Why record trends and oscillography at the distribution level?

(A Case Study)

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Abstract:

The bottle-necking of massive loads and the inherently critical nature of the power grid has always justified the commensurately high cost of system-wide use of fault and disturbance recording equipment throughout the nation's transmission system.

Advances in technology over the last twenty years have made accurate, high resolution recording more accessible than anyone could have anticipated maybe as late as 1980. But while microprocessor technology has increased the functions that can be performed by digital fault recorders and protective relays, comparatively little has been done to devolve recording equipment and techniques into sub-transmission and distribution systems. Even formerly widespread recording practices that predate microprocessor technology have fallen by the wayside. For example, thirty-day paper chart recorders (once nearly ubiquitous in many distribution systems) rather than evolving into efficient microprocessor-based devices are now nearly extinct.

Complementary technologies like digital signal processing, broadband network architecture, and the application of embedded operating systems to device design are all offshoots of what a power engineer might describe collectively as microprocessor technology. But these different fields have not matured at an equal speeds. In any case they have not been adapted to power system operational problems at the same speed as discrete microprocessor-based devices. Nevertheless, in the power industry today, there is probably a broader familiarity with these technologies than with microprocessor-based protective relays twenty years ago.

So it might be reasonable now to ask *Does digital recording belong in the distribution system, and don't protective relays already do that?*

It is probably impossible to answer to that conclusively at the present time. But a recent field service experience, in which the author participated, suggested some surprising conclusions. This case study illustrates the application and proposes some observations in hope of stimulating further discussion, perhaps leading to better tools and more cost effective approaches to distribution system operation and maintenance.

Background:

A typical 138kV/12kV distribution substation is operated by a major Midwestern investor-owned-utility. It serves a small regional airport and industrial park in a rural area. Local indication of the load is provided by a multifunction digital panel meter, which is connected to CTs that are series'd up in such a way as to sum the three feeder currents for use with a transformer differential relay. The combined load of the three feeders typically varies between about 250 to 800A. The panel meter also produces a serial DNP signal that is monitored by SCADA.

Beginning sometime in 2001, the system operator began to observe occasional current surges of brief duration, in excess of 2000A at irregular intervals. These unexplained current surges ranged from a few days to several weeks between repetitions and triggered alarms. This continued for months despite the maintenance department's best, if unsuccessful, efforts to locate and identify the cause. One modern microprocessor-based transformer differential relay and three microprocessor-based feeder protection relays are installed in the substation but the relays all failed to detected any such current transients and there were no unexplained operations coinciding with the alarms.

The district engineer eventually came to suspect that the digital panel instrument must have some kind of intermittent malfunction so he returned it to the manufacturer to be repaired. The manufacturer failed to replicate the field observations so the instrument was returned without any kind of repair attempted. It was placed back into service and continued to indicate the surges. Confident in the dependability of readings from the protective relays, system operators concluded the panel meter must be defective, and they silenced the alarm.

In April 2004, the field engineer met the author at a technical conference and described the problem. Now unresolved after more than two years, it had become a nuisance. He was disappointed the manufacturer was unable to repair the presumably defective product. After some discussion, it was agreed to place a feeder-level digital recorder in the substation connected to the same CTs and PTs as the panel meter to either confirm the meter as defective or record evidence pointing to the cause of the surges if they turned out to actually exist. The recorder was installed the following month.

Since no one believed the surges actually existed, there was very limited quantitative information available describing what conditions to trigger on. So it was decided to use a combination of sequence of events recording, trend recording, disturbance recording, and oscillography recording to make some initial observations. Then, it would be possible to refine the trigger settings at a later date based on the actual data collected.

Results:

With some luck, all four recorders captured clear evidence of frequent current surges varying in magnitude from less than 900A to over 2900A. Single-phase disturbances appeared on all three phases as well as several three-phase disturbances. The transients had different characteristics such as duration, magnitude, and harmonic composition. They occurred on any day of the week, both on and off peak load. This was interpreted to suggest that more than just a single cause might be responsible for the transients.

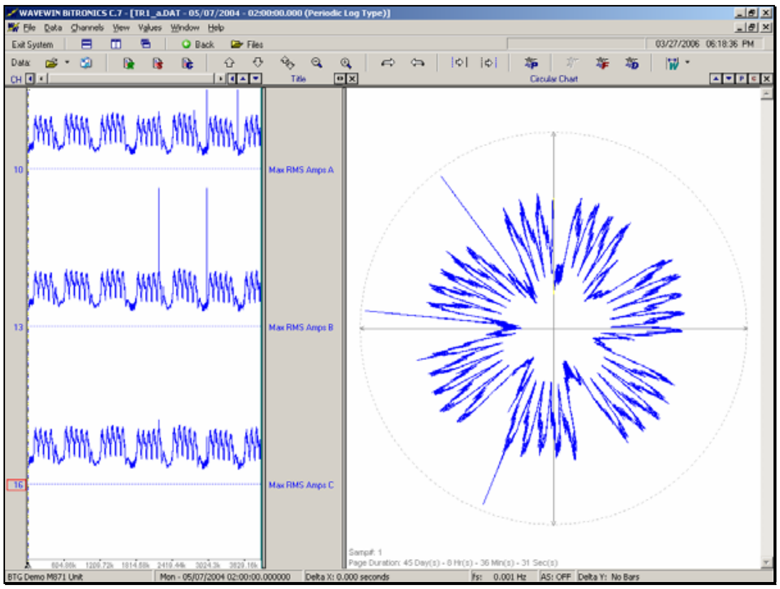


Figure 1. Seven week trend showing evidence of disturbances

The trend recording in Figure 1 illustrates a seven week long pattern of on and off-peak daily load current variation typical of the Summer season at this location, with significant spikes occurring on July 30, August 8 and August 14. A smaller spike appears on August 6, but was below the 900A threshold used to trigger oscillography. Oscillography was captured for the major spikes which helped to characterize the kind of transients that were being observed.

Figure 2 is the July 30 fault. It happened at on a Friday at 11:00AM. It was on B-phase only. The normal prefault load was 720A on that day. Fault current was 2025A, only about three times normal load and lasted for just 3 cycles. It was inductive, didn't saturate the CT and had no appreciable harmonics.

The third spike occurred on August 14. See Figure 3.

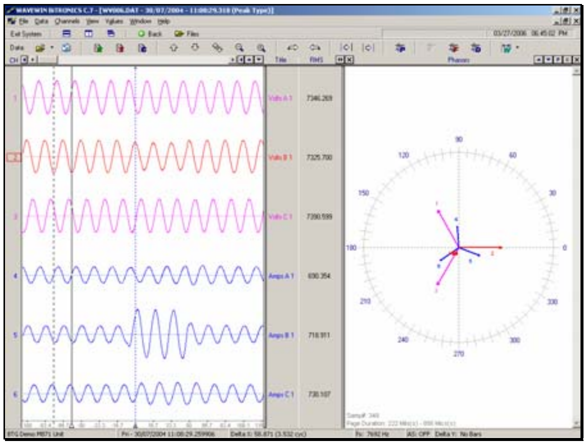


Figure 2. July 30, 2004

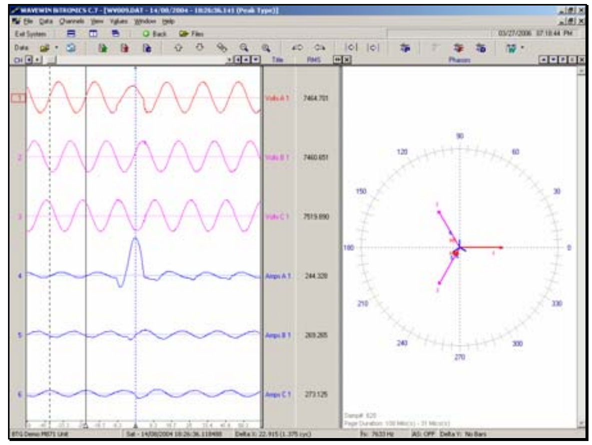


Figure 3. August 14, 2004

This fault occurred on a weekend when the normal load was just under 250A. It was on the A-phase and lasted only about 12 milliseconds. The fault current exceeded 2500A RMS, or ten times normal, (over 4700A peak). In this case there were obvious significant harmonics, much more in the current than on the voltage. The current harmonics (particularly the even components) actually increased after the fault cleared. See Figure 4.

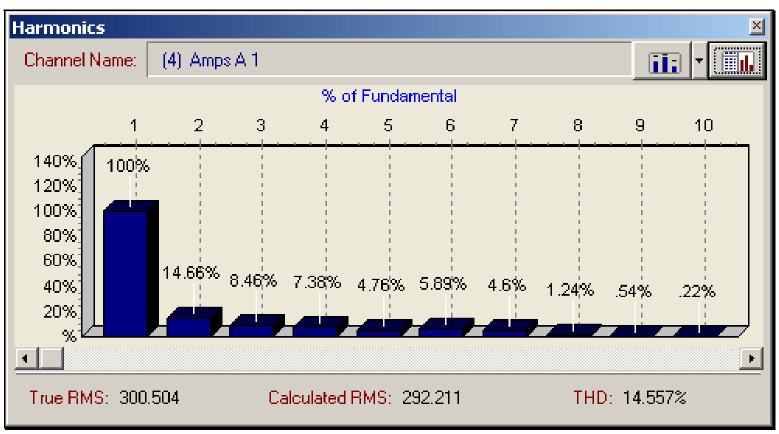


Figure 4. Harmonic distribution of August 14 fault

Interesting as these recordings are, it was concluded that both faults were self clearing, neither indicated any threat of damage to substation equipment or suggested anything (such as a relay) might be misoperating. There were no customer complaints on those dates that the recordings might have corroborated or helped to explain. After ruling out likely explanations like tree strikes and wildlife, it was decided that whatever the cause, it was not worth committing scarce resources to further investigation. The middle spike on the trend recorder was more interesting however.

Figure 5 shows an RMS recording of a 3000A B-phase fault that occurred downstream of the substation. This fault was cleared by a customer's protective relay in about one second. Notably, there appear to be two transformer inrush signatures at three seconds and fifteen seconds following the fault, possibly indicating some kind of automatic load restoration after the fault was isolated. The slow disturbance recorder places this entire sequence of events on a common time-scale making the cause/effect relationship between the incipient fault and the two resulting transients easier to visualize. See Figures 6 and 7 for oscillography recordings of the fault and the subsequent inrush.

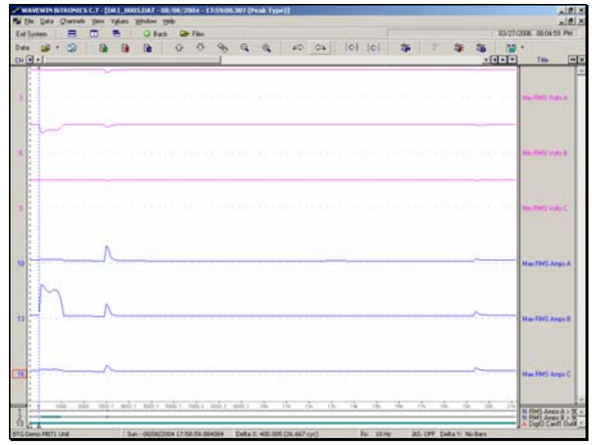


Figure 5. Slow disturbance record showing August 8, 2004 fault

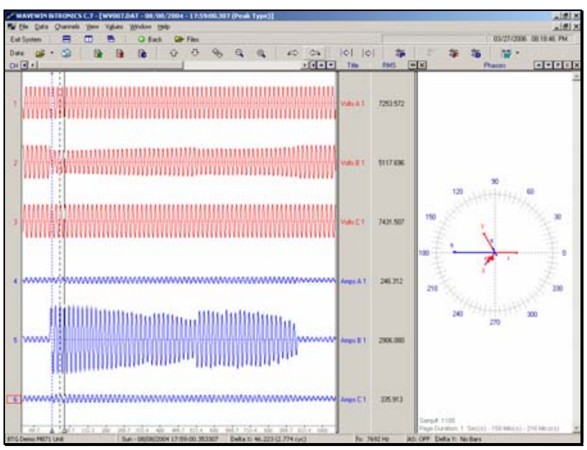


Figure 6. Oscillography of August 8 fault

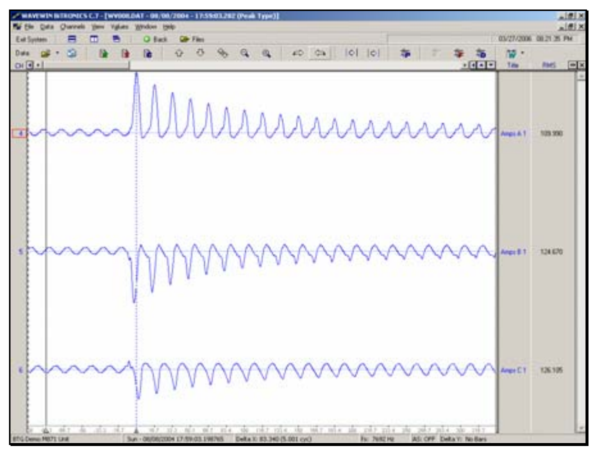


Figure 7. Transformer inrush following fault.

Why was this more interesting than the others? Because a prolonged 3000A fault could potentially trip the feeder breaker in the substation if downstream protection was set improperly or failed to operate. An alarm in SCADA is justified, and may be significant if the fault not an isolated incident but seems to repeat periodically, as this one did. As it turns out this customer's protection worked correctly and the feeder breaker never needed to trip. The utility is legitimately concerned when interruption of service to other customers is possible. When alarms occur, having the tools to be able to characterize abnormal conditions quickly and efficiently reduces cost and frees up limited maintenance resources for other work.

Follow up:

After these first records were downloaded in August 2004 and subsequently analyzed, there was no longer any question that the transients existed. The panel meter was vindicated of course, but why the relays seemed to miss the transients was now called into question. The alarms were restored and a distribution engineer was asked to determine whether the transients were cause for concern.

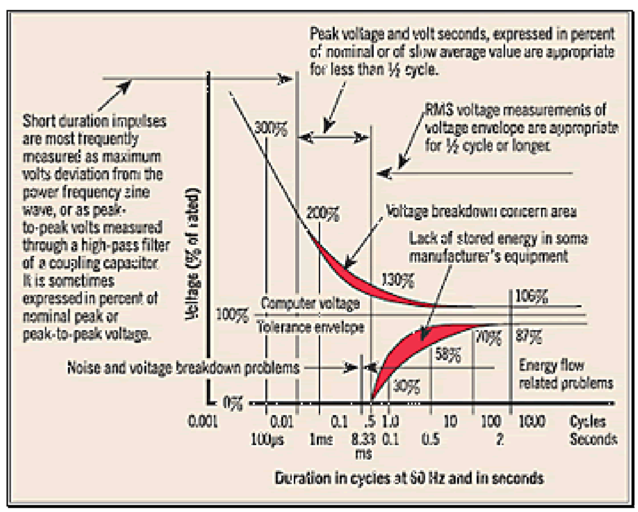
In December 2004, the distribution engineer placed two portable power quality test sets in the station, using clamp-on pick-ups to temporarily monitor two of the feeders. A third test set was not available, so only the two feeders considered most likely to have troublesome loads were monitored by the portable test sets.

Analysis of recordings downloaded in December 2004 and April 2005 revealed a regular pattern of disturbances similar to the original records collected back in August 2004, but with a few notable exceptions.

Upon removing the recorder in April 2005, the final download revealed twenty-eight spikes between 7:00 AM and 2:00 PM on Saturday, April 2 and a total outage of approximately one hour duration in the middle of the night on April 6. The cause of the outage was already known and was not related to the other disturbances. The twenty-eight spikes on April 2, however, coincided with a report of a 250 horsepower motor that failed at a manufacturing facility supplied by the station.

It was discovered that both portable test sets filled up their memory prior to the events of April 2 and 6. So they confirmed a few early observations but provided little new information that was of any interest. Some of the early spikes picked up by the installed recorder were missed by both portable test sets, suggesting that those spikes were on the feeder that was not monitored by the test sets.

Most of the disturbances captured by the portable test sets were triggered by voltage deviations exceeding tolerances of the CBEMA[1] curve. Such voltage deviations are useful for describing power quality events that affect consumer loads like computers, but are pretty common at the distribution level, and do not help identify conditions that could damage substation equipment.



[1] CBEMA: Computer and Business Equipment Manufacturers Association

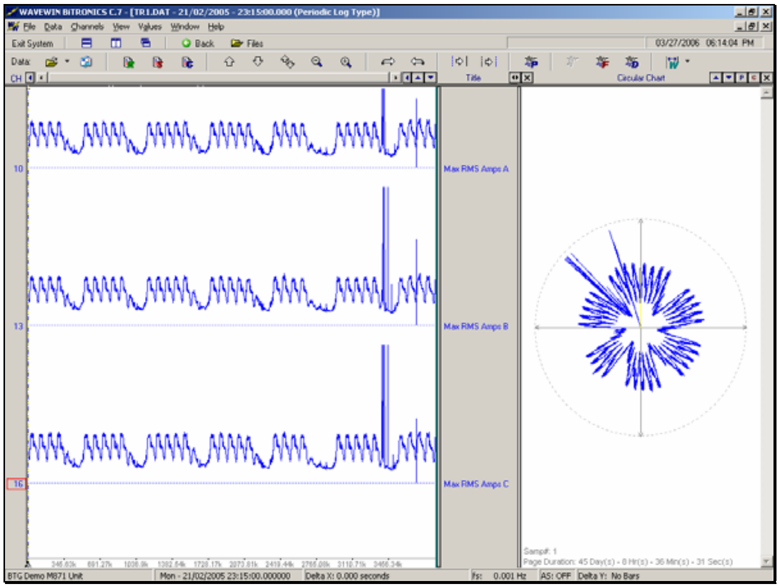


Figure 8. Trend record indicating where the 250HP motor failed

Some observations:

1. None of the modern microprocessor based relays could corroborate the presence of the transients. Why not?

There is no question the relays are sensitive enough to trip quickly on faults. But relays that share processing resources between protection and other functions must naturally prioritize protection. So the processing of data for communication with SCADA is generally less responsive than what would be expected from conventional transducers and digital panel meters. This particular panel meter was designed with a response rate fast enough to accommodate substation automation and other control applications. It is provided with separate processors for digital signal processing and serial communications. Polled data is refreshed several times per second so it is fast enough to report prolonged transients like the one second fault on August 8, but probably never saw the faster transients captured by the recorder.

2. During more than three years of interest, no attempt was ever made by the utility to use the recording capabilities of the microprocessor relays. Why not?

The engineer said there were two reasons he did not use the relays for recording. First, the relays were configured to record oscillography when they operate so the cause of the operation would be documented. He was reluctant to give up that data in case the relay operated while configured to look for something that would not cause the relay to trip. Second, the relay did not have sufficient memory to accumulate several months worth of records at a time. There was no modem in the station, and stretched resources made it inconvenient to visit the site more frequently just to download recordings. One other factor is that the relays have no provision for trend recording so the user must know what he is looking for in order to make settings. A trend record could easily distinguish normal from abnormal conditions, so settings can be refined iteratively to capture only disturbances having some practical significance.

3. Only two portable power quality test sets were available for three feeders so the disturbances on the third feeder were not recorded by the test sets. The portable test sets are expensive so a limited number is available for O&M troubleshooting.

4. Many of the files captured by the PQ test sets described only voltage-related CBEMA-type events that had nothing to do with the problem. That made it time consuming to separate the wheat from the chaff when looking for something important among hundreds of recordings. Focusing on power quality over disturbances that affect operation and maintenance limited the test set's usefulness.

Concluding notes:

Initially it was a bit of a surprise that the distribution engineer chose not to determine the exact cause of each disturbance recorded. But after some consideration, it probably illustrates the *fundamental difference* between recording at the distribution level and recording at higher voltages.

In the transmission system, loads are mainly lower voltage substations. Information is readily accessible when the source, load, lines, and all supporting equipment are owned by the utility.   At the transmission level, almost any deviation from normal operation is of interest because of the wide impact of an outage.

At the distribution level however, loads are mainly customers. Those customers may not be willing or able to provide accurate information about their loads, especially when equipment is malfunctioning. Since disturbances are more numerous in distribution and often have no impact outside the point of delivery, distribution engineers have to make a judgment call how far to go in analyzing every piece of data that might be available. Once a disturbance is judged not to be a threat and not caused by malfunction of substation equipment, it may make the most sense to just stop investigating at that point. But getting to that point quickly with a high level of confidence can save tremendous time and effort, lower cost, free up scarce resources, and avoid drawing the wrong conclusion from insufficient data.

So in the end, does it really make sense to do recording at the distribution feeder level?

Without absolutely clear cost effectiveness, the question is just moot. For example, DFRs have been available for years, but are obviously not used in distribution stations. The cost effectiveness has to fall somewhere between portable test sets and panel meters. The effectiveness of the panel meter is demonstrated by its presence in a substation that has modern relays but where the budget was tight enough that only one panel meter was used to monitor three feeders. The ineffectiveness of the portable test set is illustrated by the fact that only two units were available when three were needed. So it is probably safe to say a recorder in the price range of the panel meter should be justifiable if the data it collects is worth having.

The proliferation of Ethernet LAN architecture on a fiber-optic backbone in substations has begun and can be expected to grow in upcoming years. That will make it almost trivial to download large, high resolution files without having to visit remote stations in person or to wait for several long files to download at dial-up speeds. It will eliminate the need to rely on obsolescent ac-powered office-grade dial-up modems and expensive TELCO isolation interfaces. Network architecture should actually reduce information overload by giving different departments independent simultaneous access to data of concern to them, without going through information choke-points like SCADA.

Recorders in distribution applications need to be versatile enough to support a wide variety of applications. That should include: local indication, operations/SCADA, system planning, power quality, equipment control, equipment monitoring/verification.

Practical recorders need to span generations of existing standards so they can be used in older substations without forcing legacy equipment to be replaced. Files and protocols used should support US domestic ANSI and international IEC standards and shun proprietary formats that restrict users to a single manufacturer or expensive interfacing equipment.

Recorders that fit these criteria are beginning to become commercially available, and complementary technology like broadband communications is now in the early stages of adoption by the power industry. Utility engineers responsible for operation and maintenance of distribution and sub-transmission substations should probably begin to consider what kind of tools might make their jobs easier and free up scarce resources.

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