Synchronized Phasor Measurement Applications in Power Systems

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Abstract—Synchronized phasor measurements have become a mature technology with several international manufacturers offering commercial phasor measurement units (PMUs) which meet the prevailing industry standard for synchrophasors. With the occurrence of major blackouts in many power systems around the world, the value of data provided by PMUs has been recognized, and installation of PMUs on power transmission networks of most major power systems has become an important current activity. This paper provides a brief introduction to the PMU and wide-area measurement system (WAMS) technology and discusses the uses of these measurements for improved monitoring, protection, and control of power networks.

Index Terms—Electrical transients, global positioning system, phasor, phasor measurement unit, power system, power system control, power system monitoring, power system protection, real-time measurements, synchronized measurements, synchrophasor

I. INTRODUCTION

SYNCHRONIZED phasor measurement units (PMUs) were first introduced in early 1980s, and since then have become a mature technology with many applications which are currently under development around the world. The occurrence of major blackouts in many major power systems around the world has given a new impetus for large-scale implementation of wide-area measurement systems (WAMS) using PMUs and phasor data concentrators (PDCs) in a hierarchical structure. Data provided by the PMUs are very accurate and enable system analysts to determine the exact sequence of events which have led to the blackouts, and help analyze the sequence of events which helps pinpoint the exact causes and malfunctions that may have contributed to the catastrophic failure of the power system. As experience with WAMS is gained, it is natural that other uses of phasor measurements will be found. In particular, significant literature already exists which deals with application of phasor measurements to system monitoring, protection, and control.

This paper is organized as follows. Section II reviews the basic concepts of phasor representation of power system voltages and currents under normal and abnormal operating conditions. Section III discusses many of the applications of the phasor measurements which have been discussed in the literature. Section IV provides concluding remarks with some assessment of the direction in which short-term and long-term applications of this technology will emerge.


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Fig. 1. Phasor representation of a sinusoidal signal. (a) Sinusoidal signal. (b) Phasor representation.

II. PHASOR MEASUREMENT UNITS

A. Classical Definition of a Phasor

A pure sinusoidal waveform can be represented by a unique complex number known as a phasor. Consider a sinusoidal signal

\[ x(t) = X_m \cos(\omega t + \phi), \]

(1)

The phasor representation of this sinusoid is given by

\[ X \equiv \frac{X_m}{\sqrt{2}} e^{j\phi} = \frac{X_m}{\sqrt{2}} (\cos\phi + j \sin\phi), \]

(2)

Note that the signal frequency \( \omega \) is not explicitly stated in the phasor representation. The magnitude of the phasor is the rms value of the sinusoid \( X_m/\sqrt{2} \), and its phase angle is \( \phi \), the phase angle of the signal in (1). The sinusoidal signal and its phasor representation given by (1) and (2) are illustrated in Fig. 1.

Note that positive phase angles are measured in a counterclockwise direction from the real axis. Since the frequency of the sinusoid is implicit in the phasor definition, it is clear that all phasors which are included in a single phasor diagram must have the same frequency. Phasor representation of the sinusoid implies that the signal remains stationary at all times, leading to a constant phasor representation. These concepts must be modified when practical phasor measurements are to be carried out when the input signals are not constant, and their frequency may be a variable. This will be discussed in the next section.

B. Phasor Measurement Concepts

Although a constant phasor implies a stationary sinusoidal waveform, in practice it is necessary to deal with phasor measurements which consider the input signal over a finite data window. In many PMUs the data window in use is one period of the fundamental frequency of the input signal. If the power
system frequency is not equal to its nominal value (it seldom is), the PMU uses a frequency-tracking step and thus estimates the period of the fundamental frequency component before the phasor is estimated. It is clear that the input signal may have harmonic or nonharmonic components. The task of the PMU is to separate the fundamental frequency component and find its phasor representation.

The most common technique for determining the phasor representation of an input signal is to use data samples taken from the waveform, and apply the discrete Fourier transform (DFT) to compute the phasor. Since sampled data are used to represent the input signal, it is essential that antialiasing filters be applied to the signal before data samples are taken. The antialiasing filters are analog devices which limit the bandwidth of the pass band to less than half the data sampling frequency (Nyquist criterion).

If \( x_k \{k = 0, 1, \ldots, N - 1 \} \) are the \( N \) samples of the input signal taken over one period, then the phasor representation is given by [1]

\[
X = \frac{\sqrt{2}}{N} \sum_{k=0}^{N-1} x_k e^{-j\frac{2\pi k}{N}}. \tag{3}
\]

The multiplier in front of the summation sign may need some explanation. Note that for real input signals, the components of the signal at a frequency \( \omega \) appear in the DFT at \( \pm \omega \) and are complex conjugates of each other. They can be combined, giving a factor of 2 in front of the summation sign in (3). The peak value of the fundamental frequency thus obtained is then converted to rms value by dividing by \( \sqrt{2} \). The DFT calculation eliminates the harmonics of the input signal. However, the nonharmonic signals and any other random noise present in the input signal leads to an error in estimation of the phasor. The error of estimation due to these effects has been discussed in the literature.

C. Synchrophasor Definition and Measurements

Synchrophasor is a term used to describe a phasor which has been estimated at an instant known as the time tag of the synchrophasor. In order to obtain simultaneous measurement of phasors across a wide area of the power system, it is necessary to synchronize these time tags, so that all phasor measurements belonging to the same time tag are truly simultaneous. Consider the marker \( t = 0 \) in Fig. 1 is the time tag of the measurement. The PMU must then provide the phasor given by (2) using the sampled data of the input signal. Note that there are antialiasing filters present in the input to the PMU, which produce a phase delay depending upon the filter characteristic. Furthermore, this delay will be a function of the signal frequency. The task of the PMU is to compensate for this delay because the sampled data are taken after the antialiasing delay is introduced by the filter. This is illustrated in Fig. 2.

The synchronization is achieved by using a sampling clock which is phase-locked to the one-pulse-per-second signal provided by a GPS receiver. The receiver may be built in the PMU, or may be installed in the substation and the synchronizing pulse distributed to the PMU and to any other device which requires it.

The time tags are at intervals that are multiples of a period of the nominal power system frequency.
the frequency measurements. This and similar measurements in other parts of the country eventually led to the development of a frequency monitoring network, FNET. Although limited in the information provided the time synchronized frequency monitoring network has stimulated high interest among the academic and regulatory communities due to their operation at residential voltage level eliminating installation cost and data ownership issues. PMU and FNET data have shown that any significant loss of generation in a system will cause an electromechanical oscillation that will propagate through the system at slow speed. FNET data have shown that it is not only possible to detect these oscillations at residential voltage levels but also to use the frequency change to predict the amount of generation loss. It is also possible with some limitation to use the traveling wave to determine the location of the event [5].

In the 2003 Northeastern U.S. blackout and the 1996 U.S. West Coast blackouts, the PMU monitoring capabilities were essential for the quick and accurate postmortem analysis of the events. One of the recommendations from the United States–Canada Task Force on the 14 August 2003 blackout is to “require use of time-synchronized data recorders” to all utilities [6]. This and other recommendations led to the creation of the Eastern Interconnection Phasor Project (EIPP), now known as North American Synchrophasor Project (NASPI). The EIPP performed the first real-time wide-area monitoring in the United States after solving some minor but interesting problems, such as the determination of a common phase “a” for the whole eastern grid. NASPI continues to solve some of the existing problems for the creation of a reliable real-time synchronized monitoring system such as the availability of a commercial data concentrator capable of handling hundreds of PMUs at the high communication rates required for most proposed applications.

With PMU installation cost ranging from 10 k to 70 K (depending on the utility, location, and availability of communication channels) placing PMUs in the optimum locations is one of the first steps of a wide-area monitoring system [7]. PMU placement aimed at system monitoring is usually developed for full system observability. Concepts such as depth of observability have been developed to allow for a maximum utilization of data through a staged deployment of a monitoring system for full observability [9]. Other placement algorithms have been developed for specific applications such as Islanding and enhanced state estimation. PMU placement studies require the development of specific placement system models. System models used in commercial analysis software include virtual buses that either do not exist or are not practical locations to install PMUs, such as tapped line buses, shunt elements and series capacitor nodes. These virtual buses may add up to 1/3 more nodes to the model and increase the complexity of the problem. Not eliminating these nodes from the placement model may result in PMUs being placed in unrealistic locations. This problem is solved in small models by manually eliminating virtual buses. In the case of real system models the problem is solved by developing systematic methods to eliminate virtual buses from commercial system data models [8].

2) State Estimation: Since the 1965 Northeast blackout, state estimation has become a critical application function at energy control centers. Existing state estimation algorithms [1] use measurements of line flows and injections, both real and reactive power, to estimate all bus voltage angles and magnitudes. The complex bus voltages are the state of the system. The complex power flows in lines and the complex power injections at buses can be determined from the bus voltages and an accurate model of the network. Prior to synchronized phasor measurements, the state could not be measured directly but only inferred from the unsynchronized power flow measurements. This fact and the process of getting large numbers of measurements into the control center (a scan) forced early state estimators to make compromises that persist today and have an influence on how phasor measurements are integrated into existing state estimation algorithms. The most significant of these assumptions is that the system did not change during the scan—that the system was static. Another view of the resulting estimate of the state is that it is the state of a hypothetical system which could support the complete set of measurements. Depending on how long the scan takes and the changes in the system that took place during the scan, the hypothetical system may not exist or may be quite different from the real system. While scans have become quicker, the introduction of phasor measurements forces reconsideration of the static assumption.

The direct integration of a few synchronized phasor measurements into an existing nonlinear estimator is straightforward but results in an estimator that has most of the limitations of the original conventional estimator. The new estimator is still recursive and still has the assumptions required for the static state estimator. The issue of how to place the precisely timed PMU data into the scanned data can also introduce a skew.

If an estimate could be formed with only PMU data, then the issues of data scan and time skew could be eliminated. The PMU data would be time tagged and the static assumption removed. Since the voltage and current measurements are linear functions of the system state, the estimation problem is simple a linear weighted least squares problem which requires no iterations. Given PMU data can be reported at rates as high as 60 times a second, a truly dynamic estimate would be available. An estimate of a dynamic system at an instant in time corresponding to the measuring instant would be obtained. Issues that must be addressed include the need for redundancy to eliminate bad data and determination of how many PMUs are required.

Recognizing that a PMU in a substation would have access to line currents in addition to the bus voltage reduces the number of PMUs needed. Measuring line currents can extend the voltage measurements to buses where no PMU is installed. Using a model of the transmission line, the line current can be used to compute the voltage at the other end of the line. With a large number of PMUs the redundancy issue is addressed. On the other hand, the smallest number of PMUs needed to indirectly measure all the bus voltages and the optimum PMU location to achieve this has been a subject of a number of papers. [9]–[11]. With different approaches, treatment of zero injection buses, and differing assumptions about types of PMU used, the consensus is that the minimum number of PMUs is approximately one-third the total number of buses. A compromise between the full nonlinear and linear formulations is described in [12].

An interesting subproblem is the issue of sequentially adding PMUs to a system. With limited annual investments it would be desirable to add a limited number of PMUs until a final goal
was achieved. Initially there will not be enough PMUs to have a linear estimator. The attempt is to place the PMUs so that at each stage the selection satisfies some design criteria. One criterion is the degree of unobservability [11], which measures how far away a bus is from a PMU. The solution to this problem is available using the technique from [12].

\[
A = \begin{bmatrix}
1 & 1 & 0 & 0 & 1 & 0 & 0 & 0 & 0 & 0 & 0 & 0 & 0 & 0 & 0 \\
1 & 1 & 1 & 1 & 1 & 0 & 0 & 0 & 0 & 0 & 0 & 0 & 0 & 0 & 0 \\
0 & 1 & 1 & 1 & 0 & 0 & 0 & 0 & 0 & 0 & 0 & 0 & 0 & 0 & 0 \\
0 & 1 & 1 & 1 & 1 & 0 & 1 & 0 & 1 & 0 & 0 & 0 & 0 & 0 & 0 \\
1 & 1 & 0 & 1 & 1 & 1 & 0 & 0 & 0 & 0 & 0 & 0 & 0 & 0 & 0 \\
0 & 0 & 0 & 0 & 0 & 1 & 0 & 0 & 0 & 1 & 1 & 1 & 0 & 0 & 0 \\
0 & 0 & 0 & 0 & 0 & 0 & 1 & 0 & 0 & 0 & 0 & 1 & 1 & 0 & 0 \\
0 & 0 & 0 & 0 & 0 & 1 & 0 & 0 & 1 & 1 & 0 & 0 & 0 & 0 & 0 \\
0 & 0 & 0 & 0 & 0 & 0 & 0 & 0 & 1 & 1 & 0 & 0 & 0 & 0 & 0 \\
0 & 0 & 0 & 0 & 0 & 0 & 0 & 1 & 0 & 0 & 0 & 1 & 1 & 0 & 0 \\
0 & 0 & 0 & 0 & 0 & 0 & 1 & 0 & 0 & 0 & 1 & 1 & 0 & 0 & 0 \\
0 & 0 & 0 & 0 & 0 & 0 & 0 & 0 & 0 & 0 & 0 & 1 & 0 & 0 & 1 \\
0 & 0 & 0 & 0 & 0 & 0 & 0 & 0 & 0 & 0 & 0 & 0 & 0 & 0 & 1
\end{bmatrix}.
\tag{4}
\]

The bus–bus incidence matrix \( A \) is a square matrix with the dimension of the number of buses. There is a one on each diagonal and a one in the \( ij \)th position if bus \( j \) is connected to bus \( i \). The \( A \) matrix for the IEEE 14 bus system is given in (4). If we imagine placing a PMU at bus 2, for example, we would learn the voltages at buses 1, 2, 3, 4, and 5, which are the nonzero entries in column 2 of \( A \).

The placement problem for complete observability is then given by the integer programming problem in (5) [14]. It is interesting to note that the powers of the incidence matrix have an interpretation that helps extend the integer programming problem to the partial observability problem

\[
\begin{align*}
\min & \ f^T x \\
\text{subject to} & \ Ax \succ 0, \ x_i = 1 \text{ or } 0 \\
& f^T = [1 \quad 1 \quad 1 \quad \cdots \quad 1].
\end{align*}
\tag{5}
\]

**Theorem:** The \( ij \) entry in the \( n \)th power of the incidence matrix for any graph or digraph is exactly the number of different paths of length \( n \), beginning at vertex \( i \) and ending at vertex \( j \) [13] (see (6)).

\[
\text{sign}(A^2) = \begin{bmatrix}
1 & 1 & 1 & 1 & 1 & 1 & 0 & 0 & 0 & 0 & 0 & 0 & 0 & 0 & 0 \\
1 & 1 & 1 & 1 & 1 & 1 & 1 & 0 & 1 & 0 & 0 & 0 & 0 & 0 & 0 \\
1 & 1 & 1 & 1 & 1 & 1 & 1 & 1 & 1 & 1 & 0 & 0 & 0 & 0 & 0 \\
1 & 1 & 1 & 1 & 1 & 1 & 1 & 1 & 1 & 1 & 1 & 0 & 0 & 0 & 0 \\
1 & 1 & 0 & 1 & 1 & 1 & 1 & 0 & 0 & 1 & 1 & 1 & 1 & 1 & 1 \\
0 & 1 & 1 & 1 & 1 & 0 & 1 & 1 & 1 & 1 & 1 & 0 & 0 & 0 & 0 \\
0 & 0 & 0 & 0 & 0 & 1 & 1 & 1 & 1 & 1 & 1 & 0 & 0 & 0 & 0 \\
0 & 0 & 0 & 0 & 0 & 0 & 1 & 1 & 1 & 1 & 1 & 0 & 0 & 0 & 0 \\
0 & 0 & 0 & 0 & 0 & 0 & 0 & 0 & 0 & 0 & 0 & 1 & 1 & 1 & 1 \\
0 & 0 & 0 & 0 & 0 & 0 & 0 & 0 & 0 & 0 & 0 & 1 & 1 & 1 & 1 \\
0 & 0 & 0 & 0 & 0 & 0 & 0 & 0 & 0 & 0 & 0 & 0 & 0 & 0 & 1 \\
0 & 0 & 0 & 0 & 0 & 0 & 0 & 0 & 0 & 0 & 0 & 0 & 0 & 0 & 1 \\
0 & 0 & 0 & 0 & 0 & 0 & 0 & 0 & 0 & 0 & 0 & 0 & 0 & 0 & 1
\end{bmatrix}.
\tag{6}
\]

The proof is by induction. The signum of \( A^2 \) is the incidence matrix of another graph that has branches added to the graph in Fig. 3. The dashed branches in Fig. 3 represent connections between nodes that pass through another node, i.e., those nodes are one step removed. If we imagine the complete observability problem is solved \( x_{1j} \) is the solution to (5) the one degree of unobservability problem is the solution of

\[
\begin{align*}
\min & \ f^T x_2 \\
\text{subject to} & \ \text{sign}(A^2)x_2 \succ 0, \ x_{2i} = 1 \text{ or } 0 \\
& f^T = [1 \quad 1 \quad 1 \quad \cdots \quad 1].
\end{align*}
\tag{7}
\]

And the addition of the constraint \((f - x_{1})^T x_2 = 0\) forces the solution to be chosen from the PMU location in \( x_{1j} \) [8]. So in general the sequence of integer programming problems in (8)

\[
\begin{align*}
\min & \ f^T x_n \\
\text{subject to} & \ \text{sign}(A^{n+1})x_n \succ 0 \\
& (f^T - x_{n-1})^T x_n = 0
\end{align*}
\tag{8}
\]

produce a nested sequence of PMU locations. For the 14-bus system the locations are given in Table I.

Solutions of (8) for a 1400-bus system with a depth of 5 are given in [1]. The first problem is a large amount of computation for large systems. The subsequent problems are much easier.

**B. Power System Protection**

Synchronized phasor measurements offer solutions to a number of complex protection problems. In general, phasor measurements are particularly effective in improving protection functions, which have relatively slow response times. For such protection functions, the latency of communicating information from remote sites is not a significant issue. A few examples of protection systems that could benefit from remote phasor measurements information could include (B-1), control of backup protection of distance delays (B-2), protection functions concerned with angular stability of networks (B-3),
Fig. 4. Loadability limit imposed by zone-3 setting of a distance relay. The illustration shows a mho characteristic, which is commonly used in many relays. As the load increases along the bold arrow, it would enter the tripping zone of the relay and cause an inappropriate trip.

Fig. 5. Supervisory control for backup protection.

voting schemes where dependability and security could be reassessed based upon the stress of the system. A number of other WAMS-based protection improvements can be found in [1].

1) Control of Backup Relay Performance: Backup zones of distance relays are prone to tripping due to load encroachment during power system disturbances. This has led to a call for reassessing and sometimes abandoning the use of backup zones—in particular zone-3 of distance relays (see Fig. 4), which is used to protect downstream circuits in case their protection systems fail to remove a fault on those circuits. [15] Abandoning Zone-3 may be too drastic, and should not be applied as a blanket policy. The remote backup policy is designed to cover certain contingencies [16] for which no other protection is available. Under these circumstances, it becomes necessary to consider ways in which the loadability limits imposed by the remote backup zones can be circumvented [17].

Wide-area measurements offer a possibility for restraining the remote back-up relays in the event that the load swing is being interpreted by the relay as a fault [18]. Consider the conditions illustrated in Fig. 5. Zone-3 of relay A is assumed to be picked up. If a significant negative sequence current is present (indicating an unbalanced fault), the zone-3 pick up is appropriate, and no further action is necessary. However, if the currents in the line are balanced, either a three phase fault on the neighboring circuits or a possible loadability violation may be inferred. The PMUs at the buses corresponding to the terminals of lines which are to be backed-up by relay A may then determine if any of them see a Zone-1 three-phase fault. If none of the PMUs indicate that a Zone-1 three-phase fault exists, then the Zone-3 pick-up of relay A must be due to loadability limit violation. If tripping on this condition by relay A is to be avoided, it would then be possible to block its operation by supervisory control of its output.

2) Adaptive Out-Of-Step Protection: It is recognized that a group of generators going out of step with the rest of the power system is often a precursor of a complete system collapse. Whether an electromechanical transient will lead to stable or unstable condition has to be determined reliably before appropriate control action could be taken to bring the power system to a viable steady state. Out-of-step relays are designed to perform this detection and also to take appropriate tripping and blocking decisions.

Traditional out-of-step relays use impedance relay zones to determine whether or not an electromechanical swing will lead to instability. In order to determine the settings of these relays, it is necessary to run a large number of transient stability simulations for various loading conditions and credible contingencies. Using the apparent impedance trajectories observed at locations near the electrical center of the system during these simulation studies, two zones of an impedance relay are set, so that the inner zone is not penetrated by any stable swing.

Problems With Traditional Out-of-Step Relays: Traditional out-of-step relays are found to be unsatisfactory in highly interconnected power networks. This is because the conditions and topologies assumed when the relay characteristics are determined become out-of-date rather quickly, and in reality the electromechanical swings that do occur are quite different from those studied when the relays are set. The result is that traditional out-of-step relays often misoperate: they fail to determine correctly whether or not an evolving electromechanical swing is stable or unstable. Wide-area measurements of positive sequence voltages at networks (and hence swing angles) provide a direct path to determining stability using real-time data instead of using precalculated relay settings.

It should be noted that a related approach was developed for a field trial at the Florida–Georgia interface [19]–[22] where the interface was modeled as a two machine system. The machines in Fig. 6 are equivalents of the eastern interconnection on the left and Florida on the right with the four buses being physical buses in the interconnection. The equation of motion of the angle difference between the two rotors of the two machines is given by (9) where \( \delta = \delta_1 - \delta_2 \). \( M_1 \) and \( M_2 \) are the two rotor inertias, and the remaining terms in (6) are obtained from the equivalent system. As the system undergoes changes due to a fault and its clearing the parameters of the differential equation \( P_c \) and \( P_{\text{max}} \) change and the classical equal-area criterion
can be used to determine stability. That is, the area $A_1$ must be smaller than the area $A_2$ for stability (see Fig. 7). The issue in adaptive out-of-step is to determine the new parameter values $P_c$ and $P_{\text{max}}$ from real time measurements. A least squares estimate of $P_m$ [22] from samples of $\delta$ is used in [19]. The estimate is obtained from five or six consecutive measurements of $\delta$

$$M \frac{d^2 \delta}{dt^2} = P_m + \{P_c - P_{\text{max}} \sin(\delta - \gamma)\}. \quad (9)$$

It is of course possible to determine whether or not a swing is unstable by waiting long enough and observing the actual swing. However, in order to take appropriate control action it is essential that a reliable prediction algorithm be developed which provided the stable–unstable classification of an evolving swing in a reasonable time. In the Florida–Georgia experiment a period of observation of actual angular swings for a maximum of 250 ms was used to obtain a reliable prediction of the outcome.

For large power networks it is not possible to apply the equal area criterion as used in the example of Florida–Georgia interface. As a first step after a transient stability event begins, groups of coherently swinging machines are identified. After two distinct groups of coherent machines are determined, they may be converted to a system of two equivalent generators connected by a network. At this point one may apply an equal area criterion as used in the example of Florida–Georgia interconnection. The phasor data will be time tagged so that control could be based on the actual state of the system at an order of 15–60 Hz is certainly sufficient to handle the control task.

with their multiple zones of protection and redundant systems are biased toward dependability, i.e., a fault is always cleared by some relay. The result is a system that virtually always clears the fault but as a consequence permits larger numbers of false trips. High dependability is recognized as being a desirable protection principle when the power system is in a normal “healthy” state, and high-speed fault clearing is highly desirable in order to avoid instabilities in the network. The consequent price paid in occasional false trip is an acceptable risk under “system normal” conditions. However, when the system is highly stressed false trips exacerbate disturbances and lead to cascading events.

An attractive solution is to “adapt” the security—dependability balance in response to changing system conditions as determined by real-time phasor measurements. Adaptive relaying with digital relays was introduced on a major scale in 1987 [23], [24]. With three primary digital protection systems it is possible to implement an adaptive security–dependability scheme by using voting logic (see Fig. 8). The conventional arrangement is that if any of the three relays sees a fault, then the breaker is tripped. A more secure decision would be made by requiring that two of the three relays see a fault before the trip signal is sent to the breaker. The advantage of the adaptive voting scheme is that the actual relays are not modified but only the tripping logic responds to system conditions.

C. Power System Control

Prior to the introduction of real-time phasor measurements power system control was essentially local. Some subsystems such as machines were controlled with only local signals. Other control action was taken based on local measurements and a mathematical model of the external world. External equivalents are such models. The introduction of phasor measurements offers the possibility of control based on measurement value of remote quantities. Latency of the phasor measurements is an issue, but the fact that many of the processes are in the 0.2–2.0 Hz range is encouraging. The phasor data will be time tagged so that control could be based on the actual state of the system a short time in the past. The frequencies involved are representative of transient stability, electromechanical oscillations, and certain overload phenomena. The frequency of measurements of the order of 15–60 Hz is certainly sufficient to handle the control task.
Wide-area measurements allowed the system to react to threatening situations without employing continuous feedback control. Monitoring of angles to detect possible instabilities and taking discrete switching controls in an attempt to mitigate against these events is a form of control made possible with synchrophasors [25], [26]. The training of the switching logic for such controllers has used simulation to train support vector machines [27] and decision trees obtained from data mining [26]. Incorporation of synchrophasor measurements into new system integrity protection schemes (SIPS) has also been described [28].

Early applications with continuous feedback were aimed at problems where a few phasor measurements could be applied to problems in which the control objective were global in nature: for example an HVDC controller may be called upon to damp electromechanical oscillations between two widely separated areas of a power system. Control of HVDC systems, excitation control, power system stabilizers, and FACTS devices control [29]–[37] were approached in a similar fashion. Because of the nonlinearity of these problems, the power system dynamics were linearized and linear feedback based on various robust control techniques employed. Uncertain parameters were used to model unknown time delays [37], unmodeled dynamics were used to deal with the unmeasured portion of the system [38], and LMI techniques used to design a robust $H_{\infty}$ or $H_2/H_{\infty}$ controller [29], [39].

These techniques can be used to coordinate a number of local controllers of different types. For example, a collection of power system stabilizers, dc lines, and FACTS devices could be coordinated to provide damping for a collection of interarea modes with a variation of the technique used for PSSs alone [29]. A representative scheme for such controllers is shown in Fig. 9. The local controllers retain their local input signals but have additional inputs from the wide-area controller. Selection of the PMU locations to be used and verification of the robustness of the overall scheme are important issues.

Fig. 9. A typical control based on remote synchrophasor measurements.

IV. CONCLUSION

With the growing interest in PMUs and WAMS throughout the world, it is clear that these systems will be implemented in most major transmission networks. To a large extent the success of this endeavor depends upon adherence to the industry standard governing the PMUs [2]. This standard is being revised to include requirements for compliance when power system is in nonstationary state. Compliant PMUs will assure that PMUs of different manufacture can be used interchangeably.

The earliest applications of PMU technology in most power systems are likely to be: a) validation of system models, and b) accurate postmortem analysis. As experience with real-time PMU data is gained by system operators, the next logical step would be to include PMU data in system state estimation procedures in energy management systems. With sufficient number of PMUs installed, it would be possible to perform linear state estimation, and it would be possible to track dynamic phenomena in real time. Ultimately, this ability will lead to the use of PMUs for improving protection and control functions. The goal of such improvements is to make the power system less immune to catastrophic failures and to reduce the severity of such failures when they do occur.

REFERENCES

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