

USE OF SYNCHROPHASOR MEASUREMENTS IN PROTECTIVE RELAYING APPLICATIONS

Power System Relaying Committee Report of Working Group C-14 of the System Protection Subcommittee

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Use of Synchrophasor Measurements in Protective Relay Applications

1.0 Introduction

The availability of low cost, high precision timing sources, such as Global Positioning System (GPS) and IEEE 1588 compliant network clock sources, and the networking capability of protective relaying devices and systems are fundamentally changing the way that many current and future protective relaying applications are or will be implemented. Synchrophasor measurements, i.e., phasor measurements with high accuracy time stamping, have been used in a number of protective relaying applications, and are also being considered for many future protective relaying applications. Although synchrophasor measurements are used in many other power system applications, such as wide-area monitoring and situational awareness applications, this report focuses primarily on its use in practical protective relaying applications that either have been implemented or are considered for future implementations. The report provides protective relaying engineers and the industry with practical information in synchrophasor measurement applications in the protective relaying area.

The report includes general background information about the synchrophasor measurement technology, and several major aspects in the application of the technology, such as the communications needs, the performance and interoperability requirements, timing source related considerations and other related topics. The protective relaying applications that utilized the technology are described in two groups, those that have been implemented and those that, at the time of writing, are considered to be implemented in the future.

2.0 Background

2.1 Definition of Synchrophasor Measurements

During steady state in an electric power system, the voltage and current signals are virtually sinusoidal waveforms. A phasor is a vector consisting of magnitude and angle that corresponds to a sinusoidal waveform at a given frequency. The phasor of a signal can be derived using Fourier transforms utilizing the data samples of the signal within a selected time window. For a steady state signal, the magnitude is a constant, while the value of the angle depends on the starting point of samples. The angle is a relative quantity and a reference has to be selected.

Measuring devices are placed at different locations in a power grid to capture voltage and current waveforms, from which phasors can be calculated. If the samples obtained by the measuring devices are not synchronized to a common timing reference, the angles of the phasors computed at different locations will not be comparable. This hinders the understanding and analysis of certain power system phenomena and the development of certain advanced applications. To remove this barrier, phasors measured across the power grid should have a common timing reference such that direct comparison is feasible.

The IEEE standard, C37.118 defines the term and the requirements for synchronized measurement of phasors, or Synchrophasor. A synchrophasor is defined as “A phasor calculated from data samples using a standard time signal as the reference for the measurement. Synchronized phasors from remote sites have a defined common phase relationship.” As a result, synchrophasors measured across an interconnected power grid will have a common timing reference and thus can be compared directly.

According to the standard, a synchronizing source that provides the common timing reference may be local or global. The synchronizing signal may be distributed by broadcast or direct connection, and shall be referenced to Coordinated Universal Time (UTC). One commonly utilized synchronizing signal is the satellite signal broadcast from the Global Positioning System (GPS).

2.2 History of Synchrophasor Measurements

In 1994, the IEEE PSRC working group H-7 prepared an IEEE paper that discussed synchronized sampling of phasors for relaying and control applications. In 1995, a standard on synchrophasors was introduced, IEEE 1344 [1], which was reaffirmed in 2001. In 2005, IEEE 1344 was replaced by the IEEE synchrophasor standard C37.118-2005 [2]. This standard was split into two standards which were both published in December 2011. C37.118.1-2011[3] carries the measurement requirements from the C37.118-2005 and extends them with frequency and rate of change of frequency requirements and adds performance under dynamic conditions for all measurements. C37.118.2-2011 [4] carries the data communication requirements from C37.118-2005 without significant change, adding a new configuration message and few minor changes for ongoing compatibility.

2.3 Why Utilities Would Use Synchrophasor Measurements

Time-stamped synchronized measurements offer a tremendous benefit for protective relay applications. These real time measurements represent actual system conditions at any given time and can be utilized in relay protection.

Relays are set based on pre-determined static system conditions that typically are either maximum or minimum. However, the configuration of the system constantly changes and may not necessarily be at its maximum or minimum but somewhere in between, as the system conditions vary due to changing loads, network switching operations, or faults. Therefore, the relay settings based on the extreme system conditions may not necessarily result in a correct relay operation for a given system condition in a dynamic state.

The best example of inadequacy of the relay settings based on the static system conditions is the power swing detection function. Its method of operation requires a comparison of the phase angles of the two systems that are synchronized to each other. The angle difference threshold setting in the power swing detection relay is set based on calculated impedances of the two systems for certain system conditions. Should the system conditions be different from those the relay is set for, the angle difference threshold setting may not be optimal, and the relay may either fail to operate when necessary or misoperate for a non power swing condition.

On the other hand, if the real time synchrophasor measurements are utilized, the angle difference between the two systems is determined based on these measurements and any system condition is accounted for, producing accurate relaying response.

The relays that are set to make a trip decision based on synchrophasor measurements constitute a class of adaptive or predictive protective devices. At this time, they appear to have a very promising future, and system protection engineers are very interested in applying real time synchrophasor measurement technology to perform system protection and control functions to achieve protection systems' adaptability to account for all possible system operating conditions.

Real time synchrophasor measurements are already being applied for system monitoring and eventually may enhance or even replace the state estimator in system operations. Tasks associated with visualizing, storing, and retrieving the phasor measurement data are being worked on by the industry, and the application of the synchrophasor measurement technology in the area of system protection is now also a reality.

The following is an example where alarms for encroachment of relay trip characteristics would have prevented further outages and aided in restoration:

The investigation of a significant outage event involving the greater New Orleans area in July of 1981 is summarized here.

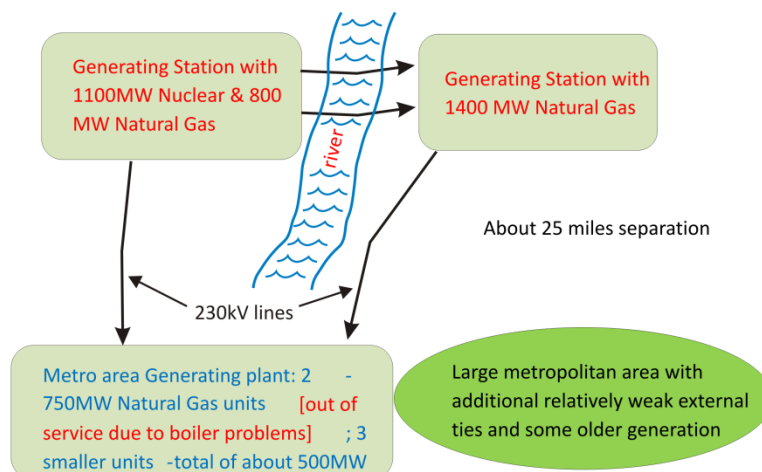


Figure 2.1: Scenerio conditions

On a Friday morning, one of the larger generators in the metropolitan New Orleans area, a 750 MW “once-through” natural gas unit, experienced a boiler tube leak that required taking the unit out of service. The loss of this unit during the peak loading time of year was seen as a potentially serious condition due to the limited transmission capability between the two

generating plants located about 30 miles upriver and the significant summer loads of the New Orleans area. The two generating plants had a nuclear plant of about 1100 MW capacity, two natural gas fired units at the same plant total 800 MW capacity, and a 3 unit natural gas fired plant located on the opposite sides of the river separated by only about 4 miles. The second plant totaled about 600 MW of capacity.

During mid-morning on Saturday, one of the 230kV transmission lines from the upriver plants to the metropolitan area experienced an outage. Operators attempted to restore the line, but closing would be followed shortly by the line retripping. The conclusion was reached that the line was sagging into some of the fast growing willow trees that lined the Mississippi river. Crews were dispatched to try to find and correct the problems.

Within an hour, a second 230kV line between the remote plants and the city experienced a trip. This trip led to cascading operations of the other sources into the metropolitan area. These outages were accompanied by operation of all levels of under frequency relays, resulting in a load reduction of approximately 300 MW. Within a few seconds of the load shedding, the 2nd 230kV line reclosed incorrectly by Hot Bus / Dead Line logic. The low load area voltage appeared as a dead line. This line reclosing resulted very quickly in other source lines reclosing by synchronism check and holding.

The resulting investigation revealed that all internal generation to the islanded load area tripped with one exception, which stayed in service “incorrectly”. Restoration of all loads required about 10 hours.

Hindsight speculation, based on the technology provided by synchrophasor devices, might conclude that the knowledge of the phase angle between the two remote generating plants and the metropolitan area could have been used to implement controlled islanding, which may have resulted in reduced outages and expedited re-energization.

2.4 CT Considerations

Most phasor measuring unit (PMU) applications, like state estimation and load flow monitor, are developed using voltage and current near nominal values. With such applications in mind the IEEE standard C37.118.1-2011 defines the PMU accuracy only in a band between 10-200% of nominal current and 80-120% of nominal voltage values. For accuracy benefits the PMUs should be connected to metering CTs for these applications. If PMUs are used for protection applications, the selection of CTs needs to follow the same guidelines that are used for protection CTs (see for example C37.110, IEC60044-6).

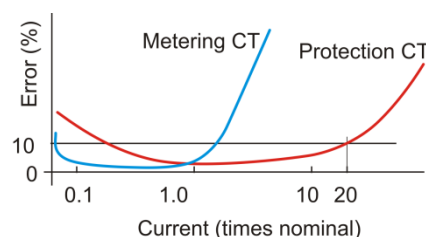


Figure 2.2: Relative errors for metering and protection CTs

As shown in figure 2.2, the accuracy will be quite different between metering CTs and protection CTs for the different working areas. If the PMU is supposed to perform protection function with high fault currents, the PMU should be always connected to a protection CT even though metering applications will have to endure higher measurement errors for small currents. Metering CTs would saturate heavily even with symmetrical fault currents and no DC offset.

The user needs to be aware that for PMUs there is no present standard that specifies accuracy limits for waveforms which include transients caused by fault values.

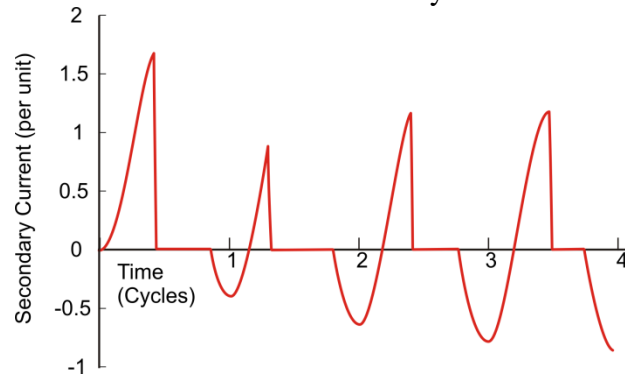


Figure 2.2: Saturated fault current with DC offset

The response from different PMU devices could be quite different and could include amplitude and phase errors which can result in unsecure and unreliable operation. Therefore the development of fast protection functions ($< 100\text{ms}$) with PMU data is not practical at this time. In this document, the discussion centers on the use of PMU data for back up protection functions with operating times $> 100\text{ms}$ where it can be assumed that most of the transients (DC offset, CCVT transient for example) have disappeared and that currents and voltages are sinusoidal. Another consideration is that the measured fault currents and voltages may be outside the range for which accuracy is specified by the IEEE C37.118 standards. Theoretically the phase and amplitude error can be significantly different and would not allow a secure and reliable coordination from different PMU models. However, most of the PMUs will use similar digital filter technology to filter out the nominal frequency and it can be assumed that the accuracy will be similar even for values outside of the specified band and therefore it is viable to use PMU data for back up protection functions.

It is necessary to verify the accuracy of the PMU data in the range of the fault values before the PMU data are used for back up protection. For phase overcurrent applications only the amplitude error is needed. For ground overcurrent or negative sequence overcurrent applications where the ground or the negative sequence current is calculated by using the three individual phase currents, the phase angle accuracy is important as well. The protection functions that process two phasors for a trip decision, like directional overcurrent, distance protection, differential protection, need to consider both the amplitude and phase angle error.

2.5 Impact of Reporting Rates and Latency

Protection systems, utilizing synchrophasor data streams (differentiated from synchrophasor information), must be designed to meet certain performance criteria. The ability to meet the

overall protection requirements may be impacted by a variety of well understood synchrophasor phenomenon. The following paragraphs attempt to give guidance in regards to some of the issues that need to be considered:

- **Reporting Rate of the PMUs:** The reporting rate of the PMUs determines the best case timing for detecting a change that may require protection action.

As an example, consider a reporting rate of 30 reports per second. This reporting rate means that changes of data will be sent every 33 ms, perhaps not detecting or conveying transient data.

- **Measurement Delay time:** IEEE Std. C37.118.1:2011 sets the limit for delay time as the result of testing the response to steps in magnitude and phase. Measurement delay time is defined as the time interval between the instant that a step change is applied to the input of a PMU and measurement time that the stepped parameter achieves a value that is halfway between the initial and final steady-state values. In effect, measurement delay time represents the amount of time elapsed between an event occurring on the system and the PMU time stamp assigned to that event.

Response time: IEEE Std. C37.118.1:2011 sets the limit for response time, defined as the time to transition between two steady-state measurements before and after a step change is applied to the input and is the result of testing the response to steps in system magnitude and phase. The response time is the period of time the PMU measurement is outside specified error limits during a step change and informs the system designer of the response of internal filtering associated with PMU measurement.

- **Measurement Latency:** Whereas the reporting rate sets the best case communications time, each individual PMU may have internal latencies in measurements and communications capability that may be greater than the reporting time period. Not all PMUs have the same latencies (e.g. from measurement to transmission). Protection system design should account for such internal latency in order to determine if the selected equipment can actually achieve the desired protection scheme performance. IEEE Std. C37.118.1:2011 sets the limit for measurement latency which is the maximum period (specified as integer number of reporting periods). The test report for PMUs considered for relaying applications should be reviewed by the system designers to determine the measurement reporting latency.
- **Impact of intermediate systems:** The performance characteristics of intervening communications and data concentrators need to be well understood. These systems would potentially include Ethernet Switches, Routers, and Phasor Data Concentrators(PDCs).

In regards to PDCs, a systematic analysis of the selected implementation should be performed to determine its impact on communications latency and reporting rate.

3.0 Communications Infrastructure

3.1 Requirements

Data communications requirements can generally be categorized as bandwidth, latency, reliability, and availability as well as details such as connectivity and protocols. Synchrophasor data can be carried in any system and over any medium, but for consistency this section will address communications using the C37.118 protocol in systems that are commonly used.

C37.118 is designed for transmission over any standard communications system. Data is transmitted in frames that consist of several measurements that correspond to a specific time. Frames are sent at 1 to 60 per second. The data can be transported over asynchronous serial (such as RS232), synchronous serial (such as RS422), or network communications using raw packet transmission or a stacked protocol such as IP. Bandwidth requirements vary depending on the data rate and the amount of data being transmitted. The following Table 3.1 summarizes the data transmission speed requirements using this protocol. The rates in the table are based on 10 bits/byte of information which is required for RS232. UDP/IP or TCP/IP bandwidth requirements need to include overheads for TCP/IP (22 bytes/packet) and UDP/IP (28 bytes/packet). For smaller C37.118 frames, these overheads could be greater than 50%.

Table 3.1

Approximate bandwidth needed for data transmission of synchrophasor data using the C37.118 protocol. A phasor is a complex number consisting of two real numbers that represent a real-imaginary or magnitude-angle value. It thus has two number values for each phasor. An “analog” is a scalar quantity (such as power, temperature, frequency, etc.) that consists of a single number value. In both cases a number value can be represented in 16-bit integer form (2 bytes) or 32-bit IEEE floating point form (4 bytes). A digital quantity is a 16-bit value in which each bit represents a boolean value (0 or 1). It is always 16-bits (2 bytes).

Data rate Frames/s	5 Phasors 1 Analog, (integer)	10 Phasors, 4 Analog, 2 digital, (integer)	10 Phasors, 4 Analog, 2 digital, (floating point)
12	4800 bps	8400 bps	14160 bps
30	12000 bps	21000 bps	35400 bps
50	20000 bps	35000 bps	59000 bps
60	24000 bps	42000 bps	70800 bps

Data is sent continuously rather than polled as it is impractical to do a query/response type system at this rate. Since data is sent continuously, there is little opportunity to recover lost data. The communications system must be reliable and available continuously to support this type of system. A dial-up or batch processing communications system does not work with this type of application.

Data loss due to errors, dropouts, or unavailability should be 0.1% or less per minute, depending on the application. Experience has shown this is very achievable with standard communication systems that are available to power systems. Visualization applications with 1-2 dropouts/minute are not seriously affected. Analysis using recorded data can easily bridge over 1-2 points at a time if they are reasonably spread out. Control applications should be designed to tolerate an occasional single bad data point without degradation. However all these applications can be seriously affected if data loss occurs as a block, even if the long term data loss is very small. Consequently, the data loss should be specified as % over a given unit of time. This given unit can be applied at any point in time to be sure there is no excessive error accumulation. For example, at a data rate of 30 phasors per second that is typical in North America, 0.1 %/min is 1.8 frames per minute that are lost. Dropout tolerance depends on the particular application, so it should be determined on a case by case basis.

Acceptable latency is highly dependent on the application. Data used for archiving applications can be delayed without degrading system performance. Applications used for displays and operator awareness can usually tolerate 1-2 seconds of delay through the transmission system without degradation. Applications used in automatic controls such as RAS or SIPS usually require much less delay, usually less than one second. Latency requirements depend on the particular application, so they have to be determined on a case by case basis. Latency of the communication channel may need to be considered, depending upon the application. Latency is the time it takes from the first bit to be transmitted until the last bit is received. Latency includes the physical delay of the communication channel and equipment being used for the signaling, where the channel latency could be insignificant depending upon the media being used. Table 3.2 shows some example communication latencies.

Table 3.2
Example Communication Channel Latencies

Description	Delay
Analog modem using simple, direct modulation at 2400 BPS	8 – 12 ms
Analog modem using complex coding (V.32bis, V.34)	60 – 100 ms
Digital with async SONET	38 – 45 ms
Direct digital, sampled into sync system	18 – 24 ms
Network, 10baseTX, direct with no routers, minimal distance	4 – 8 ms
Network, 10baseTX, over WAN narrowband, 2 routers, 200 mi	17 – 19 ms

Latency and bandwidth can also be impacted by the connection management aspects of TCP and UDP. With TCP, the connection is managed with handshaking and packet retransmission, requiring additional bandwidth for that management but the connection state is known. With UDP, there is less overhead and bandwidth, but packets can be simply dropped. With IP networks, use of TCP and UDP should be carefully considered in conjunction with the application performance requirements and how the application corrects for any missing frames.

3.2 Reliability

Any synchrophasor system relying on information obtained from different hardware devices requires a reliable communications infrastructure. Although, depending on the application, the security and dependability requirements may vary; protection related schemes will typically have a higher demand on communications reliability than state estimation or visualization systems, for example. Reliability includes the reliability of the channel and the reliability of the communications equipment.

It is normally considered that direct trip channels should have the highest reliability and be less susceptible to noise burst [5]. Table 3.3 illustrates the security levels considered in pilot schemes for protective relaying channels.

Table 3.3
Susceptibility to noise bursts per [5]

Pilot Scheme Type	Security (Bursts / Undetected Error)
Blocking	10^4
Permissive Tripping	10^7
Direct Tripping	10^8

For protective relaying schemes using synchrophasors, it may be inferred that similar reliability in the communications channel is required.

One other aspect of communications reliability that protective relaying systems using synchrophasors should consider is the recovery of the data stream when the information is lost. The architecture of the communications system can be used to provide duplicate or alternate data paths when the primary path is lost. Protective relaying logic should be provided to account for a total loss of the data stream and the recovery time to receive the stream through an alternate path.

The criticality of the protective relaying scheme will demand standard or advanced forms of recovery. There are two aspects of recovery on an IP network, the recovery of the network due to a network failure and the recovery of a dropped packet provided by TCP retransmissions. For example, in an Ethernet network designed using a ring architecture, when a data path is disturbed, the network can recover using the spanning tree protocol (STP) in a few seconds or using the Rapid Spanning Tree Protocol (RSTP) in tens of milliseconds. SONET networks can recover the data stream in around 5 milliseconds. TCP retransmissions are done using an adaptive retransmission mechanism, which results in a retransmitted packet that will likely fall outside the application performance requirements due to the varying time taken to detect the dropped packet, resulting in a dropped synchrophasor frame. A differential scheme using synchrophasor data, making decision in 100 msec cannot use STP for reliability.

Protective relaying schemes using synchrophasor measurements for protective relaying applications should consider reliable communications means. The data stream should be transmitted securely and the recovery of the data stream should be reliable and accounted for in the schemes logic.

The reliability of the communications equipment being used should also be considered. Equipment that meets IEEE 1613 and IEC 61850-3 is designed to survive the substation environment.

3.3 Satellite Clock Issues

3.3.1 Hijacking of the Satellite Time Signal

The Global Positioning System (GPS) time signal is a critical part of Synchronized Phasor Measurement systems. Loss of the time signal is readily detected by both the GPS satellite receiver and the Phasor Measurement Unit (PMU) and the correct action on loss of time signal is easily achieved. There is also a potential for the time signal to be hijacked and the incorrect time be provided to a PMU without detection.

A device that transmits ordinary satellite signals only needs to be located nearby to a satellite receiver, not necessarily inside the attacked facility. The satellite receiver would eventually lock on to the false signal as it would appear as the clearest and strongest source. The same device could replicate multiple satellite signals thus bypassing any security measure that would require signals from multiple sources. After the satellite has locked onto the false signal, the device could modify the transmission by altering the signal little by little until it represented any time the originator wished. A PMU with the incorrect time reference could cause an undesired operation of a protection system or could cause an operator to take incorrect action.

A control or protection scheme using synchronized phasor measurements should have elements designed into the scheme that limit the exposure to hijacking of the satellite signal. The detection, prevention or mitigation of GPS hijacking is beyond the scope of this report.

3.3.2 Loss of Time Signal / Time Quality of GPS Signal

When the PMU is successfully decoding information from the GPS satellites and the local time marker is consistent with that decoded from the satellite, the time signal is considered to be “locked.” The methods and parameters, e.g. number of satellite signals being received, used in determining a locked time signal and how often the evaluation is made will vary from vendor to vendor. If the time signal is locked then the signal’s quality is considered to be good.

When the time signal is unlocked then the PMUs local clock (oscillator) begins tracking time and there is a time drift error that is determined by the oscillator’s accuracy. There are $24 \times 60 \times 60 = 86400$ seconds in a day. One percent clock accuracy results in an error of 864 seconds for the day. That is 14 minutes a day! Oscillators are therefore specified by their accuracy (drift) in PPM (parts per million – $\text{PPM}/10^6$). A 100 PPM clock, for example, drifts 100 us/sec, which would be 8.64 seconds/day – a 0.01% error. A 1 PPM clock drifts 1 us/sec, which would be error 86.4 ms/day – a 0.0001% error. Typical crystals are rated 1 to 100 PPM, however high accuracy crystals can be provided down to 0.0001 PPM or better.

The time quality indicator code as determined by the PMU clock function is discussed in both IEEE Standards C37.118-2005, and C37.118.2-2011 in section 6.2.2. Basically the quality code

defines if the satellite signal is locked (good) and if unlocked, the quality code defines the current worst case drift error as “time within T seconds,” where T ranges from 10^{-9} to 10 seconds in logarithm steps. If the error T exceeds 10 seconds then the quality code defines the time as unreliable. The C37.118.2 standard includes an additional 3-bit time quality indicator as part of the status message that is valid at all times whether the source indicates it is locked to a primary source or not. This provides additional quality indication for the actual time reference.

The phasor, time value and quality code are sent to the PDC (phasor data concentrator) where the phasors measured from around the system are synchronized using their respective time stamps and then served to applications. The accuracy requirements of the application determine the usability of the synchrophasor values based on the time quality code.

4.0 Present Applications

4.1 Power Swing Detection

4.1.1 Introduction to Power Swing

A power system in steady state has all of the synchronous generators rotating at constant speed and the rotor angle differences between the generators remain nearly constant. In response to the variation of load, the generator rotor angles will change correspondingly to achieve the balance between generation and loads. On the other hand, in the transient state, major disturbances such as sudden drop of large load or generation will cause oscillation of the speed of the generators. As a result, the rotor angles will vary or oscillate considerably during that period. Such dynamics of the rotor angles during the power system transients is called power swing. The locus of the angle variation can be either oscillatory or non-oscillatory. For oscillatory angle variation, it could be further classified as stable or unstable power swing.

Following the disturbance, if the rotor angle between any two generators eventually settles to a new value that is smaller than 90 degrees, the system is stable, or otherwise the system is unstable. Instability can occur between two single generators or between groups of generators.

Power angle stability associated with a sudden disturbance is usually called transient stability. Protection literature addressing power swing detection or out-of-step protection has been mainly focusing on this type of stability problem. In contrast, another type of angle stability problem is called small-signal angle stability problem, which is related to gradual changes of system conditions. A detailed definition and classification of the angle stability problems are presented in an IEEE paper prepared by an IEEE/CIGRE working group [6].

There are various methods for analyzing power swing problems. For a simplified system such as a single generator connected to an infinite bus, the equal area criterion is an established technique for analyzing the power system angle stability [7]. For more complex systems, extensive computer simulations and system studies based on network and generator models are usually necessary to understand the angle stability of the system.

To detect a power swing, traditional relay algorithms utilize the measured impedance trajectories based on voltage and current quantities at one end of a transmission line. Another possible method is to employ two distance units of concentric characteristic with different reach settings to detect a power swing. To correctly set the relays, computer simulations are usually entailed based on certain assumed system conditions. The challenges of the method are that if the actual system conditions don't match the simulated case studies, the relays may not operate properly as anticipated [8].

Since the synchrophasor technology can directly measure the phase angles, research work has been done to improve power swing detection and protection by using synchrophasors. The following sections present the details.

4.1.2 Power Swing Detection Utilizing Synchrophasors

Reference [9] presents two possible methods for detecting a power swing by utilizing synchrophasors. For the first method, it is assumed that the system in study can be represented by a two-machine system. The phasors of the terminal voltages of the two machines can be measured synchronously, and then the angle difference between the internal voltages of the two machines can be calculated. During any disturbance, the machine angle difference can be computed, and the equal area criterion is applied to determine whether the system will reach a new stable operating point or not.

For the second method, the phasors of selected buses are measured synchronously, and the angle difference between any two phasors can then be calculated. During a disturbance, the angle difference will vary and may settle to a new stable value or diverge leading to angle instability. By making use of real time measurements of the difference of phase angles, it may be possible to predict the trend of the angle difference over the next period of time. Based on the prediction, one can tell whether the system will be stable or not. If the prediction can be made early enough, appropriate protection and control algorithms may be developed to enable the operation of the power system to follow a more desirable course of action.

In Figure 4.1, an example of synchrophasor measurement is presented showing pre-fault and post-fault angle difference between two buses. The system oscillations damp out after load shedding.

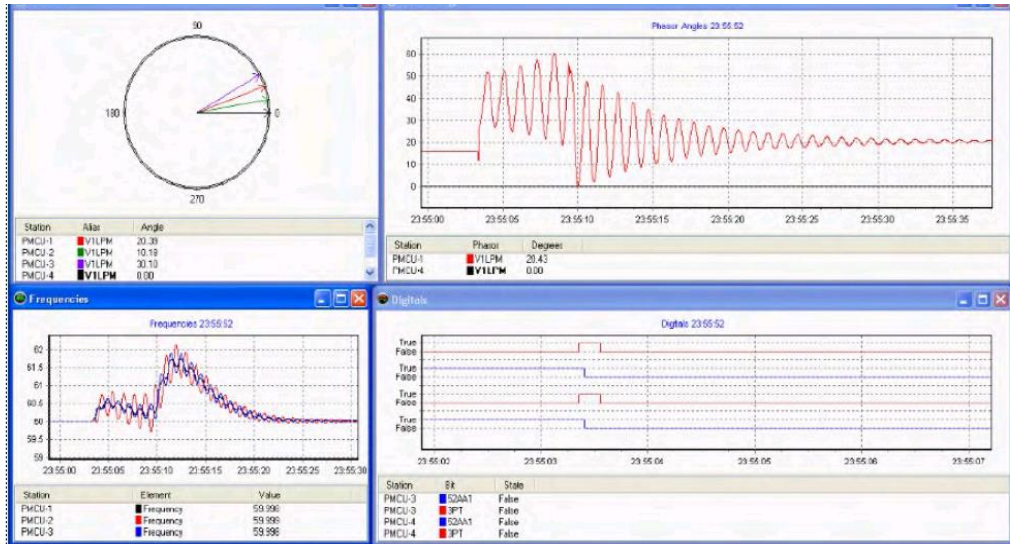


Figure 4.1: Synchrophasor measurement example

4.2 Load Shedding

The current applications of wide-area measurement (not necessarily synchrophasors) for load shedding exist as System Integrity Protection Schemes (SIPS) used synonymously with Remedial Action Schemes (RAS) and Special Protection Schemes (SPS). According to the NERC Glossary of Terms Used in Reliability Standards, such schemes are “designed to detect abnormal system conditions and take pre-planned, corrective action (other than the isolation of faulted elements) to provide acceptable system performance” [10]. This definition specifically excludes the performance of protective systems to detect faults or remove faulted elements. It is system oriented both in its inception and in its corrective action. Such action includes, among others, changes in demand (e.g. load shedding), changes in generation or system configuration to maintain system stability or integrity, and specific actions to maintain or restore acceptable voltage levels.

Such schemes involve measurements over a large part of the system, typically of relay operations, voltage magnitudes, and power flows. These inputs are used to identify crucial outage of a transmission and/or generation system. Such outages are pre-identified based on contingency analysis. The scheme then takes pre-determined actions like generation rejection, load shedding, switching on/off reactive support and other actions listed in [11]. This document summarizes the result of a survey of 111 SPS schemes. Around 11% of these schemes employ load shedding as a mitigating measure.

Bonneville Power Administration (BPA), in collaboration with Washington State University, are in the process of implementing a Wide Area Stability and Voltage Control System (WACS) that employ sensors that react to the *response* of the power system to arbitrary disturbances [12]. Voltage magnitudes from several 500-kV stations and the reactive power output from several generators are measured at strategic locations and the inbuilt algorithms provide commands for remedial actions that are similar to those of SPS (including load shedding), but not pre-determined.

4.3 Line Reclosing Selectivity Utilizing Synchrophasors

The significant growth of urban areas in Spain has caused a noticeable increase of partial power line burying, expanding the number of mixed lines in the REE (a local utility) portfolio. These mixed lines have a considerably shorter underground section as compared with the overhead section (cable is less than 15-20% of the overhead section); therefore, reclosing is used to recover from transient overhead faults. Cable faults, on the other hand, should not be reclosed, first, as a measure of public safety since many faults are caused by crews operating machinery in the vicinity of the cable. Also, cable faults are mainly permanent faults, with reclosing worsening the existing damages.

To detect the faulted section, overhead or underground, the original solution used in every mixed line was to install two line differential relays at both ends of the cable. The differential relay operation sends, via communications, a block signal to the reclosers located at both ends of the mixed line. Such solution has the inconvenience of requiring current transformers, DC power, etc., at both ends of the cable with the consequent increase in cost of both the installation and the maintenance. Another solution, currently used, is the installation of distance relays at both ends of the mixed line with a specific zone to detect faults in the overhead section. Reclosing is subject to the operation of any of these two distance zones. This second solution is much more economical since it does not require protective relays at the ends of the cable. The disadvantage of the second approach is that the distance zones, used to detect overhead faults, cannot cover 100% of the overhead section due to the possible overreaching effect by the following factors: the mixed nature of the fault loop when the fault is located in the cable or in the next overhead section (the zero sequence compensation for overhead lines is very different from the values for cables); the lack of consideration of the line capacitance; the inaccuracies of the zero sequence impedance value of the overhead section; the non-homogenous nature of the system and the load flow in the line for resistive faults; possible errors in the selection of fault type; etc. The usual distance zone reach is set to 85-90% of the positive sequence impedance of the overhead section. Therefore, many of the faults in the overhead section not covered will be undetected by the distance zones and tripped without reclosing. Even faults located in the covered zone can be undetected in case of underreach effects present with very resistive faults.

The operation of the distance zones covering the overhead section can be complemented with a fault locator, which has a longer operating time to perform calculations, but is able to pinpoint the faulted section. This information can be sent to the control center, and in cases where the fault is located in the overhead section outside the distance protection zones, a manual close can be done in a relatively short time. Nevertheless, REE intends to locate the faulted section based solely on the fault locator, which should perform its calculations before the reclosing sequence is completed, being able to abort the cycle in case of faults in the cable. In this final solution, all instantaneous trips would initiate the reclosing sequence.

Fault locators based on measurements at one end of the line do not provide good results since the algorithms require the use of the zero sequence impedance of the cable, which varies depending on the current return path on ground faults. Fault location based on metering by two PMUs

located at both ends of the line can rely only on the positive sequence network, eliminating the problem described. Since the positive sequence network is used in every fault, there is no need to determine the fault type. As an added bonus, the algorithm is not affected by the fault resistance, load flow and the non-homogenous nature of the system.

4.4 Power System Analysis

Synchrophasors provide a new way to analyze both small and large disturbances in a power system [13]. Examples of these wide-area disturbances include the 2003 Midwest blackout and the 2008 Florida blackout. Regarding the Florida blackout, North American Electric Reliability Corporation CEO Rick Sergel, said that “while we can’t predict the timetable of analysis, information collected by new monitoring technologies, called ‘synchrophasors,’ will enable our teams to analyze yesterday’s outages more quickly than in the past. This new technology is like the MRI of bulk power systems, giving operators and analysts more granulated data and helping them to dissect and piece together the events that occurred step by step, microsecond by microsecond [14].”

4.4.1 Wide-Area Frequency Monitoring

In New Zealand, engineers were concerned with how their power system would react to a major loss of generation. Huntly is a thermal generation site with an approximate capacity of 400 MW. Whakamaru is a substation near a small hydro generation station. A 220 kV double-circuit line connects the two stations (see Figure 4.2). In order to confirm proper system operation, engineers installed a synchrophasor system with archiving capability at the Huntly and Whakamaru Substations.

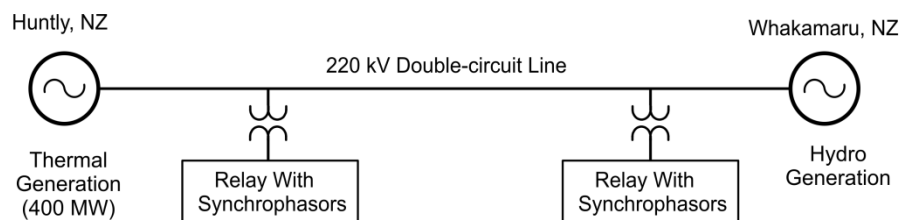


Figure 4.2: New Zealand wide-area monitoring system

By using synchrophasors to monitor the main network near the Huntly generation site and further away at Whakamaru, engineers gained a better understanding of how the system would respond if a generator the size of Huntly was removed.

Figure 4.3 shows the drop in frequency as a result of removing 200 MW of generation from the system. Shortly afterwards, the governors of the generators still connected to the power system began to compensate and bring the frequency back to nominal.

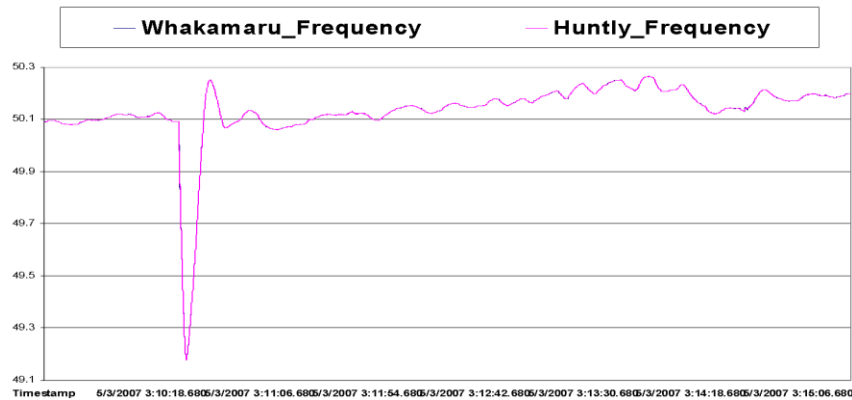


Figure 4.3: Synchrophasor graph showing frequency disturbance

What may not be immediately obvious is that both the Huntly and Whakamaru frequency plots are identical. Synchrophasors allowed the engineers to accurately plot the frequency disturbance using an Excel spreadsheet without any special data manipulation. Synchrophasor relays provided distributed monitoring points throughout the system that allowed the engineers to measure and correlate data not available with traditional measuring devices. Because synchrophasor data are already time aligned to a common reference point, they did not need to perform post data processing. This is a tremendous time saver, especially if this had been a real event requiring immediate analysis.

4.5 Synchrophasor-Assisted Black Start

Starting generation units without using power from the bulk grid is called a black start. Salt River Project (SRP) used synchrophasors not only to provide system visualization over traditional SCADA during black-start testing, but also as a synchroscope to connect the SRP and WECC systems [15].

Figure 4.4 shows SRP's black-start system. For the purposes of the black-start testing, SRP islanded from WECC at the 230 kV V2 bus via breaker 678.

SRP had two black-start goals: synchronize the thermal and hydro units and synchronize the SRP and WECC systems. SRP's synchrophasor system includes the following:

- Relays with synchrophasors installed at the SRP/WECC tie point (230 kV V2)
- High-precision GPS clocks that provide accurate time to the relays.
- Relays that communicate synchrophasor data at 10 messages per second.
- An OC-1 SONET multiplexer that connects the substations to the power dispatch office.
- Synchrophasor visualization software that displays magnitudes, angles, frequency and rate-of-change of frequency.

During synchronization of the thermal and hydro units, SRP used synchrophasors to monitor frequency and slip differences between the systems to verify when to connect them. With both

the hydro and thermal units online, the synchrophasor visualization software monitored the phase-angle difference. They used the synchrophasor data to verify that the systems were connected and within phase-angle-difference tolerances. With both systems connected, they observed improved frequency stability. Figure 4.5 shows actual synchrophasor frequency plots of the SRP hydro and thermal units (in red) compared to the WECC frequency (in green and used only as a reference for this test). Before connecting the hydro and thermal units, SRP observed about 150 mHz of frequency deviation. After connecting the hydro and thermal units, they observed only about 50 mHz of deviation.

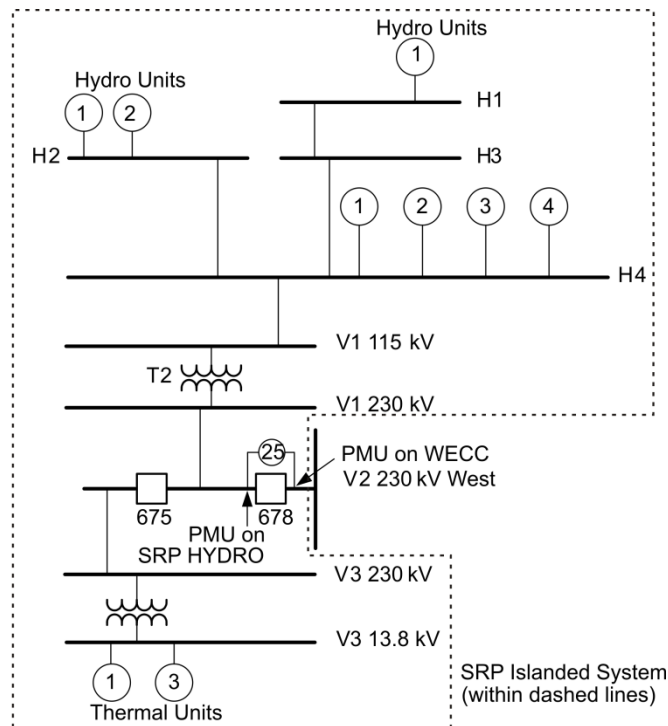


Figure 4.4: Black-start island test system [15]

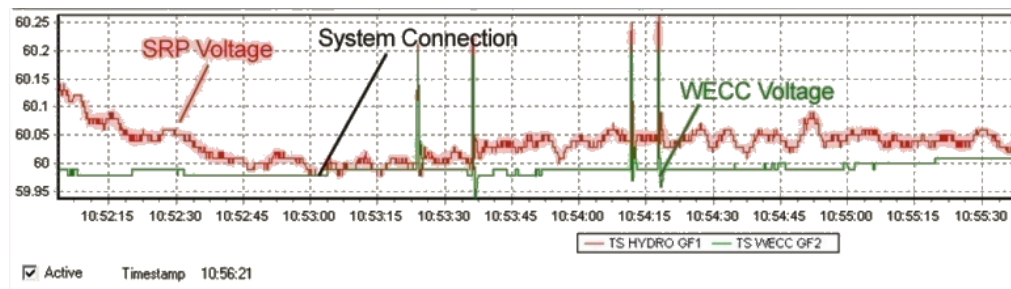


Figure 4.5: SRP and WECC Pre- and post-system connection frequency deviation

The next test was to connect their system with the WECC system. During this test, the automatic synchronizer was not operational. The operator used synchrophasor visualization software to view the angle separation and slip between the two systems and manually close the tie breaker. Figure 4.6 shows the synchrophasor synchroscope and the system connection at 11:28:37.



Figure 4.6: SRP and WECC System connection

SRP's synchrophasor relays provide two distinct advantages over their previous system.

- **Multiple measurement sources**
Relays with synchrophasors installed throughout the power system provide multiple measurement sources that can be used as synchroscopes throughout the power system.
- **Higher update rates**
Synchrophasors are available at higher update rates (up to 60 times per second) than traditional SCADA scans. In SRP's case, the SCADA scan was about five seconds. The faster update rate tolerates more slip.

By installing a Phasor Data Concentrator (PDC), they can completely automate the synchronization process. Further, relays with synchrophasor capabilities throughout the power system, coupled to the PDC, can allow synchronization at any point in the system without additional, stand-alone synchronization devices.

4.6 Distributed Generation Anti-Islanding

Fostered by the push for energy independence and accelerated Smart Grid technology development, Distributed Generation (DG) is gaining popularity across the world. Integrating DG resources into existing utility networks poses multiple challenges, requiring deployment of robust anti islanding schemes which detect islanding conditions and trip the DG. Figure 4.7 shows a typical network with DG (Local Generation).

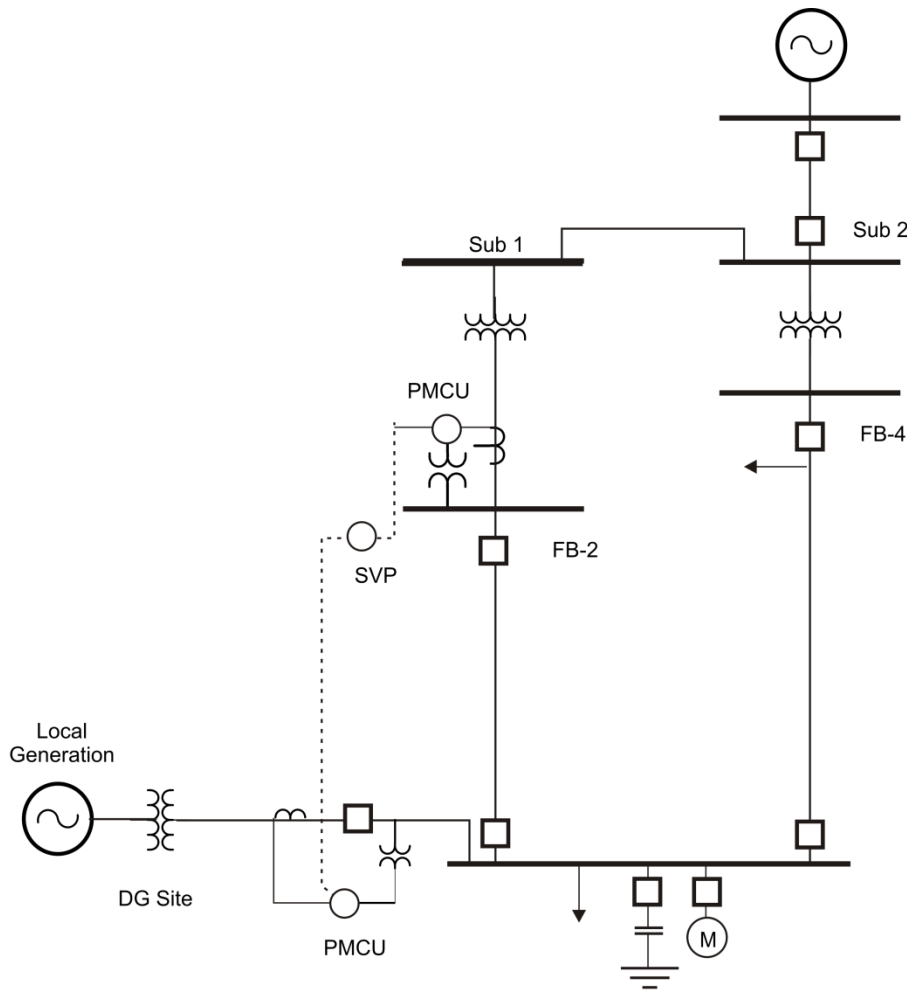


Figure 4.7: DG network example.

Failure to trip islanded generators poses multiple challenges, including potential personnel safety hazard, out of phase reclosing and degradation of the power quality within the island [16].

In addition to the IEEE 1547 compliant protection schemes typically installed by the DG owner, utilities require an installation of an interconnection protection system, dedicated to:

- Protection of customer equipment from DG that operates outside nominal voltage and frequency limits
- Protect utility equipment from adverse effects caused by the DG responding to faults within the utility system.

Utilities also often require an anti-islanding protection system, and may also be interested in small signal oscillations/system stability effects caused by combining large number of DG resources.

Anti-islanding schemes can be implemented locally (at the DG site), or globally, using communications technology. Local schemes can be divided into two categories: passive and

active detection schemes. Passive schemes are based on locally measured voltage, frequency, and rate of change of frequency. Passive schemes rely on the load unbalance within the island, and have difficulty detecting islanding conditions in cases when the island load closely matches local generation. Active schemes use inverter driven low frequency current injection performed in such a way to measure the utility system source impedance. Active systems have difficulties with paralleling large number of distributed resources.

Communications based islanding detection schemes can be implemented by simply exchanging breaker status information. Such schemes work well for simple topologies in which single (or a small number of breakers) controls the interconnection. In a real life situation with more complex dynamically varying network topology, it may become impractical to reliably collect all of the required breaker positions. A simpler method may be to use synchrophasor communications to constantly monitor the DG angle in relations to the bulk power system. Figure 4.8 shows this approach using two phasor measurement devices (PMCU) in combination with a Phasor Data Concentrator (PDC).

Synchrophasor based system is capable of reliably detecting all islanding conditions and can perform small signal stability monitoring, detecting and alarming in case of DG induced power system oscillations. Figure 4.8 shows operating time comparison between the standard generator protection package, dedicated local measurement based islanding detection scheme, and the synchrophasor based wide area islanding detection scheme.

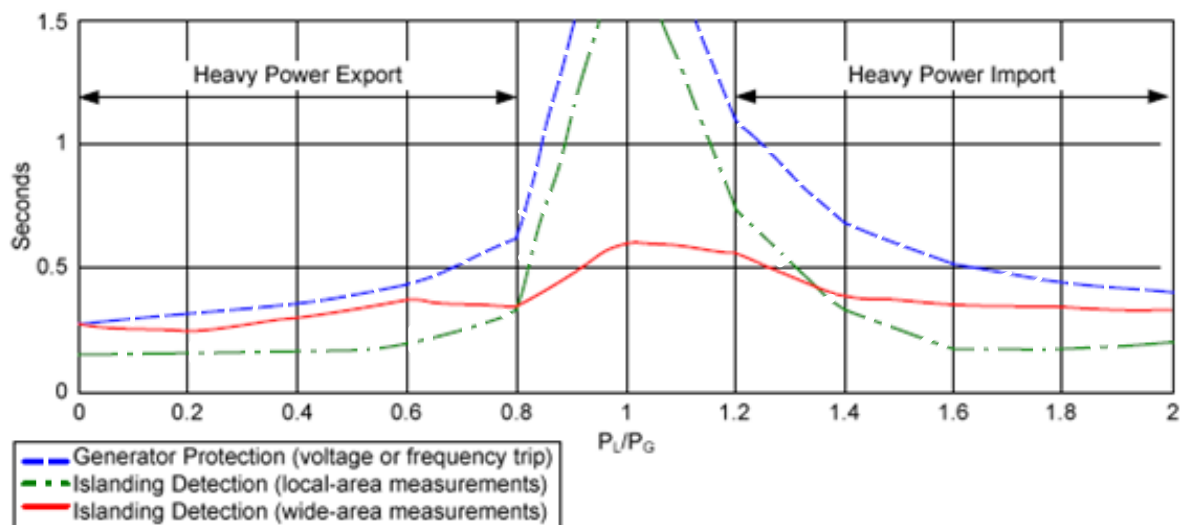


Figure 4.8: Operating times of generator protection, local islanding detection, and synchrophasor based wide area islanding protection schemes

It is easy to see superior performance of the wide area scheme whose sensitivity can be further adjusted to match the exact application requirements. Wide area scheme detection logic is shown in Figure 4.9.

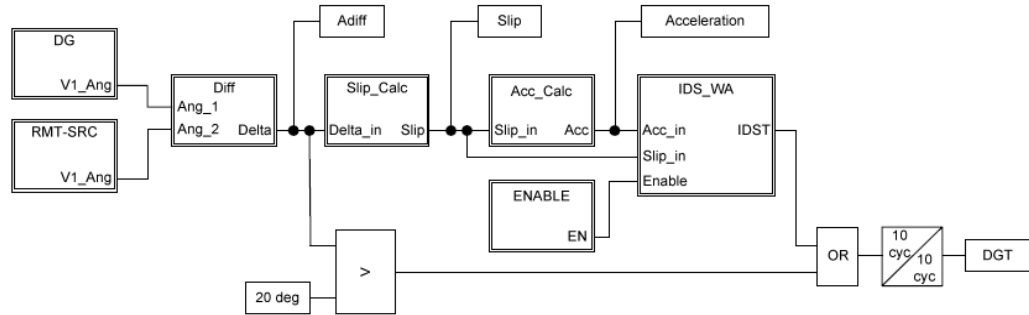


Figure 4.9: Synchrophasor based wide-area islanding detection scheme logic

Figure 4.10 shows islanding detection system behavior when the DG generation closely matches the local island load. DG angle separation threshold was set to 20 degrees. It is easy to see that the synchrophasor system (marked IDS WA TRIP) trips first, followed by various local measurement based schemes.

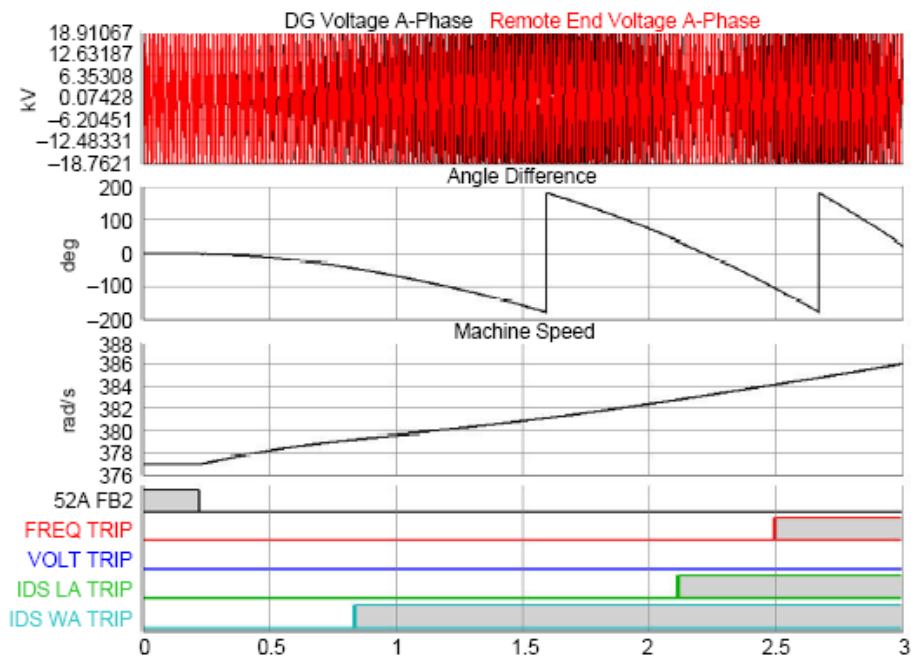


Figure 4.10: Synchrophasor based wide area islanding protection scheme operating example with well balanced DG/ local load conditions (minimal power exchange before separation)

4.7 Automatic Generator Shedding

Comisión Federal de Electricidad (CFE) in Mexico implemented an automatic generation-shedding scheme (AGSS) based on relays exchanging real-time synchrophasor information [17]. CFE has specific regional generation and transmission challenges because of large loads at the center of the country and large hydroelectric generation in the Southeast.

During normal conditions, Angostura can generate up to 900 MW, while the total load of Tapachula and the Southern region does not exceed 100 MW (see Figure 4.11). The excess power in the region flows from Angostura to Chicoasén and from there to the rest of the system. If the 400 kV transmission link between Chicoasén and Angostura is lost, all areas remain connected through the 115 kV network. During this condition, the Angostura generators may experience angular instability, and the 115 kV network will overload. CFE must shed Angostura generation in order to maintain system stability if the link between Chicoasén and Angostura is lost.

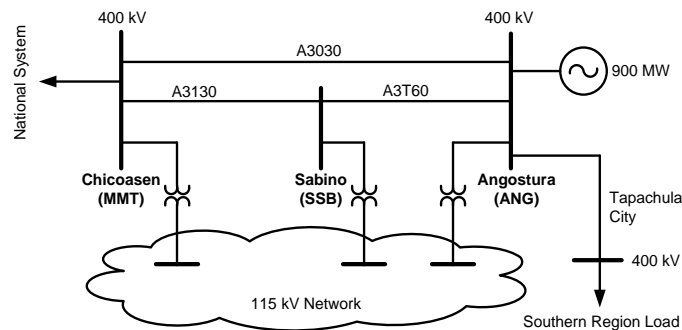


Figure 4.11: Chicoasén-Angostura 400 kV transmission link with parallel 115 kV network

CFE implemented a new method to detect a loss of transmission capacity using relays with synchrophasor measurement and control capabilities. In this new AGSS, relays exchange synchrophasor data and calculate the angle difference between Angostura and Chicoasén in real time. If an angle difference between Angostura and Chicoasén is greater than a user-defined threshold, the scheme sheds generation according to the logic in Figure 4.12.

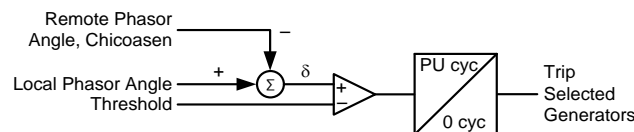


Figure 4.12: Angle-based AGSS logic at Angostura

CFE determined that a double-line outage produces an angle difference of 14 degrees, resulting in instability. A single-line fault causes an angle difference of less than 7 degrees and does not cause instability. Based on these results, CFE chose an angle difference of 10 degrees as the detection threshold for double-line outages.

CFE placed relays with synchrophasor measurement and control capabilities at Angostura and Chicoasén to measure the local 400 kV bus voltage. The relay at Angostura receives remote bus voltage from the relay at Chicoasén. The relay at Angostura time-aligns the synchronized local and remote phasor data, calculates the angle difference, compares it to the angle-difference setting, and issues a generator trip if the calculated angle difference exceeds the phase-angle-difference threshold.

The communications link connecting the substations is a fiber-optic multiplexer. Relays communicate with the multiplexer via EIA-232 (V.24) asynchronous interface at a data rate of

19,200 baud (see Figure 4.13). Fast Message protocol exchanges synchrophasor data between the relays at a rate of 20 messages per second.

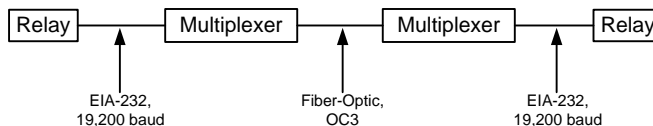


Figure 4.13: Synchrophasor control communications link

4.8 Communication Channel Analysis

In December of 2007, New Brunswick Power and Bangor Hydro began loading the new 345 kV international tie line from Point Lepreau nuclear plant in New Brunswick, Canada and Orrington Substation in Maine (see Figure 4.14).

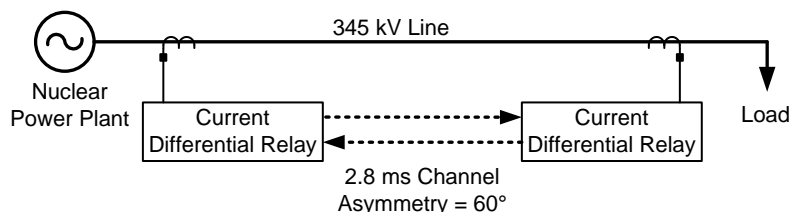


Figure 4.14: Line current differential communications diagram

The transmission line protection included a line current differential relay with synchrophasor capabilities. When they energized and lightly loaded the line, the charging current was higher than expected, which caused the differential element to approach its tripping angle thresholds. However, the engineers believed that by adding load to the point where the current magnitude reached the current differential operational magnitude, the differential angle would retract into the restraint region. While monitoring the differential metering during a light-load test, they noted that as they increased load, the line current differential Alpha Plane values moved toward the trip threshold instead of away from it. The differential communications path on the New Brunswick side was via asynchronous transfer mode (ATM) over Internet protocol (IP). They expected it to have only a degree of asymmetry, resulting in a small rotation of the Alpha Plane angle toward the trip condition. However, they observed an Alpha Plane angle of nearly 60 degrees.

After compensating for the load and charging currents, the remaining angular difference was much higher than the utility communications group had predicted. By checking all measurements and calculations, they identified two possibilities for the increase of the differential element into the operate region. Either the communications asymmetry was much higher than specified, or the system was incorrectly phased end-to-end and one set of CTs was connected in reverse polarity, which would result in a 60-degree error.

To isolate the problem, they used synchrophasors to verify each relay's metering quantities. With known measurement values, the engineers could determine whether there was a communications asymmetry issue or a more serious and costly phasing error.

They collected synchrophasor information from both terminal ends. Data analysis showed the relays were measuring approximately the same current values. This eliminated the phasing error. Further analysis showed the communications asymmetry was much higher than predicted and the line differential relay was connected and measuring power system quantities correctly.

4.9 Verifying Voltage and Current Phasing

Usually, relays and meters use the A-phase voltage as the reference for the other phases. If a meter command is issued to the relay and only the voltages are considered, it would look similar to this:

$$\begin{aligned}V_A &= 67 \text{ kV} \leq 0^\circ \\V_B &= 67 \text{ kV} \leq -120^\circ \\V_C &= 67 \text{ kV} \leq 120^\circ\end{aligned}$$

If instead, the voltage phases are rolled during initial construction or modification, such that the V_A source is wired to the V_B terminals, V_B to V_C terminals, and V_C to V_A terminals, a meter command with this wiring configuration will receive the same results. Simply issuing a meter command to all the relays and verifying that all the V_A - V_B - V_C relationships are the same is not sufficient to ensure correct panel-to-panel wiring of all phases. The reason is that each relay normally uses whatever is on its A-phase voltage input as the reference.

Synchrophasors solve this issue. If the relays have synchrophasor technology and if the relays are connected to the same time source, then the time-stamped measurements of each and every relay in the panel lineup can be compared.

The voltage magnitude and phase are now referenced to absolute time. A cosine wave with its peak exactly on the second, to the microsecond, is the zero-degree reference. Once synchronized, the relays are all measuring against this common and very accurate time source. Another way of looking at it is the angle reference for all voltages and currents is a 60 Hz cosine wave that has its peaks on the second, to the microsecond.

Issuing meter commands to relays trigger measurements (snapshot) at a specified instant. The relays then report the phasor information. Engineers can record the data from each device or automate the process using a common spreadsheet program.

Figures 4.15 and 4.16 show the results of issuing the meter command to two relays, at time 13:22.

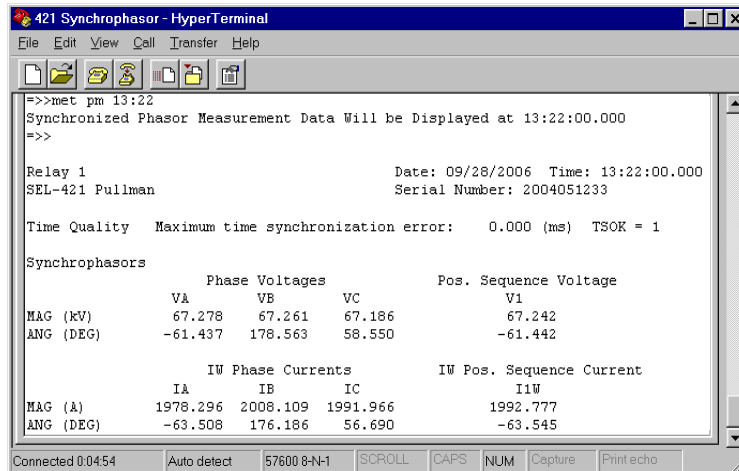


Figure 4.15: Relay 1 synchrophasor snapshot at 13:22

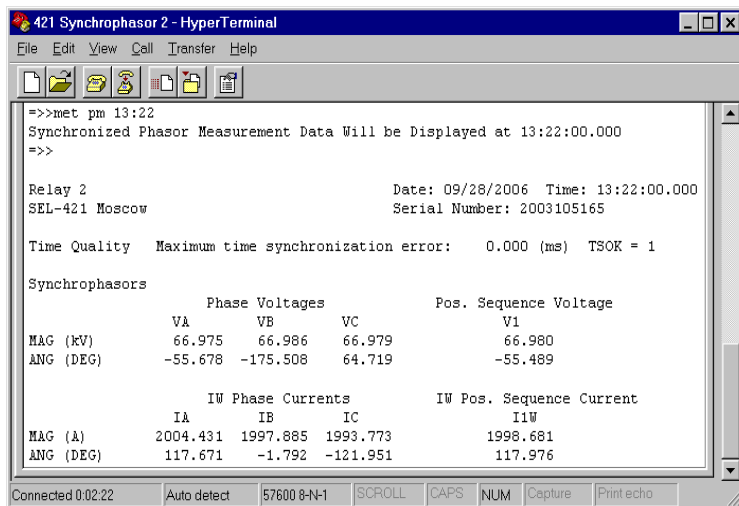


Figure 4.16: Relay 2 synchrophasor snapshot at 13:22

The meter command instructs each relay to measure the phasor data at that predetermined and precise instant of time. The angles for the A-phase voltages are not zero in this example. They would be zero only in the rare situation where V_A actually was at zero degrees with respect to the reference cosine with its peaks on the second. The relays also measure the voltage magnitudes at precisely that instant, the magnitudes and angles can be accurately compared without concern about the usual movements in the voltages being measured.

The process can be easily automated with a communications processor, as in the following example, where a communications processor communicates with eleven relays and a computer (see Figure 4.17).

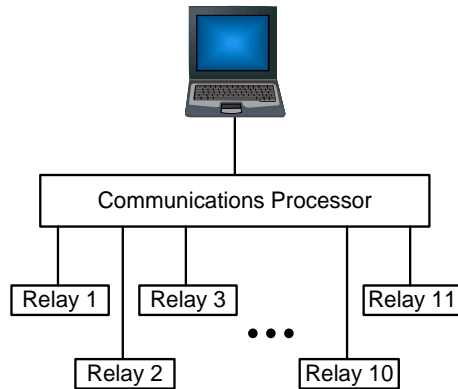


Figure 4.17: Automated synchrophasor polling system

The communications processor was programmed to automatically issue the meter command to all eleven relays at advancing and identical instants of time. The communications processor was also programmed to parse the responses from the relays and put the synchrophasor information into registers. An engineer then manually read the information out of the communications processor registers and entered the synchrophasor data into the spreadsheet in Figure 4.18.

	A	H	I	J	K	L	M	N	O	P	Q	R	S	T	U	V	W	X	Y
11	Shelbyville																		
12		IAW Mag	IAW Ang	IBW Mag	IBW Ang	ICW Mag	ICW Ang	IAX Mag	ICX Ang	IA MAG	IA ANG	IB MAG	IB ANG	IC MAG	IC ANG				
13	SEL-421	61.788	-39.839	58.382	-157.272	63.607	83.676	0	0	61.788	-39.839	58.382	-157.272	63.607	83.676				
14	SEL-451	40.901	-40.465	37.791	-158.3	41.039	82.984	20.813	87.275	61.66379	-38.8166	58.01969	-156.679	63.47528	84.50223				
15									Currents	OK	OK	OK	OK	OK	OK				
16	Greensburg																		
17		IAW Mag	IAW Ang	IBW Mag	IBW Ang	ICW Mag	ICW Ang	IAX Mag	ICX Ang	IA MAG	IA ANG	IB MAG	IB ANG	IC MAG	IC ANG				
18	SEL-421	58.774	144.271	55.18	26.959	62.211	-93.272	0	0	58.774	144.271	55.18	26.959	62.211	-93.272				
19	SEL-451	39.322	143.742	36.296	27.978	39.997	-91.569	19.387	-93.789	58.66608	145.2801	55.51979	27.52991	62.73512	-92.3738				
20									Currents	OK	OK	OK	OK	OK	OK				
21	Capacitor																		
22		IAW Mag	IAW Ang	IBW Mag	IBW Ang	ICW Mag	ICW Ang	IAX Mag	ICX Ang	IA MAG	IA ANG	IB MAG	IB ANG	IC MAG	IC ANG				
23	SEL-421	0.147	-134.396	0.495	16.99	0.255	-79.32	0	0	0.147	-134.396	0.495	16.99	0.255	-79.32				
24	SEL-451	19.602	-31.966	19.002	-151.793	22.199	86.825	19.878	-94.253	0.277814	141.4367	1.041412	29.86238	0.879426	-122.606				
25									Currents	OUT	OUT	OUT	OUT	OUT	OUT				
26	Transformer																		

Figure 4.18: Microsoft® Excel® Spreadsheet showing results of magnitude and phase angle measurement checks

This example shows a quick and efficient way of determining proper phasing within a substation breaker panel lineup. Using relays with synchrophasor capabilities removes the need for extra equipment to determine the results on a station-wide basis.

4.10 Distance to Fault

Synchrophasors can be used for fault location on multi-terminal transmission lines.

Since a stream of synchrophasor measurements contains current and voltage phasors with time synchronized values, they can be exchanged over the communications link between the two (or more) ends of the transmission line.

The measured and received synchrophasor measurements at each end of the line should be stored in a buffer and when an Intelligent Electronic Device (IED) detects a fault condition, the new

values of magnitude and angle should be recorded for a sufficient period of time as required by the fault location algorithm.

The benefit of using synchrophasor measurements is that multi-terminal fault location provides much higher accuracy compared to the conventional single ended fault location algorithm.

A utility example from the Taiwan power system on distance to fault PMU application is provided here.

In Taiwan, several stand-alone phasor measurements units (PMU) and numerous IEDs without PMU capability are installed at a number of 345kV and 161kV substations. During the steady-state, synchrophasor data, produced by stand-alone PMUs or IEDs, are transmitted to two control centers equipped with a SQL database via utility intranet at a data transfer rate of 30Hz for system stability monitoring. However, if a fault occurs on a transmission line, then the sampled and time-tagged waveform data with sampling frequency ranging from 960Hz to 1440Hz depending on the types of IEDs are transmitted to the control center with a data transfer rate of 50Mbps. Then, these sampled waveform data are converted to synchrophasor data using a Discrete Fourier Transform with window size of 16 or 24 points. If a PMU loses GPS synchronization and/or IEDs waveform data are not synchronized, then built-in software in the central station can automatically resynchronize the raw synchrophasor data to be more time-accurate synchrophasor data. Using synchrophasor data, a Windows-based user friendly transmission line fault location platform has been developed. The referenced papers [18], [19], [20] and [21] give the details as to how the fault location works.

The fault location platform has been in use since 2008. More than 40 field events including two/three-terminal compound lines (which combine overhead transmission lines and underground power cables) have been evaluated during the period from Jan. 2008 to Sep. 2011. The platform successfully located several fault events in Taiwan power system. For two-terminal compound transmission lines, the average fault location error percentage (which is measured by the absolute value of the difference between the exact fault point and the estimated fault point divided by the total length of the line) of the using two-ended synchrophasors is about 1.878% which is less than the average error of 10.927% by the built-in IED fault location function. Meanwhile, for three-terminal compound transmission lines, the average error using three-ended synchrophasors is about 1.356% less than the average error 38.431% by the IED built-in fault location function.

The use of synchrophasors and synchronized measurements substantially improved the location capability of system faults on the Taiwan Power Grid. Previous results from embedded IEDs of questionable value have been superseded by highly accurate results on compound lines in multi-terminal configurations.

5.0 Future Applications

This section describes some applications being considered for the future. Some of these applications may require higher communications rate of frames than is currently mandated.

5.1 Voltage Instability Predictor

Undervoltage relays provide a simple, cost-effective mitigation of voltage collapse. They “detect” a collapse by comparing the local voltage against a *fixed* threshold. If the voltage drops and stays below the threshold then the usual practice is to shed some load. Multiple thresholds are possible, and each threshold is linked to a separate amount of load.

It is convenient to map the operation of a conventional undervoltage relay to the impedance plane [22]. Consider a relay with a setpoint of 0.95 p.u. For illustration, assume that the Thevenin voltage at the present moment is 1.05 p.u. The relative position between such a circle and the Thevenin circle is shown in Figure 5.1. Clearly the two circles do not coincide. Recall that the Thevenin circle represents maximum power transfer. Thus, wherever the two circles do not overlap a misoperation of the conventional undervoltage relay can occur. An impedance trajectory such as #1 is yet to reach maximal power transfer, but is treated by the conventional relay as voltage instability. An impedance trajectory such as #2 has clearly reached maximal power transfer, yet it is not detected by the conventional relay.

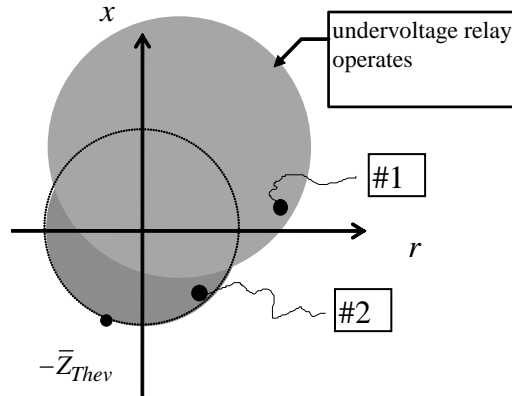


Figure 5.1: Misoperation of undervoltage relay: Premature (Case #1) and failure to operate (Case #2).

A Voltage Instability Predictor (VIP) relay is a little bit more advanced than a regular undervoltage relay as it can estimate the system proximity to voltage collapse using the local area measurements. The technology for synchronized, real-time measurements of voltage as well as all incident current phasors at the system buses, is available in the form of phasor measurements from PMUs.

Tracking the Thevenin equivalent is essential to detection of voltage collapse. Many methods exist to track the Thevenin parameters. For example, a Kalman filter could be used when the data is noisy. However, a traditional curve-fitting technique on a small number of consecutive samples may be sufficient and tracked by Equation 5.1-1:

$$\bar{E} = \bar{V} + \bar{Z}_{Thev} \bar{I} \quad (\text{eq. 5.1-1})$$

Measurements taken at two or more different times are required to solve for the unknowns. In the real environment, measurements are not precise and the Thevenin parameters drift due to the

system's changing conditions. To suppress oscillations, a larger data window needs to be used. The estimation therefore attempts to minimize the error in a least-squares method, paying attention to practical issues such as data memory, window size, measurement noise, nearby faults, etc.

The local voltage stability monitoring and control, at time instant t_k , is based on a time-dependent two-bus equivalent, consisting of the generator \bar{E}_k that supplies local load $P_{L,k} + jQ_{L,k}$ over the branch impedance $\bar{Z}_k = R_k + jX_k$, as shown in Figure 5.2.

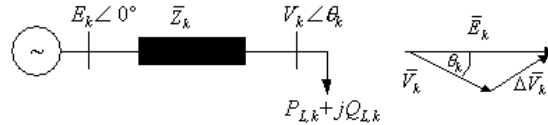


Figure 5.2: Two Bus Equivalent.

The parameters of the voltage source \bar{E}_k and line impedance \bar{Z}_k as seen from the local bus at time t_k , are estimated from the time sequence of voltage and current phasor measurements at the bus. The voltage stability condition, derived from the two-bus equivalent of the systems calculated in real-time, assuming constant power loads, suggests that in the critical condition, the two-bus equivalent generator voltage phasor E_k is twice as large as the projection of the load bus voltage onto it. Also, voltage drop ΔV_k across the branch impedance \bar{Z}_k is equal to the load bus voltage V_k :

$$E_k = 2V_k \cos \theta_k \quad \text{and} \quad \Delta V_k = V_k. \quad (\text{eq. 5.1-2})$$

A VIP relay assesses the risk of voltage collapse in a presence of constant power loads by monitoring, the Voltage Stability Load Bus Index ($VSLBI$):

$$VSLBI_k = \frac{V_k}{\Delta V_k}. \quad (\text{eq. 5.1-3})$$

A $VSLBI_k$ value close to one is indicative of the proximity to voltage collapse and reaches unity when the power transfer through Z_k becomes unstable for a voltage collapse. Comparison of $VSLBI_k$ provides information on relative vulnerability of various buses, which can be used for remedial actions. The smallest value among all indices at a time instant t_k , gives the voltage stability index (VSI_k) of the whole system:

$$VSI_k = \min_{i \in \alpha_{PQ}} \{VSLBI_{i,k}\} \quad (\text{eq. 5.1-4})$$

Where:

i denotes the load bus index

α_{PQ} represents a set of the system load buses with VIP's.

Limitations in reactive power generation cause sudden changes in the $VSLBI$'s and VSI and therefore prevents the operator from acting within an acceptable time. During heavy loading conditions, reactive power produced by the generator increases with load to maintain its terminal voltage. When the generator reaches its limit, voltage control is lost, and the generator switches

from PV to PQ mode of operation. At the transition points, VSI changes abruptly. The outcomes of the PV-PQ transitions are hard to predict because the transitions introduce discontinuities in the model. This problem is more emphasized as voltage dependent loads represent a greater portion of the total load. For these reasons, a decision on the triggering of protective/emergency controls cannot be made by considering a *VLBSI* value only. The decision also needs to consider generator reactive reserves.

A VIP with communications capability can estimate the onset of the voltage collapse point based on both the *VLSBI* indicator calculated from the local phasors measurements and the system-wide information on reactive power reserves. The control actions are deployed only when the stability margin is small and the reactive power reserves are nearly exhausted.

Detecting the reactive power reserves in real-time is similar to corresponding impedance based VIP derived quantities, but is a more intuitive way of detecting voltage stability margins [23]. It is applicable for several real-life condition implementation variants such as bus, transmission line, transmission corridor, and load center. The voltage stability boundary (based on simple, VIP derived quantities) is assumed as a parabolic equation in the P-Q plane identified using measurements at a specific substation, transmission path, or load center. The computed stability boundary could be visualized in a P-Q plane, together with a point representing the current operating conditions, and generally re-computed as soon as the new set of measurements is collected (preferably at high rates using PMUs) as shown in Figure 5.3.

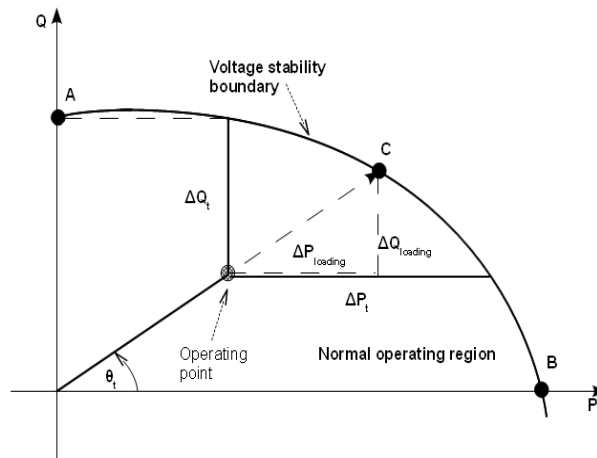


Fig. 5.3: Voltage stability power margins in P-Q plane

The results of voltage instability detection using the VIP method on a real-life BPA system are shown in Figure 5.4. The load center configuration in the BPA system is shown in (a). The results are shown in terms of voltage magnitude at the bus in load center (b), time evolution of Q-margin compared with the results of the BPA Q-V analysis tool (c) and simple visualization in P-Q plane (d). Q-margin results, as compared to model-based Q-V analysis, are very accurate when the system is closer to voltage stability boundary (c). Results given in Figure 5.4 correspond to the scenario with linear load increase in the load center and a line tripping in generation dominant area. These disturbances trigger several shunt capacitors switching in both

generation area and load center. Computed Q-margin illustrates that all switching are accounted for as well as the important system events such as line tripping. The same holds true for other VIP derived quantities (equivalent load and system impedances and their ratio). A shrink in voltage stability boundary has been observed after the line tripping, as illustrated in Figure 5.4.d.

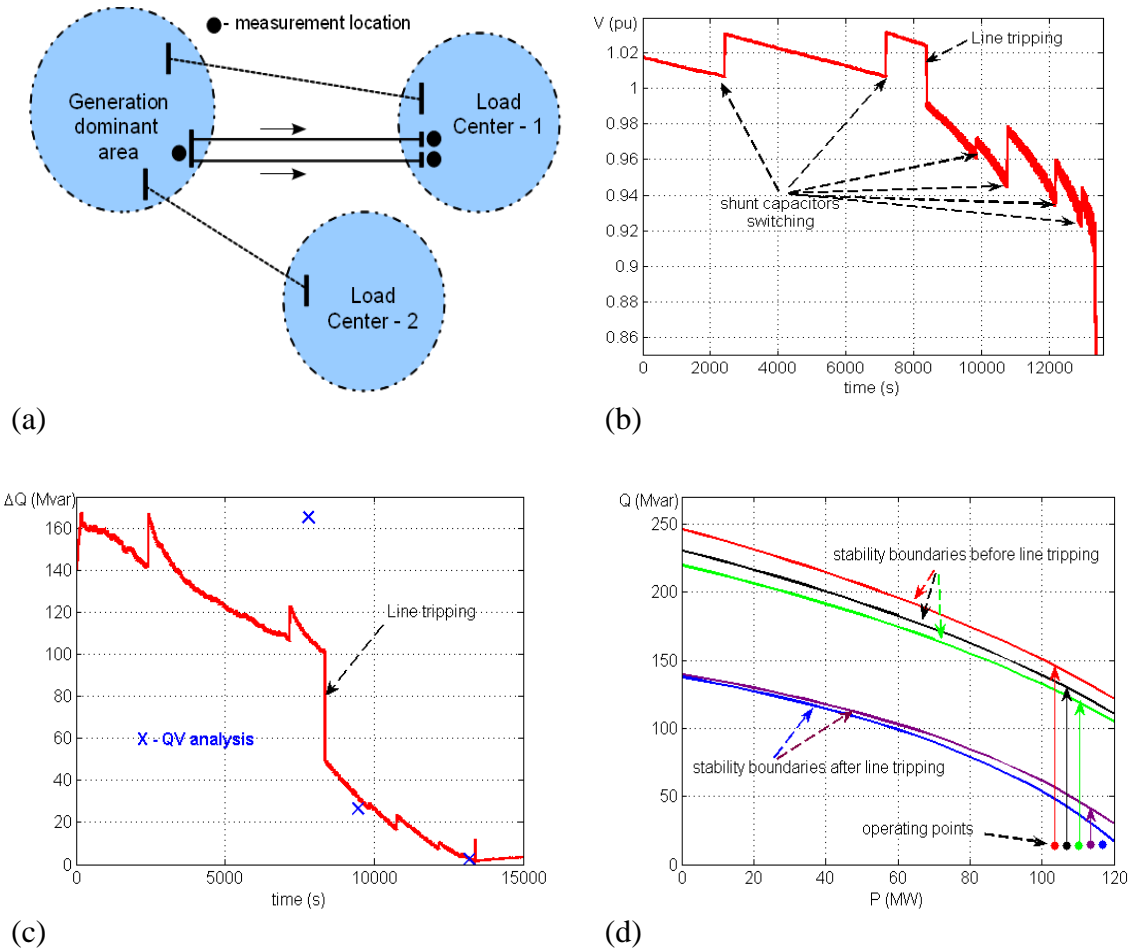


Figure 5.4: The results of a VIP method on the BPA system load center

Simplicity in using local voltage and current measurements allows the VIP model-free method to be used either for local automated actions, an addition to SIPS, or a tool to increase situational awareness as a significant improvement to undervoltage relay measurements.

5.2 Loss of Field

Loss of Field (LOF) is typically characterized by high real power (MW) flow out of the generator with a large reactive power (Q) flow into the generator. Failure of conventional LOF protection to disconnect a large machine can result in prolonged voltage depression or collapse. One option for LOF backup protection is to use a PMU that measures real and reactive power flow into the machine, giving better ability to detect a potential failure or slow operation of the primary generator LOF relay.

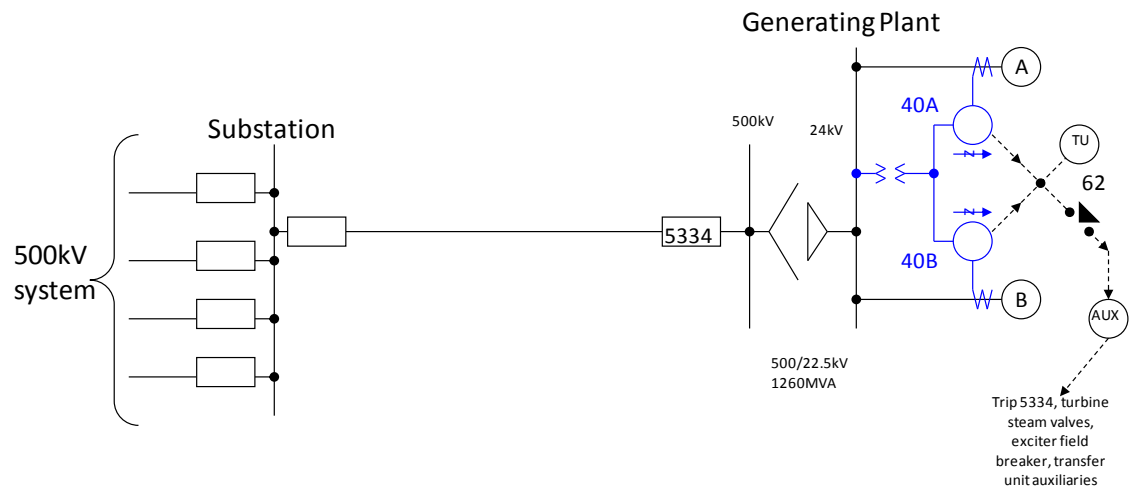


Figure 5.5: Generating Plant LOF

For the generating unit shown in Figure 5.5, assume the monitoring of real and reactive power flows on the line to the generating plant using a PMU located at the substation bus. Inverse time-characteristic relaying is chosen that looks at the reverse Q flow into the generator, above a preset threshold and MW flow out of the generator.

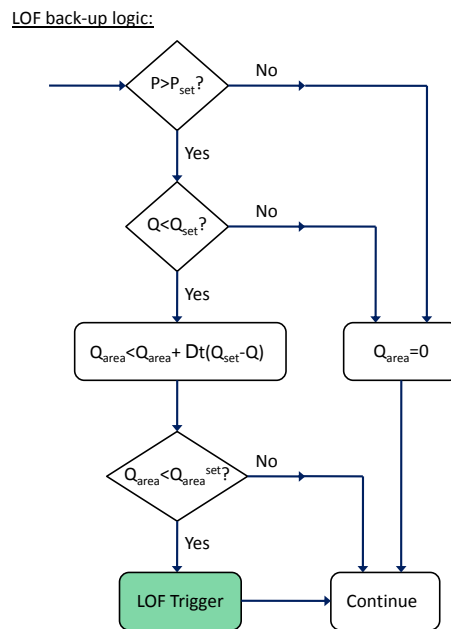


Figure 5.6: LOF Backup Logic

To calculate the settings, first define P (MW) and Q (MVAR). Both P and Q on the line are assumed to be available at the substation bus. The relay logic looks for high values of P

together with persistently large negative values of Q in real-time using synchrophasors. Reset logic should be included to prevent false tripping under system swings. Accordingly, tripping can be made slower under partial LOF conditions by encoding an inverse time characteristic on the trigger logic. The LOF back-up logic is shown in Figure 5.6.

5.3 Bus Differential Relaying

Differential protection schemes are commonly used due to fast operation and simplicity of design. The possibility of implementing such schemes using Synchrophasor technology [24] now exists, however, may be significantly slower than the conventional solutions if using level 1 filtering requirements prescribed in C37.118-2005. The newer standard, C37.118.1, has updated these requirements with the P class and M class operations where P class is specified for the highest speed of operation. This standard also specifies operation behavior under dynamic conditions and defines higher output rates which will help assure interoperability among PMUs used for high speed systems. The following section describes a backup bus differential protection scheme based on the 2005 synchrophasor standard which was in force when this was developed. The scheme allows for as many as 64 terminals [25], and consists of one Phasor Data Concentrator (PDC) aided by relays with Synchrophasor measurement and control capabilities. Relays measure currents of all bus terminals and control local breakers, as illustrated in Figure 5.7. The scheme uses the real-time topology processor available within the PDC to dynamically adapt the differential element to different bus configurations and operating conditions.

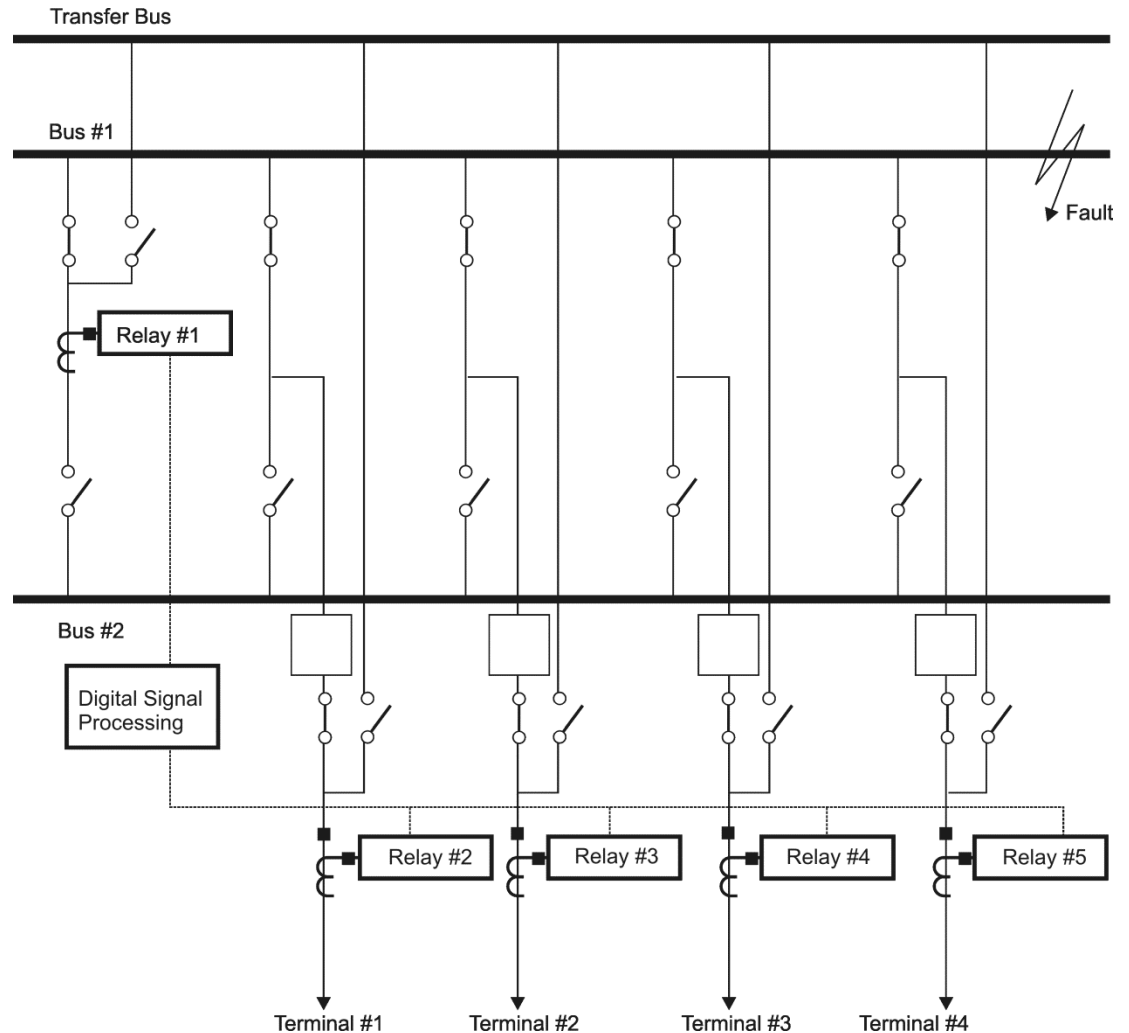


Figure 5.7: Distributed backup bus differential protection scheme example

The PDC can connect up to 16 relays, with each relay capable of monitoring up to 4 terminals. PDC based backup bus differential protection scheme performs the following tasks:

- Bus topology information processing necessary to determine the appropriate protection zones.
- Bus fault detection for each of the zones
- Trip signal transmission to appropriate relays.

Bus topology processor operation is critical for reliable system operation as shown in Figure 5.8.

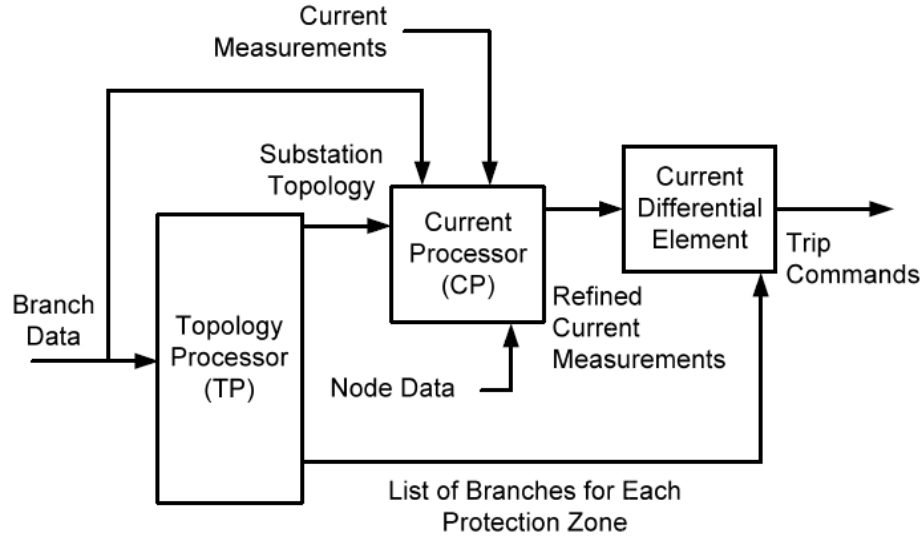


Figure 5.8: Distributed bus protection scheme zones are determined using the Synchrophasor based topology and current processors.

The Current differential element, as shown in Figure 5.9, uses the refined currents from the current processor and the list of branches for each protection zone. The differential element characteristic consists of two slopes Slope 1 and Slope 2. Slope 1 is effective for internal faults, while Slope 2 covers external faults. This slope adaptability adds security during external fault conditions.

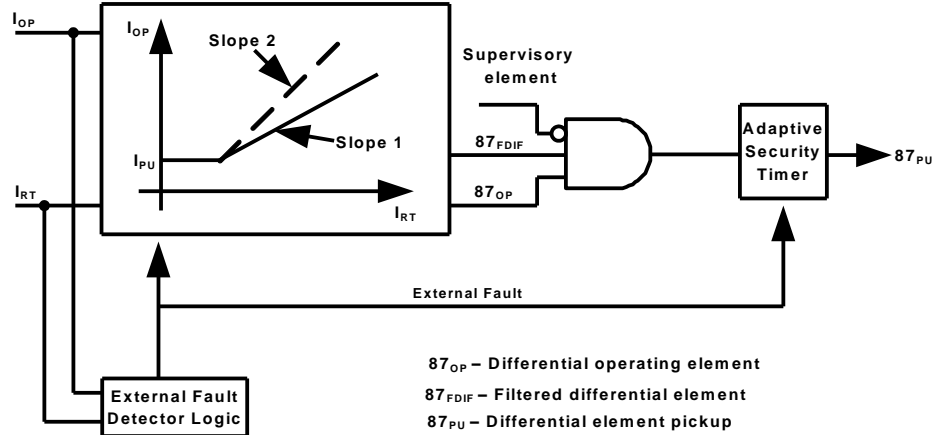


Figure 5.9: Current differential element characteristics, external fault detection logic and 87R output logic.

The above scheme was extensively tested using the Real Time Simulator (RTS) as shown in Figure 5.10. Simulations included 3 cycle delay intended to emulate the breaker operating time.

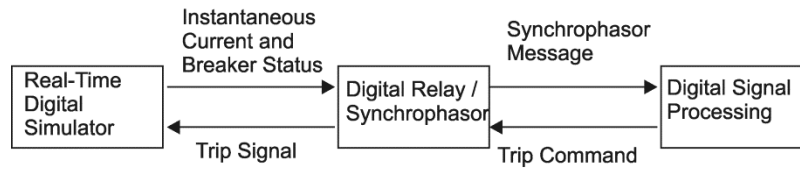


Figure 5.10: Test Setup.

The scheme performance for internal faults is shown in Figure 5.11. Relays receive the trip command 45ms after the fault inception, with the fault being cleared in less than 85ms. The example shows that properly designed PMU devices can reliably measure both steady state and system fault conditions.

While relatively slow for mainstream bus protection, the above example illustrates the advantage of using Synchrophasor technology for backup protection applications.

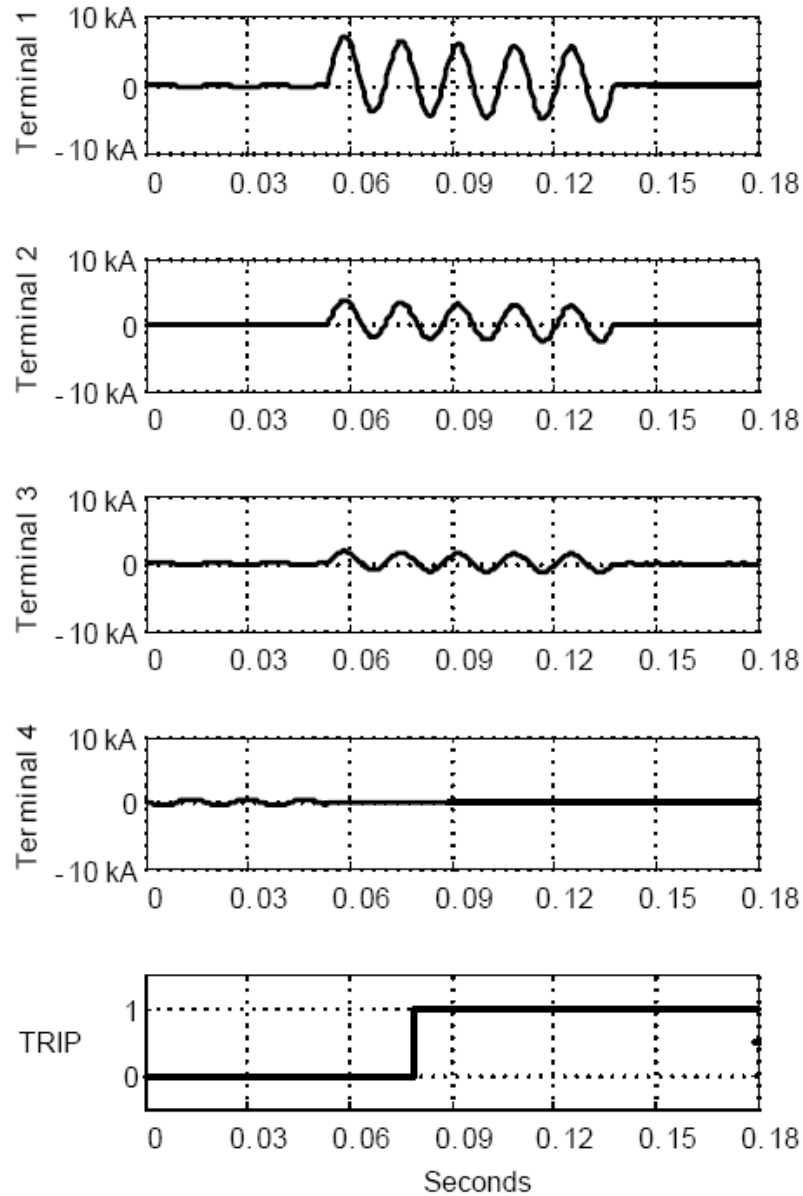


Figure 5.11: Distributed backup bus differential protection clears an internal bus fault in less than 85ms

5.4 Line Differential Protection

Synchrophasors can be used for the protection of transmission and distribution lines.

Since a stream of synchrophasor measurements contains current phasors with time synchronized values, they can be exchanged over the communications link between the two (or more ends of the transmission line.

When each IED receives the new values of magnitude and angle, they are used to calculate the differential current for the zone of protection.

The benefit of using synchrophasor measurements is that it uses a common time reference, thus allowing easy alignment of the phasor from all ends of the protected line. At the same time this method is not sensitive to delays in receiving a new synchrophasor measurement, since the processing of the data is done based on the time stamp and not on the time when the measurement was received.

The use of synchrophasors for line differential and other protection applications may require a higher number of synchrophasor measurements – for example 2 or 4 per cycle. The communications channel between the two (or more) ends of the line needs to be capable of transmitting this number of synchrophasors.

The issue that needs to be considered is the loss of synchronization of the PMUs at one of the ends of the line. It may result in an error in the line differential current calculation.

5.4.1 Negative and Zero-Sequence Line Differential Protection

The negative-sequence current differential element (87LQ) characteristic uses operating (I_{2OP}) and restraint (I_{2RT}) quantities according to equations 5.4.1-1 and 5.4.1-2.

$$I_{2OP} = \left| \overline{I_{2L}} + \overline{I_{2R}} \right| \quad (\text{eq. 5.4.1-1})$$

$$I_{2RT} = \left| \overline{I_{2L}} - \overline{I_{2R}} \right| \quad (\text{eq. 5.4.1-2})$$

where:

$\overline{I_{2L}}$ is the local negative-sequence current phasor.

$\overline{I_{2R}}$ is the remote negative-sequence current phasor.

The element operates when the following conditions are met:

$$I_{2OP} > 87_Slope \cdot I_{2RT} \quad (\text{eq. 5.4.1-3})$$

$$I_{2OP} > 0.1 \cdot I_{NOM} \quad (\text{eq. 5.4.1-4})$$

where:

87_Slope is the slope of the 87LQ element characteristic.

I_{NOM} is the relay rated current.

The relay aligns the local and remote phasors according to their time stamps. Therefore, one advantage of using time-stamped phasors is that channel asymmetry does not affect the element operating and restraint quantities. The 87LG element operates similarly to 87LQ but uses zero-sequence quantities.

5.5 Distance Function

Consider a two-terminal system in figure 5.12 below.

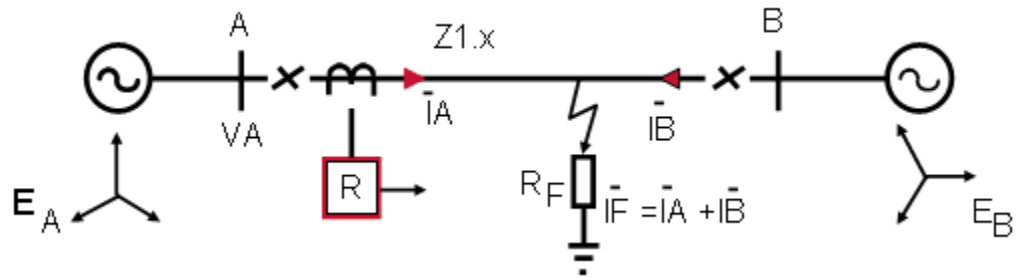


Figure 5.12: Sample system

Where.

- V_A = Relay voltage,
- I_A = Relay current,
- $Z1$ = Positive sequence impedance of the protected line , ohms/mile,
- X = Distance of fault from relay location, miles,
- R_F = Fault resistance,
- I_F = Fault current, $I_A + I_B$, for fault on the protected line,

Voltage at relay location;

$$V_A = I_A \times Z1 \times X + I_F \times R_F \quad (\text{eq. 5.5-1})$$

The impedance measured by the relay, Z_A ;

$$Z_A = V_A / I_A = Z1 \times X + R_F \times I_F / I_A \quad (\text{eq. 5.5-2})$$

An additional term is measured by the relay, $R_F \times I_F / I_A$ which may both a resistive and an inductive component due to phase angle difference between I_F and I_A (i.e. phase angle difference between I_A and I_B).

Normally relay algorithms assume I_F to be in phase with the residual or negative sequence currents at relay location to compensate for the inductive part of the measured impedance as it may cause the relay to over or under reach depending on the prefault current flow. However, if I_B measurement can be made available to the relay by transmission of this value from the remote end PMU, the relay measurement will be very accurate and misoperations will be prevented. It is noted that same argument also applies to distance to fault location algorithms.

5.6 Fine Tuning of Line Parameters

Transmission line parameters, including series resistance, series reactance and shunt susceptance, are important inputs to protective relaying algorithms. Precision of line parameters is essential in ensuring the reliable performance of relays.

In the Liao and Kezunovic, 2009 paper [26], an online optimal estimator for line parameters is proposed based on synchronized phasors measured from both ends of a transmission line. The line is shown in Figure 5.13. The state estimation technique is used to identify possible measurement errors contained in both the voltage and current phasors and the potential synchronization error. Only the reliable measurements are employed to estimate line parameters to improve accuracy.



Figure 5.13: Transmission Line (Liao, Kezunovic, 2009)

In the Liao, 2009 paper [27], an online approach is described to estimate the parameters for series compensated lines. The proposed method makes use of synchronized voltage and current phasors from both ends of a line. The compensation device can be a simple capacitor bank, or more complicated thyristor-controlled power flow controller. The voltage across the compensation device can also be estimated in real time, and may be utilized for monitoring and control purposes. The transmission line considered is shown in Figure 5.14, with the compensation device located at point R.

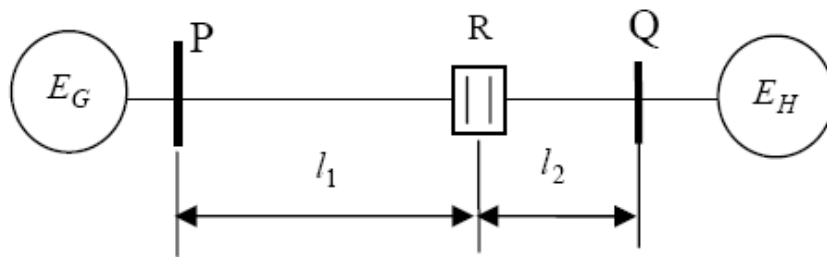


Figure 5.14: Transmission line with compensation device (Liao, 2009)

5.7 Distribution Synchronizing

Distribution substations supplied from different sources can have a significant phase angle difference between them. Tying distribution feeders together on loop systems that are fed from different sources can cause power flow between the stations possibly causing overloads on the distribution transformers and circuit conductors. The high currents can cause protective devices to operate, creating unintended operations.

Synchrophasor measurements at each of the distribution substation busses could be used to provide data to distribution dispatch personnel. The dispatcher would then know the phase angle difference between the distribution substation buses prior to allowing feeder connections. This information could also be used to predict when significant power flow would occur if the two stations were bridged together. Feeder reconfiguration could be rescheduled to a time when the angle differences were within tolerable levels, or system loading and configuration could be adjusted to bring the angles to within tolerable levels.

Only positive-sequence voltage magnitude and angle would need to be measured and transmitted to the dispatch center. A data rate of one sample per second would be sufficient and would minimize the required communications bandwidth.

5.8 Alarms for Encroachment of Relay Trip Characteristics

PMUs provide the technology to alarm for various system conditions, such as when system power swings encroach upon relay trip characteristics. The alarm ensures that distance relays will not trip due to loadability violations and the alarm may serve as a time-saving tool in that protection engineers will no longer be required to periodically review their settings. Over-tripping due to encroachment of the trip characteristics on distance relays has been both an initiating factor and a cascading factor in wide-area blackouts. For example, the 1965 Northeast blackout was caused by the false tripping of a distance relay whose settings had become obsolete [28].

The objective is to monitor relays that are most susceptible to false tripping due to encroachment of their trip characteristics by an increase in loading or power swings. Alarms are created to alert operators of encroachment due to power swings and when encroachment is imminent. The alarm uses PMUs to calculate the apparent impedance seen by a relay, and then compares it to the trip characteristics of the relay. Alarms are placed at every relay in the system that are most at risk of encroachment as determined by exhaustive contingency analysis.

For distance relays and loss-of-excitation relays the primary concern is the minimum perpendicular distance of the apparent impedance from the relay's trip zone. When this distance reduces to less than 20% of the radius of the largest zone an alarm is issued to warn of the potential for encroachment. A supervisory boundary which is a concentric circle with a radius 20% larger than the radius of the largest zone is used to determine when the impedance has gotten too close to the relay's trip characteristics. A similar technique may be used for loss-of-excitation relays since their characteristics are also defined in the impedance plane. Figure 5.15 shows how a supervisory boundary is used to monitor the third zone of a distance relay.

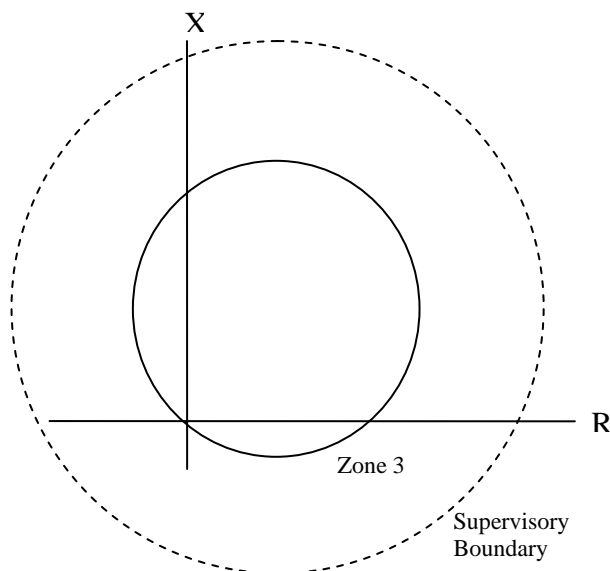


Figure 5.15: Supervisory Boundary for the 3rd Zone

5.9 New Trends in Adaptive Out-of-Step Protection

A group of generators going out-of-step with the rest of the power system is often a precursor to a complete system collapse. Whether a transient will lead to stable or unstable condition has to be determined quickly and reliably before appropriate control action is taken.

Out-of-step relays are designed to perform this detection and also to make appropriate tripping or blocking decisions. Traditional out-of-step relays use impedance relay zones and impedance trajectory analysis to determine whether or not a power swing will lead to instability. Stable swings usually do not require any control action, whereas unstable swings usually lead to out-of-step blocking or tripping actions at predetermined locations. The performance of traditional out-of-step relays has been found to be unsatisfactory in highly interconnected power networks since the conditions assumed when determining the relay settings become out-of-date rather quickly and the swings that occur may be quite different from those studied. Traditional out-of-step relays are prone to misoperation during cascading phenomena when the system is in an unusual operating state. In these cases unwanted tripping can exacerbate the already stressed system and lead to an even greater catastrophe [29].

Distance relays are prone to unanticipated operation during a power swing, regardless if it is a stable or unstable one. To secure the proper operation of distance relays during power swings, functions such as power swing blocking and out-of-step tripping are often integrated within the distance relays.

Wide-area time-synchronized measurements of positive-sequence voltage phasors throughout the power system provide a direct path to determining stability using real-time data.

Although PMUs have been used in detecting out-of-step conditions, progress could be made towards an out-of-step relay which adapts itself to changing system conditions. Angular swings

could be observed directly, and time-series expansions could be used to predict the outcome of an evolving swing. The objective would be to initially develop this technique for known points of separation in the system. The use of past experience as well as current predictor models and their contingency should be considered in the new algorithm's architecture. In time, as experience with this first generation adaptivity is gained, more complex system structures with unknown paths of separation could be tackled [28].

An algorithm can be developed for determining the principal coherent groups of machines as the power swings begin to evolve. The algorithms could include the inferring of rotor angles from observed bus angles, and determine criteria for judging coherency between machines and groups of machines. It is expected that centers of angles for each coherent group will be used in determining out-of-step condition.

The determination of whether or not a swing is evolving into unstable is possible by waiting long enough to observe the actual swing. However, in order to take appropriate control actions a reliable prediction algorithm is required that provides the stable-unstable classification of an evolving swing, within a reasonable time. By observing the swing evolution, a time-series approximation to the swings can be made in order to predict the stability of the swing.

The concept of adaptive out-of-step protection is implemented at the Florida-Georgia interface with the interface modeled as a two-machine system as shown in Figure 5.16. In this application the equal-area criterion was used to predict stability after observing the actual angular swings for up to 250 ms [29].

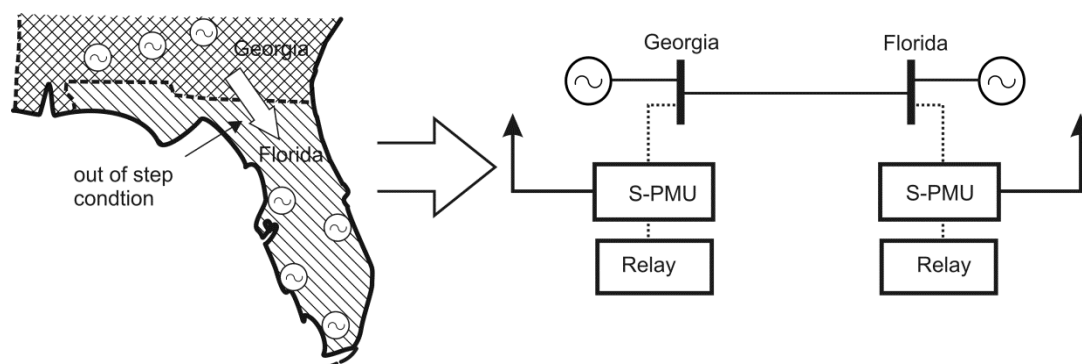


Figure 5.16: The Reduced Florida-Georgia System [29]

5.9.1 Tokyo Electric's Predictive Out-Of-Step Protection System Based on Synchronized Phasor Measurements

A predictive out-of-step protection system based on observing phase differences between power centers using the real-time phasor measurement principle [30] has been in successful operation with Tokyo Electric Power Company (TEPCO, Japan) since February, 1989. This is one of several examples of the various types of WAMPAC (Wide-Area Monitoring, Protection and Control) schemes well-established in Japan. These schemes utilize instantaneous sampled measured values adopting the 'ping-pong' method to achieve sampling timing synchronization.

These schemes currently don't get their data from synchrophasor devices as described in C37.118 but the concept lends itself for future implementation in that manner.

A major characteristic of the TEPCO bulk electric power system is that power generation areas are remote from areas of load consumption. The eastern, northern, and southeastern generator groups are linked by a bulk power system comprising 500 kV double-circuit transmission lines, which are configured in duplex and triplex routes, each forming a "trunk". The western generator group and large local loads are linked to the bulk power system via points (a) and (a') shown in the simplified system arrangement in Figure 5.17. The western generator group tends to be heavily loaded, and its own capacity cannot meet demand. Power is received from the bulk power system to make up the deficiency.

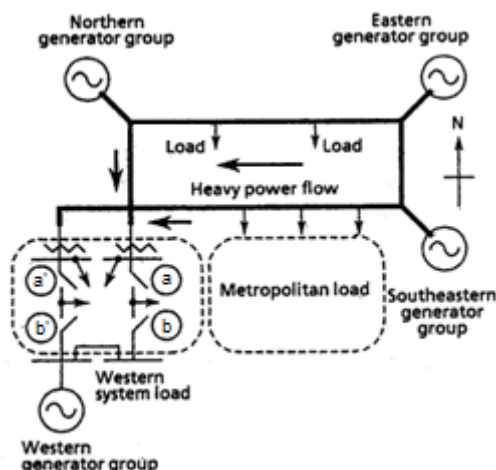


Figure 5.17: Simplified Model of Trunk Line and Generators

When a double circuit fault occurs on lines that form one of the routes, transmission capability is interrupted. If a successive fault occurs after reclosing, a slow cyclic power swing develops between the western generator group and the bulk power system. The same situation occurs in the event of a failure of a bus-bar protective relay to operate during a bus-bar fault. Over time, the phase difference of the generator groups thus undergoes an oscillating divergence. If this condition is not corrected, an out-of-step condition will commence in various parts of the power system and may lead to its total collapse.

In order to maintain the reliability of the power system a predictive protection system was developed that would prevent a total collapse of the power system. This protection system is based upon synchronized phasor measurements, and it utilizes online data collected before and after the onset of a system disturbance to determine the characteristics of the power swing and predict an out-of-step condition. The system operates during the incubation period so that appropriate control can be performed before the out-of-step condition occurs.

The western generator group can be islanded (Figure 5.17) from the bulk power system at an optimal point in a controlled manner ensuring that the balance between supply and demand is maintained before an out-of-step occurs and can then be operated independently. This eliminates power swings between the generator groups of the two systems and restores stability.

The protection scheme is outlined in Figure 5.18. The status of each generator group (East, North, Southeast, and West) is obtained by measuring the bus-bar voltages of neighboring substations as representative values. From these, the phase differences between the western generator group and the bulk power system are obtained. From the phase difference values, the corresponding values for 200 ms in the future are predicted. If the latter exceed the setting value the respective generator groups are judged to be unstable.

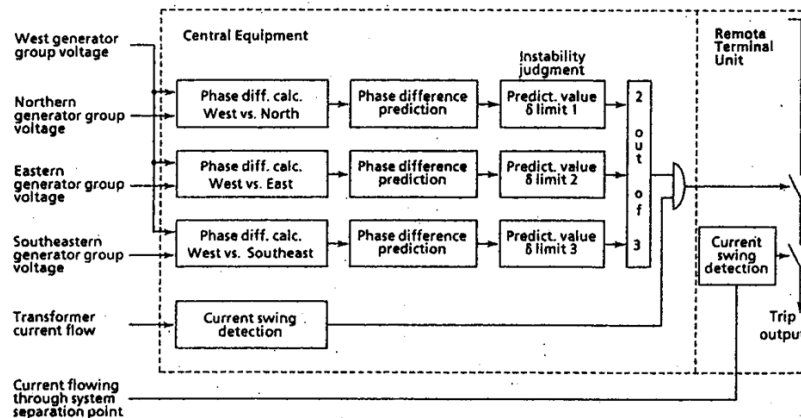


Figure 5.18: Protection Scheme Outline

A two out of three voting logic is employed to judge instability of all the groups and to prevent unwanted operation in the event of an out-of-step of one generator group within the bulk power system. In order to initiate system separation, a current swing detection element must operate based upon the current flowing through the transformers at the linkage substations at points (a) and (a') between the bulk power system and the western area (Figure 5.17).

When the two out of three generator groups have been determined to be unstable and the current swing detection element has operated, an islanding command is issued from the Central Equipment to the separation point. The trip command is executed if the current swing detection element in an RTU has operated on the current flowing through that point. The current swing detection element is provided as a fail-safe measure for the protection calculation based upon phase difference.

When utilizing conventional out-of-step relays, normally located at both ends of the transmission line, system separation is delayed, because the relays will not operate until the phase difference between both ends exceeds 180 degrees. Moreover, a cyclic power swing within the bulk power system does not result in convergence even if the system has been separated. By means of applying this WAMPAC scheme, it has been confirmed by simulations that fast separation of the targeted system at the appropriate point can be achieved and a slow cyclic power swing can subside.

5.10 Synchrophasor Application to Controlled Islanding

The islanding of the electric power system in a controlled manner instead of the spontaneous islanding that usually occurs during a wide area disturbance has significant advantages due to the

fact that it allows the creation of an island where it is possible to balance the available generation with the important loads. In the best case scenario it should be possible to balance the generation and the loads by properly selecting the locations in the system where the islanding should be executed.

The synchrophasor data from multiple locations in the electric power system can be used to calculate the overall load – generation balance in different possible islands in the system. When a wide area disturbance condition is detected, the SIPS will send the commands to:

- trip the breakers that will island the specific area of the system
- shed load or generation to achieve balance in the area

5.11 Adaptive Voting Scheme

Protective relays have two basic failure modes: false tripping and failing to trip. “Security” and “dependability” are two aspects of protection that oppose each other. Protection systems can be designed with either bias based on operational margins, transmission capability, company preference, and consequences. When a system is stressed, such as the condition of wide-area generation loss, the desire may be to shift the bias towards security instead of dependability.

For critical transmission lines there are often multiple protection systems with different operating principles on the same line. In a normal operating state each of these systems is capable of tripping the line independently. When it is determined that the system is in a stressed state the security could be increased by making two out of the three relays see the fault before the protected line is tripped. Relay’s settings are not altered in this scheme, as the adaptive security/dependability is achieved by the redundancy of the protection devices [28].

A decision tree can be used, such as in Figure 5.19, to determine the state of the system [28]. Synchronized PMUs from key locations in the system are entered in the decision tree. The output is a binary signal that indicates if the system is in a normal or a stressed state.

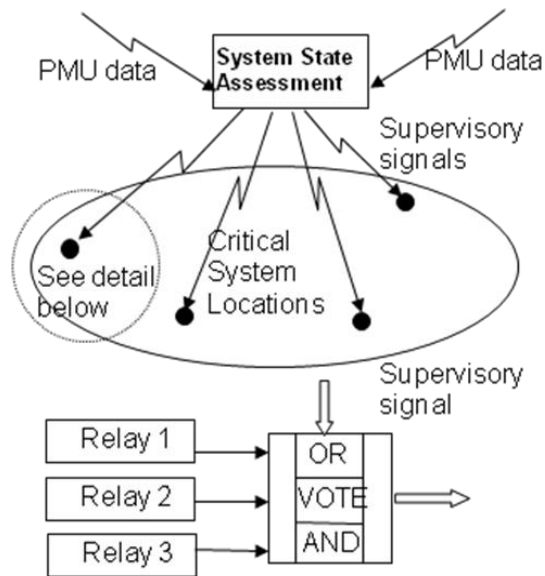


Figure 5.19: Adjustment of dependability-security balance under stressed conditions [28]

The decision tree is built by entering a large number of cases, where each case has a target and a set of predictors. The target is the variable that is to be predicted. In this case the variable is the state of the system which is a 0 if the load flow converged or a 1 if the load flow could not be solved. The predictors are the variables that are used to make the decision. In this case the variables are phasor measurements at buses throughout the system. The full set of cases is entered into a data program, which builds the most accurate decision tree. Some of the predictors may not be used in the tree. The accuracy of the resulting decision tree depends on the size of the training set and how inclusive it is of all system conditions [28].

5.12 Real-Time Substation Voltage Measurement Refinements

Figure 5.20 shows four line relays and a bus relay, each connected to its own instrument transformer. When the four circuit breakers are closed, the five voltage measurements should be nearly the same. The primary voltages E_1 , E_2 , E_3 , E_4 , and E_5 differ only by the very small voltage drops between the instrument transformers. The secondary voltages $V_1 \dots V_5$ differ by errors introduced by the instrument transformers, measurement devices, cable differences, and installation differences.

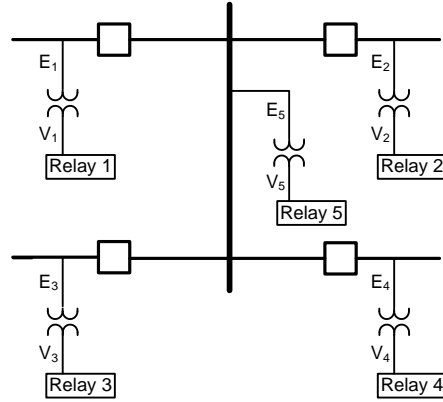


Figure 5.20: Four-breaker configuration used in best bus-voltage estimate

The five measurements can be used in several ways:

- a) local checks of phasing and synchronism across any open breaker
- b) With at least one breaker closed,
 - 1) detect and report on any large and unexpected differences
 - 2) average “good” measurements to gain accuracy
 - 3) communicate measurements to adjacent stations for further comparisons.

Equation 5.12-1 allows the focus on managing the measurement errors within the station for closed breakers in terms of the primary voltage and the total error:

$$V_i = E_i + \varepsilon_i \quad (\text{eq. 5.12-1})$$

where:

V is the measured voltage,

E is the true voltage, and

ε is the total error.

First, all voltage measurements need to be within a reasonable range, i.e., the maximum deviation between any two voltage measurements is less than a predefined value. This check is performed by a comparison of the voltage measurements to one another using the PDC. For the bus configuration in Figure 5.20, this comparison would equate to the calculations in Table 5.1.

Table 5.1
Difference Voltage Calculations

Relay 1	Relay 2	Relay 3	Relay 4
v1 – v2	-	-	-
v1 – v3	v2 – v3	-	-
v1 – v4	v2 – v4	v3 – v4	-
v1 – v5	v2 – v5	v3 – v5	v4 – v5

Voltage is calculated:

$$\Delta v_i = v_i - v_j \quad (\text{eq. 5.12-2})$$

where:

$i = 1$ to $N - 1$,

$j = i + 1$ to N , and

N = number of nodes.

After making each delta calculation, a comparison between an absolute threshold and the delta voltages is computed

$$\text{Max_Threshold} > |\Delta v_i| \quad (\text{eq. 5.12-3})$$

Measurements above the maximum threshold are flagged and removed from the voltage estimation. The estimation of bus voltage is calculated using the average of the measured bus voltage:

$$\hat{E} = \frac{\sum_{i=1}^N v_i}{N} \quad (\text{eq.5.12-4})$$

where:

E is the best estimate bus voltage,

v is the measured value, and

N is the number of measurements.

The PDC then forwards the best estimate to SCADA or other similar systems that can benefit from refined analog measurements.

Equation 5.12-5 describes the number of delta voltage calculations required per number of measurement points within a particular zone:

$$\text{Num_Calcs} = \frac{N \cdot (N - 1)}{2} \quad (\text{eq. 5.12-5})$$

As N becomes large, the number of comparison calculations becomes very large. For example, if N is 6, there are 15 calculations to perform. If N is 18, there are 153 calculations. Because we are trying to find a best estimate using an average, we can break the system into subcomponents and follow the same procedure. For example, if the system consists of 18 points, we can break the system into three sections. The resulting number of calculations would be $15 + 15 + 15 = 45$ comparisons, which is much less than the 153 calculations that would be required if we did not break the system into subsections. We then average the subsections' best estimate voltages to produce the system's best estimate voltage.

5.13 Detection of Power System Inter-Area Oscillations

The PDC uses built-in modal analysis (MA) function blocks and flexible programming logic equations to detect unstable inter-area oscillations and then automatically initiates remedial actions. Power system disturbances, such as line tripping and generation loss, cause local and inter-area power system oscillations. Usually, local oscillation modes range in frequency from 0.7 to 2.0 Hz [31]. Inter-area oscillation, which refers generally to a group of generators in one area that swing against a group of generators in another area, normally ranges in frequency from

0.1 to 0.8 Hz [31]. The local oscillation involves a few generators within a small portion of a power system and has little impact on an overall power system. Inter-area oscillations constrain the amount of power that can be transferred through some parts of interconnected power grids. Without proper remedial actions, inter-area oscillation can result in power system separations or blackouts.

The traditional approach to preventing inter-area oscillation involves modal analysis of the results of power system dynamic simulations at the planning stage. The inaccuracy of both the power system dynamic model and the availability of the number of contingencies and operating conditions available to perform the analysis, limits the traditional approach.

PMU technology allows advanced computing and signal-processing technology to detect and mitigate inter-area oscillations in real time. The PDC uses Modified Prony Analysis (MPA) to perform MA. MPA uses the linear combination of multiple exponential oscillation modes to approximate an original signal that a device samples at fixed time intervals. For an array of data samples $x[1], \dots, x[N]$, the MPA estimates $\hat{x}[n]$ according to equation 5.13-1 for $1 \leq n \leq N$:

$$\hat{x}[n] = \sum_{m=1}^M A_m e^{\sigma_m(m-1)T} \cos(2\pi f_m(m-1)T + \phi_m) \quad (\text{eq. 5.13-1})$$

where:

- T is the best estimate bus voltage,
- A_m is the amplitude of the exponential function.
- σ_m is the damping constant in seconds⁻¹.
- f_m is the frequency in Hz.
- ϕ_m is the initial phase in radians.
- M is the number of modes.

The corresponding signal-to-noise-ratio (SNR) calculation in equation 5.13-2 quantifies the quality of the curve fit. MPA is a linear approximation technique, so it will produce a low SNR value if the data sample array contains nonlinear transitions. In power systems, discrete switching events, such as line tripping, can cause nonlinear transitions. The SNR value normally improves as a switching event leaves the observation window of MA, and the power system settles into pure oscillation mode. A high SNR value (greater than 80 dB, for example) indicates that the analysis result is a good approximation of the original signal.

$$SNR = 10 \log_{10} \left(\frac{\sum_{n=0}^N x[n]^2}{\sum_{n=0}^N (x[n] - \hat{x}[n])^2} \right) \quad (\text{eq. 5.13-2})$$

5.13.1 Inter-Area Oscillation Mode Identification

Power system oscillations are visible in power system quantities such as bus voltage, angle difference, frequency, active power transfer, and reactive power transfer through transmission lines. MA uses synchrophasor measurements of these power system quantities as an input signal. The MA result includes an array of modes and an SNR value. Each mode is a data structure that includes amplitude A_m , frequency f_m in Hz, damping constant σ_m , damping ratio ζ_m , and initial phase angle ϕ_m in degrees. Equation 5.13.1-3 calculates the damping ratio from the frequency

and the damping constant. A negative damping ratio (positive damping constant σ) indicates that the corresponding mode is an increasing oscillation mode.

$$\zeta_m = \frac{-\sigma_m}{\sqrt{\sigma_m^2 + (2\pi f_m)^2}} \quad (\text{eq. 5.13.1-3})$$

The array of calculated oscillation modes includes both local oscillation modes and inter-area oscillation modes. To identify the inter-area oscillation modes from the array of modes, additional logic must process the MA results based on measurements from different areas before control actions can occur. Figure 5.21 illustrates the decision-making process based on MA results.

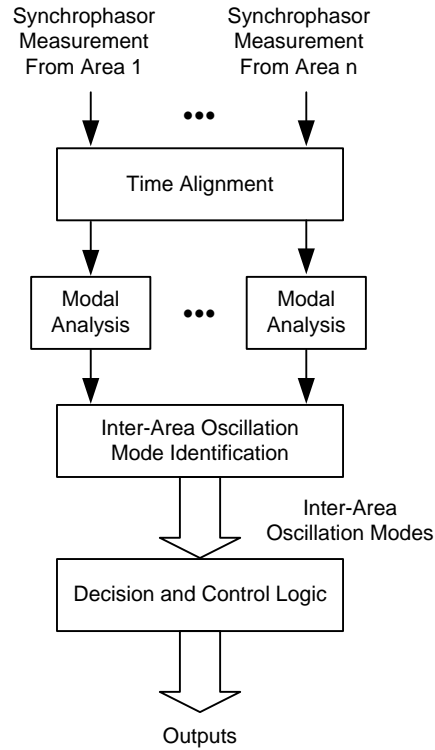


Figure 5.21: Remedial action based on modal analysis results

MPA involves numerical approximation, so the calculated mode frequencies from different areas can vary for a common inter-area oscillation mode. Therefore, the process of identifying the common oscillation modes normally uses a frequency deviation threshold. The PDC identifies a common oscillation mode if the difference between the calculated mode frequencies within a group and their mean value is less than a user-specified threshold.

The PDC then feeds the parameters of the common inter-area oscillation mode to the Decision and Control Logic block. This block activates alarm and control output signals. Figure 5.22 illustrates an example of the decision and control logic. The SNR must be greater than SNR_{thre} to enable the control signal output. The f_{high} and f_{low} thresholds define the frequency band of the inter-area oscillation mode in which we are interested. The mode frequency f_m must be within this frequency band to activate the control signal output. If the mode amplitude A_m is greater than

A_{thre} , the damping ratio ζ_m is less than ζ_{thre} , and the condition persists longer than the damping ratio pickup ($DRPU$), the alarm or control output asserts.

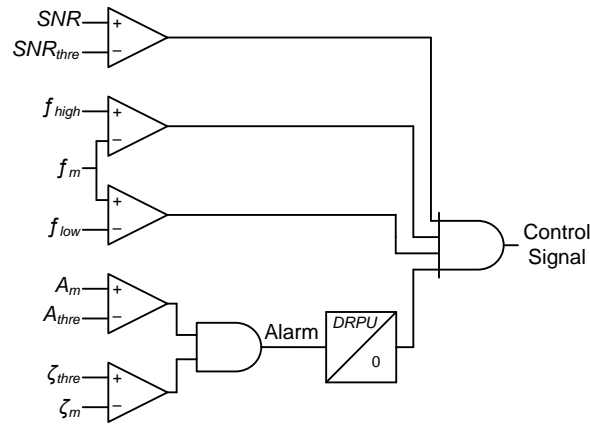


Figure 5.22: Oscillation mode-based decision and control logic

5.14 Synchrophasor-based Line Backup Protection

The apparent impedance seen by the relays under very heavy loads may lead to relay tripping. This is especially true in the case of long transmission lines or Zone 3 elements that have to provide backup protection for lines outgoing from substations with significant infeed. This is quite dangerous during wide area disturbances and will result in quick deterioration of the system and a blackout. Analysis of recent blackouts in the North America clearly demonstrates this problem with typical distance protection applications [46].

Moving forward, synchrophasor technology could improve backup protection by helping decide at a PDC/controller location (Figure 5.23) if there is a fault in the protected zone and, consequently, avoid unnecessary zone 3 tripping on load encroachment [32]. Most PMUs today are able to stream synchrophasors at rates in the range of 30 to 120 phasors per second. Given that a PDC is receiving multiple streams of data from multiple ends of a transmission line (Figure 5.23) at the above-stated rates and given a low-latency communication system (5–20 ms), a PDC/controller will have sufficient information to make a trip decision in the 50- to 100-ms time frame—significantly less than the present backup time of 500 ms. Faster detection of failed protection and subsequent correction action increases the stability margin of a power system.

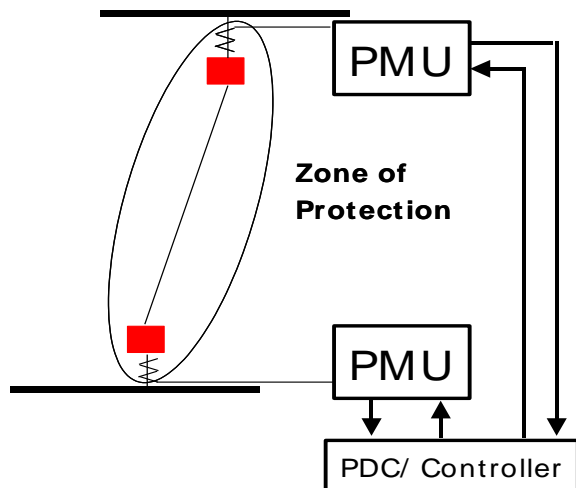


Figure 5.23: Synchrophasor-based Backup Protection

6.0 Conclusions

Synchrophasor measurements have been used in a number of protective relaying applications and are also being considered for many future protection applications. This report has shown some of the existing uses and the future uses being developed. Protection Engineers will continue to think of more uses in the future and the manufacturers will refine their devices to accommodate those uses.

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A Appendix A – Acronyms

A/D	Analog to Digital
AGSS	Automatic Generation Shedding Scheme
ANSI	American National Standards Institute
ATM	Asynchronous Transfer Mode
BER	Bit Error Rate
DG	Distributed Generation
GPS	Global Positioning System
IED	Intelligent Electronic Device
IEEE	Institute of Electrical and Electronics Engineers
IP	Internet Protocol
LOF	Loss of Field
MA	Modal Analysis
MPA	Modified Prony Analysis
PDC	Phasor Data Concentrator
PMU	Phasor Measurement Unit
RAS	Remedial Action Scheme
RSTP	Rapid Spanning Tree Protocol
RTS	Real Time Simulator
SCADA	Supervisory Control and Data Acquisition
SIPS	System Integrity Protection Scheme
SNR	Signal to Noise Ratio
SONET	Synchronous Optical Network
STP	Spanning Tree Protocol
TCP	Transmission Control Protocol
UDP	User Datagram Protocol
UTC	Coordinated Universal Time
VIP	Voltage Instability Predictor
VSLBI	Voltage Instability Load Bus Index

B Appendix B – Informational Uses of Synchrophasors

B.1 Alarm for Generation Control

On September 18, 2006, a preplanned 500kV line switching event in the vicinity of Cumberland Fossil Plant (CUF) initiated a dangerous undamped plant oscillation (Figure B.1). This condition continued for almost three minutes and had steadily escalated to a 700 MW oscillation at 1.2 Hz by that time. It was only arrested after the preplanned line outage was reversed and the line placed back in service.

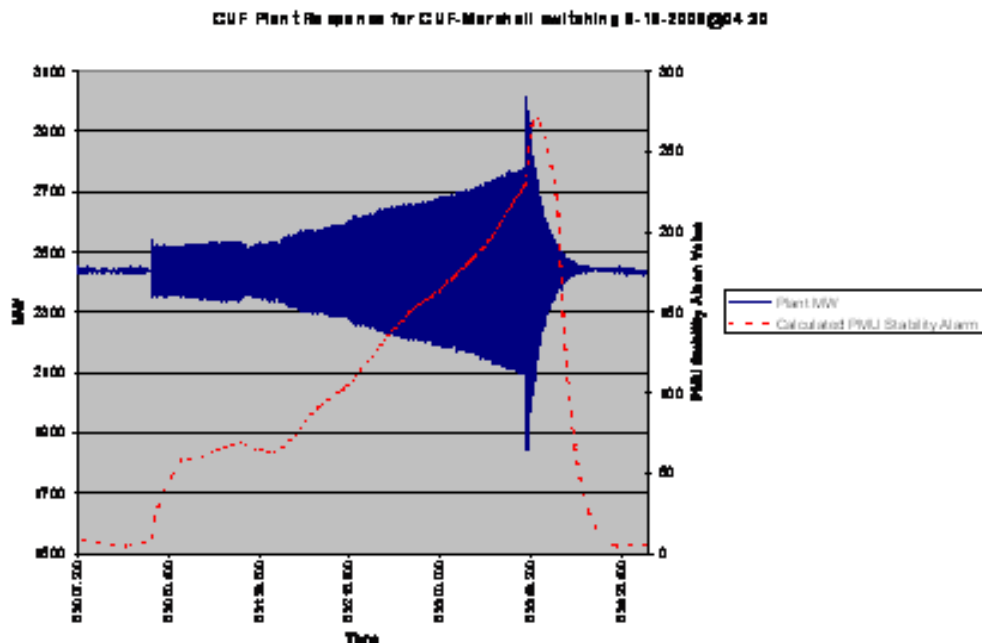


Figure B.1: Plant response graph

A CUF Stability Alarm was developed within the SCADA system based on data from the PMU at CUF sampled at 30Hz. The CUF Stability Alarm is based on the standard deviation calculation of the CUF total plant MW output, which is indirectly calculated by summing the MW flows on the three 500kV lines terminated at CUF and each monitored by a PMU.

The standard deviation is calculated using the previous 450 samples or previous 15 seconds worth of data. This analog value calculated 30 times per second is updated every ten (10) seconds and provides an indication of the MW oscillations occurring on the two units at CUF. Standard deviation is a measure of how widely sampled values are dispersed from the average mean value of the entire range of samples. It is calculated using the "unbiased" or "n-1" method. The formula is:

$$\sqrt{\frac{\sum (x - \bar{x})^2}{(n-1)}}$$

where \bar{x} is the sample mean AVERAGE
(number1,number2,...) and n is the sample size.

High values of this stability alarm point indicate unsafe oscillations that can lead to an unstable system state. The pie chart shown on the SCADA single line display for CUF (see Figure B.2) provides a visual indication of the real-time value.

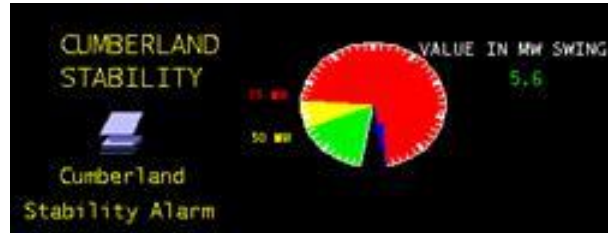


Figure B.2: SCADA Single Line Display Pie chart

Thresholds (see Table B.1) were developed empirically by analyzing line switching and fault-clearing events within two buses of CUF:

Table B.1

MW Swing Value	Color	Indication
Less than 50MW	Green	Safe - oscillations minimal
Between 50 and 75MW	Yellow	Warning Limit exceeded - Monitor closely
Greater than 75MW	Red	High Operating Limit exceeded - Action required

Local plant operators and transmission operators monitor this MW swing value. Required action includes controlled derates in steps down to minimum load until the oscillations subside. If derates are not effective, one unit will be removed from service.

B.2 Wide Area Disturbance Recording

B.2.1 Eastern Interconnection

TVA utilizes synchrophasor measurements for internal use as well as providing external partners with valuable wide area information. Data from 19 continuously reporting PMUs within the TVA service area is employed to present a timely representation of its grid status to the system operators. A visualization designed in the EMS software and used in the control room shows the real-time frequency from these devices along with the angle differences between them, indicating egregious swings with color coding and triggered alarms. In addition to TVA-owned PMUs, TVA also serves as the central repository for long term storage as well as a data router for over 120 of the PMUs in the Eastern Interconnect to a visualization tool RTDMS. This

widely used tool, developed by the Electric Power Group under the auspices of NERC, is used in control centers at major ISOs in the East and solely uses the data concentrated at the TVA open PDC to inform these operators of interconnect wide system status.

B.2.2 WECC Wide-Area Disturbance Recording

Having a precise record of wide-area power system events allows engineers to quickly analyze and explain those events. However, analyzing wide-area data from several utilities can be challenging. Wide-area synchrophasor communications links are uncommon between neighboring utilities, including members of the Western Electric Coordinating Council (WECC). To overcome the lack of intercommunications links, the WECC members implement local synchrophasor disturbance recorders (SDRs) to record disturbances within their operating territory. They then share the data with other WECC members. WECC members record data continuously keeping all data for at least 2 weeks. When a significant event occurs, a call for data is issued and members copy and send files that cover the request period to WECC. WECC uses the resulting data, gathered from the various measurement points within the system, to analyze outages, review system tests, and examine large switching events. Following are some WECC member SDR system descriptions.

B.2.2.1 Arizona Public Service (APS)

The Westwing Substation includes seven relays streaming synchrophasor data to a PDC, which then reports to a BPA PDC. The BPA PDC also receives data from other dedicated PMUs located in other areas of the power system. The BPA PDC then streams synchrophasor data to a desktop computer running the BPA StreamReader software. The StreamReader software archives the synchrophasor data in a .dst file format (disturbance file, which is a binary proprietary format).

B.2.2.2 Salt River Project (SRP)

This system consists of several relays, two PDCs, and archiving software. The PDCs and archiving software collect data from the relays, concentrate and convert all data to a common format, and then store the data. SRP uses a comma-delimited format (.cvs) as the storage file format.

B.2.2.3 Nevada Power (NP)

Six relays located at Harry Allen Substation are connected to a PDC. The PDC streams data via BPA protocol to the StreamReader software located at NP's relay/operations office in Las Vegas. The StreamReader software archives the synchrophasor data in a .dst file.

B.2.2.4 Sierra Pacific (SP)

Five relays at East Tracy Substation, along with one relay at another nearby substation, send synchrophasor data to a PDC. The PDC collects and sends data to a desktop PC at East Tracy running the BPA StreamReader software, which archives the synchrophasor data in a .dst file.

B.2.2.5 Southern California Edison (SCE)

This system is a mixture of dedicated PMUs, relays, and a PDC. SCE has a communications link to BPA. In this case, SCE and BPA each archive data locally using the .dst file format.

B.2.2.6 San Diego Gas and Electric (SDG&E)

Five relays, spread throughout their system, report data to a centralized PDC. The PDC reports data to a PI historian, the StreamReader software, and synchrophasor visualization software. The StreamReader software archives the synchrophasor data in a .dst file.

B.2.2.7 Idaho Power Company (IPC)

Five relays, spread throughout their system, send data to a centralized PDC. The PDC sends data to synchrophasor visualization software and to the StreamReader software for local archiving of the synchrophasor data in a .dst file.

B.2.2.8 BC Hydro

Dedicated PMUs, along with relays, take synchrophasor measurements and send them to a PDC. The PDC streams data to BPA via a dedicated communications link. The StreamReader software archives the synchrophasor data in a .dst file.

B.2.2.9 Bonneville Power Administration (BPA)

A wide variety of PMUs, along with a number of proprietary portable synchrophasor units, reports data to a BPA PDC. The PDC sends the data to the StreamReader software, which archives the synchrophasor data in a .dst file.

B.2.2.10 Western Area Power Administration (WAPA)

In this system, PMUs report data to a BPA PDC located in Loveland, Colorado. The PDC sends the data to the StreamReader software, which archives the synchrophasor data in a .dst file. WAPA also has a direct communications link to BPA for archiving .dst files.

After an event or test, WECC collects data from the various members for analysis. Though this system is not fully automated, it does provide a precise, time-aligned, wide-area measurement system that allows WECC to easily analyze wide-area system events.

B.3 System Monitoring in Washington State

The benefits of synchrophasors extend beyond high-voltage transmission system monitoring. Synchrophasor measurements used throughout a power system, from transmission through distribution, allow engineers to monitor and quickly analyze disturbances without the tedious correlation of various event reports. A BPA system disturbance, where two 500 kV lines and one 230 kV line tripped, resulted in a loss of 1300 MW (see Figure B.3 and B.4). The graphs were captured by a relay having synchrophasor measurement capability that was monitoring a 115 VAC wall plug at a laboratory in Washington State.

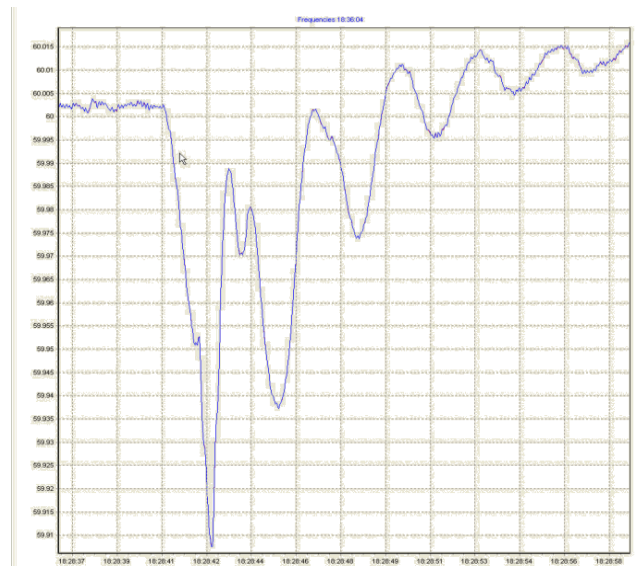


Figure B.3: Synchrophasor data plot showing frequency excursion at distribution voltages



Figure B.4: BPA Synchrophasor data plot frequency excursion at transmission voltages

B.4 Generator Voltage and Power Angle Measurement

B.4.1 Measurement Methods

There are two methods that can be used for estimating the internal voltage angle and power angle of generators. The rotor-angle is the angle from the stator voltage phasor of the machine to the q-axis of the machine. This angle is also referred to as the power-angle or load-angle.

Electrical calculation method: The internal voltage and the power angle of a generator can be derived from knowledge of the direct-axis reactance X_d , the quadrature-axis reactance X_q , and

real-time PMU or SCADA data measurements representing the terminal voltage and current. This method may lead to errors because the values of X_d and X_q might vary with the generator operating conditions.

Rotor position measurement method: The angle of internal voltage and the power angle of a generator can be calibrated against the rotor position and the terminal voltage angle. This method has good accuracy and is suitable for real-time power angle measurement when the power system is subject to a disturbance. The rotor position measurement method may be therefore considered advantageous for measurement of the generator power angle and frequency.

B.4.2 Input Signal

For measurements of internal voltage and power angles, the input signals to the PMU include the terminal voltages and currents of the generator, and a signal representing the rotor position, all with respect to the same time reference.

B.4.3 Measuring Process

The rotor position of a generator may be monitored by optical or magnetic means. In the optical method, some kind of shaft encoder can be used. In the magnetic method, a periodic pulse signal may be produced by a slot added for the purpose at some arbitrary location on the rotor, and a sensor on the stator. By comparing the rotor position signal with the reference time signal, the rotor position angle (called α) of the generator can be calculated. When the generator runs with no load, the power angle of the generator is zero, and any offset between the rotor position signal and the internal voltage angle can be calibrated as follows.

Under no-load conditions, the voltage angle at the terminals of the generator is the same as the angle of the internal voltage angle of the generator. Measured relative to the reference time signal, the angle of the terminal voltage under no-load is indicated as angle β in Figure 4.36. The rotor position, which depends on the position of shaft encoder or the slot on the rotor of the generator, is at some angle α . The angular offset (γ) between the angles α and β can be obtained. This angle γ remains constant unless something in the physical machine is changed; for example, the coil assembly is rebuilt during maintenance.

Thus the angle γ does not change when the machine is under load. Therefore, when the generator is operating, the angle of the internal voltage can be calculated from knowledge of the rotor angle and the calibration offset γ (see Figure B.5). The voltage angle β is found by subtracting γ from α (which is observable). The generator power angle δ is then given by the difference between the internal voltage angle β and the terminal voltage of the generator, as shown in Figure B.6.

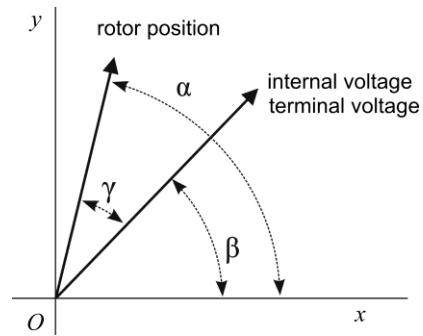


Figure B.5: Phasor diagram under no-load conditions

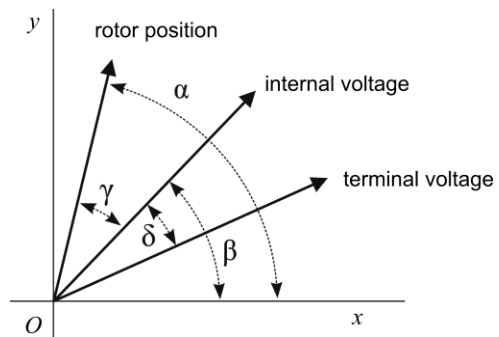


Figure B.6: Phasor diagram with load on generator