# Wide-Area Protection and Emergency Control

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*Invited Paper*

*System-wide disturbances in power systems are a challenging problem for the utility industry because of the large scale and the complexity of the power system. When a major power system disturbance occurs, protection and control actions are required to stop the power system degradation, restore the system to a normal state, and minimize the impact of the disturbance. In some cases, the present control actions are not designed for a fast-developing disturbance and may be too slow. The report explores special protetion schemes and new technologies for advanced, wide-area protection. There seems to be a great potential for advanced wide-area protection and control systems, based on powerful, flexible and reliable system protection terminals, high speed, communication, and GPS synchronization in conjunction with careful and skilled engineering by power system analysts and protection engineers in cooperation.*

***Keywords*—*Emergency control, power system protection, wide-area protection.***

## I. Introduction

From time to time, power systems are exposed to serious disturbances, which lead to the interruption of the power supply to the customers [4], [37], [39], [40]. The planners of the power system try to design reliable systems that are able to cope with probable contingencies. But even for the best planned system, unpredictable events can stress the system beyond the planned limits. Some of the reasons why completely reliable operation cannot be achieved are the following.

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1) Practically an infinite number of possible operating contingencies in modern, interconnected power systems.
2) The evolving nature of power systems, generates unpredictable changes. Inevitably, the operation of the power system is considerably different from the expectation of the system designers, particularly during an emergency. For example, deregulation provided financial motivation to transfer power from generation (e.g., independent power producers) to remote loads, As the existing power systems were not designed for those transfers, additional stress is put on the system.
3) A combination of unusual and undesired events (for example, human error combined with heavy weather and scheduled or unscheduled maintenance outages of the important system element).
4) Reliability design philosophy that is pushing the system close to the limits brought about by economic and environmental pressures.

While reliability is the concern of system designers, operators deal with system security. Security is an online, operational characteristic which describes the ability of the power system to withstand different contingencies without service interruptions. Security is closely related to reliability: an unreliable system cannot be secure. The security level of the power system (desired to be high enough to enable robust operation) changes dynamically as the power system operation changes and depends on the factors outside the control of power system operators (e.g., weather).

The trend in power system planning utilizes tight operating margins, with less redundancy, because of new constraints placed by economical and environmental factors. At the same time, addition of nonutility generators and independent power producers, an interchange increase, an increasingly competitive environment, and introduction of flexible ac transmission (FACTS) devices make the power system more complex to operate and to control, and thus more vulnerable to a disturbance. On the other hand, the advanced measurement and communication technology in wide-area monitoring and control, FACTS devices (better tools to control the disturbance), and new paradigms (fuzzy logic and neural networks) may provide better ways to detect and control an emergency.

The modern energy management system (EMS) is supported by supervisory control and data acquisition (SCADA) software; by numerous power system analysis tools such as state estimation, power flow, optimal power flow, security analysis, transient stability analysis, midterm to long-term stability analysis; and by such optimization techniques as linear and nonlinear programming. The available time for running these application programs is the limiting factor in applying these tools in real time during an emergency, and a tradeoff with accuracy is required. The real-time optimization software and security assessment and enhancement software do not include dynamics. Further, propagation of a major disturbance is difficult to incorporate into a suitable numerical algorithm, and heuristic procedures may be required. For example, unexpected hidden failures in relaying equipment may cause unexpected multiple contingencies. The experienced and well-trained operator can recognize the situation and react properly given sufficient time, but often not reliably or quickly enough.

In modern interconnected networks, a fast-developing emergency may comprise a wide area. Since operator response may be too slow and inconsistent, fast automatic actions are implemented to minimize the impact of the disturbance. These automatic actions may use local or centralized intelligence, or a combination of both.

Currently, the local automatic actions are conservative, act independently from central control, and the prevailing state of the whole affected area is not considered. Actions incorporating centralized intelligence are limited to the information anticipated to be relevant during foreseen contingencies. There are few schemes that are adaptive to intelligence gathered from a wide area that respond to unforeseen disturbances or scenarios.

Furthermore, future power systems will encounter new components (energy storage, load control, and solar power), new systems (FACTS elements and HVdc integration), as well as regulatory changes (wheeling of power, nonutility generators). An intelligent and adaptive control and protection system for wide-area disturbance is needed to make possible full utilization of the power network, which will be less vulnerable to a major disturbance.

Historically, only centralized control was able to apply sophisticated analysis because only at this higher level could computers and communication support be technically and economically justified. However, with the increased availability of sophisticated computer, communication and measurement technologies, more intelligence can now be used at a local level. The possibility to close the gap between central and local decisions and actions will depend on the degree of intelligence put in the local subsystems. Decentralized subsystems that can make local decisions based on local measurements and remote information (system-wide data and emergency control policies) and/or send preprocessed information to higher hierarchical levels are an economical solution to the problem. A major component of system-wide disturbance protection is the ability to receive system-wide information and commands via the data communication system and to send selected local information to the SCADA center. This information should reflect the prevailing state of the power system.

## II. Disturbances: Causes and Remedial Measures

Phenomena that create wide-area power system disturbances are divided, among others, into the following categories: angular stability, voltage stability, overloads, power system cascading, etc. They are fought against using a variety of protective relaying and emergency control measures.

*The angular instability*, or loss of synchronism, condition occurs when generators in one part of the network accelerate while other generators somewhere else decelerate, thereby creating a situation where the system is likely to separate into two parts. The conventional relaying approach for detecting loss of synchronism is by analyzing the variation in the apparent impedance as viewed at a line or generator terminals. Following a disturbance, this impedance will vary as a function of the system voltages and the angular separation between the systems. Out of step, pole slip, or just loss of synchronism are equivalent designations for the condition where the impedance locus travels through the generator. When the impedance goes through the transmission line the phenomenon is also known as power swing. However, all of them refer to the same event: loss of synchronism.

Out-of-step protection as it is applied to generators and systems has the objective to eliminate the possibility of damage to generators as a result of an out-of-step condition. In case the power system separation is imminent, it should take place along boundaries, which will form islands with matching load and generation. Distance relays are often used to provide an out-of-step protection function, whereby they are called upon to provide blocking or tripping signals upon detecting an out-of-step condition.

The most common predictive scheme to combat loss of synchronism is the equal-area criterion and its variations. This method assumes that the power system behaves like a two-machine model where one area oscillates against the rest of the system. Whenever the underlying assumption holds true, the method has potential for fast detection.

*Voltage stability* [20]–[27] is defined by the System Dynamic Performance Subcommittee of the IEEE Power System Engineering Committee [29] as the ability of a system to maintain voltage such that when load admittance is increased, load power will increase, and so that both power and voltage are controllable. Also, voltage collapse is defined as being the process by which voltage instability leads to a very low voltage profile in a significant part of the system.

It is accepted that this instability is caused by the load characteristics, as opposed to the angular instability, which is caused by the rotor dynamics of generators.

The risk of voltage instability increases as the transmission system becomes more heavily loaded [17], [18]. The typical scenario of these instabilities starts with a high system loading, followed by a relay action due to either a fault, a line overload or hitting an excitation limit.

Voltage instability can be alleviated by a combination of the following remedial measures means: adding reactive compensation near load centers, strengthening the transmission lines, varying the operating conditions such as voltage profile and generation dispatch, coordinating relays and controls, and load shedding. Most utilities rely on planning and operation studies to guard against voltage instability. Many utilities utilize localized voltage measurements in order to achieve load shedding as a measure against incipient voltage instability [2], [41], [42].

*Overloads* frequently occur during wide-area disturbances due to the increasingly high utilization of equipment capability. These overloads may result in faults (such as lines sagging into trees) or equipment damage if overload protection is not provided. On the other hand, overloads sometimes result in premature removal of equipment due to short-circuit protection relays that do not allow the full short-time overload capability of the equipment to be utilized. Overloads are counteracted by applying monitoring and protection equipment that model the primary equipment thermal capability given precontingency loading, ambient temperature conditions, and other influencing factors. For moderate overloads, the monitoring equipment allows operators to take action to relieve the overload before equipment damage. For severe overloads, protection equipment could be applied to initiate controlled curative actions such as transmission reconfiguration or load shedding before the equipment becomes damaged.

Outage of one or more power system elements due to the overload may result in overload of other elements in the system. If the overload is not alleviated in time, the process of *power system cascading* may start, leading to power system separation. Uncontrolled separation often occurs as a result of transmission line short-circuit protection systems interpreting power swings as short circuits. Controlled separation can be initiated by a special protection system (SPS) or out-of-step relaying.

When a power system separates, islands with an imbalance between generation and load are formed with a consequence of frequency deviation from the nominal value. If the imbalance cannot be handled by the generators, load or generation shedding is necessary. A quick, simple, and reliable way to reestablish active power balance is to shed load by underfrequency relays. There are a large variety of practices in designing load-shedding schemes based on the characteristics of a particular system and the utility practices [3], [4].

While the system frequency is a final result of the power deficiency, the rate of change of frequency is an instantaneous indicator of power deficiency and can enable incipient recognition of the power imbalance. However, change of the machine speed is oscillatory by nature, due to the interaction among generators. These oscillations depend on location of the sensors in the island and the response of the generators. The issues and recommendation regarding the rate-of-change of frequency function are as follows [5].

- A smaller system inertia causes a larger peak-to-peak value for rate-of-change of frequency oscillations. Large oscillations require that a rate-of-change of frequency relay needs sufficient time to reliably determine the actual rate-of-change of frequency. Although as system inertia decreases a frequency of oscillations increases (enabling relays to faster detect average value), it may still take too long to accurately detect a rate-of-change value. One example showed that oscillations with $\sim 2.5$ Hz/s peak-to-peak value have a frequency of oscillations of $\sim 1,45$ Hz ($\sim 0.68$ s). Measurements at load buses close to the electrical center of the system are less susceptible to oscillations (smaller peak-to-peak values) and can be used in practical applications.
- Even if rate of change of frequency relays measure the average value throughout the network, it is difficult to set them properly, unless typical system boundaries and power imbalance can be predicted. If this is the case (e.g., industrial and urban systems), the rate of change of frequency relays may improve a load-shedding scheme (the scheme can be more selective and/or faster).
- Adaptive settings of frequency and frequency derivative relays, based on actual system conditions, may enable more effective and reliable implementation of load-shedding schemes.

## III. Relay Hidden Failures

Failures or malfunctions in various protection systems are very significant factor in the overall process of reported wide-area disturbances. Of all the protection system failures, the ones that remain dormant or hidden until some unusual system events occur are the most important [34], [35]. The abnormal power system states are usually due to faults, heavy load, shortages in reactive power, etc. They can trigger the hidden failures to cause relay malfunction, which can worsen the situation, since the power systems may already be operated in an emergency state when those abnormal states occur, eventually leading to the wide-area disturbances. Commonly used transmission relaying systems have been studied to identify possible hidden failures and their consequences on the power systems. A concept of region of vulnerability associated with each mode of hidden failure has been proposed. It is the region in which the hidden failure can cause a relay to incorrectly trip its associated circuit breaker. The relative importance of each region of vulnerability, called the vulnerability index, can be computed using steady-state and transient stability criteria. A larger value of the vulnerability index indicates that the relay in which if that hidden failure mode exists is relatively more important and can cause more serious wide-area disturbances or has a higher possibility to cause the disturbances than the one with a smaller index. Therefore, more attention should be paid to those key relays to prevent the hidden failure and its consequences.

It has been observed that of all the reported cases of major system blackouts (wide-area disturbances) in North America, about 70% of the cases have relay system contributing to the initiation or evolution of the disturbance. On closer examination, it became clear that one of the major components of relay system misoperations is the presence of relays which have failed during service, and their failure is not known. Consequently, there is no alarm, and no repairs or replacements are possible. These *hidden failures* are different from straight relay misoperations, or failures which lead to an immediate trip. The hidden failures remain undetected (and substantially undetectable), until the power system becomes stressed, leading to an operating condition which exposes the hidden relay failures.

## IV. Technology Issues in Wide-Area Protection

### A. Monitoring and Protection for Wide-Area Disturbances

The disturbance in the power system usually develops gradually; however, some phenomena, such as transient instability, can develop in a fraction of a second. Regardless of the phenomena and available measures, any protection/control procedure during an emergency should consist of the following elements: identification and prediction, classification, decisions and actions, coordination, corrections, and time scale.

## V. Available Actions

The corrective and emergency actions are limited to a finite number of measures. A detailed description of these measures will be provided as implementation issues for different types of disturbances are analyzed. A set of available measures includes *out-of-step relaying, load shedding, controlled power system separation, generation dropping, fault clearing, fast turbine valving, FACTS control, dynamic braking, generator voltage control, capacitor/reactor switching and static VAR compensation, load control, supervision and control of key protection systems, voltage reduction, phase shifting, tie line rescheduling, reserve increasing, generation shifting, HVdc power modulation*, etc.

As an emergency progresses and the state of the system degrades, less desirable measures may become necessary. All the above measures are suitable during *in extremis* crisis. However, "last resort" measures are acceptable only in an unavoidable transition to *in extremis* crisis. Alternatively, preventive measures, are usually only measures suitable in an alert state.

The above measures are implemented in the emergency procedures for the power system. Every system has its own emergency control practices and operating procedures dependent on the different operating conditions, characteristics of the system, and engineering judgment. In other words, the operating procedure for every system is unique and heuristic procedures are extensively used, although the set of measures is the same.

State of the system parameters and sensitivity of the system to certain measure are the factors that influence the choice of the measure. Any one of the measures mentioned above is usually helpful for different problems, having direct or indirect influence. From the problem perspective, different measures can help to overcome different problems with some degree of sensitivity. Another important aspect in implementing control actions is optimization with respect to security and costs. For example, such a coarse measure as load shedding need not be executed if generation shifting is satisfactory (regarding speed and amount) in relieving overloaded lines. Further, even when load shedding is necessary to help alleviate overloads, less load is required to be shed if it can be determined that there is a generation shifting capability. Thus, appropriate coordination can optimize actions.

A major component of adaptive protection systems is their ability to adapt to changing system conditions. Thus, relays which are going to participate in wide-area disturbance protection and control must of necessity be adaptive. At the very minimum, this implies a relay system design which allows for communication links with the outside world. The communication links must be secure, and the possibility of their failure must be allowed for in the design of the adaptive relays.

## VI. Technology Infrastructure

### A. Phasor Measurement Technology

The technology of synchronized phasor measurements [38] is well established. It provides an ideal measurement system with which to monitor and control a power system, in particular during conditions of stress. A number of publications are available on the subject. The essential feature of the technique is that it measures positive sequence (and negative and zero sequence quantities, if needed) voltages and currents of a power system in real time with precise time synchronization. This allows accurate comparison of measurements over widely separated locations as well as potential real-time measurement based control actions. Very fast recursive discrete Fourier transform (DFT) calculations are normally used in phasor calculations.

The synchronization is achieved through a global positioning satellite (GPS) system. GPS is a U.S. government sponsored program that provides worldwide position and time broadcasts free of charge. It can provide continuous precise timing at better than the 1-ms level. It is possible to use other synchronization signals, if these become available in the future, provided that a sufficient accuracy of synchronization could be maintained. Local proprietary systems can be used, such as a sync signal broadcast over microwave or fiber optics. Two other precise positioning systems, GLONASS, a Russian system, and Galileo, a proposed European system, are also capable of providing precise time.

Fig. 1 shows a typical synchronized phasor measurement system configuration. The GPS transmission is received by the receiver section, which delivers a phase-locked sampling clock pulse to the analog-to-digital converter system. The

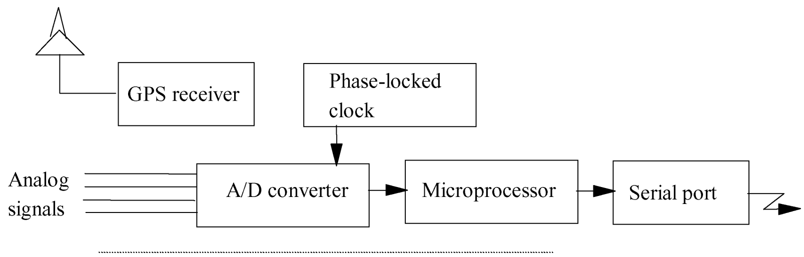


**Fig. 1.** Block diagram of the synchronized phasor measurement system (PMU).

sampled data are converted to a complex number which represents the phasor of the sampled waveform. Phasors of the three phases are combined to produce the positive sequence measurement.

Any computer-based relay which uses sampled data is capable of developing the positive sequence measurement. By using an externally derived synchronizing pulse, such as from a GPS receiver, the measurement could be placed on a common time reference. Thus, potentially all computer based relays could furnish the synchronized phasor measurement. When currents are measured in this fashion, it is important to have a high enough resolution in the analog-to-digital converter to achieve sufficient accuracy of representation at light loads. A 16-b converter (either a true 16-b or a dynamic ranging converter with equivalent 16-b resolution) generally provides adequate resolution to read light load currents, as well as fault currents.

For the most effective use of phasor measurements, some kind of a data concentrator is required. The simplest is a system that will retrieve files recorded at the measurement site and then correlate files from different sites by the recording time stamps. This allows doing system and event analysis utilizing the preciseness of phasor measurement. For real-time applications, from soft real time for SCADA to hard real time for response-based controls, continuous data acquisition is required.

Several data concentrators have been implemented, including the phasor data concentrator (PDC) at the Bonneville Power Administration. This unit inputs phasor measurement data broadcast from up to 32 PMUs at up to 60 measurements/s, and performs data checks, records disturbances, and rebroadcasts the combined data stream to other monitor and control applications. This type of unit fulfills the need for both hard and soft real time applications as well as saving data for system analysis. Tests performed using this PMU-PDC technology on the BPA and Southern California Edison (SCE) systems have shown the time intervals from measurement to data availability at a central controller can be as fast as 60 ms for a direct link and 200 ms for secondary links. These times meet the requirements for many types of wide-area controls.

A broader effort is the Wide-Area Measurement System (WAMS) concept explored by the U.S. Department of Energy and several utility participants. WAMS includes all types of measurements that can be useful for system analysis over the wide area of an interconnected system. Real-time performance is not required for this type of application, but is no disadvantage. The main elements are timetags with enough precision to unambiguously correlate data from multiple sources and the ability to convert all data to a common format. Accuracy and timely access to data is important as well. Certainly with its system-wide scope and precise timetags, phasor measurements are a prime candidate for WAMS.

## VII. Communication Technology

Communications systems are a vital component of a wide-area relay system. These systems distribute and manage the information needed for operation of the wide-area relay and control system. However, because of potential loss of communication, the relay system must be designed to detect and tolerate failures in the communication system. It is important also that the relay and communication systems be independent and subject as little as possible to the same failure modes. This has been a serious source of problems in the past.

To meet these difficult requirements, the communications network will need to be designed for fast, robust, and reliable operation. Among the most important factors to consider in achieving these objectives are type and topology of the communications network, communications protocols, and media used. These factors will in turn effect communication system bandwidth, usually expressed in bits per second (BPS), latency in data transmission, reliability, and communication error handling.

Currently, electrical utilities use a combination of analog and digital communications systems for their operations consisting of power line carrier, radio, microwave, leased phone lines, satellite systems, and fiber optics. Each of these systems has applications where it is the best solution. The advantages and disadvantages of each are briefly summarized in the following paragraph.

Several types of communication protocols are used with optical systems. Two of the most common are synchronous optical networks (Sonet/SDH) and the asynchronous transfer mode (ATM). Wide-band Ethernet is also gaining popularity, but is not often used for backbone systems. Sonet systems are channel oriented, where each channel has a time slot whether it is needed or not. If there is no data for a particular channel at a particular time, the system just stuffs in a null packet. ATM by contrast puts data on the system as it arrives in private packets. Channels are reconstructed from packets as they come through. It is more efficient, as there are no null packets sent, but has the overhead of prioritizing packets and

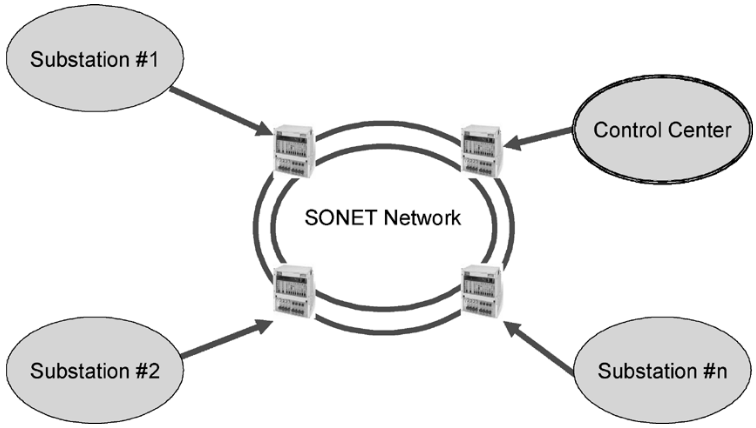


**Fig. 2.** Architecture of SONET communication network.

sorting them. Each system has different system management options for coping with problems.

Synchronous optical networks are well established in electrical utilities throughout the world and are available under two similar standards: 1) Sonet is the American system under ANSI T1.105 and Bellcore GR Standards, and 2) Synchronous Digital Hierarchy (SDH) under the International Telecommunications Union (ITU) standards.

The transmission rates of Sonet systems are defined as Optical Carrier $x$ (OC$x, x = 1\ldots192$); with OC$1 = 51.84$ Mb/s and OC$192 = 39.8$ Gb/s. Available in the market and specially designed to meet the electrical utility environment are Sonet systems with bit rates of OC$1 = 51.8$ Mb/s and OC$3 = 155$ Mb/s.

Sonet and SDH networks are based on a ring topology (Fig. 2) [12], [13]. This topology is a bidirectional ring with each node capable of sending data either direction; data can travel either direction around the ring to connect any two nodes. If the ring is broken at any point, the nodes detect where the break is relative to the other nodes and automatically reverse transmission direction if necessary. A typical network, however, may consist of a mix of tree, ring, and mesh topologies rather than strictly rings with only the main backbone being rings.

Self healing (or survivability) capability is a distinctive feature of Sonet/SDH networks made possible because it is ring topology. This means that if communication between two nodes is lost, the traffic among them switches over to the protected path of the ring. This switching to the protected path is made as fast as 4 ms, perfectly acceptable to any wide-area protection and control.

Communication protocols are an intrinsic part of modern digital communications. The most popular protocols found in the electrical utility environment and suitable for wide-area relaying and control are the distributed network protocol (DNP), Modbus, International Electrotechnical Commission Standard IEC870-5, and the Electric Power Research Institute (EPRI) universal communications architecture/multiple messaging system (UCA/MMS). TCP/IP is probably the most extensively used protocol and will undoubtedly find applications in wide-area relaying.

UCA/MMS protocol is the result of an effort between utilities and vendors (coordinated by EPRI). It addresses all communication needs of an electric utility. Of particular interest is its "peer-to-peer" communications capabilities that allows any node to exchange real time control signals with any other node in a wide-area network. DNP and Modbus are also real-time type protocols suitable for relay applications. TCP on Ethernet lacks a real-time type requirement, but over a system with low traffic performs as well as the other protocols. Other slower speed protocols like the Inter Control Center Protocol (ICCP) (in America) or TASEII (in Europe) handle higher level but slower applications like SCADA. Many other protocols are available but are not commonly used in the utility industry.

## VIII. Remedial Actions Against Wide-Area Disturbances

### *A. SPSs*

The following definition of an SPS comes from a North American electric Reliability Council (NERC) planning standard [31]: "A special protection system (SPS) or remedial action scheme (RAS) is designed to detect abnormal system conditions and take preplanned, corrective action (*other than the isolation of faulted elements)* to provide acceptable system performance." Note that 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. One design parameter that sets these schemes apart is that many of them are "armed" and "disarmed" in response to system conditions. For example, a watchdog type of scheme may be required and armed at high load levels, but not at lower load levels. Some SPSs are armed automatically by the system control center computer, others require human operator action or approval, others are manually operated, and some are armed all the time [1], [11].

NERC further defines the standards to which an SPS shall adhere. In part, they are as follows.

- A SPS shall be designed so that cascading transmission outages or system instability do not occur for failure of a single component of a SPS which would result in failure of the SPS to operate when required.
- All SPS installations shall be coordinated with other system protection and control schemes.
- All SPS operations shall be analyzed for correctness and documented.

Reference [1] reports on the experience of 111 SPSs and lists the most common schemes being used as follows:

- generator rejection;
- load rejection;
- underfrequency load shedding [7], [8];
- undervoltage load shedding;
- system separation;
- turbine valve control [6];
- stabilizers [14];
- load and generator rejection;
- HVdc controls;
- out-of step relaying [9], [10];
- dynamic braking;
- discrete excitation control;
- generator runback;
- VAR compensation;
- combination of schemes;
- others.

The popularity of the three schemes at the beginning of the above list is not surprising. The fundamental cause of wide-area outages, almost by definition, is the unbalance between generation and load following the loss of a line or generator due to correct operation following a fault or incorrect operation by human error, hidden failure, etc. Therefore, an SPS seeks to correct this unbalance by removing load or increasing generation. In this survey, a distinction was made between direct load rejection, i.e., removing preplanned customers through controls, and automatic underfrequency load rejection if the unbalance results in decreasing frequency. *The underfrequency tripping of load may not be considered by everyone as an SPS, since it is installed by many utilities as a normal protective measure.*

An increasingly popular SPS is the separation of the system into independent islands, leaving the faulted area to fend for itself, thus greatly reducing the impact of an outage. The use of the GPS to synchronize relays across the system and adaptive digital relays makes this scenario particularly attractive. The challenge lies in identification of key parameters and settings that define the boundary between two alternatives. Should the regions be kept interconnected to provide support or separated to prevent a nonviable system condition from expanding? It is to answer this question that system analysts and protection and communications engineers need to work together to develop robust, adaptive, and reliable SPS using advanced techniques to provide optimum solutions.

The concept of out-of-step relaying has been known for some time. However, the specific setting philosophy has been a major problem in applying it. As noted in the discussion of the French EDF DRS and Syclopes schemes later in this paper, there are significant limitations and difficulties in using and setting out-of-step relaying to separate unstable interconnected regions in a wide area with widely varying operating conditions.

Combining all of the schemes applied to the turbine generator has become feasible by the introduction of reliable and fast-acting electronics. Fast valving and dynamic braking are particularly noteworthy as methods to reduce generator output without removing the unit from service and thus allowing for rapid restoration.

The reliability of SPS was addressed in [1] and indicates that the equipment and schemes perform very similarly to traditional protective schemes. System conditions requiring action does not occur often, but when it does occur, the SPS usually performs its function correctly. The most common failure (43% of those responding) was hardware failures with human failure (20%) next. Inadequate design accounted for about 12% of the failures and incorrect setting less than 10%.

In this section, all possible protective actions against wide-area disturbances that we have been able to find during the work have been listed, commented, and evaluated. The discussion has mainly dealt with curative actions.

## IX. Trends and Architectures in Wide-Area Protection

The meaning of wide-area protection, emergency control, and power system optimization may vary dependant on people, utility, and part of the world. Therefore, standardized and accepted terminology is important. Since the requirements for a wide-area protection system vary from one utility to another, the architecture for such a system must be designed according to what technologies the utility possesses at the given time. Also, to avoid becoming obsolete, the design must be chosen to fit the technology migration path that the utility in question will take. The solution to counteract the same physical phenomenon might vary extensively for different applications and utility conditions.

The potential to improve power system performance using smart wide-area protection and control, and even defer high voltage equipment installations, seems to be great. The introduction of the phasor measurement unit (PMU) has greatly improved the observability of the power system dynamics. Based on PMUs different kinds of wide-area protection, emergency control and optimization systems can be designed. A great deal of engineering, such as power system studies and configuration and parameter settings, is required, since every wide-area protection installation is unique. Sometimes, the enhancements are obtained using heuristic methods, such as fuzzy logic or neural networks [15], [16], [28], [30], [32], [33]. A cost effective solution could be based on standard products and standard system designs.

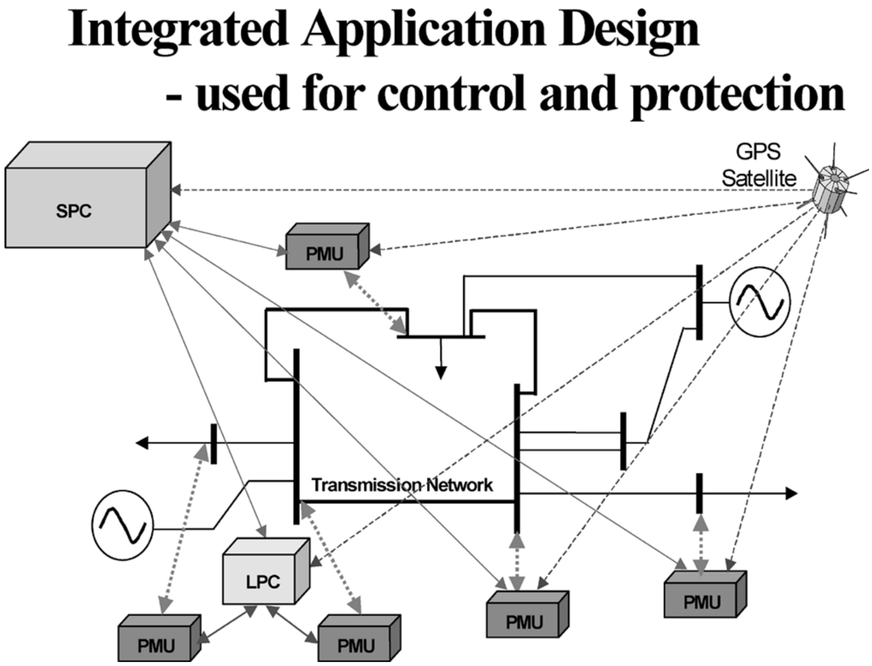


**Fig. 3.** Multilayered network of GPS-synchronized PMUs, connected through LPCs and an SPC.

Tailor-made wide-area protection systems against large disturbances, designed to improve power system reliability and/or to increase the transmission capacity, will therefore most likely be common in the future. These systems will be based on reliable high-speed communication and extremely flexible protection devices, where power system engineering will become an integrated part of the final solution. This type of high-performance protection schemes will also be able to communicate with traditional SCADA systems to improve functions like demand side management (DSM), distribution automation (DA), EMS, and state estimation.

As the electricity market is restructured all around the world, the nature of utility companies is changed. In particular, the downsizing of the staff makes it difficult or impossible for the utility to perform many R&D functions. As a result, there is a trend in the industry where utilities collaborate with vendors to cope with issues related to the grid. The utility can view its partnering vendor as a substitute for its vanishing R&D department to perform tasks that its existing staff cannot handle. The vendor sees the partnering utility as the "sounding board" for its product development and the place to demonstrate its latest products. This closed-loop collaboration, which already exists in the form of pilot projects in wide-area protection, is found to be fruitful to both parties.

### A. *Enhancements to SCADA/EMS*

At one end of the spectrum, enhancements to the existing EMS/SCADA can be made. These enhancements are aimed at two key areas: information availability and information interpretation. Simply put, if the operator has all vital information at his fingertips and good analysis facilities, he can operate the grid in an efficient way. For example, with better analysis tool for voltage instability, the operator can accurately track the power margin across an interface, and thus can confidently push the limit of transfer across an interface.

SCADA/EMS system capability has greatly improved during the last years, due to improved communication facilities and highly extended data handling capability. New transducers such as PMUs can provide time-synchronized measurements from all over the grid. Based on these measurements, improved state estimators can be derived.

Major problems during fast-developing disturbances occur due to:

- alarm bursts, as operator is not able to filter and analyze important signals;
- unavailability of critical functions.

Improved EMS/SCADA systems would require ability to filter, display, and analyze only critical information and to increase availability of critical functions to 99.99%.

Advanced algorithms and calculation programs that assist the operator can also be included in the SCADA system, such as "faster than real-time simulations" to calculate power transfer margins based on contingencies.

The possibilities of extending the SCADA/EMS system with new functions tend to be limited. Therefore, it might be relevant to provide new SCADA/EMS functions as "stand alone" solutions, more or less independent of the ordinary SCADA/EMS system. Such functions could be load shedding, due to lack of generation or due to market price.

### B. *Multilayered Architecture*

A comprehensive solution, that integrates the two control domains, protection devices and EMS, can be designed as in Fig. 3. There are up to three layers in this architecture. The bottom layer is made up of PMUs, or PMUs with additional protection functionality. The next layer up consists

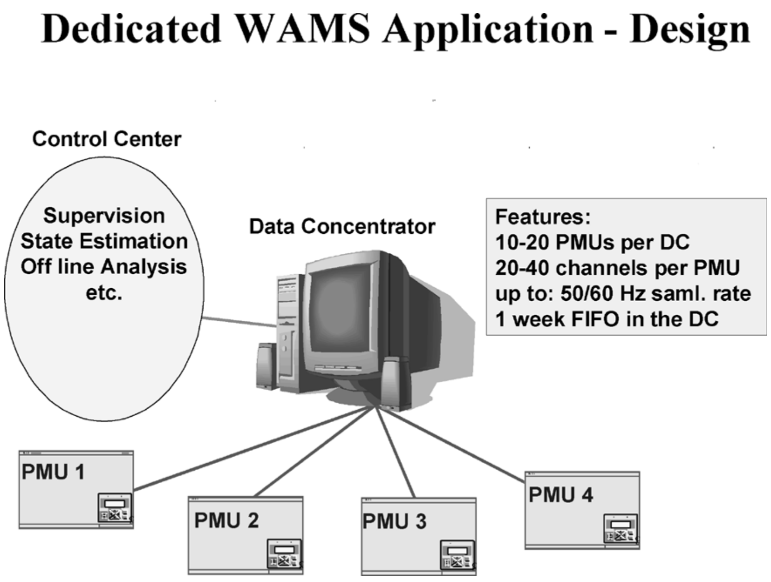


**Fig. 4.** WAMS design.

of several local protection centers (LPCs), each of which interfaces directly with a number of PMUs. The top layer, the system protection center (SPC), acts as the coordinator for the LPCs. Designing the three-layered architecture can take place in several steps. The first step should aim at achieving the monitoring capability, e.g., a WAMS. WAMS is the most common application, based on PMUs. These systems are most frequent in North America, but are emerging all around the world. The main purpose is to improve state estimation, postfault analysis, and operator information. In WAMS applications a number of PMUs are connected to a data concentrator, which basically is a mass storage, accessible from the control center, according to Fig. 4.

Starting from a WAMS design, a data concentrator can be turned into a hub-based LPC by implementing control and protection functions in the data concentrator. A number of such LPCs can then be integrated into a larger system wide solution with an SPC at the top. With this solution, the LPC forms a system protection scheme (SPS), while the interconnected coordinated system forms a defense plan.

### C. *"Flat Architecture" With System Protection Terminals*

Protection devices or terminals are traditionally used in protecting equipment (lines, transformers, etc.). Modern protection devices have sufficient computing and communication capabilities to be capable of performing beyond the traditional functions. When connected together via communications links, these devices can process intelligent algorithms based on data collected locally or shared with other devices.

Powerful, reliable, sensitive, and robust, wide-area protection systems can be designed based on decentralized, especially developed interconnected system protection terminals. These terminals are installed in substations, where actions are to be made or measurements are to be taken. Actions are preferably local, i.e., transfer trips should be minimized, to increase security. Relevant power system variable data is transferred through the communication system that ties the terminals together. Different schemes, e.g., against voltage instability and against frequency instability, can be implemented in the same hardware.

Using the communication system, between the terminals, a very sensitive system can be designed. If the communication is partially or totally lost, actions can still be taken based on local criteria (fallback performance is not worse than with conventional local relaying). Different load-shedding steps that take the power system response into account—in order not to overshed—can easily be designed.

Based on time-synchronized measurements of voltage and current by PMUs at different locations in the network, real-time values of angle differences in the system can be derived with a high accuracy. With this new type of real-time measurements, efficient emergency actions, such as PSS control, based on system-wide data, load shedding, etc., can be taken to save the system stability in case of evolving power oscillations.

### D. *System Protection Terminal*

Traditionally, remedial action schemes have been hub based, i.e., all measurements and indicators are sent to a central position, e.g., a control center, for evaluation and decision. From this central position, action orders are then sent to different parts of the power system. Such a centralized system is very sensitive to disturbances in the central part. With the ring-based (or WAN) communication system, a more robust system can be achieved. One communication channel can, for example, be lost without any loss of functionality. If one system protection terminal fails in a flat decentralized solution, a sufficient level of redundancy can be implemented in the neighboring terminals. In other technological areas the decision power is moving closer to the process, with increasingly more powerful sensors and actuators, for decisions based on rather simple criteria. Such an independent SPS, based on powerful terminals, can

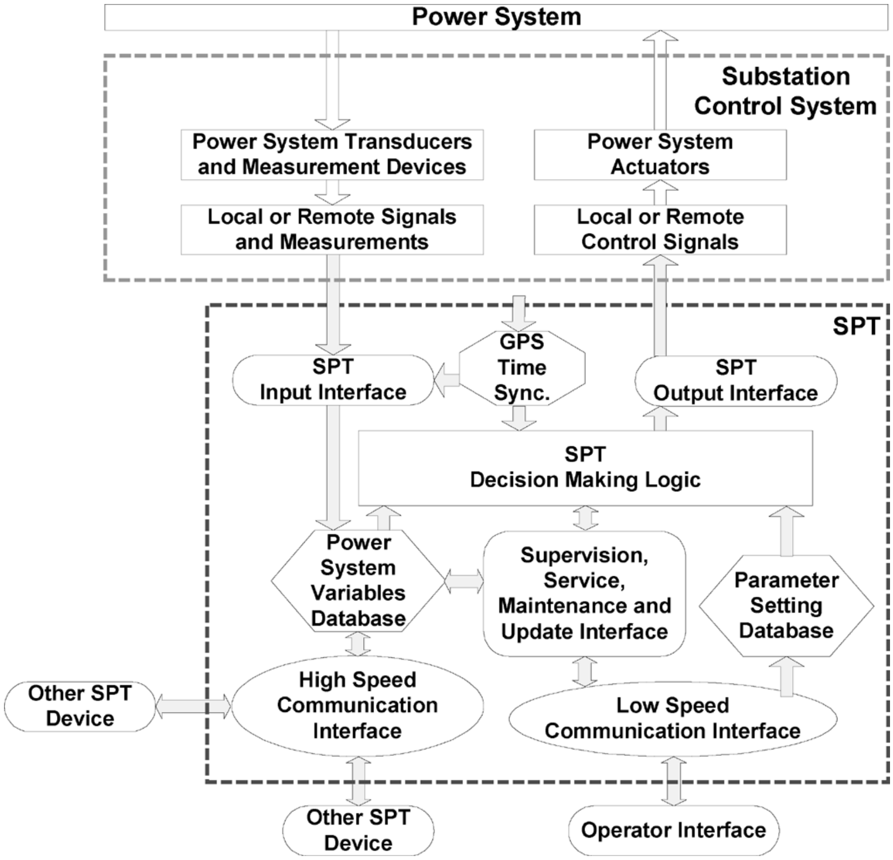


**Fig. 5.** System protection terminal, design, and interfaces.

also serve as a backup supervision system that supplies the operator with the most critical power system data, in case of a SCADA system failure.

The system protection terminal will probably be designed from a protection terminal to fulfill all requirements concerning mechanical, thermal, EMC, and other environmental requirements for protection terminals. Design and interfaces of a system protection terminal are shown in Fig. 5.

The terminal is connected to the substation control system, CTs, and VTs as any other protection terminal. For applications that include phasors, i.e., phase angles for voltages or currents, a GPS antenna and synchronization functions are also required. The system protection terminal comprises a high-speed communication interface to communicate power system data between the terminal databases. In the database, all measurements and binary signals recorded in that specific substation are stored and updated, together with data from the other terminals, used for actions in the present terminal. The ordinary substation control system is used for the input and output interfaces toward the power system process. The decision making logic contains all the algorithms and configured logic necessary to derive appropriate output control signals, such as circuit-breaker trip, AVR-boosting, and tap-changer action, to be performed in that substation. The input data to the decision-making logic is taken from the database and reflects the overall power system conditions. A low-speed communication interface for SCADA communication and operator interface should also be available. Via this interface, phasors can be sent to the SCADA state estimator for improved state estimation. Any other value or status indicator from the database could also be sent to the SCADA system. Actions ordered from SCADA/EMS functions, such as optimal power flow, emergency load control, etc., could be activated via the system protection terminal. The power system operator should also have access to the terminal, for supervision, maintenance, update, parameter setting, change of setting groups, disturbance recorder data collection, etc.

It can be concluded that there is a the great potential for wide-area protection and control systems, based on powerful, flexible, and reliable system protection terminals, high-speed, communication, and GPS synchronization in conjunction with careful and skilled engineering by power system analysts and protection engineers in cooperation.

## X. Examples of Wide-Area Protection Systems

In this section, a small number of wide-area protection systems will be described.

### A. *Protection Against Voltage Collapse in the Hydro-Québec System*

The Hydro-Québec system is characterized by long distances (up to 1000 km) between the northern main generation centers and the southern main load area. The peak load is around 35 000 MW. The long EHV transmission lines have high series reactances and shunt susceptances. At

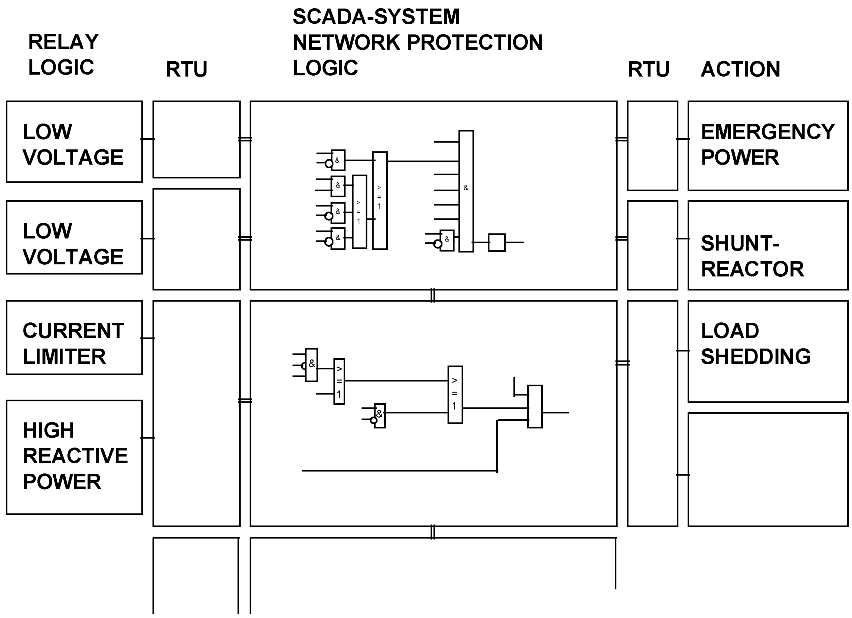


**Fig. 6.** SCADA system network protection logic in the Swedish system.

low power transfers, the reactive power generation of EHV lines is compensated by connecting 330 Mvar shunt reactors at the 735-kV substations. At peak load, most of the shunt reactors are disconnected while voltage control on the lower side of transformers implies connection of shunt capacitors. Both effects contribute to a very capacitive characteristic of the system.

Automatic shunt reactor tripping was implemented in 1990, providing an additional 2300-Mvar support near the load centers. The switching is triggered by low 735-kV bus voltages or high compensator reactive power productions. Another emergency control used is the automatic increase in voltage set-points of shuntC capacitors.

### *B. SPS Against Voltage Collapse in Southern Sweden*

The objective of the SPS is to avoid a voltage collapse after a severe fault in a stressed operation situation. The system can be used to increase the power transfer limits from the north of Sweden or to increase the system security or to a mixture of both increased transfer capability and increased security. The SPS was commissioned in 1996. The system is designed to be in continuous operation and independent of system operation conditions such as load dispatch, switching state, etc. A number of indicators such as low voltage level, high reactive power generation, and generator current limiters hitting limits are used as inputs to a logical decision-making process implemented in the Sydkraft SCADA system. Local actions are then ordered from the SCADA system, such as switching of shunt reactors and shunt capacitors, start of gas turbines, request for emergency power from neighboring areas, disconnection of low-priority load, and, finally, load shedding. Shedding of high-priority load also requires a local low-voltage criterion in order to increase security. The logic is shown in Fig. 6.

The SPS is designed to have a high security, specially for the load-shedding, and a high dependability. Therefore, a number of indicators are used to derive the criteria for each action.

### *C. Wide-Area Undervoltage Load Shedding (BC Hydro System)*

BC Hydro has developed an automatic load shedding remedial action scheme to protect the system against voltage collapse. The voltage collapse may be caused by a second or multiple sequential contingencies such as the forced outage of a critical major transmission line while the system is already weakened by another outage. A closed-loop feedback scheme will monitor the system condition, determine the need of load shedding, shed appropriate blocks of preselected loads in 10–120 s with sequential time delays, and stop when proper system voltage and dynamic VAr reserves are restored.

The scheme is based on a centralized feedback system which continually assesses the entire system condition using the actual dynamic response of the system voltages at key buses and dynamic var reserves of two large reactive power sources in the load area to identify impending voltage instability and then sheds predetermined loads in steps recursively until the potential for voltage collapse is eliminated. The use of both low voltage and low var reserve provides an added security against possible voltage measurement errors and allows higher than usual undervoltage settings to protect against conditions where collapse starts at near normally acceptable operating voltage levels. The key voltage buses are selected based on their sufficiently high fault levels and having multiple low-impedance connections to load centers so that local system outages or var equipment operations will not affect the voltages significantly to cause misoperation. The var sources are selected based on their large capacity relative to the total load area dynamic var capacity. In addition, they must have multiple connections to the load center so that their reserves can be reliably used to reflect the system reserves. Since the low voltage and low var reserve occur for system voltage instability irrespective of the cause, such as different line outages, major reactive support equipment outages, increased loading and intertie flows, transformer tap movement, or shifted generation patterns, this scheme will provide a safety net against voltage collapse from such causes.

### *D. Ontario Hydro System*

A coordinated undervoltage protection scheme is employed consisting of the following.

a) Short-time automatic reclosure on major 230-kV lines supplying areas with voltage collapse risk.
b) Automatic load shedding of different areas in two time steps. If in reference substations, the voltage measurement gives voltage drops below a certain reference value, the areas are shed in 10 s.
c) Automatic capacitor switching for maximum reactive power infeed and voltage support.
d) Automatic OLTC blocking.

### *E. Florida Power and Light (FPL) Fast Acting Load Shedding (FALS)*

FPL installed an FALS system to protect against severe system overloads not covered by conventional underfrequency load shedding in 1985 [36].

System planning studies revealed that the addition of two 500-kV lines had strengthened connections to neighboring utilities so much that system separation could not be assured under certain double contingency losses of FPL generation. This meant that existing underfrequency load shedding would not operate to keep the system stable under these double contingencies. Simultaneous loss of two or more large generators (with more than 1200 MW total output) could result in excessive power import into the state of Florida which could result in what was called a "stable but overloaded" system condition. That condition would leave the systems intact (without separation) but with severe thermal and reactive overloads which could lead to voltage collapse and uncontrolled system separations after approximately 30 s.

The FALS program runs in the system control center (SCC) computers in Miami, FL, and uses statewide SCADA communications to recognize a "stable system overload" that results in lines operating above their ratings, low system voltages at predetermined key substations, and heavy reactive power demands upon generators. When this condition is detected, FALS initiates a trip signal to shed a predetermined amount of load by tripping subtransmission lines at certain stations to prevent loss of bulk transmission lines and/or generators that could cause a blackout.

The FALS program is based on a six-by-six matrix of alarm conditions of individually telemetered points. Each matrix cell shows (in order) the monitored point, the present value and the alarm point setting. At least one point in each row must be in the alarm condition to set a flag for that row. All six rows must have their respective flag set to initiate a load shed signal with no intentional delay. Load shedding without delay is expected to occur within 20 s of a disturbance that requires shedding. A delayed load shed is initiated if four specific row flags are set and verified in the alarm condition for a specific time delay. The time delay is to allow offline capacitor banks to switch in and mitigate those less severe overloads.

Each element in the matrix uses voltage or power measurements already available in the computer. Only one phase is monitored for voltage measurements, and two and one-half-element watt transducers are used for the power measurements.

The program must shed a minimum of 800 MW, independent of the system load. Since fewer transmission lines need to be shed at high loads to reject the 800 MW, the FALS program bases the number of lines to be shed on the current system load.

To improve the security of the scheme, the FALS trip signal received at each substation is supervised in a permissive mode by an underfrequency relay. These relays are set at 59.95 Hz, which will allow operation for most generation disturbances in the state. The underfrequency relays' outputs remain energized for 1 m to allow time for load shedding if necessary.

The matrix parameters are revised as the system changes so that the FALS program remains coordinated with the system response.

### *F. France, EDF: DRS Scheme Against Losses of Synchronism*

*Principle of Operation:* The French system can be decomposed in areas of dynamic coherence. When a loss of synchronism appears, all the units of the area lose synchronism together. Within these areas, generators are strongly connected to each other. Links between areas are weaker. In the case of loss of synchronism, tripping the faulted units with a pole slip relay protects the generator, but does not ensure that the collapse will be completely stopped, especially when the system is highly meshed. It is necessary to prevent the instability from propagating through the system, and the best way to achieve it is to isolate the areas that have lost synchronism so to rescue the system, before losses of synchronism are induced in other areas (neighboring or distant).

After several incidents in the 1970s, out-of-step relays named "the DRS Plan" were installed at both ends of the lines crossing the borders of the dynamically coherent areas. Their aim is to open all the transmission lines bordering the area so to isolate it. The out-of-step relay watches the voltage locally, triggers when large voltage deviations are detected (one of the effects of the loss of synchronism), and trips the line. The triggering criteria are the depth and the number of swings. These criteria are set with the help of simulation tools for each voltage level. This protection scheme operates locally at only one voltage level and does not need communication with any other device.

The use of out-of-step relays implies that the distance relays of all lines do not trigger in the case of the loss of synchronism. Only the DRS schemes should trip the suitable lines bordering the zones to avoid uncoordinated opening of lines. One solution that ensures that no unexpected line will trip is to use out-of-step blocking scheme in the distance relays. The French system is divided into 19 areas, all equipped with the DRS protective relays on the borderlines, including the lines connected to the systems of the neighboring countries. These schemes have been in operation for more than 15 years.

*Limits of the Scheme:* Even though it proved to be efficient, the out-of-step relay plan may lead to a nonoptimal islanding of the faulted area. The potential weaknesses of the out-of-step relays scheme are inherent to its characteristics.

- The measurements are processed locally, whereas the loss of synchronism affects large areas.
- The voltage swings are only an effect of the loss of synchronism and is not the origin of it, which is angular instability.

Suboptimal efficiency can be explained with the following criteria.

- *Simultaneity*: All the lines are not tripped simultaneously, leading in some cases to delay the completed isolation of the unstable zone.
- *Completion*: Some lines may not be tripped, because the depth of the voltage swings stays under the criteria threshold (for example if the relay is located at a node of swings) but they are still able to induce losses of synchronism.
- *Selectivity*: Consequently to the definition of the homogeneous zones, when frequency instability occurs, the largest swings are expected on the borderlines between two homogeneous areas. In multizone protection with out-of-step relays, the voltage swings may sometimes be observed in a wide area. As a result, unwanted or uncoordinated line tripping is possible.

### *G. France, EDF: Syclopes—Coordinated Scheme Against Losses of Synchronism*

The advantages and weaknesses of the out-of-step relays defence plan (listed above) were highlighted by major contingencies in the early 1980s. System modeling and analysis tools became available and allowed a more complete approach.

To get accurate and quick information from the system, the scheme needs to come closer to the root of the instability: angular and frequency difference between two points. The best way to get to it is to process the phasors of the generators of each homogeneous group of generators, and then to compare continuously the angle distance between the homogeneous areas. This principle is used in the second generation of SPS against loss of synchronism developed by EDF, and called *Syclopes* (see Fig. 7). The functions that *Syclopes* realizes are:

- detection of the loss of synchronism;
- tripping of all the lines bordering the homogeneous areas that loses synchronism; and
- order for load shedding if needed.

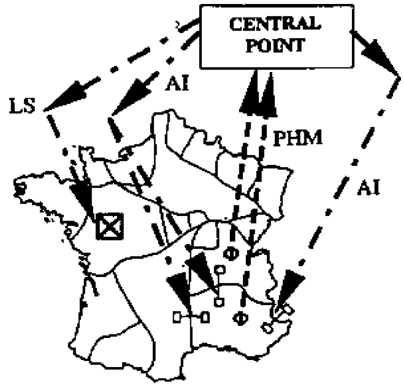


**Fig. 7.** Syclopes communication network diagram (PHM = Phase Measurements, AI = Area Islanding, LS = Load Shedding).

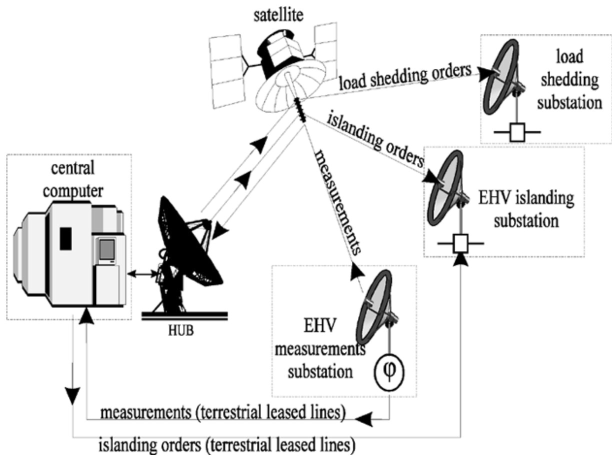


**Fig. 8.** Syclopes communication network.

The principle of operation of this new SPS is that the information of the whole power system is processed in one central point, in a global and coordinated task:

- local measurements on the network are sent to the central point;
- information from the whole system is processed in the central point computer, and the affected zone is detected;
- the central point orders actions to local substations so to isolate the affected zone by opening all the border lines of it; and
- if necessary, the central point orders actions to HV/MV substations for load shedding, so to prepare the active power balance for the postislanding sequence and keep the frequency within an acceptable range.

In the first step (see Fig. 8), *Syclopes* has been developed for the isolation of two southeastern coherent areas in the French system that were identified as critical toward the loss of synchronism. These areas are exporting large amounts of active power and need loads to be shed most often when cut out from the rest of the system, to prevent induced loss of synchronism. When compared to the DRS plan, the coordinated SPS *Syclopes* brings the following improvements.

- Phasor detection of the loss of synchronism is closer to the origin of the event and reduces the delay for detection.
- Global processing gives selectivity and accuracy of the actions.
- Simultaneity and completion of the line tripping process with limited delay preserve the stability of the generators in remote areas.
- Simultaneity of the load shedding and the line tripping processes keep the rest of the system in a better state: higher frequency and robustness.

Every part of the SPS needs to be highly reliable and safe to guaranty that the probability of unwanted actions like line tripping or load shedding is acceptable and to ensure proper action in case of loss of synchronism, which includes:

- phasor measurements and local preprocessing;
- information transmission to the central point;
- real-time information process in central point;
- order transmission; and
- order application (line tripping, load shedding at HV/MV substations).

Additionally, the speed of the phenomenon needs quick communication means for both ways (forth from local to the central point and back).

The SPS has been installed in two southeastern coherent areas and is currently operating in an open loop; that is to say, the action orders are locked. The closed loop operation was started in the year 2000. In addition to the protection, the ongoing operation in open loop provides information through its synchronized phasor measurements. To achieve these requirements, a two-way communication network (wire/satellite) is used (see Fig. 8). Additional information is available in [43]–[48]. Two other homogeneous areas are potential future application fields for the Syclopes-coordinated SPS.

## XI. Conclusion

There are numerous existing applications of wide-area protection and control systems, and some examples have been described and discussed. Existing implementations use simple measurements. Sometimes the measurements are local only (e.g., out-of-step tripping or underfrequency load shedding). In other cases, the measurements and actions use wide-area information and communications systems. The more complex decision processes (e.g., southern Sweden's SPS against voltage collapse, and Florida's FALS) employ SCADA for information gathering that allows a time frame only of several seconds for actions. Higher speed wide-area protection systems required to prevent angular instability or fast voltage collapse (e.g., direct load or generator rejection), respond primarily to contingencies identified in offline planning studies, and are limited in effectiveness against unforeseen disturbances.

Better detection and control strategies through the concept of advanced wide-area disturbance protection offer a better management (than existing) of the disturbances and significant opportunity for more reliable system performance under higher power transfers and operating economies. This advanced protection is a concept of using system-wide information together with distributed local intelligence and communicating selected information between separate locations to counteract propagation of the major disturbances in the power system.

With the increased availability of sophisticated computer, communication and measurement technologies, more "intelligent" equipment can be used at the local level to improve the overall emergency response. There seems to be a great potential for wide-area protection and control systems, based on powerful, flexible and reliable system protection terminals, high speed, communication, and GPS synchronization in conjunction with careful and skilled engineering by power system analysts and protection engineers in cooperation. Additional information about the topics presented in this paper can be found in the companion papers [49] and [50], authored by the members of the Working Group "Wide Area Protection and Emergency Control" of the IEEE PES Power System Relaying Committee.

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