USING PQ MONITORING INFRASTRUCTURE FOR AUTOMATIC FAULT LOCATION

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ABSTRACT

This paper describes the use of substation monitoring systems (power quality monitoring, digital fault recorders, and intelligent relays) for automatic fault location on distribution systems. Fault location algorithms and required system interfaces are described. Two examples of actual implementations as part of substation power quality monitoring systems are described.

INTRODUCTION

Power quality 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.

One of the most important development areas for power quality monitoring is the implementation of intelligent systems that can automatically evaluate disturbances and conditions to make conclusions about the cause of the problem or even predict problems before they occur. Fault location is one of the most important of these intelligent applications. 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. This paper describes two of these example applications, the issues with implementing the fault location functionality, and the performance of the system for actual fault conditions.

BENEFITS OF AUTOMATED FAULT LOCATION

Automated fault location can have a direct impact on overall system reliability. Important benefits of integrating the fault location functionality with existing monitoring system infrastructures include the following:

- **Reduced time to repair faults.** Fault location will help identify problem equipment, such as cable splices, insulators, etc. and allow repair of the equipment much faster than is possible if crews have to locate the problem location using traditional methods.
- **Identify problem areas of a circuit.** Associating fault locations with each event will help identify portions of the circuit that are experiencing multiple faults over time. This is particularly important for temporary faults that could be an indication of a problem that will result in a permanent fault.
- **Identify fault causes and problem conditions.** Fault location can be used along with other information to help determine the fault cause (for instance in combination with lightning flash location data) and problem conditions, like galloping conductors.
- **Improved reliability.** The ultimate benefit is actual reliability improvement. Reduced number of faults through identification of problems ahead of time and reduced time to repair will both improve overall reliability.

OVERVIEW OF FAULT LOCATION APPROACHES

There have been many papers describing approaches for automated fault location. 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. This is more applicable to transmission lines where lines are longer, and monitors may be available at two ends of a circuit. Artificial intelligence approaches incorporating learning systems (expert systems, fuzzy logic, neural networks, and other trainable algorithms) have also been proposed. 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).

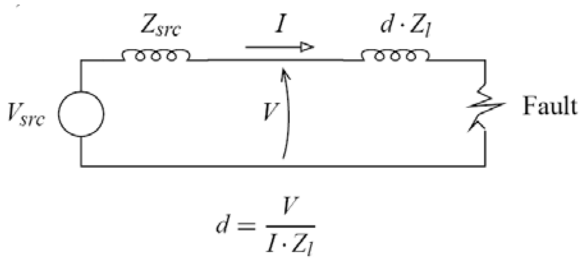

Figure 1. General approach for impedance-based fault location.

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.

Implementing the fault location functionality requires a number of important developments and integration efforts:

- The monitoring system must be able to capture the voltage and current waveforms associated with the fault condition for analysis
- The monitoring system may need to integrate data from intelligent relays and other monitoring equipment in order to obtain the required waveforms.
- Algorithms for fault location are applied to the voltage and current waveforms. As described in this paper, these algorithms generally will focus on impedance-based methods.
- The results of the impedance calculation must be integrated with electrical models of the distribution system and possibly geographic information systems to identify the possible fault locations.
- A user interface is required to display the possible fault locations for operators.

The examples provided in this paper illustrate an approach for the overall fault location implementation.

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=Va, I=Ia, Z=ZS=(2Z1+Z0)/3

Line-to-line, line-to-line-to-ground, or three-phase faults:
V=Vab, I=Ia – Ib, Z=Z1

These are all complex quantities. Figure 2 illustrates an example of implementing a “reactance to fault calculation” that identifies the fault type and uses the appropriate equations to calculate the reactance between the substation and the fault as a continuous quantity. In the example, the fault changes from a single line-to-ground fault to a phase-to-phase fault, resulting in two different calculations for the same event.

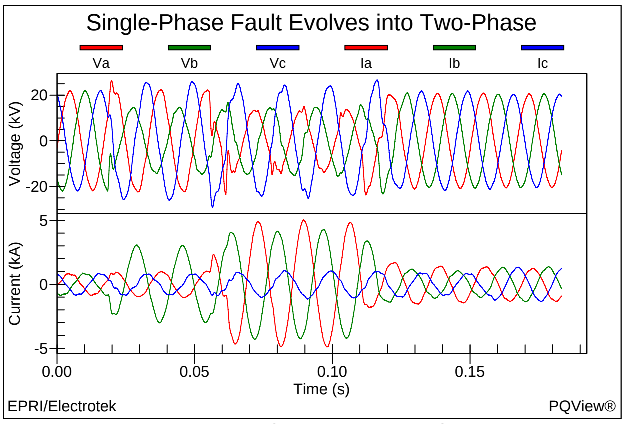

Figure 2a. Example of reactance-to-fault calculation from measured voltage and current data – voltage and current waveforms.

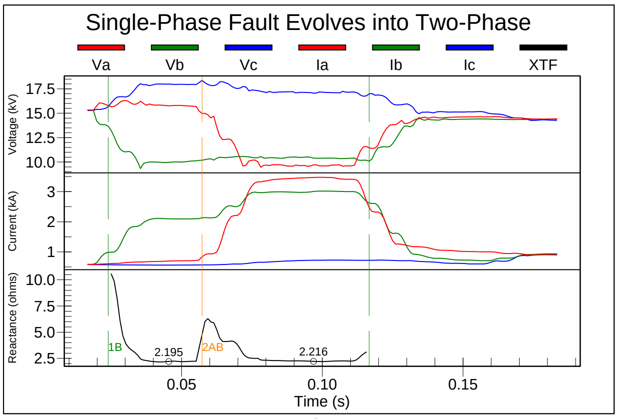

Figure 2b. Calculation of rms voltage and current quantities and the reactance to the fault during the fault.

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.

Figure 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). Figure 3 is for line-to-ground faults, so the loop impedance is the parameter of interest (2 • Z1 + Z0) / 3. 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 Figure 3 represents a different substation at utility A. There is no strong difference from site to site in this data.

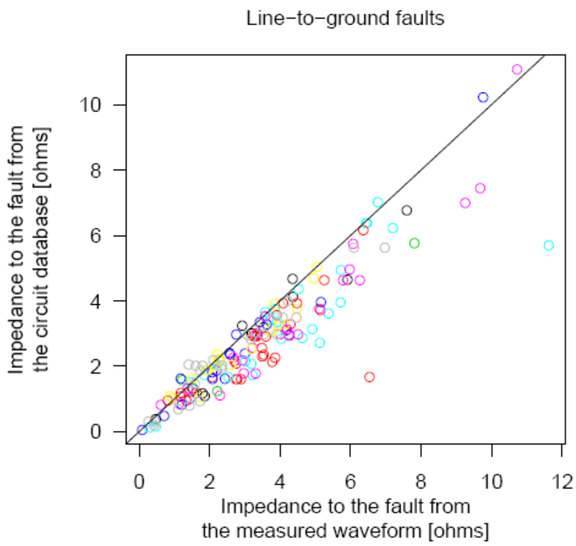

Figure 3. Example of impedance estimated from the waveform versus impedance to the fault from the circuit database.

Figure 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. The location can be narrowed by coordination with predictions of an outage management system (for instance based on customer calls) and with information about breaker lockouts from operations data.

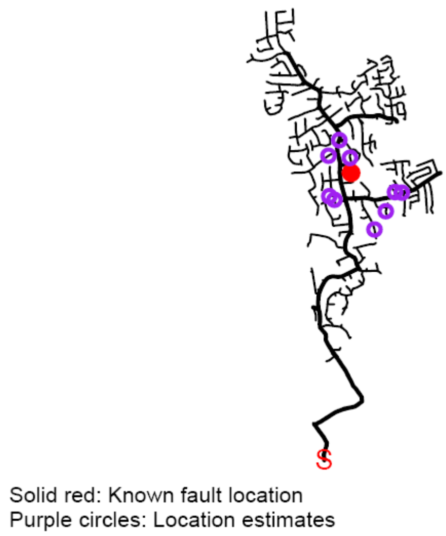

Figure 4. Fault estimates relative to a known location.

Con Edison Implementation

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. Residual current is used to identify ground faults. This is particularly effective for them because their load is mainly secondary network load connected through delta – wye transformers. 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 for line-to-ground faults and the positive-sequence impedance. For further information on the implementation and performance of their system, see Stergio [32, 33].

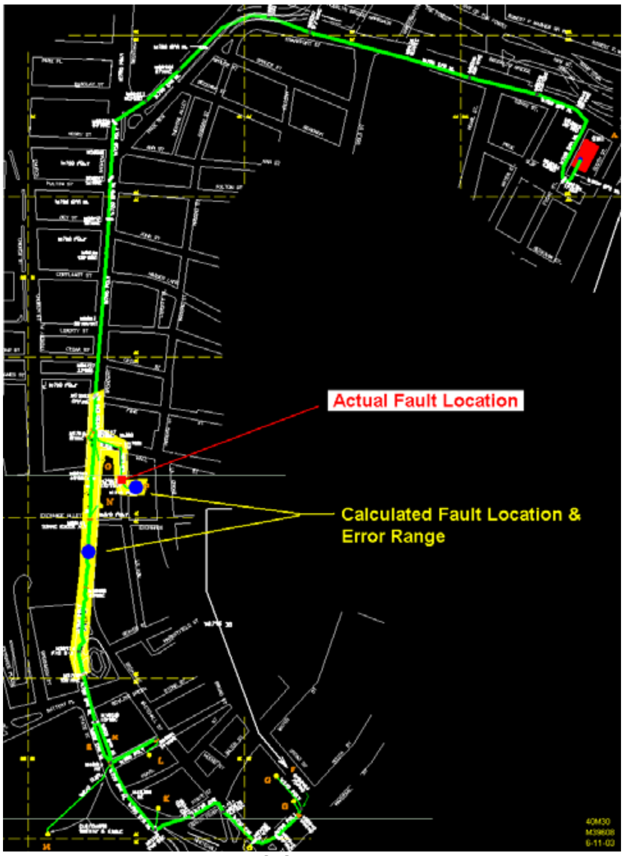

Figure 5. Example of fault location on Con Edison underground circuits in Manhattan.

San Diego Gas & Electric Implementation

San Diego Gas & Electric has also implemented the automatic fault location function as part of their substation monitoring system. The reactance-to-fault information calculated from the monitoring data is correlated with information from the distribution system electrical models to identify possible fault locations. The performance of the system has been tested with historical data from their power quality monitoring system and has shown to give quite accurate results. SDG&E is in the process of a more complete rollout of the system along with web-based visualization of the fault location results (Figure 6).

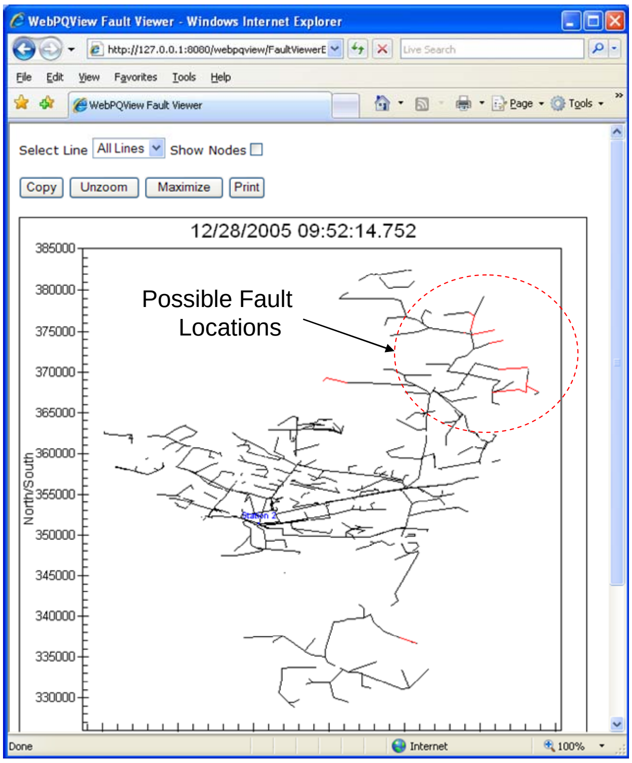

Figure 6. Web-based visualization of fault location results at SDG&E.

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 needs 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 is not 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 mapping software, one possibility is to forward fault-location information to the operator's normal mapping software for display and manipulation there.

DISCUSSION

The main finding based on analysis of the utility fault data I s that relatively accurate fault location is possible across a wide spectrum of distribution systems and monitors. Individual circuit 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 (IA + IB + IC). 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 sample rates are 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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