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Automated Waveform-Based Analytics for Enhanced Reliability, Power Quality, and Operational Efficiency

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SUMMARY

The past decade has witnessed numerous technological innovations to improve various aspects of operational efficiency and reliability. Upon the occurrence of an outage on a distribution feeder, for example, automated schemes can perform switching to localize the outage and restore service to as many customers as possible, often within seconds to minutes. Other systems use data-mining analytics to discover patterns and problems identifiable from AMI (advanced metering infrastructure) databases.

Research at Texas A&M University applies analytical algorithms at a finer level of detail than do AMI-based data-mining analytics. Specifically this research recognizes that electrical waveforms, as measured from conventional current and potential transformers (CTs and PTs), reflect load and other activity occurring on the power system and that, therefore, these waveforms hold the potential for providing the utility with heightened awareness of feeder operations and conditions.

Texas A&M's efforts in this area began in the late 1990's, at which time they focused specifically on anticipating, or predicting, future faults. Long-term instrumentation of 70 feeders at 11 utility companies created a large database of waveforms representing a wide variety of activity on feeders. The process also demonstrated that waveforms reflect a wide variety of valuable feeder information, not just incipient failures. As an example, as has been recognized for decades for protective relaying purposes, a conventional overcurrent fault produces specific variations in measured currents and voltages, and a switched capacitor bank produces specific variations that differ markedly from those of the overcurrent fault. Other project findings document, for the first time, that anomalies such as failing in-line switches or clamps also produce specific variations in waveforms. Algorithms capable of detecting and differentiating specific types of variations provide valuable situational awareness and intelligence that can help utilities proactively avoid certain faults and respond more intelligently and efficiently to faults and other system anomalies.

KEYWORDS

Waveform-based analytics, situational awareness and intelligence, reliability, condition-based maintenance.

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Introduction

Delivery of electric power relies on successful operation of the interconnection of large numbers of components. Even a single distribution feeder consists of many wires, connectors, switches, transformers, and other apparatus, which operate for decades under adverse environmental conditions. Historically the typical utility's situational awareness extended no deeper in the system than substation-based SCADA on a per-feeder basis. The utility often learned of an outage or other problem from telephone calls from customers, and then reacted by dispatching a crew to find the cause of the trouble, make repairs, and restore service.

Some utilities now deploy "self-healing systems," which combine communications with distributed sensing and intelligence, to detect faults and perform coordinated switching to restore service to as many customers as possible as quickly as possible. These systems often can restore the majority of customers within a few seconds or a few minutes, thereby providing improvements to standard measures of reliability, such as SAIDI (e.g., customer-minutes of interruption per year) and SAIFI (customer-interruptions per year). [1] Self-healing systems generally react to outages, but do not address the issue of trying to prevent those outages from occurring in the first place.

AMI (advanced metering infrastructure) systems generate large volumes of consumption data. Recent years have seen the advent of efforts to apply analytics to AMI datasets. These systems apply data-mining techniques to data retrieved at intervals ranging from seconds to hours.

Applied research at Texas A&M University (TAMU) has taken a different approach to using analytics, or algorithms, to extract actionable intelligence from raw data. As with AMI analytics, TAMU researchers recognize that electrical measurements reflect feeder activity, both normal and abnormal. TAMU's efforts, however, analyze high-fidelity current and voltage waveforms, looking for patterns indicative of a multiplicity of types of feeder activity. Researchers have identified multiple cause-specific waveform signatures. Knowledge of these distinct signatures has enabled implementation of on-line algorithms that detect waveform anomalies, determine their cause, and selectively report failures and other operational problems to utility users. Multiple utilities have used pilot installations of the technology to prevent outages, detect operational problems, and improve operational efficiency.

The remainder of this report details specific examples of how utilities can use waveform-based analytics to avoid faults and/or operate their systems more intelligently and efficiently. It is important to note the following factors related to the examples reviewed herein:

- All waveform data comes from intelligent, substation-based instrumentation connected to conventional current and potential transformers (CTs and PTs).
- The substation-based instrumentation performs the algorithms/analytics within a few tens of seconds of the event.
- The substation-based instrumentation sends results of analytics/algorithms to a central server, via Internet, for access by researchers and utility personnel.
- The substation-based instrumentation is not programmed to know its feeder's topology, and there is no communication with pole-top reclosers, capacitors, or other devices. Rather the system is intelligent enough to "discover" line devices, based on waveforms.
- Throughout the rest of this paper, the intelligent substation-based instrumentation, combined with a central server for user access to results, will be referred collectively to as the DFA system. DFA is an acronym for Distribution Fault Anticipation, because of the initial central focus on anticipating, or predicting, faults.

Example #1: Vegetation Encroachment at Pole-top Transformer

In this example, the subject feeder (Figure 1) operates at 25kV and has more than 200 km (125 miles) of overhead lines, with multiple branches and more than a dozen automatic pole-top line reclosers and other sectionalizing devices. A fault during a rainstorm caused one of the feeder's hydraulic reclosers to operate multiple times, followed by tripping of a sectionalizer downstream of the recloser. Customers placed telephone calls to the utility to report the resulting outage, and the utility dispatched a line crew. The crew restored service but reported "no cause found." Four days later, during another rainstorm, the same recloser tripped and reclosed a single time, in response to another fault. This fault did not cause any customers to experience a sustained outage, and no customers called the utility to report the momentary interruption. Most of the feeder's reclosers, including the subject recloser, do not have communications. No conventional system notified the utility that this second fault, trip, and reclose had occurred.

The DFA device at the substation head of the feeder recorded high-fidelity current and voltage waveforms associated with each of the aforementioned faults. It analyzed and reported each fault. In addition, and most importantly, it examined the feeder's fault history and recognized that both faults likely had the same underlying cause. It flagged and reported this special sequence of faults. An engineer at the utility received the DFA notification, examined supporting information that the DFA system supplied, and agreed that the second fault likely had the same cause as the one restored days earlier with "no cause found."

As noted the subject feeder has more than 200 km of overhead line, making fault location challenging. Based on sophisticated analysis of electrical waveforms recorded during the faults, however, the DFA system provided additional parameters about the fault. The utility engineer input these multiple additional fault parameters into his existing feeder model. By so doing, he determined that, with a high degree of probability, the cause of the fault lay within the ellipse encircling a small part of the feeder in Figure 1.

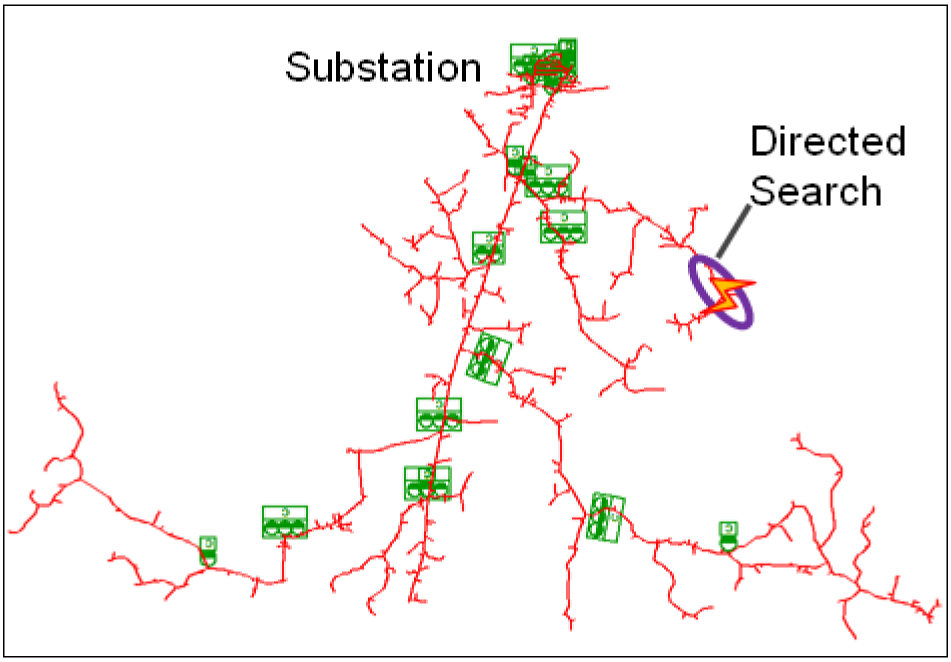

Figure 1: Diagram of subject 200-km (125 mile) feeder for example #1, with directed-search area encircled by ellipse. (Each square symbol represents a line recloser.)

Figure 2: Pole-top transformer a) with vines atop pole, b) after removal from service, with hole visible.

A line crew patrolled the encircled portion of the feeder and located a pole-top service transformer with vegetation partially covering it. As shown in Figure 2, the line crew found a hole punched completely through the lid of the transformer. The crew replaced the transformer without further incident.

To quantify the impact of cases solved in this way, one must attempt to make reasonable assumptions about consequences that would have occurred had the condition not been discovered. In this case, it would seem reasonable to assume that, absent the notification from the DFA system, the incipient failure would have caused three more momentary interruptions, probably during rainy periods, followed ultimately by a sustained outage, and that restoring service following the sustained outage would take 1.5 hours. This further assumes that the crew would have been able to determine the cause of the second sustained outage, rather than again having to restore service with “no cause found.” Under this assumed set of outcomes, the early notification enabled the utility to avoid the following reliability impacts:

- MAIFI impact: 3 momentary interruptions x 103 customers downstream of recloser = 309 momentary customer interruptions
- SAIFI impact: 1 sustained outage x 82 customers downstream of sectionalizer = 82 customer-interruptions
- SAIDI impact: 90 minutes x 82 customers = 7 380 customer-minutes of interruption

There are other benefits, not necessarily related to reliability, but rather related to early detection, location, and repair of this incipient failure:

- The utility localized the failure to a small area before dispatching a crew, enabling an efficient search.
- The utility located the failure in the light of day, during favorable weather.
- The utility replaced the failed equipment in the light of day, during favorable weather.
- The utility avoided a potential explosion. The hole in the transformer lid would allow water ingress, which in turn could lead to catastrophic failure and explosion. Although this is considered a low-probability outcome, it carries potentially severe consequences, including the ejection of burning insulating oil, and therefore should not be ignored.

Similar events have proven to occur rather frequently. Utilities have experienced a substantial number of examples in which vegetation encroachment, broken hardware, or other problems have caused repetitive faults and operations of unmonitored line reclosers. In most of those cases, contrary to conventional wisdom, customers have not informed the utility company prior to a final, sustained outage, even in cases where hundreds of customers have experienced multiple momentary interruptions, over periods of several hours, days, or weeks.

Example #2: Incipient Failure of Hotline Clamp

Texas A&M's research program has discovered that in-line, load-carrying devices, such as switches and hotline clamps, often exhibit early warning signs hours to weeks before the utility company or its customers experience a service disruption or have any other indication of a problem. These incipient failures produce anomalies detectable in electrical waveforms, measured from substation CTs and PTs, and their early-failure signatures are quite distinct and readily distinguishable from other feeder activity.

Utility dispatchers know of many distinct types of problems that can cause complaints of flickering lights or no lights. A flickering-lights report can be particularly troublesome, because it often is not clear whether the customer is experiencing momentary interruptions versus voltage sags and swells. In addition, symptoms may be intermittent, and no obvious symptom may persist at the time a crew arrives to investigate. This leaves the crew in the unfortunate situation of having to rely solely on the customer's description of the symptom.

Example #2 involves failure of a hotline clamp serving three customers. Figure 4 shows a one-line diagram of the affected portion of the system. Space limitations preclude the recitation of a detailed sequence of events, but in summary, this single clamp failure produced multiple symptoms, including flickering lights, a buzzing transformer, and blown 30-amp lateral fuse. Based only on symptoms described by customers, utility personnel found it difficult to reach a proper diagnosis. As a result, the utility had to respond to four separate customer complaints, over a period of two days, to correctly diagnose and correct this problem. In addition, they replaced two of the three service transformers shown in Figure 3, both of which proved to be non-faulted in subsequent shop testing.

The DFA system monitoring this feeder had been complaining of a hotline-clamp failure for three weeks prior to the first customer complaint. The DFA system was considered part of a research project, however, and the dispatcher and line crews were not aware of its report. Utility personnel believe that, if the dispatcher had been aware of the DFA report, he would have directed the crew differently, and that they would have reduced the number of trouble calls by two or three and would have avoided changing the two service transformers.

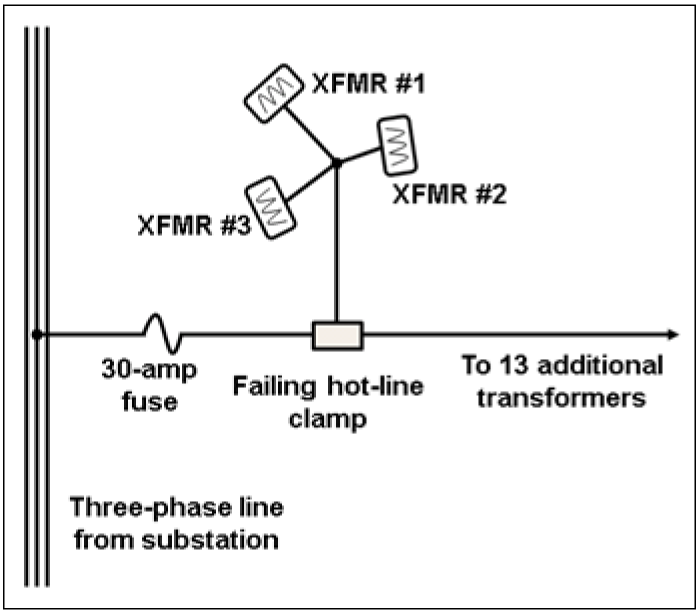

Figure 3: One-line diagram of portion of feeder with failing hotline clamp.

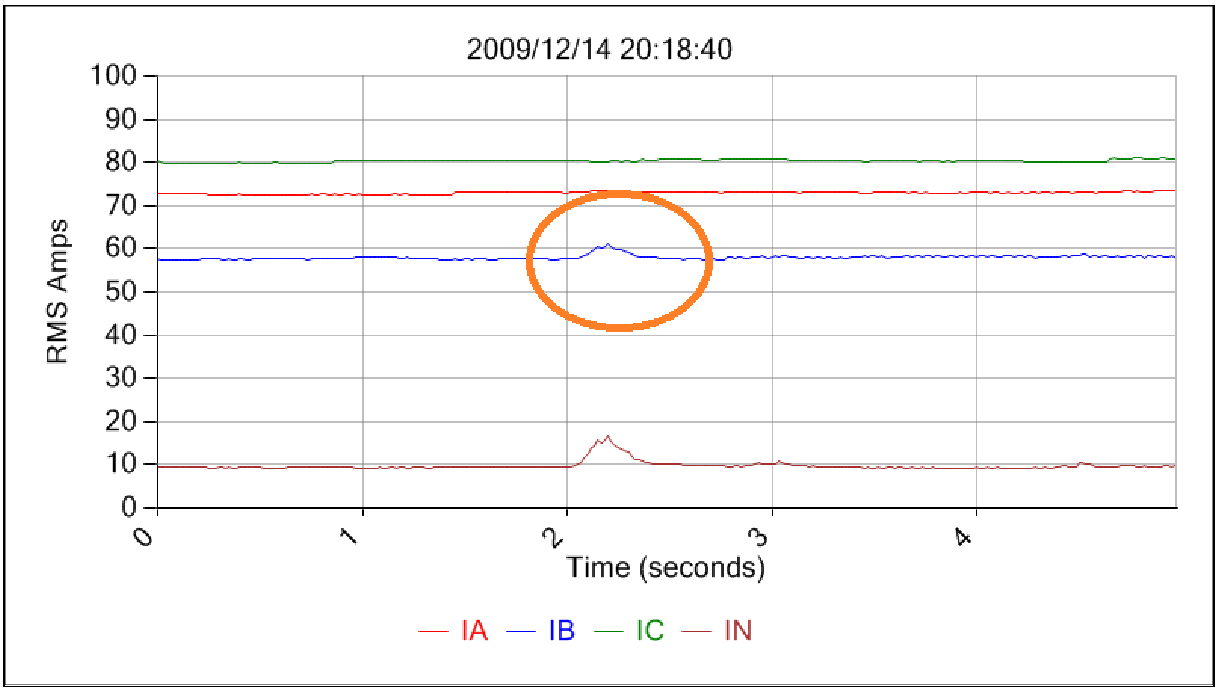

Figure 4: One of many substation measurements of RMS feeder current, during three-week clamp failure.

As noted, the failing clamp produced detectable, recognizable waveform anomalies for three weeks. It did not do so continuously, however. Rather, anomalies would occur almost continuously for a few minutes or tens of minutes at a time, after which no remarkable activity would occur for perhaps several days. Then there would be another flurry of activity. Figure 4 shows RMS line currents, for a period of five seconds, as measured by the substation-based DFA device during one particular episode. During the three-week pre-failure period, the system detected a sequence of more than 2 300 episodes similar to this. The circled "bump" in current, near the middle of the graph, increases line current by about two amperes over its normal load level, and such a "bump," as viewed here, easily could be caused by normal system activity, such as a small motor starting. System voltage is essentially unchanged by such an event. Conventional monitoring systems would not even detect the bump, and certainly would not diagnose its cause. Advanced analytics, applied to high-speed waveforms, however, readily distinguish this clamp arcing from normal-system activity.

Conclusion

Feeder operation is beginning to benefit from multiple recent technological advances. Researchers at Texas A&M University have taken a unique approach, in which they apply sophisticated signal processing and analytics to substation-based waveforms measured from conventional CTs and PTs. This approach has created a system that enables utilities to learn of and respond to incipient failures, thereby avoiding interruptions and outages. In addition, the system can advise utility personnel on the nature of problems, such as flickering lights, thereby enabling them to respond more intelligently and more efficiently.

BIBLIOGRAPHY

[1] IEEE Guide for Electric Power Distribution Reliability Indices, IEEE Standard 1366-2012, 31 May 2012, IEEE Power and Energy Society.