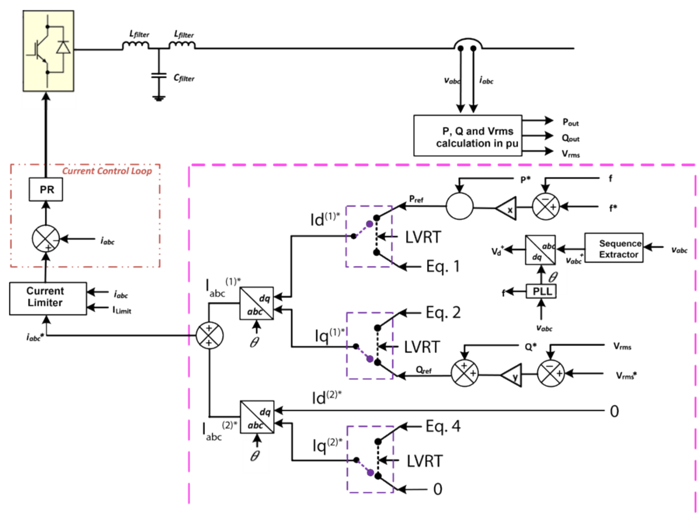

Fig. 4. Control diagram of the IBR model.

Therefore, during a fault, the IBR current references are calculated using equations (1) - (4). The IBR model can operate in I1-only mode or supply both negative and positive sequence fault current under LVRT conditions based on the value of the gains K_1 and K_2 in equations (2) and (4). For I1-only mode, $K_1 = 2$ and $K_2 = 0$; for I1+I2 mode $K_1 = 2$ and $K_2 = 2$ were selected.

$$Id^{(1)*} = \sqrt{I_{limit}^{2} - Id^{*2}} \quad (1)$$

$$Iq^{(1)*} = K_1 * (I_{limit}^{2} - Vd^{(1)}) \quad (2)$$

$$Id^{(2)*} = 0 \quad (3)$$

$$Iq^{(2)*} = V^{(2)} * K_2 \quad (4)$$

Here, $^{(1)}$ denotes positive sequence and $^{(2)}$ denotes the negative sequence and * denotes reference value for the controllers. The positive and negative sequence references are converted to abc, combined, and fed to the current limiter to limit the reference current, I_{Limit}, which is taken as 1.2 pu of the inverter rating. The current-limited reference currents are used by the current control loop, which uses a proportional-resonant (PR) controller to produce the modulation waveform required for the control system.

III. Test methodology

To measure the impact of the GIC-NBDs in the presence of IBRs, the apparent impedance observed by the distance relay and the source impedance ratio (SIR) for each of the six cases outlined in Section II were measured and compared.

A. Distance Relay calculation

Distance relays are one of the protection devices used to protect transmission and sub-transmission lines. A distance relay works by calculating the apparent fault impedance using the measured voltage and current of the line and comparing the measured impedance to a set the permitted thresholds. A mho distance relay typically consists of six elements: three phase-to-ground elements (Ag, Bg, Cg) and three phase-to-phase elements (AB, BC, CA) [18]. The phase elements calculate the apparent impedance using Equation 5, and the ground elements calculate the apparent impedance using Equation 6 [19]. The phase elements calculate the apparent impedance using equations 5 and the ground elements calculate the apparent impedance using equation 6 [19].

$$Z_{ab} = \frac{Va - Vb}{Ia - Ib} \quad (5)$$

$$Z_{ag} = \frac{Va}{Ia + (k0 * 3I0)} \quad (6)$$

$$k0 = \frac{Z0_{Line} - Z1_{Line}}{3 * Z1_{Line}} \quad (7)$$

$$3I0 = Ia + Ib + Ic \quad (8)$$

Where Va is the measured voltage in V, Ia is the measured current in A,
$k0$ is the zero sequence compensation factor, $Z1_{Line}$ is the positive sequence line impedance in Ω, $Z0_{Line}$ is the zero sequence line impedance in Ω and $3I0$ is the residual current in A. In this paper, all electrical faults simulated involve the phase A, and therefore only elements involving phase A were simulated for this experimental model. For the AG, ABG, and ABCG electrical faults, the ground distance element for phase A (Z_{ag}) was used for the AG, ABG and ABCG electrical faults, and the phase A to B distance element (Z_{ab}) was used for the AB electrical fault. The phase A to B and phase A to ground distance elements were simulated in MATLAB/ Simulink as shown in Figure 5 and Figure 6, respectively.

B. Source impedance ratios

The Source Impedance Ratio (SIR) is the ratio of the source impedance (the equivalent impedance of the system behind the relay point) to the impedance of the protected transmission line. The SIR influences several aspects of the distance relay operation, including the zone reach settings and coordination with backup relays. It also helps guide decisions between

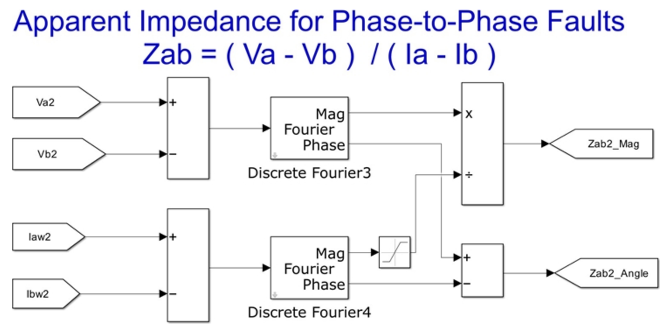

Fig. 5. Matlab model of AB distance element.

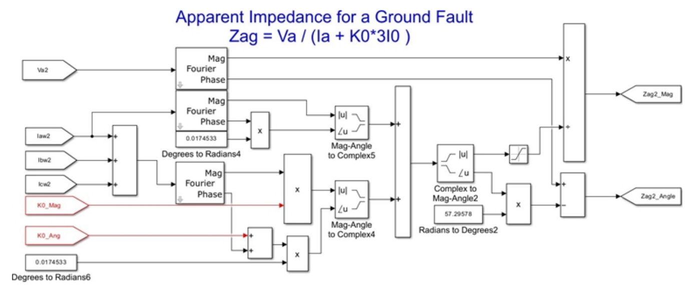

Fig. 6. Matlab model of AG distance element.

relays [20]. According to [11], a power line is considered long if its SIR is greater than 0.5, medium if its SIR is between 0.5 and 4,
and short if its SIR is less than 4. In this study, the single line-to-ground SIR (SIR_{SGL}) and the three-phase SIR (SIR_{3PH}) were calculated for each electrical fault test to observe how the power line
length and source type could affect the SIR. The SIR_{SGL} was calculated using Equation (9), and SIR_{3PH} was calculated using Equation (10).

$$SIR_{SLG} = \frac{V_{nom} - Va}{|Z1_{Line}| * (Ia + |k0| * (Ia + Ib + Ic))} \quad (9)$$

$$SIR_{3PH} = \frac{V_{nom} - Va}{|Z1_{Line}| * Ia} \quad (10$$

where …….(define variables and units for Equations (9) and (10).

(Please complete this sentence) ….distance, directional, or differential protection schemes. The SIR is well established in the industry as the preferred method for classifying the electrical length of a power line for the purpose of setting the protective relays.

where V_{nom} is the nominal phase-to-ground voltage in V, Va is the measured phase-to-ground voltage in V, $|Z1_{Line}|$ is the magnitude of the positive sequence line impedance in Ω, $|k0|$ is the magnitude of the zero-sequence compensation factor and Ia is the measured phase A current in A.

IV. Results

In this work, four the electrical fault types were simulated: ABCG, ABG, AG, and AB electrical faults. Each type of electrical fault was repeated for the six cases outlined in Section II. For each case, the distance relay Zone 1 and Zone 2 were set to 80% and 120% of the power line impedance, respectively. All electrical faults in this work were simulated at 100% of the power line length, so only Zone 2 was simulated. Figure 7 shows the measured apparent impedance for the ABCG electrical fault at 100% of the power line for all 6 cases. For both cases where the distance relay is fed by a synchronous generator, the apparent impedance was measured just beyond 100% of the power line. The cases with IBRs (both I1-only and IBR with I1 and I2 output) resulted in a slightly higher measured apparent impedance.

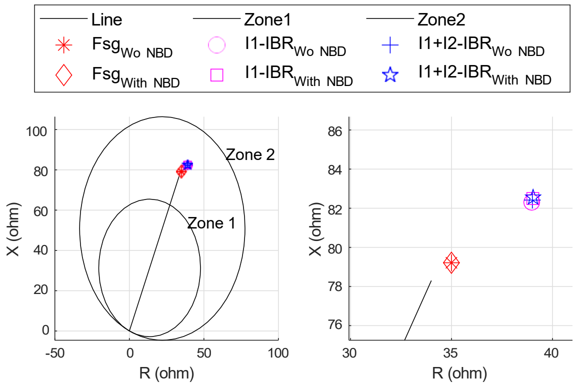

Fig. 7. Apparent impedance for ABCG fault at 100 mile power line.

Figure 8 shows the measured apparent impedances for the ABG electrical fault at 100% of the power line for all 6 cases. For all cases, the apparent impedance was measured just beyond 100% of the power line. The measured impedance of Case 1 (relay fed by synchronous generator without the GIC-NBD) had the lowest error in the measured apparent impedance compared to the other cases. Case 4 (relay fed by the positive sequence only IBR) led to the largest error in apparent impedance compared to the expected value of (what number?). However, all cases show that the CIG-NBD does not adversely affect the operation of the distance relay.

power

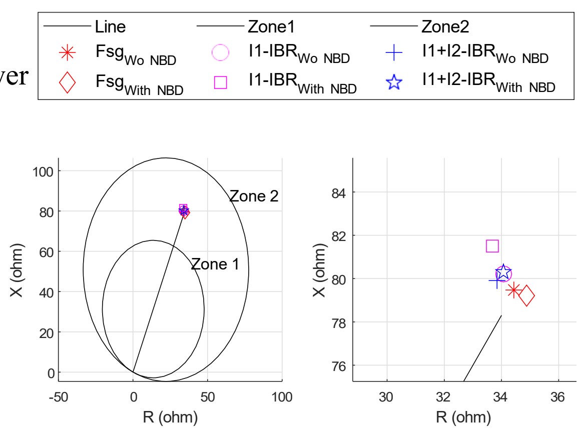

Fig. 8. Apparent impedance for ABG fault at 100 mile power line.

Figure 9 shows the measured apparent impedance for the AG electrical fault at 100% of the powerline for all 6 cases. For all cases, the apparent impedance was measured just beyond 100% of the power line. For all cases, the apparent impedance is nearly identical, once again demonstrating that the GIC-NBDs don't pose a significant challenge to the distance relays for single-line- to-ground electrical faults.

Figure 10 shows the measured apparent impedance for the AB electrical fault at 100% of the power line for all 6 cases. For all cases, the apparent impedance was measured just beyond 100% of the power line. For all 6 cases with a 100-mile power line length, the measured apparent impedance

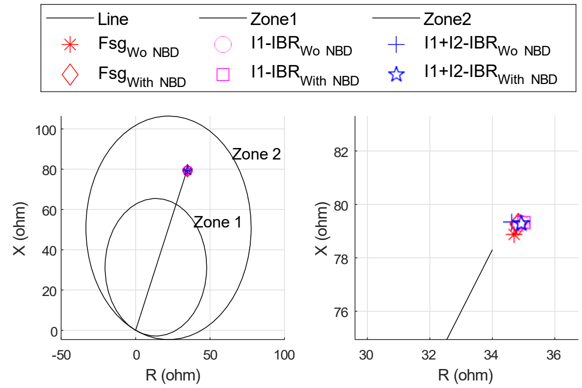

Fig. 9. Apparent impedance for AG fault at 100 mile power line.

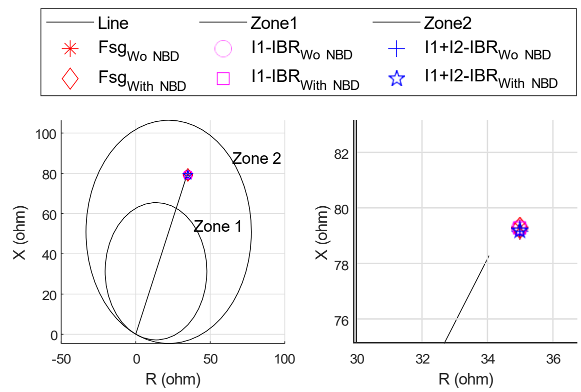

Fig. 10. Apparent impedance for AG fault at 100 mile power line.

did not impact adversely in the calculation of the apparent impedance of the distance relay.

Figures 11, 12, 13, and 14 show the measured apparent impedance for the ABCG, ABG, AG, and AB electrical faults at the end of the 50-mile power line. For all cases with a 50-mile power line, the GIC-NBD does not significantly impact the measured apparent impedance. The small impact that was observed for the 100-mile power line is diminished when looking at the 50-mile power line.

Figures 15, 16, 17, and 18 show the measured apparent impedance for the ABCG, ABG, AG, and AB electrical faults at the end of the

did not change significantly, showing that the GIC-

25-mile power line. For all cases with a 25-mile power line, the GIC-NBD does not significantly impact the measured apparent impedance. Looking at the measured apparent impedance for the 100, 50, and 25-mile power lines, it can be seen that as the power line length decreases, the impact of the GIC-NBDs decreases, and the variance in the apparent impedance decreases.

Along with the apparent impedance, the source impedance ratio was also measured for each case and the power line lengths. Table II shows the SIR for each fault type and power line length tested. The SIR shows that the power line is considered short for all cases, and there is no significant impact on the SIR due to the GIC- NBD. However, the value of the SIR increases significantly more when the power line length is decreased in the presence of the IBRs for all electrical fault types.

TABLE II
SIR FOR ELECTRICAL FAULTS AND POWER LINE LENGTHS

Electrical fault types	**Power line length (miles)**	**SIRs with GIC-NBDs (Ω)**			**SIRs without GIC-NBDs (Ω)**		
		Use case scenarios			**Use case scenarios**		
		SG	**I1 IBR**	**I1 +I2 IBR**	**SG**	**I1 IBR**	**I1 +I2 IBR**
ABC	**100**	4.46	5.01	5.01	4.63	5.00	5.01
	50	6.57	11.86	11.86	6.93	11.86	11.86
	25	10.88	24.48	24.48	11.61	19.28	24.48
ABG	**100**	4.48	5.44	13.23	4.70	5.70	14.62
	50	6.42	11.86	13.10	7.62	12.04	17.44
	25	10.14	18.93	21.10	12.72	19.28	29.53
AG	**100**	4.62	5.30	5.17	5.42	5.30	5.41
	50	6.68	11.03	12.21	8.07	10.89	13.68
	25	10.65	21.56	23.12	13.51	21.06	28.06
AB	**100**	4.54	5.99	13.18	4.70	6.00	13.13
	50	6.59	11.22	24.79	6.92	11.22	24.77
	25	10.69	21.76	23.12	11.36	21.76	28.06
SG: ……, I1 IBR:………. I1+I2 IBR:………….							

V. CONCLUSION

In this paper the impact of GIC-NBDs on distance relay performance in sub-transmission networks in the presence of IBRs was studied. The results demonstrated that while GIC-NBDs introduce minor changes in the apparent impedance measurements, they do not significantly impair distance relay operation across a range of the power line lengths and electrical fault types. Both I1-only and I1+I2 IBR configurations showed small deviations in the measured impedance compared to synchronous sources, but these deviations remained within acceptable boundaries for the protective relay operation. Further- more, the impact of GIC-NBDs on source impedance ratio (SIR) was negligible, with all power lines classified as "short" according to IEEE C37.113-2015 standard, regardless of the presence of GIC-NBDs. The influence of GIC-NBDs diminishes as the protected power line length decreases. These findings support the continued deployment of GIC-NBDs as a mitigation strategy without compromising the distance protection reliability, even in power systems with high IBR penetration.

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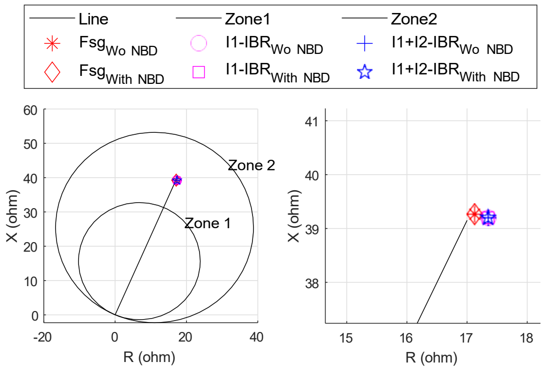

Fig. 11. Apparent impedance for ABCG fault at 50 mile power line.

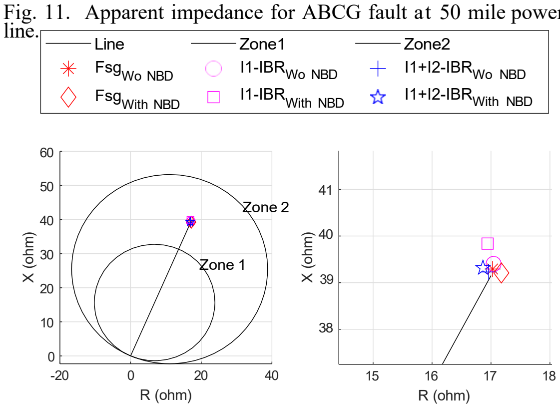

Fig. 12. Apparent impedance for ABG fault at 50 mile power line.

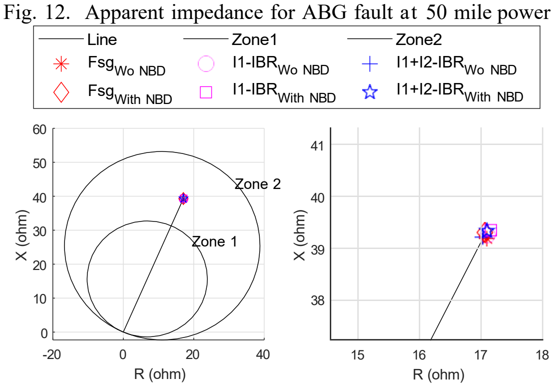

Fig. 13. Apparent impedance for AG fault at 50 mile power line.

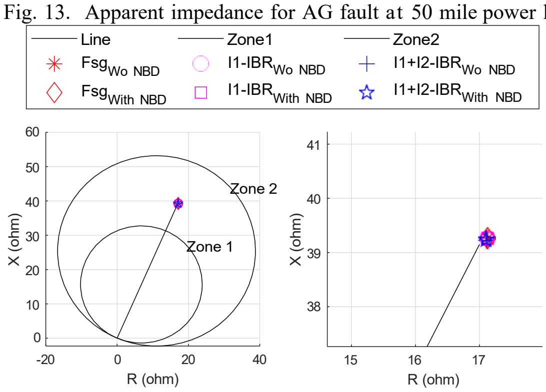

Fig. 14. Apparent impedance for AB fault at 50 mile power line.

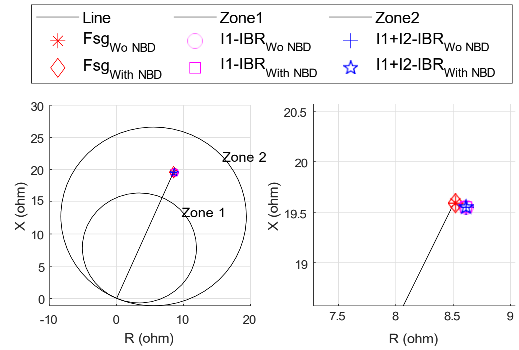

Fig. 15. Apparent impedance for ABCG fault at 50 mile power line.

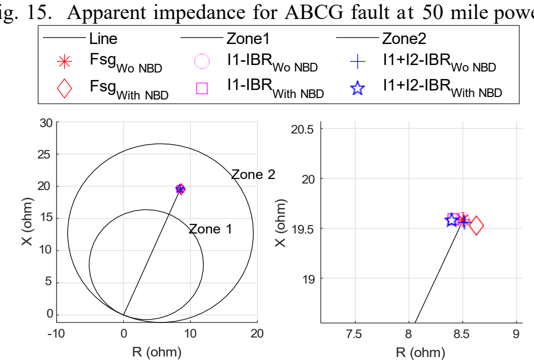

Fig. 16. Apparent impedance for ABG fault at 50 mile power line.

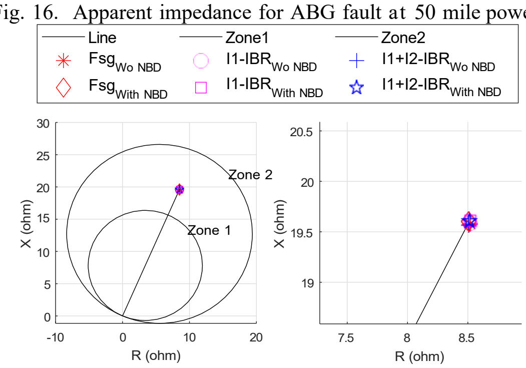

Fig. 17. Apparent impedance for AG fault at 50 mile power line.

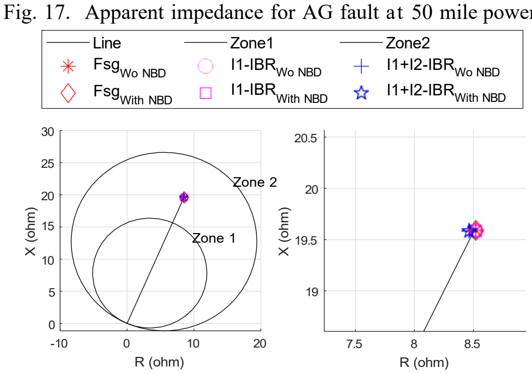

Fig. 18. Apparent impedance for AB fault at 50 mile power line.