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Using Synchronized Phasor Angle Difference for Wide-Area Protection and Control

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Abstract—Loss of generation or load because of power system faults causes changes in power system frequency and/or voltages. These changes depend on the power system robustness and the regulating systems' ability to respond to these changes. Furthermore, each power system has a unique dynamic behavior that depends on factors such as network transmission topology, load location, generation capacity, type of generation, etc. Automatic generation control (AGC) plays an important role in maintaining the load-generation balance in the system. This balance can suddenly be lost because of system contingencies. This lack of balance may result in changes in frequency, voltage magnitudes, and voltage angles according to the amount of generation/load lost. Comisión Federal de Electricidad (CFE) has implemented several wide-area protection schemes to minimize changes in power system frequency and/or voltages and avoid large disturbances during severe or multiple contingencies. Some of these schemes can use synchrophasor angle difference as a key signal to increase allowable power stability margins. In this paper, we present an example of a generation-shedding scheme in the 400 kV transmission networks where CFE is evaluating the use of synchronized phasor measurement angle difference to improve the reliability of existing generator-shedding schemes.

I. INTRODUCTION

Comisión Federal de Electricidad (CFE) uses traditional system protection schemes (SPSs) such as underfrequency and undervoltage load-shedding schemes to maintain power system stability. These schemes are known as automatic load-shedding schemes (ALSSs). Additionally, load shedding through direct transfer trip commands may occur when generation is lost. SPSs that shed generation resulting from the loss of transmission lines, buses, or loads are known as automatic generation-shedding schemes (AGSSs), and these schemes are also common in CFE. CFE uses generation shedding as a last resort to maintain the power load-generation balance while preserving system voltages and frequency within allowable operating limits [1] [2]. Generation shedding also helps to preserve the transmission limits in critical links without exceeding transmission line and transformer thermal limits.

Existing SPSs have minimized load shedding during system disturbances, but they also have negative impact because of additional thermal, mechanical, and electrical apparatus stress. AGSSs, in particular, cause significant generator stress; this stress reduces the generator's life. Under these circumstances, the power plant requires quick energy dissipation, which is difficult to achieve.

Successful remote load and/or generation shedding mainly rely on communications channel reliability. These schemes monitor the system topology to "arm" themselves and to select the generators to trip. An SPS with minimum components and reliable communications will minimize scheme misoperations.

II. WIDE-AREA MONITORING SYSTEM AT CFE

CFE has had a wide-area monitoring system (WAMS) in service since 1998. The system consists of strategically located phasor measurement units (PMUs) and phasor data concentrators (PDCs). It measures voltages, currents, and frequencies in real time and archives the data for post-disturbance analysis. The equipment features and placement depend on the information requirements of each user and the application level. The application levels of PMUs and PDCs include the following:

- Interconnected national system.
- Regional transmission management offices.
- Regional control centers.
- Transmission links among control areas.
- Large capacity and strategically located power plants and substations.

PMU real-time monitoring helps to detect changes in voltage magnitude, voltage angle, frequency, or power flows as soon as they occur. For example, the operator can become aware of changes in these quantities when one transmission line is lost in a network with parallel transmission paths using PMU data. This information is not available to the operator in traditional supervisory control and data acquisition (SCADA) systems.

The CFE WAMS integrates different PMU brands and models. In traditional PMU applications, programmable logic controllers (PLCs) perform control functions that wide-area protection schemes (WAPSSs) require. However, recent protective relays include synchronized measurement capabilities and integrated control functions. Therefore, in addition to protection functions, these relays can perform traditional PMU/PLC tasks. We call these relays phasor measurement and control units (PMCU). CFE is installing these relays to perform control actions based on voltage angle differences calculated at different locations in the power system. The success of these applications depends on the ability of the relays and communications networks to perform these tasks [3] [4] [5].

III. AUTOMATIC GENERATION SHEDDING USING SYNCHRONIZED MEASUREMENTS

The real power transfer, P , between two network buses connected by a reactance, X_L , is determined by the phase angle difference, δ , the voltage magnitudes at the buses, E_A and E_B , and the reactance, X_L (see Fig. 1). Notice that the angle at Bus B is 0. The two buses exchange real power according to (1).

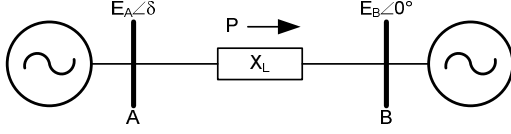


Fig. 1. δ , E_A , E_B , and X_L Determine the Real Power Transfer, P , Between Bus A and Bus B.

$$P = \frac{E_A \cdot E_B}{X_L} \cdot \sin \delta \quad (1)$$

During steady-state operating conditions, the voltage magnitudes of the network buses are close to one per unit. That is, the real power transfer capability mainly depends on the phase angle difference, δ , and the transmission link reactance, X_L . X_L depends on the number of lines and transformers in service between the two buses. When transmission lines are lost during a system disturbance, X_L increases, and the angle difference also increases to maintain the same amount of real power exchange between the two buses. Fig. 2 illustrates the real power transfer capability and the real power transfer operating point as a function of the angle difference during normal operating conditions and after transmission links are lost because of a system disturbance. Notice that the increase in impedance between the system buses reduces the system maximum power transfer capability.

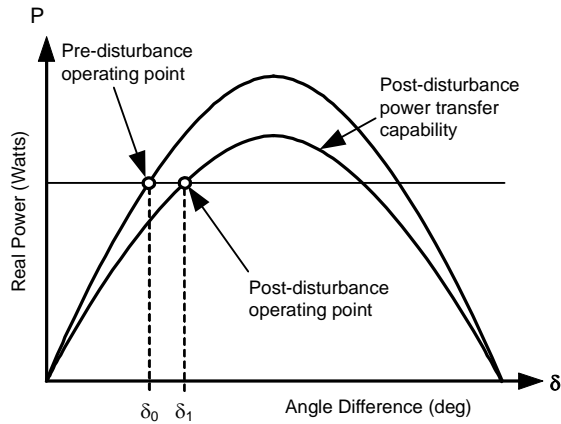


Fig. 2. Real Power Transfer Capability Mainly Depends on the Angle Difference, δ , or the Transmission Link Reactance, X_L , When E_A and E_B Are Close to Nominal Values.

For transmission links with several lines and intermediate substations, existing AGSSs monitor network topology and power transfer capability using open-line detectors for arming themselves, selecting generators to trip, or activating tripping commands. Open-line detectors are based on breaker auxiliary contact signals (52A or 52B), undercurrent, and/or underactive power elements. Usually, these AGSSs use information from

both ends of each transmission line to determine if the line is open. The number of open-line detectors that the system requires is twice the number of existing transmission lines in the scheme. For example, the six-transmission-line system depicted in Fig. 3 requires 12 open-line detectors (two per line) and several communications channels to accommodate double contingencies. For most AGSSs, the double contingencies of interest occur when two parallel lines are lost simultaneously. Notice that the power system is normally designed to withstand only single contingencies.

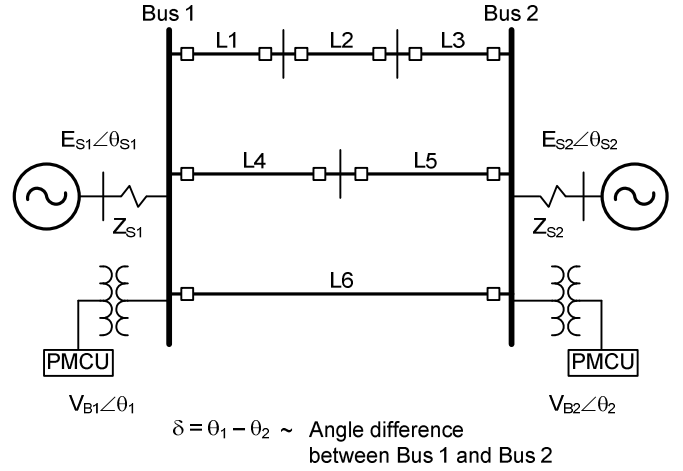


Fig. 3. Power System Network With Six Transmission Lines Requires Voltage Angle Information to Simplify the SPS.

If the scheme uses the angle difference information, δ , between Bus 1 and Bus 2, instead of the auxiliary contact signals, to detect a double contingency condition, the scheme only requires the two signals that contain the bus voltage angle information and one communications channel. With this information, the SPS has fewer points of failure and is more reliable.

Fig. 3 shows the locations of PMCUs to monitor the voltage angle difference between Bus 1 and Bus 2 and instantaneously detect changes in the transmission network impedance. With this angle difference information, the SPS can take action instantaneously.

The angle difference information between two buses can perform the following tasks:

- Arm an AGSS.
- Trip generation.
- Supervise present AGSSs to increase security.

For these reasons, we propose an AGSS based on the positive-sequence voltage angle difference between two buses at different locations of the power system.

IV. REGIONAL GENERATION AND TRANSMISSION CHALLENGES

There are several SPSs in service in the Southeast region of Mexico because the largest load on the national system is located at the center of the country, and 4,820 MW of hydroelectric generation is located at the Southeast part of the country (see Fig. 4). The distance between the heavy-load region and the large-generation region is 2,000 km. The Grijalva River Hydroelectric Complex is depicted in Fig. 5.

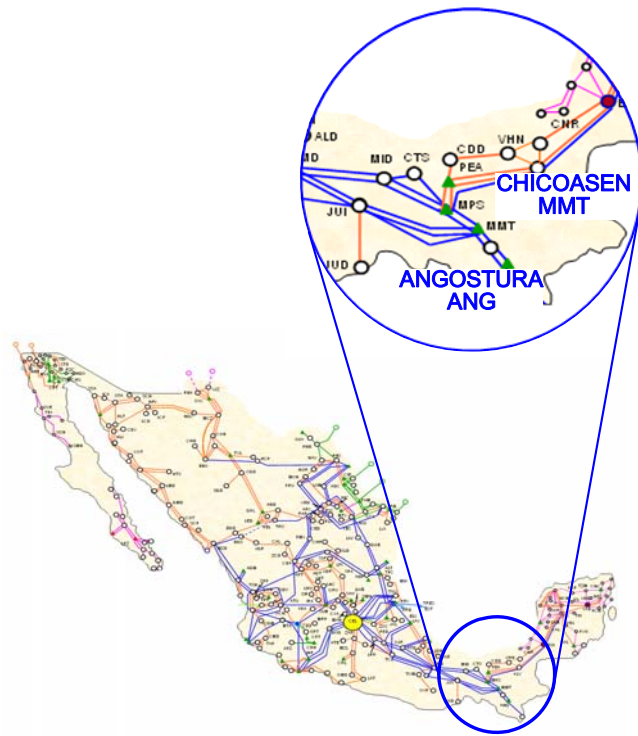


Fig. 4. Mexico's Transmission Network and AGSS System Location.

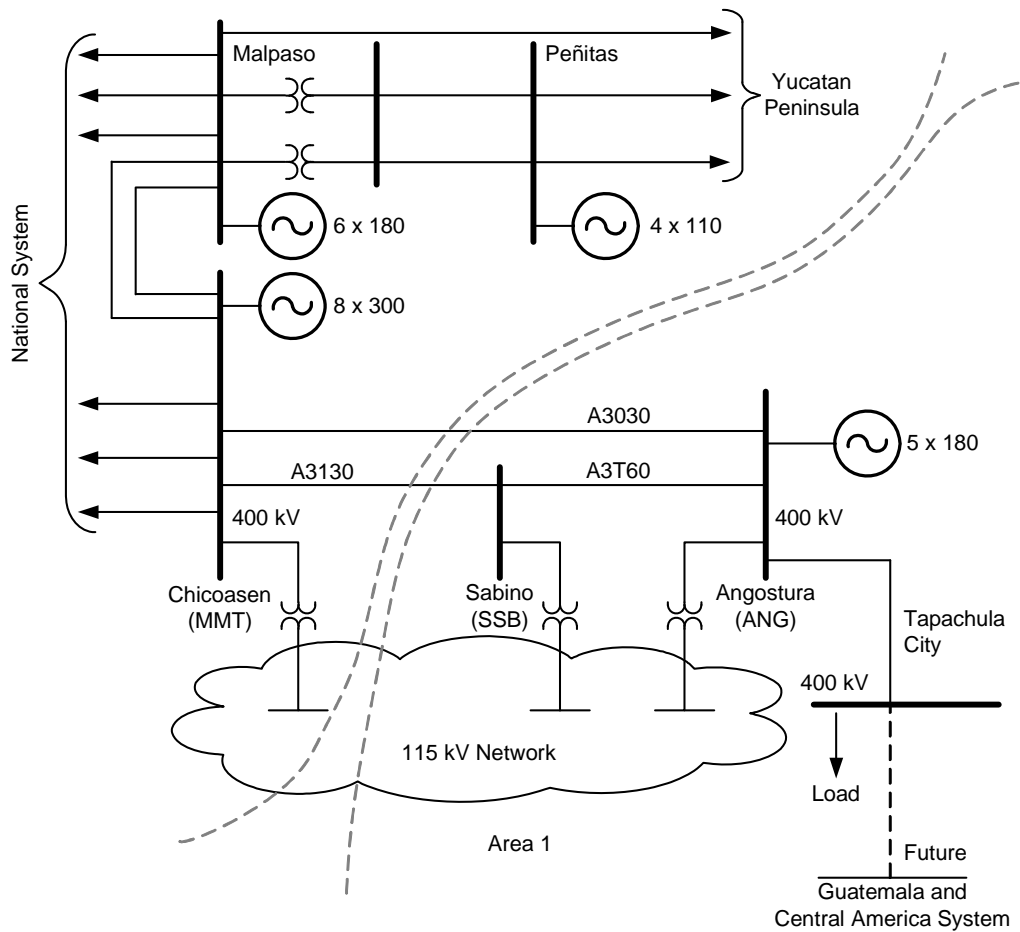


Fig. 5. Grijalva River Hydroelectric Complex, Chicoasen–Angostura Transmission Link With Parallel 115 kV Network and Future Link to Central America.

One of the AGSSs in service at Angostura Hydroelectric Power Plant monitors the loss of the transmission link between Chicoasen and Angostura. During normal conditions, Angostura can generate as much as $5 \cdot 180 = 900$ MW, while the total load of the Tapachula and South Chiapas region does not exceed 100 MW. The excess power in the region flows from Angostura to Chicoasen and from there to the rest of the system. If two 400 kV parallel lines are lost between Angostura and Chicoasen, both areas remain connected through the 115 kV network with the following consequences:

- The transfer impedance between the Angostura and Chicoasen power plants increases, causing the Angostura machines to accelerate. This machine acceleration may lead to angular instability.
- The 115 kV network is overloaded until the line or transformer overload protection operates. When this happens, the Angostura and Tapachula area (Area 1) forms a network isolated from the rest of the system.

For some operating and fault conditions, this double contingency could lead to a blackout at Tapachula City and south of the State of Chiapas. The following simulation results show angle differences between Angostura and Chicoasen for single (loss of one tie line) and double (loss of two tie lines) contingencies on this link with maximum generation at Angostura and Chicoasen if there are no protection or AGSS control actions taken.

Fig. 6, Fig. 7, Fig. 8, and Table I show PSS/E™ simulation results for steady-state and transient conditions for single and double contingencies.

Based on the following results, an angle difference threshold of 10 degrees can detect double contingencies and does not operate for single contingencies. This threshold could be used in the AGSS to trip part of the generation in Angostura.

TABLE I
SIMULATION RESULTS FOR STEADY-STATE
AND TRANSIENT CONDITIONS ON SINGLE AND DOUBLE CONTINGENCIES

Case	Prefault Angle Diff. δ	Contingency	δ at Line Trip	Additional Comments
1	3.38°	Single Chicoasen-Angostura	6.1°	Max. δ during oscillation 8.7°
2	3.38°	Single Angostura-Sabino	5.25°	Max. δ during oscillation 6.56°
3	3.38°	Single Chicoasen-Sabino	4.11°	Max. δ during oscillation 4.56°
4	3.38°	Double Chicoasen-Angostura and Sabino-Angostura	14.69°	No AGSS trip, system lost stability
5	3.38°	Double Chicoasen-Angostura and Sabino-Angostura	14.69°	AGSS trip generation after 100 ms, δ at AGSS trip 27.28°
6	3.38°	Double Chicoasen-Angostura and Chicoasen-Sabino	10.72°	AGSS trip generation after 200 ms, δ at AGSS trip 25.55°

From the results shown in Table I, the loss of one 400 kV line on this link does not cause stability problems (Fig. 6). However, if two parallel lines are lost, simultaneously or sequentially, the system stability is lost because of power transfer limitations on the 115 kV network (Fig. 7).

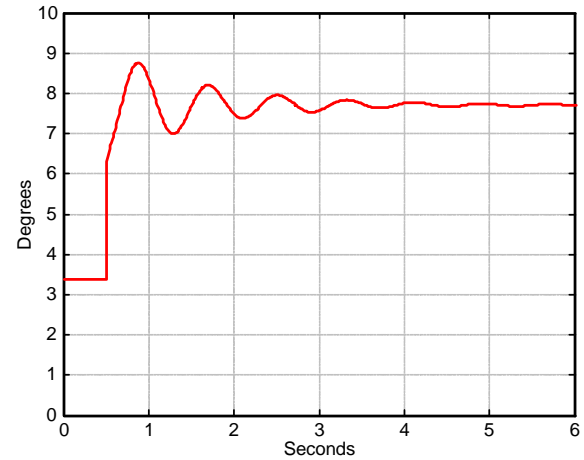


Fig. 6. Angle Difference Between Angostura and Chicoasen for a Single Contingency Without AGSS Protective Action (Case 1).

Fig. 7 shows the angle difference between Angostura and Chicoasen for the simulation of a double contingency and without AGSS action. Fig. 8 shows the angle difference between these buses when the AGSS trips generation 100 ms after the double contingency occurs. In this case, the system remains stable.

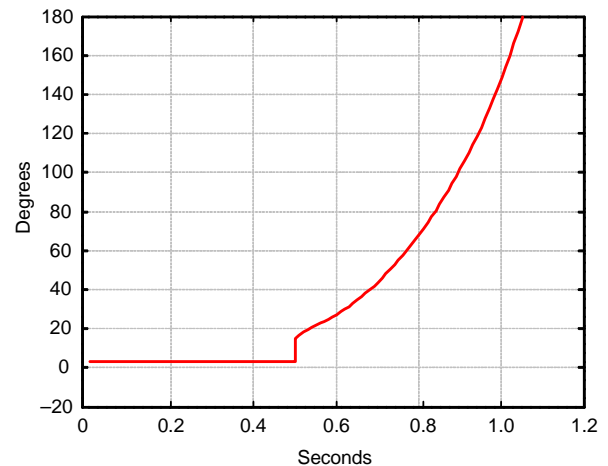


Fig. 7. Angle Difference Between Angostura and Chicoasen for a Double Contingency Condition: Lines Chicoasen-Angostura and Angostura-Sabino Open Without Control Actions (Case 4).

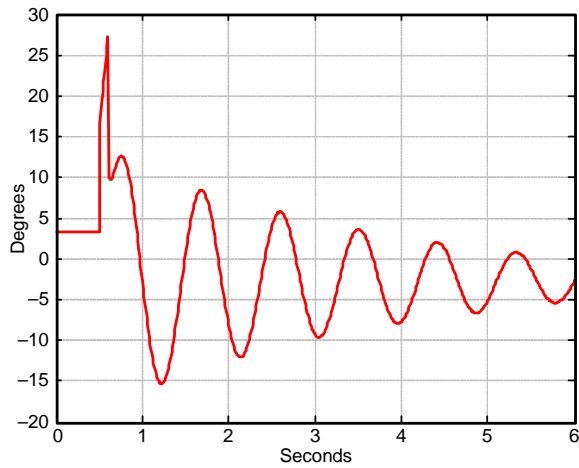


Fig. 8. Angle Difference Between Angostura and Chicoasen for a Double Contingency With AGSS Trip After 100 ms (Case 5).

V. INITIAL AUTOMATIC GENERATION-SHEDDING SCHEME

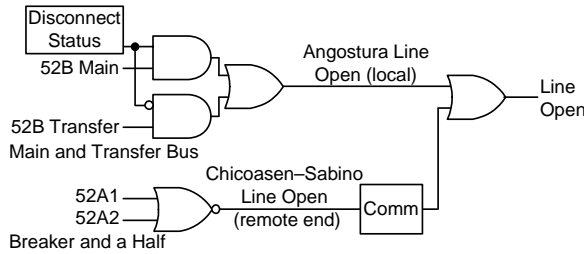


Fig. 9. Existing AGSS Logic at Angostura.

The existing AGSS scheme was commissioned before the new Sabino intermediate substation existed (see Fig. 5). At Angostura, the scheme only uses local signals from breakers and disconnect switch auxiliary contacts to detect any double contingency on this transmission link. Because the bus arrangement has main and transfer buses, the existing scheme monitors the status of the breaker disconnect switches to determine if the line is connected to its own breaker or to the

transfer breaker. This additional requirement makes the scheme more complex and less reliable. With the new Sabino intermediate substation, the AGSS logic must change to include open-line detection for each terminal in the three lines on this link.

Open-line detection can be achieved by measuring the line current to improve security and avoid false open-line detection because of incorrect breaker auxiliary signals. One problem in using current is the possibility of an open-line condition at one end of a transmission line that generates high-capacitive current at the remote end. Underactive power elements can detect an open-line condition using information from only one end of the transmission line because the open-line condition produces mainly reactive power. CFE could add underactive power elements to improve the open-line detection logic (see Fig. 10). This modified logic still requires three open-line detection signals to make the trip decision.

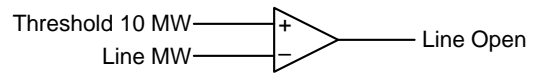


Fig. 10. AGSS Logic at Angostura With Underactive Power Supervision. This logic does not require breaker auxiliary contact information.

Fig. 11 shows the logic to arm the AGSS at Angostura. This scheme is enabled when the active power flow between Angostura and Chicoasen is greater than 180 MW. The scheme is disabled when the power flow is less than 170 MW. This hysteresis of 10 MW avoids intermittent operation of this part of the logic when power is oscillating very close to its arming threshold value. Once the scheme is armed, it only waits for a command from the double contingency, open-line detection logic to trip the selected generators. All Angostura generators are tripped except the one selected by the power plant PLC. The generator that remains in service feeds the load of Tapachula City.

The scheme depicted in Fig. 11 does the job; however, CFE experience shows that this type of scheme requires improvements in security and dependability. Scheme reliability can be improved using quantities such as the angle difference among system buses.

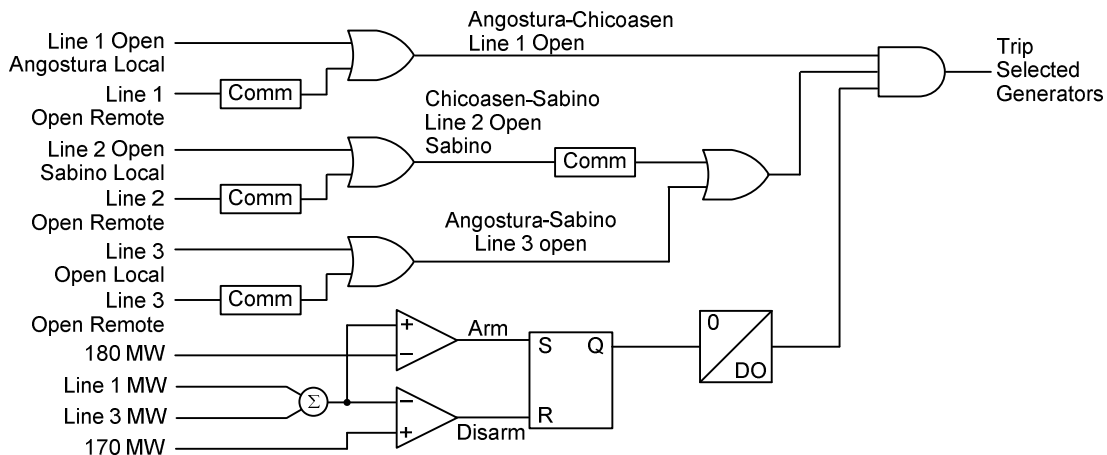


Fig. 11. Logic to Enable the AGSS and Trip Generators at Angostura.

VI. RESULTS OF AUTOMATIC GENERATION-SHEDDING SCHEME USING SYNCHRONIZED PHASOR ANGLE DIFFERENCE

A new proposed AGSS could use the angle difference information to make trip decisions or be used to supervise existing schemes. For this application, we take into account that the Chicoasen, Sabino, and Angostura substations are directly interconnected through transmission lines. For this reason, the angle difference changes instantaneously at these buses when one of the 400 kV links is lost. Fig. 12 shows the logic of the improved angle-difference-based AGSS. With the added angle difference information, the logic of the scheme is simplified and depends only on one communications channel.

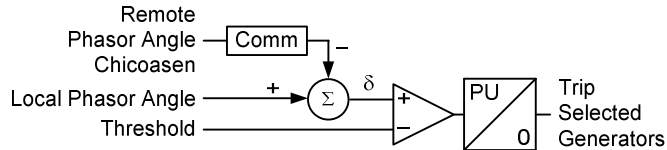


Fig. 12. Improved Angle-Based AGSS Logic at Angostura.

The angle difference must be compared against a threshold. If the angle difference indicates that the 400 kV link between Chicoasen and Angostura was lost because of a double contingency condition, the scheme sheds generation. An intentional time delay may be included in some applications to avoid tripping generation or arming the AGSS during transient or fault conditions. This application does not require such delay. Appendix A describes a detailed implementation of a synchronized real-time control network.

With load flow and stability studies (Table I), the following was determined:

- Maximum angle difference for conditions where there is no need to shed generation. Contingencies on other links, such as the 115 kV parallel network, should also be considered to ensure that maximum power transfer is achieved between these two hydroelectric plants.
- Minimum angle difference for conditions where the system requires generation shedding. In this case, Chicoasen and Angostura are connected only through the 115 kV network.

Contingencies at other power system locations that affect the bus voltage angles in the region of interest need to be considered.

CFE installed the proposed scheme with continuous remote monitoring to observe the performance of the AGSS and real-time angle difference measurement during different system operating conditions and different contingencies. The measurements were validated with an accurate power system model that includes generator dynamics, power system stabilizers, automatic voltage regulators, governor dynamics, and system loads. Next, we will present the results from testing and modeling.

Two PMCUs were installed, one at Chicoasen and one at Angostura. Each of the PMCUs is connected to monitor its corresponding bus voltage and currents from two lines. The PMCUs are interconnected through a fiber-optic multiplexer with EIA-232 (V.24) asynchronous interface at 19200 baud.

We used only serial Fast Message protocol [6] for this test. Another serial port is connected through a serial-to-Ethernet converter and sends synchronized phasor data to remote monitoring systems located at CFE regional and national offices.

On August 26, 2006, we opened and closed transmission lines A3030, A3130, and A3T60 with normal system loading conditions. During these open and close operations, we captured synchronized phasor measurements at a rate of 20 messages per second. The largest angle difference measurement between Chicoasen and Angostura, for a single contingency, occurred when Line A3030 tripped at Chicoasen (MMT) substation. Fig. 13 shows the network under study and the angle difference between Chicoasen and Angostura (ANG) for these conditions. Fig. 14 shows the measured voltages at both buses for the same operating conditions.

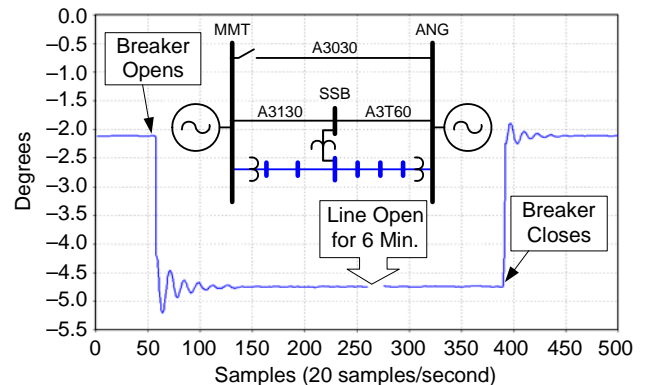


Fig. 13. Angle Difference Between Chicoasen (MMT) and Angostura (ANG) Measured When Line A3030 Trips and Closes. Six Minutes of Data During the Open Condition Are Not Shown to Shorten the Graph.

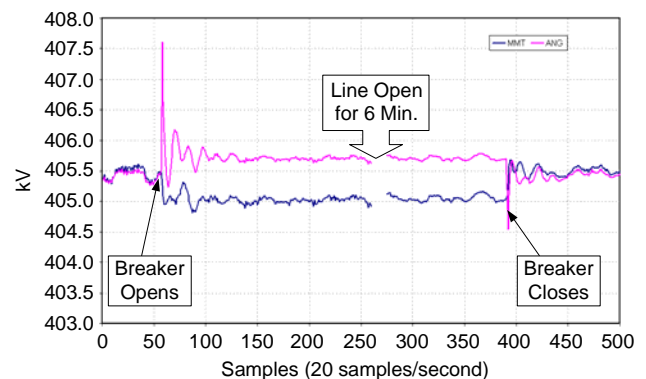


Fig. 14. Bus Voltages at Chicoasen (MMT) and Angostura (ANG) Measured During Line A3030 Trip and Close Operation.

We made dynamic system simulations to emulate the existing system operating conditions during the August 26 tests to validate both measurements and system models. Fig. 15 shows simulation results of the angle difference calculations between Chicoasen and Angostura for three cases: Chicoasen–Sabino trip, Angostura–Sabino trip, and Chicoasen–Angostura trip. From Table II, we can observe that these results match the measurements within a quarter of a degree. These results validate the model and the measurements.

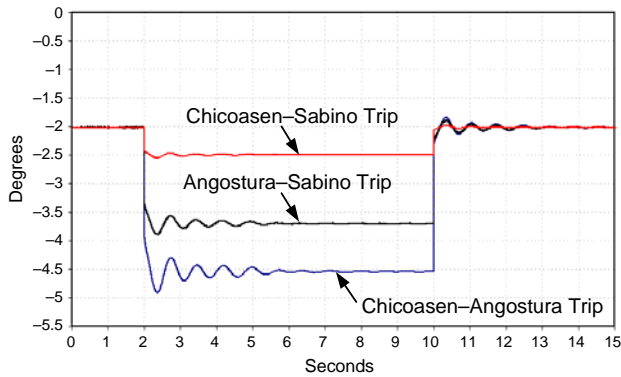


Fig. 15. Simulation Results Showing the Angle Difference Between Chicoasen and Angostura for Three Different Single Contingencies With Load and Generation Conditions Similar to the Existing Conditions During the August 26 Field Tests.

TABLE II

SIMULATION RESULTS AND MEASUREMENTS. INITIAL CONDITIONS AND MAXIMUM ANGLE DIFFERENCE WHEN LINE A3030 OPENS AND CLOSES

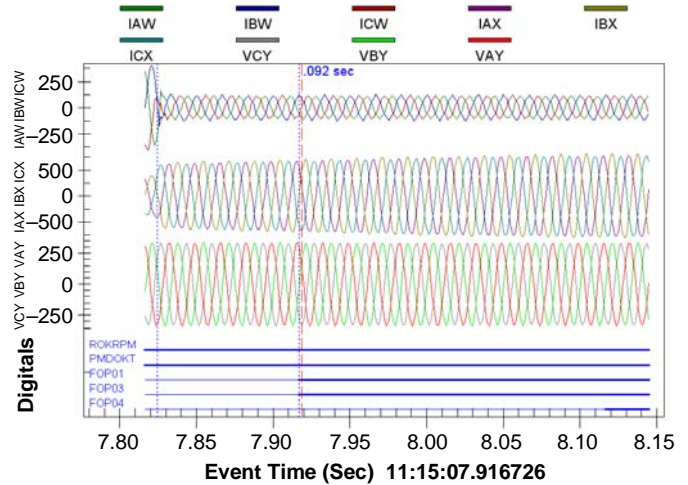
	Steady-State Initial Angle	Maximum Angle During Oscillation
Simulation	-2.01°	-4.91°
Measurement	-2.13°	-5.20°

Below are additional objectives of performing field tests:

- Test communications channel performance and communications interfaces.
- Test the logic that calculates angle difference and measures scheme operating times at different angle threshold levels.

We programmed four angle difference elements to test angle difference element logic and measure scheme operating time. We set the angle difference to 3, 4, 5, and 10 degrees, respectively. The oscillographic record, shown in Fig. 16, was taken directly from the PMCU located at Chicoasen during the MMT-A3030-ANG line trip. The oscillogram shows the current at both lines and bus voltage at Chicoasen. Digital

channels FOP01 and FP03 are angle difference elements set to 3 and 4 degrees. They operated within 92 ms. After initial instantaneous angle change, Angostura machines accelerate, the angle difference increases, and the angle difference element (set to 5 degrees [FP04]) operates after 292 ms.



- IW Angostura-Chicoasen currents.
- IX Angostura-Sabino currents.
- ROKRPM Received remote data OK.
- PMDOKT Total measurement data OK.
- FOP01 Angle difference element set to 3 degrees.
- FOP03 Angle difference element set to 4 degrees.
- FOP04 Angle difference element set to 5 degrees.

Fig. 16. Oscillographic Record, From the PMCU Located at Chicoasen, Showing Line Currents, Voltage at Chicoasen, and Angle Difference Element Operation.

The PMCU Sequential Events Recorder (SER) allows us to check digital element operation. From SER records (shown in Fig. 17), we can observe when the system oscillation triggered the angle difference element set to 5 degrees in 250 ms. Fig. 17 also shows that the element set to 4 degrees remains asserted until the line closes 6 minutes later.

```

SER
LOCAL PMCU ANGOSTURA Date: 2006/08/24 Time: 13:29:20.311
PP1 Y DEMO FASORES DIFERENCIA ANGULAR

# DATE TIME ELEMENT STATE
34 2000/08/25 10:59:11.205 Settings changed Class P 3

Line trip
33 2000/08/25 11:15:07.916 FOP03_4deg Asserted
32 2000/08/25 11:15:07.916 FOP01_3deg Asserted
31 2000/08/25 11:15:08.115 FOP04_5deg Asserted
30 2000/08/25 11:15:08.365 FOP04_5deg Deasserted

Line close
22 2000/08/25 11:21:23.913 FOP03_4deg Deasserted
21 2000/08/25 11:21:23.913 FOP01_3deg Deasserted
    
```

Fig. 17. SER Records of the Angle Difference Element Operation During One of the Tests Performed on August 26, 2006.

Table III summarizes the recorded operating times of the angle difference element set to 3 degrees for additional trip and close operations.

TABLE III
ANGLE DIFFERENCE ELEMENT OPERATING TIMES

Line	Operating Condition	Operating Time (ms)
Chicoasen–Angostura	Chicoasen Breaker Trip 11:15:07	92
Chicoasen–Angostura	Angostura Breaker Trip 11:29:14	82
Angostura–Sabino	Angostura Breaker Trip 11:58:53	75

The angle difference element operating time includes the PMCU measurement delay, communications channel delay, and the latency because of the message rate. In this case, 20 messages per second introduce a delay of as much as 50 ms. If the message rate changes to 10 messages per second, the overall scheme operating time will increase to as much as 150 ms. Simulation results show that a trip time of 150 ms is good enough to avoid stability problems in this area.

VII. CONCLUSIONS

- CFE decided to evaluate the use of angle difference on this specific AGSS for three main reasons: this scheme is one of the most simple AGSSs in the network, there are fast communications channels available in the substations, and there is the need to accommodate future network changes in the region, such as the interconnection to the Guatemala and Central America network.
- Use of PMCUs will reduce operating time and improve reliability if compared with traditional AGSSs based on traditional measurement, separate PLCs, and several remote communications channels.
- Synchronized angle difference measurements provide reliable information to detect network topology changes with minimum communications requirements.
- Fast communications channels and available PMCUs allow the angle-difference-based AGSS to operate in less than 200 ms.
- Synchronized measurement message rate affects the AGSS operating time. Message rates of 10 or 20 messages per second are still very good to avoid transient stability problems in the region.
- Present PMCUs are able to send as many of 60 voltage and current synchrophasors per second. This message rate requires a communications channel bandwidth that is not available at these substations at the moment.

For this reason, CFE decided to use only voltages at 20 samples per second (one phasor every 50 ms) to limit record size and bandwidth requirements. CFE would like to send voltages and currents to calculate power from synchronized phasor measurements and use it as a permissive signal, but multiplexer card bandwidths need to be changed.

- AGSS trip decision could be taken very fast, in less than 100 ms, if there is an instantaneous change in angle difference. Other variables could be used to improve security of the scheme, such as the change of the angle difference with respect to time.
- Records of angle difference measurements for single line contingencies validate measurements and simulation models. AGSSs must operate only when two parallel lines are lost, and studies should consider sequential or simultaneous double contingencies.
- The future interconnection with the Central America network will create power flow changes in the region. We need to analyze all possible operating conditions of the modified network to properly design the AGSS.

VIII. APPENDIX A

SYNCHROPHASOR REAL-TIME CONTROL NETWORK

The synchrophasor real-time control network, shown in Fig. 18, includes one local PMCU and two remote PMCUs that exchange synchronized measurements and commands through a communications network for real-time control, monitoring, and protection applications. The PMCUs correspond to the ones described in [7] [8]. The PMCUs transmit and receive synchronized measurement messages and command messages according to IEEE Std C37.118-2005 [9] and Fast Message protocols. The PMCUs have EIA-232 and Ethernet communications ports. The local PMCU receives and decodes these messages according to the type of communication and protocols among devices. After the PMCU decodes the messages, the local data are resampled to match the rate of the received data. Then the PMCU aligns the remote (e.g., t_{STAMP} , V_{RPMR} , V_{RPMI}) and local (e.g., t_{STAMP} , V_{LPMR} , V_{LPMI}) messages according to their common time stamp, t_{STAMP} , creating local quantities (e.g., t_{STAMP} , V_{DPMR} , V_{DPMI}). These remote and local quantities correspond to the values on the power system at a time equal to the acquisition time delay plus the channel latency. Table IV illustrates an example of local and remote quantities available in the local PMCU after decoding and time alignment. These quantities are available to the real-time math processor, internal protection algorithms, and synchrophasor metering (MET RPM). The real-time math processor performs logic and arithmetic operations to implement protection and control schemes using synchrophasor data.

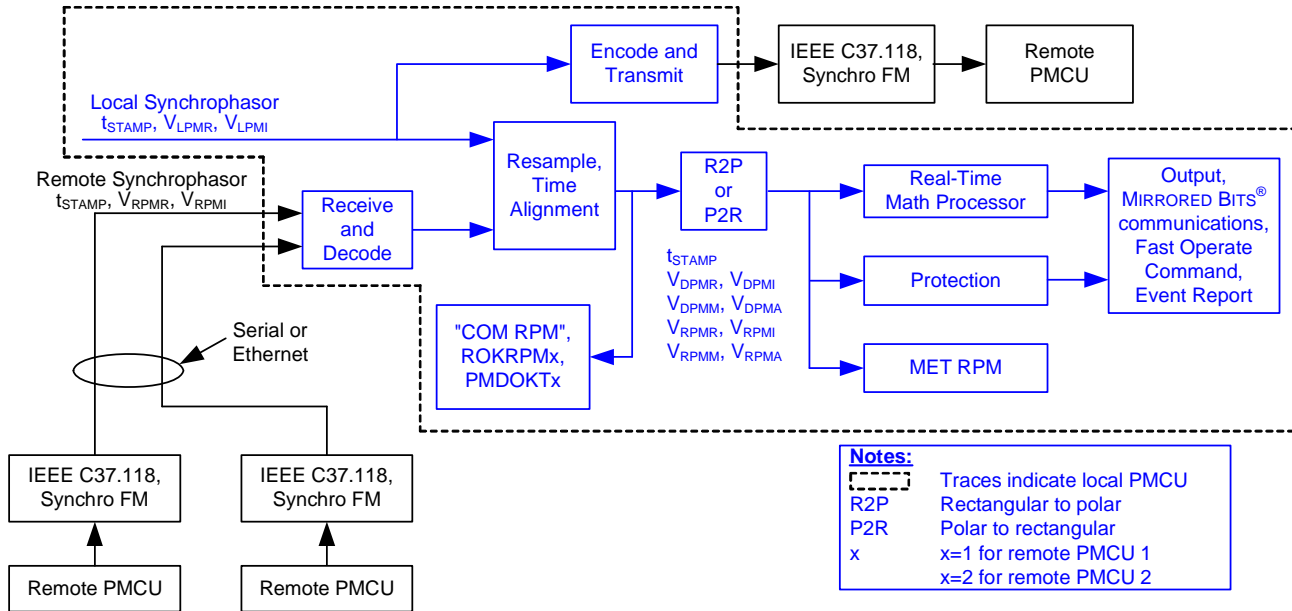


Fig. 18. Synchrophasor Real-Time Control With One Local Device and Two Remote Devices.

TABLE IV
SYNCHROPHASOR DATA AFTER DECODING AND TIME ALIGNMENT

Qty	Description
$V_{I_{RPMR}}$	Real part of the remote positive-sequence voltage.
$V_{I_{RPMI}}$	Imaginary part of the remote positive-sequence voltage.
$V_{I_{RPMM}}$	Magnitude of the remote positive-sequence voltage.
$V_{I_{RPM\alpha}}$	Angle of the remote positive-sequence voltage.
$V_{I_{DPMR}}$	Real part of the local positive-sequence voltage.
$V_{I_{DPMI}}$	Imaginary part of the local positive-sequence voltage.
$V_{I_{DPM\alpha}}$	Magnitude of the local positive-sequence voltage.
$V_{I_{DPM\beta}}$	Angle of the local positive-sequence voltage.

A. Synchronization and Communications Channel Diagnostics

The PMCU includes synchronization and communications channel diagnostics to determine the health of the synchronized real-time control network. The diagnostics include Relay Word bits to notify PMCU synchronization status, communications channel status, and a communications channel report that also includes latency measurements and the received data packet content.

1) PMDOK Relay Word Bit

The Phasor Measurement Data Okay Relay Word bit, PMDOK, indicates that the PMCU and synchrophasors are enabled.

2) TSOK Relay Word Bit

The Time Synchronization Okay Relay Word bit, TSOK, indicates that the PMCU time-synchronization jitter is better than 500 ns.

3) ROKRPM Relay Word Bit

The Received Data Okay Remote Phasor Measurement Relay Word bit, ROKRPM, indicates that all the following conditions are met:

- The local PMCU is receiving data.
- The received data message has been verified as correct.
- The received data are less than one-third of a second old.
- The remote PMCU PMDOK Relay Word bit is 1.
- The remote PMCU TSOK Relay Word bit is 1.

4) PMDOKT Relay Word Bit

The Total Phasor Measurement Data Okay Relay Word bit, PMDOKT, is set when all the following conditions are true:

- ROKRPM Relay Word bit is set.
- Local PMCU TSOK Relay Word bit is set.
- Local PMCU PMDOK Relay Word bit is set.

This bit is included to provide security to the synchrophasor data. The synchrophasor data are valid only when PMDOKT = 1.

5) Communications Channel Report

The PMCU includes a communications channel report that provides the following information:

- Remote synchrophasor message configuration.
- Remote synchrophasor status.
- Communications channel delay.
- Last received data packet date and time.

The partial report is shown in Fig. 19. The communications delay is calculated as follows:

$$\text{Delay} = \text{Present Local Synch Time Stamp} - \text{Received Remote Synch Time Stamp} \quad (2)$$

The PMCU calculates the average delay using a first-order infinite impulse response (IIR) filter with a time constant of 16 seconds.

6) Solicited Synchrophasor Messages

The PMCUs respond to the METER RPM command by reporting simultaneous synchronized phasor measurements at

local and remote ends. We can use this command to take snapshots of the local and remote synchrophasor data and compare synchrophasor measurements across the power system. Fig. 20 shows some of the information that this report provides. For example, the report shows the local and remote positive-sequence voltages. In this example, the angle difference between the local and remote voltages is approximately 15 degrees.

```

Remote Synchrophasor Configuration.
Enabled: YES
Protocol: FM
Rate: 20 Per Second
Port: 2
PMID: 1 (From remote device)

Remote Synchrophasor Status.
PMDOKT: 1 ROKRPM: 1 PMDOK(remote): 1 TSOK(remote): 1

Delay of Last 40 Packets (In Cycles):
 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1
 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1

Average Delay (over 60 sec for 20msg/sec): 0.998833
Last Received Packet Date: 05/24/2006 Time: 09:22:45.000

Received Packet Data. V1:Yes (VA,VB,VC):Yes I1:Yes (IA,IB,IC):Yes

```

The ROKRPM bit tells the status of the channel.
The remote PMDOK and remote TSOK are provided exactly as they are received in the Fast Message packet.

Fig. 19. Communications Channel Report Includes Remote Synchrophasor Channel Status, Channel Delay Information, and Remote Data Packet Configuration.

```

=>>MET RPM<Enter>

Relay 1 Date: 08/30/2006 Time: 09:29:16.000
Station A Serial Number: 2005339297

PMDOKT: 1 ROKRPM: 1 PMDOK: 1 TSOK: 1 PMDOK(remote): 1 TSOK(remote): 1

Local Synchrophasors
Phase Voltages Pos.-Sequence Voltage
VA VB VC V1
MAG (kV) 196.673 196.757 196.718 196.716
ANG (DEG) 28.032 -91.969 148.062 28.042

Remote Synchrophasors
Phase Voltages Pos.-Sequence Voltage
VA VB VC V1
MAG (kV) 197.551 197.576 197.555 197.561
ANG (DEG) 43.053 -76.946 163.085 43.064

Phase Currents Pos.-Sequence Current
IA IB IC I1
MAG (A) 128.812 135.819 133.193 132.604
ANG (DEG) 41.670 -79.363 161.110 41.130

=>>

```

Fig. 20. Solicited Synchronized Phasor Measurement Report Includes Local and Remote Data.

B. Synchrophasor Angle Difference Calculations

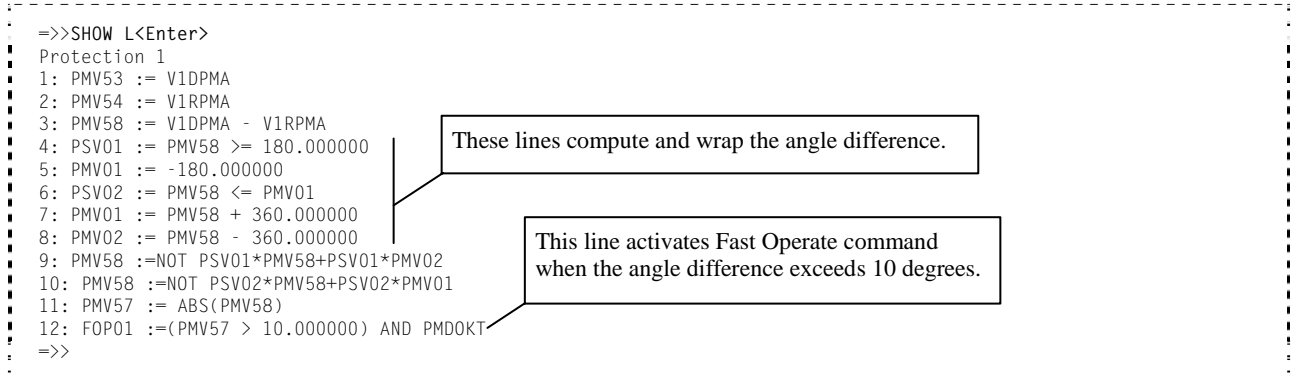


Fig. 21. Logic to Detect That the Positive-Sequence Voltage Angle Difference Between the Local and the Remote Stations Exceeds 10 Degrees.

One application example of synchrophasor real-time control is to calculate the positive-sequence voltage at both ends of the transmission line and detect when the angle difference exceeds a predefined threshold. Fig. 21 shows the programming to produce the logic to detect angle differences greater than 10 degrees. The last line activates a Fast Operate command when the PMCU detects this condition. The PMDOKT bit supervises the command to avoid misoperations when the synchronized measurements are not reliable.

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X. BIOGRAPHIES

Enrique Martínez received his MSEE from the Polytechnic Institute of Belarus, in 1986. He has been with the Federal Electricity Commission (the electrical utility company of Mexico) since 1986. He initially worked as an engineer with a focus on Power System Network Analysis and Design at the Specialized Engineering Unit of CFE and as advisor to the National Water Commission. From 1995 to 1998, Mr. Martínez worked in the Transmission Project Coordination Division of CFE as a substation and transmission line

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