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Improved Outage Response through Advanced Monitoring: Detecting and Repairing Minor Faults Before the Customer Calls

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SUMMARY

Outage response on distribution systems is typically reactive in nature, with utilities dispatching repair crews based on customer calls or, if a monitored device such as a substation recloser operates, information obtained from SCADA systems. Utilities increasingly use information from "smart-grid" systems to improve outage response times, for example using smart-meter (AMI) systems to localize a fault, or fault location, isolation, and service restoration (FLISR) systems to automatically isolate faulted sections of a line, reducing the number of affected customers. While these technologies can and do improve outage response times, as measured by SAIDI and SAIFI, gaps exist in their ability to inform utilities of certain types of events, including outages which affect only a few customers.

Distribution Fault Anticipation (DFA), a technology developed at Texas A&M University over the past fifteen years, uses features extracted from high speed waveforms to detect major and minor power system events, including events that fall below the detection and / or reporting threshold for typical "smart-grid" systems. The DFA analytics engine informs utilities, on a real-time basis, of faults and other events which may affect only a few customers and provides information to help locate the affected area. When integrated with other sources of data and operational tools in a utility's control room, alerts provided from DFA have the potential not only to inform utilities of incipient problems, but also improve outage response times for these minor outages. In addition to improving the time-to-repair for small outages, these alerts can also allow utilities to manage crew workflows more efficiently, responding to minor outages before they are reported by customers. This benefits both urban utilities, which often experience a spike of trouble calls near the end of the day as customers return home from work and discover no power, and rural areas which have a high penetration of unattended loads (e.g. water or oil wells).

This paper presents an overview of DFA technology and selected case studies which illustrate how DFA-provided alerts improve outage response in an operational context.

KEYWORDS

Power system analytics; smart grid; advanced monitoring; incipient faults; outage management
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Introduction

Distribution utilities in the United States perform outage response on a reactive basis, typically in response to customer calls. Occasionally, a utility will be able to respond before customers call, for example when an outage results in the operation of a monitored protective device, or the utility receives an alert from its SCADA system. In recent years, utilities have deployed various "smart-grid" systems to improve outage response metrics. Fault location, isolation and service restoration (FLISR) systems allow utilities to localize faults and thereby reduce the number of interrupted customers, depending on the fault location and topology [1, 2]. Utilities use smart-meter (AMI) systems to "ping" meters in areas that may be experiencing an outage, which can provide crews with valuable information to narrow the location of a fault [3-5].

These systems can and do improve reliability, as measured by SAIDI and SAIFI, as well as providing operational benefit to utility companies. There are, however, many events, including some faults which cause outages, which fall below the detection and / or reporting threshold for FLISR and AMI systems. One example would be a fault which causes a fuse operation resulting in the disconnect of a single 25kVA transformer. In such a case, the fuse operation would likely go unnoticed by the utility company until reported by a customer. Because a 25kVA transformer serves at most only a few customers, a significant amount of time might elapse between the occurrence of the fault and when it is reported (for example, because all customers served by the transformer were at work, or in the case of an unmonitored load like a water well, the "customer" may not be capable of reporting the outage at all). Such an outage would be too small to operate a FLISR system and, while pinging the affected meters might allow the utility to know of and locate the fault, pinging meters as a matter of practice is often performed only in reaction to a known circuit event (i.e. a widespread outage), rather than as a proactive procedure to detect problems that have yet to be reported.

Outages which operate monitored protective devices or outages which affect large numbers of customers (which tend to be an overlapping set) will usually be reported quickly, either because they trigger a SCADA notification or the large number of interrupted customers increases the likelihood of a customer call. For small and medium sized outages, however, there is a higher likelihood that a substantial amount of time may elapse between when an event actually occurs and when the utility becomes aware of it.

Early detection and notification of minor outages has multiple benefits for utility companies, beyond SAIDI and SAIFI metrics. In urban areas, for example, detecting small outages shortly after they occur enables the utility to distribute their outage response throughout the day, levelling their workflow, instead of waiting for a spike of reports when customers return home from work to find no power. Proactive notification also improves work crew efficiency and time-to-repair, as crews spend less time stuck in rush hour traffic. In rural areas, many loads are unmonitored, particularly in areas with significant agricultural or oil-field presence. Minor outages which affect only unmonitored loads may go unreported for an extended amount of time, causing significant downtime for customers.

Research conducted at Texas A&M University over the last fifteen years has demonstrated that many of these low grade faults can be detected, and overall response to the resulting outage improved if control center operators have access to clear, actionable information. To that end, researchers have developed a waveform analytics engine, known as Distribution

Fault Anticipation (DFA), which monitors circuit health proactively, and informs utilities of impending problems [6].

Waveform Analytics and Distribution Fault Anticipation – Overview

The field of data analytics has exploded in recent years, finding applications in everything from baseball to logistics. In broad terms, analytics refers to the process of using algorithms to extract information from large datasets, thereby allowing personnel to make more effective decisions. In electric power systems, the field of *waveform analytics* refers to the process of extracting features from high-speed waveform data, then using those features to deliver actionable information to utility personnel. Waveform analytics systems utilize various techniques to enable a broad range of functionalities, including but not limited to fault location, incipient fault detection, and condition based maintenance [7].

While SCADA and AMI systems typically collect and report long-term, steady-state trend data (usually measured over minutes), waveform analytics operate on high-speed waveform data which capture both major and minor power system transient activity. Research has demonstrated that failing power system apparatus often produce electrical transients in current and voltage signals, measured at the substation, sometimes hours or days in advance of a catastrophic failure. This activity is generally not detectable at SCADA/AMI data rates but in many cases contains important information about the health and status of devices on the circuit. Examples of such transients include faults which cause momentary interruptions but no sustained outage, "normal" operations of power system apparatus like capacitors switching, customer loads, including large three-phase motors, and minor incipient events which have not yet caused an outage, such as a failing switch or hot-line clamp.

Many utilities deploy power quality monitors or digital fault recorders on their distribution circuits. While these devices are designed to record power system transients, analysis of the recorded waveforms is almost always performed offline by an engineer. This leads to at least two significant shortcomings: 1) the monitors are set to only record transients of significant magnitude, because humans are quickly overwhelmed by the amount of data generated on an operational system and 2) analysis frequently takes place only on a post-mortem basis, often well after the usefulness of the recorded information has expired. In the authors' experience, it is not uncommon to hear a utility engineer state, "I went back and analysed my PQ data, and *if I had looked at it*, I could have prevented _______," where the blank is some major event that happened recently on their system. As a matter of practice, however, engineers are unable to manually examine even the relatively small number of recordings generated by "major" transients on an ongoing basis, especially as the number of monitored circuits approaches a number typical of an operational system. Engineers may, in fact, have the data they need, but they generally are not aware of which data is truly important and which data is noise, nor do they possess tools to help them easily make that determination.

Waveform analytics systems, like DFA, bridge this gap by performing automated analysis of every waveform recorded by monitoring devices. By comparing recorded transients to signatures associated with known events, the DFA analytics engine automatically classifies many categories of power system events, providing utility personnel with actionable information in plain English text, as illustrated in Figure 1. As examples, if supplied waveform records with the following characteristics, the DFA analytics engine would return text like, "Possible Repetitive Overcurrent Fault, Phase A, 187A, 2 occurrences in the last 15 days," or "Unbalanced Capacitor Switching Event: 1200kVAR Bank, Phase B not operating,"

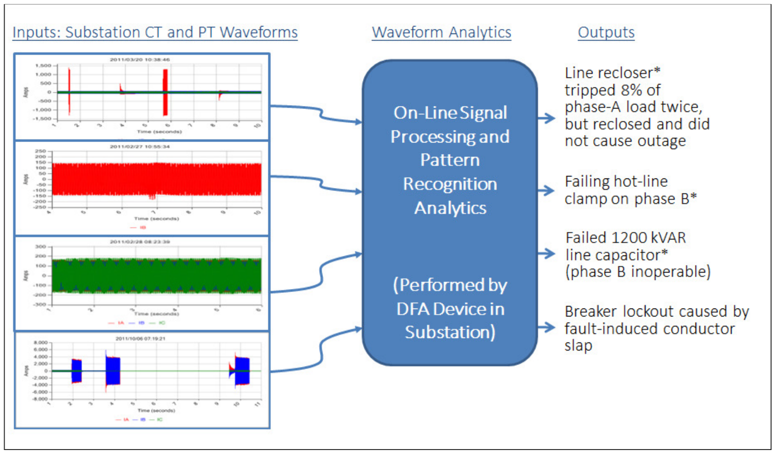

Figure 1: Block Diagram of DFA Waveform Analytics Engine

without knowing the underlying cause of the waveform event *a priori*. In other words, the DFA analytics engine is not simply performing calculations on a set of waveforms whose root causes are already known because they have been manually classified by a human (e.g. calculating fault currents for a set of waveforms known to contain overcurrent faults). Rather, DFA takes generic waveform inputs and attempts to determine the root cause of the waveform (e.g. this waveform contains an overcurrent fault) *and then* provide utility personnel with useful information associated with the event, all without a human needing to look at waveform data. This operation not only triages the initial deluge of data from monitoring devices, allowing engineers to focus on events that are truly important, it also provides engineers with information to improve manual analysis. Moreover, because a human is not responsible for looking at every waveform, the recording device can be much more sensitive, increasing the chance of recording less severe transients which may contain information about incipient events.

Case Study 1: Utility Uses DFA to Repair Outage Before Customer Call

On July 30, 2016, a DFA monitored feeder experienced a fault, shown in Figure 2. The fault was relatively brief, lasting only three cycles. The utility did not receive any customer calls following the fault, but did receive a SCADA notification for a "MinTrip" from one of the protective devices on the circuit.

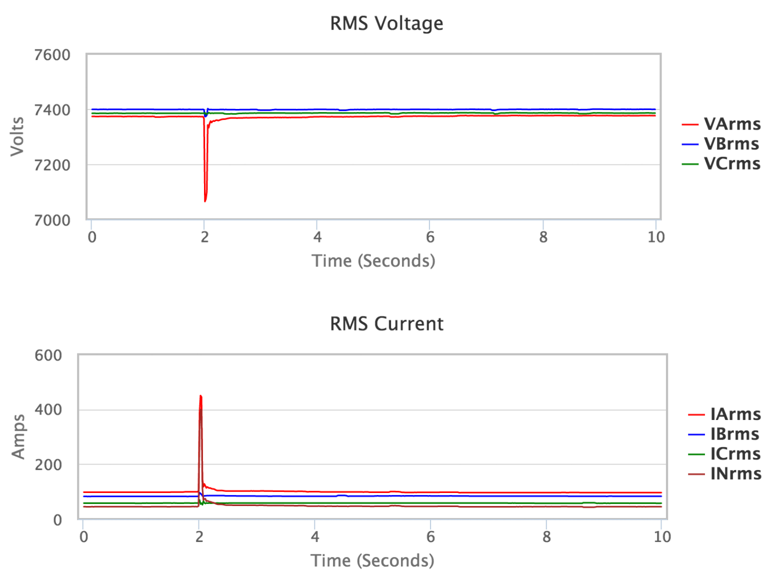

Figure 2: Fault recorded by DFA Monitor in Case Study 1

A MinTrip occurs when a recloser sees a fault current above its minimum pickup level. The MinTrip warning indicates that the device initiated a cycle to trip, but the cycle did not complete before the current returned below the minimum pickup level. A MinTrip can occur because a downstream protective device operated, or because of a self-healing incipient problem. When a utility receives a MinTrip alarm, the fault current is not automatically reported. Some utilities, including the utility which operates this circuit, will use their AMI system to ping meters downstream of the device which reported the MinTrip, looking for meters without power. With many AMI systems, however, this process can be very time-consuming, particularly if a large number of meters are beyond the associated protective device.

The control center operator had experience with the DFA system, and recognized that the DFA record associated with the fault would contain information which could improve outage response time significantly. In this particular case, the record contained two useful pieces of information: 1) that the fault was on Phase A, and 2) the fault current magnitude was 372 amperes. Combining this information with the utility's DMS, the operator was able to significantly reduce the number of meters that needed to be pinged by only querying meters on the affected phase that were also in locations which would be expected to draw approximately 370 amperes of fault current.

After pinging only the meters which met the above criteria, one meter reported to be out of power. The operator dispatched a truck to the location which found a dead bird at the base of a customer's transformer, and replaced the fuse. Even though the customer had not been home to report the outage, but DFA-supplied information, combined with the utility's other tools, allowed the outage to be detected, diagnosed and repaired before the customer knew there was a problem.

Case Study 2: DFA Detects Failed Lightning Arrestor

On July 4, 2016, the a DFA device recorded multiple trip-close operations on its monitored circuit. On this occasion, the utility did not receive any alarms or SCADA notifications of a problem. Furthermore, the utility received no customer calls, meaning the DFA-supplied notification was the utility's only indication of a problem. Researchers informed the utility of the trip close operations, and also suggested that the waveform signature indicated a lighting arrestor as the most likely cause of the fault. The circuit in question serves a rural area, and has more than 160 miles of overhead exposure. The control center operators were able to use circuit model information and the utility's AMI system to isolate the likely location of the fault to a single meter. A crew was dispatched to the location, where they found a failed lightning arrestor, shown in Figure 3, as well as a blown fuse. The crew replaced the fuse and arrestor, restoring service.

In this case, information from the DFA not only informed the utility of a problem before a customer complaint, it also

Figure 3: Failed lightning arrestor from Case Study 2

provided information as to the likely cause of the fault, improving the ability of the responding crew to properly diagnose the root cause when they arrived at the scene.

Conclusion

Smart-grid systems like AMI and FLISR provide utilities with tools to operate their systems more efficiently by decreasing the number of customers affected by a particular outage and providing information about the location of the faulted component. While these technologies improve overall outage metrics as measured by SAIDI and SAIFI, there are many events, including faults, which fall below the reporting threshold of either technology.

By sensitively monitoring current and voltage signals recorded at the substation and automatically extracting actionable information from the recorded signals, waveform analytics systems like DFA provide utilities with real-time notification about the health and status of their distribution systems, including events which FLISR and AMI systems often miss. A decade of field research has shown that DFA-provided notifications are often the utility's only indication of a problem on their circuit. Integration of information from DFA alerts with existing tools like distribution management systems and AMI meter pinging allows utilities to respond more quickly to small outages that would otherwise persist for an extended period of time, providing benefit both to utilities and their customers.

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