A Novel Method for Detecting Ground Faults on an Ungrounded Power System

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A novel method for detecting ground faults on an ungrounded power system

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Abstract

A typical Los Angeles Department of Water and Power (LADWP) distribution substation consists of two or more buses, two or more transformer banks, and multiple feeders that can be connected to any bus at any time. Voltage signals for protection purposes are measured at the transformer banks. There is no direct correlation between the zero-sequence voltage ($3V_0$) of the banks or buses and the zero-sequence current ($3I_0$) of the feeders. Presently, if the $3V_0$ magnitude of one of the banks is above a preset threshold, that $3V_0$ is switched to all the feeder relays in the substation whether they are connected to the same bus as the faulted feeder or not.

The problem with the present scheme is that if a feeder is not associated with the faulted feeder and the magnitude of $3I_0$ is above the preset threshold, that feeder may be declared faulty. This has resulted in multiple feeders being declared as faulted. Identifying the actual faulted feeder requires line crews to isolate each of the suspected feeders.

This paper briefly explains the principle of ground fault detection in an ungrounded power system and the challenges of locating the actual faulted feeder on the LADWP distribution system at present. We then discuss a new innovative algorithm developed to correctly identify the faulted feeder on the LADWP distribution system. We validated this algorithm by means of laboratory and staged-fault field testing.

1 Introduction

LADWP has met the electrical needs of the ratepayers of Los Angeles and Owens Valley for over a century. Electricity has played an important role in the development of the communities LADWP serves. The commitment to providing economical, safe, reliable, and sustainable electricity for the future will lead to a stronger, greener, and more prosperous living environment for all LADWP ratepayers. Maintaining continuity of service has always been important. Equally important is safety, and detecting ground faults in the LADWP 4.8 kV delta distribution system has always been a challenge. For 50 years, a simple $3V_0$ detection system identified when there was a ground fault somewhere on a feeder circuit within the 120 distribution substations throughout the power system. It required substation operators to manually switch circuits to pinpoint which feeder had the fault. This process was slow and prone to safety issues. The current scheme, although an improvement to the simple $3V_0$ scheme, is prone to error and struggles with accurate detection. Implementation of the scheme described in this paper gives LADWP the ability to accurately detect the faulted feeder, thereby improving the service quality to LADWP customers and power system safety. We provide a more indepth discussion on this topic in [1].

2 Ground fault detection in ungrounded power systems

In an ungrounded power system, loads are connected phase-to-phase. Therefore, under normal system operating conditions there is no $3V_0$ or $3I_0$ (assuming the power lines are perfectly transposed). Any contact between a phase conductor and ground results in the flow of $3I_0$, with the capacitance-to-ground of the unfaulted phase conductors providing the return path. The flow of $3I_0$ for a single-line-to-ground (SLG) fault in an ungrounded power system is shown in Fig. 1.

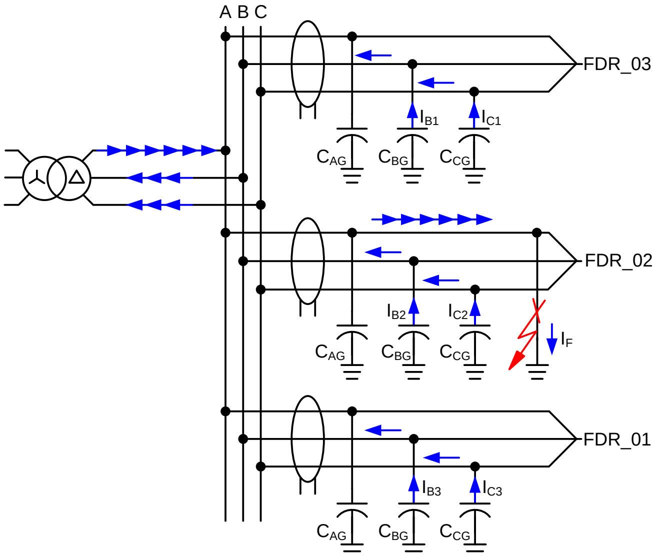

Fig. 1. Fault current flow in an ungrounded power system for an SLG fault on the system.

The operating quantity for the zero-sequence directional element is $3I_0$, and $3V_0$ is the polarizing quantity. By comparing the angle between $3V_0$ and $3I_0$, the scheme determines the faulted feeder [2] [3]. For an SLG fault in front of the relay measuring point, $3I_0$ lags $3V_0$ by an angle ranging from 90° to 180°, depending on the fault resistance (R_F) [3] [4]. For an SLG fault behind the relay measuring point, $3I_0$ leads $3V_0$ by an angle between 0° and 90° [3] [4]. Therefore, as shown in Fig. 2, if $3I_0$ lags $3V_0$ by 90° to 180°, the fault is in front of the relay measuring point. If $3I_0$ leads $3V_0$ by 0° to 90°, the fault is behind the relay measuring point.

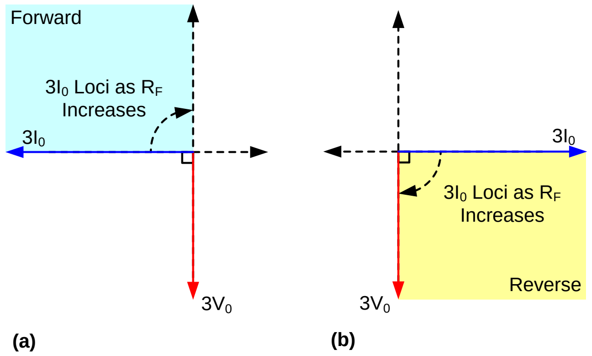

Fig. 2. The relationship between the zero-sequence voltage ($3V_0$) and the zero-sequence current ($3I_0$) for a forward fault (a) and a reverse fault (b) on an ungrounded power system.

Examining Fig. 2, we see that identifying the faulted feeder on an ungrounded power system is not too challenging. So what is unique about the LADWP ungrounded power system that makes determining the faulted feeder so difficult?

2.1 Problem description

A typical double-bus substation arrangement for the LADWP ungrounded power system is shown in Fig. 3.

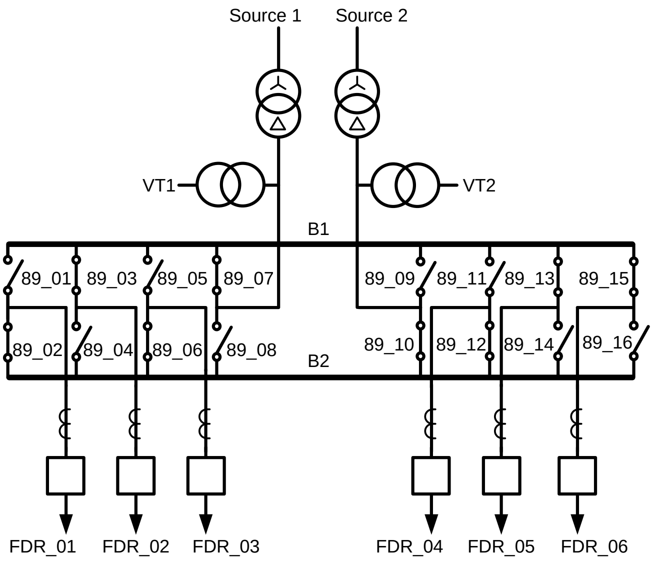

Fig. 3. Typical double-bus arrangement for an LADWP substation on the ungrounded power system.

The transformers and feeders shown in Fig. 3 can be linked to any one of the two buses (B1 or B2) at any time. This means that the scheme cannot readily determine the correct $3V_0$ needed to polarize $3I_0$ of a particular feeder during an SLG fault on the power system beforehand. If the status of the feeder and transformer isolator switches (89_*nn*) were known, then this would be a trivial task. However, there are no auxiliary contacts available on the isolator switches to indicate the position (status) of the isolator switch. To overcome the issue of not knowing which feeder is connected to which bus and which $3V_0$ voltage to route to which relay, the present protection scheme designers proposed the following solution:

- Route all $3V_0$ voltages at the substation into a programmable logic controller (PLC).
- Use the PLC to determine which one of the $3V_0$ voltages has the highest magnitude.
- If the magnitude of a particular $3V_0$ voltage exceeds a set threshold, route that $3V_0$ voltage to all feeder relays in the substation to use as the polarizing voltage.

In a perfect world, there would be nothing wrong with this reasoning because the scheme would pair the correct $3V_0$ voltage with the $3I_0$ current of the faulted feeder. However, the feeders on the LADWP 4.8 kV network are not perfectly transposed, resulting in unequal phase-to-ground capacitances. This results in a standing $3I_0$ on the feeders and power system. Loads (motor loads in particular) typically have an unequal phase-to-ground capacitance and exacerbate the problem by creating additional standing $3I_0$ currents, thereby increasing the standing $3I_0$ in a particular feeder and the power system. To understand the issues with the present ground fault protection system on the LADWP 4.8 kV ungrounded power system, assume a double-bus substation configured as follows:

- Equal number of feeders connected to Bus 1 (B1) and Bus 2 (B2) as shown in Fig. 3.
- Transformer 1 supplies B1 and Transformer 2 supplies B2.
- An SLG fault on a feeder connected to B2.

The relays connected to B2 correctly identify the faulted feeder. However, feeders connected to B1 may have a standing $3I_0$ current. Routing $3V_0$ from B2 to relays on these feeders may cause these relays to declare a fault on their feeder, if $3I_0$ of these feeders lags $3V_0$ of B2 by 90° to 180°.

While the scheme correctly identifies the faulted feeder, the problem is that it also declares faults on uninvolved feeders. From an operational point of view, line crews need to be dispatched to each of the identified faulted feeders in order to determine the actual faulted feeder and locate the fault. This is a waste of resources and is time consuming; therefore, a better ground-fault-protection scheme was required.

2.2 Possible solution

To explore a possible solution for this particular problem, we take a typical 4.8 kV LADWP substation with the feeders and transformers connected as shown in Fig. 4. Assume FDR_05 experiences an SLG fault. Once we have grouped all of the feeders (FDR_*nn*) and transformers that are connected to B1 in Zone 1 and B2 in Zone 2, we observe the behavior of $3I_0$ and $3V_0$ in the two zones before and during an SLG fault condition on FDR_05. In Zone 1, $3I_0$ and $3V_0$ remain pretty much the same before and after the fault. Zone 1 does not experience any change in $3I_0$ and $3V_0$ due to the fault. Fig. 5 shows the standing $3I_0$ and $3V_0$ for Zone 1 (the unfaulted zone) before and during the SLG fault on FDR_05.

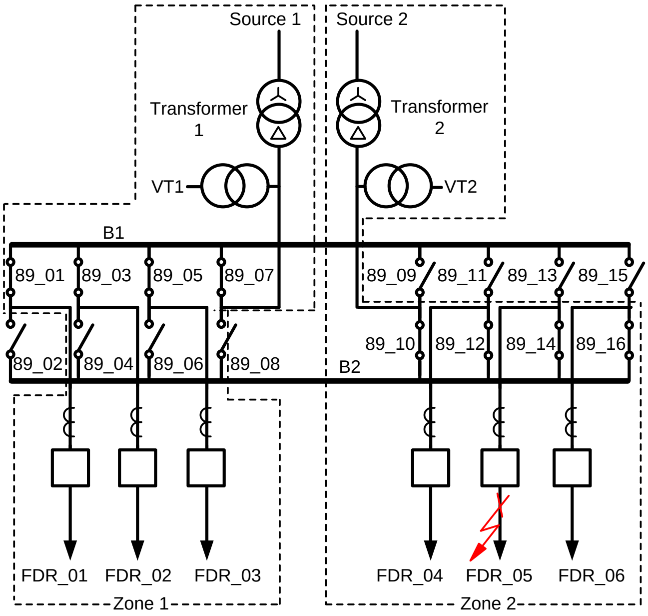

Fig. 4. Bus connections for a typical LADWP substation on the ungrounded power system, with an SLG fault on FDR_05 in Zone 2.

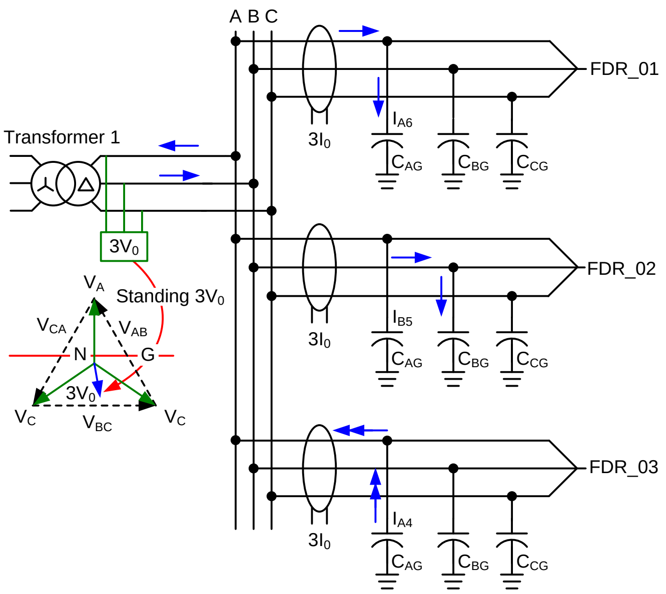

Fig. 5. Zero-sequence current flow due to system unbalances in Zone 1 (the unfaulted zone) before and during the SLG fault on the power system.

We now examine what happens to $3I_0$ and $3V_0$ in Zone 2. The prefault conditions of Zone 2 look very similar to that of Zone 1 (shown in Fig. 5). However, when the SLG fault occurs, there is a significant change in $3I_0$ and $3V_0$ in the faulted zone as shown in Fig. 6.

We can use an incremental change in $3I_0$ to determine whether a feeder is connected to the faulted zone or not. All feeders connected to the faulted zone will experience a significant incremental change in $3I_0$. The $3V_0$ used to polarize the directional element associated with each of the faulted feeders will be the $3V_0$ that experienced the greatest incremental voltage change. In this manner, we identify the faulted feeders and the correct voltage with which to polarize the directional elements. Each feeder has its own protective relay that measures the $3I_0$ current of the feeders. Therefore, it is possible for each relay to monitor the incremental change of $3I_0$ of the feeder it is protecting. However, a typical feeder protection relay has only one set of voltage inputs, so to route the correct $3V_0$ voltage to each protective relay would require an external processing unit with built-in logic capability. It would be better to use one central unit (CU) to collect the $3I_0$ currents from all feeders in the substation and all the $3V_0$ voltages.

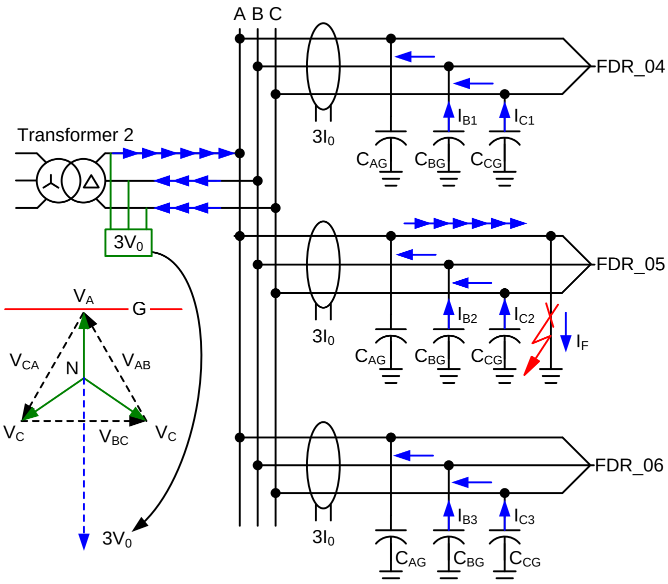

Fig. 6. Zero-sequence current flow in Zone 2 (the faulted zone) during the SLG fault on FDR_05.

3 The central unit

By using a CU to collect all of the $3V_0$ bus voltages and $3I_0$ feeder currents at a substation, we can use the following steps to accurately identify the faulted feeder [1].

- Identify which feeders are in the faulted zone.
- Identify which $3V_0$ bus voltage is associated with the faulted zone.
- Calculate the incremental torque for each feeder in the faulted zone.
- Use the incremental torque to determine the faulted feeder(s).

To determine which feeders are in the faulted zone, we need to determine which feeders experienced an incremental change in $3I_0$ due to the SLG fault. The incremental $3I_0$ logic compares the present value of $3I_0$ against a previous value of $3I_0$. If the difference between the present and previous value is above a dynamic threshold, the incremental logic asserts an output that indicates the feeder experienced a notable change in its $3I_0$ value and is therefore in the faulted zone. Fig. 7 shows a simplified sketch of the incremental $3I_0$ logic.

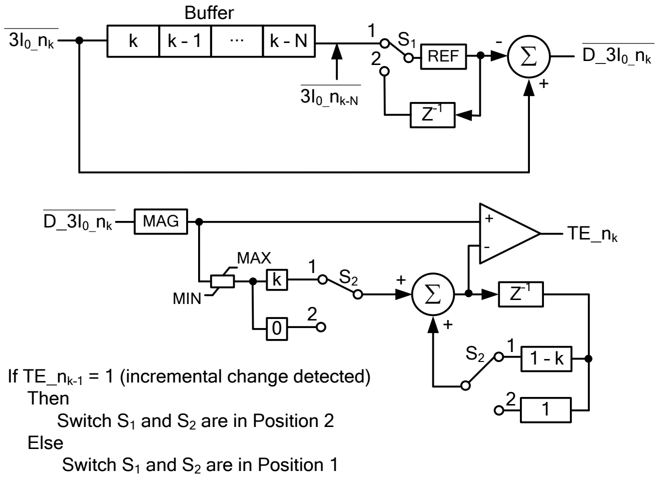

Fig. 7. Incremental detection logic used for detecting incremental changes in the $3I_0$ current of each individual feeder at a substation.

The logic used to determine which $3V_0$ bus voltage is associated with the fault is similar to the incremental $3I_0$ logic shown in Fig. 7.

If a feeder experienced an incremental change in $3I_0$ ($TE\_n_k = 1$ in Fig. 7), the logic identifies that feeder as being involved in the fault. Feeders associated with the fault have their reference value frozen (Switch S_1 in Fig. 7 moves to Position 2) to maintain the prefault reference. Similarly, the logic freezes the reference of the $3V_0$ bus voltage associated with the fault. The assertion of the incremental logic also freezes the threshold reference against which the logic compares the incremental change of $3I_0$ or $3V_0$ (Switch S_2 moves to Position 2). If the output of the incremental logic is asserted, the logic calculates the zero-sequence incremental torque for that feeder. If the output of the incremental logic for a feeder is not asserted (i.e., $TE\_n_k = 0$), the feeder is not involved with the fault and the incremental zero-sequence torque is simply set to zero as shown in (1).

$$
\begin{aligned}
&\text{If } \mathrm{TE\_n_k} = 1 \\
&\text{then} \\
&\quad \mathrm{TRQ\_n_k} = \mathrm{Im}\left(\mathrm{D\_3V_0\_REF_k} \bullet \mathrm{D\_3I_0\_n_k}^{*}\right) \qquad (1) \\
&\text{else} \\
&\quad \mathrm{TRQ\_n_k} = 0
\end{aligned}
$$

where:

$D\_3V_0\_REF_k$ = incremental change of $3V_0$.
$D\_3I_0\_n_k$ = incremental change of feeder *n* $3I_0$.
* = complex conjugate.
k = present processing interval.

Once all of the incremental torque quantities have been calculated, we could simply select the faulted feeder as the one that developed the greatest incremental torque as a result of the SLG fault. However, to increase the confidence level in the identified faulted feeder and to address more complex faults, we enter the results of the torque calculation into a fault table. The fault table is arranged in descending order of absolute incremental torque. Table 1 is an example of a fault table composed for the example substation in Fig. 4.

Number	**Absolute Torque |TRQ_n|**	**Sign of Torque**	**Feeder ID**
1	45	+	FDR_05
2	29	–	FDR_04
3	16	–	FDR_06
4	0	N/A	FDR_01
5	0	N/A	FDR_02
6	0	N/A	FDR_03

Table 1. Absolute incremental torque, sign, and identity for each feeder in descending order of zero-sequence incremental torque.

The number of rows correspond to the number of feeders in the substation. The logic declares the feeder in the first row of the table the faulted feeder if both of the following conditions are met:

- The incremental torque in the first row is positive.
- The incremental torque in all other rows is nonpositive.

The described conditions are for a typical SLG fault. To enable the scheme to perform correctly for as many scenarios as possible, we added extra criteria to the logic. We describe two of these criteria below.

For the first criteria, consider a scenario when there are only two feeders in the faulted zone. In this instance, the incremental change of $3I_0$ for both feeders is the same, irrespective of which one experiences the SLG fault. The result is that the absolute value of the incremental change of the zero-sequence torque developed by the two feeders due to the SLG fault is the same. The differentiator in this case is that for the faulted feeder, the incremental change in the zero-sequence torque is positive, whereas for the unfaulted feeder, the incremental change in the zero-sequence torque is negative. Due to possible rounding errors in the torque calculations, the torque calculated for the unfaulted feeder may be slightly higher than that for the faulted feeder, so it is entered into the first row of the table instead of the second row. In this instance, the logic looks at the sign of the incremental torque in the first column. If it is negative, it looks at the sign of the incremental torque in the second column. If the sign in the second column is positive, the logic then compares the magnitude of incremental torque between the first two rows. If these two values are very close (within 5 percent of each other) and the sign of the incremental torque of the third column is not positive, then the feeder in the second row is declared as the faulted feeder.

Note that even though there may only be two feeders in the faulted zone, the substation will likely have more than two feeders. Because the logic defaults the incremental zero-sequence torque for the unfaulted feeder to zero, the sign gets set to N/A. When the logic checks the sign of the torque in the third row, it sees that it is N/A and not positive and declares a faulted feeder.

For the second criteria, consider a scenario where two feeders simultaneously experience an SLG fault on the same phase (note that a simultaneous SLG fault on two different phases results in a phase-to-phase cross-country fault and requires one of the feeders to be taken out of service to allow further operation of the power system). In this case, the two faulted feeders experience the same incremental change in their $3I_0$ currents and, as a result, the incremental zero-sequence torque developed by these two feeders is the same in absolute magnitude and sign. All other nonfaulted feeders in the faulted zone develop lower negative incremental zero-sequence torques. When these values are entered into the fault table rows, the first two rows contain the data for the faulted feeders. The data for the unfaulted feeders are in the remaining rows of the fault table.

In this case, the logic detects that the sign for the incremental torque is positive for the first and second rows and not positive for the remaining rows. The logic then checks the magnitude of the incremental zero-sequence torque developed by the feeders in the first two rows of the fault table. If these are approximately the same (within 5 percent of each other), the logic declares a simultaneous SLG fault on two feeders and identifies the faulted feeders as the feeders in the first two rows of the fault table.

The CU forms the heart of the ground-fault-detection system described in this paper. It must receive and process time-aligned synchronized current and voltage quantities for all of the feeders in the system to detect the faulted feeders. At the same time, the CU is required to provide data via a digital signal to the local human-machine interface (HMI) system and the supervisory control and data acquisition (SCADA) system. The main requirements of the CU are as follows:

- Deterministic performance of all local and remote modules (analog as well as I/O).
- Deterministic high-speed communications [5] [6].
- Event recording and retrieval capabilities.
- IEC 61131 logic engine.
- High-speed processing.
- Hardware modularity.

4 Testing

After the proof of concept document was reviewed and approved by LADWP, the project moved into the next phase, which required that the proposed logic be programmed into a CU and tested under different operating and fault scenarios. The testing of the logic was divided into two stages. The first stage was testing the logic using a Real Time Digital Simulator (RTDS®). If this proved successful, testing would advance to the next stage—actual field testing at two LADWP substations.

4.1 RTDS testing

We modeled an ungrounded power system similar to the one shown in Fig. 4 in an RTDS, and interfaced the CU with the RTDS to create a closed-loop system. By not transposing the individual phase conductors of the feeders in the RTDS model, we created a standing system $3V_0$ voltage and a standing $3I_0$ current for each feeder. To verify that the logic would not falsely assert during normal feeder switching operations, we randomly transferred feeders from one bus to the other. Randomly switching feeders from one bus to the other did result in the standing $3I_0$ current of the feeders changing, but the incremental change in the $3I_0$ current was not large enough to exceed the dynamic threshold. This not only proved that the logic correctly handled normal feeder switching operations, but also that the threshold for the $3I_0$ current for each feeder was adaptive.

Afterward, we subjected the system to a variety of different SLG faults and changed three fault criteria during testing: the faulted feeder, the faulted phase, and the fault resistance (the latter was done to determine the sensitivity of the logic). After each fault, we inspected the CU output to verify that the feeder identified as the faulted feeder was indeed the feeder that was faulted in the simulations and that only one feeder was identified as the faulted feeder. In addition to this, the zero-sequence incremental torque developed by each feeder was recorded and verified using the incremental $3V_0$ of the faulted bus and the incremental $3I_0$ current of each feeder.

Once the implemented logic had correctly identified the faulted feeder for a single SLG fault, we tested the robustness of the algorithm by applying multiple SLG faults on the power system. For example, we applied an A-phase-to-ground fault to one feeder, and a few milliseconds later we applied a second A-phase-to-ground fault to a second feeder. Such faults are common on the LADWP system during storm conditions in which one or more feeders come into contact with vegetation. The simultaneous fault scenario was of particular interest to LADWP because it would not be possible to simulate such a fault in the field due to the field crew limitations. The logic correctly detected all of the faulted feeders.

Before concluding RTDS testing, LADWP wanted to know whether the present logic could also be used to detect an SLG fault on one of the substation buses. Because the initial fault identification logic was not designed with this type of fault in mind, we needed to modify the logic. We modified the logic such that when one of the substation buses experiences an SLG fault, all of the feeders connected to the faulted bus will see the fault behind them (i.e., the zero-sequence torque developed by each feeder is negative). We tested the modified logic, which successfully detected an SLG bus fault. To ensure that the modification to include bus faults did not break the previously tested logic, we reran a selected number of previous fault cases. With the RTDS testing successfully concluded, it was time to test the logic in the field.

4.2 Field testing

We performed field testing at two different LADWP substations to verify the system performance under real-world conditions.

We conducted the first series of tests on a feeder supplied from Substation DS-80, which consists of 16 overhead feeders and two shunt capacitor banks. The week before testing commenced at DS-80, we temporarily installed the CU. The

$3I_0$ feeder currents were obtained from existing summation current transformers (CTs) with a CT ratio of 50:1. The bus $3V_0$ voltages were obtained from broken delta voltage transformers (VTs) with a ratio of 35:1. We simulated the SLG fault by connecting one end of an insulated conductor to ground and the other end to one end of a fuse link. We connected the other end of the fuse link to one of the phase conductors of the feeder and initiated the SLG fault by closing the fuse link. The picture in Fig. 8 shows a fuse link and an insulated conductor used to initiate an SLG fault on the feeder. For this testing series, the ground was patches of sandy soil (high-impedance fault conditions), this resulted in a fault current of approximately 2 A primary (0.4 A secondary). The temporarily installed CU system successfully identified the faulted feeder, but the existing system could not detect the faulted feeder because the high-impedance ground fault did not generate enough $3V_0$ voltage to trigger the scheme.

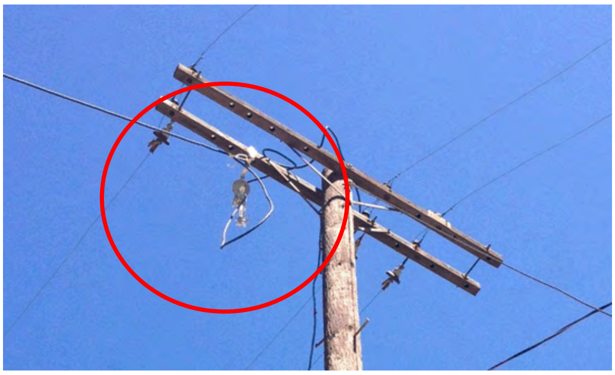

Fig. 8. A fuse link is used to create a connection between a phase on the feeder and an insulated conductor grounded at the other end. By closing the fuse link, an SLG fault is created.

We performed the second series of field tests on underground cable feeders supplied from Substation DS-34, a double-bus substation consisting of 18 underground feeder cables. The reason for selecting DS-34 was that, under normal operating conditions, the standing $3I_0$ current on the underground feeder cables is high. As in the case for DS-80, we temporarily installed the CU into DS-34 a week before testing began. Unlike the testing at DS-80, we selected several feeders to be faulted during this testing series. After the initial fault, several feeders indicated that they had experienced the fault condition. At this stage, we temporarily halted testing so as to determine the reason for the incorrect operation of the fault identification logic. After examining the incremental zero-sequence torque quantities developed by the unfaulted feeders, we determined that the polarity of the summation CTs from several of the feeders connected to the CU scheme was incorrect. After correcting the polarity of the summation CTs, we resumed testing and the fault identification logic operated as designed. The centralized scheme not only correctly identified the faulted feeder but also the faulted phase. Typical fault currents for an SLG fault on feeders from DS-34 were in the range of 0.4 to 0.6 A primary (0.08 to 0.012 A secondary). For visibility, we configured separate digital outputs on the CU front panel to indicate the faulted feeder or feeders and the faulted phase.

5 Conclusion

By collecting the incremental $3I_0$ currents and $3V_0$ voltages in a CU, we created a virtual correlation between feeders involved in a fault and the corresponding $3V_0$ voltages. This allowed us to accurately identify the faulted feeder or feeders in a system where there is no definite correlation between the feeder $3I_0$ currents and the $3V_0$ bus voltages.

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