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**Reliability Analysis for a Generation Shedding Scheme  
on the CFE Main Transmission Network**

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# RELIABILITY ANALYSIS FOR A GENERATION SHEDDING SCHEME ON THE CFE MAIN TRANSMISSION NETWORK

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## ABSTRACT

Lack of transmission network capacity because of right-of-way restrictions and limited investment requires system operation at close to stability margins. Wide-area network protection schemes (also called system-wide remedial action schemes) are commonly used in these systems to prevent transient instability or voltage collapse problems and their associated operational and economical consequences. These schemes combine protection, control, and communications devices located at different geographic areas in the power system. CFE has used auxiliary relays, protection relays, industrial programmable logic controllers (PLCs), high-level language programming on control center master SCADA computers, and combinations of these solutions to solve problems at different power system locations.

This paper analyzes a proposal for increasing reliability in a real-life case study of a 1200 MW generation-shedding scheme for CFE's southeast hydroelectric power plants. The scheme includes devices that integrate protection, control, and direct digital communications between devices and substations in a common reliable platform. We look at the root cause of limits to generation shedding in the area of the case study and determine some practical options for improving reliability.

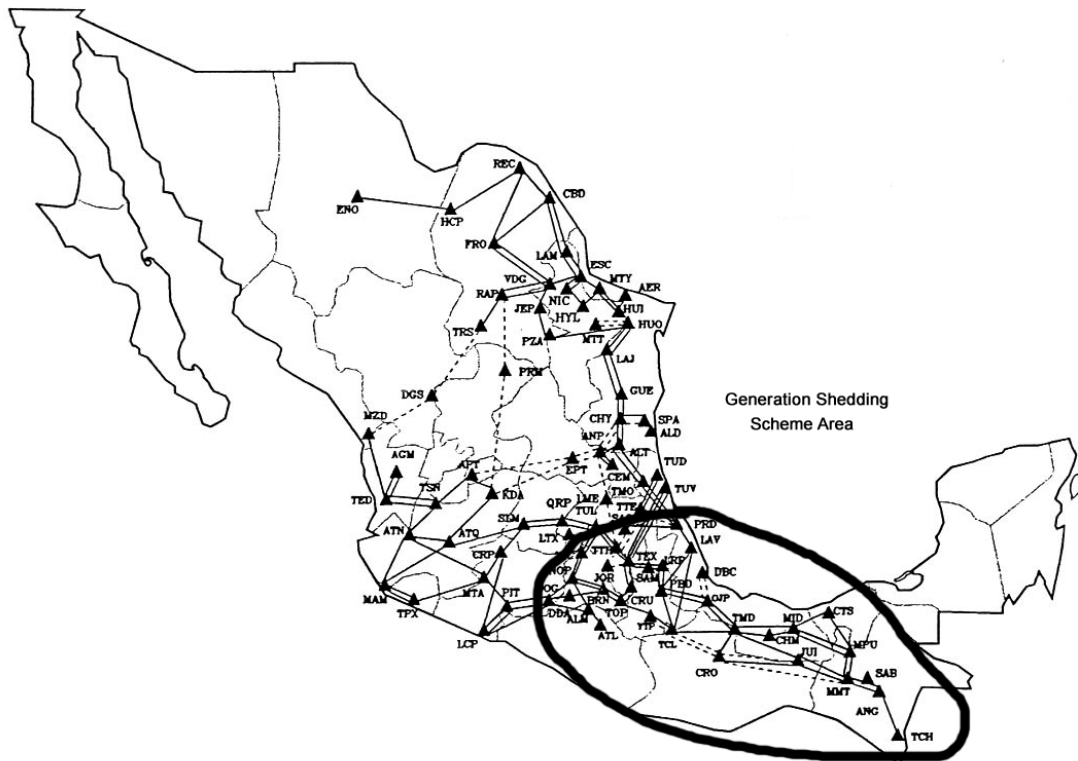
## INTRODUCTION

There are many contingencies for which several areas of the CFE network can become weak or unstable. The system requires wide-area network protection to avoid real and reactive power instability.

The power stability problems are common in networks with long transmission links between generation and load. Strong networks are susceptible to power instability after contingencies such as breaker failure or bus protection operations, where more than one line or transformer is lost.

Based on contingency studies, one can determine the needs of wide-area network protection. These types of protection can require power flow measurement, open line detection, communications, different tripping times, etc. depending on the kind of transmission limitation found. This paper shows some critical information from power system studies, but the focus is on field implementation rather than power system studies or trip decision algorithms.

In this paper, we examine the CFE southeast 400 kV transmission link between the Grijalva Hydroelectric System (about 50 percent of total national hydroelectric capacity) and the Central Region (which includes Mexico City and has the largest load). The transmission link, shown in Figure 1, is about 1000 km long, with transmission of as much as 3000 MW and as much as 1200 MW total generation shedding.



**Figure 1** Mexico 400 kV Network

Several events on February 2002 led to major disturbances. The system lost three lines and became unstable after three oscillations. The system split into two areas covering six states. In these areas, load was lost for several hours.

Previous study of this contingency led to a shedding scheme designed to use generation shedding and some low-frequency load shedding as needed to prevent blackout. Simulations showed the scheme acting correctly to save the system from collapse. Field implementation failed, however, because of a bad signal from an auxiliary relay. This was the first dependability failure of significant consequence on this scheme; similar network schemes have had similar problems. Since scheme implementation some years ago, communication difficulties and bad signals from auxiliary relays have caused a number of security failures with incorrect generation trips.

CFE uses auxiliary relays, transducers, PLCs, SCADA master, conventional microwave, and carrier communications channels for field implementation of this kind of system. In this paper, we study a method that uses different technology to improve reliability in the case study scheme.

The improved system includes simple and reliable methods for open line detection, power measurement on each line, the sum of power from all lines on a transmission link, contingency grouping and logic processing capabilities, and communications signals. Other research topics included in the CFE project include ways to improve flexibility in configuring systems and new substations, increase redundancy at some points in the network, and obtain automatic supervision for the entire system.

## POWER TRANSMISSION LIMITS

On any power system, operation should meet equality constraints, the most important being that power generation must equal power load plus system losses.

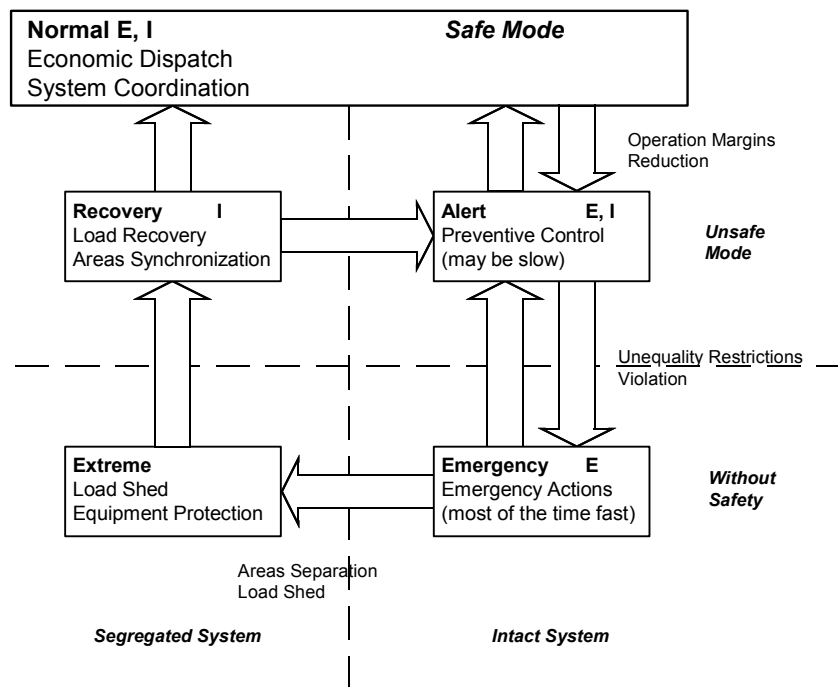
Operation should also meet the following inequality criteria:

Voltage regulation of  $0.9 \text{ pu} < V < 1.1 \text{ pu}$

Frequency regulation of  $59.8 \text{ Hz} < f < 60.2 \text{ Hz}$

Current in line  $<$  conductor thermal limit

Figure 2 [1] defines possible system states based on equality and inequality constraints.



**Figure 2** Power System Operation Under Stress Conditions, Based Upon A Diagram by Fink and Carlsen

In the normal state, the equality and inequality constraints are met, there are no overload elements on the network, and the security margins are normal. Control objectives are economic optimization of all system operations and system coordination with good security margins.

In the alarm state, the equality and inequality constraints are still met, but the security margins have been reduced or eliminated. Control objectives are increased security margins either through generation and load reallocation or through voltage and frequency regulation. Actions could be automatic or initiated by a control center operator, which can take from minutes to hours. Some weak systems may operate permanently in the alarm state during daily peak hours.

In the emergency state, the system is still intact, but the inequality constraints have been violated. Control or protection actions should be fast enough to relieve overloads and return the system to the alert state. It is better still to attempt normal control actions before the system proceeds to the emergency state, which may trigger wide-area network protection actions. Normal control actions can include fast valving, excitation control, single-pole tripping and reclose, capacitor or

reactor switching, or use of flexible alternate current transmission system (FACTS) or high-voltage direct current (HVDC) controls.

In the extreme state, the system loses integrity; some areas can become isolated from the rest of the system, the system sheds load, and some system devices can operate outside normal operational limits. Action should be as fast as possible, with the protection or control objective being the retention of as much load as possible. Normally, some load or generation can be shed intentionally at selected locations, and some areas can be isolated from the system. Changes from the normal, alarm, or emergency states to the extreme state must trigger wide-area network protection actions.

In the recovery state, the system meets the inequality restrictions, but some load remains out of service. Control actions in this state include startup or synchronization of generators to the network, load recovery, and segregated area synchronization.

Some equality or inequality constraints can be obtained transiently, while others can be steady-state conditions. Steady-state limits are the following:

- Conductor, switchgear, and current transformer or power transformer thermal limits
- Voltage regulation
- Reactive power operational margins
- Voltage collapse security margins

Thermal limits depend upon ambient conditions such as temperature, wind, and sunlight. Information is available from suppliers of conductors and switchgear equipment, from standards such as IEEE C.57 for transformers, and from generator capability curves. Because thermal problems can take seconds or even minutes to cause damage, protection can take a long time to operate and tripping times are not critical under most conditions. For thermal problems, operators or automatic control can generally take action before automatic protection schemes operate.

Voltage regulation and reactive operational margins depend upon contracts with customers or internal rules governing interconnection points and reactive capacity at power plants and other reactive power sources. You would normally not need automatic protection action, only automatic control.

Strictly speaking, voltage collapse is a transient problem, but several analyses assume steady-state conditions. Reactive power security margins decrease to a point where voltage could collapse for a slight increase in reactive power demand. Generally, there is low voltage in this condition. Then, automatic voltage regulators on some distribution or transmission transformers change taps, and the reactive power demand increases in either a few seconds or minutes, according to the time delay for the automatic load tap changers. Maximum excitation limiters can contribute to voltage collapse by reducing the reactive power after an initial fast voltage regulator response. Maximum excitation limiters operate with slower time constants than voltage regulators, changing generator terminal voltage in several seconds. In cases where you need to improve security margins, a corrective action for voltage collapse can occur after several seconds without consequences. A second contingency could develop a faster collapse, but it also causes transient stability problems, and will be discussed with similar problems later in the paper.

Tripping time for automatic wide-area network protection against steady-state limit violations is normally not a critical constraint. Dynamic limits include the following:

- Transient or first cycle stability limit
- Dynamic instability with low or negative damping of oscillations
- Slow dynamic limit, normally for frequency or voltage regulation after disturbance

Transient instability causes severe damage to generators, as well as to other equipment such as transmission transformers. Voltage, power, and torque variations are high, and the tripping mode is difficult to control after the first cycle of oscillation. Fast action is imperative.

Fast action is also necessary for dynamic instability, which causes low or negative damping of oscillations. The system might support the first cycle of operation, but oscillations will persist for several seconds until some line or generator protection operates and the system becomes unstable.

Transient and dynamic stability limits cause an oscillation frequency between 0.5 and 2 Hz and oscillation cycles from 0.5 to 2 seconds. Protection and control actions should occur before completion of the first oscillation cycle. Contingency studies can show the time limits for scheme operation.

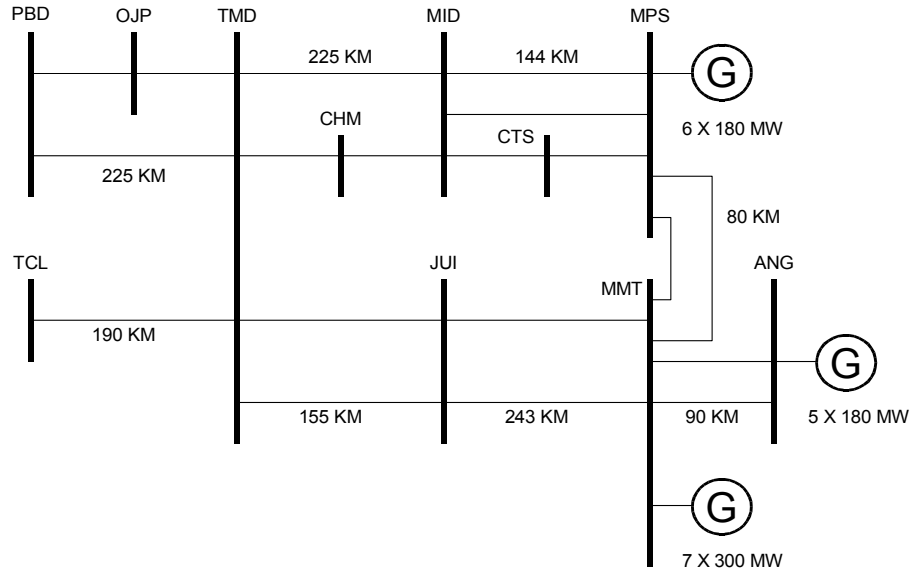
Utilities use contingency analysis to determine how, when, and where a network reaches limits. For such tasks as increasing the size of a transmission network, planning departments use n-1 (single) contingency analysis. Where investment is low, this first contingency analysis does not include breaker failure or bus failure analysis.

Operation departments should use n-2 (double contingency) or n-3 (triple contingency) analysis. This is important because, although a multiple contingency failure is unlikely to occur, such a failure would have catastrophic consequences if there were no action. Planning work should be evaluated with (n-1) analysis without loss of load. Operation work should be evaluated with the amount of load system loss after (n-1), (n-2) or (n-3) contingencies and the cost of operation in the normal state.

If the system operation takes into consideration double or triple contingencies, real power transmission limits will be very low and the operation costs can increase because power must be obtained from another source that could be more expensive. If the system operation takes into consideration only a single contingency, real power transmission limits can be high and operation expenses low. Any case of a double or triple contingency failure, however, would be costly. It is possible to use (n-1) analysis to define normal operation transmission limits with low operation cost and use (n-2) or (n-3) analysis to define wide-area network protection scheme needs and settings.

## **CASE STUDY**

The case under study involved 19 transmission lines and 11 substations as the online diagram in Figure 3 shows. We use three-letter codes to name substations; we use the names of substations at each line end to define a line. CFE has done complete contingency analyses for each single and double contingency for different operation scenarios.



**Figure 3** Online Diagram

CFE finds that almost all double contingency combinations cause transient stability problems with loss of synchronism or voltage problems near voltage collapse. Table 1 describes the way some contingencies group together on certain parts of the link.

**Table 1** Double Contingency Groups and Limits

Link	Double Contingencies	Transmission limit found	Reason to limit
MMT–JUI–TMD	MMT-JUI & MMT-JUI JUI-TMD & JUI-TMD	1600 MW from MID to TMD	Near to voltage collapse in central area
MMT-MPS	MMT-MPS & MMT-MPS	1200 MW from MMT to JUI	Transient stability limit for 3-phase failure
MPS-MID MPD-CTS-MID	MPS-MID & MPD-MID MPS-MID & MPD-CTS MPS-MID & CTS-MID	1800 MW from JUI to TMD	Near to voltage collapse in central area and dynamic stability
MID-TMD MID-CHM-TMD	MID-TMD & MID-CHM MID-TMD & CHM-TMD	1200 MW from TMD to central area	Transient stability
TMD-OJP-PBD TMD-TCL	TMD-PBD & TMD-OJP TMD-PBD & OJP-PBD OJP-PBD & TMT-TCL TMD-PBD & TMT-TCL TMT-TCL & TMD-OJP	1100 MW from TMD to central area	Near to voltage collapse in central area and dynamic stability



There are several other possible combinations. There can be, for example, double contingencies that involve lines over different links. Most of the double contingency limits were found with simulation of failure and simultaneous tripping of both lines, but the results were reviewed against a steady-state initial single contingency condition and against a second failure with very similar results.

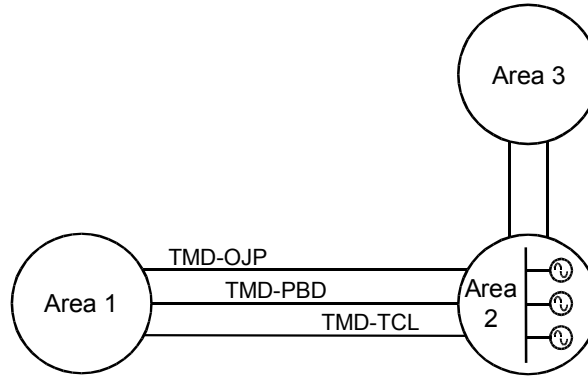
With these combinations, we notice some important points about the scheme.

- Some double contingencies can be grouped together, but there are many different limits depending on which pair of lines is lost. Each limit imposes a different amount of generation shedding. Several pilot protection channels are necessary to send different kinds of contingencies from places where a trip occurred to generation units.
- There are many different combinations of single or double contingencies to be transmitted to the next substation. These combinations should be handled by logic operations (AND, OR, NOT) with inputs from open line detection. Logic schemes could be implemented with auxiliary relays, PLCs, or logic processors.
- Transmission limitation could be measured at locations other than those where lines trip. Transmission limits are based on link total power and not on line power. Some device or system should provide a sum of all power from the different lines.
- Some of the limits are for transient stability. Fast trip is needed for these cases but could be used for other conditions.
- Fast trip means fast and reliable open pole detection; a fast and reliable direct transmission channel is needed.

## **DYNAMIC SIMULATION RESULTS AND EVENT ANALYSIS**

With the help of Figure 4, we can provide a simplified explanation of what happened during the severe disturbance on February 2002. We have divided the system into three areas. Area 1 includes the central region of Mexico, which has a very high concentration of load. Area 2 is the Grijalva Hydroelectric System, which has a high concentration of generation and low load. Area 3 is a small network on the Yucatan Peninsula with a weak link to Area 2 that contributes some inter-area oscillations.

Before the disturbance, the power flow was about 1600 MW from Area 2 to Area 1, with three lines from the TMD substation to the central region. During the February 2002 event, two parallel lines (TMD-PBD and TMD-OJP) and another line (TMD-CHM) were lost. One line (TMD-TCL) supported the link for about 7 seconds until it also tripped, causing the collapse of Area 2 and Area 3 and a great amount of load shedding from frequency relays in Area 1.



**Figure 4** Simplified Version of Transmission Links and Areas

Conditions and measurements from dynamic recorders reporting this event helped provide validation of simulation models. Dynamic recorders are important for diagnosing problems during the event, validating simulation models, and evaluating the results of the new scheme [2], [3]. From the dynamic recorders, we can obtain the following useful information:

- Real and reactive power on each line and links
- Frequency
- Voltage phasors, including magnitude and angle from synchronized measurement

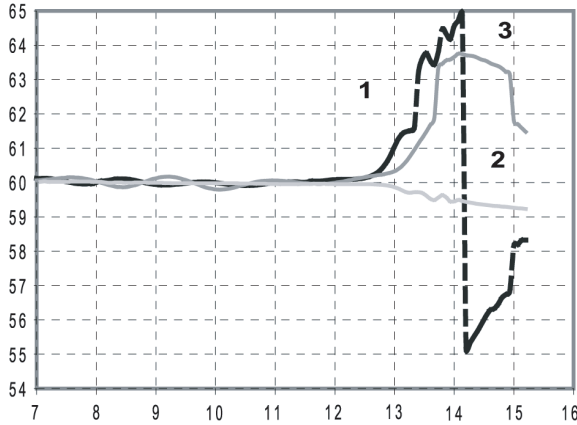
Recording of this information should be at a slower acquisition rate than that provided by line protection recorders. The dynamic event recorders make better use of memory than the line protection recorders and, as can be seen in Table 2, provide a higher acquisition rate than SCADA master recorders, from which dynamic effects cannot be seen. The total time to record each event is also an important variable; line protection recorders normally record 1 to 2 seconds, while dynamic events can last from 10 seconds to 2 or 3 minutes.

**Table 2** Features on Different Types of Event Recorders

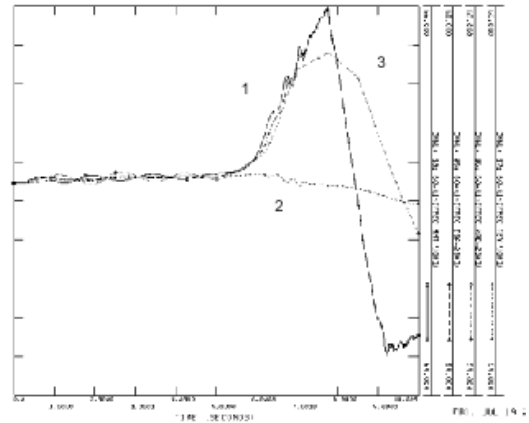
Type of recorder	Acquisition frequency	Total recording time
Line protection recorders	240 Hz to 2 kHz	0.1 to 2 seconds
SCADA master recorders	0.1 to 0.5 Hz	Continuous recording from hours to weeks
Dynamic recorders	30 to 10 Hz	10 to 180 seconds

For validation purposes, we compare the dynamic recorder records that were obtained during the disturbance versus the simulation results.

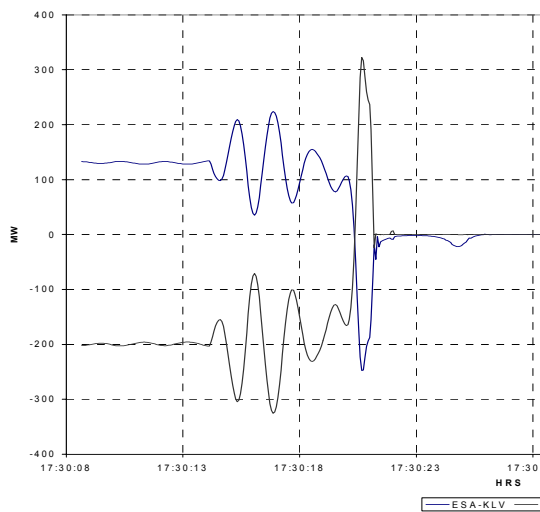
Figure 5, Figure 6, Figure 7, and Figure 8 show the frequencies for the three areas, the records of total link power from dynamic recorders for areas 1, 2, and 3, and the simulation results for the same variables and fault conditions.



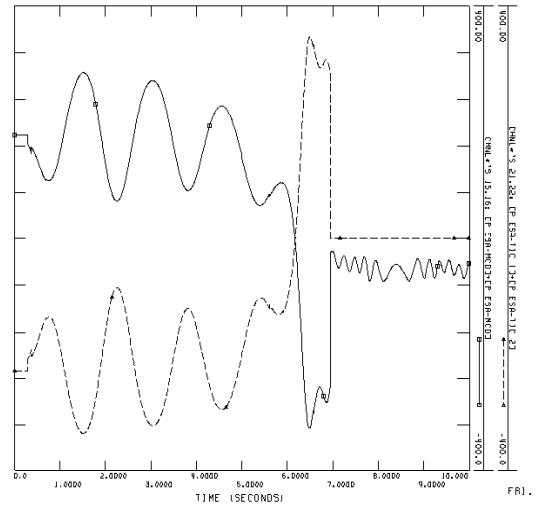
**Figure 5** Record of Frequencies in Three Areas.



**Figure 6** Simulated Frequencies



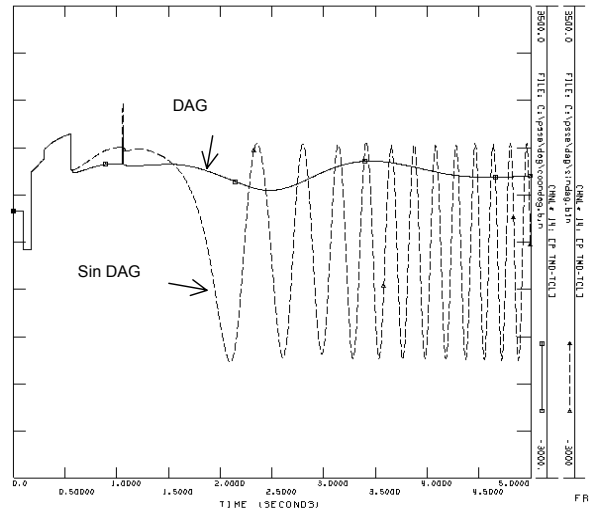
**Figure 7** Record of Real Power Exchange Between Areas 2 and 3



**Figure 8** Real Power Exchange From Simulation

The simulation results closely match the records, so we can assume that the model is valid and that we can simulate several contingencies and conditions to analyze the factors that influence the correct performance of a generation shedding scheme.

With this model, CFE simulated the effects of correct operation for a generation shedding scheme. Figure 9 compares simulation results for operation or no operation of generation shedding.

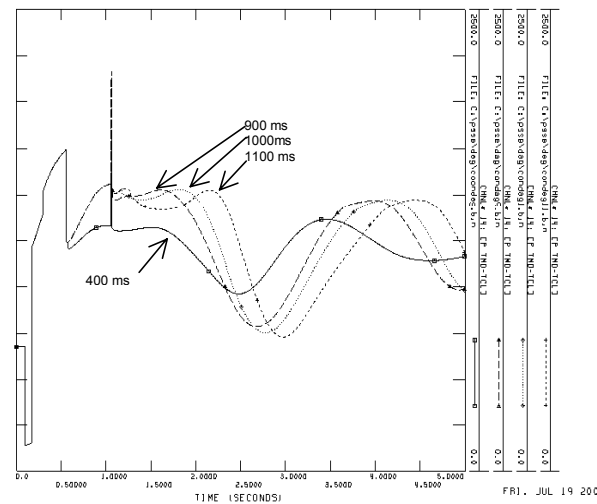


**Figure 9** Real Power on TMD-TCL With and Without Generation Shedding

One of the most important factors to consider for these schemes is time delay of the communications channels. Although wide-area network protection problems do not need short time delays such as those for pilot protection tripping, some time delays are critical, and very slow generator tripping does not cause necessary stabilization.

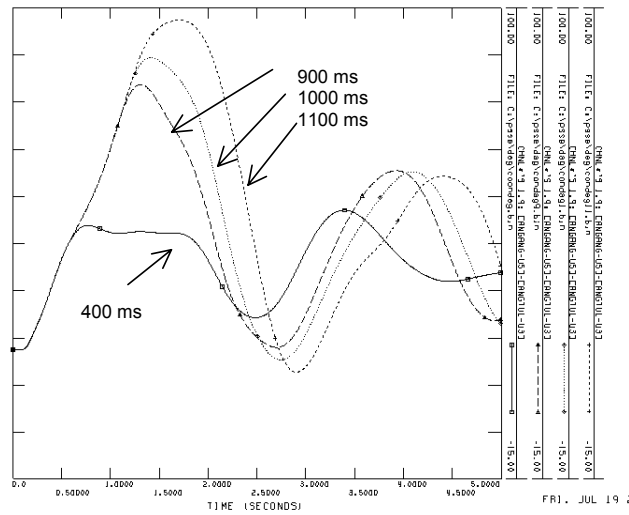
Consider also that the channel time delays are cumulative; signals traveling from substations to generators, over lines open for some specific contingency, often go through other substations where communications devices serve as “repeaters.”

Figure 10 shows real power flow on Line TMD-TCL (the only line that does not trip after the initial disturbance) for different channel time delays and tripping times for generators.



**Figure 10** Real Power Flow on Line TMD-TCL for Different Tripping Times

We can see that oscillations increase according to increases in tripping times. This effect is more apparent when looking at the angular difference between areas 2 and 3, as in Figure 11.



**Figure 11** Angular Difference Between Areas 2 and 3 for Different Tripping Times

The critical time for generator tripping is 1100 ms for this specific case. We need a complete analysis to determine the critical tripping time for each contingency and the maximum acceptable channel delays, but this example shows some typical characteristics:

- Although the maximum tripping time is 1100 ms, it is clear that faster operation reduces oscillations and the possibility of other generator trips or line protection operations. A good real life maximum time could be near 400 ms.
- Tripping times of 200 to 400 ms or faster are handled easily with pilot protection direct channels including four or five repeaters, but these tripping times are not feasible with SCADA-type communications channels. This limitation is important to remember because, in the parts of a wide-area system dependent upon a SCADA regional master, a trip signal must travel directly between substations, with a great economic impact on the scheme.
- Power oscillations are large for some stable disturbances. If we try to measure power after such a disturbance and decide to trip with this information, it is not possible to use an instantaneous power level detector; there are other events where the system will not need generator shedding, and oscillations beyond the power limit will occur for a short time.
- If we try to use a definite-time delay characteristic for power level detection, we should wait some time to trip. This time delay, related to the first oscillation time, should be longer than 400 ms in most cases. This time delay is not acceptable for transient instability problems, but could be used for problems such as voltage collapse or thermal limits.
- Because this part of the network is almost radial, total real power flow is almost the same after and before the initial disturbance. It is possible to measure real power, determine a power level, and pre-select a tripping mode, all before the disturbance. Then, the only delay between initial disturbance and generator trip comes from open line detection, logic schemes that make decisions about double contingencies at each location, and channel delay.

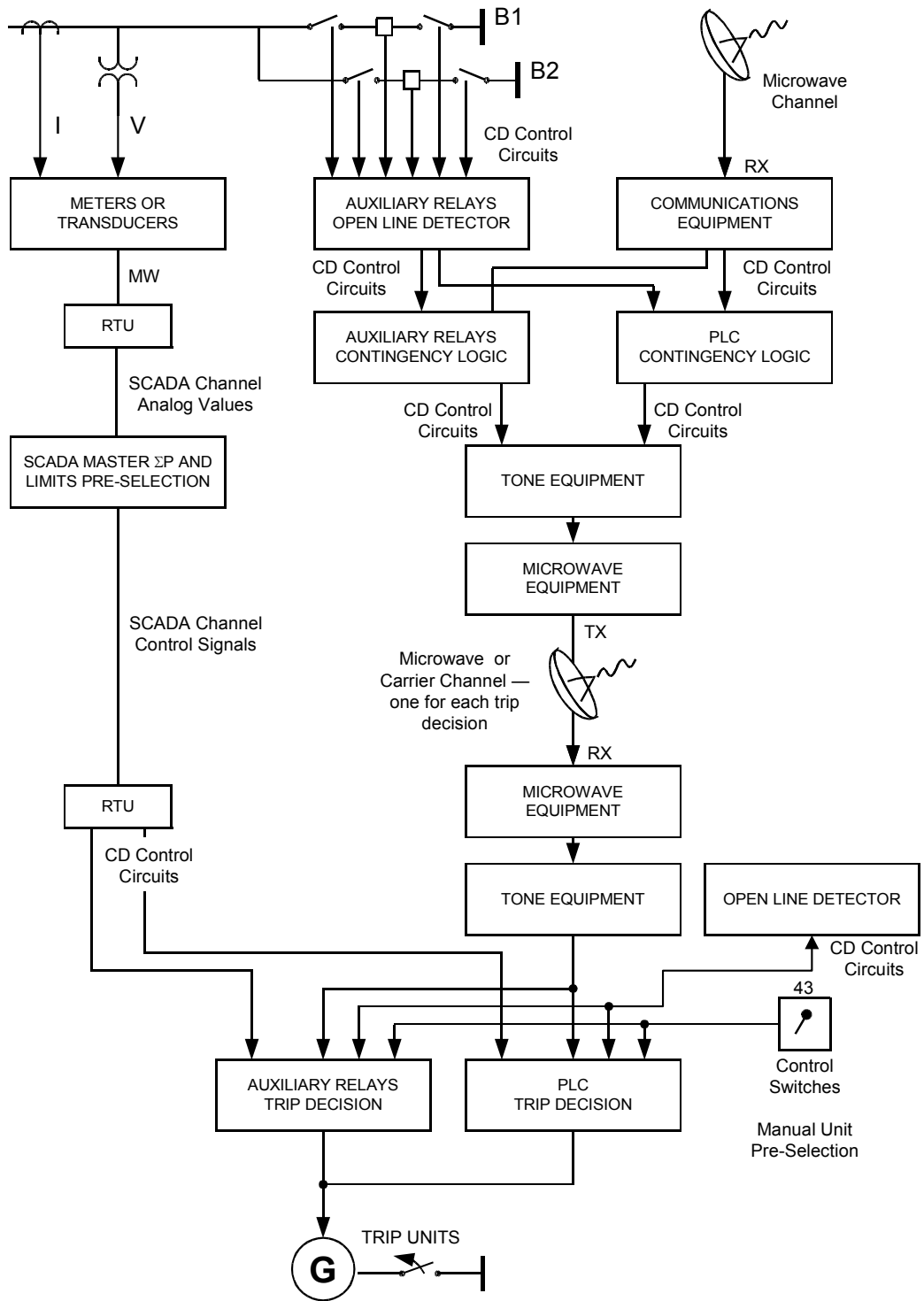
From the simulation and contingency analysis, we can determine that the scheme needs the following features:

- There must be a measure of total link power for three substations, MMT, TMD, and MPS. Some device or system must determine the sum of real power flow from as many as three lines and send this information to the power plants. Only a total link power limit decision from TMD to the central region must be transmitted to generators. MMT and MPS must each determine locally the total flow for their own power plants.
- To pre-select or prepare a generation shedding scheme, there must be a power limit decision before the disturbance. There is no specific time limit for this because power flow changes slowly before a disturbance.
- After preparation or pre-selection of a generation shedding scheme, open line detectors must detect tripping of certain specific combinations of lines. PLCs, logic processors, or auxiliary control circuits must then logically combine these lines to form double contingency groups as Table 1 shows, and send a tripping decision to generator units.
- Several communications channels are necessary to transmit trip decisions to generators. For the worst-case scenario, a repeater (channel repeater, tone-to-tone equipment connection, logic processor, auxiliary control circuit, etc.) must retransmit these decisions through four substations (four pilot protection channel services for each trip decision). Because one line can trip only at one end, either more channels are necessary to send open line information to the remote end, or each line must have direct transfer trip. Tripping time must be less than 400 ms.

## **PRESENT GENERATION SHEDDING SCHEME**

Figure 12 shows an overview of the present scheme. The regional control center at Puebla has all the network measurement information for SCADA and energy management systems. The information comes from both digital meters and transducers. A program at the regional master station adds the real power for the entire link, compares this total real power against specific levels shown in Table 1, and sends pre-selection instructions to generation plants. Information is available also for system operators who telephone the power plants and order manual pre-selection of generators in case of any problem with SCADA control signals. Unless a control signal fails to arrive at a power plant, there is no alarm for a control signal problem. Single contingency pre-selections are always made by phone between the system and the plant operators.

## Present Scheme



**Figure 12** Present Scheme

On each line control circuit, there are auxiliary relays in parallel with the trip coils. When a line trips, an auxiliary relay sends notification of this trip through the control circuit to hardwired single and double contingency logic schemes. Other sets of auxiliary relays connect by means of the control circuit to digital inputs in a PLC that has single and double contingency logic schemes.

Substation configurations include breaker-and-a-half and double bus with double breaker. For open line detection, both line breakers must trip. Under maintenance conditions, switch disconnectors can isolate one breaker, while the remaining breaker activates line trip detection. Auxiliary relays with hardwired logic schemes for each line (also known as line detectors) feed information from all such conditions and from trip bus and disconnector auxiliary relays to PLCs or other hardwired logic schemes for contingency identification.

Both PLC and auxiliary relay logic schemes use timers to prevent double contingencies where only a few seconds separate trips on different lines. Analysis shows this as a weakness of the present system. Some line could be open for several minutes, but a second failure will cause exactly the same effects as if both lines had tripped together for contingencies resulting in voltage collapse problems. A similar effect could occur for stability problems.

PLC or auxiliary relay logic schemes send decisions for a generation trip over conventional microwave or carrier channels without power limit supervision; only the master can send this information to the power plant substations. Mean tripping times are very good, as fast as 14 ms from channels without repeaters and nearly 60 ms total tripping time for the worst case situation involving four repeaters. Table 3 shows the total number of channels needed, without redundancy. Full redundancy on communications channels is costly, so we implement full redundancy only on certain links.

**Table 3** Communications Channels Used by the Present Scheme

<b>From</b>	<b>To</b>	<b>Channels</b>
TCL	TMD	1
OJP	TMD	1
CHM	TMD	1
TMD	MID	2
MID	MPS	5
MPS	MMT	4
MMT	ANG	2
CHM	MID	1
CTS	MID	1
JUI	MMT	2
	TOTAL	20

Auxiliary relays at power plant substations trip after receiving generation trip signals, whereas PLCs or hardwired logic schemes must take into account the trip signals from remote contingencies, local contingencies, power limits from SCADA, and local generation unit selection



before making a trip decision. Selection of generation units must follow several considerations including which units are manually selected and which units you want to trip first.

The present scheme allows the following failures, all of which have occurred in the past:

Security failures:

- Some line detectors and associated auxiliary relays have sent incorrect trip signals during line relay maintenance.
- Some line detectors have sent incorrect trip signals during vibration and during such work as changes or upgrades to relays and wiring.
- Some remote incorrect trip signals have been caused by confusion over terminals during maintenance work on protection or communications panels.
- Some remote incorrect trip signals have been caused by transitory signals on the pilot protection channel.
- Manual selection of generators to trip or temporary SCADA channel failure to send information deselecting generation units during a decrease in power flow can cause overpower trips.

Dependability failures:

- An auxiliary relay failure on the line detector can cause a failure to send a generator trip signal when needed.
- An open dc circuit can cause a failure to send a generator trip signal when needed.
- SCADA channel failures can cause a failure to select generation units at the necessary time. This failure consists of two parts: a failure to receive power information and a failure to send pre-selection signals to power plants.
- A channel failure can cause a trip signal to not be sent. The present system has channel redundancy on some links but not on the entire system.

Since January 2001, this part of the transmission network has had 47 events with line tripping, and CFE has experienced three security failures with incorrect tripping of generation. One such failure was the result of an incorrect signal from the SCADA system. The second failure was an incorrect generator trip reception caused by channel noise problems, and the last failure resulted from a dc circuit transient. The system has experienced one major dependability failure, as we described before. Analysis and operation statistics show the need for a more reliable system.

## **PROPOSAL FOR NEW GENERATION SHEDDING SCHEME**

For our proposal, we analyzed the best options for providing open line detection, line power measurement, measurement of total link power, limit detection, and digital local and remote signal communication. The following discussion includes the results of this analysis.

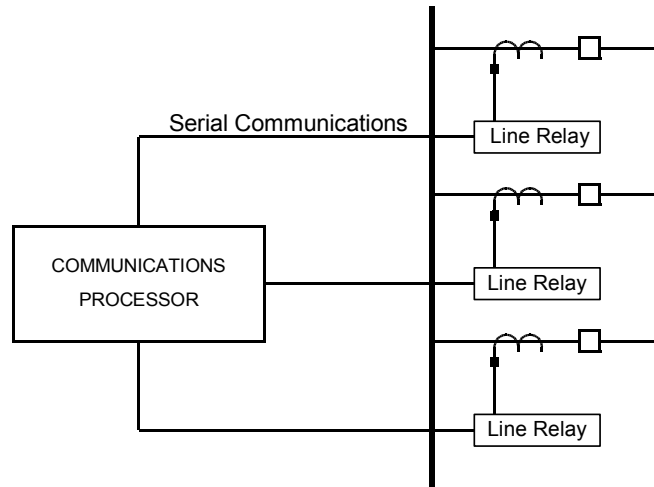
### **Open Line Detection and Line Power Measurement**

Line protection makes use of multifunction digital relays, such as distance relays and directional overcurrent relays, to provide primary and backup protection. These relays already receive all the signals necessary for each line.

We take advantage of the ability of these multifunction digital relays to provide power measurement and transmit such measurement information through serial communication to other scheme devices. Current detectors in these relays, together with internal relay logic that detects switch-onto-fault conditions, will provide us with pole open detection. Current signals are more reliable than auxiliary signals and provide us with more dependable open line detection than that available from auxiliary relays. On some lines where special low load conditions could fall below the sensitivity limits of the current detector, line side potentials or circuit breaker auxiliary relays together with current signals could provide open line detection. As we will see later, in an unusual case where the current is so low that a current detector alone sends incorrect open line detection information, the system will use power limit detection to block transmission. The proposed system does not use disconnecter position signals.

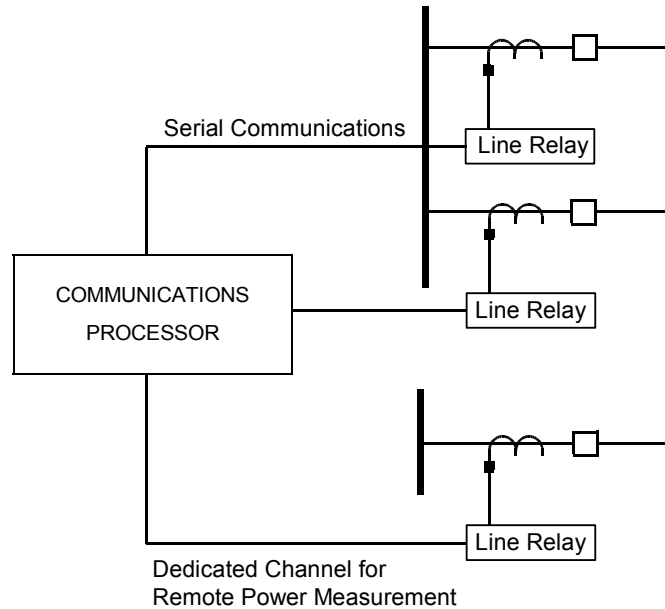
**Total Link Power Measurement and Limit Detection**

A local communications processor receives real power measurement by means of a direct serial connection from line relays. The communications processor adds power from different lines to obtain a measurement of the power on the entire link. It then compares this sum against the limits from Table 1. The power limit detection for the communications processor is available locally, through contacts or serial communications, and remotely, through serial communications. This is possible because the limits in use are from substations where all link power goes through only one substation, as Figure 13 shows. The communications processor must have analog operators (for providing power summation) and analog comparators (to provide level detection).



**Figure 13** Total Link Power Limit Detection

If two or more substations are involved in providing total link power, then a channel is necessary. This channel could be a dedicated channel between substations (Figure 14), which is preferable to having a SCADA channel to the regional control center.



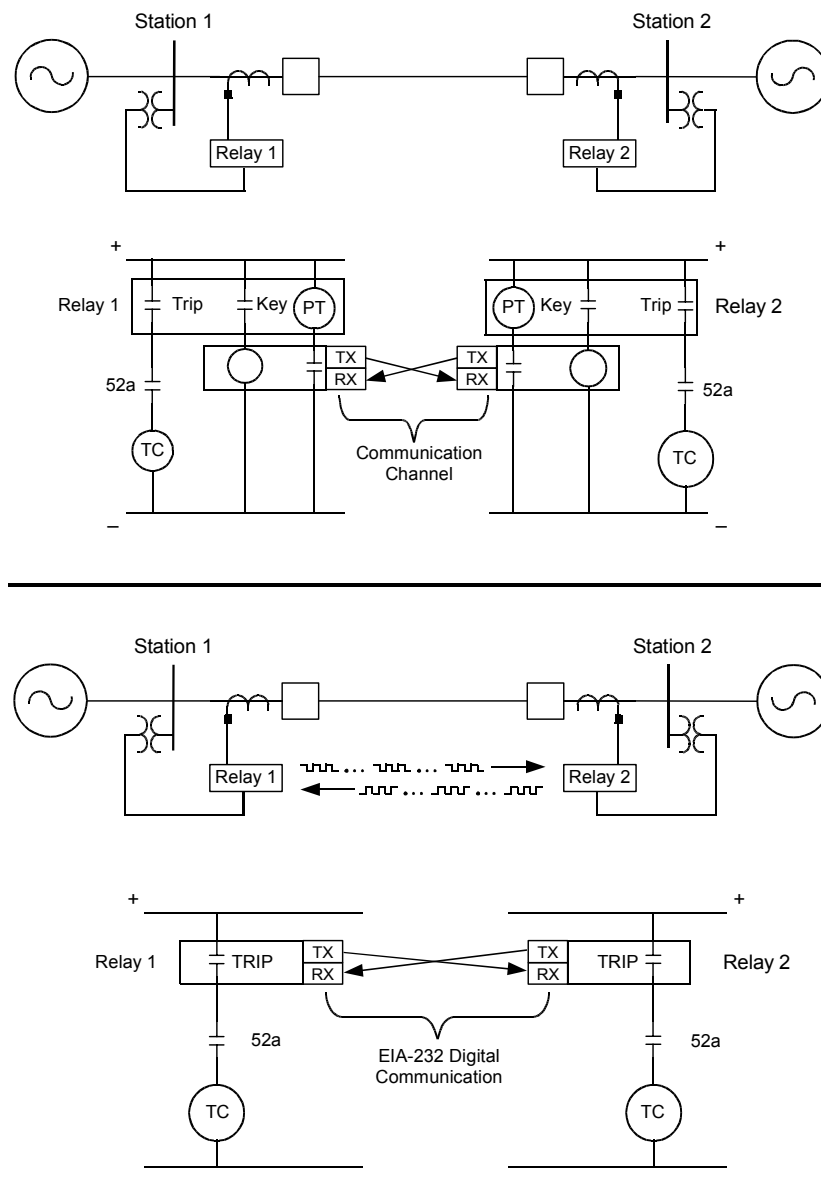
**Figure 14** Total Link Power Limit Detection From Two Substations

This configuration has several advantages over the present system:

- A SCADA channel failure does not affect the system.
- Local testing is easier.
- It is easier to add power from new lines with digital meters or relays.
- Power limit pre-selection is available locally, and pre-selection messages could be sent with generator signals to other substations and power plant logic schemes. This may appear at first to require more dedicated channels, but the proposed solution for channels eliminates this as a problem.
- Power limit pre-selection can be used locally to supervise local trip transmission signals for added security.
- While the present system has four points of failure: meter or transducer—remote thermal unit (RTU)—SCADA channel—master, the proposed system has two points of failure: digital relay—communications processor.
- The proposed system time response, although not critical to total link power measurement and limit detection, is better than for the present system. The maximum time response we measured in testing the proposed system was 2.6 seconds, and the minimum time was 0.9 seconds. The present system time response is about 10 seconds.

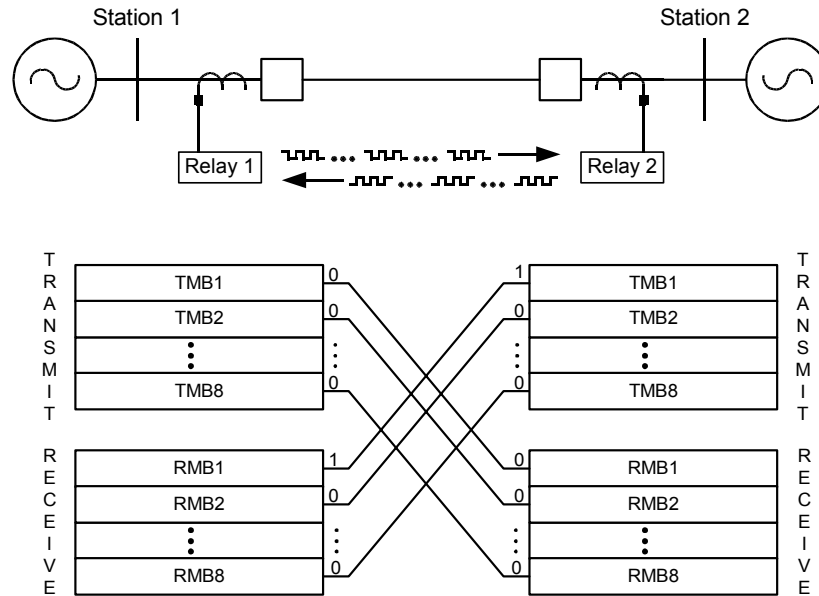
### **Digital Local and Remote Signal Communications and Channels**

Technical paper [4] discusses technology capable of transmitting digital information directly between relays for the pilot protection functions and other high-speed signals over such low bandwidth channels as a microwave analog channel. This technology takes advantage of the capability of logic processors and digital relays to communicate directly over serial port connections without external communications equipment (see Figure 15).



**Figure 15** Relay-to-Relay Communications Technology Versus Traditional Pilot Protection Communications

Through the application of relay-to-relay communication, as shown in Figure 16, we can use a serial port connection to obtain a two-way virtual transmission of eight bits of high-speed control signals. Message security is continuously monitored, and alarm signals are available if any connection fails.



**Figure 16** Virtual Connection of Eight High-Speed Control Signals

The proposed scheme uses this relay-to-relay communications technology for two different purposes. The first purpose is to provide communication of open line detection from digital relays to a control processor, while the second purpose is to provide transmission of remote signals.

For the first purpose, use of a control processor is similar to a PLC in the sense that one can program logic schemes. A control processor, however, receives serial-supervised messages, rather than the hardwired dc input signals available to PLCs. Communications between relays and a control processor occur in a quarter cycle, or about 4 ms. A control processor has logic schemes to determine each kind or group of single or double contingencies and to send generator trip signals through contacts or serial connections.

For transmission of remote signals, logic processors send generator trip decisions, power limit detection signals, and pre-selection signals to power plant processors in some substations. Because eight control points are available on each channel through relay-to-relay communications, we can multiply by eight the service each channel provides, use fewer channels than those assigned to the present scheme, and provide redundancy at a reasonable cost.

**Table 4** Communications Channels Used By the Proposed Scheme

From	To	Channels	Generator trip signals	Power limit and unit pre-selection signals
TCL	TMD	1		
OJP	TMD	1		
CHM	TMD	1		
TMD	MID	1	2	3
MID	MPS	1	5	3
MPS	MMT	1	4	3
MMT	ANG	1	2	
CHM	MID	1	1	3
CTS	MID	1	1	3
JUI	MMT	1	2	3
	TOTAL	10		

The advantages of this improvement include the following:

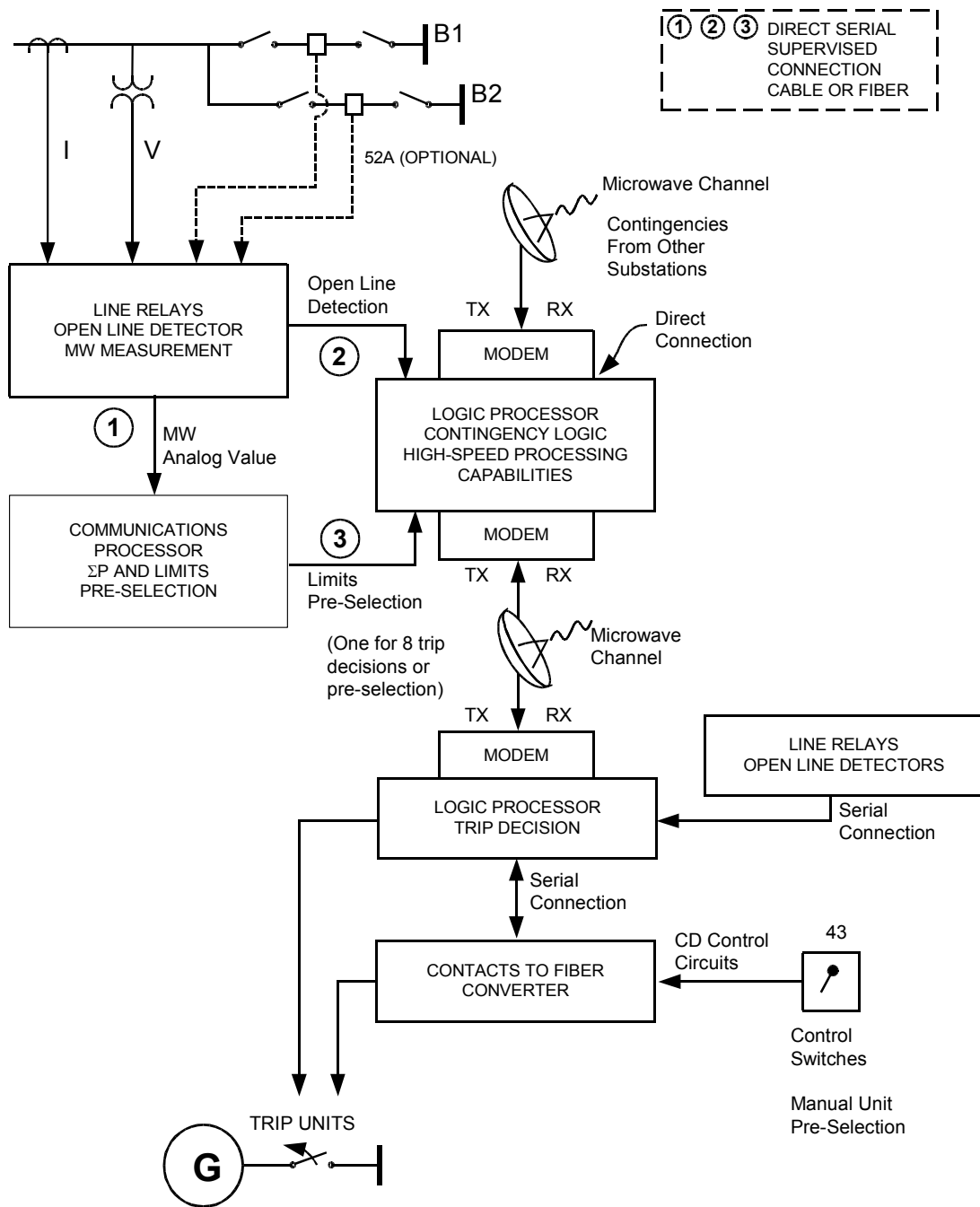
- Signals between open line detectors and equipment for contingency logic schemes are supervised in real time; any interruption can be monitored and resolved quickly. There are no possible auxiliary relay failures in the proposed scheme.
- Communications processor reliability, similar to that for a digital relay, is much better than industrial PLCs.
- Communications processors at each location receive contingency signals and power limit signals. Power limit signals are used as supervision to send or repeat a received generator trip signal.
- The total number of channels in use decreases from 20 on the present scheme to 10, cutting channel costs by half.
- Communications are continuously monitored, and alarms are available for the failure of any channel. While the present scheme can accomplish this, there are two differences: records and statistics from any channel failure belong to the generator shedding scheme instead of to the communications scheme, and power limits for generator pre-selection are monitored continuously. The present scheme uses a SCADA channel to send pre-selection signals to power plants without automatic supervision.

Electric cables or multimode fiber-optic cables provide the physical serial connections between relays in use as open line detectors and logic processors. Serial connection between substations is through a specially designed modem that converts digital serial signals to analog signals at a transmission speed of 9600 baud. To avoid an external power source, a communications processor serial port provides power to the modem, which is also designed to avoid any error correction or other extra delays common to conventional modems. The four-wire analog signal from the modem connects directly to an analog microwave channel. The proposed scheme does not use an electromechanical contact interface (tone equipment), and so reduces one point of failure (Figure 15).

The modem causes a longer delay than direct conventional pilot protection channels. With this modem, we measured a one-way channel delay of 28 ms. A worst case trip signal through four repeaters would take 112 ms, compared to 60 ms for conventional pilot protection channels. Simulation results show that any time less than 200 ms is good, and that any time less than 400 ms is acceptable. With 1.1 seconds as the critical trip time, the longer delay with the modem poses no problem.

To integrate with system signals from other vendor devices, control switches, and conventional communications channels with electromechanical contact interfaces, the proposed scheme uses contacts to serial communications over fiber-optic converters. This allows both integration of other devices lacking direct serial communications technology and gradual upgrading of the scheme. CFE installed and tested in the field the proposed scheme for two of 11 substations. The proposed scheme integrates easily with the present scheme and allows future upgrading of the entire scheme with contacts to a serial communications converter. The prototype CFE scheme and general architecture are shown in Figure 17 and Figure 18. Other advantages of the new scheme are reduced maintenance and built-in event recording of scheme operations.

## Proposed Scheme



**Figure 17** Proposed Scheme Architecture



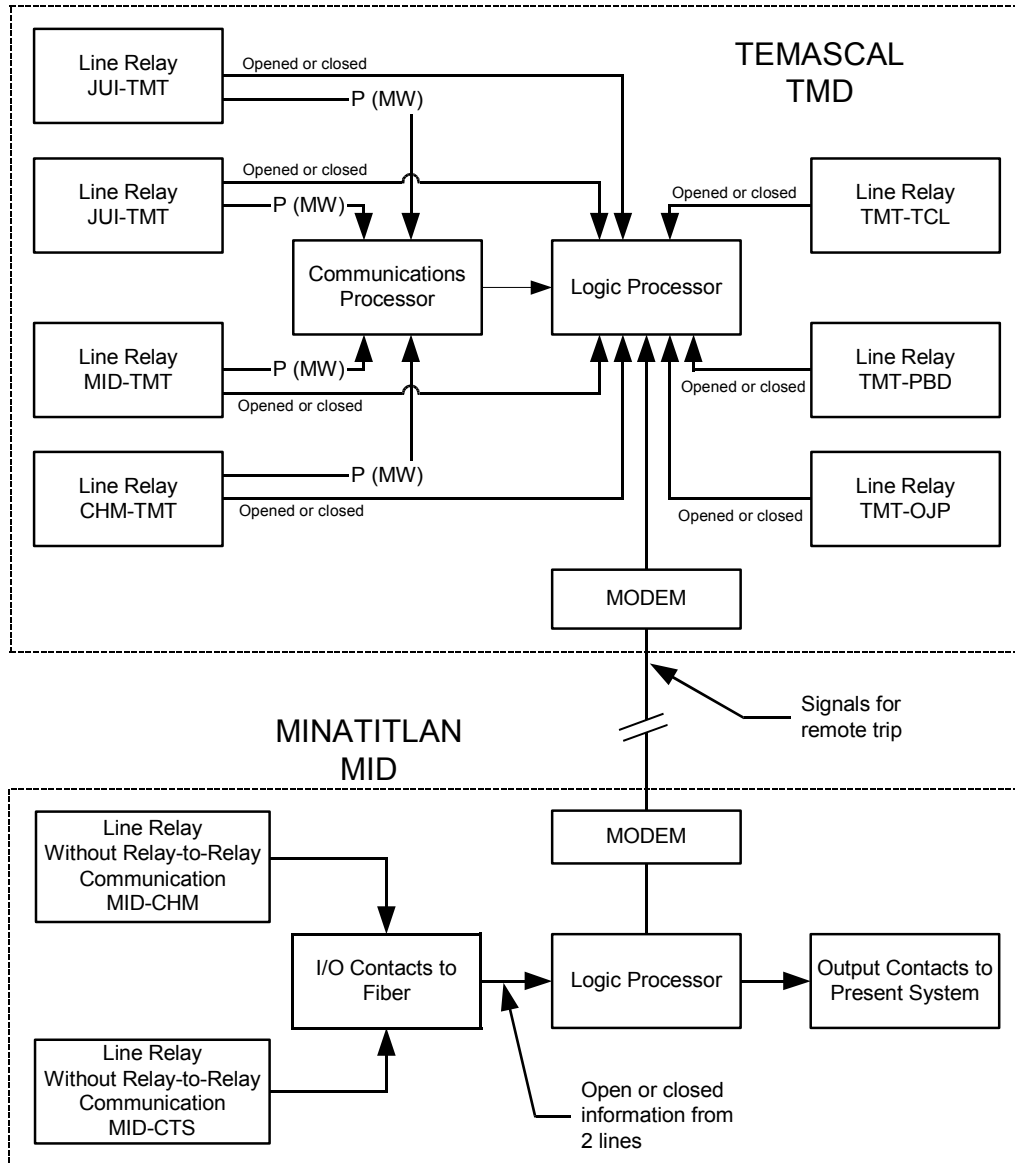


Figure 18 Block Diagram of Prototype

## FAULT TREE RELIABILITY ANALYSIS

To numerically evaluate reliability improvements, we use fault tree reliability analysis. This method is easy to apply, and use of the method for protection and automation reliability estimates has been previously documented [5] [6].

The scheme failure of concern is called the top event. The probability that the scheme fails for the top event is a combination of the failure probabilities of the components in the scheme. For an OR gate, any inputs to that OR gate can contribute to scheme failure. Total probability is the sum of the input events. For an AND gate, any inputs to that gate must fail together to cause scheme failure. The upper level probability for scheme failure from an AND gate is the product of input probabilities.

To estimate the failure probability for each device in the scheme, we can use the device failure rate. One industry practice is to provide failure rates as Mean Time Between Failures (MTBF). MTBF could be based on field failure data or on assumptions about complexity and exposure of equipment. If we have 200 auxiliary relays and only one such relay fails per year, we can assume a failure rate of 1/200 failure per year or an MTBF of 200 years from field experience. Some communications equipment vendors, however, estimating failure rates based upon complexity, could publish an MTBF of 80 years.

To use this information to estimate probability, we should know or assume the fraction of time that a device cannot perform. Unavailability, as calculated in the following equation, provides us with this information.

$$q = \lambda T = T / \text{MTBF}$$

where:

q is unavailability

$\lambda$  is failure rate

T is average down time per failure

MTBF is mean time between failures

T is the fraction of time MTBF when the device is either not useful or has failed. If a communications channel has a guard signal and a failure alarm, we could easily detect a failure on these devices. Then, T could equal two days for detection, analysis of the failure, and repair or replacement before the device is again in service and useful. Unavailability with this example information is  $2 / (80 \times 365) = 0.0000684$  or 0.025 days/year.

One of the principal weaknesses of the present scheme is the dependency of the scheme on several auxiliary relays for open line detection, contingency logic schemes, tone equipment, etc., MTBF could work well for auxiliary relays, but T is always large because of a lack of automatic supervision. Failure of an auxiliary relay could go unnoticed until the next maintenance period or until operation of that relay is required. If the maintenance or testing period is each year, a failure could occur the day following a maintenance test or one day before the next period, an average time of six months. Unavailability with this example is  $(6 \times 30) / (200 \times 365) = 0.002465$  or 0.9 days/year, 36 times worse than the example with the communications channel, even considering the much better MTBF.

Unavailability gives direct information about the probability that a device on the scheme will fail and contribute to scheme failure. From references [5] and [6], we obtain unavailability or MTBF for devices used in the present and the proposed scheme. These numbers, although the approximations are subject to dispute, provide valuable information for checking the degree of magnitude improvements and for estimating the impact of redundancy or other changes on the scheme configuration. We were unable to obtain failure rates for the auxiliary relays, so we used an optimistic estimate to compare with a proposed solution that does not use an auxiliary relay.

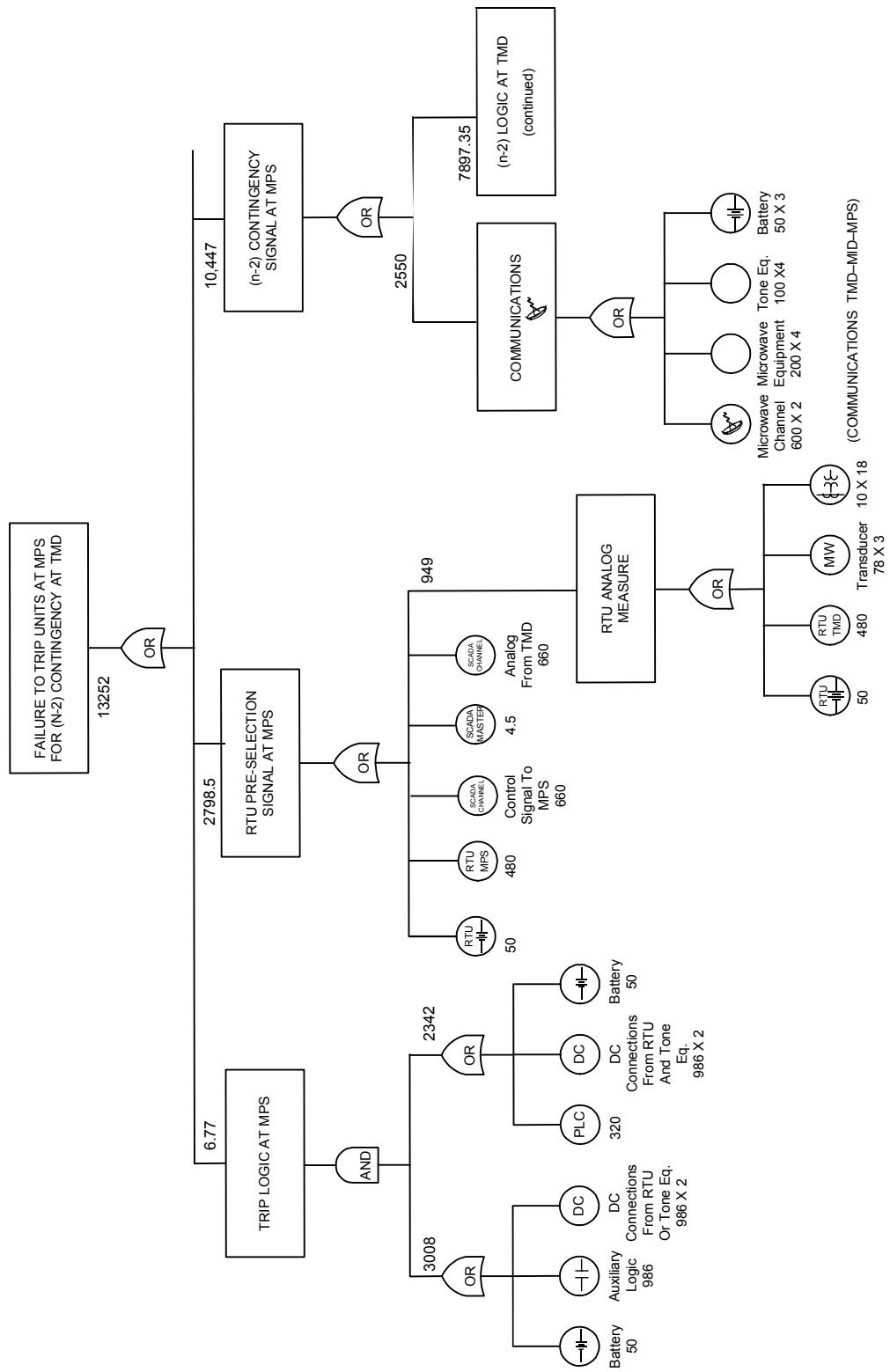
**Table 5** Unavailability Indices for Devices Used on Present and Proposed Schemes

Devices or basic events	MTBF	T	Unavailability x 10 <sup>6</sup>
Current transformers	500 years	2	10
Potential transformers	500 years	2	10
Transducer	70	2	78
RTU	100,000 hours	48 hours	480
SCADA channel (2 modems plus microwave or carrier channel)			660
SCADA master computer (with redundancy)	22,500 hours each workstation	48 hours	4.5
Microwave transmission channel			600**
Analog microwave equipment			200
Tone equipment			100
Auxiliary relay	500 years	6 months	986
CD wiring	500 years	6 months	986
Monitored CD battery			50
PLC	17 years	2 days	320
Line relay	168 years*	2 days	32.6
Communications processor	200 years	2 days	27
Logic processor	200 years	2 days	27
Modem for protection			30
Serial supervised direct connections	100 years	2 days	54

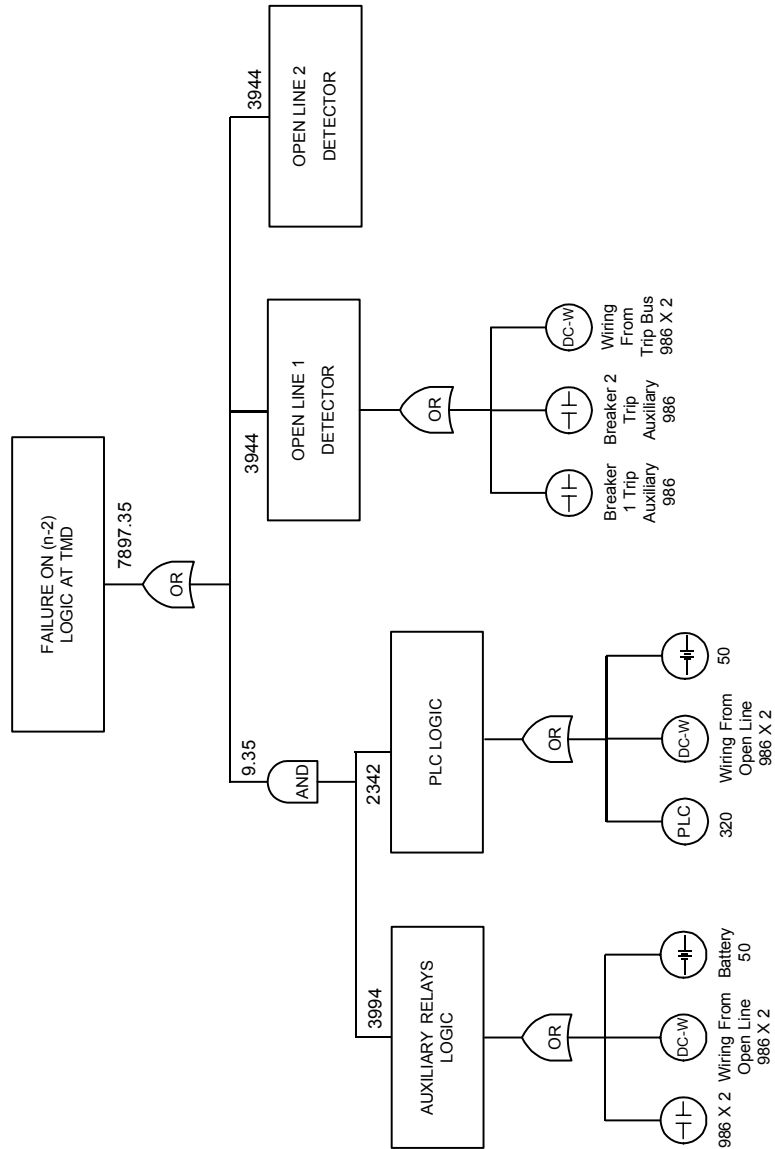
\* MTBF observed by CFE from a total population of about 12,000 relays with similar technology.

\*\* Unavailability observed by CFE during a 5-day test on TMD-JUI microwave link with direct relay-to-relay communications and modems.

With the data from Table 2 as input, we can develop the fault tree in Figure 19 for a top event (Failure to Trip Units at MPS for (n-2) Contingency at TMD) similar to the February 2002 event. This first analysis shows the scheme as it presently exists at some locations, with a single channel but redundant trip and contingency logic schemes.

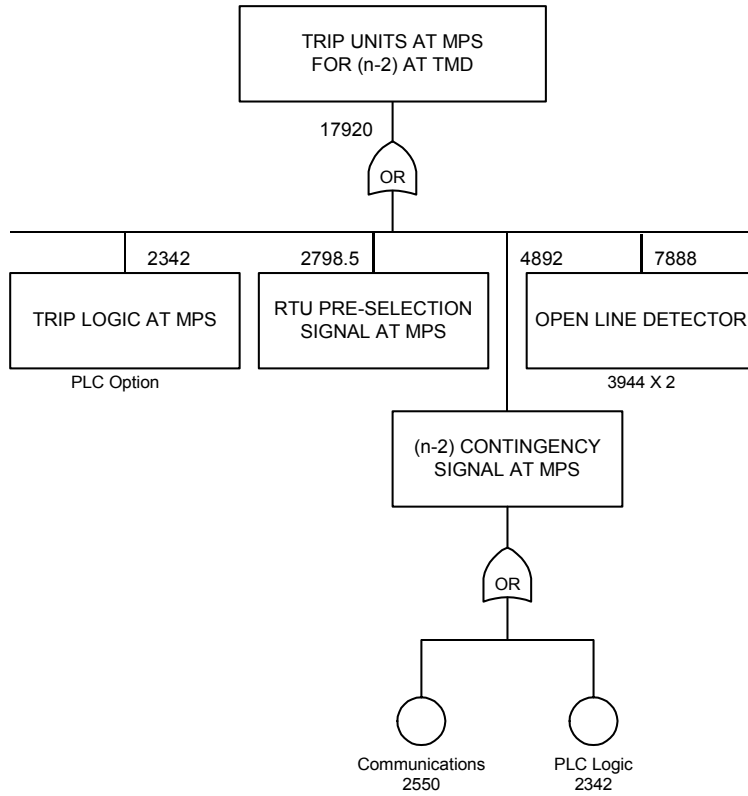


**Figure 19** Fault Tree for Present System—Case 1: Trip and Contingency Logic Redundancy Single Channel (continued)

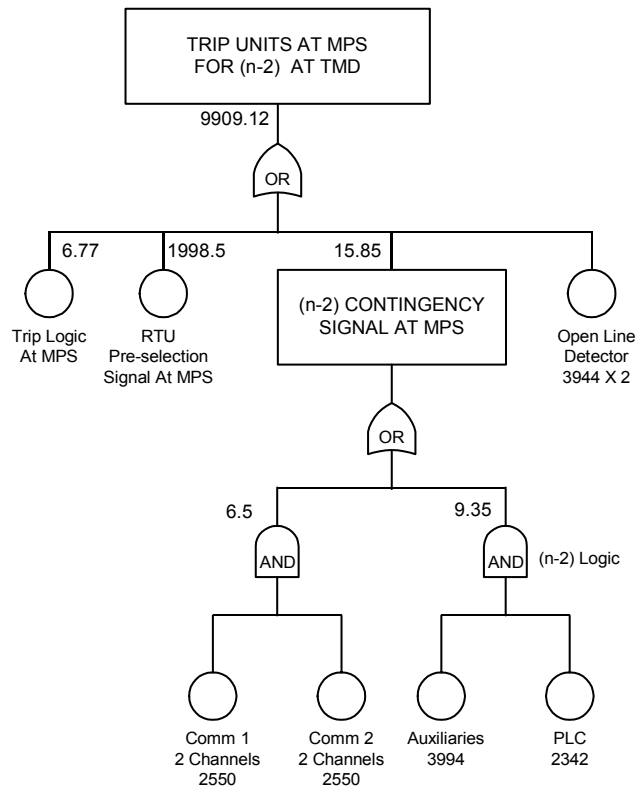


**Figure 19** Fault Tree for Present System—Case 1: Trip and Contingency Logic Redundancy Single Channel

Unavailability of this scheme for the specific top event is  $13252 \times 10^{-6}$  or 1.32 percent. Our analysis involved hardware failures only, but the scheme can experience such other failures as human errors with settings or testing. We can use some results from this fault tree to analyze two other cases with minor variations: no redundancy (Figure 20), or redundancy for trip and contingency logic and for channels (Figure 21).



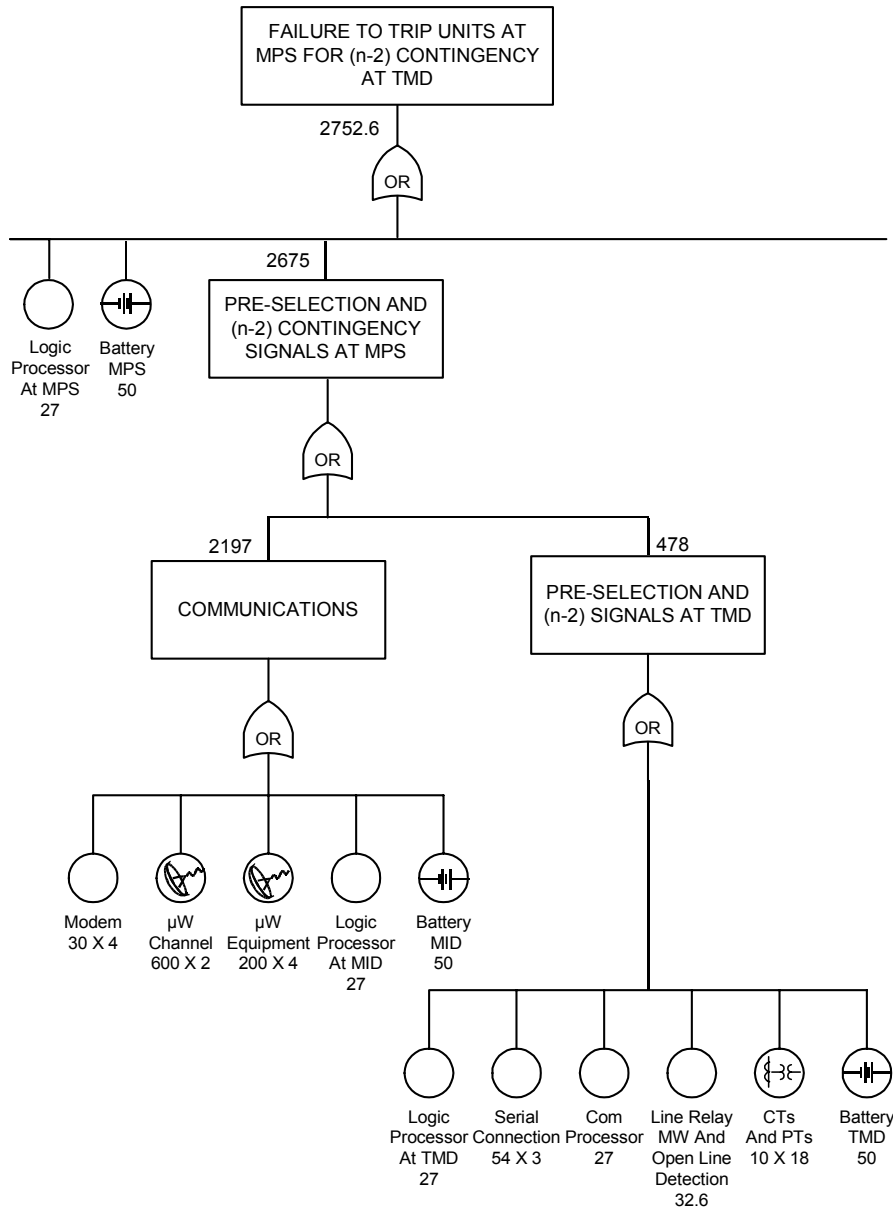
**Figure 20** Fault Tree for Present System Without Redundancy



**Figure 21** Fault Tree for Present System With Full Redundancy

We can observe, and operation experience shows, that in all configurations using the present technology, the main causes of failure include the SCADA remote scheme and communications channels and the open line detectors with auxiliary relays.

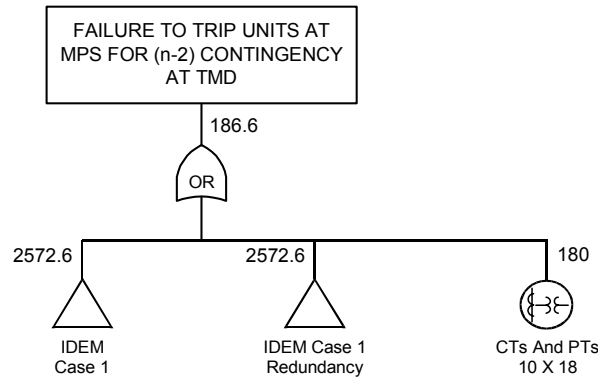
We can develop a fault tree analysis for the proposed scheme without redundancy, as in Figure 22, and with full scheme redundancy, as in Figure 23.



**Figure 22** Fault Tree for Proposed System Without Redundancy

Unavailability for the proposed scheme without redundancy is  $2752.6 \times 10^{-6}$ , or 0.27 percent, 4.81 times better than the present scheme with partial redundancy (Figure 3). Unavailability for the proposed scheme with full redundancy is  $186.6 \times 10^{-6}$  or 0.0186 percent, 71 times better than the present scheme in Figure 3. The main sources for enhancement include the use of open line current detection instead of auxiliary relay trip detection, local power limit processing instead of

SCADA master power limit detection, and the possibility of channel multiplication providing full redundancy at reasonable cost.



**Figure 23** Fault Tree for Proposed System With Full Redundancy

Table 6 shows a chart correlating all options with reliability. It shows unavailability results only for a top event similar to the February 2002 event. A complete analysis is necessary for all possible modes of operation.

**Table 6** Correlations Between Reliability and Equipment Used for Different Generation Scheme Options

<b>Solution</b>	<b>Unavailability x10<sup>6</sup></b>	<b>Related enhancement</b>	<b>Total solution equipment as related cost information</b>
Present solution with trip and contingency logic redundancy, single channel	13252	Reference (Figure 3– present system for this top event with partial redundancy)	7 PLCs 7 sets of auxiliary relays for contingency or trip logic 36 sets of auxiliary relays for line trip detection 20 pilot protection communications channels, 40 analog microwave equipment services and 40 tone equipment services 3 SCADA channels, 3 RTUs, 2 master stations and 8 real power transducers are involved in the system (but are not part of the generation scheme direct cost)
Present solution without any redundancy	17920	35% worse than reference	7 PLCs 36 sets of auxiliary relays for line trip detection 20 pilot protection communications channels, 40 analog microwave services and 40 tone services



<b>Solution</b>	<b>Unavailability x10<sup>6</sup></b>	<b>Related enhancement</b>	<b>Total solution equipment as related cost information</b>
Present solution with trip and contingency logic redundancy and channel redundancy	9909	33% better than reference	7 PLCs 7 sets of auxiliary relays for contingency or trip logics 37 sets of auxiliary relays for line trip detection 40 pilot protection communications channels, 80 analog microwave services and 80 tone services
Proposed solution without any redundancy	2752	4.81 times better than reference	4 communications processors 10 logic processors 10 pilot protection communications channels, 22 modems, 22 analog microwave services 36 line relays are involved (but are not part of the generation scheme direct cost)
Proposed solution with full redundancy	186.6	71 times better than reference	8 communications processors 20 logic processors 20 pilot protection communications channels, 44 modems, 44 analog microwave services

## **FUTURE CONSIDERATIONS**

A lack of transmission network capacity, because of right-of-way restrictions and limited investment, is making wide-area network protection schemes increasingly more important. References [7] [8] are among several works dealing with new algorithms that improve the ability to detect conditions that can affect power system integrity. Such works discuss synchronized phasor measurement schemes for transient stability or voltage collapse estimates and neural networks to identify unsafe conditions and emergency control actions on complex meshed networks. From the development of algorithms to field implementation, all new and improved performance schemes should take reliability issues into consideration.

Communications will continue to become cheaper and safer with the increased use of digital fiber networks by most utilities. New communications will allow schemes that use more information to make better decisions. Intelligent use of these lower cost digital networks will have a strong impact on the development of wide-area network protection schemes.

To implement wide-area network protection schemes, more facilities will require analog operators and comparators such as those used in the proposed solution. Analog operators for new algorithms should include sum, multiplication, division, sine, and cosine functions. These features could be part of line relays or processors at every location to allow future implementation and changes as schemes develop and change. Some local control stations have high-level programming languages that allow mathematical operations, but the reliability of these is low and the processing speed is not deterministic; these local control stations cannot serve the purposes of wide-area network protection.

## CONCLUSIONS

1. Wide-area network protection schemes allow economic power system operation without impacting reliability, even considering multiple contingencies.
2. Detailed steady-state and dynamic stability contingency studies should be done to specify wide-area network protection schemes and answer questions about such field implementation issues as the features needed at each location and maximum tripping time.
3. Each contingency causes different problems and imposes different requirements on field implementation. Control devices, rather than wide-area network protection, can solve some of these problems. Only contingencies causing a system to go into the “extreme” state should trigger action from a wide-area network protection scheme.
4. Dynamic event records, with different variables, acquisition rates, and event report lengths for relay operation evaluation or for SCADA, provide validation of dynamic studies. The dynamic event records are also useful for evaluating the operation of wide-area network protection schemes.
5. Typical maximum tripping times for stability problems are between 200 ms and 2 seconds. Normal SCADA channels and control signals are not fast enough. Trip signals must travel by pilot protection channels directly from a contingency detection to the power plants.
6. Because of oscillations that occur with the present contingency criteria, real power after a disturbance cannot be used as a variable for determining whether to trip. Power limits must be continuously monitored, and pre-selection of generators for tripping each kind of contingency must occur before a disturbance.
7. To improve reliability, total link power limit detection should occur locally.
8. Open line detection is critical for scheme performance; current-based methods are more simple and reliable than auxiliary relay methods.
9. Direct relay-to-relay communications technology improves scheme reliability in two ways: such technology avoids unsupervised dc control circuit wiring between devices, and the technology multiplies pilot protection channels to allow channel redundancy at a reasonable cost.
10. The fault tree method is a valuable tool for analyzing and quantifying reliability improvements on wide-area network protection schemes.
11. Field performance statistics for individual system components provide excellent input data to obtain more accurate unavailability estimates.
12. The proposed scheme without redundancy provides more than four times the availability of the present scheme with partial redundancy and cuts communications channel costs in half.
13. The proposed scheme with full redundancy provides more than 71 times the availability of the present scheme without increasing costs beyond those for the present scheme with partial redundancy.

## BIOGRAPHIES

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**Eduardo Mora Alcaraz** has been a regional supervisor protection engineer for Comisión Federal de Electricidad at Veracruz, México since 1988. He has worked on several projects for extra high-voltage protection and control equipment, single-pole trip and reclose applications, wide-area load and generation shedding schemes, and new device evaluation. He received his BSEE degree from Metropolitan Autonomous University UAM in Mexico City.

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