Application of Phasor Measurement Units for Disturbance Recording

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1. Introduction

This paper looks at the specific application of Phasor Measurement Units (PMUs) for disturbance recording, with a special emphasis on wide area cross-triggering of recording PMUs during events. Disturbance recording, or long-term recording of phasor data, provides valuable information when analyzing wide area disturbance and power swings in the utility system. The newly approved NERC PRC-002 and PRC-018 standards require the installation of disturbance recording equipment at strategic points on the power system. The value of this equipment is only realized when discrete records are captured simultaneously at all points on the power system, to provide a complete snapshot of a specific event. Traditional recorders rely on local triggers to capture the data, however, an individual recorder may not trigger for a specific event, or may trigger in a different time frame than other recorders on the system, and not capture valuable data. A practical challenge is adding the disturbance recording *function* to existing substations and relay systems.

Ongoing projects, such as the Eastern Interconnect Phasor Project, promote the installation of PMUs to provide real time measurement of the state of the power system, by streaming highly accurate synchrophasors at a high sampling rate. The PMUs are generally installed at the same strategic substations that require disturbance recording. In addition, today's digital relays (such as a line distance relay or current differential relay) are capable of synchronous phasor measurements. In addition to streaming data to a centralized database, PMUs may have the ability to record data at the PMU based on local trigger conditions. The record may include synchrophasor data as well as additional analog values and digital status. This recorded data meets the disturbance recording requirements set by NERC. The paper discusses the applicability of synchrophasor data to disturbance recording, and the capabilities of PMUs to capture the appropriate data.

This paper also discusses practical aspects of using the IEEE Synchrophasor standard communications in conjunction with IEC61850 communications for wide area cross-triggering of PMUs. Also discussed are communications channels requirements and expected performance of cross-triggers. Other disturbance recording applications exist in the industrial domain, such as motor starting failure events on large motors. Synchronized measurements provide the ability to correlate the failure with other events in the industrial process. This paper will discuss industrial applications of PMUs.

2. Phasor Measurement Units and recording

In the context of this paper, disturbance recording is defined as recording of phasor or RMS values of data over a long period of time. Disturbance recording is intended to show the response of the power system and equipment due to power system faults, such as an out-of-step condition, as opposed to power equipment faults, such as a short circuit. The time interval for these "long term" events can range from 1 second (in the case of a fault and high-speed reclose) to many minutes (in the case of system oscillations). The fast sample rates (30 to 60 phasors per second) of today's synchrophasors-based disturbance recording devices can be used to analyze both power system faults and the more traditional power equipment faults. The term Dynamic Swing Recorder (DSR) is also often used to describe a device that captures disturbance data over a long period of time. A more complete description of these terms is available in [1].

NERC has issued Standard PRC-002-1 entitled: Define Regional Disturbance Monitoring and Reporting Requirements. Section R3 specifically addresses criteria for dynamic disturbance recording, including location of recorders, electrical quantities to record, recording duration, and sampling rate. The NERC standard essentially states that DSRs are to be situated at key locations, are to record voltage, current, frequency, megawatts and megavars for monitored elements, and are to record the RMS value of electrical quantities at a rate of at least 6 records per second.[2]

The Regional Reliability Councils (RCCs) of NERC are responsible for refining these standards for a specific operating region. By reviewing the standards as interpreted by some of the RCCs, it is possible to provide a good overview of disturbance monitoring requirements.

Location of DSRs. DSRs are to be located at key substations for the power system. Key substations are generally defined as transmission substations with significant connected generation, large transmission substations (containing 7 or more transmission lines), transmission substations that interconnect to another regional authority or company, at major load centers (such as load centers greater than 2500 MW), or where undervoltage load shedding schemes are implemented.

Electrical quantities to record. The NERC requirement is to record voltage, current, and frequency, with the ability to derive or record megawatts and megavars for each monitored element. The minimum requirements defined by the RCCs are:

- Bus voltages: at least one three-phase measurement per voltage level, with two measurements per voltage level recommended
- Frequency: at least one frequency measurement for every voltage measurement
- Three-phase line currents for every critical line
- Megawatts and megavars, three-phase, for each monitored line.

Record length. Disturbance recording, and DSRs, are intended to capture longer term power system faults. DSRs therefore require longer record times. The recording length is typically specified as 90 to 180 seconds, including 30 seconds of pre-fault data. DSR records may be require to automatically extend in length when additional triggers occur during recording.

A second option for record length is to use continuous recording. A DSR therefore always captures data for all analog channels, and typically stores the last 30 days of data. The challenge with continuous recording is to manage the large amounts of data. Also, it is important to be able to retrieve the key pieces of the data to analyze an event.

Triggers. Triggers are necessary to initiate recording for the typical DSRs that have a discrete record length. For continuous recording, triggers provide markers into the key pieces of data during an event. The ability to "share" triggers between multiple sites is also necessary in order to capture a wide-area view of an event.

There are many types of triggers available in DSRs, including:

- Magnitude triggers, on voltage, current, frequency, real power, reactive power and apparent impedance
- Rate-of-change triggers, on voltage, current, frequency, real power, reactive power and apparent impedance
- Harmonic content triggers, on a specific harmonic frequency, or on total harmonic distortion
- Delta frequency triggers
- Contact triggers, such as breaker operation or communications channel operations
- Symmetrical components trigger.

Frequency rate-of-change and voltage rate-of-change triggers are the most commonly applied triggers. Previous papers at this conference have suggested that real power rate-of-change triggers also have the sensitivity and selectivity to trigger recording for power system faults, without triggering recording for power equipment faults.[1] Impedance triggers are an interesting case for this paper. Impedance triggers will only operate when the center of impedance of a power system fault is close to the location of the DSR. However, there are some events, such as load encroachment, or when the DSR is located close to the center of impedance, where this trigger can capture valuable data.

Sampling rate. The minimum sampling rate required by NERC is 6 Hz. However, a higher sampling rate, such as 30Hz or 60Hz, provides a more accurate picture of the measured electrical quantities during a power system event, providing frequency responses up to 15 and 30 Hz respectively.

The requirements for disturbance recording as described in this section are a synthesis of the requirements as defined by a few of the Regional Coordinating Councils of NERC. For complete details of an individual RCC, please see [3], [4], [5].

The term Dynamic Swing Recorder is a generic term to describe any device capable of capturing RMS or phasor values of electrical quantities. While typically a DSR is simply a function available in a digital fault recorder, other devices may have the capability to capture this type of data. One such device is the Phasor Measurement Unit (PMU), a device that measures synchrophasors, a highly accurate time-synchronized phasor measurement.

The typical PMU is designed to communicate these synchrophasors to system operators for real-time control of the power system. However, some PMUs have the ability to trigger on system anomalies, and record synchrophasor data, to meet the requirements of disturbance recording.

2.1. *PMU as disturbance recorders*

An AC waveform can be mathematically represented by the equation:

$$x(t) = X_m \cos(\omega t + \theta) \qquad \text{Equation 1}$$

where X_m = magnitude of the sinusoidal waveform,
ω = $2 * \pi * f$ where f is the instantaneous frequency
ϕ = Angular starting point for the waveform

Note that the synchrophasor is referenced to the cosine function. In a phasor notation, this waveform is typically represented as:

$$\overline{X} = X_m \angle \theta$$

Since in the synchrophasor definition, correlation with the equivalent RMS quantity is desired, a scale factor of $1/\sqrt{2}$ must be applied to the magnitude which results in the phasor representation as:

$$\overline{X} = \frac{X_m}{\sqrt{2}} \angle \theta$$

Adding in the UTC-based absolute time mark, a synchrophasor is defined as the magnitude and angle of a *fundamental frequency* waveform as referenced to a cosine signal (Figure 1).

In Figure 1, time strobes are shown as UTC Time Reference 1 and UTC Time Reference 2. At the instant that UTC Time Reference 1 occurs, there is an angle that is shown as "$+\theta$" and, assuming a steady-state sinusoid (i.e. – constant frequency), there is a magnitude of the waveform of X_1. Similarly, at UTC Time Reference 2, an angle, with respect to the cosine wave, of "$-\theta$" is measured along with a magnitude or X_2. The range of the measured angle is required to be reported in the range of $\pm \pi$. It should be emphasized that the synchrophasor standard focuses on steady-state signals, that is, a signal where the frequency of the waveform is constant over the period of measurement.

In the real world, the power system *seldom* operates at exactly the nominal frequency. As such, the calculation of the phase angle, θ, needs to take into account the frequency of the system at the time of measurement. For example, if the nominal frequency of operating at 59.5Hz on a 60Hz system, the period of the waveform is 16.694ms instead of 16.666ms – a difference of 0.167%.

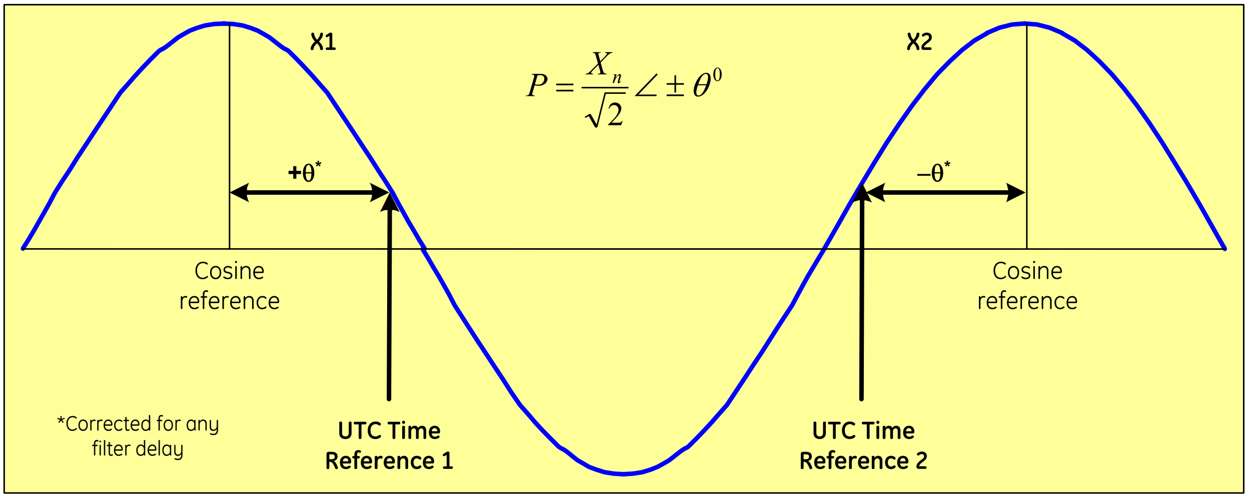

Figure 1: Synchrophasor definition

The captured phasors are to be time tagged based on the time of the UTC Time Reference. The Time Stamp is an 8-byte message consisting a 4 byte "Second Of Century – SOC", a 3-byte Fraction of Second and a 1-byte Time Quality indicator. The SOC time tag counts the number of seconds that have occurred since January 1, 1970 as an unsigned 32-bit Integer. With 32 bits, the SOC counter is good for 136 years or until the year 2106. With 3-bytes for the Fraction Of Second, one second can be broken down into 16, 777,216 counts or about 59.6 nsec/count. If such resolution is not required, the C37.118 standard allows for a user-definable base over which the count will wrap (e.g. – a base of 1,000,000 would tag a phasor to the nearest microsecond). Finally, the Time Quality byte contains information about the status and relative accuracy of the source clock as well as indication of pending leap seconds and the direction (plus or minus). Note that leap seconds (plus or minus) are not included in the 4-byte Second Of Century count.

2.2. Synchronized phasor reporting

The IEEE C37.118 revision of the IEEE 1344 Synchrophasor standard mandates several reporting rates and reporting intervals of synchrophasor reporting. Specifically, the proposed required reporting rates are shown in Table 1 below.

Table 1: Synchrophasor reporting rates

System Frequency:	50 Hz		60 Hz				
Reporting Rates:	10	25	10	12	15	20	30

A given reporting rate must evenly divide a one second interval into the specified number of sub-intervals. This is illustrated in Figure 2 where the reporting rate is selected as 60 phasors per second (beyond the maximum required value, which is allowed by the standard). The first reporting interval is to be at the Top of Second that is noted as reporting interval "0" in the figure. The Fraction of Second for this reporting interval must be equal to zero. The next reporting interval in the figure, labeled T_0, must be reported1/60 of a second after Top of Second – with the Fraction of Second reporting 279,620 counts on a base of 16,777,216.

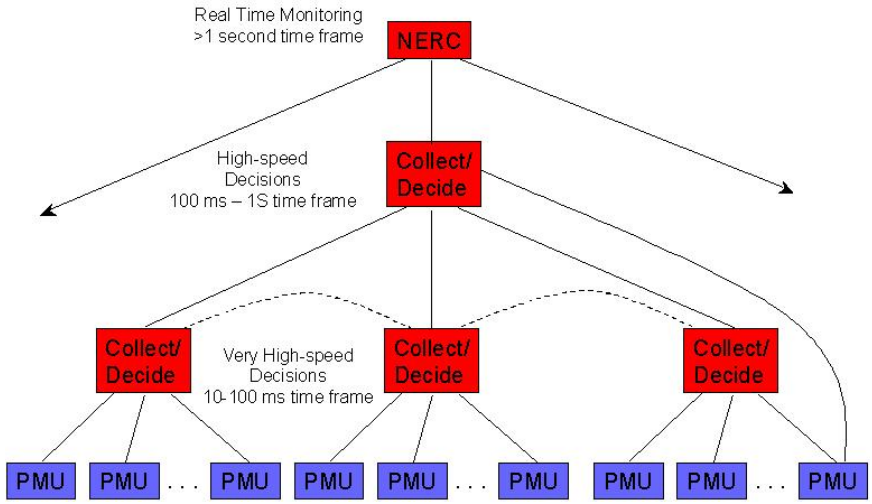

Figure 2: Synchrophasor reporting hierarchy

2.3. PMU Distributed Architecture

The Synchrophasor standard and associated communication protocol was designed to aggregate data from multiple locations. As each dataset is transmitted synchronous to top of second and as each transmitted dataset contains a precise absolute time stamp, the data aggregation function becomes a simple matter of combining sets of data with common time stamps. The “box” that performs this function is known as a Phasor Data Concentrator or PDC. In a “total” system, there will be a hierarchy of PDCs as shown in Figure 2. The hierarch is designed to support different performance criteria/data rates – depending on the application. With the assumption that higher-level PDCs operate at lower data rates, the data from the lower layer PDCs provides the most frequency resolution. Depending on type and number of PMUs installed in a substation, a substation-based PDC may or may not be required as this function can be integrated into the PMU.

A major advantage of Synchrophasor measurements compared to a normal DSR is that, as a result of standardization, data from multiple manufacturers can be seamlessly integrated. This is possible because the Synchrophasor standard requires that magnitude and phase angle errors resulting from magnetic and filter components be compensated in the final result.

Throughout North America, there exist today “pockets” of data concentration. Specifically, the Eastern Interconnect Phasor Project (now the North American SynchroPhasor Initiative – NASPI) has created a network of PMUs that span most of the eastern half of the continent. Data is being streamed at a rate of 30 phasors/sec into a Super Phasor Data Concentrator as operated by TVA. Communication bandwidths in the order of 64,000 to 128,000 bits per second will be required – depending on the number of data items and the selected stream rate. At the receiving site, real-time visualization of the data is available. Additionally, the data is archived and can be retrieved to perform system dynamic analysis as well as forensic analysis for larger system events.

In as much as remote communications may be disrupted by an event, most PMUs/PMU Systems have the ability to locally store synchrophasor data based on a range of event triggers. Typical triggers include over/under frequency, rate of change of frequency, over/under voltage, over current, over/under power, and status change. Synchrophasor recording times in excess of 20 minutes can be obtained within the confines of existing PMU memories.

3. Wide Area Recording

The benefits of disturbance recording, or power swing recording, are already well established. The phasor data captured in these records are used to validate system models of the power system, validate the operation of system integrity protection schemes and wide area protection schemes, and to provide root-cause analysis of equipment operation during power system faults. Some typical uses for the data include identifying the impact on the system due to a loss of generation or loss of a significant transmission line. Another use for this data is to analyze the performance of distance relays due to power swings. [6],[7] In all of these cases, for proper analysis, the phasor data must be measured simultaneously at various points on the power system. By collecting and coordinating records from multiple locations, the engineer can evaluate the response of the system, and specific equipment, to a power system or power equipment fault. The challenge is to capture simultaneous recordings across the system.

The present method of disturbance recording is to use discrete recording equipment, and local triggers. DSRs are placed at key locations on the system. Each DSR is configured much like a protective relay: trigger criteria are specific for the location of the DSR. Therefore, a DSR will only create a record when a power system fault is observable at the location of the DSR. Therefore, the more remote a DSR is from the center of inertia of an event, the less likely the DSR will capture a record for an event. Also, local triggers are dependent on the propagation time of the event across the system. A common trigger for DSRs is rate-of-change of frequency. In one known case, full load rejection of a 1,100 MW generating station took approximately ½ second to propagate across the utility power system.[7] Local triggers will therefore be problematic in such a case. With discrete DSRs, and local triggers, records (such as for the load rejection example) may be created at different instances in time. An engineer must identify, retrieve, and combine the appropriate records from multiple devices. And this assumes that all the DSRs in use are accurately time-synchronized, typically to Coordinated Universal Time using GPS clocks.

Wide area recording or wide area cross-triggering can solve some of these issues. Wide area recording creates one synchronized record across the power system when any local DSR triggers a recording. The challenges in a wide area recording system are similar to that of local recording, with the added complexity of communications channel time delays. The only wide area recording system presently available is a closed, proprietary solution. This solution links DSRs as part of a client-server software system. When one DSR triggers a recording, this DSR sends a message to the server. The server then sends a message to trigger a recording, with the same trigger time, on all other connected DSRs. This system solves communications channel delay by using a rolling data buffer to store data in the DSR. Once the recording is finished, the server then retrieves the records from all the DSRs. This system absolutely requires that each DSR is accurately time synchronized, to ensure the data in the individual records are in phase.

Wide area cross-triggering sends a cross-trigger command to other DSRs via communications when one DSR triggers for a power system fault. Wide area cross-triggering has not been used, in part due to the challenges of communications, as the cross-trigger signal must be sent to multiple DSR locations simultaneously. Therefore, the complexity of communications is added to the same challenges in creating simultaneous records. However, the use of a PMU as the DSR can reduce these challenges.

In a typical DSR, although the records are time synchronized, there is no agreement among manufacturers as to how and when a measurement is made. However, when using a PMU as a DSR, the measurement is standardized and time synchronized per standard. Therefore, the trigger time of the record is not vitally important. The data from records captured at two different PMUs with different trigger times can be coordinated based only on absolute time.

The other challenge in wide area cross-triggering is sending the cross-trigger signal to multiple locations across the power system. This assumes an intact communication channel. Speed is not critical as long as the PMU can provide pre-trigger data memory. By setting the pre-event memory to be longer than the trigger and re-trigger communication time, no data is ever lost. The IEEE Synchrophasor standard has, as part of the message format, a trigger signal that is typically sent as a PMU-to-PDC signal. Once in the PDC, logic is needed to receive the trigger signal and then to forward it to all PMUs connected to the detecting PDC. Once the signal is received by one PMU in a station, that PMU can issue a GOOSE message to trigger other data captures or execute controls in other devices in the substation. Figure 3 illustrates this architecture.

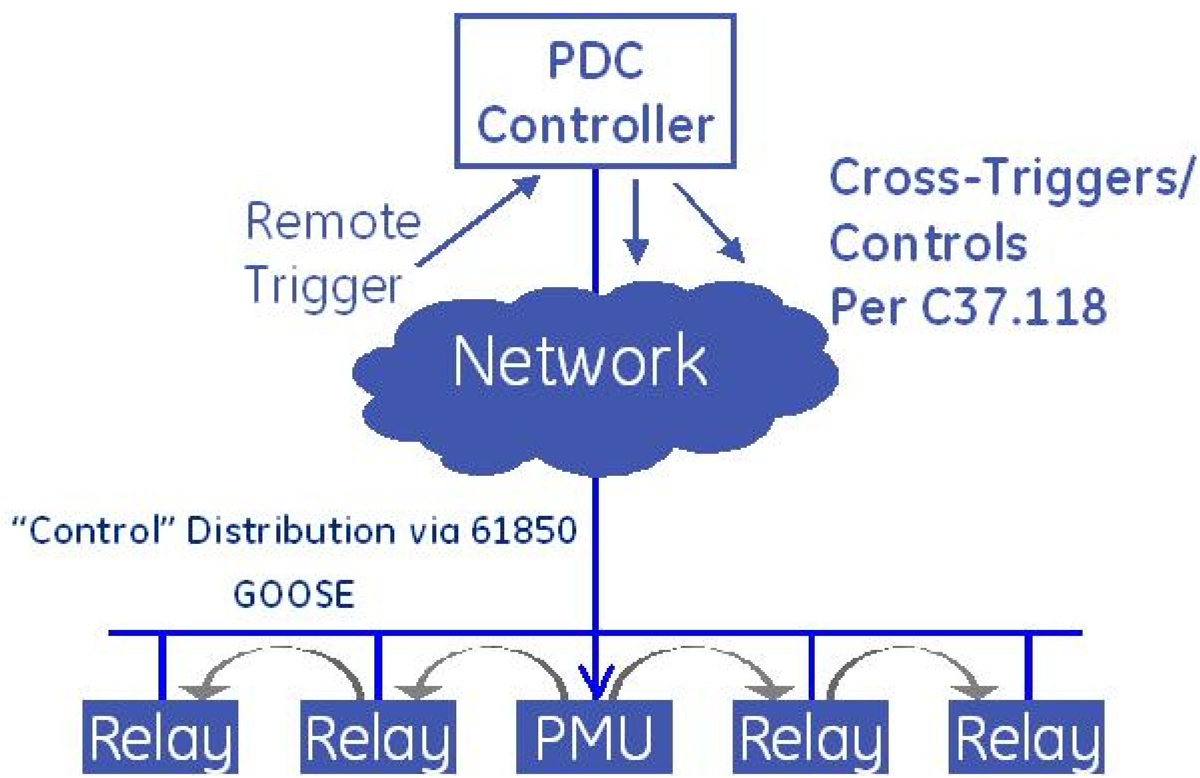

Figure 3: Phasor measurement unit cross-triggering

3.1. The need for cross-triggering PMUs

PMU installations are normally designed to stream PMU data via communications to a centralized database that stores synchrophasors quantities for later analysis of the power system. This seems to eliminate the need for cross-triggering recording, as the data is readily available at a central location. However, the data is not necessarily available. As more devices, such as protective relays, can provide synchrophasors data, the less likely these devices will continuously stream data to the centralized database. The bandwidth of communications channels may limit data transmission, and data storage requirements may limit reception of data. Also, protection engineers may not have the same easy access to stored synchrophasors data as the system operations and system planning departments do.

In addition, for analysis of relatively local events, there may be the need to capture additional data beyond synchrophasors, such as power, power factor, and impedance. The cross-trigger signal can also be used to initiate recording in a traditional DSR as well.

4. Applications of PMU data for analysis

4.1. Large motors

In the industrial environment, many processes have start-up and shut-down times that are in the multi-second time frame and sometimes, problems occur that either abort a startup or initiate an undesired shut-down. Traditional oscillography, although high-resolution, is typically set to record data only during fault conditions and, as such, will not record the longer start-up or shut-down events. Moreover, most industrials will own neither a swing recorder nor an oscillograph. Synchrophasor capability in motor protection can enable data capture in these instances and can provide a high-resolution, long-term view of these events. In addition, with proper trigger settings, the effects of power system disturbances on plant processes can be observed.

4.2. AGC / SIPS analysis

System Integrity Protection Schemes (SIPS) is rapidly becoming a common occurrence in many utilities around the world. A SIPS event is usually a last ditch effort to prevent a complete power system shut down. It is very desirable to measure the effect of a SIPS action on the electric power grid. This measurement is most easily effected through the collection of synchrophasors across the system. Using the cross-triggering methodology previously described, the wide-ranging effects of a SIPS action can be observed and used to validate system studies and models.

One such scheme protects large multi-generator power plants against the severe disturbances that occur on transmission lines. Based on the disturbance severity, the typical results are intensive swings or loss of plant synchronism, which will lead into loss of the entire generation complex either by out-of-step protection, or unit shutdown by protective devices reacting to voltage dips at auxiliary buses. Wide area recording of synchrophasors allows the analysis of the power swing phenomena across the system, to verify the operation of the SIPS scheme.

4.3. *Capacitor Bank Performance*

Capacitor Banks are used to help maintain a flat voltage profile on the transmission system. Capacitor bank installation typically use some type of automatic control to switch in and switch out the capacitor bank. This switching operates on some criteria involving time of day, voltage magnitude, reactive power magnitude, or power factor. The performance of the capacitor bank is monitored at the system operations level by direct observation of the changes in the system voltage. Direct recording of the changes to local part of the system could provide some interesting insights into the impact of capacitor bank operation on the system voltage.

The primary data necessary to analyze the performance of a capacitor bank is the voltage magnitude and the reactive power flow. PMUs directly record the voltage and current synchrophasors, and can also record the real power, reactive power, power factor, and system frequency. Consider the arrangement of Figure 4. Rich Substation is a major load substation, with a switched capacitor bank that operates on voltage magnitude. Recording PMUs are installed at both Rich Substation and Mark Substation, a major transmission substation. The PMU at Rich Substation is configured to trigger a recording on operation of the capacitor bank controller. Both PMUs are configured to send a cross-trigger command via IEC61850 GOOSE messaging.

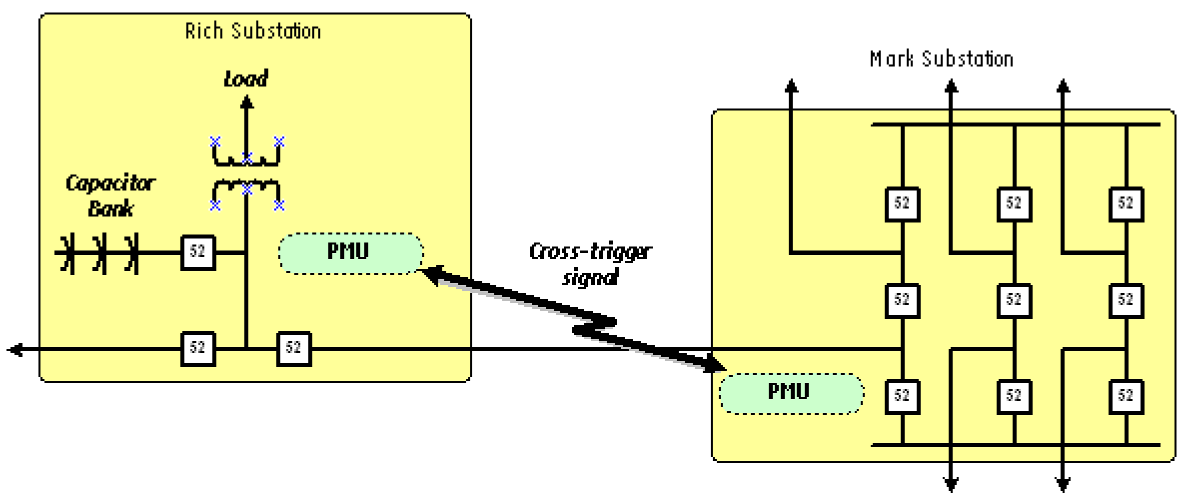

Figure 4: PMU cross-trigger for capacitor bank operation

A voltage profile may look something like that of Figure 5, where increasing load drags the system voltage down. The voltage recovers after the capacitor bank is switched in.

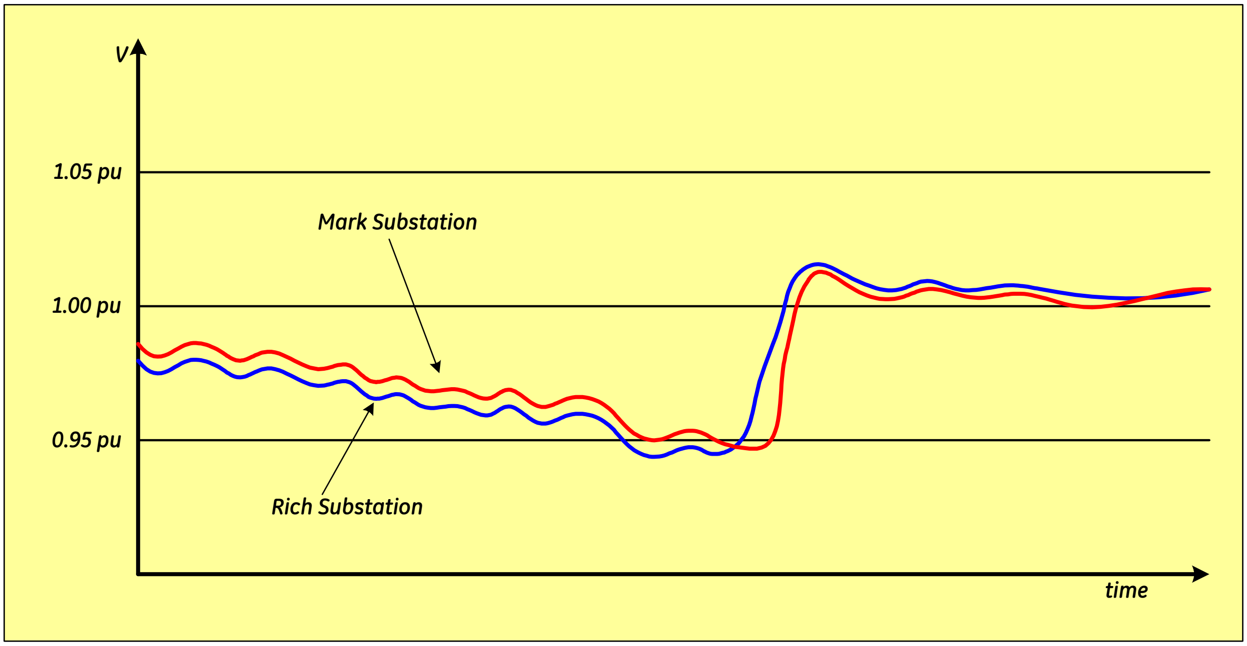

Figure 5: Capacitor bank operation voltage profile

Recording the data at both PMUs can provide some valuable information. The basic information includes the voltage magnitude at each bus. Once the capacitor bank is switched in, the data will show the impact on the voltage at each bus, the amount of overshoot on the voltage correction, and the time lag between capacitor switching and voltage correction at the remote bus. The end goal of using this type of data is to improve the efficiency of capacitor bank switching, to ensure that bank switching procedures result in the desired improvement in system voltage level.

There are two advantages to using IEC61850 GOOSE messaging as the cross-trigger signal. The first advantage is the GOOSE message can be sent to one specific device or group of devices, or it can be sent to all devices on the system. In this example, GOOSE messages need only be sent between the two PMUs. The second advantage is the non-proprietary nature of IEC61850.

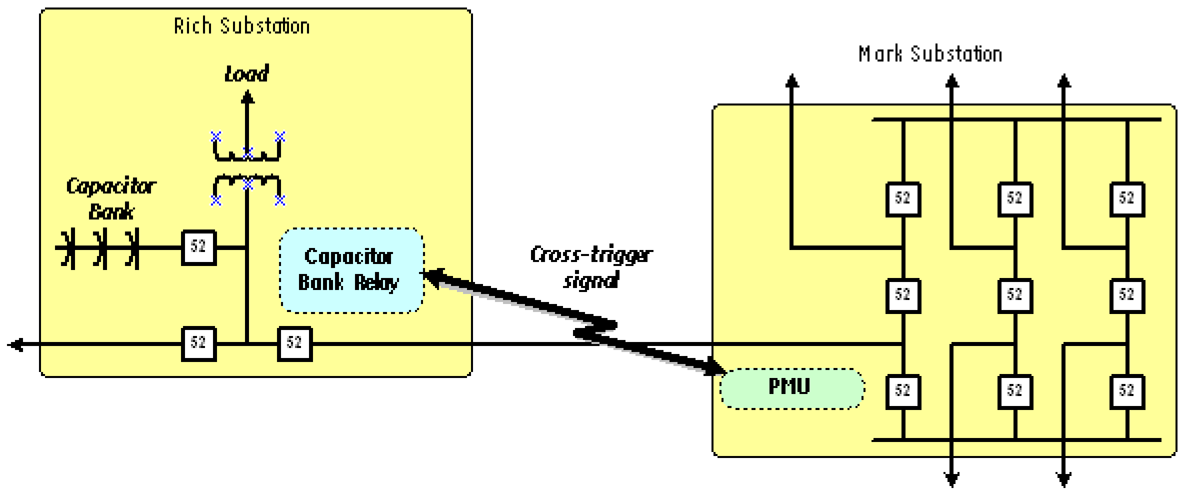

Figure 6: Load substation without PMU.

It is more typical that a PMU will not be installed at a simple load substation. However, any device that can send an IEC61850 GOOSE message, such as a modern capacitor bank relay, can send a cross-trigger signal to the PMU at a remote substation. This ensures a local switching operation still captures valuable data.

4.4. Analysis of load shedding schemes

Underfrequency and undervoltage load shedding schemes are used to prevent system collapse. The typical scheme uses a local relay with a fixed threshold against voltage or current. A block of load is shed when the frequency or voltage drops below this threshold. Multiple thresholds are typically used to shed multiple blocks of load. The power system phenomenon that predicates the use of a load shedding scheme is a reduction in the system frequency or system voltage due to a significant imbalance between generation and load. At an individual device location, the apparent impedance will fluctuate in response to the changes in the system voltage and current.

Analysis of the performance of a load shedding scheme requires both verifying the performance of local devices, and verifying the performance system-wide. Recording synchrophasors in the substation, along with power flow and device data, can verify the local operation of the load shed devices, and the local impact on load. Capturing this data across the system can verify the performance of the load shed scheme system-wide. In addition, this information can be used to determined the center of inertia of the system during the event, and how close the system was to the voltage instability point.

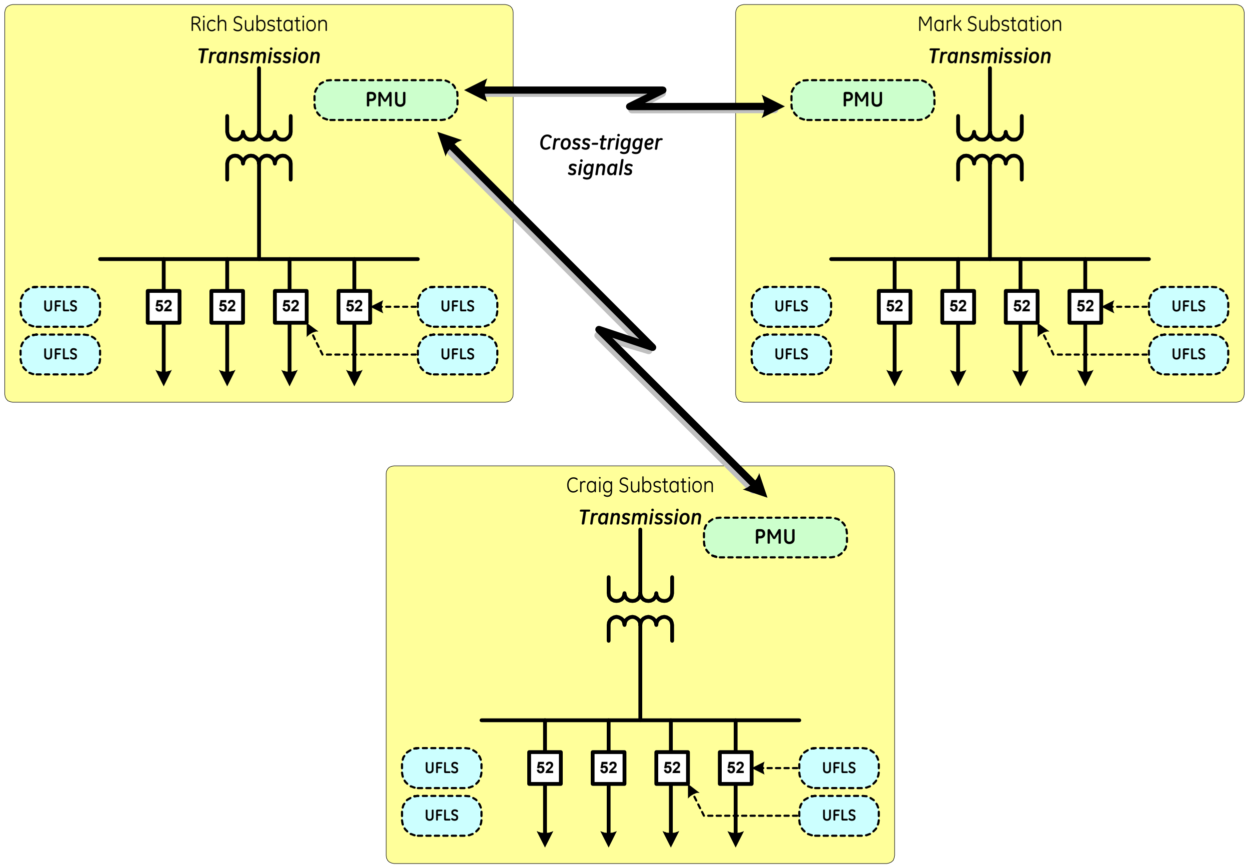

Figure 7: Cross-triggers for load shedding analysis

4.5. Distance relay performance during small disturbances

Not all disturbances need to be a system-wide phenomenon to be of interest to study. Significant changes in voltage or current may cause the operation of a distance relay. Of special concern are distance relays that use a large over-reaching zone as remote backup of lines from the next station. Even small disturbances, such as the loss of a nearby generator, or heavy line loading, may cause the operation of this distance element. PMUs can be used to identify events where the apparent impedance of the line comes close to a tripping zone of the relay.

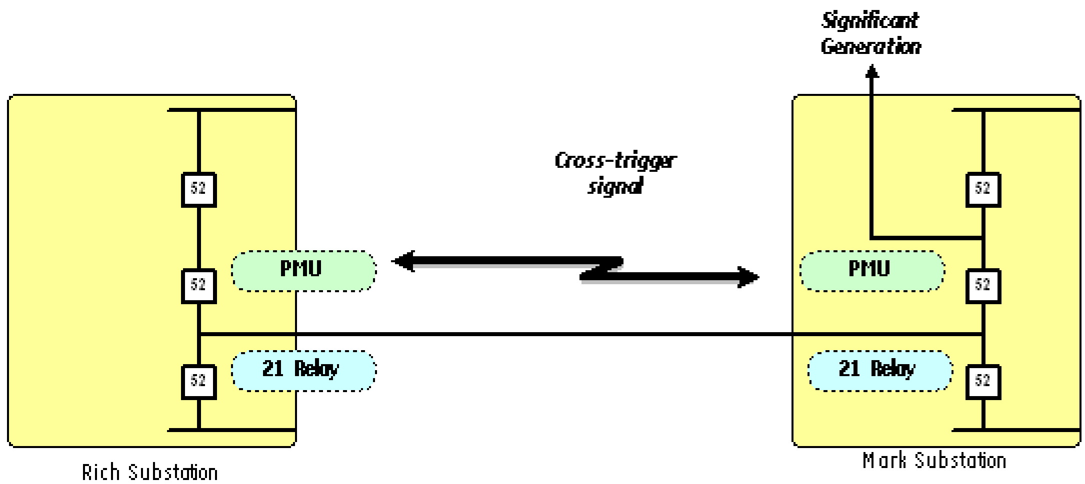

Figure 8: Transmission line example

Consider the simple transmission system of Figure 8. There is significant generation located one bus away from Mark Substation. When this generation trips off, a small power swing occurs. This power swing may encroach into the relay operating zone for the relay at Rich Substation.

The data that is most interesting is the apparent impedance as seen by the distance relays at both ends of the line. This requires the recording of the current and voltage by both PMUs. In terms of the total power system, this disturbance may not be significant, and may not trigger criteria. However, the local PMUs can be configured to recognize the power swing conditions, and capture a recording. The cross-trigger signal can be an IEC61850 GOOSE message that is only received by these two PMUs. A big advantage of PMU data, is the synchrophasors data is always synchronized.

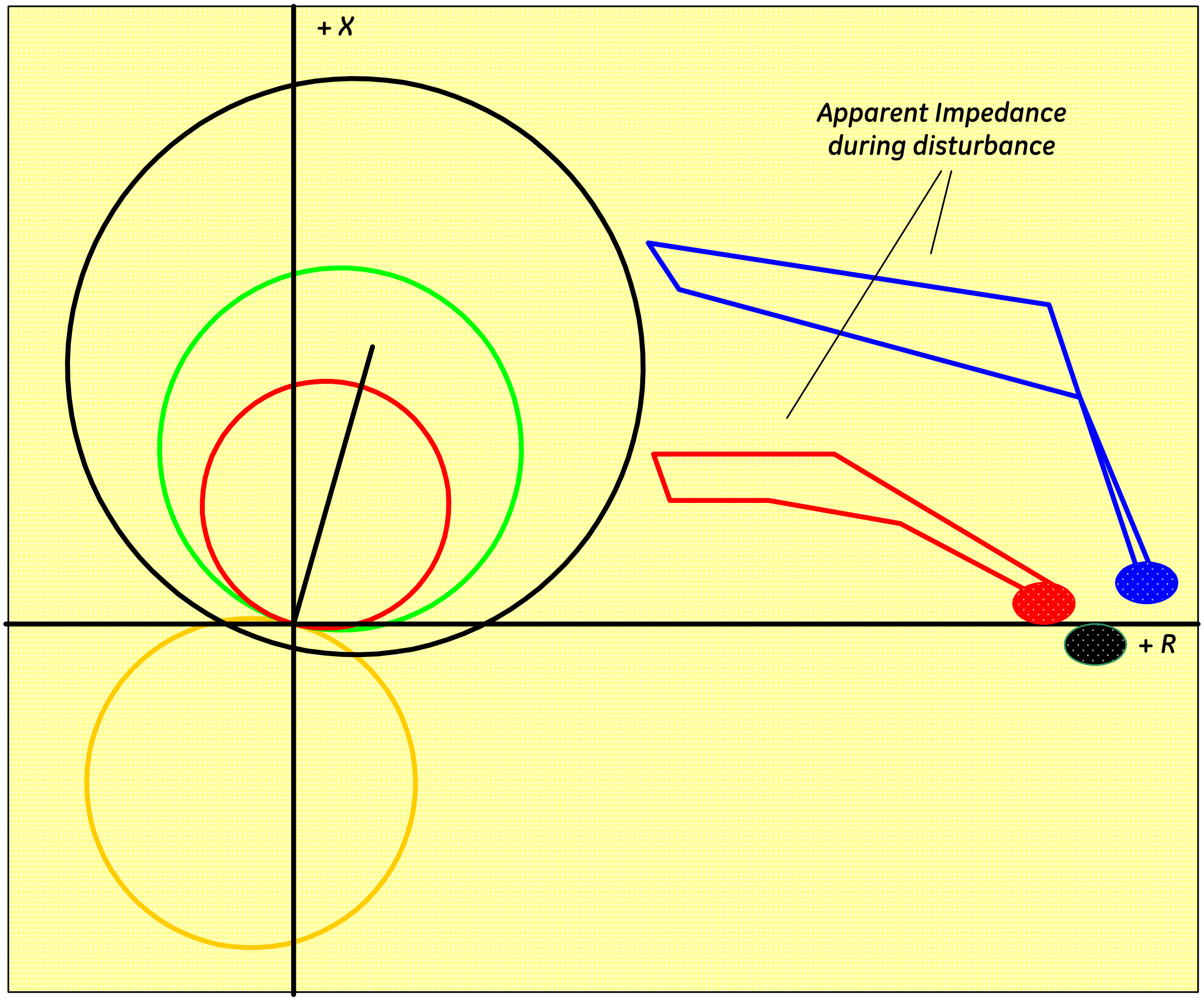

Figure 9: Apparent impedance during disturbance

Figure 9 shows some results for a small-scale disturbance. The apparent impedance seen by the relay came close to the largest tripping zone of the distance relay. This small margin justifies a contingency study to determine if the reach settings for this zone are secure against local small-scale system disturbances.

5. Conclusions

The value of disturbance recording to analyze the response of the power system to power system faults is well established. For this reason, the NERC guidelines for recording require utilities to capture RMS or phasor values of voltage, current, frequency, and power to analyze power system faults. Phasor measurements with recording capabilities are ideal devices to provide disturbance recording. The explicitly time-synchronized synchrophasors data meets the accuracy requirements and time requirements of the NERC guidelines.

The real strength of using PMUs for disturbance recording is the ability to easily support wide area recording using existing communications networks. Capturing data at various points on the system provides better analysis of system performance during power system faults. The challenges of synchronizing data are eliminated, as each piece of data is explicitly time synchronized. Cross-triggering signals are sent via non-proprietary communications, such as defined in the IEEE Synchrophasor standard and IEC 61850 standards.

6. References

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