Power Quality Benchmark Results and Analytical Tools

New Visualization and Metrics Examples

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ABSTRACT

The work under the Electric Power Research Institute (EPRI) Power Quality Program Project 1.002 continues to expand on the framework for articulating power quality data at the end-user customer level as well as at the utility management level. The key to the effort is the process of consolidating complex information into a selection of visuals that enable users to make actionable decisions based on the information. Over the past several years, this work has incrementally expanded on traditional reliability metrics used by utilities and regulators to ensure that the material is actually useful at the customer interface. This work is expected to result in new ways to accomplish power quality management objectives. This year's effort puts forth a selection of new visualization concepts that will be vetted by utility power quality staff to assess their potential value. The specific visualizations described include the following:

- Two new metrics for harmonic distortion trending
- Two "lost load" evaluation techniques to score low root mean square event severity
- A detailed capacitor bank performance process
- Several color coding visualization concepts

Keywords

Benchmarks
Harmonic trending
Indices
Metrics
Power quality
Power monitor

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1 OVERVIEW

1.1 The Importance of PQ Benchmarking

Understanding the frequency and characteristics of power quality events, which are part of the normal electrical environment, is critical for designing end-use equipment immunity. In order for the performance metrics to be useful, they must characterize service quality in a way that is understandable by both utilities and customers. EPRI is intent on leading the industry in this arena and understands that with appropriate benchmarks and quality indices, electric service providers have more options for determining what levels of quality, as represented by the calculated quality metrics, are appropriate and economically feasible. This information also is important for defining baseline levels of power quality that could be expected by a customer and sets the stage for informing standards bodies, equipment manufacturers and system integrators.

Increasingly, electricity providers and consumers are interested in metrics which relate the actual system performance for a given period of time. In order for the performance metrics to be useful, they must characterize service quality in a way that is understandable by both utilities and customers. The long range EPRI plan related to metrics and analytics is to work toward the development of methodology suitable for advancing the state-of-the-art in power quality benchmarking and to make that information more actionable with scenario modeling concepts and with new metrics capabilities using “guided analytics.”

A major challenge related to useful benchmarks and metrics is that it has been well documented over time that the numbers traditionally reported for annual frequency and duration of outages does not translate well to process and system downtime. Two key objectives for this research are determining better ways to help set customer expectations and creating outputs that can be used by power quality standards making bodies to present the metrics in a consistent and understandable manner.

To that end, the work under the power quality programs project 1.002 continues to expand on the framework for articulating power quality data at the end-use customer level as well as at the utility management level. The key to the effort is the process of consolidating complex information into a selection of visuals that enable the user to make actionable decisions based on the information. Over the past several years, this work has incrementally expanded on traditional reliability metrics used by utilities and regulators to insure that the material is actually useful at the customer interface. This work is expected to result in new ways to accomplish power quality management objectives.

What has just recently been recognized is that if power quality event indicators and other system monitoring can be configured with proper triggering capabilities—and if the data is more intelligently analyzed “on the fly” relatively small data samples can be used to conduct some amazing predictive and preventive functions. Some examples of this concept will be described in this year’s update and the work is intended to be vetted out and expanded on over the next several years.

This progress update will focus on new visualizations or metrics that will be vetted out by project sponsors over the next few years to understand the intrinsic value of each. These visualizations include:

- Two new metrics for harmonic distortion trending
- Two “lost load” evaluation techniques to score low root mean square (rms) event severity
- A detailed capacitor bank performance process
- Several color coding visualization concepts

2
TRENDING HARMONICS

A key challenge related to understanding harmonics as they affect transmission and distribution system design is the variability over both time and with circuit type. Other power quality metrics and indices for power quality performance are conducive to either; the number of occurrences per time period (per year, per month etc.) or to the total duration per time period. Unfortunately, harmonic analysis over time is just not that simple because the initial data we use for this analysis is a statistic itself that happens to be a time varying steady state phenomenon having multiple dependent variables.

With the goal of defining less complex visualizations for harmonic trends in mind, the EPRI Power Quality Benchmarking project embarked on an intensive analysis of DPQ/TPQ III data focusing on the best ways to accomplish a simplified harmonic trending and the remainder of this chapter discusses the findings and proposed methodology.

The goal of this research intended to answer the following core research questions:

1. Can either harmonic voltage or current distortion measurements be used to trend harmonic increase or decrease over time for a given circuit?
2. Can the subject harmonic distortion measurements be used to trend "system wide" harmonic increase or decrease over time?
3. If trending over time is possible, what are the appropriate statistics (CP50, CP95 etc.) and parameters (Ithd, Vthd, V_3rd, I_3rd etc.) most suitable for such trending?
4. What are the practical implications of the findings in terms of whether or not the data is available for prior years or decades and what is the specification for insuring the data is collected and maintained moving forward?

The following sections describe the findings of the research aimed a answering these questions.

2.1 Harmonic Data Suitable for Trending

To understand and answer the first research question regarding whether or not either harmonic voltage or harmonic current distortion measurements would be the more useful parameter to trend harmonic increase or decrease over time for a given circuit. Data from 60 unique circuits ranging in voltage class from 480 V to 500kV were evaluated. This was a non trivial task in itself and the initial time intensive analysis resulted in some useful data compression recommendations for follow-on efforts.

The overall answers were:

- Data trending for a given circuit is not difficult and can be accomplished with careful understanding of what the data is (and is not) telling us based on the monitor location
- Current distortion is a much more useful indicator of *year over year* increase or decrease
- Voltage distortion is the more useful indicator of overall circuit health.

To expand on this discussion, current harmonics through the power system impedance create the harmonic voltage drops that generate the harmonic voltage distortion. Knowing the total current distortion or demand distortion and trending the demand distortion for a given bus or feeder is actually a useful metric – irrespective of whether the data is gather at a customer point of common coupling or at a substation. Unfortunately most utilities do not collect this information and while it would be the most useful year over year benchmark it is not typically available at the present time primarily because this essentially doubles the amount of data being collected and stored and in the past there was no clear vision or understanding of how this data might be useful for such trending. This concept is not new and since the 1992 version of IEEE 519 there has been a definition of the term, total demand distortion (TDD). This term is the same as the total harmonic distortion THD except that the distortion is expressed as a percent of maximum demand load current rather than as a percent of the fundamental current magnitude. The IEEE standard sets limits for TDD and the individual components as a function of short circuit ratio (utility short-circuit current at the point of common coupling divided by customer average maximum demand load current). Higher levels of harmonic-current generation are allowed on stronger systems (higher short-circuit ratios) because it is harder for the customer to impact the system voltage distortion. Regardless of limits, the TDD metric is simply an excellent trend parameter.

On the other hand, voltage distortion is a second order indicator of the demand distortion and since most utilities do collect the demand distortion information, the analysis focused on the best ways to use the available voltage distortion information for trending.

The key conclusions from the analysis were:

1. Because impedance of the power system increases as the monitoring location moves closer to the end of the circuit, one would expect voltage distortion to increase accordingly. This suggests that the general *level of total harmonic distortion* should be de emphasized—while the year over year and seasonal increase or decrease would be the more useful metric.
2. If one were to consider 5 minute harmonic samples of all three phases for both voltage and current to the 50^{th} harmonic, the amount of data for a single year of analysis becomes well over 100 million samples. To trend this over ten years would involve one billion plus samples just for a single monitor. Clearly a statistical approach is desirable to reduce this to a manageable level without losing resolution. The key finding of the statistical analysis is that use of a cumulative value such as the 95^{TH} percentile or CP95 for a single week of voltage distortion and a single phase of voltage (or just one data point per week was just as accurate and resolute as compared to analyzing the full data set for the week representing over 310 thousand samples set. In essence using one statistical value provides a 310 thousand to one compression without loss of resolution for the year over year trend of interest. In essence this is the equivalent of turning the 1 billion actual data samples into 520 statistical samples for a ten year trend analysis.

2.2 Example Trends

The following figures show two examples from the 1000 circuit analysis – detailing unique individual voltage distortion trends over approximately five years. These trends are actually a plot of the cumulative probability for 95% of the samples in any given week or the CP95 where one data point represents this statistic for any given week. This is a useful metric for evaluation of harmonics, but in the first two plots, it is not very easy to identify whether the trend over time is flat or is increasing. What can be derived from the first two plots is that there is a seasonal trend for the harmonic levels.

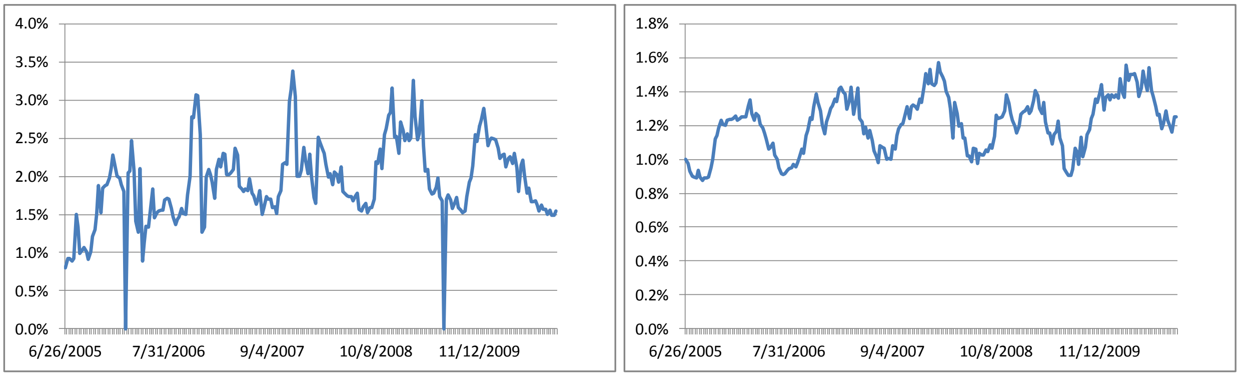


Figure 2-1
Examples of a five-year trend of weekly CP95 statistics for total harmonic distortion

Unfortunately plotting the CP95 statistic (as a stand along parameter) does little to improve the visual understanding of the data, therefore other alternatives must be considered. To remedy this visual challenge a simple trendline (linear regression analysis) is added to the plot and this trendline provides a useful reference for the slope of the data. For the second set of plots shown in Figure 2-2, the inserted trend line clearly provides a better sense of whether the harmonic data is showing an increase or a flatness. With the trendline, it is much easier to see the increase over the five year plot and one could imply from the data that the amount of harmonic load on both circuits has increased over the time period shown.

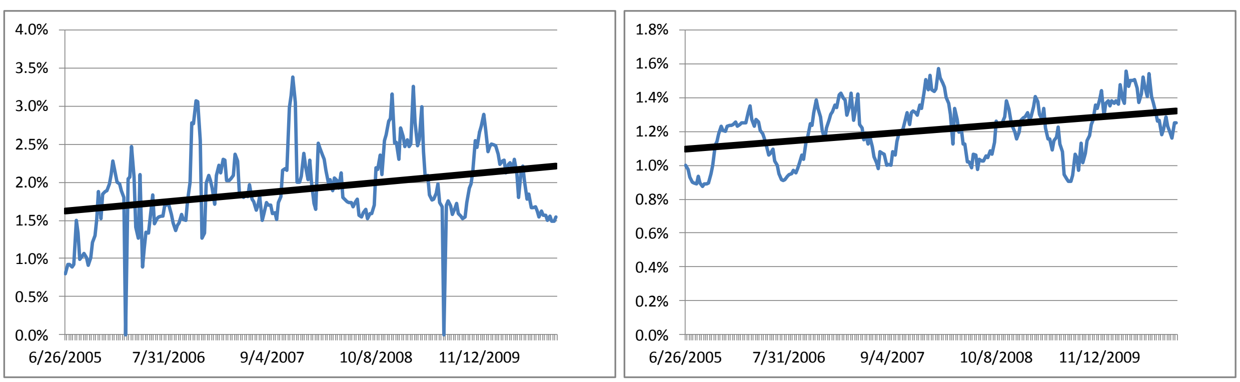


Figure 2-2
The same CP95 values from Figure 2-1 with the addition of a trendline to better articulate the slope of the change over time

While the trendlines provide a suitable way to look at individual circuits, one of the key goals of (harmonic analysis over time) is to evaluate large groups of circuits simultaneously to see what is happening – system wide. With that goal in mind, an attempt was made to combine similar dates and CP95 voltage distortion from multiple feeders to see how this combination might work out. The first few attempts to combine similar circuits provided some unusual results that don't really tell any story or yield any meaningful information.

To minimize the impact of feeder variability, an alternative analysis was developed that considers that seasonal deviation and even daily or monthly deviation in the CP95 values can and should be expected, but that *time based* evaluation is not important for combining sites to get a ~~system~~ wide trend. In this case all the data for each year can be combined to get a single vertical line for each of the years under analysis. This is shown in the next set of figures and provides a much more reader friendly visual as compare to the previous graphs.

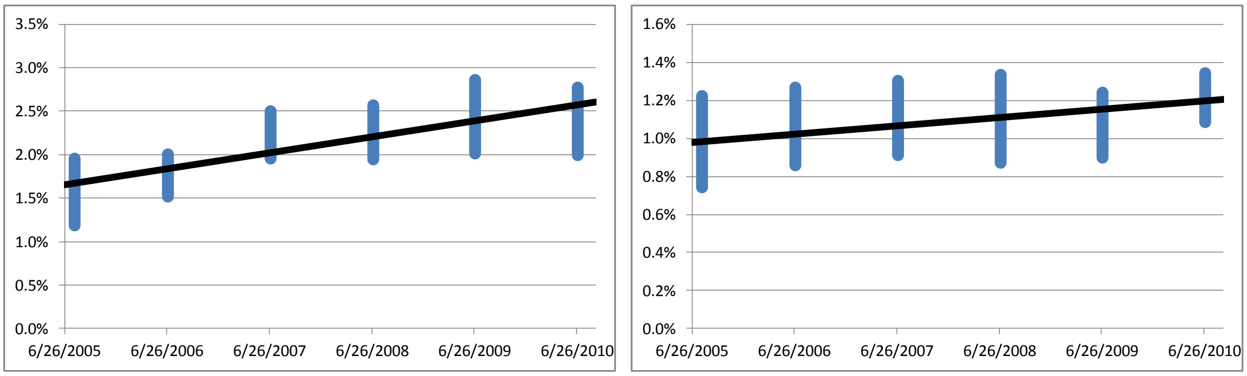


Figure 2-3
The same data from Figures 2-1 and 2-2 with the exception that the yearly data points are aggregated to create vertical bars—one for each year

Using the approach shown in Figure 2-3 enables a quick understanding of the range over an entire system where the lower end of each vertical bar indicates the feeder with the peak CP95 value that was on the low end of all THD measurements and the upper end of each bar indicates the feeder with that was on the high end. This kind of analysis would subsequently identify the circuits that were out of spec with respect to the others. It would further be easy to include upper control limit lines as well as extra horizontal bars for CP50, residential, commercial, and so on.

2.3 Summarizing the Harmonic Trendline Recommendations

The "Harmonic Trendline Analysis" method provides a unique visualization technique to take literally millions of harmonic data samples and compress the necessary data down to a few thousand data points – while still providing meaningful visualizations for feeder wide and for individual circuit "big picture" views. The process needs to be iterated by project sponsors to identify opportunities to streamline or refine the specification. An ideal result for this topic would be to develop the full set of recommendations and publish them as an IEEE PES transactions style publication in order to get the methodology into common application

The preliminary recommendation for the vetting process is as follows:

1. Use a PQ instrument suitable for accurate harmonic quantification to at least 1kHz (i.e. the 17^{th} harmonic)
2. Using a sample window of 15 minutes, maintain just one weekly CP95 and CP50 data point for the following parameters:
   a. Vthd – Total harmonic distortion for one phase
   b. Itdd – Total demand distortion for one conductor
   c. 3rd, 5th, 7th, 9th harmonic quantities for a and b

2. For individual circuits, plot the data year over year where the column for the date information contains just the year information in the respective cells and not the day and month.

3. For multiple circuits, use just one single value or data point per year for each circuit. For example use the max CP95 value in one graph and the median CP95 values for another graph.

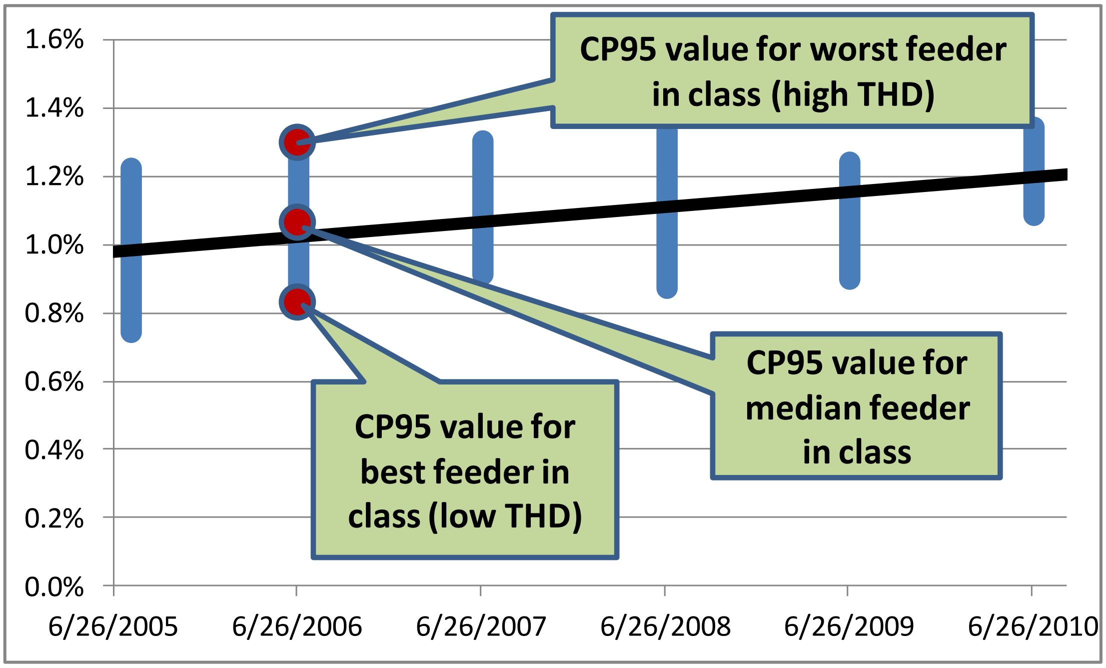


Figure 2-4
For a multi-circuit example using the max CP95, the best circuit for the year 2006 shows a THD of just below 0.8% while the worst circuit shows a THD of approximately 1.25%

3
COLOR CODING FOR HARMONIC SEVERITY ANALYSIS

Last year the benchmarking and metrics project described a guided analytics approach for harmonic distortion data with the objective to apply harmonic voltage and current measurements in more useful and meaningful ways. Primarily to support improved system design, as well as to justify the need for harmonic limits for certain load types. Success in this area would facilitate a better understanding of incremental changes over time that might warrant the need for either standards or system hardening. Proper benchmarking and metrics was deemed to additionally provide better understanding of thresholds of concern and setting targets or alarm levels for feeder wide visualizations.

Regarding this topic of feeder wide visualizations, one of the clear ramifications of harmonic voltage distortion metering is the challenge that the harmonic voltage drops through the power system impedances are additive as one move the monitoring location further and further away from the generation sources. For an example radial system with just one generation source it is easy to calculate the harmonic voltage drops and the total harmonic distortion by simply knowing the impedances and the load current spectrums. It would not be uncommon under this example scenario to see less than two percent distortion at the substation bus, four percent THD at the last customers meter base and perhaps six percent THD at some of the 120 V load receptacles inside of the facility.

This simplistic explanation is not the reality of the actual power system where we have distributed generation, reactive power sources (cap banks etc.) time varying harmonic load, looped circuits and networks that compound the analysis. However for the purposes of understanding the concept that one monitoring point along a system does not yield a useful understanding of where concerns may exist and relying on a single monitoring point at a substation does little to identify those “hot spots” where a customer or group of customers may be getting close to problem levels.

To expand more on the color coding in the context of benchmarking, within the next ten years the smart grid will be outfitted with many new sensors that will have a capacity to provide voltage or current harmonics data. Most of today’s sensors lack the frequency response to do this, but the modifications are in progress (*Report of Advanced Sensor Technology Applications for Smart Distribution Systems*. EPRI, Palo Alto, CA: 2010. 1020088) and the ten year objective for capable sensors is very achievable. In addition, most of the advance metering infrastructure contains the metrology necessary to capture harmonic data (if enabled). Once the grid is outfitted with these additional sensors, the color-coded modeling results can be replicated with even more accuracy by applying the real measurements from the various nodes or sensors (substation bus to end use load).The idea behind this graphic is that we can take a geographic representation of the power system and assuming that it is outfitted with the appropriate number of new sensors in conjunction with existing PQ monitors, smart meters and other intelligent devices that can provide harmonic information. It is a simple extension of the color coding concept to view the possible areas of concern on any given system. This entire area of research is moving forward and extends far beyond just harmonics analysis, but is an important area for advancement of the state of the art and the utility industries ability to claim ownership of the harmonics topic.

Currently in order to gain the level of understanding necessary to visualize harmonic levels "feeder wide" a very accurate system model must be developed and then applied with a best guess of where the load is and a very good estimate of how the harmonic load is distributed across the feeder. Examples of this method and the visual outputs can be found in *Power Quality for T&D: Grid IQ Circuit Analysis Using 2030 Load Mix Projection.* EPRI, Palo Alto, CA: 2012. 1024084. This modeling technique is useful but it would be even more useful to leverage the new sensor capabilities afforded by the monitoring equipment and AMI being installed for smart grids.

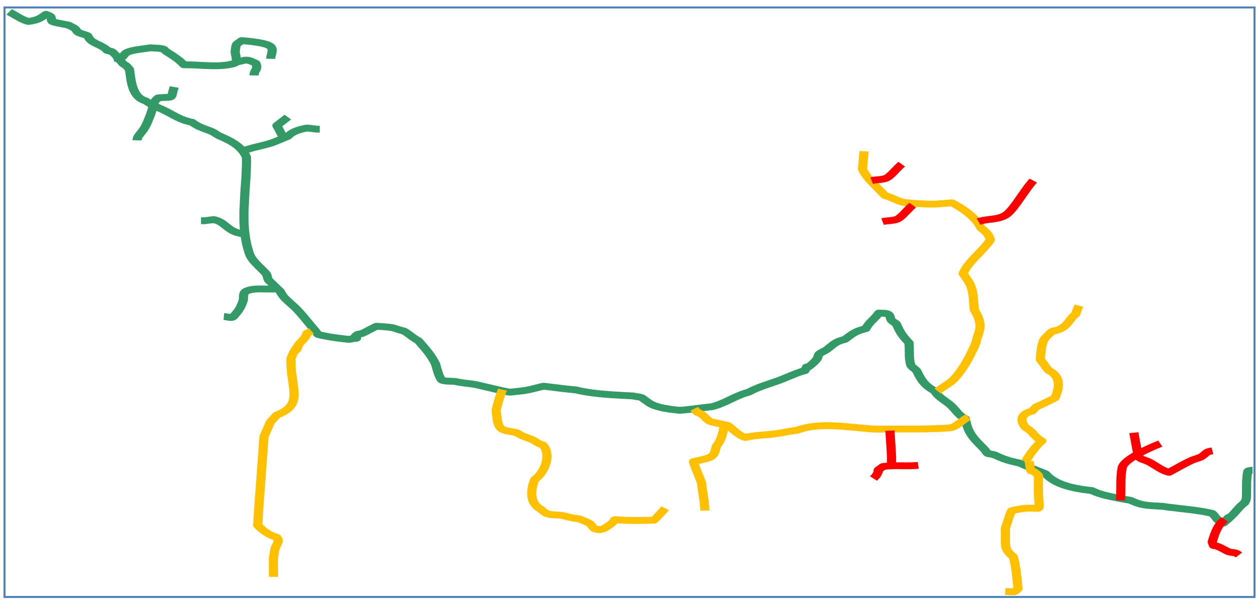


Figure 3-1
Severity by color code concept for power quality metrics

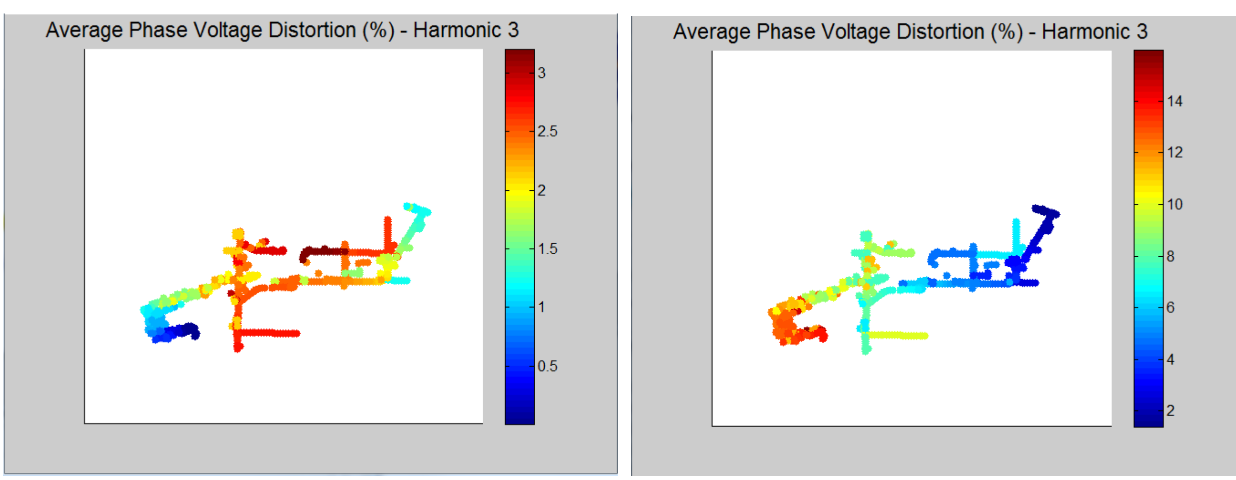


Figure 3-2
Examples of color coding for harmonic severity from the EPRI harmonics analysis module

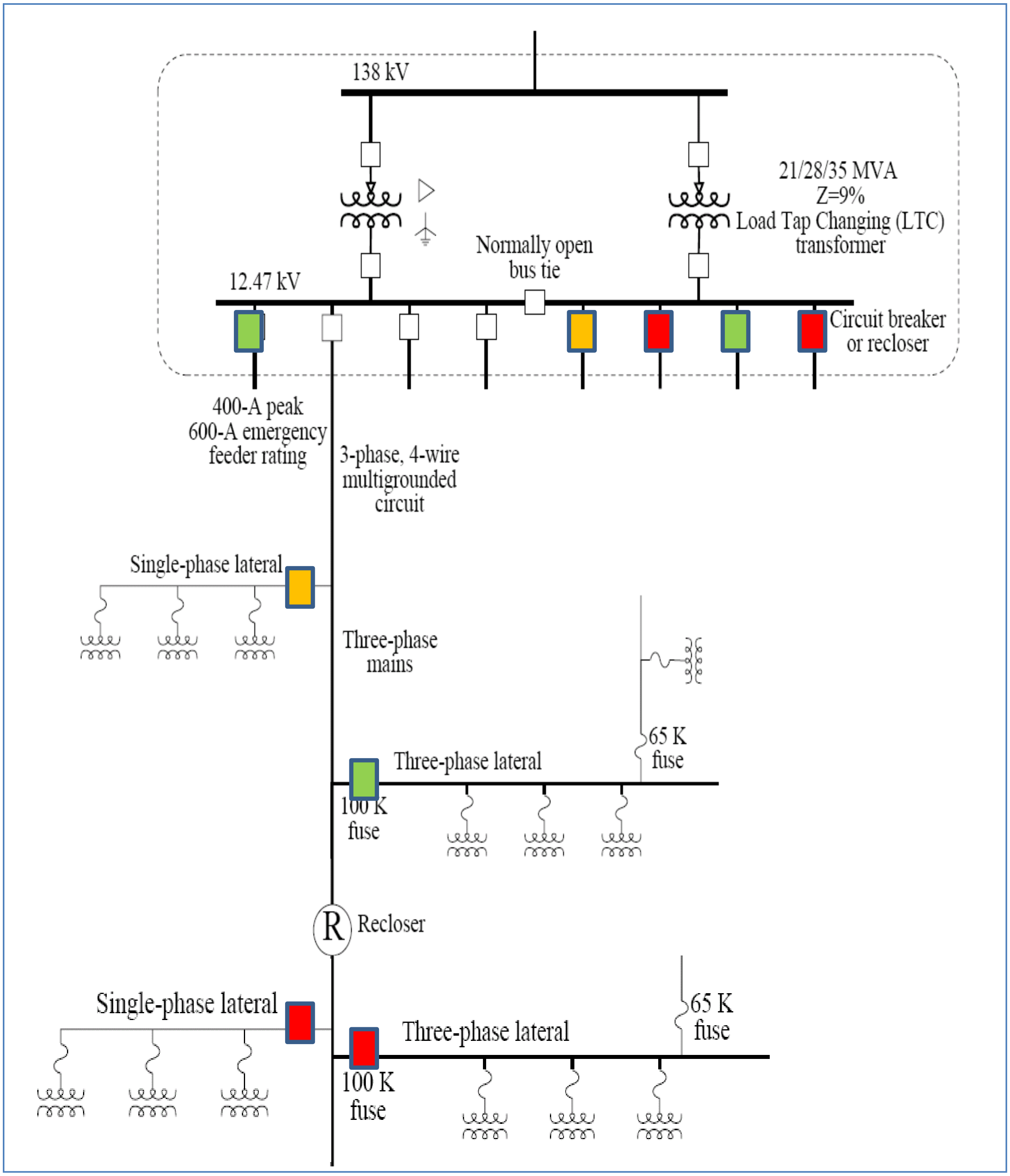


Figure 3-3
Other options for color coded circuit maps to visualize problem or concern areas

4

FEEDER LEVEL PARAMETER VISUALIZATIONS

The benefits of a feeder level visualization metric and display of such is the possibility of using the same circuit model and data layers to look at literally dozens of parameters either individually or in combination. The following figure provides an example of what the circuit model used for the visualization might look like:

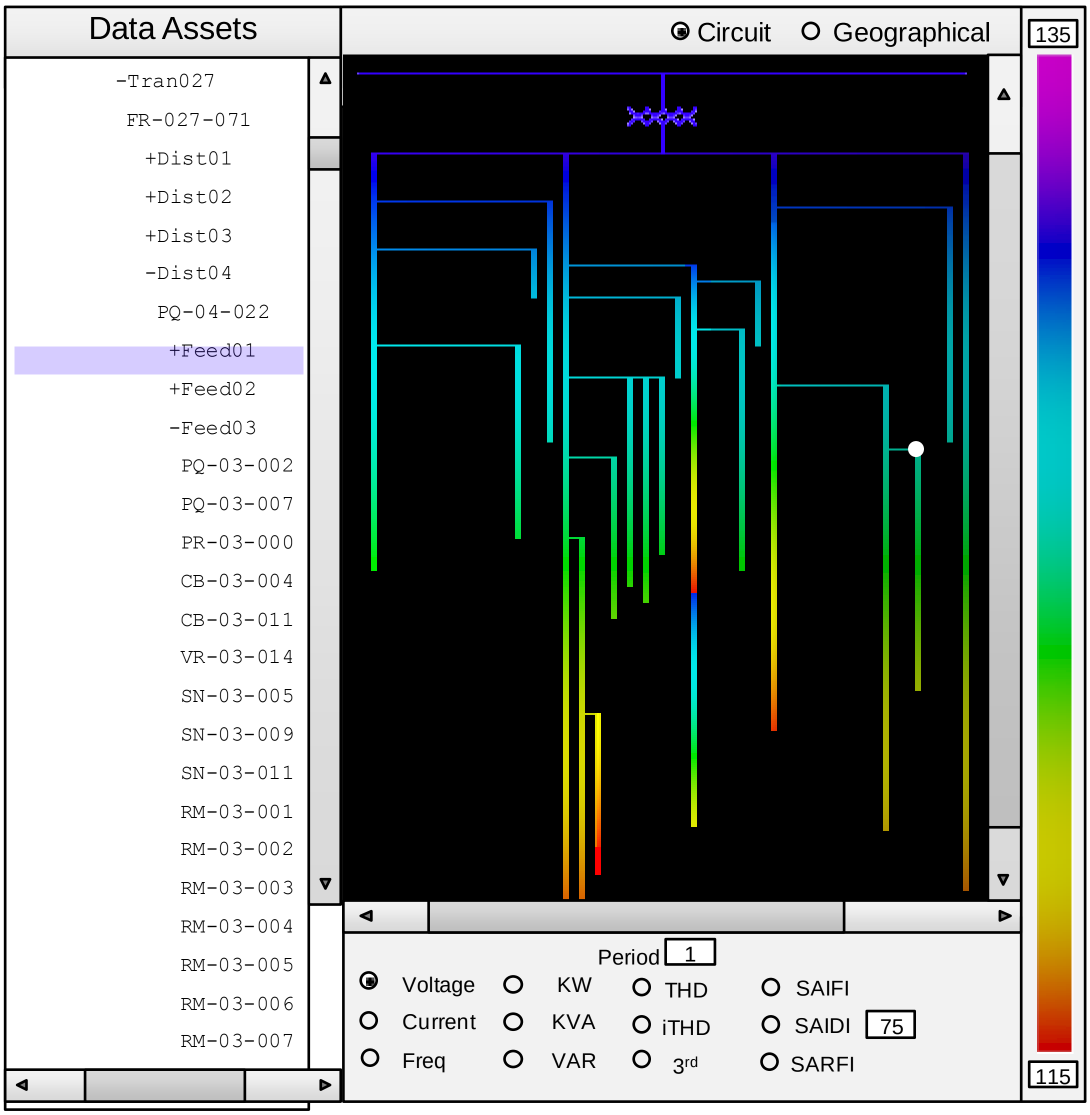


Figure 4-1
Example of color coding for a dashboard with multiple power variables as layers

In the example shown, virtually any parameter of interest can be layered on a screen shot of the circuit map. The circuit map can additionally be displayed in a GIS form. In another rendition of the same information the figure shown in 4-2 represent a similar concept with hover points where monitoring is available. At these points the concept involves the ability to hover over the monitored point to obtain the metrics of interest.

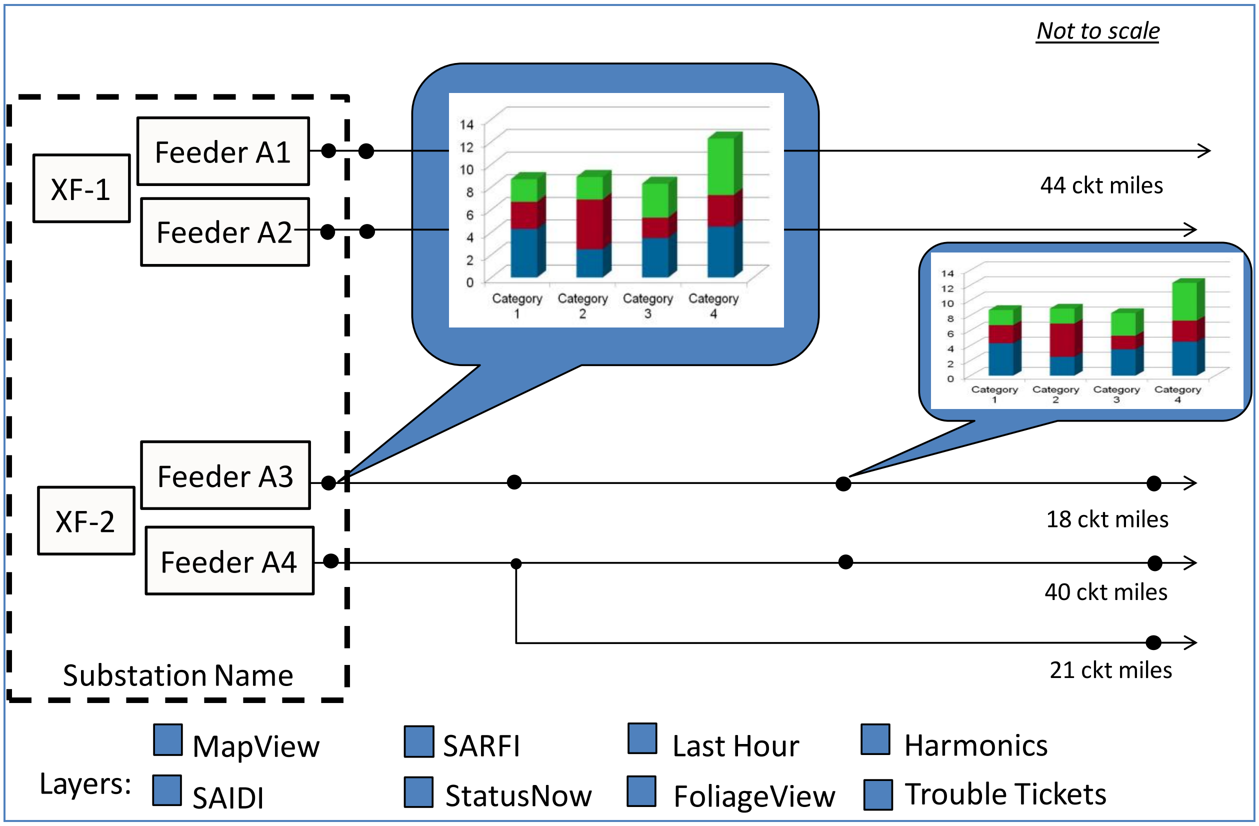


Figure 4-2
Feeder level data visualization concept

4.1 Dashboard Metric for Event Analytics

Yet another opportunity for event metrics visualizations is the application of the type of concept used on new exercise equipment where a dashboard supplies a fast visual to articulate, progress, performance and level of workout intensity within desired age and health criteria. Interestingly this same concept could be applied to power quality metrics with minimal modification.

The next figure is a screen capture from one such exercise machine. It is envisaged that a sag metric could be evaluated with a display such as this one to determine best and worst circuit's relative the median and mean circuits in the same voltage class. Further it would be simple to use a range scale to apply the concept to all voltage classes in the service territory by simply dragging the range bar.

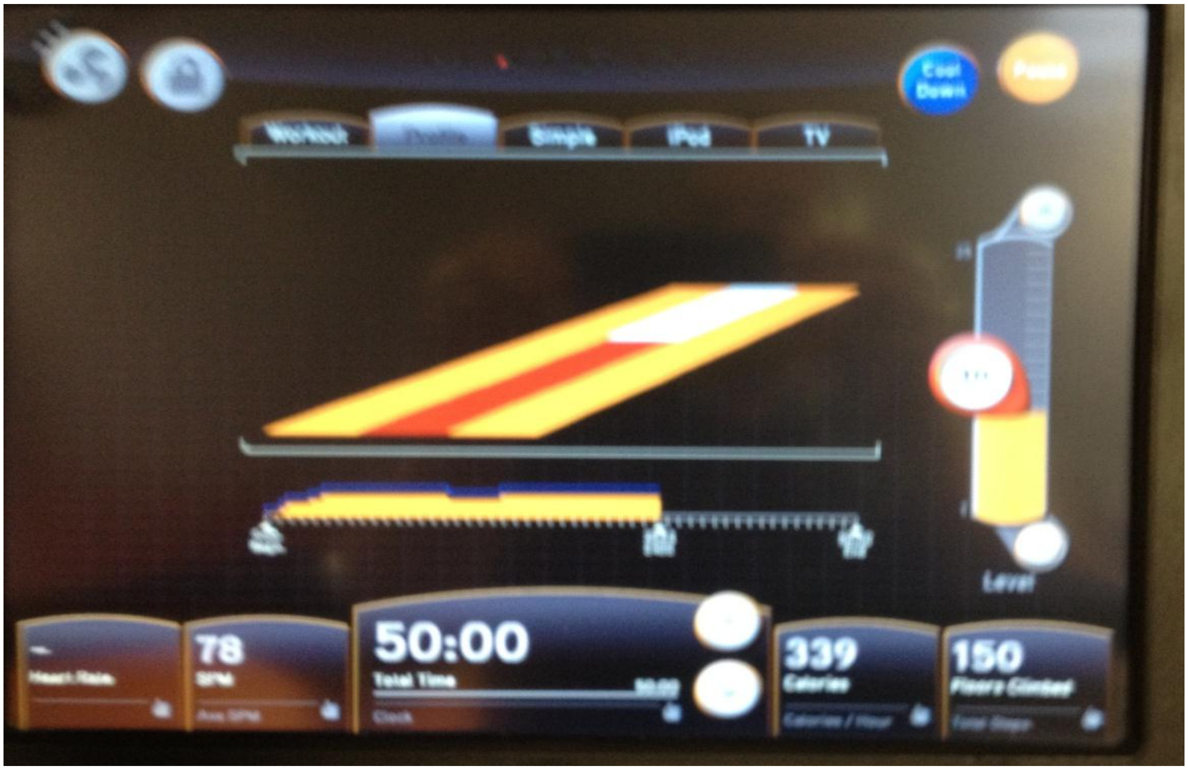


Figure 4-3
Application of exercise machinery visualizations could make PQ visuals more understandable

5 CAPACITOR BANK HEALTH AND MAINTENANCE VISUALIZATION

Yet another unique visualization opportunity comes from capacitor bank monitoring. The basis of this visualization is derived from the monitoring of changes in reactive power on the circuit of interest as the capacitors are switched in or out—in conjunction with the characteristics of a dynamic power system switchable device. In summary, a feeder level monitoring device would record a decrease in reactive current anytime a downstream capacitor bank is switched in and that decrease would be discernible at both the high resolution millisecond sample level as well as at a lower resolution revenue level. The most discernible component is the reactive current change; however there are even more diagnostic signatures available from the voltage information.

In terms of a useful visualization concept a circuit and system dashboard is envisioned that would enable the viewer to quickly identify the circuits and associated capacitor banks that are out of limits with respect to the others. Specific indicators would include:

- More switching than expected for the circuit and load type
- Abnormally high voltage transient levels during switching
- Indications of blown fuses from a VAR unbalance metric
- Indicators of other hardware issues
- Circuit resonance threshold warnings

Presently the most efficient system for the type of data visualization described here comes from the EPRI sponsored Texas A&M distribution fault anticipation DFA technology, but the concept is certainly not limited to a single technology and it is believed that over time devices such as the DFA along with smart meters and other sensors—and the combined data from all of these resources will enhance the diagnostic ability of a smart grid even more. The following sections describe some of the methodology and rationale for the capacitor bank metric.

5.1 Overview

Capacitor banks provide voltage support and reactive power support for feeders. Because voltage and reactive power needs vary diurnally and seasonally, many banks utilize controllers that switch them ON and OFF based on perceived real-time need. Some banks switch autonomously, often controlled by parameters such as time and temperature, which act as proxies for voltage and VAR needs, whereas other banks have one-way or two-way communications and can be controlled and sometimes monitored remotely. Many capacitor banks switch frequently (e.g., daily), and capacitor banks are widely known to experience a wide variety and significant numbers of failures.

Some utilities have systems that enable them to control and, in some cases monitor, their capacitor banks remotely. Some systems provide for remote ON/OFF control of banks. Some utilities without two-way capabilities monitor VAR flows, immediately following switching commands, to detect whether VAR flows change by the expected amount. With some two-way systems, a bank's controller can detect and provide notification of certain problems, such as failure to open/close or failure of a phase (e.g., blown fuse or capacitor can). These systems can be utilized to determine gross failures of capacitor banks, such as failure to switch or a blown phase. They cannot, however, detect certain other problems with capacitor banks. It also should be noted that even utilities with the most advanced capacitor control systems often have only a fraction of their total capacitor banks equipped with this relatively new technology, with many legacy banks continuing to operate unsupervised for the foreseeable future.

By applying analytics to substation electrical waveforms, the DFA system provides substantial visibility for all switched capacitor banks at remote points along a feeder line. When a capacitor switches, it causes variations in electrical waveforms, and the DFA device at the substation analyzes those variations. Using a substation-based device only, DFA analytics can recognize problems with capacitor banks anywhere on the line, including the following.

- Inoperative phase(s)—This can occur for multiple reasons, including: a blown phase fuse, a blown phase capacitor, a stuck or otherwise inoperative switch. DFA has detected this problem many times at many utility companies. Some other control systems can detect this problem, too.
- Unbalanced phases—This can occur either because one of the three phase "cans" is sized differently than the other two or because one of the phase cans is partially short-circuited internally. DFA has detected this problem many times at many utility companies. Some other control systems may be able to detect this problem, too.
- Excess operations—This typically occurs when the capacitors themselves may be healthy, but a failure or improper configuration causes the bank's controller to switch OFF and ON far more frequently than necessary or proper. Banks with this problem may cycle OFF and ON dozens or even hundreds of times, often without customer complaints or other notice to the utility company.
- Capacitor switch arcing—This occurs when a capacitor bank's switch contacts fail to close/open completely. Severe voltage and current transients occur, usually repetitively over an extended period of time. The severe, repeated transients have been documented to cause process upset problems for customers.
- Capacitor switch bounce—This occurs as a switch closes its contacts, if the contacts mechanically separate and then re-engage one or more times before "sealing in." This can cause greater transients than normal capacitor closing, because there are multiple transients instead of one, and because second, third, and subsequent transients can tend to have greater severity than the initial closing transient.

- Capacitor restrike—Whereas switch bounce can occur during closing operations, restrikes can occur during opening operations. Restrike occurs when the voltage across a switch's contacts increases more rapidly than the dielectric strength of that gap can support. When the contacts begin to separate, the instantaneous line voltage remains trapped on the capacitor and therefore on one of the switch's contacts. Because a switch stops conducting at a natural current zero, and because a capacitor's current leads its voltage by 90 degrees, the trapped voltage will be at full peak line voltage, either positive or negative. The switch's other contact continues to vary according to the normal power-system frequency. As a result, a potential difference develops between the two contacts. Within a few milliseconds, the potential difference can be substantial. If sufficient dielectric strength has not developed by that time, the switch will experience restrike
- Capacitor fault/fuse blow—Both switched and fixed capacitor banks can experience fuse operations, either because of a short circuit in a phase capacitor can or because of simple failure of the fuse itself.

5.2 Case Example from a DFA Enabled Circuit

The previous bulleted list of capacitor bank performance concerns is significant and as opposed to addressing each of them individually, the following example provides a process oriented approach to analytics and diagnostics that could form the basis of a new capacitor health visualization.

The EPRI/TAMU fault anticipation technology or DFA has detected multiple instances of restrike during capacitor switching on DFA-monitored feeders. The following image (Figure 5-1) shows a report pulled from the DFA website for one such feeder. The report has three entries, all related to restrike. The topmost indicates restrike detected on phase-C of a feeder capacitor bank. The middle and bottom items indicate that the DFA also has detected restrikes on phases B and A, respectively.

Feeder	Condition	Phases	Grounded	Phase A kVARS	Phase B kVARS	Phase C kVARS	Occurrences (30 days)	Last Occurred
A-DFA1/38-2-1/10-13	CAP: Restrike	C	Yes	621	629	617	4	05/12/12 00:57:38

Event Type	Phases	Occurred
Capacitor restrike	C	05/12/12 00:57:38
Capacitor restrike	C	05/07/12 06:50:49
Capacitor restrike	C	05/06/12 06:30:56
Capacitor restrike	C	05/05/12 02:09:47

A-DFA1/38-2-1/10-13	CAP: Restrike	B	Yes	630	625	616	2	05/08/12 18:01:37
A-DFA1/38-1-1/10-13	CAP: Restrike	A	Yes	616	615	625	1	04/28/12 19:37:39

Figure 5-1
Information display from the DFA website

Exploring the topmost item more fully, from left to right, the columns indicate: the feeder designation; the particular category of capacitor problem (in this case, restrike); the phase or phases involved in a particular event (in this case, C); an indication of whether the bank is grounded or not; the estimated kVAR-step sizes measured on each phase, at the time of the switch-opening operation that exhibited restrike; the number of times this condition has been detected on this phase in recent history; and finally time date and time of the most recent episode. Each of the reported phase kVAR step sizes is slightly above 600 kVAR. Capacitor specifications permit -0/+16 percent VAR tolerance at rated voltage. In addition feeder voltages tend to run slightly above nominal. Therefore it is clear that the VAR rating of this capacitor bank is 600 kVAR per phase, or 1800 kVAR (1.8 MVAR) for the three-phase bank.

In Figure 5-1, the topmost entry has been expanding by clicking the + sign at the far left of that row. The resulting dropdown detail shows the timestamps of the four individual episodes of phase-C restrike (one each on 5/5, 5/6, 5/7, and 5/12/2012).

For any system with remotely controlled banks that make a record of each operation in a central database, it would be straightforward to determine precisely which capacitor bank is experiencing restrike, by comparing DFA-reported capacitor restrike timestamps to the timestamps that the remote control system logs that it reported opening specific, known banks.

The following waveform graphs, obtained from the DFA website, illustrate the restrike phenomenon. A word of explanation about the plotted quantities is necessary, however, before proceeding. If one were to record current waveforms at the terminals of a particular capacitor bank, that recording would represent the current flowing through the capacitor bank. When one records waveforms from a remote location, such as a substation, however, the recorded current contains all feeder loading, not just the capacitor current. To aid analysis of transients, including capacitor-switching operations, *DFA software estimates a pre-event, steady-state current waveform, including the fundamental and harmonics. It then numerically subtracts that estimated waveform, point by point, from present measurements. The result is a waveform that approximates the change that a temporal anomaly creates in the current waveform*. For ease of reference, the term "differenced current" has been used to represent the resulting current waveform, sans steady-state, pre-event components. When a capacitor switches ON, for example, the digitally created "differenced current" waveform represents the current flowing through the capacitor. Conversely, when a capacitor switches OFF, the "differenced current" waveform represents the current "lost" as a result of the switching operation. In other words, it represents a mirror image of the current that had been flowing through the capacitor immediately before the switch opened.

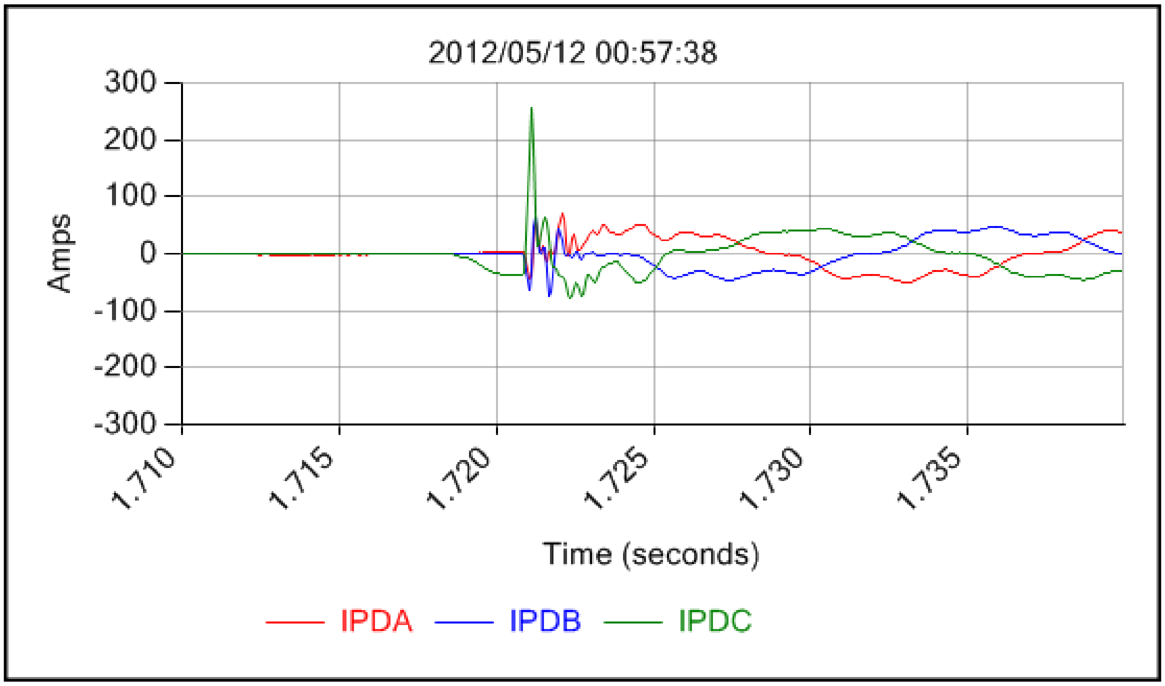


Figure 5-2
Feeder current transients captured during a capacitor bank operation

In the waveforms plotted in Figure 5-2, the quantities represent the differenced currents of phase A, B, and C. The phase-C differenced current first becomes substantially non-zero at approximately t=1.719 seconds, which represents the moment at which a capacitor bank's phase-C switch contacts first interrupted the capacitor's current. This would have occurred at a natural current zero, which corresponds to peak line voltage. For approximately two milliseconds thereafter, the phase-C waveform has a relatively sinusoidal shape, representing the instantaneous capacitor current lost to the system when the phase-C switch opened. The current changes abruptly at t=1.721 seconds, with the phase-C differenced current waveform reversing itself and spiking instantaneously to approximately 250 amps. The restrike lasts only a fraction of a millisecond, after which the differenced current resumes its normal, steady-state, "lost current" shape and magnitude.

The waveforms in Figure 5-3 represent the "differenced voltage," which DFA software numerically calculates in the same way it calculates differenced current. The interpretation is somewhat different, in that voltage does not "flow through" a capacitor or any other component as a current would. The differenced voltage, however, does represent the point-by-point change from the pre-event steady-state value. Therefore the 5,000-volt spike in differenced voltage approximates the high-frequency voltage transient caused by the restrike. Because this differenced voltage is based upon substation-bus measurements, it represents the transient experienced by customers and equipment on all feeders served by that bus, not just customers and equipment on the subject feeder. The voltage transient would tend to be more severe at or near the capacitor bank itself.

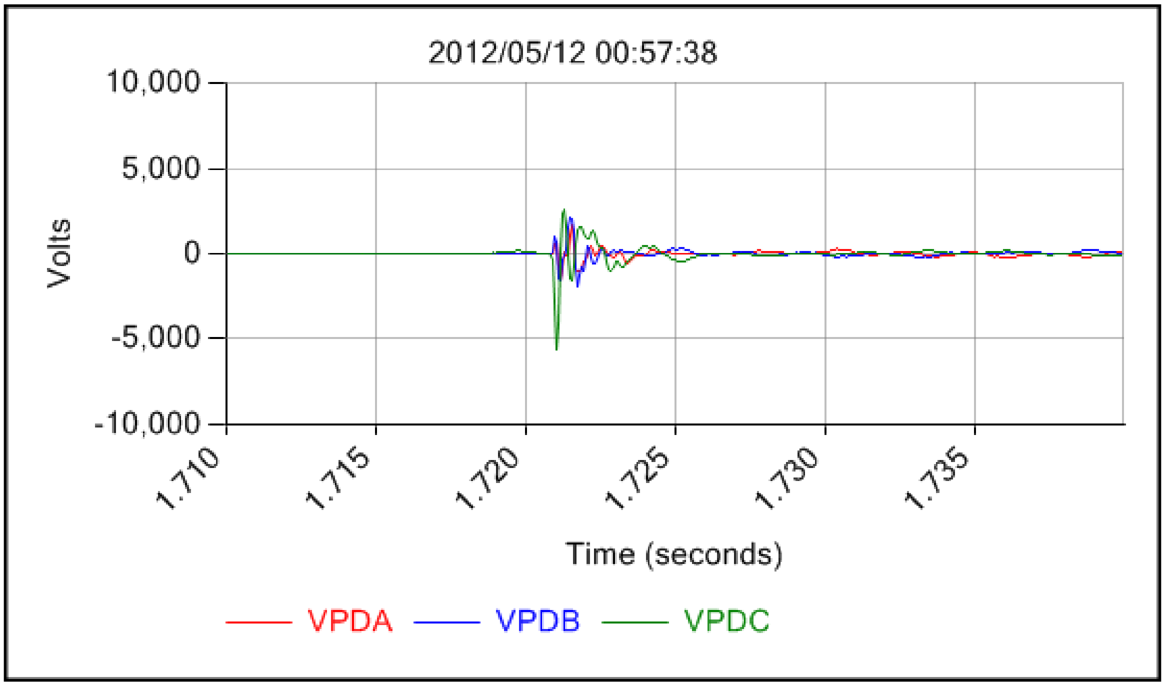


Figure 5-3
Differenced Voltage Waveforms Captured During Capacitor Bank Operation

5.3 Capacitor Switch Bounce

This subsection presents another common capacitor phenomenon that DFA analytics, applied to substation waveforms, readily detects and reports. This event type represents a second condition that neither conventional maintenance nor remote capacitor controllers would detect.

Figure 5-4 illustrates a five-second recording of VAR flows, as measured from the substation, at the time when a capacitor bank on the feeder switched ON. The subject bank has a three-phase VAR rating of approximately 2400 kVAR. DFA computations represent leading VARs as negative quantities and lagging VARs as positive. Therefore when a 2400 kVAR capacitor bank switches ON, feeder VAR flows will decrease by approximately 2400/3=800 kVAR per phase. As expected phase-A VARs decrease by approximately 800 kVAR (within capacitor VAR tolerances) approximately at the 3.6-second mark, and phase-C VARs decrease by a similar amount at approximately the 4.2-second mark. The 0.6-second discrepancy between the closing of the phases is common and generally not a cause for concern. Phase-B VARs also decreased by approximately 800 kVA, approximately coincident with the decrease in phase-A VARs, but a few cycles later, the phase-B VARs resumed their pre-switching value. This sequence indicates the phase-B switch closed for a few cycles but then re-opened. Over a period of 0.7 seconds, the capacitor effectively connected and disconnected the phase-B capacitor multiple times, and then finally “sealed in.”

A capacitor switching ON typically creates a high-frequency current and voltage transient that damps out over a fraction of a cycle. When a switch bounces, it causes multiple transients within a period on the order of a second. In addition to the increased number of transients, the second and following transients can have amplitudes greater than the original. This occurs because a substantial voltage may be held on the capacitor each time it temporarily disconnects from the system, so that when the next connection occurs, the voltage difference between the instantaneous line voltage and the voltage stored on the capacitor may exceed (up to 2X in theory) the maximum voltage that could exist between the instantaneous line voltage and a discharged capacitor (1X maximum).

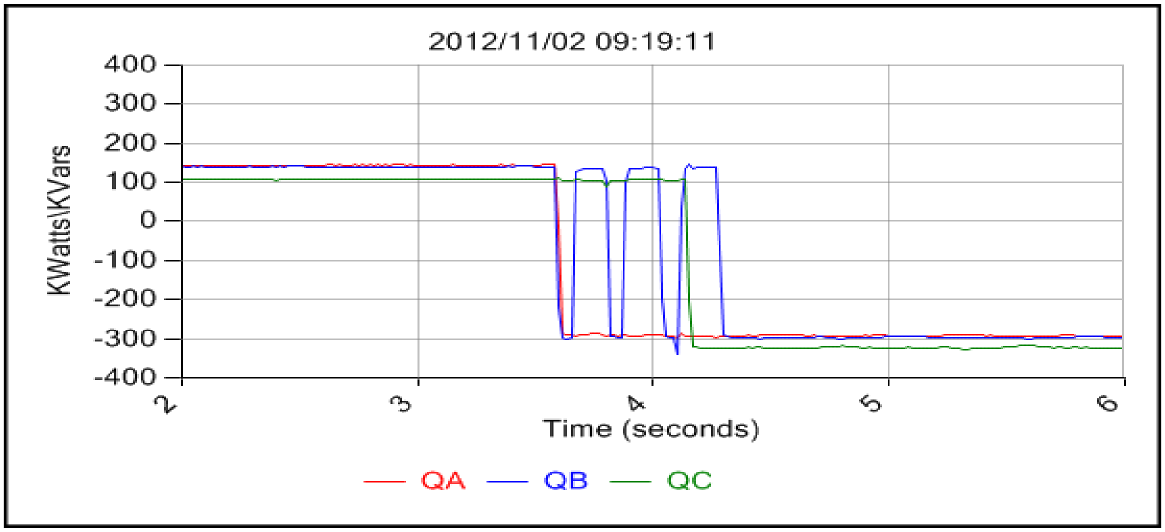


Figure 5-4
VAR flow change over 5 seconds during capacitor bank operation

The next two figures (5-5 and 5-6) illustrate the transients produced by the subject case of switch bounce. The initial transient corresponds to the initial closing. The subsequent transients correspond to subsequent closings. The closing at t=3.81 seconds produces the greatest current transient, which exceeded 1100 amps. At the moment of the transient, the voltage, as measured at the substation, momentarily drops to less than 20 percent of its nominal. Because of the nature of the stored-voltage phenomenon, it is even possible for capacitor switch bounce to cause voltage to reverse polarity on an instantaneous basis. As with the restrike phenomenon, all customers and loads on all feeders served by the same substation bus will experience the same sequence of voltage transients, and customers and loads near and past the subject bank may be more severe than those measured at the substation bus.

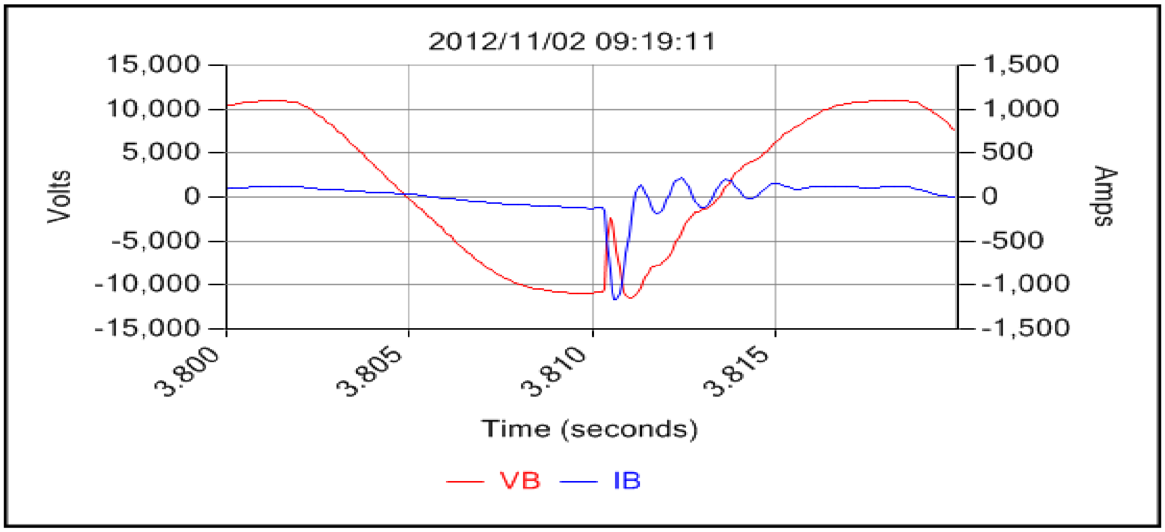


Figure 5-5
Switch bounce voltage transient

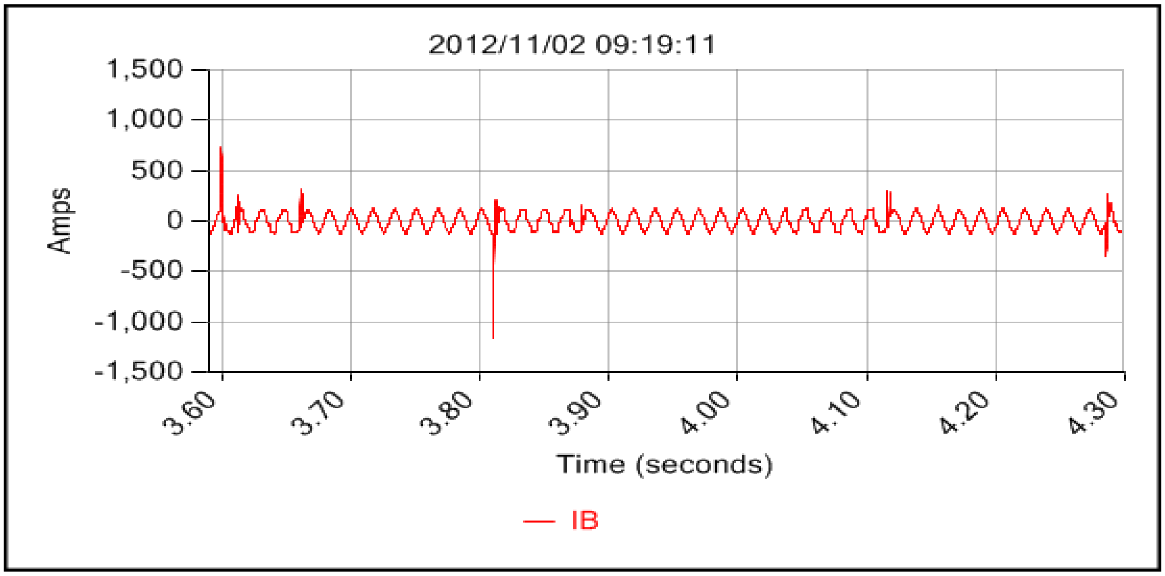


Figure 5-6
Switch bounce current transient

5.4 Capacitor Phase Failure

Yet another capacitor failure consideration involves non-functional phase units resulting from blown fuses or short-circuited capacitors. Such failures cause readily recognizable electrical changes during capacitor switching operations. As an illustrative example Figure 5-7 shows per-phase VARs, measured from the substation, as a 1200 kVAR capacitor bank switches OFF. Switching a healthy, balanced, three-phase capacitor bank would cause the VAR flows on all three phases to change by similar amounts, subject to tolerance limits. By contrast, in the figure, only two phases show significant change. Phases A and C each exhibit a change of approximately 400 kVAR per phase, but the VAR flow of phase B remains essentially unchanged, indicating that it is not switching. In this particular case, the positive change in

VARs indicates the bank is switching OFF, given the previously discussed sign convention in which lagging VARs are represented as positive and leading as negative. This type of non-functional phase can be detected both when a bank switches either ON or OFF. It generally is not possible to differentiate between faulty fuses, stuck switches, and short-circuited phase capacitors (which in turn cause fuse operations), because all three conditions result in the same unbalanced step changes in phase VARs.

Some remote capacitor control systems can detect failed capacitor phases. Some advanced controllers having two-way communications can detect and report elevated neutral current or some other indicating quantity, as measured at the bank itself, when such an unbalanced switching operation occurs. This requires, however, additional sensing and instrumentation at the capacitor bank, to make the required measurements.

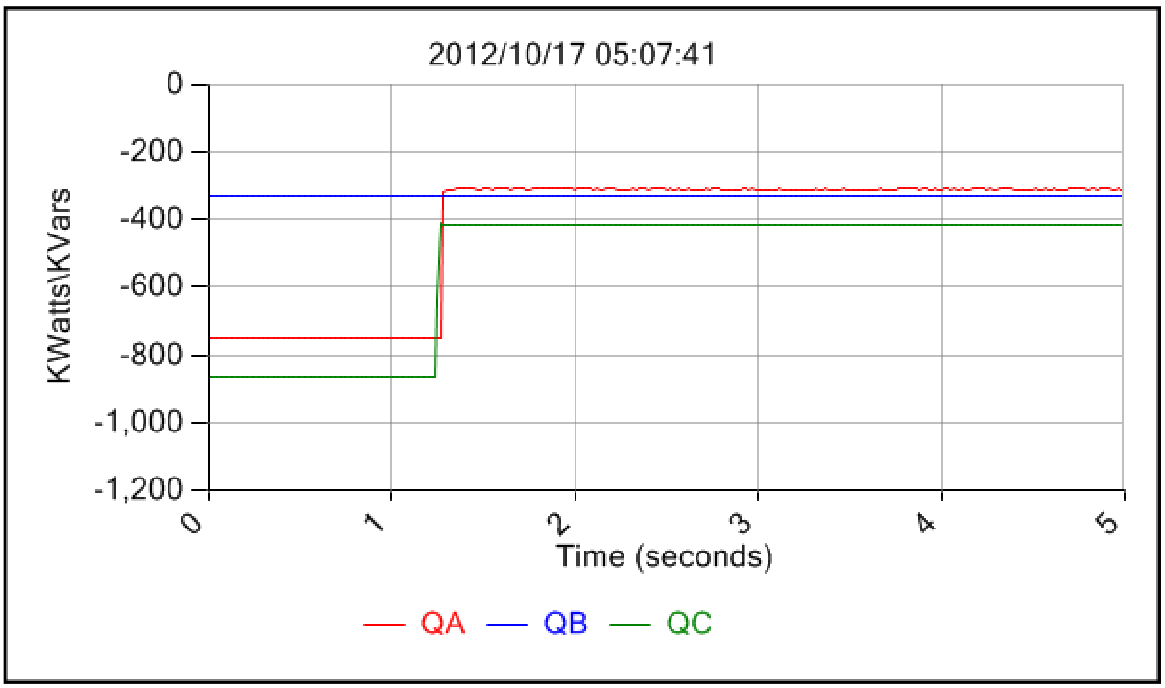


Figure 5-7
Per-phase VAR data from a "switch off" capacitor bank operation

Some remote control systems with one-way communications also can detect this type of condition, without additional sensing or instrumentation at the capacitor bank. Such a system transmits a command for a bank to switch and then monitors VARS, typically at the substation, looking for the expected level of change in VARs shortly thereafter. Such a system can detect whether three-phase VAR changes are near zero (bank fails to switch altogether), 1/3 of the expected change (only one phase operational), 2/3 of the expected change (two phases operational) or the full expected change (proper operation). This requires coordination of the command system, which tells the bank to switch, and a system for measuring real-time VAR flows.

By contrast, the DFA system's substation-based analytics require only the CT and PT connections common to performing not only capacitor-related but all other functions. This does not permit detection of complete, three-phase bank failure, because the analytics do not know the bank was supposed to switch, but it does provide for detection of failures of one or two phases of a three-phase bank, and it does so without requiring communication with the bank, sensing at the bank, or coordination with any other system.

5.5 Discussion

Utilities use capacitor banks ubiquitously, for VAR support and voltage support. Some modern banks have remote control and some even have two-way control and feedback. Most feeders, however, continue to have standalone banks that operate autonomously based on various parameters, such as time, temperature, power factor, etc.

Capacitor banks have multiple failure modes and are known to experience a significant number of failures. To keep banks operating acceptably, utilities' conventional practice inspects and tests each bank on a periodic basis—a suboptimal practice that consumes valuable resources, misses some failure modes, and sometimes even introduces problems into otherwise healthy banks. Routine maintenance practices such as this often are adopted because utilities lack alternatives.

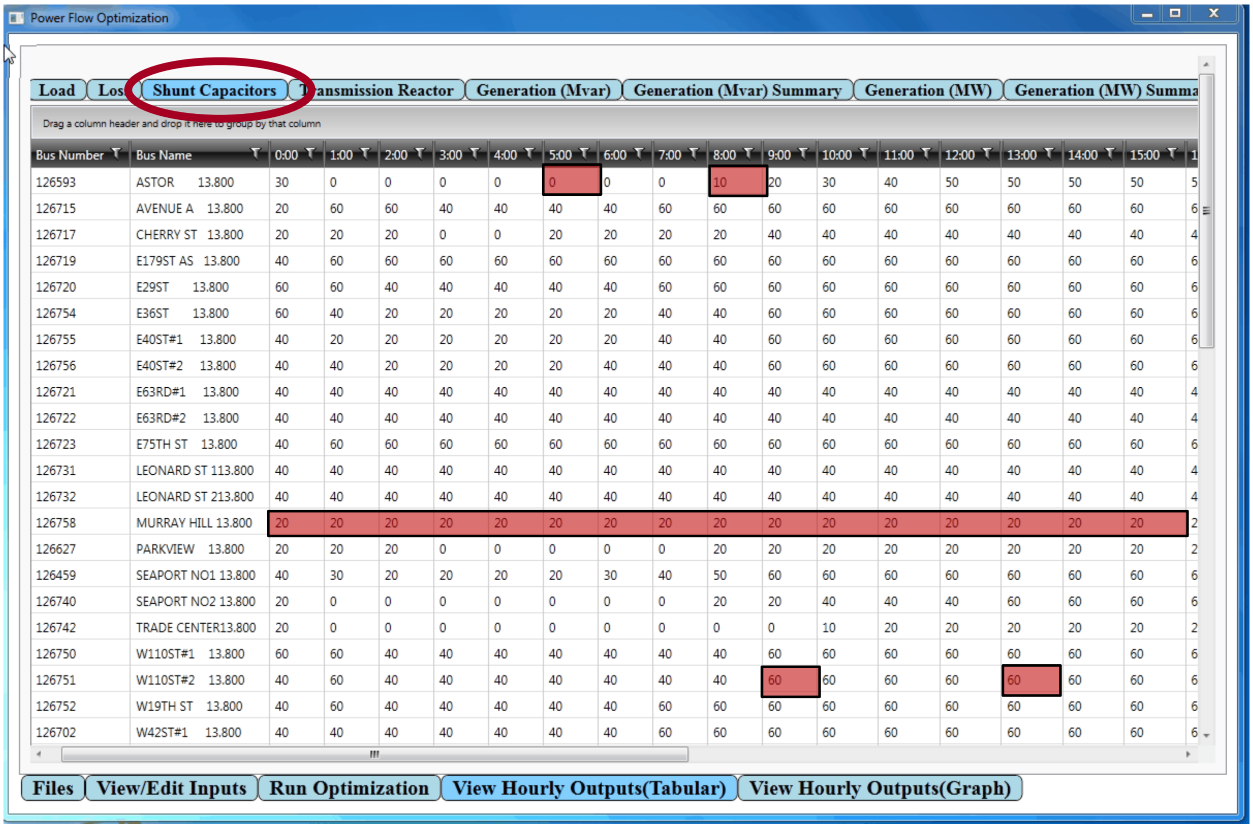
Traditional maintenance and remote control systems can detect gross capacitor-bank failures, such as a failed phase. DFA analytics also can detect these failures, but also subtler conditions, such as switch restrikes, switch bounce, and arcing capacitor switches, based solely on electrical current and voltage waveforms measured from conventional CTs and PTs at the substation. Whereas conventional maintenance practices will identify gross failures, such maintenance occurs only at intervals, often annually, so failures can exist for many months prior to discovery, leaving the system to operate in a suboptimal fashion for that period. By contrast, DFA analytics can detect both the gross failures and the subtler failures in real-time as banks switch OFF and ON. The result is that, with only substation-based instrumentation and conventional CTs and PTs, DFA analytics can enable savings in maintenance dollars and simultaneously enable faster notice and therefore response when failures occur. In addition, neither conventional maintenance nor remote controllers can detect the subtler symptoms, such as bouncing switches and switch restrikes, which occur intermittently and can cause hard-to-diagnose power-quality problems, particularly with industrial customers with sensitive electronic control systems.

Clear advantages of substation-based waveform analytics for capacitor-health monitoring include the following:

- Detection of a wider variety of capacitor failure modes than either conventional maintenance programs or advanced, communicating control systems.
- Improved manpower efficiency as compared to periodic maintenance programs.
- Faster detection and notification (near real-time) of capacitor failures than provided by periodic maintenance programs, which typically incorporate annual maintenance intervals.
- Utilization of existing, conventional sensors (CTs and PTs) at the substation, and no requirement for communication to pole-mount capacitor locations.

- Application in multi-function platform with numerous other functions, without single-function hardware.
- Ability to manage legacy banks without the addition of sensing, communications, or sophisticated controllers.

The new challenge associated with capacitor bank monitoring becomes the single dashboard metric that can yield the high level view at a system level with the drill down capabilities when desired. The initial concept slide for the visual is found in Figure 5-8.



Bus Number	Bus Name	0:00	1:00	2:00	3:00	4:00	5:00	6:00	7:00	8:00	9:00	10:00	11:00	12:00	13:00	14:00	15:00	1
126593	ASTOR 13.800	30	0	0	0	0	0	0	0	10	20	30	40	50	50	50	50	5
126715	AVENUE A 13.800	20	60	60	40	40	40	40	60	60	60	60	60	60	60	60	60	6
126717	CHERRY ST 13.800	20	20	20	0	0	20	20	20	20	40	40	40	40	40	40	40	4
126719	E179ST AS 13.800	40	60	60	60	60	60	60	60	60	60	60	60	60	60	60	60	6
126720	E29ST 13.800	60	60	40	40	40	40	40	60	60	60	60	60	60	60	60	60	6
126754	E36ST 13.800	60	40	20	20	20	20	20	40	40	60	60	60	60	60	60	60	6
126755	E40ST#1 13.800	40	20	20	20	20	20	20	40	40	60	60	60	60	60	60	60	6
126756	E40ST#2 13.800	40	40	20	20	20	20	40	40	40	60	60	60	60	60	60	60	6
126721	E63RD#1 13.800	40	40	40	40	40	40	40	40	40	40	40	40	40	40	40	40	4
126722	E63RD#2 13.800	40	40	40	40	40	40	40	40	40	40	40	40	40	40	40	40	4
126723	E75TH ST 13.800	40	60	60	60	60	60	60	60	60	60	60	60	60	60	60	60	6
126731	LEONARD ST 113.800	40	40	40	40	40	40	40	40	40	40	40	40	40	40	40	40	4
126732	LEONARD ST 213.800	40	40	40	40	40	40	40	40	40	40	40	40	40	40	40	40	4
126758	MURRAY HILL 13.800	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20	2
126627	PARKVIEW 13.800	20	20	20	0	0	0	0	0	20	20	20	20	20	20	20	20	2
126459	SEAPORT NO1 13.800	40	30	20	20	20	20	30	40	50	60	60	60	60	60	60	60	6
126740	SEAPORT NO2 13.800	20	0	0	0	0	0	0	0	20	20	40	40	40	60	60	60	6
126742	TRADE CENTER13.800	20	0	0	0	0	0	0	0	0	0	10	20	20	20	20	20	2
126750	W110ST#1 13.800	60	60	40	40	40	40	40	40	40	60	60	60	60	60	60	60	6
126751	W110ST#2 13.800	40	60	40	40	40	40	40	40	40	60	60	60	60	60	60	60	6
126752	W19TH ST 13.800	40	60	40	40	40	40	40	60	60	60	60	60	60	60	60	60	6
126702	W42ST#1 13.800	40	40	40	40	40	40	40	60	60	60	60	60	60	60	60	60	6

Figure 5-8
Example of a visual concept for identifying shunt capacitors that are out of limits

6
A NEW SAG SEVERITY "LOAD IMPACT" METRIC AND VISUALIZATION METHODOLOGY

One of the most challenging aspects of the many sag or dip metrics developed over the past 20 years is in the translation of the magnitude and duration of an event captured at a transmission or distribution substation to the actual impact on customer load. Previous efforts have included:

- SARFI X metrics which provide a system average for the frequency of low rms variations at a given magnitude (X) or percentage of remaining voltage.
- SAG contour plots with Equipment Susceptibility Overlays—These contour plots estimate the number of equipment trips per year based on sag frequency and equipment trip points
- Area of Vulnerability (AOV) studies—Where faults are applied to a power system to understand how large an area of vulnerability a given facility has to the sags associated with geographically dispersed fault conditions.
- Sag Severity Metrics—Involving parameters such as; sag duration, sag magnitude, number of phases involved, phase shift, remaining energy and the effect of transformations from wye to delta or grounded to ungrounded etc.

Each of these metrics provides useful insights and benefit when evaluating customer impacts due to low rms variations, but the real parameter of interest for any given feeder is not the metric or the number, but is rather the load served versus load interrupted by the event. This sounds fairly simple and in fact is a very basic metric, however, power quality instruments and SCADA systems as they are set up today are not easily able to provide this data primarily due to either triggering limitations or data sampling limitations.

With this in mind, the EPRI power quality T&D program research agenda has earmarked some future effort to the validation of a new "Load Impact" metric that will evaluate the magnitude of a sag as measured at a substation bus against the percent of load dropped on any given feeder impacted by the sag event. The expectation from such a "Load Impact" metric is that different feeder types and customer types can be evaluated based on the load impact factor as opposed to arbitrary parameters such as the number of events or the magnitudes of the events.

6.1 The Proposed Specification

For initial data collection by utilities, the following specification defines the rough concept as follows:

1. The data acquisition equipment must be capable of collecting:
   a. The sag event waveforms including magnitude and duration of the event

   b. The system current immediately preceding the sag event

   c. The system current immediately after the sag event

The rationale from having these quantities is that if the steady state load before the event was (for example) 700 amps and the load after the sag event was 700 amps – clearly the sag severity was not bad enough to impact much of the load. Alternatively if the steady state (SS) load before the event was 700 amps and the steady state load right after the sag event was around 350 amps, we can assume the sag severity was bad enough to drop 50% of the load

Depending on the magnitude of the sag event and the ratio of the SS load before to the SS load after the event it is a reasonably simple calculation to come up with a number that can be used as a metric for different feeder/customer types.

For 2013 follow-on validation efforts the requirement would be for each utility with suitable monitor data to identify a few radial circuits with the substation monitor and a detailed look at the voltage and current information that was captured before and after some of the low rms events recorded by that monitor. The goal would be to understand firstly, if the data is adequate to support the metric or secondly, if the monitor setting could be adjusted to obtain the data. For example by storing the SS current the minute before and the minute after the event.

The first of its kind sample data was provided in Figure courtesy of TVA. This particular example shows a fairly significant sag event occurring around noon and about a one and one half hour time window following the event before the load is back to its pre-sag level. While the resolution for this event is not easy to discern from the figure, it is clear that more than 50% of the load was lost immediately after the Sag Event, therefore this event would have a Load Loss Severity Index of at least 50 (LLSI50) – where 0 means no load was lost and 100 means that 100% of the load was lost.

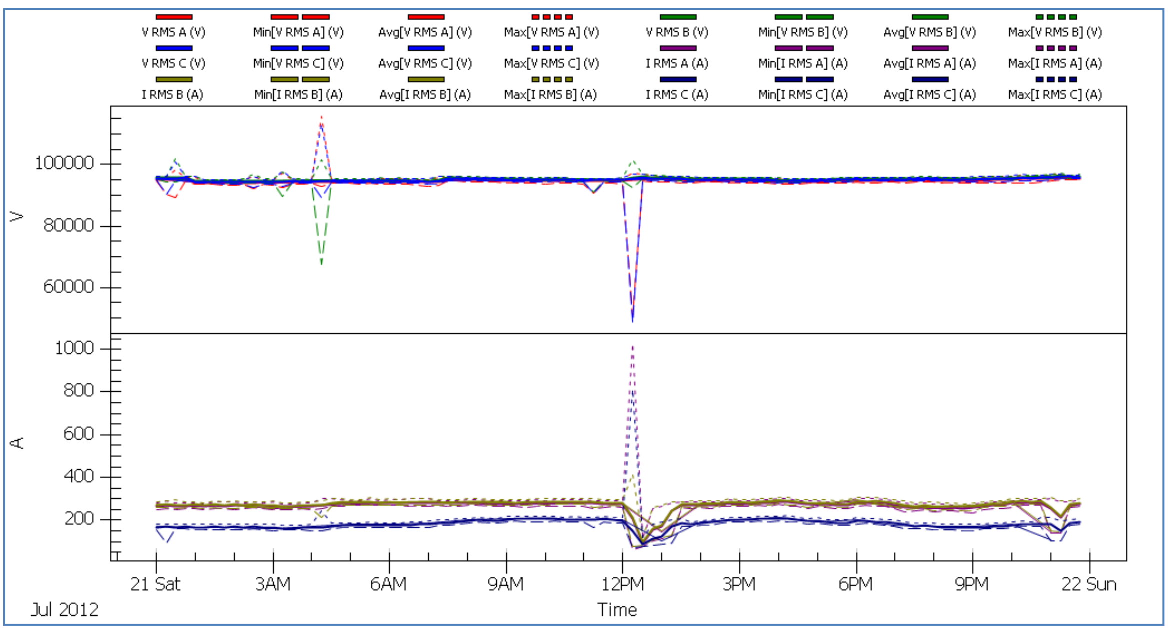


Figure 6-1
Example of the data required to evaluate the load lost sag metric. The sag event just after 12 PM results in a load drop for the better part of the next 2 hrs.

6.2 Load Loss During Fault Conditions

The primary application of the "Load Loss Sag Severity Metric" involves either transmission faults or faults on parallel feeds that results in a voltage sag on the circuit under evaluation. To extend the concept to faults on the feeder in question, some data from fault conditions downstream of the circuits experiencing the sag from the EPRI/TAMU DFA project are analyzed in the following sections.

6.2.1 Background

Momentary interruptions on distribution feeders occur for a variety of reasons. Many such interruptions have transient causes, such as nearby lightning strikes during a storm, and the utility may not choose to investigate every such event. In other cases, however, momentary interruptions result from incipient failures, such as cracked bushings and intermittent vegetation intrusions. These failures often cause repeated momentary interruptions. Environmental factors often influences the period between episodes. For example a cracked bushing may flash over when sufficient moisture, such as from rain or from heavy dew, creates a condition conducive to conduction. The flashover causes a high-current event, often drawing approximately bolted fault current for its position on the feeder, and clearing this fault requires operation of a protective device. The flashover event often generates sufficient localized heat to dry the bushing's surface so that, on feeders incorporating automatic reclosing, the flashover does not redevelop immediately, and all customers have their service restored following the momentary interruption.

The DFA research program has documented recurrent faults and momentary interruptions having a wide range of underlying causes, including vegetation intrusion, cracked bushings, a "death grip" bird, an overlong jumper, and wind on slack span. DFA research also has demonstrated that, contrary to conventional wisdom, customer calls do not provide reliable notification for even repeated momentary interruptions. In one such documented example, a cracked bushing flashed over once per week for five weeks, momentarily interrupting 903 customers downstream of a three-phase line recloser, and the utility did not receive a single customer call until the bushing went to final failure and created a sustained outage on the sixth flashover event.

Even if the utility company knows repeated momentary interruptions are occurring, locating the problem can be quite a challenge. This is particularly challenging on long feeders having single- and/or three-phase sectionalizing reclosers at a multiplicity of locations. The process often starts with patrolling the line to record operations-counter values for reclosers in the vicinity of known interruptions, and then checking those counter values again days later to determine which recloser is operating. Making that determination indicates the underlying problem lies somewhere downstream of that device. The utility next can perform patrols downstream of the identified recloser, but that often entails patrolling significant miles of line. In total the process can be labor intensive and take many days or even weeks to resolve.

The graphs found in Figures 7-2 through 7-4 illustrate current data related to a fault cleared by a single momentary interruption. The data contains much information useful for locating the fault. The most obvious and commonly used parameter that can be had from the data is the fault-current magnitude. The data also contain other information that actually may be more useful than magnitude, because a given fault magnitude, taken alone, could point to numerous places spread geographically across a large portion of the feeder's footprint.

Consider a long feeder, having a significant number of line reclosers. Each recloser will be either a single-phase device or a three-phase device, and it will operate on a specific set of I-t curves. It also will have a predetermined sequence of open intervals between each trip and automatic reclose operation. For example, some reclosers may be set for two-second open intervals while others may be set for other open-interval durations. In addition, a certain amount of the feeder's total load will be downstream of each recloser's location. If the performance parameters measured during the fault can be assessed and compared to the corresponding parameters for the fleet of reclosers on a given circuit, then the search area can be narrowed to the line segments downstream of a small number of reclosers, often a single recloser. If a visual patrol downstream of the recloser so identified fails to locate an obvious problem, then the fault-current magnitude can be used to further narrow the search, often to within a few pole spans of the problem.

The following pages have multiple graphical representations of a fault, selected somewhat at random from many such events routinely recorded and reported by the DFA system. From those electrical waveforms alone, the DFA system produced the following single-line summary report on this fault.

Single-Phase reclose	F-(3.0c,585A,BG)-T-(0,20,0)%-1.9s-C-2.3s- F-(16.5c,588A,BG)-T-(0,20,0)%-2.0s-C-5.2s- F-(17.5c,591A,BG)-T-(0,20,0)%-2.0s-C	3 ops	09/05/12 19:40:04

From left to right, the report contains the following information about this fault and the recloser that interrupted it.

Column 1:

- The fault was interrupted by a single-phase recloser.
- The recloser successfully reclosed. This is implicit, because a recloser that goes through one or more operations and then locks out would be shown as 'Single-phase trip,' instead of 'Single-phase reclose.'

Column 2:

- The initial fault lasted three cycles, drawing 585A of fault current on phase B.
- The recloser then tripped ('T').
- When the recloser tripped, it interrupted an estimated 20% of the load on phase B (0% on A and C).
- After a 1.9-second open interval, the recloser closed ('C').
- After this first reclose, the fault did not resume for 2.3 seconds.
- Then the fault did resume, this time lasting 16.5 cycles and drawing 588A of fault current on phase B.
- The recloser then tripped ('T'), again interrupting 20% of the load on phase B.
- After a 2.0-second open interval, the recloser closed again ('C').
- After the second reclose, the fault did not resume for 5.2 seconds.

- The fault resumed, again on phase-B, this time drawing 591A of fault current, and tripping in 17.5 cycles, again interrupting 20% of the load on phase-B.
- After another 2.0-second open interval the recloser closed again and stayed closed.

Column 3:

- The recloser went through three operations (as detailed in Column 3).

Column 4:

- The last column shows the date and time at which the fault occurred.
- Note that the full report would show the name of the substation and feeder, but those are omitted as superfluous for purposes of this document.

The DFA system's on-line analytics derived all of the bullet-list information from electrical waveforms recorded at a substation, using conventional current and potential transformers (CTs and PTs).

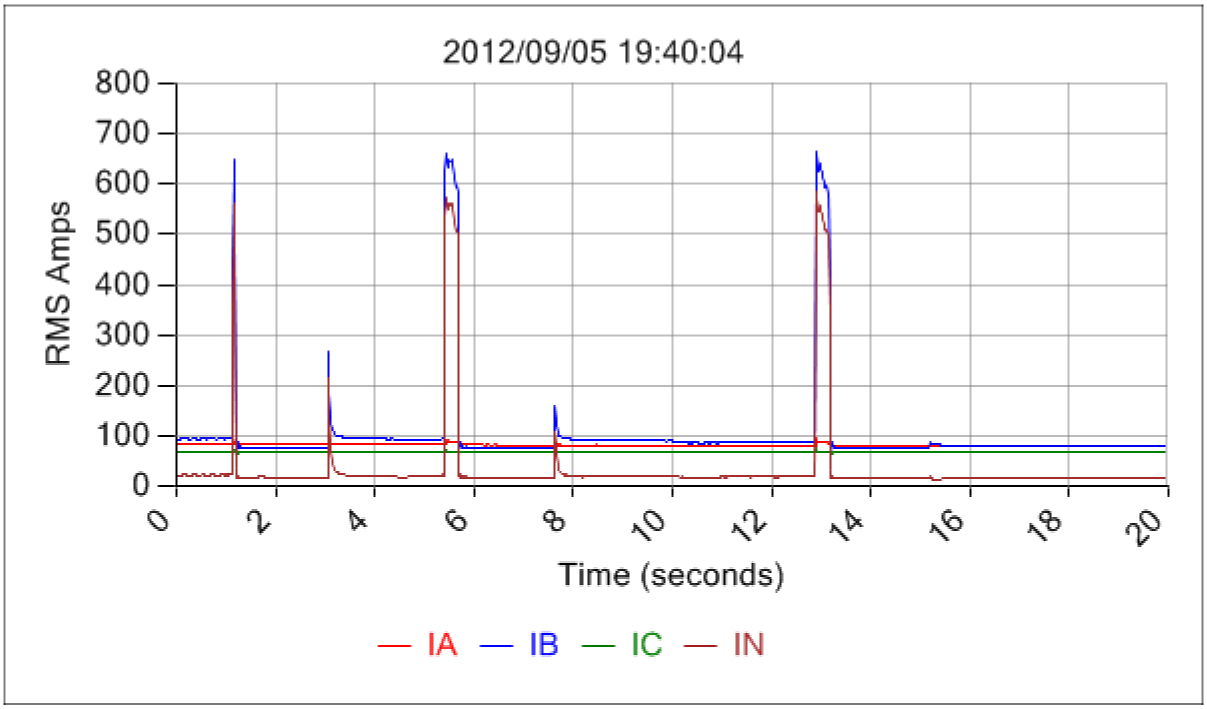


Figure 6-2
Current signatures captured by DFA during fault sequence

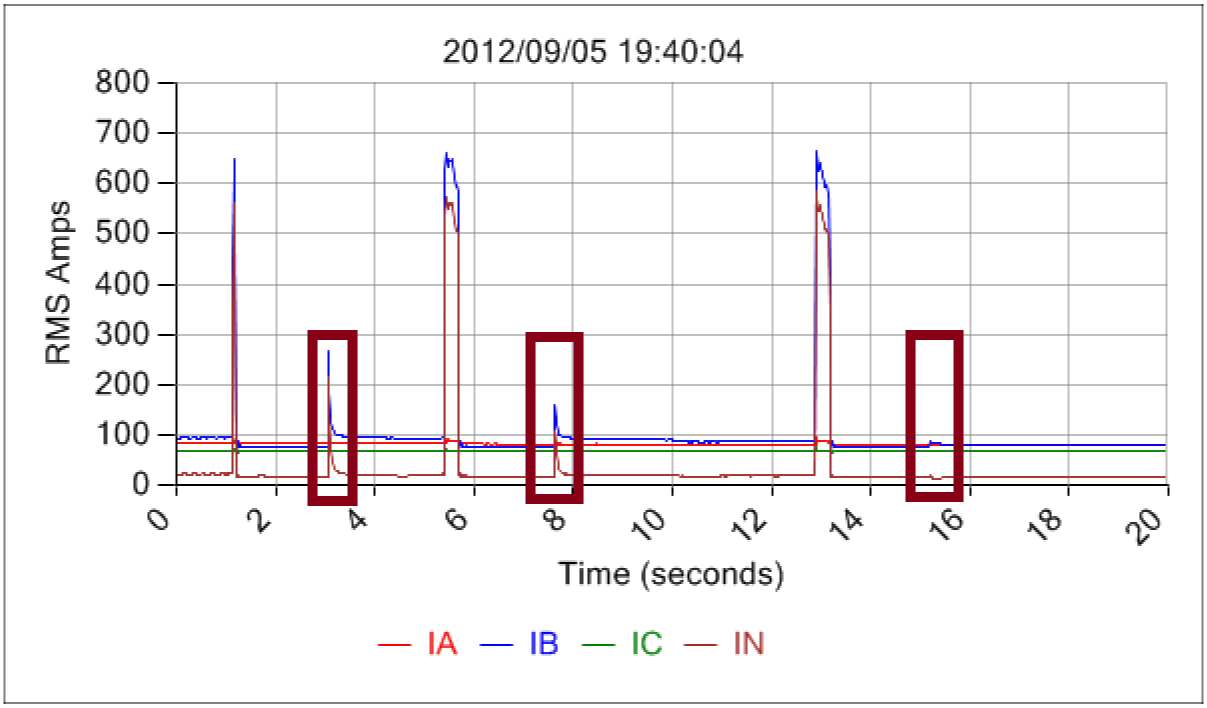


Figure 6-3
Three telltale current signatures indicating the location of the fault based on the load current concept

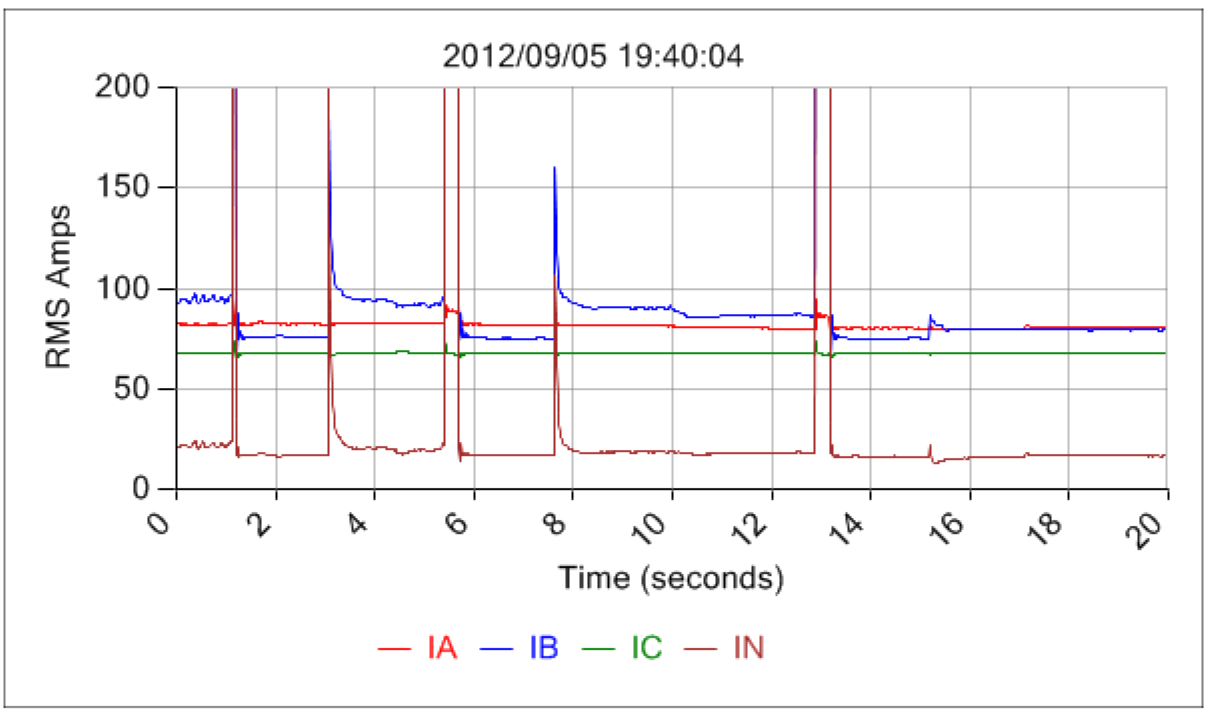


Figure 6-4
Twenty-second sequence of current

7

CONCLUSIONS

In the very near future, the communications and sensor enabled smart electric power grid will provide better metrics and visibility regarding electric power system performance—as well as more automated methods for diagnosing power quality concerns and incipient failures. In addition electric service providers will have useful tools that enable system planners to understand the implications of new power electronic load proliferation over time. The key requirements for accomplishing such objectives include more structured power quality data, strategically placed voltage and current sensors, and more advanced custom modeling tools. EPRI and a number of electric service providers have been demonstrating the core capabilities that will enable such benchmarking and predictive response.

One of the key benefits of such "smart and sensorized" circuits will be better visualization methodology for benchmarking power quality parameters over time. This technical update presented some of the most likely scenarios for such visualization and predictive understanding of many power quality related parameters. Of most significance for setting customer expectations and developing more useful customer satisfaction metrics would be the concept of using the Load Loss Severity Index described in section 5 to understand the circuit wide impact of voltage sags or dips in terms of the percentage of customer load that was dropped during the event. As this particular metric becomes more refined there will be a unique opportunity to evaluate how the index might vary by residential, commercial and industrial customer percentage on a given feeder.

In terms of standards development and support, the harmonic trendline visualizations described in section 2 are already impacting the discussions on North American wide harmonic limits for certain categories of load equipment and once the specification for this metric is implemented in utility power quality data collection programs the year or year and decade to decade trending patterns for harmonic proliferation or for harmonic control will start to become clearer.

Finally the metrics described for analyzing capacitor health and for understanding circuit fault events more clearly by utilizing the EPRI/TAMU distribution fault anticipation technology as discussed in sections 4 and 6 provide a modern day understanding of the potential that exists for applying power quality parameters and knowledge based algorithms to derive previously unknown information about feeder performance.

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