Using PQ Monitoring and Substation Relays for Fault Location on Distribution Systems

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***Abstract*—Fault location is of considerable interest for utilities to improve their reliability and speed storm restorations. Power quality recorders, relays, and other monitors can provide information to help locate faults. In this paper, some basic impedance-based fault-location methods are evaluated on utility measurement data with known fault locations. The main finding is that reasonably accurate fault locations are possible on a wide range of distribution circuits with either feeder-level or bus-level substation monitoring. Another important finding described is how monitoring can be used to estimate the parameters of the fault arc. This can improve fault locations and help with accident investigations, equipment failure forensics, and other hazards related to the power and energy created by the arc.**

***Index Terms*—Arc voltage, fault location, power distribution, power quality, reliability.**

I. Introduction

Power system monitoring systems continue to get more powerful and provide a growing array of benefits to the overall power system operation and performance evaluation. Permanent monitoring systems are used to track the ongoing system performance and to watch for conditions that could require attention, as well as to provide information for utility and customer personnel when there is a problem to be investigated.

Automatic fault location can reduce the time to repair faults and have a direct impact on overall system reliability.

Fault location is an area of significant interest and research in the industry. The Electric Power Research Institute has a project that is a multi-year effort to evaluate different approaches, identify limitations, and develop recommendations as a function of types of systems. In addition, a number of utilities are implementing fault location functionality to their existing substation power quality monitoring systems.

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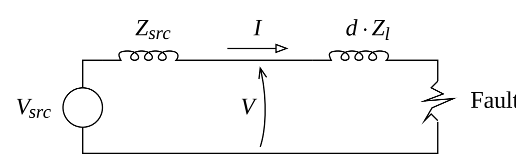
The literature review by Diaz and Lopez [3] provides a good overview of 89 papers and other citations focusing on distribution fault location. Most distribution fault-location approaches concentrate on impedance-based fault location techniques where fundamental-frequency parameters are used to estimate fault locations. Some commonly cited references on distribution circuits are by Girgis et al. [8], Schweitzer [19], and Santoso et al. [18]. Many of the impedance-based algorithms developed for distribution circuits are outgrowths of single-ended transmission-line location algorithms. Some commonly cited works include those by Takagi [20], Eriksson [7], and Sachdev [17].

Beyond impedance-based methods, other approaches have been suggested. Traveling-wave methods use timing difference between multiple monitors to arrive at a location estimate. That method is more applicable to transmission lines where lines are longer, and monitors may be available at two ends of a circuit. Another category of fault location algorithms is various learning systems. These can include expert systems, fuzzy logic, neural networks, and other trainable algorithms. These can be used in conjunction with other methods or as standalone algorithms. A key issue is getting a suitable training data set.

Progress Carolina has an advanced monitoring system that they use to locate faults. For further reference, see Lampley [10] and Peele [11, 12] plus some of the analysis done at NC State based on their data by Kim et al. [9] and Baran et al. [1]. Progress Carolina records steady-state trend data and fault events on all of their feeders using a remote-terminal unit (RTU) that can sample at 16 samples per cycle. Progress Carolina uses the fault current from the measurement along with a fault-current profile from the given circuit to select possible fault locations. They assume a bolted fault (no fault resistance).



$$d = \frac{V}{I \cdot Z_l}$$

Fig. 1. Fault location calculations.

Lampley [10] reported that their locations were accurate to within 0.5 miles 75% of the time; and in most of the remaining cases, the fault was usually no more than one to two miles from the estimate. Progress Carolina has reduced their CAIDI (average restoration time) from about 80 minutes to 60 minutes since 1998 when they started using their system for fault location.

Con Edison has recently implemented a fault location system in the New York City area with goals of reducing fault locating time and cost, directing crews more efficiently, and maintaining network reliability. For monitors, they use power quality monitors that are monitoring voltages and currents on a substation transformer. The monitors sample at 128 points per cycle. They use the reactance-to-the fault method of locating faults. They find the reactive part of the impedance to the fault and compare that with the reactance from the substation to the fault based on their circuit models. They use the residual current to pick out ground faults. This is particularly effective for them because their load is mainly secondary network load connected through delta – wye transformers. Because the load is connected phase to phase, the ground current does not have load current mixed in. Their system models do not include zero-sequence impedances, so they use adjustment factors (k-factors) tuned for each site to adjust for the differences between the loop impedance to line-to-ground faults and the positive-sequence impedance. For further information on the implementation and performance of their system, see Stergio [32, 33].

II. Impedance-Based Fault Location

If we know the voltages and currents during a fault, we can use these to estimate the distance to the fault. The equation is just Ohms Law (see Fig. 1):

$$d = \frac{V}{I \cdot Z_l}$$

where,

V = voltage during the fault, V
I = current during the fault, A
Z_l = line impedance, ohms per length unit
d = distance to the fault, length unit such as miles

With complex values entered for the voltages and impedances and currents, the distance estimate should come out as a complex number. The real component should be a realistic estimate of the distance to the fault; the imaginary component should be close to zero.

A simplification of this approach is to use the reactance to the fault as:

$$d = \frac{\mathrm{Im}\left(\frac{V}{I}\right)}{\mathrm{Im}(Z_l)}$$

Using the reactance has the advantage of avoiding the arc impedance which is mainly resistive.

While the idea is simple, a useful implementation is more difficult. Different fault types are possible (phase-to-phase, phase-to-ground, etc.), and each type of fault sees a different impedance. Fault currents may have offsets. The fault may add impedance. There are uncertainties in the impedances, especially the ground return path. Conductor size changes also make location more difficult. With changing conductor sizes, we need to compare the estimated impedances with the impedances along various fault paths possible on the distribution circuit. For comparison, the absolute value, real part, or imaginary part may be used.

The most critical input to a fault impedance algorithm is the impedance data. Be sure to use the impedances and voltages and currents appropriate for the type of fault. For line-to-ground faults, use line-to-ground quantities; and for others, use phase-to-phase quantities:

Line-to-ground fault
$V=V_a$, $I=I_a$, $Z=Z_S=(2Z_1+Z_0)/3$
Line-to-line, line-to-line-to-ground, or three-phase faults
$V=V_{ab}$, $I=I_a-I_b$, $Z=Z_1$

These are all complex quantities. Although the voltages and currents are complex, we can also estimate the distance just using the absolute values. Although we lose some information on how accurate our solution is because we lose the phase angle information, in many cases, it is as good as using the complex quantities. So, the simple fault location solution with absolute values is:

$$d = \frac{V}{I \cdot Z_l}$$

where,

V = absolute value of the rms voltage during the fault, V
I = absolute value of the rms current during the fault, A
Z_l = absolute value of the line impedance, ohms per length unit
d = distance to the fault, length unit such as miles

With this simple equation, we can estimate answers with voltage and current magnitudes. For a ground fault, $Z_l=Z_S$ is about one ohm per mile. If the line-to-ground voltage, V=5000 V, and the fault current, I=1500 A, the fault is at about 3.3 miles (5000/1500). Use the phase-to-phase voltage and $|I_a - I_b|$ (and not $|I_a| - |I_b|$) for faults involving more than one phase, and use the positive-sequence impedance (typically about 0.7 ohms per mile for mainline overhead circuits).

Other impedance-based fault location methods are available. The Tagaki method [20] is used in popular relays. Fault location is possible using just the short-circuit current. Using a short-circuit profile (Fig. 2), use the measured fault current, and interpolate the distance. It is also possible to just use voltages and use a voltage divider (with a known source impedance) to solve for the distance to the fault.

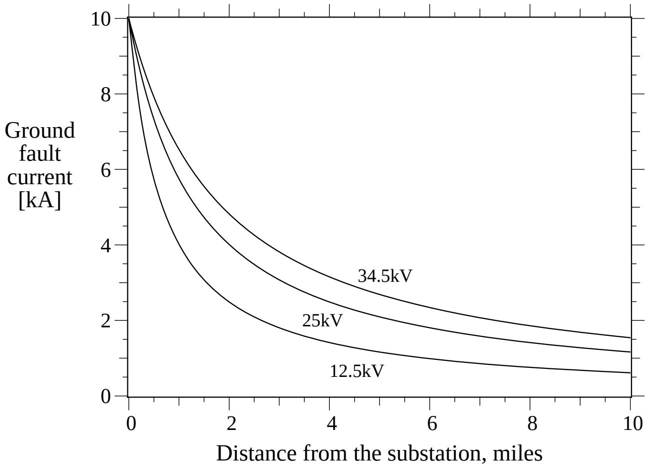


Fig. 2. Fault current profile.

III. Using Relays to Locate Faults

Digital relays have long had built-in fault location capability using impedance-based methods. See Schweitzer [19] and Zimmerman and Costello [21] for more background on the use of relays for fault location. Relays typically sample at 16 or 32 points per cycle. This is sufficient for good fault location accuracy.

The advantages of using the built-in locating ability are:

(1) Simpler data transmission—The relay does the calculations and boils down the results into one estimate of the distance. This result can be tied into SCADA for direct transmission to system operators.

(2) No need for a system model—The relay does not use a system model, so there is no need to interface a Cyme, Milsoft, or other system model with the fault location setup.

The disadvantages are:

(1) Constant wire size—The relay does not have a system model. It assumes one constant wire size. This can make the location inaccurate for systems with changing wire size.

(2) Limited algorithm—The location algorithm in a typical relay does not handle the impacts of arc voltage, pre-fault load, infeeds, and some other issues that may require more sophisticated processing.

(3) No pole or manhole location number—The output is a distance. Further interfacing is necessary to translate this distance into a pole or manhole location or physical map location for better use by operators and field crews.

(4) Voltage inputs needed—The relay needs voltage inputs as well as current inputs to estimate a distance to the fault.

Overall, if a utility's circuits are well represented by a constant wire size, then using the built-in fault location capability can give reasonable results.

IV. Example Fault-Location Results

Seven utilities provided EPRI with over 1500 fault events for analysis. Each event has monitoring data, a system circuit model, and a known outage location from an outage management database. Such a wide range of events provides a good database to analyze fault location approaches.

"Utility A" provided a dataset that included events from several substations during one year. This utility is a mainly overhead utility with predominantly 13.8 kV distribution. The data was recorded by power quality monitors measuring the substation bus voltages and currents. The initial set of matches between the monitors and the outage database narrowed the list of events. Outages and monitor events were matched if their times were within 30 minutes, they were at the same substation, and the outage had a pole number or other location indicated in the database. Then, each monitor event was manually reviewed to see if it matched the utility outage database records.

Fig. 3 shows estimates of impedance to the fault from the utility's circuit database and known fault location compared to the estimate of the same impedance estimated from the fault waveshape. For perfect fault location, these would be equal and fall on top of the straight line shown (the line is not a linear fit to the data). Fig. 3 is for line-to-ground faults, so the loop impedance is the parameter of interest $(2 \cdot Z_1 + Z_0) / 3$. The waveshape estimate is used to predict the fault location.

For this dataset, the impedance from the fault waveshape overestimates the distance to the fault. This can be corrected with a linear adjust multiplier. The more important parameter is the spread around a linear fit. Except for a few outliers, all of the data is within plus or minus one ohm. Ohms are not what we want for a final answer on accuracy—we want an estimate of the distance accuracy. For this, we can use the fact that overhead lines have an impedance of about one ohm per mile for the loop impedance. Therefore, can be interpreted as having the x and y axis scales in miles. So, we see that almost all of the estimates are within plus and minus one mile.

Each of the colors in Fig. 3 represents a different substation at utility A. There is no strong difference from site to site in this data.

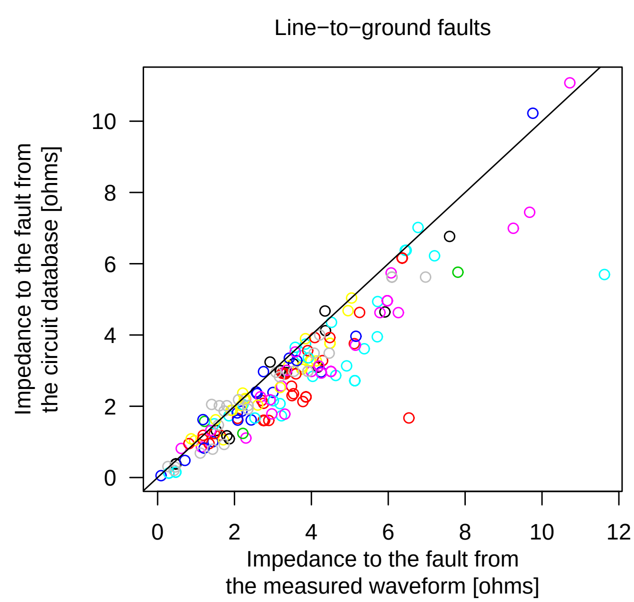


Fig. 3. Utility A: Impedance estimated from the waveform versus impedance to the fault from the circuit database.

Fig. 4 shows one example of an actual fault location compared with estimated locations. Multiple locations are estimated because the radial circuit has a number of branches. For cases where the circuit breaker or a recloser locked out, an operator could narrow the choices just to those on the mainline—assuming coordination of downstream protective devices. As with many of the faults at utility A, this prediction is an overestimate. The overestimate can be factored out of the model by including a multiplying factor.

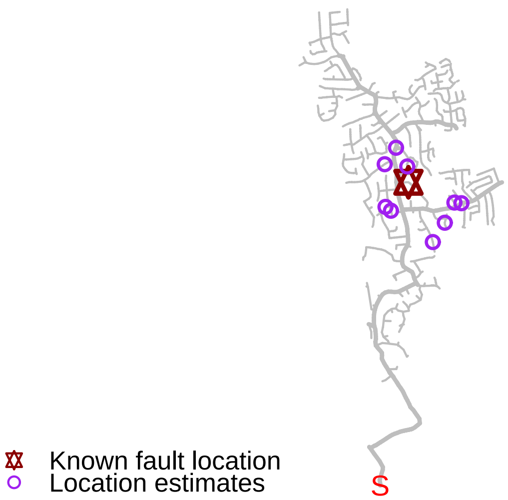


Fig. 4. Fault estimates relative to a known location.

Fig. 5 shows a similar comparison but for double line-to-ground faults. The correlation between the circuit database impedances and the impedances from the waveform appears even better than for line-to-ground faults. This is surprising because the monitors at utility A are bus-level monitors with significant loading. For line-to-ground faults, loading interferes less with fault location, because the residual current can be used ($I_A + I_B + I_C$). For multiphase faults, the load current on each phase makes it more difficult to separate the fault current from the load current. In Fig. 5, the data is segmented by load. There is no noticeable impact on whether the total loading on the circuit was high or low when the fault happened.

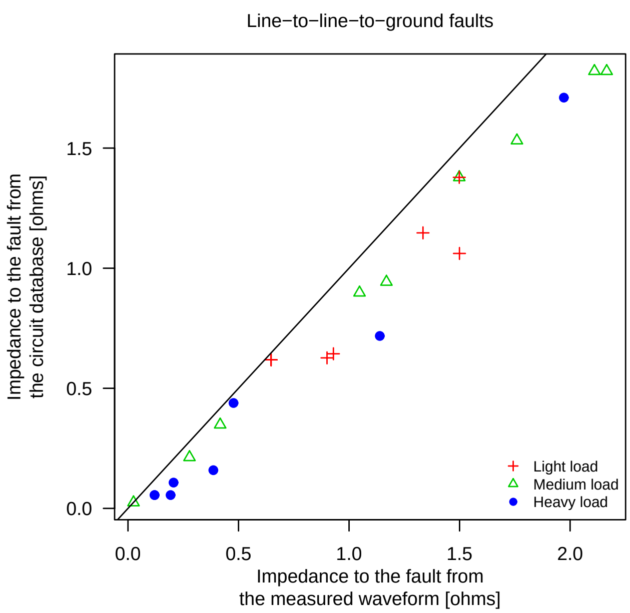


Fig. 5. Utility A: Impedance estimated from the waveform versus impedance to the fault from the circuit database.

"Utility E" provided a number of events measured by Schweitzer SEL-251 and 351 relays. This utility is mainly suburban and rural with 12.5 and 34.5 kV. Both line-to-ground faults and multiphase faults are included. Correlation was good except for a handful of short-duration events as shown in Fig. 6. On these events, the downloaded data had filtering enabled. The filtering can reduce the magnitude of the fault current and increase the apparent impedance (because Z = V/I).

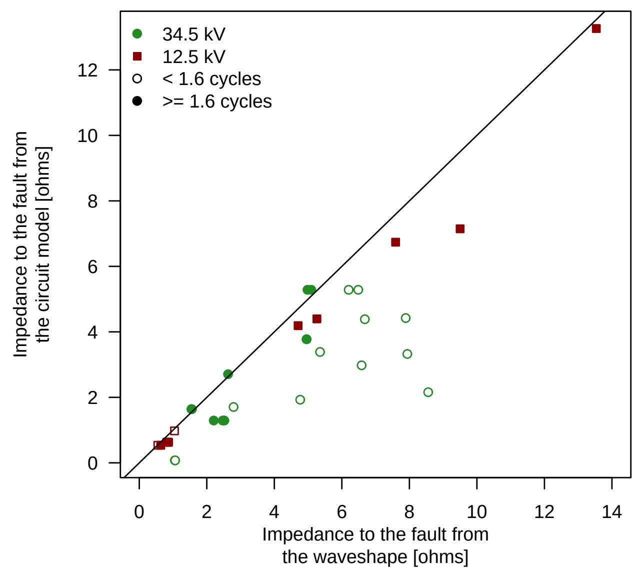


Fig. 6. Utility E: Impedance estimated from the waveform versus impedance to the fault from the circuit database.

"Utility D" provided data that included the results based on the relay's internal fault-location algorithm. Fig. 7 compares the impedance from the built-in location algorithm to that from the circuit database. The X-axis value in Fig. 7 was obtained by taking the impedance settings of the relay (R1, X1, R0, and X0) and multiplying by the relay's estimate of distance and dividing by the line length setting in the relay (LL). At the five locations where fault locating was enabled, the built-in locating algorithm worked well.

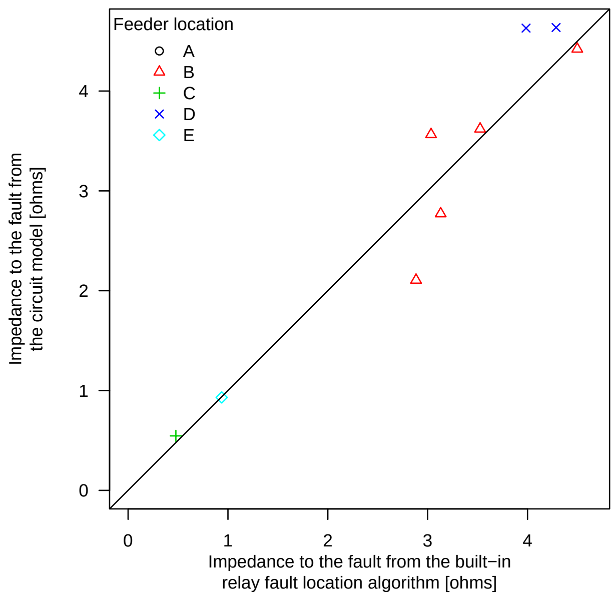


Fig. 7. Utility D: Impedance estimated from Schweitzer relays' built-in location estimate versus impedance to the fault from the circuit database.

V. Impact of Arc Voltage

One of the surprising and important outcomes of this project is finding that it is possible to use monitoring waveforms to predict arc voltages during a fault. Knowing the arc voltage may help improve fault location estimates and has the potential to help in other ways.

Good fault location can be done by assuming a bolted fault—no fault arc resistance. The reactance-to-fault method used by Con Edison and the fault-current method used by Progress Carolina assume a bolted fault (but the reactance-to-fault method attempts to bypass the fault resistance by only considering the reactive part). Results from the EPRI fault study published in the early 1980's showed that actual fault currents were close to the calculated value [2, 4]. The EPRI study found that calculated fault currents were approximately 2% higher than the measured value. Therefore, we assume that fault resistance cannot play a drastic role, but some faults may have enough arc voltage to make the bolted-fault assumption less accurate than desired.

An arc voltage waveform has distinguishing characteristics. Fig. 8 shows an arc voltage measured during the EPRI DPQ project. The voltage on the arc is in phase with the fault current (it is primarily resistive). When the arc current goes to zero, the arc will extinguish. The recovery voltage builds up quickly because of the stored energy in the system inductance—the voltage builds to a point and causes arc reignition. The reason for the blip at the start of the waveform (it is not a straight square wave) is that the arc cools off at the current zero. Cooling lowers the ionization rate and increases the arc resistance. Once it heats up again, the voltage characteristic flattens out. The waveform is high in the odd harmonics and for many purposes can be approximated as a square wave.

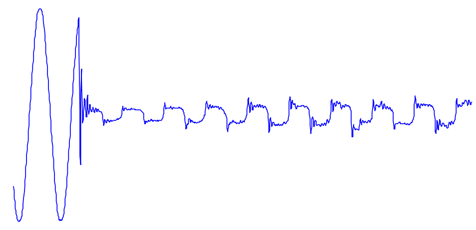


Fig. 8. Example of an arcing fault measured during the EPRI DPQ study.

EPRI's Distribution Power Quality (DPQ) project [5, 6, 16] provided data that confirms that it is possible to accurately account for a nonlinear arc. Fig. 9 shows two example events where the predicted arc voltage obtained from substation measurements matched well with the arc voltage measured downstream of the fault.

The arc estimation algorithm is an extension of the method developed by Radojevic et al. [13-15]. Their approach relies on the approximation that the arc voltage is a square wave and uses that assumption along with a least-squared error minimization to solve for the arc voltage.

Fig. 10 shows the distribution of arc voltages for faults at Utility A (mainly overhead with 13.8 kV). The median arc voltage is about 600 V, and about 20% of events have an arc voltage of over 1200 V. In open air, 1200 V corresponds to an arc length of about three feet.

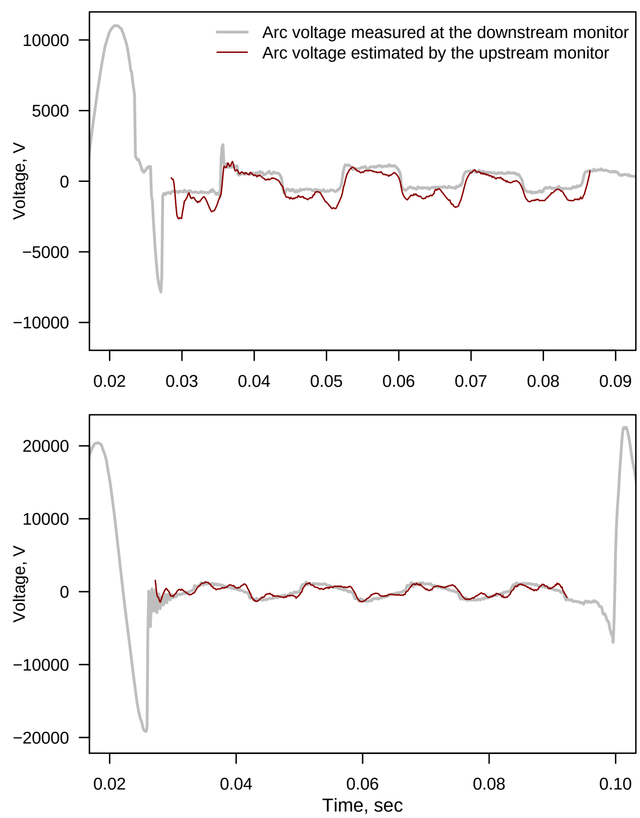


Fig. 9. Comparing arc voltages with estimates from feeder monitors for two different events (EPRI DPQ Study).

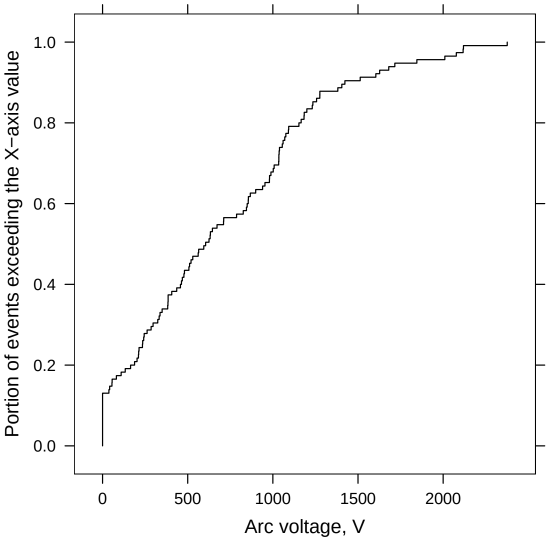


Fig. 10. Distribution of estimated arc voltages measured during line-to-ground faults at utility A.

Being able to estimate the arc voltage could help utilities in several ways:

Improving fault location algorithms—Accounting for the impact of arc voltages can possibly improve the accuracy of fault locations.

Estimating arc power and energy—Equipment explosions, manhole explosions, and arc flash are fundamentally a function of the power and energy in an arc. Monitoring can provide better knowledge of arc energies in these situations. Monitoring to estimate arc energies can be used to develop better estimates of safety hazards, design arc flash boundaries or clothing requirements, or help perform failure forensics.

Fault type estimation—It may be possible to use the arc voltage to help differentiate between different types of faults. Preliminary data shows a marked difference between splice failures and cable failures. It may also help to differentiate between tree faults and lightning for example. Such knowledge can help field crews when searching for the fault.

VI. Implementation Issues

Fault-location algorithms are only one component of an integrated, automated system to locate faults. In fact, the algorithms may be the easiest part. A fault location system must be integrated with the monitoring event database and the system circuit information. This must be brought together and presented to the operator. The event data must be made available within minutes to be most useful to dispatchers.

Timely downloads of data from monitors or relays is important for fault location. There are a number of data consolidation and communication issues to coordinate.

Utilities have circuit data in a variety of formats that would need to be accessed by a fault-location system. Data may be in a distribution analysis package or in a GIS system. Most distribution analysis packages use database storage, and most of the database table structures are straightforward, so writing data-import or conversion routines should not be complicated for most distribution analysis programs. The circuit model needed for fault location is a simplification of what is normally stored by distribution analysis programs. For fault location, only connectivity and impedance information are needed, not loads, regulators, capacitor banks, or any protective devices. Reading data from GIS systems or other systems may be more complicated.

The operator interface is the focal point of the system. The interface should display recent fault events. As much as possible, the selection of fault events and location of faults should be automatic. For a fault location, the interface should display the fault and circuit graphically as well as provide pole numbers or other physical location notation. If operators normally use some mapping software, one possibility is to forward fault-location information to the operator’s normal mapping software for display and manipulation there.

VII. Discussion

The main finding based on analysis of the utility fault data is that relatively accurate fault location is possible across a wide spectrum of distribution systems and monitors.

Feeder-level monitors are the best, but good fault location can be achieved with bus-level monitors. For line-to-ground faults, the key to achieving good location accuracy is using the residual current ($I_A + I_B + I_C$). This avoids most of the load current. For line-to-ground faults, the bus-level currents and the feeder-level currents are consistent within a multiplier factor for 70% of events.

Measuring both voltage and current is the best, but voltage-only fault location is possible. Voltage-only fault location is less predictable because a prefault voltage is needed as a reference to the faulted voltage during the fault.

Relays and other devices with low sample rates can still give useful fault locations. Even relays that report four samples per cycle can give useful fault locations, but higher is better. More advanced algorithms and filtering are better at higher sample rates. The power quality recorders that have 128 or more samples per cycle are the best. Relay-level sampling of 16 samples per cycle is good but still may not be enough to allow accurate arc voltage modeling.

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