

POWERMAX[®] SOLUTIONS

Power Management Systems for Industries
Remedial Action Schemes for Utilities



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POWERMAX[®] Offerings

Apply SEL's POWERMAX solutions to any utility or industrial application. These solutions are scalable from small to large, starting with the control of a simple, isolated microgrid up to a complex wide-area power system.

Maximize system uptime and mitigate problems before you experience an outage with proactive, high-speed load shedding, generation control, voltage control, and load management. Receive total system awareness through graphical user interfaces, automatic waveform capture, report analysis software, and report generation tools. SEL's POWERMAX solutions provide access to system information and SCADA while performing protection, control, automation, and management functions. These solutions are flexible and configured to meet your system's needs.

SEL has a cross-functional organization of resources that focus on these POWERMAX solutions for projects throughout the world.

POWERMAX Solutions for Industries and Utilities

- Load-Shedding Systems
- Steam Controls
- Generation Shedding and Runback Systems
- Autosynchronization Systems
- Fast Decoupling Solutions
- Generation Control Systems
- Factory Acceptance Tests
- Control System Simulations
- Security
- Synchrophasor Monitoring and Control
- MOTORMAX[™]



POWERMAX[®] Solutions for Industries and Utilities

LOAD-SHEDDING SYSTEMS

Event-Based Load-Shedding System

- High-speed, contingency-based load-shedding processor sheds load on breaker opening.
- Asset overload initiates load shedding on predicted or measured equipment overloads.

Frequency-Based Load-Shedding System

- Hybrid underfrequency-based load-shedding processor provides an excellent backup to a contingency-based load-shedding processor.
- Inertia-compensated, load-tracking load shedding represents the next generation of load shedding.

Voltage-Based Load-Shedding System

Undervoltage- and flux-based load shedding prevents voltage collapse.

Closely-Timed/Simultaneous Events

Proprietary fast power flow recalculation and prediction engine allows load shedding to accurately make decisions after multiple simultaneous or closely timed events.

Load Management

- Load re-acceleration safely starts large motors on a microgrid.
- Load-start inhibit stops motors from starting, preventing grid collapse.
- Transfer inhibit intelligently stops the wrong loads from starting on grid-islands.
- Provides intuitive metering for better business unit decision making.

Load Priority List Options

- Simple: Requires one load priority list for the system.
- Comprehensive: Requires one unique load priority list for each contingency.
- Process-oriented: Action tables actively modify the priority list based on process-related data.

STEAM CONTROLS

Pressure Disturbance Rejection

Valve feed forward control prevents header pressure over- and undershoot conditions caused by rapidly changing turbine governor or electrical load conditions.

Steam Load Shedding

- Simple: Low boiler pressure initiates steam load shedding.
- Advanced: Predicts steam mismatch conditions before they happen by monitoring the electrical power system.

GENERATOR SHEDDING AND RUNBACK SYSTEMS

Event-Based Generator Shedding and Runback System

High-speed, contingency-based generation shedding and runback system sheds generators on breaker opening of tie lines, bus couplers, and bus ties.

Frequency-Based Generator Shedding and Runback System

- Supplies hybrid overfrequency-based generator shedding.
- Performs inertia-compensated load tracking.

Closely Timed/Simultaneous Events

Performs fast power flow recalculation to process closely timed/simultaneous events.

Generator Priority List Options

- Simple: Requires one priority list for the system.
- Comprehensive: Requires one unique generator priority list for each contingency.
- Process-oriented: Action tables actively modify the priority list based on process-related data.

AUTOSYNCHRONIZATION SYSTEMS (25A)

Island Synchronization System

- Provides synchronization of tie lines, bus couplers, and other breakers to rapidly put power systems back together.
- Unit synchronization of individual generators.

FAST DECOUPLING SOLUTIONS

Rapidly separates a facility from a failing grid using intelligent combinations of the following technologies: 81 RF, dv/dt, df/dt, and synchrophasors.

GENERATION CONTROL SYSTEMS

Automatic Generation Control

- Turbine load sharing keeps generation balanced under all scenarios.
- Islanded frequency control simultaneously balances turbines and keeps a microgrid at nominal frequency.

Voltage Control System

- Excitation load sharing keeps reactive power balanced under all scenarios.
- Islanded voltage control simultaneously balances reactive power and keeps a microgrid at nominal voltage.
- Motor-starting algorithm supports dispatch of generator exciters and on-load tap changer to support a motor start under islanded conditions.
- On-load tap changer control performs in conjunction with excitation load sharing to optimize the facility volt/volt-ampere reactive balance.

Tie Line Control System

- Utility tie power factor control optimizes conductor usage.
- Utility tie active power control economically dispatches plant power production.

Island Control System

- Generator island detection monitors the most complicated power systems and finds dangerous microgrids.
- Governor mode selection modifies the operational mode of governors and exciters for islanded (microgrid) conditions.

Other Features

- Generator start/stop functionality provides automated response to emergency situations.
- Dynamic capability curve calculation to constantly monitor the maximum capability of onsite generation.

FACTORY ACCEPTANCE TESTS

All POWERMAX solutions are tested with panel, integration, static simulator, and Real Time Digital Simulator (RTDS®) factory acceptance tests:

- Panel testing.
- Integration with other systems (e.g., switchgear and distribution control system).
- Static simulator.
- Dynamic simulator.

CONTROL SYSTEM SIMULATIONS

Static Simulator

- Static simulator panels are used to train new operators.
- Online data captures are used to initialize simulator systems with real-time data.
- Save/restore scenarios are used to build and retrieve interesting events for playback.
- RTDS rack interfaces are used to provide a simple static simulator.

Semidynamic Simulator

Power flow recalculation improves static simulator, including governor/exciter/OLTC and the behaviors of other equipment.

RTDS Simulation

- Models are built by SEL experts to analyze the mechanical and electrical characteristics of a power system.
- Provides model validation reports for every system modeled by SEL.
- Uses under- and overfrequency coordination reports to create relay settings for decoupling, load shedding, and equipment protection.
- Provides voltage stability reports for customers experiencing voltage collapse or weak supply conditions.
- Provides motor-starting reports for grids frequently islanded.
- Provides transformer inrush analyses for protective relays to operate correctly under the worst-case magnetization of equipment.
- Provides transient stability reports for maximum breaker clearing time with a variety of system faults.

Racks can be leased or purchased from SEL as a fully programmed plant simulation.

SECURITY

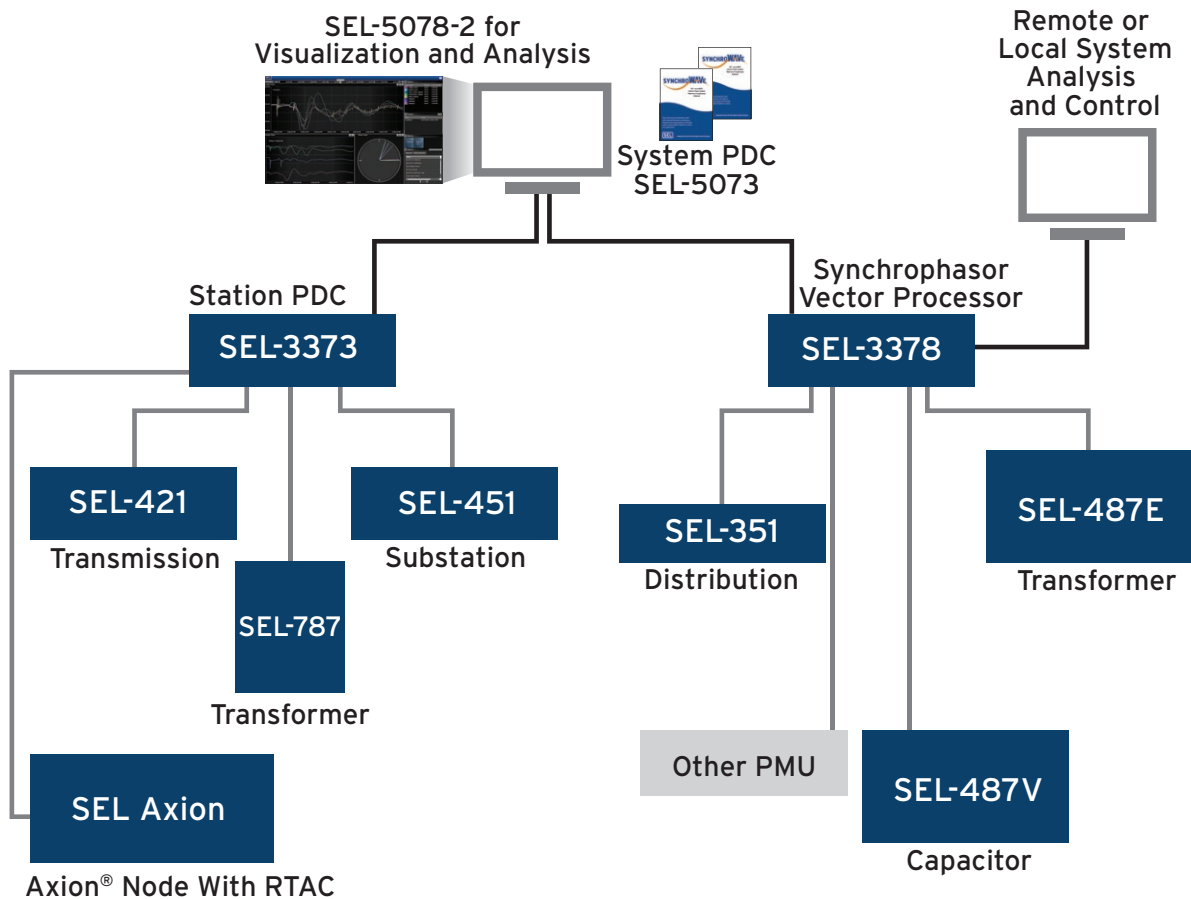
Risk Analysis

- Ethernet risk assessment reports are generated for complex, mission-critical control systems that depend on Ethernet technology.
- Security and information gateways and firewalls are used to bridge data between separate onsite networks.
- Centralized password management and user-level access tools are used to provide and keep critical control systems safe.
- Remote view connection capabilities are designed to allow remote views of data and problem solving.

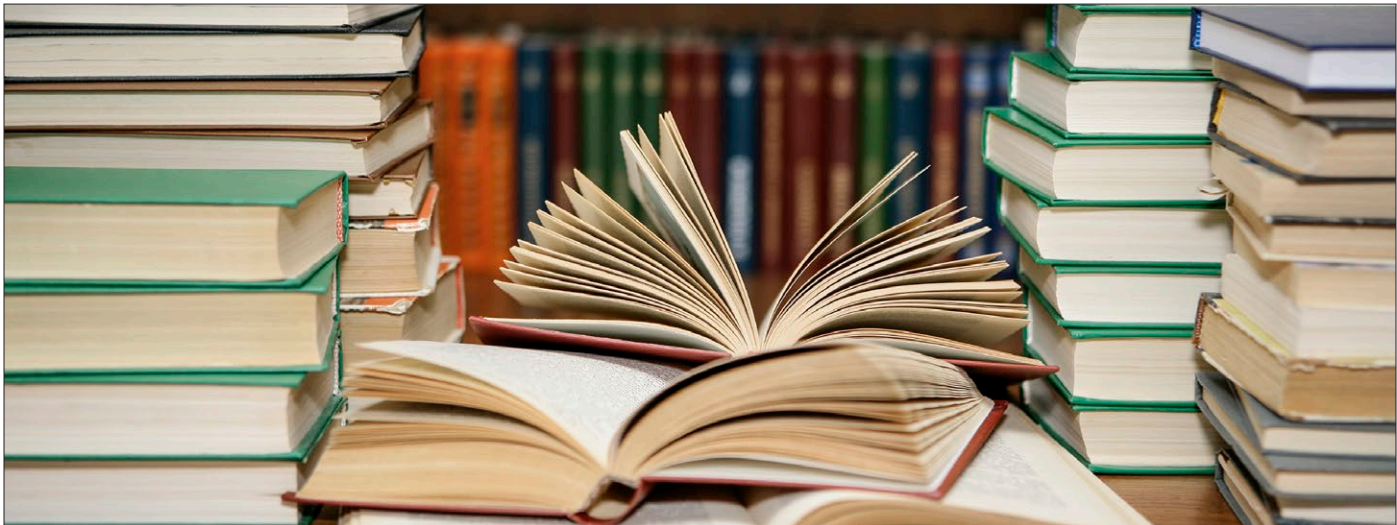
SYNCHROPHASOR MONITORING AND CONTROL

Continuously monitors power system using synchrophasors. The following toolkits detect problems in real time:

- Wide-area monitoring and control.
- Modal analysis.
- Inter-area oscillation detection.



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Case Study: Smart Automatic Synchronization in Islanded Power Systems

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Case Study: Smart Automatic Synchronization in Islanded Power Systems

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Abstract—Automatic synchronizing systems are used to reconnect multiple islanded power grid sections. These systems are required to function automatically with minimal human supervision because they must dispatch multiple generators simultaneously to reduce slip and voltage difference at the interconnection point.

This paper describes a smart automatic synchronizing system that can connect multiple generators in an industrial power system during islanded and utility-connected modes via six different bus-tie and utility tie breakers. The automatic synchronizing system performs matching by controlling multiple governor and exciter interfaces within the facility.

Controlling slip and voltage difference across any of six different breakers in any combination is accomplished with up to six different and simultaneous power system islands. The power system studied is a large refinery containing six generators, totaling about 260 MW of generation.

The functionality, operation, and validation of this automatic synchronizing system using real-time digital simulator (RTDS) tests are discussed.

Index Terms—Automatic Synchronization; Case Study; Closed-Loop Real-Time Simulation; Exciter Control; Generation Control; Governor Control; IEC 61850 GOOSE; Microgrid; Optimal Load Sharing; Redundancy.

I. INTRODUCTION

An alumina processing facility (refinery) installed a new double-bus, single-breaker gas-insulated substation (GIS) to meet plant growth and reliability requirements. Included in the project was a plant-wide generator control system (GCS) that can perform reliability islanding to ensure uninterrupted power and steam service to the critical process loads throughout the facility. The refinery power system includes six steam turbine generators that can operate in up to six independent microgrids. The focus of this paper is the synchronizing system that is used to resynchronize an island back to the utility grid or to other islands within the facility.

Due to the nature of and the complexity involved in the many possible islanded microgrids, the refinery project included the requirement that no manual synchronization is allowed. For this reason, the automatic synchronizing system had to be fully redundant to allow operations to continue in the event that the primary system failed.

An automatic synchronizing system connects a spinning power system to another spinning power system. Breaker closing ideally happens when the voltage, frequency, and phase angle are within tolerable limits for the two power systems.

The automatic synchronizing system for this project performs the following tasks:

- Identifies the electrical equipment connected on either side of the breaker being synchronized. This includes breakers, buswork, generators, utility tie lines, on-load tap changers (OLTCs), loads, and so on.
- Measures the slip, angle, and voltage difference across the breaker being synchronized.
- Controls multiple governors, exciters, and OLTCs to minimize slip, angle, and voltage difference.
- Closes the breaker once slip, angle, and voltage criteria are satisfied.

The automatic synchronizing system described in this paper automatically synchronizes multiple generators in the power system during any combination of islanded and utility-connected modes. The functionality and operation of the automatic synchronizing system are discussed.

The refinery is an operating facility. Therefore, the new generators, bus and feeder circuits, load-shedding system, and GCS had to be commissioned while not causing major disruption to production processes. To reduce risk, the system upgrade was fully validated in the laboratory by simulating the power system and generator controls using a closed-loop real-time digital simulator (RTDS).

II. ELECTRICAL NETWORK FOR REFINERY

Fig. 1 shows a simplified one-line diagram of the refinery. The top half of the diagram, including Buses GIS1A, GIS1B, GIS2A, and GIS2B, shows the new GIS. Generating Units G5 and G6 were also added in the plant power system upgrade. Note that the power system includes six steam generators, totaling 260 MW of capacity. The two utility tie lines can support up to 85 MW each. This GIS transfers power between medium-voltage (11.5 kV) busbars (B1 through B6), utility tie lines, and the two GIS-connected

generators (G5 and G6). Note that the 11.5 kV bus is connected to the 132 kV GIS bus with OLTC transformers.

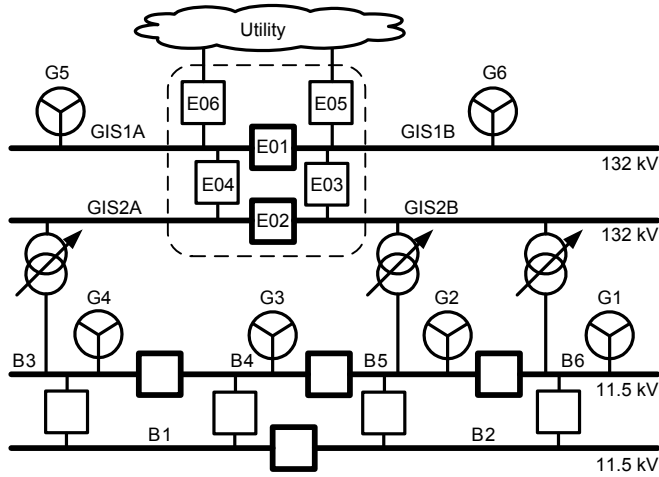


Fig. 1. Simplified One-Line Diagram of Refinery Power System

The power system supports loads on multiple buses, many with no generation. Each of the six generators can support loads independently on different islands, making it possible for six islands to occur simultaneously. These generators also supply power to the GIS bus for loads throughout the refinery. The refinery power system can be connected in various topologies, requiring the automatic synchronizing system to be flexible and adapt to all refinery electrical grid topologies. The automatic synchronizing system controls synchronization for the two bus sectionalizing breakers (E01 and E02), two bus-tie breakers (E03 and E04), and the two

utility tie breakers (E05 and E06). Each generator has its own synchronizer for coming online during startup, so the generator breakers are not controlled by the system.

III. AUTOMATIC SYNCHRONIZING SYSTEM DESIGN

This section describes the design and functionality of the automatic synchronizing system. This system (shown in Fig. 2) has two major components: the advanced automatic synchronizer (A25A) and the GCS. For redundancy, there are two A25A devices. When a synchronizing scenario is selected, the A25A sends the slip and voltage difference error signals to the GCS.

The GCS monitors the power system topology and identifies which generators are within each island or utility connection. The GCS receives the slip and voltage difference from the A25A and determines which group of generators to control for the synchronizing scenario that is selected. The GCS provides proportional correction pulses to adjust the governors and exciters of the parallel-connected generator units on each bus section as necessary for synchronization.

The A25A monitors the slip and voltage difference and, once the GCS has reduced them to within the synchronizing acceptance limits, initiates breaker closing at the slip-compensated advanced angle to ensure that the two systems are joined at the instant of zero-degree angle difference.

This synchronizing system can synchronize across six breakers in any island formation to create a larger island from two islanded systems or synchronize an island to the utility grid.

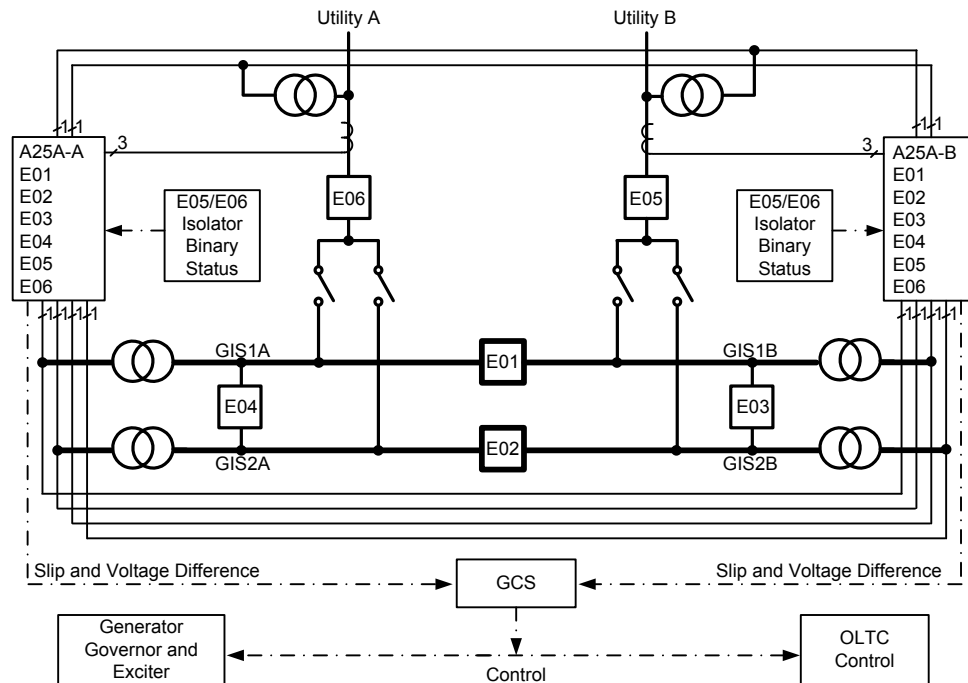


Fig. 2. A25A and GCS Interaction

The synchronizing system described in this paper must identify all island formations and dispatch generators appropriately. Simultaneous steam extraction requirements in tons per hour complicate the generator dispatch during the synchronization. Generator terminal voltages and bus voltages must be kept within manufacturer tolerances simultaneous with MVAR output load sharing between generator excitation systems. This is accomplished by controlling both OLTCs and exciters.

The automatic synchronizing system implemented at the refinery is a fully automatic, closed-loop system that dispatches multiple generators in parallel for synchronization and actively monitors the process until synchronization. The A25A can detect a failed or successful close by monitoring the breaker after the close command is initiated.

One of the features of this system is its ability to calculate advanced angle and issue a close command to compensate for the breaker closing delay. The A25A measures the slip and calculates the advanced angle at which the close coil should be energized. The slip-compensated advanced angle is calculated using (1) [1].

$$\text{ADVANG}^\circ = \left(\frac{(\text{SLIP})\text{cyc}}{\text{sec}} \right) \left(\frac{\text{sec}}{60 \text{ cyc}} \right) \left(\frac{360^\circ}{\text{cyc}} \right) ((\text{TCLS})\text{cyc}) \quad (1)$$

where:

ADVANG is the advanced close angle.

TCLS is the circuit breaker close mechanism delay.

A. A25A Device

The A25A, which is a microprocessor-based protection-grade relay, can synchronize across 6 breakers at the GIS as previously described. For each breaker, there are 2 synchronizing scenarios, resulting in a total of 12 synchronizing scenarios.

In the case of the bus sectionalizer and bus-tie breakers, the two scenarios govern which bus is to be controlled by the GCS to match frequency and voltage. For example, Breaker E01 can synchronize Bus GIS1A to GIS1B, or it can synchronize Bus GIS1B to GIS1A. The GCS must determine which generators are on the bus to be controlled by monitoring the system topology and send matching pulses to the correct governors and exciters.

The utility tie breakers also have two scenarios; these breakers can be connected to either of two buses. For example, Breaker E05 can synchronize Bus GIS1B to the utility grid or GIS2B to the utility grid, depending on the status of the bus isolators. Note that buses connected to the utility grid cannot be controlled.

The A25A also provides underfrequency and overfrequency tripping functions for the buses connected to the utility tie lines. These elements are used to intentionally island the refinery during power system disturbances on the

electric utility grid. These elements operate at the set points shown in Table I.

TABLE I
FREQUENCY-BASED ISLANDING FROM UTILITY

	Frequency	Pickup Time
Underfrequency	49.1 Hz	5 cycles
Overfrequency	50.5 Hz	5 cycles

The A25A selects the appropriate incoming and running voltages from its six voltage inputs based on the scenario selected. The large number of voltage transformer (VT) inputs on the relay allows this selection to be performed without any physical switching of the VT signals. Two A25A devices are provided for redundancy. Each A25A is designated as the primary synchronizer for 6 of the 12 scenarios and as the alternate synchronizer for the remaining 6 scenarios.

Both A25A devices have inputs from single-phase VTs from all four buses and each utility tie, as shown in Fig. 2. Both of the 52A and 52B statuses from the synchronizing Breakers E01 through E06 are wired to the terminals of each A25A and are monitored for the validity of the breaker status. Isolator status signals (89A and 89B), shown in Fig. 2, are wired to a separate I/O module and communicated to the A25A devices using the IEC 61850 Generic Object-Oriented Substation Event (GOOSE) protocol. Both 89A and 89B isolator statuses are monitored for the validity of the isolator status, and any incongruence creates an alarm, inhibiting the operator from initiating an automatic synchronizing process. The communications link status between the I/O module and the A25A is monitored internally in the A25A for the reliability of the GOOSE messages from the I/O module.

There are three conditions that the A25A must recognize to close a circuit breaker. They are:

- Synchronizing close (slip is detected, and matching is required).
- Parallel permissive close (both buses are live, but no slip is detected).
- Dead-bus permissive close (one or both buses are dead).

Automatic synchronizing close permissive asserts when voltage and frequency across the breaker are in normal operation; therefore, slip and voltage differences exist across the breaker, and frequency and voltage matching is required. The GCS needs to send raise and lower pulses to the governors, exciters, and OLTCs to bring the slip, voltage difference, and angle on both sides of the breaker within the synchronizing acceptance criteria, as shown in Table II [2] [3].

The parallel permissive close asserts when voltage and frequency on both sides of the breaker are within normal operating range and there is no slip across the breaker. This

permissive is used to close a breaker when the two systems are synchronized through another path, such as when three of the bus breakers are closed and it is desired to close the fourth.

TABLE II
SUPERVISION SETTINGS FOR AUTOMATIC SYNCHRONIZING
FOR SYNCHRONIZED CLOSE

	IEEE C50.12 and IEEE C50.13	A25A Acceptance Criteria
Angle	$\pm 10^\circ$	Target 0°
Voltage	$\pm 5\%$	$\pm 5\%$
Breaker Close Time	NA	3 cycles
Slip	± 0.067 Hz	± 0.04 Hz

A dead-bus permissive close asserts when either bus, or both buses, in the selected synchronizing scenario is dead. The permissive logic excludes a live bus and dead tie line condition for the utility bus-tie breakers to prevent ever backfeeding the utility grid from the refinery.

The synchronizing process can be initiated from multiple places, either from the front panel of the A25A (see Fig. 3

and Fig. 4) or from a remote human-machine interface (HMI). In both cases, the operator makes a selection for the breaker to synchronize the two systems together. Once a breaker is selected, if any three of the permissive conditions described are true, then the **OK TO INI AUTO SYNC/CLOSE** light-emitting diode (LED) asserts and the breaker is ready to be closed. The front-panel LED provides indication in terms of voltage, frequency, slip, and angle to the operator.

The A25A also provides analog data regarding voltage and frequency on either side of the breaker to the HMI and GCS. In the case of automatic synchronizing close, the control signals need to be sent to the generator and the OLTCs to reduce slip and voltage difference so that the breaker can be closed.

Once the slip and voltage difference come within the user-specified synchronizing acceptance criteria, the A25A sends a close command to the close coil at the advance angle to close the breaker. The A25A monitors the breaker for closing, and if the breaker fails to change state, the A25A asserts a close fail alarm to notify the operator. If the breaker closes but opens again immediately, the A25A asserts a close lockout alarm to notify the operator.

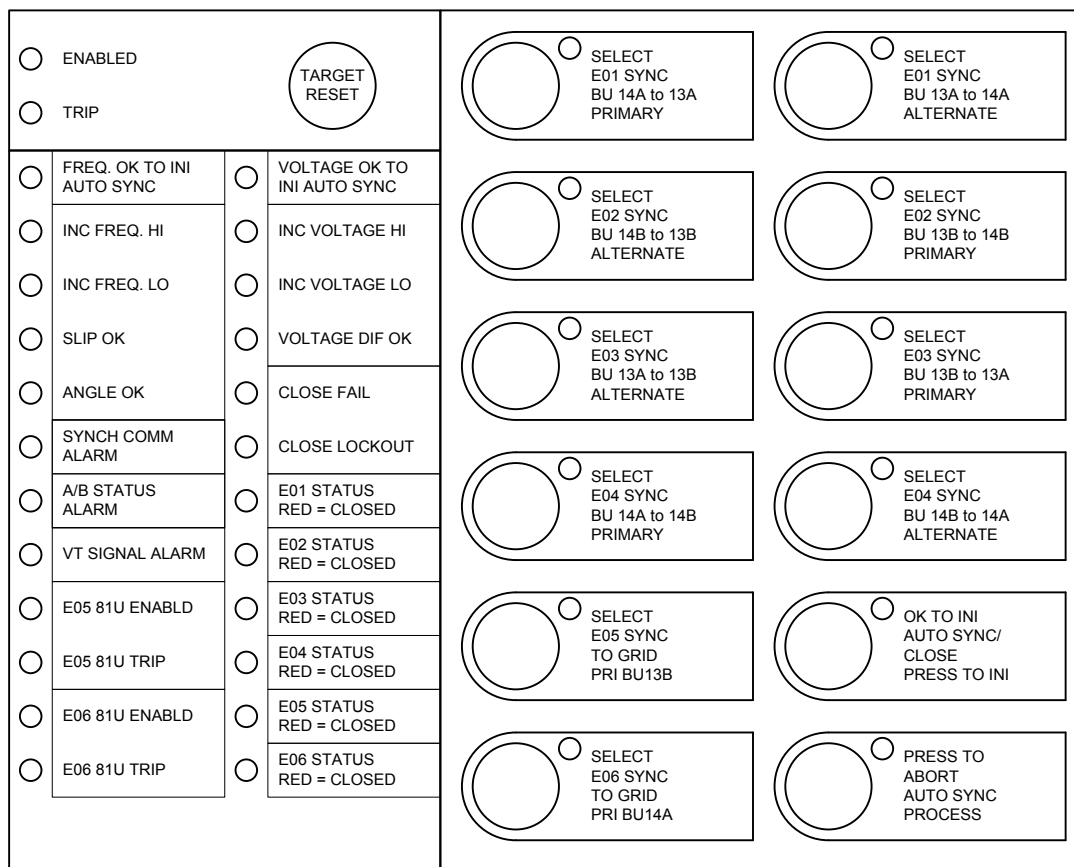


Fig. 3. Front Panel of the Automatic Synchronizer A25A-A

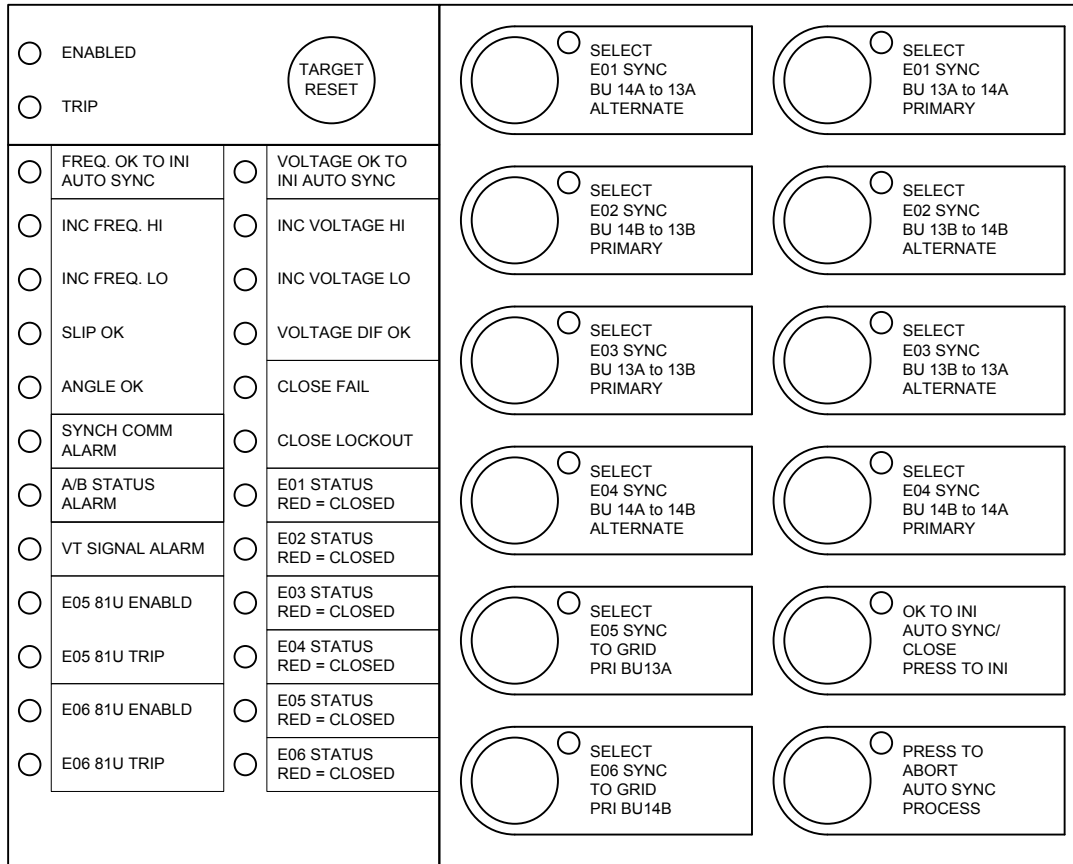


Fig. 4. Front Panel of the Automatic Synchronizer A25A-B

The A25A devices have extensive recording capability. There are 98 logic points for critical logic signals inside the A25A that are programmed to be monitored by the Sequential Events Recorder (SER) function. These logic points have been programmed with human-readable aliases.

The A25A devices record two types of oscillographic records. COMTRADE files contain raw sample data at a 1 kHz sampling rate. Compressed event (CEV) files contain filtered data that are synchronized to the one-eighth power system cycle processing interval of the A25A. The A25A devices are programmed to record a 4-second oscillographic record with 2 seconds of pretrigger capture when triggered. An oscillographic record is triggered when the A25A attempts to close a circuit breaker.

The front-panel display of the A25A provides information regarding the synchronizing process and its parameters along with any associated alarms. Fig. 5 shows the front-panel rotating display that provides any alarms that an operator needs to be aware of before initiating a breaker. The A25A also provides detailed information regarding the breaker selected for the synchronizing process. The right side of Fig. 5 shows the information regarding the breaker. A similar screen for each of the breakers is available in the front-panel display of the A25A.

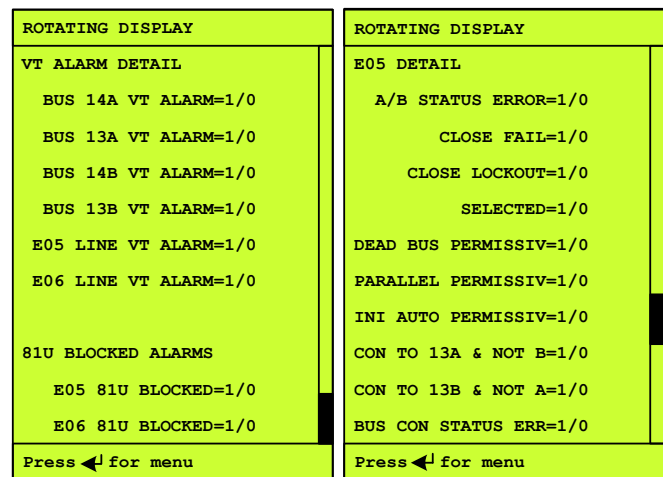


Fig. 5. Front-Panel Rotating Display

B. Generation Control System

The A25A does not have sufficient data processing power to dispatch the six governors, exciters, and OLTC controllers in accordance with plant operating requirements. The GCS augments the A25A by providing topology tracking, equal percentage load sharing of governors and exciters, and simultaneous bus voltage regulation. The GCS in this project

also supplies a great deal of additional functionality, which is not described here because it is not pertinent to synchronizing.

Because of the diversity of bus-switching scenarios, any of the six governors, exciters, or OLTCs can be on either side of the breaker being synchronized. The function of determining which islanded section these devices are connected to is called topology tracking. Topology tracking requires complete knowledge of all the switching devices. To track all the possible topology scenarios, 82 breaker (52) status inputs and 64 isolator (89) status signals were supplied to the GCS via intelligent electronic devices (IEDs) located throughout the plant, as shown in Fig. 6. These input signals are run through topology tracking and island detection algorithms, as shown in Fig. 7.

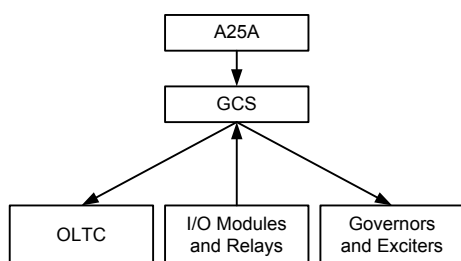


Fig. 6. GCS Communications Architecture

All the breaker statuses, isolator statuses, VT connections, current transformer (CT) connections, and controls are hard-wired to relays and I/O modules located throughout the plant. Breaker and isolator statuses, active power (P), reactive

power (Q), voltage (V), and frequency (F) are sent to the GCS. Control signals from the GCS are sent to the generators, exciters, and OLTC controllers via I/O modules. The A25A sends slip, voltage difference, and angle measurements to the GCS.

The refinery in this example required that the generators always be load-balanced to minimize the possibility of tripping during transient conditions, which can occur after separating into an island. The GCS does this by keeping the output from generators on a grid section (island) equally balanced throughout the entire synchronizing process. Part of the reason the load is balanced is to prevent operating any of the six turbines at their upper or lower limits, which lessens the likelihood of tripping a unit offline. For example, should a disturbance such as a large motor load trip occur, a generating unit operating close to zero output could potentially trip on reverse power as the governor correctly tries to close the control valve and prevent frequency overshoot. It is for these reasons that the GCS has an optimal load-sharing algorithm, as shown in Fig. 7.

Load balancing of multiple turbines becomes further complicated because the units involved are from different manufacturers and have different response rates and output ratings (the largest unit is 80 MW, and the smallest is 30 MW). The generators on the 11.5 kV buses also have the limitation of operating in a limited range of output due to the steam extraction requirements of the plant. Equal percentage (optimal) load-sharing techniques are used to overcome these challenges.

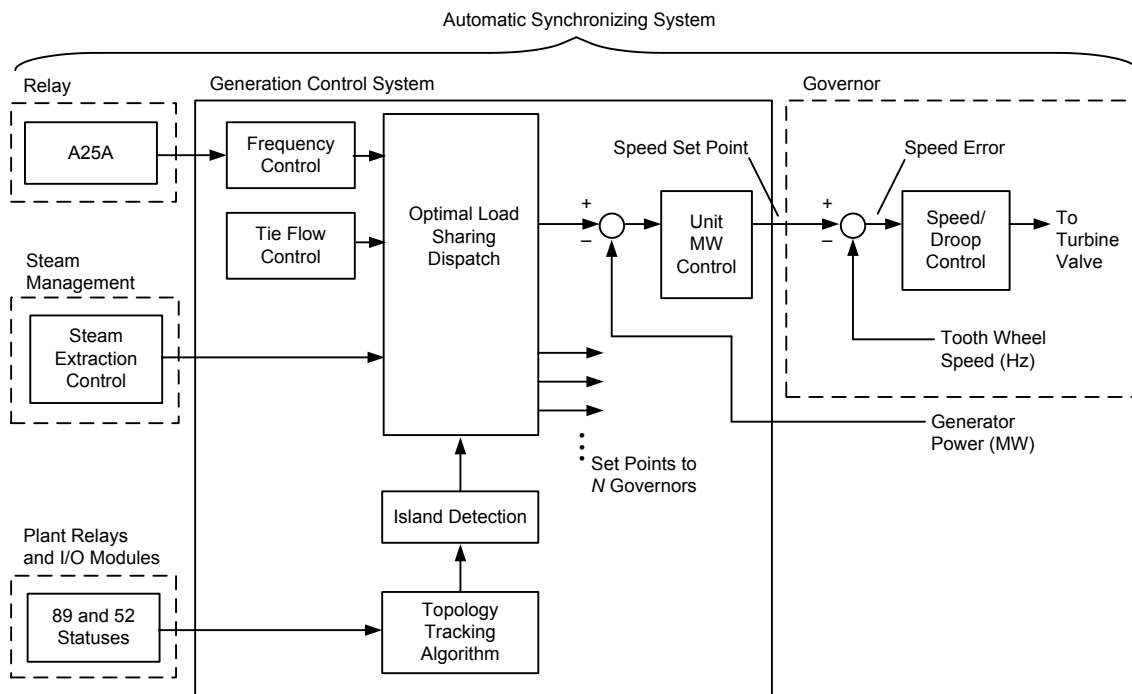


Fig. 7. Partial GCS Control Loop Architecture

To further complicate matters, it is common for generators to have unstable operational areas or undesirable areas of operation. The solution to this problem is to create artificial upper- and lower-limit boundaries that are user-settable limits, as shown in Fig. 8. Equal percentage (optimal) load-sharing techniques load all the turbines to an equal dispatched location within the lesser of the upper and lower bounds, the capability of the turbine, and the capability of the generator. The turbine capability is entered by the user, and the generator capability is derated according to cooling water temperature measurements.

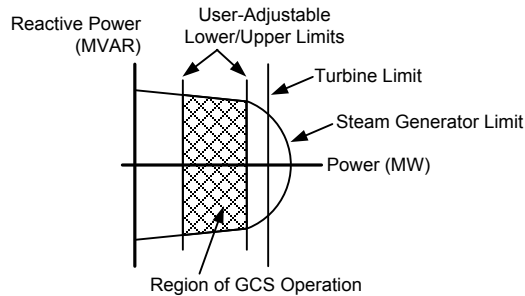


Fig. 8. Region of GCS Operation

The GCS also provides optimal exciter load (VAR) sharing and simultaneous bus regulation of all the buses in Fig. 1. Similar to optimal load (MW) sharing, the optimal exciter load (VAR) sharing equally shares the VAR contribution percentage from each generator. Unlike exciter load (MW) sharing, however, the exciter VAR contribution is limited by terminal and bus voltage magnitudes. To accommodate this, an adaptive volt/VAR-sharing algorithm regulates the OLTC to keep exciters away from their upper and lower bounds simultaneously, ensuring that the generator stator terminals remain inside equipment ratings.

C. Human-Machine Interface

The automatic synchronizing system installed at the refinery also has an HMI for remote automatic synchronizing. The front panel of the A25A was replicated in the HMI screen. Operator training was minimized by making the HMI and A25A front panel identical in look and feel. The LED display and pushbuttons shown in Fig. 3 and Fig. 4 are replicated in the HMI along with voltage, frequency, and analog variables, as shown in Fig. 9. The incoming and running frequencies reflect the frequencies of the incoming bus and the running bus. The automatic synchronizing system controls the frequency and voltage of the incoming bus to match the running bus by controlling the governors, exciters, and OLTCs on the incoming bus.

The HMI also provides alarms regarding communications failures, incongruence of the breaker status, close failures, VT failures, and overfrequency and underfrequency trips.

Capability curves for each generator, such as the one shown in Fig. 10, are included in the HMI. The capability curves show the desired set point and current operating point for the GCS MW (load) and MVAR (excitation) controls. The turbine capability is shown as the vertical line. The synchronous generator capability curves are dynamically updated with live generator cooling water temperatures.

INC FREQ	(Hz)	<input type="text" value="0"/>
SLIP FREQ	(Hz)	<input type="text" value="0"/>
RUN FREQ	(Hz)	<input type="text" value="0"/>
ANGLE DIFF	(Deg.)	<input type="text" value="0"/>
VOLTAGE DIFF	(kV)	<input type="text" value="0"/>

Fig. 9. Analog Variable Display for HMI

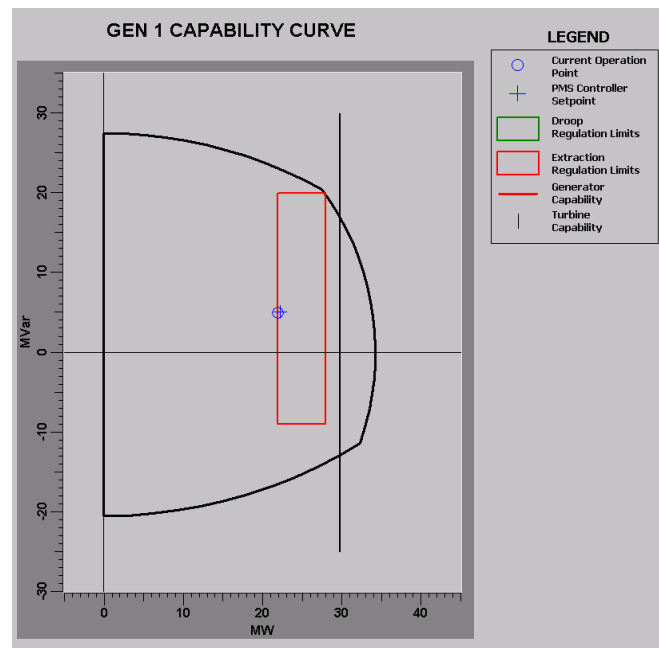


Fig. 10. Generator Capability Curve

IV. SYSTEM VALIDATION

Prior to installation of the advanced automatic synchronizing system at the refinery, complete testing was performed in a laboratory. An RTDS model was created to validate the functionality of the synchronizing system. This model included six custom governor, exciter, and turbine models, detailed load modeling, and a detailed electrical system model, which included all generators, turbines, exciters, breakers, loads, transformers, cables, and buses.

The RTDS model was validated by comparing model performance with known site conditions. This included the comparison of short-circuit fault currents, governor and turbine response characteristics, exciter response characteristics, and load reactive and active power consumption as a characterization of voltage and frequency.

Several studies were done using the model, providing insight into plant operation, vulnerabilities, and the system response for many contingency events. Studies were also completed to determine optimal set points for the power management system load-shedding system and GCS controllers.

The real-time model also permitted the A25A devices and GCS to be tested as a live simulation in the user-observed factory acceptance test. As shown in Fig. 11, this was accomplished by connecting the GCS and A25A to the simulation hardware.

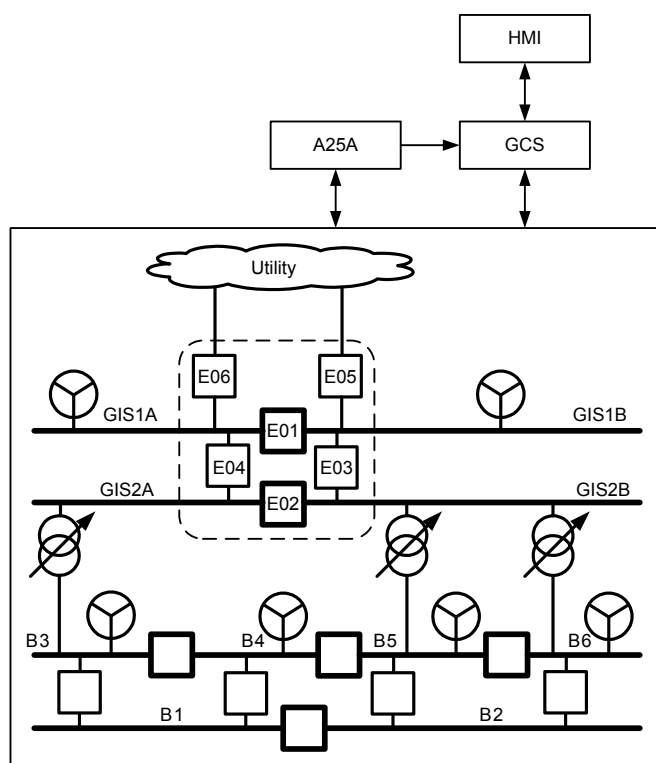


Fig. 11. Closed-Loop Real-Time Simulation

A real-time model allowed the authors to model the dynamics of the refinery power system with a simulation time step sufficiently fast to test all closed-loop controls of the automatic synchronizing system. Thousands of test cases were run, improving the likelihood that all systems will react as expected under the most adverse field scenarios. This

testing method also minimized the commissioning time and expense in the large control and protection system, something especially valuable in an operating facility.

Several communications protocols were used in the testing and implementation of the automatic synchronizing system for the refinery. The communications protocol used between the A25A and I/O module was IEC 61850 GOOSE. Transmission Control Protocol/Internet Protocol (TCP/IP) was used for communication from the controllers to the HMI. The breaker statuses and VT connections were brought to the A25A and I/O modules using the hard-wired I/O from the real-time simulation hardware. The low-level injection voltages from the real-time simulation hardware to the A25A provided VT connections.

Several test scenarios were created for all the breakers, including dead-bus close, parallel permissive close, and automatic synchronizing close. These scenarios allowed an opportunity for the careful observation of the dynamic response of the power system after synchronization, which is especially valuable for a dead-bus close scenario. These tests proved that the functionality of the A25A and GCS fit the specifications of the refinery. Two of the test cases are described in the following subsections.

A. Case A: Island-to-Island Synchronization

In the case of island-to-island synchronization, Breakers E01, E02, E05, and E06 were opened so that the system was islanded from the utility and the refinery was split into two separate islands. Breaker E01 was selected to synchronize. Across E01, on GIS1A and GIS1B, bus voltage difference, frequency difference, and angle difference were present.

Breaker selection was performed using the HMI. Once the synchronizing scenario was selected, the **OK TO INIT AUTO SYNC/CLOSE** LED indicated the system was ready for synchronization. Once initiated, the A25A began sending the breaker selection, voltage difference, and slip to the GCS. The GCS then sent control pulses to the governor, exciter, and OLTC to match the voltage and frequency across the breaker. The GCS controlled the incoming bus. However, in this case, the selection of the incoming bus was somewhat arbitrary because neither side of the bus was connected to the utility.

While the GCS reduced slip and voltage difference, the A25A monitored the process and provided the operator with continuous feedback using the front-panel display and the HMI. Once the A25A detected that the synchronizing acceptance criteria were satisfied, the A25A sent a breaker close command to close the E01 breaker at the slip-compensated advanced angle. In this scenario, an event report and SER reports were generated in the A25A.

Fig. 12 shows the slip across Breaker E01 during the automatic synchronizing process. At 30 seconds, the automatic synchronizing process was initiated; it was completed at 190 seconds. The starting slip was -0.21 Hz, and then at 90 seconds, it was less than 0.02 Hz, which was within the acceptance band. The automatic synchronizing system waited for the compensated breaker angle to come to zero. At 100 seconds, the slip went from negative to zero to positive. This process continued until the angle criteria were met. The instant the angle difference was nullified, which was at 190 seconds, the system transformed from two separate islands to one large island.

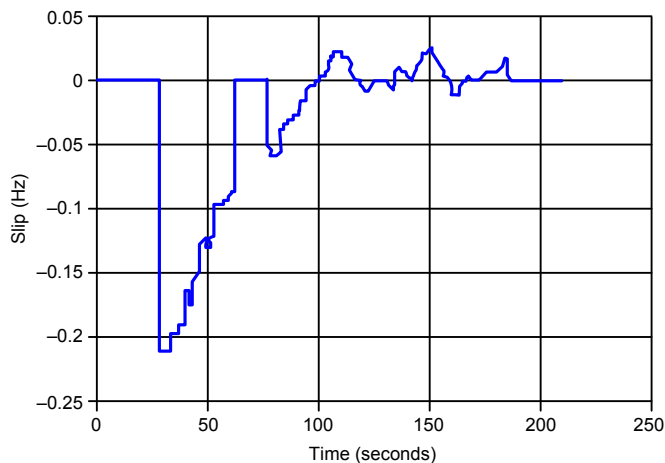


Fig. 12. Slip During Island-to-Island Synchronization

B. Case B: Island-to-Utility Synchronization

In the case of island-to-utility-connected power system synchronization, E03 and E04 were closed and Breakers E01, E02, and E05 were opened so that the island on GISA (GIS1A and GIS2A) with multiple generators was islanded from the utility and GISB (GIS1B and GIS2B) with multiple generators was connected to the utility via E06. The refinery was split between two islands. GISA and GISB where utility was connected to GISB bus while GISA was islanded. Breaker E01 was selected to synchronize. Across E01 on GIS1A and GIS1B, bus voltage difference, slip, and angle difference were present.

Breaker selection was performed using the HMI. The front-panel rotating display shown in Fig. 5 provided indication as to the selection. Once the breaker was selected, the **OK TO INIT AUTO SYNC/CLOSE** LED indicated the system was ready for synchronization. Initiation of this process resulted in the A25A communicating with the GCS

regarding the breaker selection, voltage difference, and slip. The GCS then sent controls to the governor, exciter, and OLTCs to match the voltage and frequency on both sides of the breaker. The GCS controlled the incoming bus. However, in this case, the selection of the incoming bus was GISA because the GISB bus was connected to the utility.

During the process of control signals being sent by the GCS, the A25A monitored the synchronizing acceptance parameters and provided operator feedback using the front-panel display and front-panel LEDs.

When all of the synchronizing parameters shown in Table II were met, the A25A sent a breaker close command to close the breaker at the slip-compensated advanced angle. The breaker status was monitored for a successful close.

V. CONCLUSION

Synchronization between multiple generators and utility tie lines or between the multiple generators in an isolated system creates a need for a smart and flexible automatic synchronizing system that is composed of both an A25A relay and a GCS controller.

The fully redundant automatic synchronizing system installed at the refinery improved the reliability and accuracy of breaker synchronism across all six GIS breakers without the need for physical VT switching

Testing of the automatic synchronizing system provided critical insight into the system operation. The real-time digital simulation of the model power system allowed for a better understanding of system functionality and provided a valid test in terms of meeting the specification of the design, which reduced the amount of labor and expense during commissioning of the system.

VI. ACKNOWLEDGMENTS

The authors gratefully acknowledge the contributions of Dr. Abdel R. Khatib and Jordan Bell from Schweitzer Engineering Laboratories, Inc. for providing support during testing.

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VIII. BIOGRAPHIES

Scott M. Manson received his M.S. in electrical engineering from the University of Wisconsin–Madison and his B.S. in electrical engineering from Washington State University. Scott worked at 3M as a control system engineer for six years prior to joining Schweitzer Engineering Laboratories, Inc. in 2002. Scott has experience in designing and implementing control systems for electric utility customers, refineries, gas separation plants, mines, high-speed web lines, multiaxis motion control systems, and precision machine tools. Scott is a senior member of IEEE and a registered professional engineer in Washington, Alaska, North Dakota, Idaho, and Louisiana.

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Michael J. Thompson received his BS, magna cum laude from Bradley University in 1981 and an MBA from Eastern Illinois University in 1991. He has broad experience in the field of power system operations and protection. Upon graduating, he served nearly 15 years at Central Illinois Public Service (now Ameren), where he worked in distribution and substation field engineering before taking over responsibility for system protection engineering. Prior to joining Schweitzer Engineering Laboratories, Inc. (SEL) in 2001, he was involved in the development of several numerical protective relays while working at Basler Electric. He is presently a principal engineer in the engineering services division at SEL, a senior member of IEEE, chairman of the substation protection subcommittee of the IEEE PES Power System Relaying Committee, and a registered professional engineer. Michael was a contributor to the reference book *Modern Solutions for the Protection, Control, and Monitoring of Electric Power Systems*, has published numerous technical papers, and has a number of patents associated with power system protection and control.

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The Application of a Redundant Load-Shedding System for Islanded Power Plants

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Abstract—In order to maintain power system stability and process survivability for major system faults under a variety of system configuration topologies, the implementation of a load-shedding scheme is essential. Islanded power systems present very distinct challenges, whereby the lack of a utility interconnection hinders the system's ability to recover from a loss of generation. In order to maintain power system stability in an islanded configuration, fast tripping and shedding of strategically selected loads in response to a specific event in the plant are the key factors governing plant survivability.

The load-shedding application presented in this paper involves a large petrochemical facility. The load-shedding system covers two process plants, one newly constructed and one existing, connected by a 12 km, 115 kV transmission line. The system contains 12 sheddable loads and can be broken into various topologies. All selectable, sheddable loads are large (approximately 15 MW) synchronous motors.

As specified by the end user, the load-shedding system has three requirements.

- Minimize process disruption
- Work under all system topologies (bus configurations)
- Operate in 60 ms or less

The load-shedding system also contains a backup, frequency-based algorithm. The combination of the two systems provides a complete solution for contingency- and noncontingency-based events.

The primary scheme uses a comprehensive power management system (PMS) that calculates predicted power deficits resulting from predetermined events (contingency based), using system inertia and governor response models for system generators. The secondary scheme is based on the pickup of underfrequency relays (conventional, frequency based). The objective of the secondary scheme is to operate based on levels of underfrequency if the system frequency drops below operator-defined thresholds.

I. INTRODUCTION

Presently, it is very challenging to control system-wide disturbances in power systems, either in utilities or industrial facilities. The objective of a power management system (PMS) is to avoid system degradation via active and reactive system controls and, accordingly, minimize the impact of system disturbances. In previous decades, load-shedding logic and subsequent control responses were ineffective due to technological limitations.

A load-shedding system requires accurate logic and control actions to achieve fast operation, particularly in islanded operation mode. Slow responses may lead to cascading outages and ultimately to total blackouts. Conventional,

frequency-based schemes act more slowly because they depend on the frequency decaying to some threshold before they operate. In some operational scenarios, the system may not be stable or able to recover the nominal frequency due to the slow response. Accordingly, blackouts may occur.

In general, the speed of any implemented load-shedding system in islanded operation mode is the key design parameter because of two main factors: system inertia and generator operating points. Because the inertia of an islanded system is relatively low, compared to a utility, a system disturbance will have a greater impact on the system frequency. Equation (1) represents the relationship of inertia to frequency in a synchronous machine.

$$J \frac{d\omega_m}{dt} = T_m - T_e \quad (1)$$

where:

J = combined moment of inertia

ω_m = angular velocity of the rotor

T_m = mechanical torque

T_e = electrical torque

Equation (1) shows that the rate of change of the frequency, or angular acceleration, is inversely proportional to the inertia, so the lower the inertia, the greater the rate of change of frequency, given a torque imbalance due to a system disturbance.

In the case of load shedding, the torque imbalance would occur because of the power imbalance caused by a loss of generation, as shown in (2).

$$\left(\frac{P_m - P_e}{\omega} \right) = T_m - T_e \quad (2)$$

The total electrical torque would be roughly equal to the mechanical torque in a steady-state system. A loss of generation would cause an increase in load on the remaining generator(s), which would increase the mechanical torque on the system. At the instant the disturbance happened, the mechanical torque would remain constant until the governor controllers started to react. This time depends on the tuning parameters of the governor control system. Accordingly, before the governor controllers start to react, a net decelerating torque (T_a), as shown in (3), will be present on the system, and the frequency will begin to decay.

$$\frac{d\omega_m}{dt} = \frac{T_a}{J} \quad (3)$$

where:

$$T_a = T_m - T_e = \text{net accelerating torque.}$$

From (3), the inertia of the power system (J) dictates the rate at which the frequency will decay—the larger the inertia, the slower the decay.

Despite the fact that inertia does play a role in power system stability, it is not simple or economical to manipulate. The most economical way of improving system stability is to equalize the generation to load (via load shedding), thereby minimizing the disturbance impact to the power system.

Using high-speed governors and turbines with quick reaction time is another method to mitigate power deficiencies; however, this is not a cost-effective solution. Further proactive techniques consist of a variety of methods to maintain capacity reserve margins, ensuring that the protective systems have enough time to react to disturbances, thereby preventing system instability.

II. ELECTRICAL NETWORK

The existing electrical network (Plant A) is isolated from any utility and consists of four combustion gas turbines and large-, medium-, and small-size compressors and pumps. The existing load-shedding scheme is a conventional, frequency-based design, where the sheddable loads are only the large-size compressors.

The new electrical network (Plant B) consists of three combustion gas turbines and large-, medium-, and small-size compressors and pumps. The two networks are connected by a 12 km, 115 kV transmission line, constituting an isolated electrical grid. Fig. 1 shows the subject electrical network.

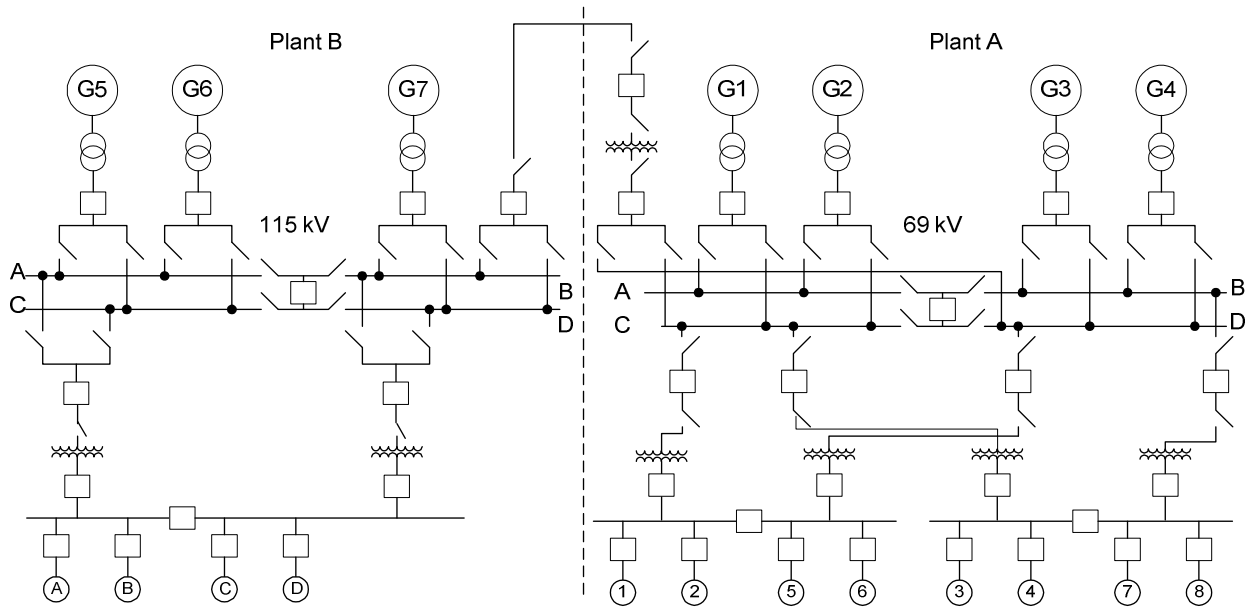


Fig. 1. Electrical Network Under Review

In order to maintain the new system's stability and reliability, a PMS was proposed. One of the system's roles is to implement an integrated load-shedding scheme. The objective of this scheme is to maintain the power supply to the plant's critical loads. In order to achieve this objective, the following design criteria were adopted:

- Fast load shedding to avoid frequency excursions at levels that cannot be recovered.
- Selectable load shedding to shed loads in the same disturbed facility. For instance, if a disturbance occurs in Plant A, load will be shed in the same plant to facilitate operational coordination.

Based on the design criteria, a contingency-based load-shedding system was adopted as a primary defense. The contingencies are primarily established based on the loss of generation unit, transmission tie line, or the bus coupler between the two buses.

The existing power plant (Plant A) has an underfrequency-based load-shedding system. This existing system was modified to coordinate with the new contingency-based system in terms of load-shedding steps and underfrequency set points.

III. CONTINGENCY-BASED PRIMARY LOAD-SHEDDING SCHEME

The primary load-shedding scheme implemented in the PMS dynamically calculates the load-shedding amounts for each predetermined event (contingency) and selects the individual loads to shed based on settable priorities, measured power consumption, and the present configuration of the power system. Each contingency has its own set of priorities.

A. Conceptual Architecture

The primary load-shedding scheme was designed based on the design requirements, predetermined events, and a contingency load priority list. Fig. 2 illustrates the conceptual architecture of the primary load-shedding system.

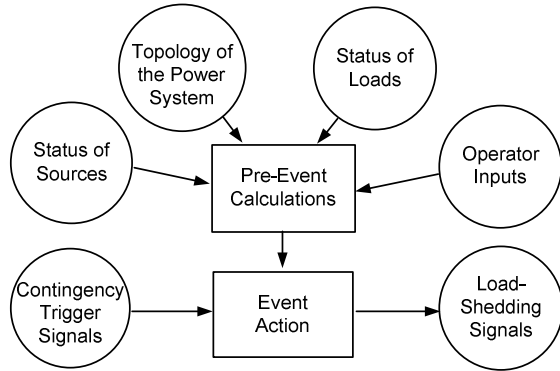


Fig. 2. Conceptual Architecture

B. Load-Shedding Contingencies

The load-shedding system was developed to respond on loss of generation, tie line, or bus coupler breakers. These events are termed contingencies and are initiated by the change of state of the breakers, trip signals, or lockout relay operation. When a contingency breaker opens under load, power may be lost to some portion of the system. In this project, the system was identified in terms of the number of contingencies that needed to be addressed. Each contingency then had its own priority list of sheddable loads. These sheddable loads were identified previously and chosen so that they would have minimal impact on the system processes, while still being large enough to adequately satisfy the load-reduction needs of the system to ensure stability. Referring to Fig. 1, a total of ten contingencies were identified:

- Generator breaker (G1 through G7, a total of 7)
- Bus-coupler breakers (2)
- Tie-line breaker (1)

Fig. 3 shows the human-machine interface (HMI) that the operators use to set load priorities for the system. In Fig. 3, each row in the DESCRIPTION column lists the loads that are available to shed. Under LOAD SHEDDING PRIORITY, each column corresponds to a contingency that the load-shedding system is monitoring. The highlighted boxes contain a number that indicates the shedding priority of the motor load for that particular contingency. This number is settable by the operator.

DESCRIPTION		LOAD STATUS				LOAD SHEDDING PRIORITY											
BREAKER NUMBER	DESCRIPTION	11KV SHED SELECTED	BREAKER STATUS	11KV BUS LOAD	11KV BUS POWER	11KV BUS TIE/POWER	LOAD SHEDDING PRIORITY	LOAD SHEDDING PRIORITY	LOAD SHEDDING PRIORITY	LOAD SHEDDING PRIORITY	LOAD SHEDDING PRIORITY	LOAD SHEDDING PRIORITY	LOAD SHEDDING PRIORITY	LOAD SHEDDING PRIORITY	LOAD SHEDDING PRIORITY	LOAD SHEDDING PRIORITY	LOAD SHEDDING PRIORITY
SDR-0335	SDR-0335 AP-0335 COMPRESSOR	NORMAL	ON	0	0.00	0.00	1	1	1	1	1	1	1	1	1	1	1
SDR-0336	SDR-0336 AP-0336 COMPRESSOR	NORMAL	ON	0	0.00	0.00	1	1	1	1	1	1	1	1	1	1	1
SDR-0337	SDR-0337 AP-0337 COMPRESSOR	NORMAL	ON	0	0.00	0.00	1	1	1	1	1	1	1	1	1	1	1
SDR-0338	SDR-0338 AP-0338 COMPRESSOR	NORMAL	ON	0	0.00	0.00	1	1	1	1	1	1	1	1	1	1	1
SDR-0339	SDR-0339 AP-0339 COMPRESSOR	NORMAL	ON	0	0.00	0.00	1	1	1	1	1	1	1	1	1	1	1
SDR-0340	SDR-0340 AP-0340 COMPRESSOR	NORMAL	ON	0	0.00	0.00	1	1	1	1	1	1	1	1	1	1	1
SDR-0341	SDR-0341 AP-0341 COMPRESSOR	NORMAL	ON	0	0.00	0.00	1	1	1	1	1	1	1	1	1	1	1
SDR-0342	SDR-0342 AP-0342 COMPRESSOR	NORMAL	ON	0	0.00	0.00	1	1	1	1	1	1	1	1	1	1	1
SDR-0343	SDR-0343 AP-0343 COMPRESSOR	NORMAL	ON	0	0.00	0.00	1	1	1	1	1	1	1	1	1	1	1
SDR-0344	SDR-0344 AP-0344 COMPRESSOR	NORMAL	ON	0	0.00	0.00	1	1	1	1	1	1	1	1	1	1	1
SDR-0345	SDR-0345 AP-0345 COMPRESSOR	NORMAL	ON	0	0.00	0.00	1	1	1	1	1	1	1	1	1	1	1
SDR-0346	SDR-0346 AP-0346 COMPRESSOR	NORMAL	ON	0	0.00	0.00	1	1	1	1	1	1	1	1	1	1	1
SDR-0347	SDR-0347 AP-0347 COMPRESSOR	NORMAL	ON	0	0.00	0.00	1	1	1	1	1	1	1	1	1	1	1
SDR-0348	SDR-0348 AP-0348 COMPRESSOR	NORMAL	ON	0	0.00	0.00	1	1	1	1	1	1	1	1	1	1	1
SDR-0349	SDR-0349 AP-0349 COMPRESSOR	NORMAL	ON	0	0.00	0.00	1	1	1	1	1	1	1	1	1	1	1
SDR-0350	SDR-0350 AP-0350 COMPRESSOR	NORMAL	ON	0	0.00	0.00	1	1	1	1	1	1	1	1	1	1	1

Fig. 3. HMI Load Priority Screen

C. Determination of Load-Shedding Amount

One of the most important factors in any load-shedding system is determining how much load to shed. Conventional, frequency-based schemes are inaccurate in the amount they shed because they do not consider the amount of lost generation, only the level of the system frequency. Accordingly, these schemes may not operate quickly enough, and may result in a system blackout. Alternately, the newly implemented system accurately calculates the amount of load to shed, thereby minimizing the impact on the process plants and shedding specific loads that will allow the system to recover.

The response of the remaining generation units must also be taken into account when determining the amount of load required to shed. Each generator's step-load capability must be factored in to the load-shedding algorithm. This step-load capability is determined by modeling the generator governor and simulating its step-load response to various sized load increases.

In addition, the current operating point of the generator needs to be monitored to ensure that the load-shedding system considers the active and reactive power output capabilities of the remaining generators in its algorithm. In particular, each generator has an output limit governed by the capability of the machine and the prime mover.

IV. UNDERFREQUENCY-BASED SECONDARY LOAD-SHEDDING SCHEME

As a backup system, the underfrequency load-shedding scheme is applied by using the pickup of underfrequency relays. If the system frequency falls below a certain threshold, load shedding will be initiated via pickup of the underfrequency relays.

A. Existing Load-Shedding Scheme

The existing load-shedding system in Plant A is conventional, where frequency relays at the incoming switchgear are used to execute the required load shedding. The load-shedding scheme in Plant A can be summarized as shown in Table I.

TABLE I
LOAD-SHEDDING SEQUENCE IN PLANT A

Load-Shedding Step	Load	Underfrequency Trip Level	Time Delay
1	Motor 6 Motor 5	59 Hz	No time delay
2	Motor 4 Motor 3 Motor 2 Motor 1	58.7 Hz	No time delay

For the selection of the underfrequency load-shedding scheme, a trial-and-error procedure was applied to develop the best combination of number and size of loads to shed. One combination of the load-shedding amounts and underfrequency settings was studied through dynamic simulation.

Considering both upper and lower thresholds, this scheme evenly divides each motor load into 4 groups and evenly divides the thresholds between minimum and maximum levels.

The selection of underfrequency delay (or pickup) times is primarily based on the security, accuracy, and noise levels in the frequency measurement. Secondly, the minimum underfrequency delay time is selected based on the short duration frequency disturbances caused by short-circuit and motor-starting conditions. The upper constraint on the selection of pickup time is predicated by system inertia and the frequency band between pickup levels. Based upon these considerations, if both power plants operate separately, the pickup time of 0.1 seconds for all load-shedding steps is proposed through the simulation case studies.

In addition, the proposed underfrequency load-shedding scheme of Plant B could be integrated with the existing load-shedding system in Plant A. In this case, the scheme had been designed to assign two different time delays in Plant B based on whether the tie-line breaker connecting the two plants is closed or opened. If the tie-line breaker is closed, paralleling Plant B with Plant A, then the pickup time is set to 0.3 seconds to coordinate with the backup underfrequency load-shedding scheme in Plant A.

Table II illustrates the selected load-shedding scheme to protect overload condition and accordingly maintain system stability whether the two plants are separated or connected.

TABLE II
UPDATED LOAD-SHEDDING SEQUENCE FOR BOTH PLANTS

Freq. Pickup (Hz)	Plant A		Plant B		
	Sheddable Load (Syn. Motors)	Time Delay (s)	Sheddable Load (Syn. Motors)	Time Delay (s)	
				Tie CB Open	Tie CB Close
59.0	Motor 4	0.1	Motor D	0.1	0.3
58.7	Motor 3	0.1	Motor C	0.1	0.3
58.3	Motor 2	0.1	Motor B	0.1	0.3
58.0	Motor 1	0.1	Motor A	0.1	0.3

B. Updated Load-Shedding Scheme

The incremental load-shedding amounts and underfrequency settings were determined through case studies to ensure the best probability that the system would remain stable. The amount of load shedding was decided based on the system overload conditions with respect to system operation conditions.

The underfrequency load-shedding scheme must be coordinated within the operating limitations of the generator and motor loads with respect to low-frequency operation. The continuous operating condition of the gas turbine is between 59 and 61 Hz, and the lower threshold for underfrequency step selection must be greater than the generator protection setting (57.5 Hz). It must also be greater than the damage point of all synchronous and induction motors. The lowest and last step of underfrequency load shedding should be set at least 0.5 Hz above the damage point of all synchronous and induction motors. Accordingly, this criterion selects the lowest step at an underfrequency level of 58 Hz.

The upper threshold for underfrequency step selection must be properly coordinated with the incremental reserve margins of the primary (contingency-based) load-shedding system. Accordingly, 59 Hz is selected as the upper threshold.

V. COMMUNICATION FOR CONTINGENCY-BASED LOAD SHEDDING

As technology expands and the speed of communication becomes faster and more reliable, industries that are not in a position to be on the experimental edge continue to adopt time-proven methods. The proven technologies tend to stay static for years before their once experimental phase matures into the robust and reliable phase. This point tends to become a major paradigm shift for companies that have relied on one set of technologies and realized a new set of technologies can accomplish the same job more efficiently. The recent introduction of the IEC 61850 standard has become the latest turning point at which the tried and true serial communications are often successfully supplanted by Ethernet-based technologies. The utility community is seeing a growing acceptance of Ethernet communications and IEC 61850 throughout the substation for data acquisition, automation, and some protection functions.

A. High-Speed Data

High-speed data need to be communicated every 2 ms. High-speed data involve all information concerned with the trip signals or breaker operations that isolate generation from the system, as well as the trip signals initiated to trip load offline. Consider the operation of a generation breaker. When this breaker operates, generation is immediately lost, and the system capacity is reduced by roughly the amount the generator was supplying to the system. Once this generation is lost, it is of the utmost importance that enough load be removed from the system to maintain system frequency. Given this requirement, it becomes obvious that both the indication that generation has been lost and the corresponding trip signals to the loads selected to shed must be transmitted quickly and securely. If the loss of generation is not detected quickly enough or the trip signals are slow to arrive at the chosen loads, then the system may not be able to recover, or, more likely, an underfrequency backup scheme will operate.

B. Low-Speed Data

Low-speed data are communicated about every 1 second. Low-speed data encompass all information that, while important for calculation of various set points within the load-shedding system, does not change frequently enough nor suddenly enough to warrant the need for high-speed transmission. These values include MW flow, disconnect switch status, load consumption, etc. These values are used to arm the load-shedding system, but the high-speed data actually trigger the system to operate. Because these low-speed data play no role in the triggering of the load shedding, they can be updated less periodically.

C. Engineering Access Traffic

Engineering access traffic is information that is not associated with the actual real-time operation of the load-shedding system but permits the retrieval of historical monitoring and configuration information from the system. These data are not speed-critical but can require a higher bandwidth due to the amount of information being transferred. Frequently used engineering access traffic includes event report retrieval, Telnet access to individual relays within the system, remote desktop services, and ad hoc diagnostics.

D. Combining the Three Types

Traditional serial communications require three separate communications channels to transport the three separate types of necessary data. Not to mention, when dealing with systems that are as critical as a load-shedding system, redundancy is nearly always required. This means a minimum of six communications channels with the proper redundancy must be available for the load-shedding system to be functional. For communications channels within a substation, adding more channels is as easy as running a cable to each device. When building a substation from the ground up, proper planning and system specifications make this issue a triviality compared to the overall system. However, as was the case with this project, communication between substations becomes more of a challenge.

With two substations separated by 12 km, more communications channels mean more cable runs or fiber over those 12 km of transmission line. This is often not feasible, and, as was the case with this particular project, only two pairs of fiber were allotted for all communications between the two substations. Given this restriction and the original intent of using high-speed serial communications for the high-speed data, the obvious choice was to install a multiplexer to combine the different data and send one data stream across a pair of fiber. Using this method, installing two multiplexers at each end carrying identical data streams across the two pairs of fiber allowed for redundancy of the system. See Fig. 4 for the serial communications architecture of a nonredundant system. A redundant system would have a total of two multiplexers on each end, and each device would be connected to both.

VI. SERIAL COMMUNICATIONS

While this architecture was, at least on paper, a viable option, an uncomfortable uncertainty existed with regard to the use of multiplexers. Two concerns immediately came to the surface—determinism and reliability. Reliability always plays an important role when it comes to designing systems, especially systems for refineries, where massive amounts of money are dependant, to a large extent, on the ability to keep the electricity flowing. Multiplexers are largely used for communications purposes that can rarely be classified as critical and are designed and manufactured accordingly. To that extent, serial multiplexers are efficacious in what they are designed for, but what they are designed for, in most instances, does not include high reliability within extreme environments. Not to mention, with the current trend of Ethernet and other high-speed data communications, serial communications products are becoming less and less available.

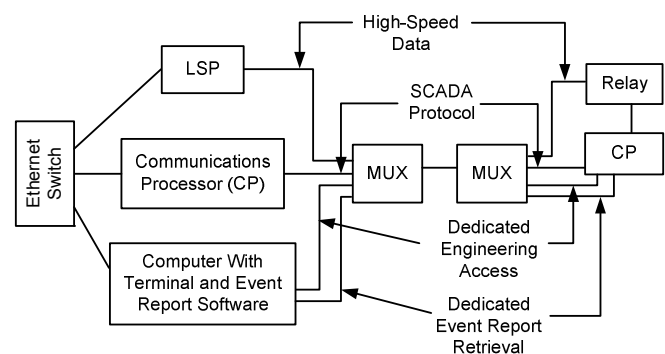


Fig. 4. Nonredundant System Architecture

Determinism was also a very important consideration. It is extremely important that when high-speed data are sent from one end or the other, the data arrive at the other end 100 percent of the time, without worry of retransmissions, being held in queue, or simply getting lost or corrupted. If high-speed information is sent, then it must, under all circumstances, make it to the other end reliably and in a timely fashion. This takes extensive testing and collaboration with

the multiplexer manufacturer in order to guarantee the performance required for the system.

Considering all of these requirements, multiplexers have still found their way into the utility protection arena and have performed as well as could be expected. However, Ethernet communications have begun to reach a maturity where utilities are more accepting and able to rely on their performance, and, therefore, are making them a larger piece of their system communications schemes.

VII. ETHERNET COMMUNICATIONS

While serial communications remain widely used throughout the communications world, Ethernet communications are becoming more prevalent for substation communications. Serial communications are sure to remain because dedicated point-to-point, high-speed, secure, low-overhead protocols are still the preferred standard for protection communications. However, Ethernet is taking hold in this realm as well.

The IEC 61850 standard includes a high-speed, multicast protocol: GOOSE messaging. GOOSE messaging is an Intranet-only routable, OSI Layer 2, broadcast/subscription, Ethernet-based protocol that evolved from the UCA2 GOOSE messaging protocol. GOOSE is not an IP (Internet Protocol) message. It is restricted to routing among network addresses on a LAN or Intranet. GOOSE cannot be routed between networks across a WAN or Internet. It can be deployed similar to traditional point-to-point protocols or among switched Ethernet LANs and is very useful in some protection-type applications. In particular, it is ideally suited for this load-shedding application, because it is sufficiently fast and, being an Ethernet protocol, it can run on the same communications line with several other protocols.

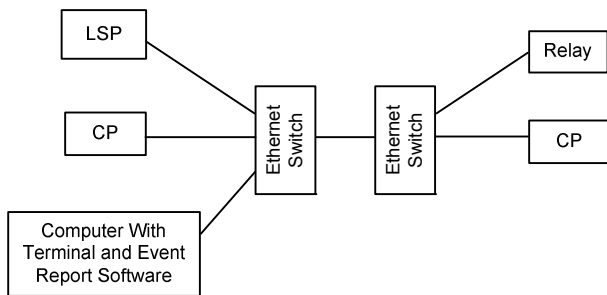


Fig. 5. Ethernet Network

VIII. THE DECISION BETWEEN SERIAL AND ETHERNET

The proposed load-shedding system called for redundant communications. For this redundant communications ring, we were provided with two pairs of optical fiber. With this in mind, we were restricted in that all communications had to use one communications path. Considering this, we were faced with two options, multiplexing the serial data or changing over to Ethernet.

It is important to note that other options do exist, namely wireless, for the transmission of data over 12 km. The two substations are within line-of-sight with no obstructions, so this would be an ideal application for spread-spectrum radio or similar technologies. However, in this particular case, the area may encounter sand storms, which would be more than enough to disrupt the signal and stop communications. Considering this possibility, the system architecture was limited to wired communications solutions only.

Economically speaking, the multiplexed serial data would have required the purchase of four multiplexers, as opposed to Ethernet, where there were already switches installed at each substation. However, each switch would need to be supplied with cards for 9-micron fiber-optic cable connections. Regardless, the Ethernet cards were roughly one-fourth of the cost of the multiplexers. In terms of reliability, the addition of more hardware inherently decreases the reliability of the system.

While the addition of the 9-micron Ethernet cards to the switch was technically no different than adding multiplexers to the system, in terms of the hardware added, the Ethernet cards are rated for extreme environmental conditions, whereas the multiplexers are not. In the end, in terms of both reliability and cost, moving to Ethernet communications not only became a feasible alternative, it looked to be a better alternative than the original design, considering the limitation of the physical communications paths that was allotted.

IX. SYSTEM ARCHITECTURE

The system is segregated into two halves, local and remote. As mentioned earlier, the remote substation is located 12 km away from the local substation. The load-shedding system algorithm is centralized on a computer with a Linux® operating system, referred to hereafter as the LSP (load-shed processor), at the local substation. Data collected from the field intelligent electronic devices (IEDs) are concentrated in a communications processor and sent via unsolicited messaging to the LSP. These data consist of the low-speed data discussed earlier, breaker and disconnect switch statuses, and meter analog values. These data are gathered by the LSP and used to perform system calculations to decide if generation is lost on the system, how much, if any, load should be shed, and which loads are selected. Low-speed data (data sent by the communications processors) are essentially used to calculate the reaction in the event of lost generation. High-speed data communicate what event has occurred (the tripping of a generation breaker, tie line, etc.) and send the commands to trip the required load.

Because the LSP resides in the local substation, all relays communicating these high-speed “event” data can communicate serially. Premade fiber-optic patch cable can be used between the local relays and the LSP, making it possible to connect all the relays providing high-speed data. These serial connections were one of the preexisting design choices that did not need to change. However, the need for the high-speed Ethernet GOOSE protocol became evident when gathering and transmitting high-speed data from the remote substation.

Because these low- and high-speed data, along with Telnet-type engineering access traffic, can coexist on the same communications line, Ethernet is the prime choice for this application. See Fig. 6 for the Ethernet system architecture.

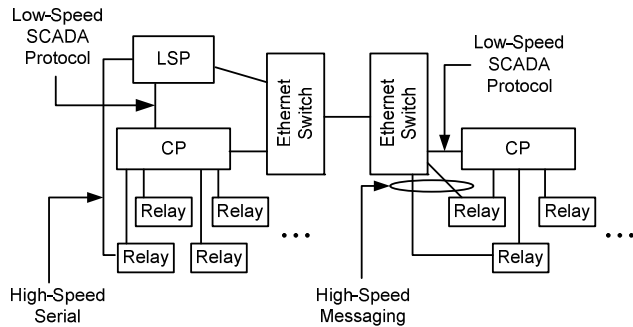


Fig. 6. Ethernet System Architecture

The sequence of events for a typical load-shedding event would initiate upon the opening of a generation breaker or the receipt of a trip signal from the tripping relay associated with a generation breaker. This breaker status, or trip status, would be sent via high-speed serial communications in the case of an event occurring in the local substation and via Ethernet GOOSE in the case of the remote substation, and then received at the LSP. The LSP receives and processes this signal and issues **TRIP** commands to the relay outputs of the loads that have been selected to shed. Fig. 7 is typical of the local substation where the high-speed serial communications are used.

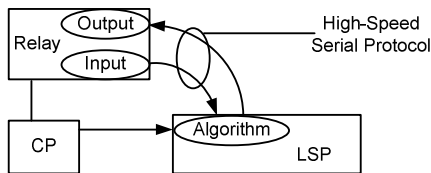


Fig. 7. Basic Function of the LSP

Fig. 8 illustrates the path the trip signals originating from the remote substation must follow. Because of the intermediary Ethernet link, the data path is not as direct as within the local substation. This Ethernet segment, while still fast enough for our application, does slow the overall response of the load-shedding system. This issue will be addressed later.

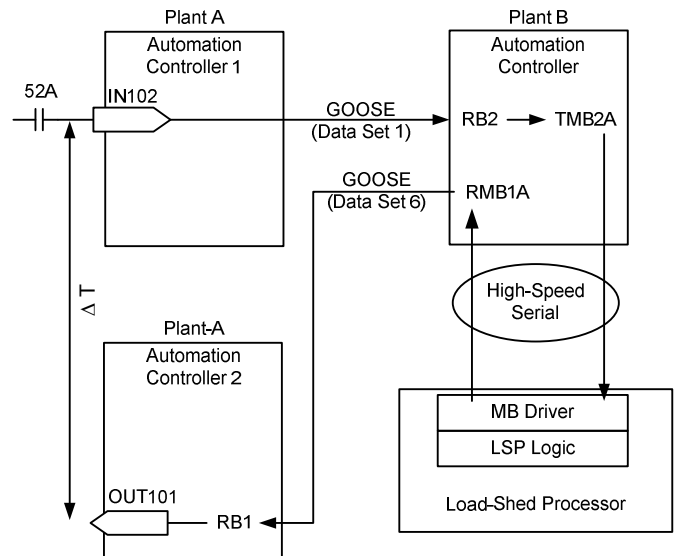


Fig. 8. General Architecture

A. Why Timing Is Critical

Load shedding is becoming a more popular protection-type functionality. Until recently, load shedding was not capable of being done quickly by today's standards, but faster computer processors and data communications have allowed industries to begin investigating subcycle load shedding.

The purpose of load shedding is to protect a system in the event of lost generation and help the system to maintain stability and system frequency. When generation is lost, if the remaining generation is not capable of outputting additional power to make up for the deficit, the system frequency will eventually decay beyond recovery and collapse. However, if a system is in place that can calculate exactly how much power will be lost and how much the remaining generation can supply in addition to what it is currently supplying, the LSP can then calculate how much load must be shed in order for system frequency to maintain stability. This is the essence of a load-shedding system: to calculate the effect a loss of generation would have on a system and then determine how much, if any, load should be shed to maintain stability.

In a modern, high-speed, load-shedding system, the load-shedding algorithm is being processed quickly enough that dynamic system decisions can be processed and operate in times under 16 ms. Not only can it be processed in under 16 ms, but the trigger that initiates the process, the process itself, and the receipt of the output of the process are transmitted in less than one power cycle. Traditional automated systems would require significantly longer times to process data and make a dynamic decision based on these data. Technology now allows us to not only process this information but communicate it to the necessary hardware, which could be separated by larger distances, to take corrective action. Such technological capability becomes a veritable panacea for power stability related issues.

In the case of load shedding in particular, the load-shedding system must be coordinated with backup under-frequency protection schemes so that the system frequency never falls below the underfrequency threshold. The time that

it takes for the system frequency to decay to this point is largely dependent on the system makeup. Systems with large system inertia and a large composition of synchronous machines have the benefit of their system frequency being held up by the sheer inertia behind those machines. Therefore, the frequency with large system inertia will not decay as quickly as a system with smaller generators, induction motor loads, and resistive loads.

Load-shedding systems act as large, wide-area, protective relays, thereby blurring the line between automation and protection systems. Not very long ago, automation and protection were completely separate functions. An automation group at an industrial plant or utility would work on applications involving remote control of the system and data acquisition, and the protection group would focus on high-speed protection of the system assets. Now, automation schemes are being coordinated with protection schemes, bringing both groups together. In the case of load shedding in particular, the protection engineers complete detailed studies of how robust the system is in response to a loss of generation. The automation engineers use that information to determine what to expect of each generator when writing the LSP algorithms.

B. Time Tests

The load-shedding system presented here has two components: a serial side and an Ethernet side. Below we will compare the performance of the two different communications types and discover how they compete with each other. As mentioned before, the Ethernet communications scheme does add time to the performance, which should be no surprise, because it is an additional path that the serial communications side does not encounter.

For an illustration of the test setup, refer to Fig. 8. Input IN102 detects a trip signal from a generator breaker. IN102 is part of a GOOSE messaging data set that triggers on change. The changing state of IN102 causes a change of state GOOSE message to be issued. The receiving device has mapped the GOOSE message to local bit RB02, which is subsequently mapped to the high-speed serial protocol transmit bit. This bit is transmitted to the LSP where it is then processed and, in turn, issues a **TRIP** command via the high-speed serial protocol. That **TRIP** command is received by the sending device and mapped to a GOOSE message to be transmitted over the Ethernet network. Once transmitted, the receiving device detects the GOOSE message, processes it, and asserts an output to trip the selected load. This whole process takes, as shown in Table III, an average of 40 ms, roughly two-and-a-half cycles. Observed timing with time-synchronized Sequential Events Recorder (SER) records has ranged from 35 ms to 42 ms.

TABLE III
ETHERNET PATH
(REFER TO FIG. 8. TIMING INDICATIVE OF AVERAGE TIMES RECORDED)

Action	Time Duration Since Previous Action	Time Duration Since Start
Trigger and GOOSE Message Publication at Plant A AC1	Start	Start
Wide-Area GOOSE Trigger Transmission		
GOOSE Trigger Message Receipt at Plant B AC	11 ms	11 ms
GOOSE-to-Serial LSP Interface		
Subsequent Serial Message Publication to LSP Within Plant B AC	4 ms	15 ms
LSP Algorithm Processing		
Receipt of Serial Message From LSP at Plant B AC	12 ms	27 ms
Wide-Area GOOSE Trip Transmission		
GOOSE Trip Message Receipt at Plant B AC	10 ms	37 ms
Trip Control Output at Plant A AC2	4 ms	41 ms

In Table IV, we eliminated the Ethernet side of the communications and rely completely on the serial communications. See Fig. 7 for a basic illustration of the test setup. An input is received and transmitted via a high-speed serial protocol to the LSP. The LSP processes the input and issues a **TRIP** command. The **TRIP** command is received by the tripping device and asserts an output. Taking out the Ethernet loop, we see greatly improved performance. We measure 13 ms from input to LSP decision to output. With the direct serial communications, we were well under one cycle.

TABLE IV
SERIAL PATH
(REFER TO FIG. 7. TIMING INDICATIVE OF AVERAGE TIMES RECORDED)

Action	Time Duration Since Previous Action	Time Duration Since Start
Trigger and Serial Message Publication at Plant A Relay	Start	Start
Wide-Area Serial Trigger Transmission		
Serial Trigger Message Receipt at Plant B LSP	5 ms	5 ms
LSP Algorithm Processing Plus Wide-Area Serial Trip Transmission		
Receipt of Serial Trip Message From LSP at Plant A Relay AC	4 ms	9 ms
Trip Control Output at Plant A Relay	4 ms	13 ms

X. CONCLUSIONS

This paper proposed and demonstrated a redundant load-shedding scheme for islanded power plants. Contingency-based load shedding is an important tool for use in a PMS. When done properly, it provides an added layer of protection that cannot be matched by conventional, frequency-based schemes. Given the current technologies available to the industry, there is a wide array of methods by which to implement such a scheme.

In addition to the primary contingency-based load-shedding scheme, the application of underfrequency relays acts as a secure secondary load-shedding scheme in the event that the primary scheme is unavailable.

Ethernet communications are becoming a viable option for protection-related automation schemes. While, with this scheme, the direct serial communications operated in one-third the time the Ethernet scheme took to operate, it should be noted that the GOOSE messages were preprocessed by another device, relieving the LSP of this processing burden. However, in distributing the processing burden, additional time was added to the overall round-trip timing. Taking the preprocessing equipment out of the equation takes 8 ms out of the transfer time for the Ethernet-based scheme. This brings the time comparisons a little closer. Where the serial communications system operates in less than one cycle, the Ethernet system operates in approximately two cycles. Both times met the specification, and the Ethernet system adds flexibility to the system and requires fewer communications lines because it is part of the Ethernet network. However, the obvious drawbacks to Ethernet-based systems are slower responses, larger computational requirements, and possibly less security.

The most important design element to keep in mind is that the hybrid serial and Ethernet system met previously set design criteria. Ethernet for remote communications provides a robust, inexpensive, and reliable method to transport high-speed, low-speed, and engineering data between stations. The Ethernet solution dovetailed into the existing system and also met the timing requirements. Future refinements may further improve timing and simplify communications, but this design satisfies all the acceptance criteria.

While it is important to address the options available within certain constraints and how this project is similar to any number of projects currently under development, it is interesting to note the paradigm shift that is occurring within the industry.

XI. FURTHER READING

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XII. BIOGRAPHIES

Boungwook Cho received his BSEE degree in 1981 and his MSEE degree in 1985 from Seoul National University. He is a registered professional engineer in Korea. He has more than 20 years experience in the design, analysis, and application of power plants. He was recently involved in the design of a power management and load-shedding system for the Shaybah project for Saudi Aramco in Saudi Arabia. He joined Hyundai Engineering Company in 1985, and he is currently responsible for the electrical department of power plants group.

Heechul Kim received his BSEE degree in 1997 and his MSEE degree in 1999 from Myongji University. He has over 10 years experience in the electrical design, analysis, and application of power generation plants. He was recently involved in the design of a power management and load-shedding system for the Shaybah project for Saudi Aramco in Saudi Arabia. He joined Hyundai Engineering Company in 1999, and he is currently an electrical engineer with the electrical department of power plants group.

Musaab M. Almulla graduated from King Fahd University of Petroleum & Minerals in 1998 with a BS degree in Electrical Engineering. After graduation, Musaab joined Saudi Aramco in the power distribution department, where he was responsible for the engineering, operation, and maintenance work related to power generation and distribution at Saudi Aramco facilities, focusing mainly on relay coordination studies and generation control. In 2002, Musaab graduated from Arizona State University with a MS degree in Electrical Engineering/Power Area. In 2005, he joined the project management team at Saudi Aramco, where he has been involved in the development, design, construction, and commissioning of all electrical activities related to the power generation facilities in the Shaybah Expansion Project.

Nicholas C. Seeley graduated from the University of Akron in 2002 with a B.S. degree in Electrical Engineering. After graduation, Nic began working at American Electric Power in Columbus, Ohio, for the Station Projects Engineering group, where he focused on substation design work. In June 2004, Nic was hired at Schweitzer Engineering Laboratories, Inc. in the Engineering Services division, where he is currently an automation engineer involved in the development, design, implementation, and commissioning of numerous automation-based projects.

Considerations for Generation in an Islanded Operation

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Abstract—This paper discusses the conceptual design and operation of an isolated power system, recognizing the reality that generator or turbine trips will occur. The level of reserve generating capacity must be set with proper balancing of capital expenditures and operating costs against revenue lost in a production shutdown. The way that reserve capacity is provided is as important as the amount of reserve; seemingly adequate reserve can turn out to be badly insufficient if it is not well distributed across the available reserve sources.

The dynamic behavior of reserve capacity, as much as the amount of capacity that is ultimately available, is critical in determining how an isolated facility will behave in the wake of a unit trip or the loss of a grid connection.

In this paper, experiences with detailed dynamic simulations of a range of isolated systems are described. These are related to test work and operational incidents that have provided practical calibrations. Based on simulation and experience, some guidelines are offered for configuring generation and selecting strategies for maintaining stability in large, isolated continuous-process facilities.

Index Terms—dynamic stability, islanded power generation, incremental reserve margin, model validation, single-shaft gas turbine, spinning reserve, transient stability, load shedding.

I. INTRODUCTION

A common misconception is that the so-called “spinning reserve” in a power system can be evaluated satisfactorily by simply summing up the amount of connected generating capacity and subtracting the amount of connected load. An isolated (or islanded) system designed simply to have the difference between these totals greater than the largest potential loss of generation, or increase in load, is not very secure. The power system will experience difficulties in disturbances that seemingly should not affect it. This becomes extremely important when the facility’s power system operates in isolation from a utility grid, either as a normal condition or in the wake of an event that interrupts a connection to a strong grid.

An islanded power system poses different operational “dynamics” on power generation units than those found on a strong utility grid. This paper focuses on the operation of large industrial-frame turbine-generation units in an islanded power system. It examines the limitations of turbine and governor response, the importance of accurately modeling the dynamic response of the turbine, validation of a turbine model, system design and operational considerations of multiple units in the

islanded system, and the importance of a proper load-shedding system to ultimately maintain power system stability.

II. CASE STUDIES

This section relates experiences with two large industrial oil and gas production complexes for which the authors did extensive analytical studies.

A. Asia

The first complex is a large oil and gas production system located in Asia. This complex is capable of producing approximately 600,000 barrels of oil per day. It has a distributed power generation complex as shown in simplified form as Fig. 1.

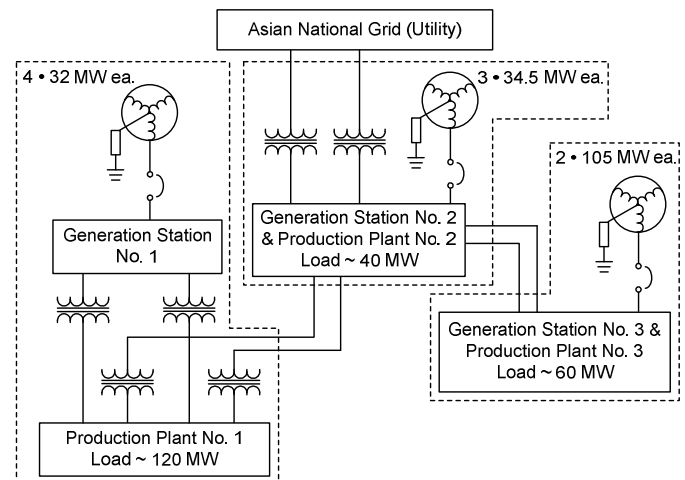


Fig. 1 Simplified One-Line Diagram of the Asian Complex

The system has three distinct production areas, each having a power generation station. Generation Station No. 1 has four early-generation, 32 MW, single-shaft, industrial-frame gas turbine units. Generation Station No. 2 has three relatively new, 34.5 MW, single-shaft, industrial-frame units. Generation Station No. 3 has two 105 MW units. All generating units are industrial-frame, single-shaft, gas turbine-driven, air-cooled generators. The three facilities are connected together by 110 kV redundant tie lines. Generation Stations No. 2 and 3 are outdoor, air-insulated substations arranged in a double-bus, single-breaker arrangement. A redundant, limited-capacity utility tie with the national grid is maintained for standby power import. It should be noted that with the power system arranged

in this manner, the 110 kV substation for Generation Station No. 2 becomes a power wheeling substation between Generation Station No. 3 and Generation Station No. 1.

Prior to the recent addition of Generation Station No. 3 and its associated production load, six of the seven units of Generation Stations No. 1 and 2 were used to handle the entire system power load. A spinning reserve margin of approximately 20 MW was left between the total generation and total load. Historically, if a single generation unit tripped, the power system was minimally impacted. The limited capacity tie to the utility and power that the remaining generation units could quickly assume, called the incremental reserve margin (IRM), easily picked up the load displaced by the tripped unit.

The two large units at Generation Station No. 3 were added with the expectation that these machines could be operated fully loaded and supply 75 percent of the total complex load. The remaining 25 percent of the complex load would be supplied by the three newer generation units at Generation Station No. 2. The Generation Station No. 1 units could be shut down and either dismantled or maintained as standby units held in ready reserve.

Neither the project personnel nor the power generation OEM (original equipment manufacturer) representatives understood the implications of having two generation units carry the majority of the power system load and the dynamics imparted by tripping one of these large units at full load. In the event of the loss of one large generation unit, the power system would now be required to pick up 37 percent of the load on the remaining online machines; whereas in the past, the loss of a single, smaller unit represented a pickup of approximately 19 percent of the load. The sudden step of 37 percent of total system load on the online machines represents a significant event on this power system, even with the assistance of the limited utility tie. Study work showed that the response capability of the remaining online generation units was not sufficient to handle such an event. The utility tie helped to provide immediate incremental reserve, but study results indicated varying amounts of load shedding might still be required to maintain the system.

B. Indonesia

The second case study involved a large oil production complex located in Indonesia. This complex produces approximately 300,000 barrels of oil per day and has a distributed power generation complex as shown in simplified form as Fig. 2.

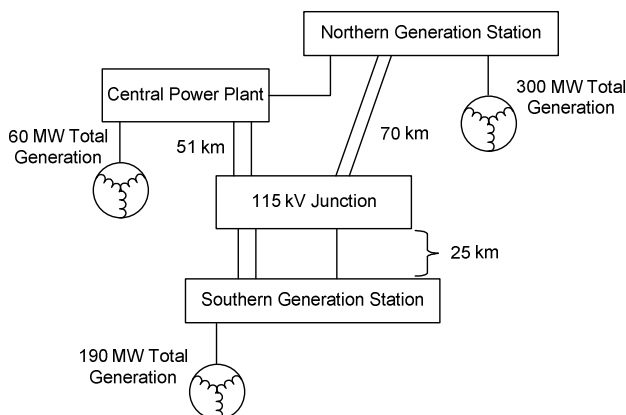


Fig. 2 Simplified One-Line Diagram for Indonesian Island Power System

Power generation for this complex is essentially located in two areas. The older portion of the facility has a southern power station with eight 20 MW units and three 35 MW units. A newer northern generation station has three 105 MW units. All generating units are single-shaft, industrial-frame machines. The entire power system is self-contained (islanded) with no connection to the external national grid.

The northern generation station produces both power and process steam and is located over 70 kilometers away from the southern generation station. The two generation stations are interconnected by a 230 kV transmission line. Power is distributed to the entire production field by 115 kV transmission lines. The loads on this system are predominantly induction motors. The total system load averages 430 MW. To support this load, the three large generation units at the northern station are operated at nearly base-loaded condition, and generally, eight smaller units at the southern station are operated with a spinning reserve margin of approximately 40 MW.

This facility experienced an instrumentation failure on one of the large northern station turbines. The result was the tripping of the unit and, within minutes, the collapse of the entire power system. Multiple layers of underfrequency load shedding totaling more than the lost generation were triggered, but the system still collapsed.

In the case of the Asian system, a planning study anticipated operational problems. In the Indonesian case, studies were undertaken to explain the behavior of the system after the event and to plan measures to prevent recurrences. A review of the Indonesian event revealed that the magnitude of the load-shedding stages initiated by underfrequency relaying was too small to arrest the frequency decay. This is further explained in the next section.

III. LIMITATIONS OF TURBINE GOVERNOR RESPONSE

So why was an underfrequency load-shedding system with what was thought to be adequate spinning reserve unable to save the Indonesian system? Was it not possible for the turbine governors to simply push the turbines to utilize their spinning reserve?

The governor controls for large, industrial-frame turbine generators have traditionally been designed with the expectation that they will be connected to a strong utility grid and that speed (frequency) variations will be minimal. The oil and gas industries, however, are placing facilities in remote locations where there is no utility tie or the utility system is weak. In these environments, the turbines can experience large variations of speed, and their ability to respond to these changes is critical to the security of the system. The events may be as simple as a large motor start, loss of a generation unit, failure of a switchgear bus or transmission/distribution line, or loss of the fuel gas supply to the engines. Understanding the response limitations of the engine is very important.

It is also important to understand that the arithmetic difference between connected capacity and load is not a useful indication of the generating units' ability to pick up load on the time scale needed to arrest a rapid fall of frequency. Terminology is important. This paper uses "spinning reserve" to refer to the difference between present turbine-generator output and the maximum that can be achieved, up to thermal limits, given sufficient time, without starting another unit. Additionally, "incremental reserve margin" is used in this paper

to describe the increase in output that can be achieved in a short time interval, typically 5 to 10 seconds.

As a general guide, the gas turbine can be expected to quickly pick up 10 to 15 percent of its site-rated capability and then assume additional loading at a rate of 0.5 percent (of its site output rating) per second. This is very different from assuming that the full spinning reserve is instantaneously available.

Fig. 3 illustrates this delayed response. The Indonesian 100 MW machine was loaded to 92 MW, and a step load of approximately 5 MW was added at 5 seconds. The solid black line (Series 1) represents turbine speed (or system frequency). Notice that it dips as the step load is added. The thin black line (Series 3) represents the electrical power output of the generator. The change in electrical output is instantaneous. The gray line (Series 2) represents the mechanical power output of the turbine. It is not an instantaneous step. The initial instantaneous electrical change is determined by Kirchoff's laws and system impedance; it is not affected by turbine characteristics or even by turbine-generator inertia. The subsequent oscillatory component of electrical response is determined by impedances and mechanical inertias. The response of turbine power, on the other hand, is determined by the combined influences of the thermal characteristics, the turbine governor, and the supervising elements of the turbine controls that are intended to avoid damaging conditions in the turbine.

There is a clear lag between the generator output and the turbine power output. It took nearly 5 seconds for the turbine governor and the fuel control valve to add enough fuel to increase the turbine power output to match the power demand on the generator.

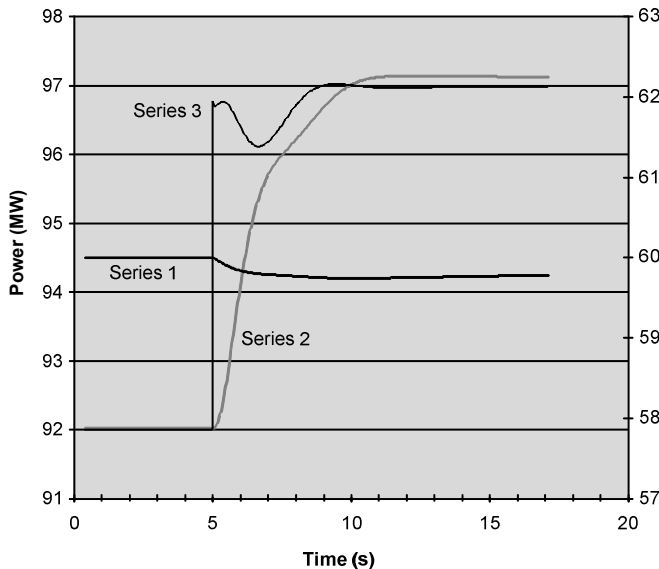


Fig. 3 Power Output and Speed of an Industrial-Frame Turbine and Generator, Small Load Step Response

The difference between electrical power and turbine power creates an accelerating or decelerating torque on the turbine-generator shafts. The system speed (frequency) continues to decay until the collective turbine power output matches or exceeds the collective electrical demand. In this particular instance, speed dipped by only 16 rpm before recovering.

The decay of speed can only be arrested and corrected when, and if, the governors can bring the collective turbine power up to match and exceed the collective load. In this context, it is important to recognize that the maximum output allowed by the gas turbine controls is reduced roughly in proportion to the square of the speed as the turbine speed decreases. This limitation on output does not appear instantaneously; it is imposed as the measured exhaust temperature rises and the temperature limiting controller takes command of fuel flow. The limitation on turbine output may cause an event that seems initially to be survivable to evolve into a power system collapse.

In Fig. 4, three units of the isolated system were running near site-rated base load, supplying a total load of approximately 280 MW. A unit carrying 93 MW tripped, causing a very rapid decay of system frequency. Significant load shedding was necessary because of this sudden loss of 33 percent of online generation on essentially base-loaded machines. Underfrequency relaying was set to drop load in excess of equivalent generation in several stages of approximately 20 MW each. The dashed line (Series 1) represents turbine speed (or system frequency). The black solid line (Series 3) represents the electrical power output of the generator. The gray solid line (Series 2) represents the mechanical power output of the turbine. Again, the electrical load on the generator jumps instantly. The turbine governor starts to respond but is limited immediately by the temperature limit. Speed decreases rapidly under this large step load. Underfrequency relaying operates, and at about 12 seconds, speed appears to stabilize. At about 16 seconds, the system seemingly recovers. Fig. 5 shows this same exact plot, but with time extended to 24 seconds. At 18 seconds, it becomes obvious that the system is crashing.

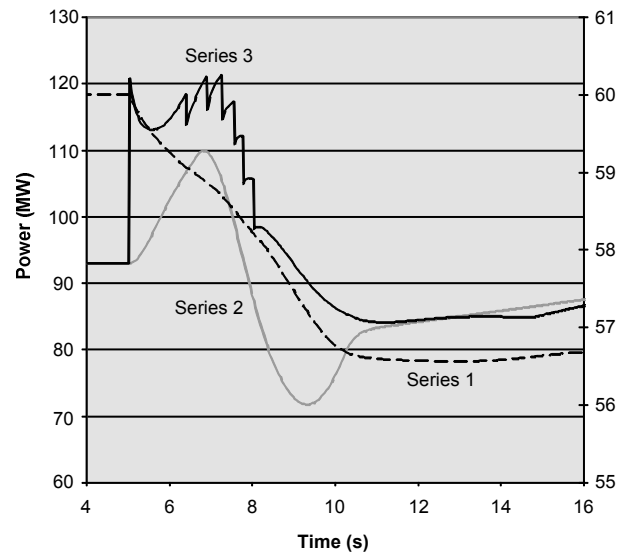


Fig. 4 Power Output and Speed of an Industrial-Frame Turbine and Generator, Apparent Successful Recovery

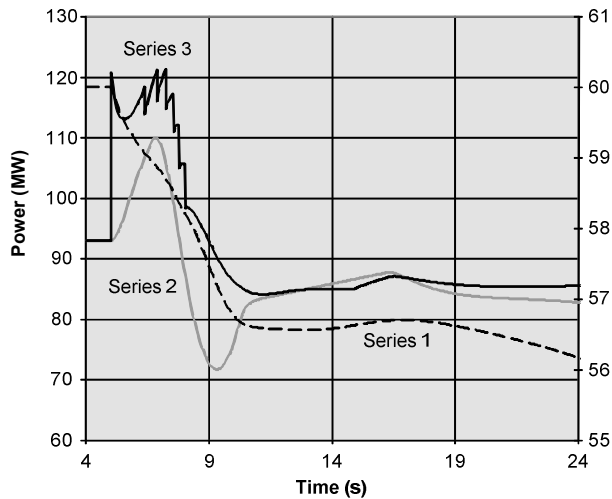


Fig. 5 Power Output and Speed of an Industrial-Frame Turbine and Generator, Failed Recovery

Studies of system behavior must accurately take into account turbine limitation such as is shown in Fig. 4 and Fig. 5. This requires accurate models of governors and turbine controls for valid simulations.

When a given facility load is covered by a large number of generating units (e.g., five or more), the loss of one unit might be covered adequately by the dynamic response of those remaining online. If a smaller number of larger units are used

to cover the load, the dynamic response of those remaining will not be able to cover the loss of one unit, even if the arithmetic summations suggest that there is adequate spinning reserve. Under these circumstances, load shedding will be essential.

Capital planning of unit sizes, the design of load-shedding systems, and the broad range of related operational issues all require dynamic simulation studies in which the response capabilities of turbines are modeled comprehensively.

IV. VALIDATING THE TURBINE AND TURBINE GOVERNOR MODEL

Effective studies of reserve response require both computer programs that provide the appropriate dynamic models and assurance that these mathematical models are properly calibrated. The presence of a model in the library of a computer program does not give the required assurance of proper representation. Models must be calibrated against the measured behavior of in-service units.

A typical model is shown in Fig. 6; this example represents a 120 MW industrial-frame turbine and its principal controls. This model's form was reviewed by comparison with site-specific, as-built control schematics. As-built control information provides reliable values for some parameters, such as droop setting, but cannot provide calibration with regard to the behavior of the turbine itself. Overall calibration is best achieved by comparing simulations with the recorded results of response tests.

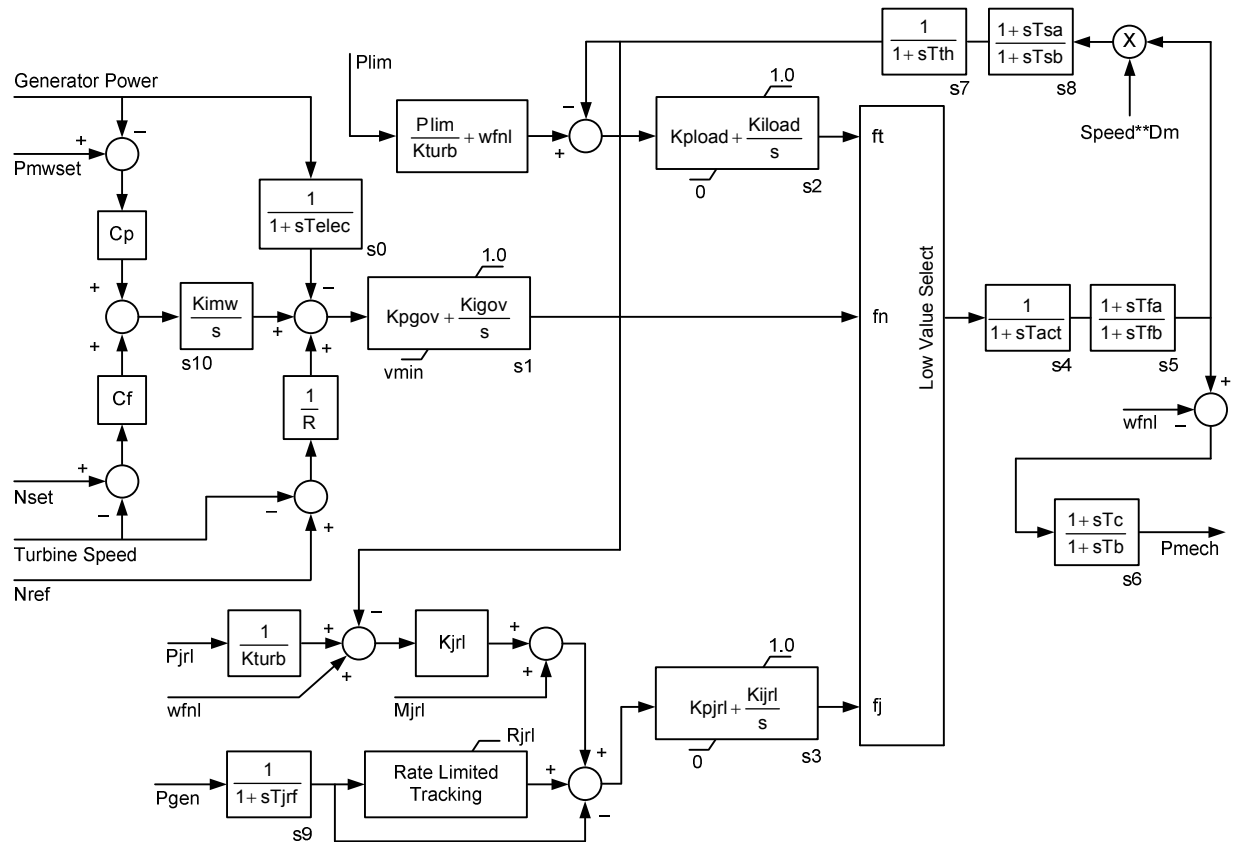


Fig. 6 Generic Governor and Turbine Model (WGOV1)

A. Tests for Model Validation

The response tests needed for validation of dynamic performance models can be undertaken generally as follows:

1. Test a unit that will fairly represent the type under consideration.
2. Record the following signals at a rate of at least 10 samples per second:
 - a. Generator MW
 - b. Turbine fuel command
 - c. Turbine compressor speed (if a multishaft engine and if available)
 - d. Turbine power shaft speed (generator speed or frequency)
 - e. Turbine exhaust temperature
 - f. Turbine pressure ratio (if available)
3. If circumstances allow operation into a resistive load bank, switch the load on and off to produce steps ranging from 5 to 15 percent of the rated output.
4. Where the generator must be tested in its service connection, initiate changes of output by making step changes to the governor speed-load reference so as to change the output by amounts between 5 and 15 percent. Note that the output changes of the test may change the frequency of the power system if the test generator is large in relation to the system of which it is a part.
5. In both test situations, apply output increase steps that will take the turbine decisively up to its exhaust temperature limit; for example, apply a step that would take the turbine from 95 to 102 percent output in the absence of the limit.

It can be anticipated that test personnel would need to be on site at least a day prior to the test to discuss the test procedure, prepare operational loading plans, and set up recording systems. It is imperative that the recording system be tested and proven in normal operation prior to the start of testing.

B. Model Validation

Testing does not validate a dynamic model. Model validation is an analytical process based on test results. Each of the tests made as described above should be simulated with the dynamic model proposed to represent the machine. The parameters of the model are adjusted until the behavior shown by the model in a simulation of each test is a fair match to the observed test behavior. A perfect fit between a single test recording and simulation result is rarely achieved and is less important than achieving a fair fit over a range of magnitudes of test disturbance and a range of initial loading levels. This process requires exact knowledge of the way the tests were conducted, expertise in modeling, and sound knowledge of the turbine and controls under consideration. This analytical part of the exercise is more demanding than the test phase in terms of the availability of expertise, elapsed time, and cost. Attempts to minimize cost by having test work done by field technical staff and analytical work by other specialists have been notably unsuccessful.

It is fair to regard dynamic model validation as a significant expense when taken on its own. However, the costs of failed system performance because of inaccurate analysis in the planning stage are significantly greater.

Fig. 7 shows the measured data from a step response test of one of the engines located at the Indonesian facility. The three 100 MW units were connected to an islanded utility grid and loaded to approximately 85 percent. The governor speed-load reference for northern generation station Unit No. 2 was stepped upward to make the engine increase its output by 8 MW. After 50 seconds, the speed-load reference was stepped back to its original setting. The plot shows the fuel command signal, rotor speed, (electrical) power output, and power reference signal. Because of the large size of the turbine in relation to the size of the isolated power system, it was necessary to limit the test steps to 8 MW; the turbine could have made larger steps, but these would have caused unacceptable changes in system frequency.

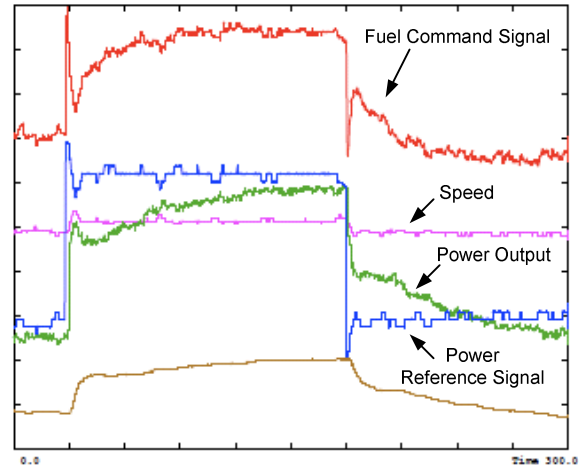


Fig. 7 Actual Plot of Test Data for a 110 MW Industrial-Frame Turbine Engine

Fig. 8 shows the model simulation of the test shown in Fig. 7 after all model parameters had been adjusted to correspond to known as-built values where applicable and to give the required fair match of simulation to test. The good correspondence between simulation and test validates the model for use in system studies.

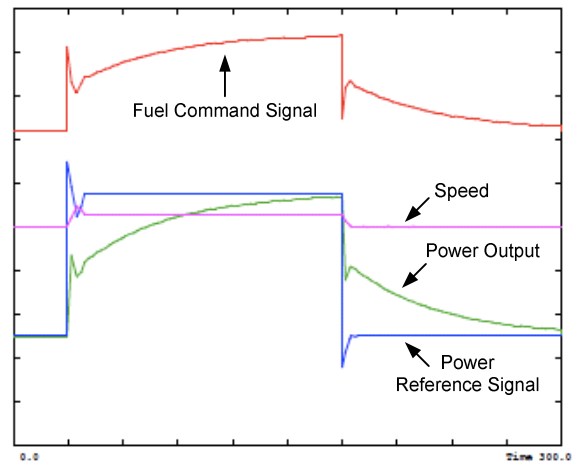


Fig. 8 Plot of Results for a Model of the Engine Plotted in Fig. 7

V. SIMULATION STUDIES AND GENERATOR CONFIGURATION

What should be the approach to validating the configuration for an islanded power generation system? The first step is to realize that there is a difference between an electrical transient stability study and a power system dynamic study. The transient stability study usually concentrates on events that are of very short duration, such as power system short circuits and clearance by circuit breakers, and whose time window of interest is up to approximately 1 second from the event's appearance. This time duration is too short for the turbine governors to respond. A dynamic study looks at the effects to the power system for approximately 1 to 20+ seconds following the event.

The second step is to develop an accurate system model for the facility's power generation and power distribution (including the facility loads). This model can then be employed for transient and dynamic system response studies with the user looking very carefully at the behavior of the power generation elements. For the transient stability study, a grossly simplified model of a governor is acceptable or may not even be required. However, a system dynamic study requires a governor model that contains accurate depictions of the thermal, mechanical, and governor limits of the turbine. A system can seemingly survive a transient disturbance only to collapse some time later because of the protective controller actions from the governor.

The third step is to subject the system to all possible contingencies it may see. This includes the loss of one generation unit, a fault on the generator bus, a fault on a distribution bus, a fault on a cable feed, the start of a large motor, the loss of a bus coupler or tie line, and the loss of significant load.

The fourth step is to analyze the simulation results and validate them as credible. This means that the user has to understand the capabilities of the equipment being modeled, which in turn implies the user must have a certain level of experience with this equipment.

The fifth step, once the system dynamics have been properly modeled and understood, is to properly implement protection systems that will take action and ensure that power system stability is maintained.

VI. LOAD-SHEDDING PROTECTION SYSTEMS

Power system collapses quite commonly occur because the power system frequency decays at an extreme rate and protection systems trip off motors and generators, causing further generation to trip, eventually cascading into a full system outage. However common the outcome, the origination of a system outage can have many different initiating factors. The initiating events for a system outage may have occurred seconds, minutes, or hours prior to the collapse. For small industrial and islanded power systems, the most common form of initiating event is the sudden loss (circuit breaker trip) of a generator, bus coupler breaker, or tie breaker. If any of these breakers suddenly are opened (under load), a power imbalance will occur between the mechanical power created by the turbines and the net sum of the electrical load on the power system. This section deals specifically with proven remediation methods used to rebalance the remaining turbines and loads, thereby preventing system frequency decay.

The frequency decay rate of an electrical system under a power deficit is related to the magnitude of the power deficit,

the load composition (induction motor, synchronous motor, resistive loads, electronic loads), and system inertia (H constant). For approximately the first second, this decay will occur regardless of the type or quality of the turbine governor. As an example of both extremes of governor control action, Fig. 9 shows the initial decay rate is identical for turbine governors running in base load (no speed control) and governors in droop mode (speed control with power bias factor). Therefore, for all power systems, an underfrequency load-shedding system will only detect a frequency decay after the initiating condition of a power deficit. As shown previously, this delayed response time can quite frequently result in a cascading blackout.

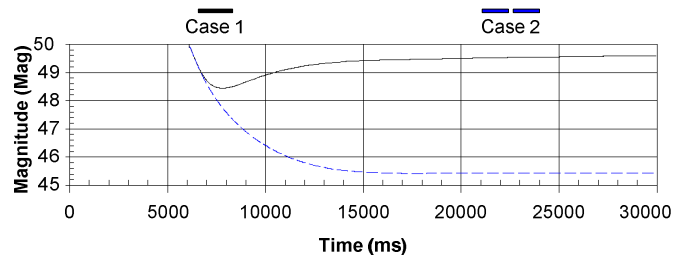


Fig. 9 Frequency Response Comparison of a Governor in Droop and Base Modes

A. Contingency-Based Load Shedding

A proven method for correction of power generation versus load unbalance is to shed (trip) loads immediately upon the opening of breakers through which active power is flowing. The opening of a generator, bus coupler, or tie breaker under load can create a power disparity. These are therefore classified as contingencies that can cause power imbalance. Therefore, this form of system is referred to as a contingency-based load-shedding protection system.

The contingency-based load-shedding protection system has many names and acronyms throughout the world. These systems are commonly called "special protection schemes" (SPS) or "remedial action schemes" (RAS) by electrical utilities. For industrial and commercial electric power systems, these protection schemes are most commonly integrated into an overall electrical power system protection package containing many hundreds of multifunction protective relays. These load- and generation-shedding protection schemes are commonly included in many industrial power demand management systems (PDMS).

Depending on the communications protocols and media, modern, contingency-based load- and generation-shedding protection systems can have closed-loop response times of faster than 12 milliseconds over hundreds of kilometers, thousands of contingencies, and tens of thousands of loads [1]. This time is the measured total time from an input voltage asserting to 90 percent of full voltage to an output contact fully conducting on a controller's I/O terminal blocks. This includes the full conduction of output contacts that are rated for tripping; therefore, interposing relays are no longer used in modern systems. Because of these speeds, contingency-based protection systems are now realistic for any size or type of power system.

Various signals have been used over the years to initiate a load-shedding contingency. These include breaker contacts (52 A and B contacts), 86 lockout contacts, current thresholds, out-of-step (OOS) conditions, protective relaying trip signals, synchrophasor phase angle deflection [2], thermal limits on

generators, transformer overloads, voltage depressions, and more. Each of the aforementioned contingency triggering conditions has an impact on the overall system-shedding time and the operational security of the overall scheme.

A single failure of a communications processing, logic processing, or I/O device can be catastrophic in a contingency-based protection scheme. It is for this reason that modern load- and generation-shedding schemes are built exclusively on protection-class equipment with substation environmental ratings. All protocols used are encrypted, protection-class signals communicated over devoted communications channels. For the most rigorous of applications, triple modular redundant (TMR) voting schemes are used [3].

Modern, contingency-based load-shedding protection systems perform all of their calculations and subsequent load selections continuously and prior to any contingency event [4]. In this way, the system is always armed with the appropriate load-shedding solution and continuously reports to the operators the outcome of every possible future contingency event.

The basic underlying equation used to select the amount of load to be shed is:

$$L_n = P_n - \sum_{g=1}^m \text{IRM}_{ng} \quad (1)$$

where:

- n = contingency (event) number
- m = number of sources (generators) in the system
- g = generator number, 1 through m
- L_n = amount of load selected for “n” event (MW)
- P_n = power disparity caused by “n” event (MW)
- IRM_{ng} = incremental reserve margin of all generators (sources) remaining after “n” event (MW)

There are several key characteristics of modern load-shedding systems, including:

1. Pre-armed load-shed events, per (1). These arming signals are commonly loaded into a construct called a crosspoint switch matrix for ease of indexing and operator display.
2. Operator selection of sheddable load priorities.
3. Operator selection of IRM for each power source (generator).
4. Event logs (event reports) that capture detailed analog and digital information of each event that occurs, with up to 1-millisecond accuracy and time durations of up to 30 seconds.
5. Sequence of event (SOE) logs, which capture all changes of state of digital signals with 1-millisecond accuracy.
6. 1-millisecond or better accurate time synchronization of all electronics to coordinated universal time (UTC). This is most commonly accomplished by synchronization of all electronics with IRIG-B satellite time-synchronization signals.
7. System diagnostic logs to capture and time-stamp any equipment anomalies.

8. Real-time, temperature-compensated modeling of the long-term reserve margin capabilities of generators and turbines. This is used to provide realistic limits to any operator-entered IRM values.
9. System topology tracking. This includes complete tracking of all breakers and disconnect statuses carrying power between sources and loads. Load-shedding algorithms must know the routes in which power is flowing between sheddable loads and sources.

The inclusion of these basic concepts into a contingency-based load-shedding system is the reason many systems are described with such terms as “predictive,” “flexible,” “adaptive,” or “intelligent.” Reference [5] identifies a large number of other critical characteristics of these systems.

Modern, contingency-based load- and generation-shedding systems must handle multiple, closely timed events. Unfortunately, current and voltage values commonly oscillate following such a power system disturbance (contingency event). These transient oscillations are easily measured with modern electronics; however, without steady-state information, the evaluation of (1) becomes impractical. Allowing a contingency-based system to shed load based upon transient information will commonly undershed or overshed, possibly making a bad situation worse. Contingency-based systems are therefore commonly inhibited from tripping action for some time period following the first disturbance (contingency). Two methods are commonly employed to provide load-shedding protection for multiple, closely timed events:

- Queuing of contingency events and submillisecond power-flow recalculation. This power flow is used to determine the new steady-state conditions during times of transient oscillations. Such schemes are most commonly employed on mission-critical generation-shedding schemes for utility systems [3].
- Backup underfrequency load-shedding system. These systems provide protection for power disparities during the contingency-based system transient inhibit [4].

B. Underfrequency Load Shedding

Underfrequency load-shedding schemes are commonly employed in industrial power systems as a backup to a contingency-based load-shedding system. In addition to transient inhibit periods, maintenance issues such as equipment failures, broken wiring, shorted CT windings, and dc battery failures will cause a contingency-based load-shedding protection system to not operate when needed. Clamping and slew rate limiters in governors or fuel/air problems are other situations for which a contingency-based load-shedding protection system will not operate. Improper installation or commissioning of protection equipment can also be another reason that a contingency-based system will not react when needed. All of these reasons make it mandatory that a backup underfrequency-based load-shedding system be employed to supplement a contingency-based system.

Unfortunately, there are severe limitations in traditional underfrequency load-shedding protection systems, primarily because this type of system only reacts after the system is in a state of decay due to overload. These limitations have caused

load-shedding systems to gain a bad reputation as “untrustworthy.” It is the authors’ experience that underfrequency-based systems based on single-function underfrequency relays have an approximately 50 percent likelihood of rescuing a power system from decay.

Hybrid underfrequency load-shedding systems serve to correct all of the known weak points of traditional underfrequency systems. These hybrid schemes still shed load based on several underfrequency thresholds; however, the signals are sent from remote devices to a centralized processor. These protection schemes then dynamically select from a prioritized load list. It is this similarity to contingency-based systems that gives this category of underfrequency load-shedding systems the name “hybrid.”

Table I summarizes the advantages of hybrid underfrequency schemes over traditional schemes that use underfrequency elements in remote, separate relays.

TABLE I
UNDERFREQUENCY SCHEME COMPARISON

Item	Hybrid Underfrequency Scheme	Relay Underfrequency Scheme
1	Selects correct amount of load to shed for every underfrequency threshold based on live power (MW) and knowledge of the power system R value.	Underfrequency elements operate with any amount of load through the shed breaker. May not shed load if load is off, or may shed too much if load is larger than anticipated.
2	Always sheds the optimal amount of load (MW).	Basically a fixed, nonadaptive system.
3	Sheds less load with better impact.	Commonly sheds too much load, sometimes resulting in power system instability or overfrequency.
4	Changing priority of sheddable load is very easy; just change the load priority from the user interface.	Changing priority requires changing underfrequency pickups and timers on discrete relays, very labor intensive.
5	No maintenance.	Regular maintenance and testing required on old single-function underfrequency relays.
6	Typically > 99.99999% of availability.	Typically < 99.99% of availability.

The advances over traditional underfrequency load shedding that these hybrid systems provide include the following:

- Loads are dynamically selected (only active loads are selected to be shed).
- Load consumption (MW) is incorporated into the selection of load to shed.
- Power system topology is tracked, guaranteeing that all loads that are shed are on the bus or island that required load shedding.
- The incremental change in frequency (F) versus power consumption (MW) is selected by the user ($\Delta F/\Delta MW$). This ratio is normally determined by a power system dynamic stability study.

C. System Modeling and Validation

It is imperative to characterize a power system before the configuration of any modern contingency- or underfrequency-based load-shedding scheme. This characterization is only possible with a hardware and/or software package capable of providing accurate “power system dynamic studies.” This is not to be confused with “electrical transient stability studies,” as previously discussed in this paper. The package used for load-shedding characterization must include accurate modeling of governors, turbines, exciters, rotating machinery inertia, load mechanical and electrical characteristics, electrical component impedances, and magnetic saturation of electrical components. Several of the parameters that come out of these dynamic stability studies include: the IRM of each generator and connected utility, ($\Delta F/\Delta MW$) of the system, coordination validation between underfrequency backup systems and contingency load-shedding systems, load makeup ratios, and total system inertia (H). These parameters are crucial to the proper operation and coordination of modern load-shedding systems.

Various levels of testing go into the validation of any complete load- or generation-based shedding. For the most mission-critical applications, a live real-time simulation environment is used to validate complete system performance. This is accomplished with a hardware package capable of providing both power system dynamic and electrical transient frequencies of responses (i.e., it must accurately model all mechanical and electrical systems). Such tasks are only accomplished with several hundred parallel processors running real time in a single-purpose simulation environment. To fully validate the load- or generation-shedding protection systems, the processors have direct, hard-wired connections to the protection equipment’s CT, PT, and I/O connections. The authors’ experience is that this form of real-time, closed-loop simulation is essential to fully validate any new generation of contingency-based load- and/or generation-shedding equipment.

VII. OPERATIONAL CONSIDERATIONS

The purpose of this section is to provide some guidance for applying the information provided in the previous sections of this paper.

The first consideration in selecting the proper generation configuration and load-shedding protection scheme is to identify the sensitivity of the process to power outage events. If the process can easily withstand significant loss of load without adverse safety implications to the plant and personnel and if lost profit opportunities are not a concern, the number of generation units can be closely matched to the operating load and loads shed as appropriate to minimize the outage. This type of situation may be found in an islanded power system, such as that found on floating production, storage, and offloading vessels called FPSOs. A significant amount of load that can be shed without adversely affecting the vessel’s production may include water injection and sea water pumps. These may be of enough magnitude to compensate for the loss of one generation unit. It must be noted that even though the process can tolerate load shedding, the generation units must never be operated near the turbine’s firing temperature limit. There has to be some margin left between the turbine’s loading and the site-rated thermal maximum limit to allow for

small deviations in load. This can also be referred to as a margin for frequency maintenance. As small loads are switched on and off onto a small group (four or less) of base-loaded machines, the frequency of the system may start a slow decay. This becomes especially true if the small additional loads stay on continuously. Unless safeguards are in effect to automatically shed load or alert the operator to shed load, the frequency may decay over several hours to a point that one or more units reach a stall condition. The result will be a trip of the turbine to protect it from entering a surge condition. The other generation units are already at maximum loading when the displaced load of a tripped generation unit is imposed upon them. The whole system will collapse. Fast load shedding may not be enough to prevent the system collapse for a system operated in this manner.

If the process is deemed critical and load shedding should be kept to a minimum, another philosophy must be adopted. The authors recommend that for a critical process, the size of the largest generation unit should not exceed 20 percent of the total generation capacity. For a system of equally sized machines, this translates to a minimum of five equally sized units. In the authors' experience, for such a system with five equally sized machines operating with 20 percent thermal margin left on each machine, the loss of one unit is compensated for by the remaining four machines. The thermal margin will of course vary depending upon the ambient temperature, condition of the machines, and degradation of the air inlet filters. With less thermal margin, a minimal amount of load shedding may be needed to maintain the system's integrity. The optimal number and type of machines must be considered from an economic perspective as well. Factors such as capital equipment cost, maintenance intervals, and, in some instances, size and weight may influence the final selection of size, number, and type of turbine generation units.

Many islanded systems employ a large number of generation units connected to a generation bus or a main power distribution bus. In such situations, the user is encouraged to look carefully at the X/R ratio of the current imposed on the bus and circuit breakers during short-circuit conditions. It may be that the dc offset created by the higher X/R ratios of close-coupled generation may exceed the capabilities of the circuit breakers. Higher-rated equipment, delayed breaker operation, or series impedance may be needed to compensate for this condition and allow the equipment to operate safely.

Should the system architecture be designed such that the overall power system can be broken into separate islands, care must be taken not to separate load from generation by high impedance. This is especially true if an expansion to an existing facility may be adding additional load and generation that would be coupled to the existing system by tie lines or transformers. If too much impedance is required to connect the various system parts together, a bottleneck to reactive power flow will be created, and voltage support issues will arise.

A power management system with automatic generation control may be considered to operate a system with multiple generation units. This system can monitor the topology of the system and dispatch the generation as needed to load each generation unit in equal percentage. Reactive power flows can be adjusted by this type of controller through transformer on-load tap changers. Fast load shedding and fast generation shedding can also be implemented as a subset of this system but should be kept separate for system integrity reasons. Both fast load-shedding and fast generation-shedding systems need

to maintain optimal response times less than 200 milliseconds (including breaker opening times) to be effective. Times longer than 250 milliseconds enter the time-response capability of traditional underfrequency relaying.

VIII. CONCLUSION

The dynamic response of the turbine governor becomes particularly important when the engines are operated to their limits. This can be under normal operation of base-loading the engines; it can be through imposition of large step-load demands on the engines through loss of generation or through the addition of significant blocks of load.

Islanded power systems with fewer, larger generators must rely more heavily on strategies like contingency-based load shedding. Traditional, underfrequency-based load-shedding systems are not appropriate as primary blackout remediation techniques for islanded systems. Hybrid underfrequency schemes have proven to be an appropriate backup scheme if they are properly coordinated with a primary, high-speed, contingency-based system. Preferably, all load-shedding system coordination and controls must be validated with a full power system dynamic study with generator models that have been validated against real data.

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X. VITAE

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PacifiCorp's Jim Bridger RAS: A Dual Triple Modular Redundant Case Study

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Abstract—The Jim Bridger Power Plant, located near Rock Springs, Wyoming, is a mine-mouth, coal-fired generation station jointly owned by PacifiCorp and Idaho Power Company. Jim Bridger operates four 530 MW units that transmit the majority of their power through three 345 kV lines west through the Borah West Corridor in southern Idaho. Two 230 kV lines connect to the Wyoming transmission system as well. A subcycle remedial action scheme (RAS) allows system operators to push more power through their existing transmission infrastructure, meanwhile protecting against several known dynamic stability problems.

The existing RAS consists of two systems, one a triple modular redundant (TMR) programmable logic controller (PLC) and the other a hard-wired relay panel. Both systems are obsolete and at the limit of maintainability. They are also difficult to expand in terms of improving logic and adding I/O for new transmission.

PacifiCorp contracted with a supplier to implement a dual TMR RAS system to satisfy PacifiCorp and WECC (Western Electricity Coordinating Council) requirements. The system utilizes proven substation-grade, IEC 61131-3-compatible programmable controllers and high-speed I/O. Each TMR system consists of three identical systems gathering I/O, performing two-out-of-three voting on the data, and performing calculations to decide if an action is necessary. Total loop timing from input assertion to output contact conduction is less than 17 milliseconds. An action (generator trip or capacitor insert/bypass) cannot be executed unless two of the three systems in a TMR RAS agree. The two fully independent TMR RAS systems have dual supervisory units to ensure that a different action can never be taken by the two independent RAS systems. Due to the dual TMR nature of the RAS, a total of four very specific device failures is necessary before the RAS is incapable of reaching a decision.

I. BACKGROUND

A. Power System

The Jim Bridger Power Plant is located 22.7 miles east of Rock Springs in southwestern Wyoming. The coal-fired electrical generating plant with its four 530 MW units is adjacent to a coal mine from which most of the fuel for the plant is obtained. The plant, which is jointly owned by PacifiCorp and Idaho Power Company, is operated by PacifiCorp. The transmission system that connects the Jim Bridger Power Plant to the transmission grid consists of three 345 kV lines and three 230 kV lines. Although the plant is in Wyoming, it is an energy resource for the PacifiCorp and Idaho Power loads in Idaho, Oregon, and Washington. The power from the plant is transported over three 345 kV and two 230 kV transmission lines that radiate out to the west. Those transmission lines and the critical parts of the transmission

system across the states of Wyoming, Utah, Idaho, and Oregon are parts of the transmission system monitored by a remedial action scheme (RAS) located at the Jim Bridger Substation. Since the plant was built in the early 1970s, a RAS has been required to achieve the transmission path rating needed to move the energy from the plant to the loads. When the transmission path is being operated at the path limit and a transmission line in the path is lost, the generation at Jim Bridger must be reduced to maintain the transient stability of the power grid.

The complete loss of the RAS for any reason requires that the Jim Bridger Power Plant be reduced to 1,300 MW. The full capacity of the Jim Bridger Power Plant is greater than 2,200 MW.

B. History

There have been three generations of Jim Bridger RAS control systems, and each successive system has increased in complexity. The reason for the additional complexity has been to reduce the number of times that generator units must be tripped. Each generation of Jim Bridger RAS has monitored additional statuses of the power system. With the additional information, the arming levels for tripping generator units for different line faults were raised. The worst-case scenario must be assumed for any condition that is not being actively monitored by the RAS. The less complex, older systems have therefore caused unnecessary tripping of generator units for the loss of transmission lines. The system being described in this paper has more inputs, a more complex algorithm, and therefore will shed less generation than any of the preceding systems used for the Jim Bridger RAS.

C. Description of Dynamic Problem

When a fault occurs on the transmission system, the power flow, as a result of the fault, is predominantly reactive power, since the impedances of the transformers and lines are predominantly inductive. During the fault, the voltage at the fault is zero, and the voltage at the terminals of the generators is significantly reduced. The low voltage restricts the real power flow from the generators. Since the turbines driving the generators are continuing to pour real power into the generators, the units start to accelerate. This acceleration continues until the faulted transmission line is disconnected from the system. With the fault removed, the real power starts moving from the generators to the load, and the generators decelerate. With the removal of the faulted transmission line from the power system, the transmission path impedance is increased.

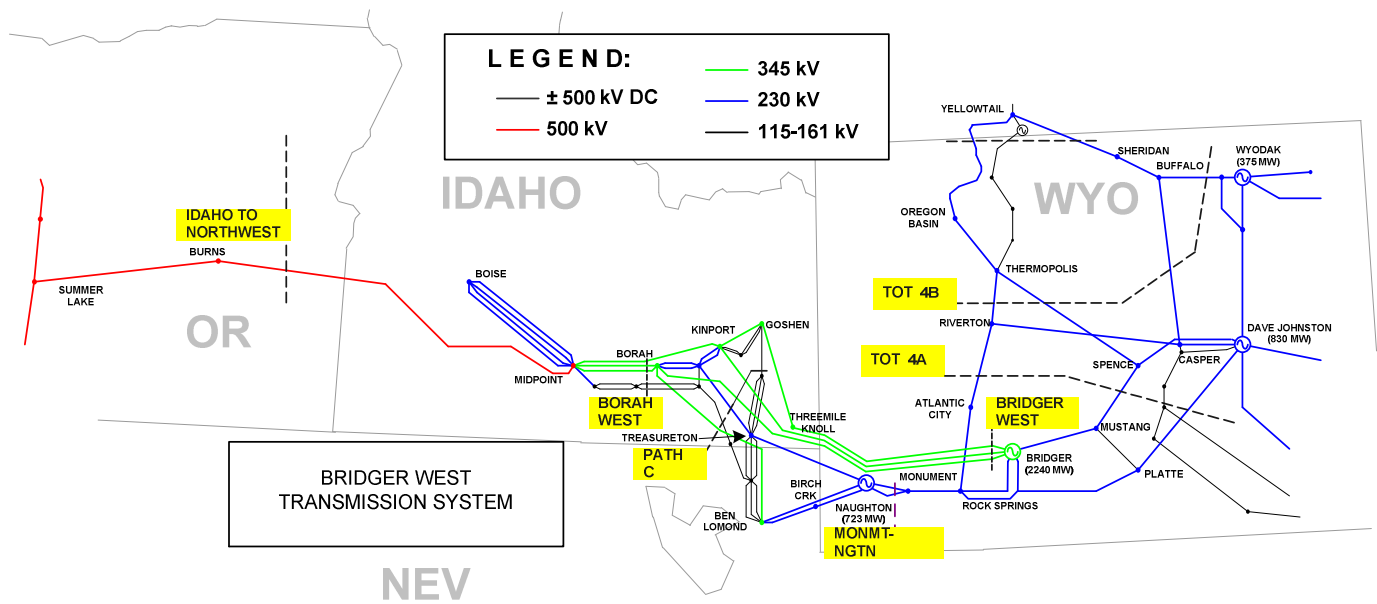


Fig. 1. Map of Transmission System

The increase of the transmission path impedance combined with the generator acceleration during the fault results in an oscillation between the generator rotors and the power system. If the real power flow is low enough and the increase in transmission path impedance small enough, the oscillations will dampen, and a new equilibrium state will be reached. If the new conditions are too extreme, the oscillations will not dampen, and the Jim Bridger generators will go out of step with the PacifiCorp power system.

The generation oscillations will cause the voltage at Jim Bridger to swing in magnitude. The voltage magnitude on the first swing after the fault is cleared is an indicator of the stability of the system. The Western Electricity Coordinating Council (WECC) requires that the voltage on the first swing not drop more than 30 percent from the prefault value. The Jim Bridger RAS action is needed to prevent the voltage at Jim Bridger from dropping more than the 30 percent limit following the loss of a transmission line when the plant is operating near the transmission path limit. To arrest the voltage dip, the power output from the plant must be reduced and, in the most severe cases, within 5 cycles on a 60 Hz base. The 5 cycles are measured from the inception of the fault until the generator breaker disconnects the generator.

II. RAS CONTROLLER REQUIREMENTS

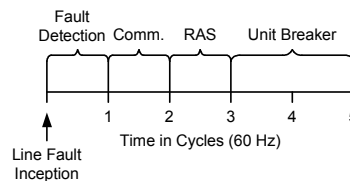
A. Timing Requirements

Based on stability studies for the most severe fault case (a multiphase fault on a 345 kV line close to Jim Bridger), the total time from event to resulting action must not exceed 5 cycles. Fig. 2A1 shows the time allocation for this case. Zone 1 faults (faults close to Jim Bridger) are the most severe N events; for these events, the overall reaction time is 3.7 cycles. (See Section VI, "RAS Design," for a further explanation of N events.) The breakdown for Zone 1 events includes 16 milliseconds for the line relays, no communica-

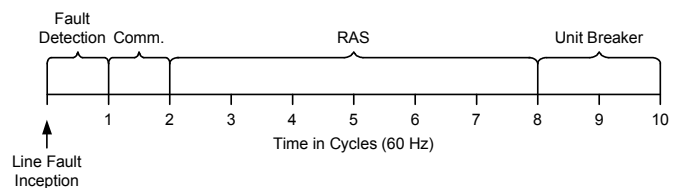
tions time, 20-millisecond RAS processing time, and 25-millisecond unit breaker clearing time. When the typical fault detection, communications time, and unit breaker opening time are excluded from the total time budget, the RAS is left with 20 milliseconds of operating time. The RAS operating time is the total measured time from an input voltage asserting to 90 percent to an output (trip contact) fully conducting.

A: For Jim Bridger Area Line Loss

A1: For Multiphase Line Faults



A2: For Nonmultiphase Line Faults (Single-Line-to-Ground or Nonfault Line Opening)



B: For Non-Jim Bridger Area Line Loss

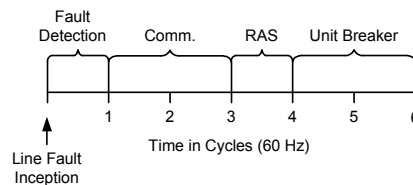


Fig. 2. Timing Charts

For less severe fault cases, less speed is required. Fig. 2A2 shows the time allocation for a single-line-to-ground fault on a 345 kV line. Although the Jim Bridger RAS has the capability to process the signals in the time needed for the most severe

case, the process is deliberately delayed for single-line-to-ground faults. Since a single-line-to-ground fault can evolve to a multiphase fault in the time it takes to detect and clear the fault, delaying the RAS response is beneficial. If the processing for the initial event is not delayed, excessive generator tripping could result. If, due to system conditions, a small amount of generation tripping was required for the single-line-to-ground fault but the output of the selected generator for tripping was inadequate for a multiphase fault event, multiple generators could be tripped when the fault evolved to a multiphase fault. By delaying the RAS to see if the fault condition will worsen, the minimum amount of generation will be tripped.

For the loss of a transmission line at a great distance from Jim Bridger, the line loss status needs to be communicated to Jim Bridger. This communication over several hundred kilometers adds additional delay, but studies have shown that the delayed response will not have an adverse effect on the stability of the power system. Fig. 2B shows the time allocation for the loss of a remote transmission line, such as the Three Mile Knoll – Goshen line.

B. Triple Modular Redundant Requirement

With the correct and timely response of the Jim Bridger RAS being critical to the stability of the power grid, the dependability of the Jim Bridger RAS is important. For this reason, the Jim Bridger RAS must be a system containing redundant inputs, outputs, and processing units. Transmission line fault incidents are unusually high for this transmission system due to the following factors:

- The 240-mile length of the transmission lines
- The rugged terrain the lines cross
- The 8,300-foot elevation of the lines
- Difficult grounding conditions
- Many unknown factors

The average incidence of faults on this transmission system is 0.8 faults per week. The plant is base loaded 24 hours a day. Between the plant's loading and the transmission line fault incidents, the Jim Bridger RAS is often called on to react. Most of these events do not require generator unit tripping, because the plant is operated at loading levels below the arming level for the most common transmission line faults, single-line-to-ground faults. The consequence of tripping a 530 MW coal-fired unit involves significant costs and reduces the reliability of the unit. For these reasons, balancing dependability with security against false operations is very important. This is why the Jim Bridger RAS is a triple modular redundant (TMR) voting control system. Two out of three identical systems must agree on the status of the inputs and the resulting outputs for the system to cause a generator unit to trip.

This triple modular redundancy is extended to the power transducers feeding the RAS data. Due to cost and complexity, the triple redundancy was not extended to two of the major

subsystems of the Jim Bridger RAS: the communications systems from remote locations and the fault severity units. These subsystems are only redundant. To accommodate the limitations of these subsystems and TMR system maintenance, dual TMR systems were specified and installed. The transmitters and receivers that use one communications network and one set of fault severity units, which are associated with each transmission line terminating at the Jim Bridger Substation, are connected to one TMR system. The communications equipment using the alternative communications network and fault severity units is connected to the second TMR system. Both TMR systems are normally in service, and either system can trip the generator units.

Due to the speed at which the Jim Bridger RAS must operate, the accuracy of the power transducers, and the scanning nature of a programmable logic controller (PLC), there are several predictable circumstances where the two TMR systems will not select the same generator unit to trip for the same event. The most likely circumstance would be when a unit's power output is near an analog threshold; in this case, one of the TMR systems could select one unit and the other select a different unit as the apparent level of the unit operating at the edge moves in and out of selection. This condition would result in tripping two generators rather than one. Since this is an unacceptable event, provisions were designed into the Jim Bridger RAS to prevent this type of event from happening. Two independent processors review what each of the TMR systems is planning to do if an event were to occur. This is possible because of the way the TMR systems predetermine their action for each of the possible line loss events based on current system conditions. Statuses as to the health of the subsystems are communicated to the monitoring systems. If the predetermined actions of the two TMR systems do not agree, the system with the healthier subsystems is permitted to take the action if the event takes place. If the health of all systems is equal and the two TMR systems will perform different actions for the event, a predetermined TMR system will be permitted to perform the action.

The other important issue is that the previous TMR systems were not designed to tolerate and perform correctly in the substation environment. Most TMR systems on the market are designed for industrial applications, and the substation introduces different environmental issues. The previous TMR system was designed with external protection elements on the inputs and outputs of the system that brought the overall system up to meeting the IEEE relay equipment environmental standards. These auxiliary systems performed well in protecting the TMR system, but later in the life of the RAS, these auxiliary systems began failing at a higher rate than the TMR primary systems. The new systems meet the IEEE relay equipment environmental standards out of the box, which should provide longer trouble-free life to the overall RAS.

C. Events and Actions

The following is the list of transmission lines for which the statuses are monitored in a real-time, high-speed manner. The single or combined loss of multiples of these lines is an event that could trigger an action from the Jim Bridger RAS.

- Jim Bridger – Borah 345 kV line
- Jim Bridger – Kinport 345 kV line
- Jim Bridger – Three Mile Knoll 345 kV line
- Jim Bridger – Rock Springs 230 kV line*
- Jim Bridger – Rock Springs via Point of Rocks 230 kV line*
- Three Mile Knoll – Goshen 345 kV line
- Goshen – Kinport 345 kV line*
- Midpoint – Borah #1 345 kV line*
- Midpoint – Borah #2 345 kV line*
- Midpoint – Kinport 345 kV line*
- Midpoint – Summer Lake 525 kV line

The loss of a transmission line marked with an asterisk will not, as a lone condition, cause generation tripping at Jim Bridger, regardless of the plant loading. However, closely timed or simultaneous successive combinations of line outages will cause generation to trip. The RAS was designed to respond to closely timed or simultaneous events; this functionality is key to a successful RAS control strategy.

The cause of the transmission line loss is taken into consideration for the loss of the lines that radiate out from the Jim Bridger Substation. The severity of the fault will impact the action to be taken. Relays throughout the PacifiCorp system are set up for fault detection and discrimination; the relays categorize each detected fault into one of the following:

- No fault or single-line-to-ground fault
- Phase-to-phase close-in fault
- Phase-to-phase remote fault
- Three-phase close-in fault
- Three-phase remote fault

The following is the list of the Jim Bridger RAS actions:

- Jim Bridger Unit 1 trip
- Jim Bridger Unit 2 trip
- Jim Bridger Unit 3 trip
- Jim Bridger Unit 4 trip
- Burns series capacitor bypass transmitter signal
- Goshen shunt capacitor transmitter signal
- Kinport shunt capacitor transmitter signal

The Jim Bridger RAS evaluates the prefault conditions and determines which of the above actions needs to be executed for each contingency. The primary conditions used to determine whether generator units need to be tripped for the different line loss events are the real power output of the plant or the real power flow on the three Jim Bridger 345 kV transmission lines and the impedance of the remaining lines. The 345 kV lines are series compensated with multisegment series capacitor banks. The number of series capacitor segments that are bypassed in the remaining lines prior to the line loss reduces the stability of the system and lowers the arming levels in the RAS. In addition to the power flows and compensation levels, an extensive number of critical power

network elements are also monitored. The status of those critical power network elements as well as the prior outage of transmission lines for which the loss of the lines has triggered an event are considered preexisting states for the RAS. The pre-event state of the power system establishes the arming levels for RAS action.

III. ANCILLARY CONTROL FUNCTIONS

There were two functionalities added to the RAS controllers that were not part of the core Jim Bridger RAS. These are described in the following subsections.

A. Subsynchronous Resonance Avoidance

The three 345 kV transmission lines that terminate at the Jim Bridger Substation are series compensated with multisegment series capacitor banks at the remote substation terminals. Each series capacitor has a bypass breaker. When a fault or switching event (N event disturbance) occurs on the local transmission system with the series capacitors bypassed, the system currents change from the previous operating state to the new state with less than a quarter cycle of high-frequency transients. In contrast, when a fault or switching event occurs on a system with series capacitors, the currents change from one state to another with a low-frequency transient characteristic.

The low-frequency switching transient forces an exchange of stored energy in the series capacitors (electrical field) and the stored energy in the inductance (magnetic fields) of the transmission system. During normal operation (prior to an event), the energy in these two systems is in a state of equilibrium. The frequency of this electromagnetic oscillation is dependent on the natural frequency associated with the value of the inductive and capacitive reactance of the power system.

Unfortunately, several turbine generators in the local system have mechanical resonance frequencies that coincide with the electromagnetic natural frequency of the electrical power system. Because of this, the fault or switching event that initiated the low-frequency transients in the electric power system will also initiate mechanical oscillations on the turbine generator. Because the electromagnetic and mechanical natural frequencies are so close, they exchange energy at the frequency of oscillation. Unfortunately, there is not sufficient damping in the combined electrical and mechanical system; this causes the amplitude of the natural frequency oscillation to be maintained or grow indefinitely. This phenomenon is called subsynchronous resonance (SSR). SSR events place additional stress on the shaft of the mechanically oscillating turbine-generator units. The cumulative effect of multiple SSR events has caused shaft fatigue and failures at power plants in the PacifiCorp system.

Several control systems are applied on the Jim Bridger power system to prevent SSR. One of these systems is implemented in the same hardware as the RAS. The RAS controllers monitor status points from the plant to determine when it is permissible to insert the last stages of the series capacitors on all three transmission lines. This prevents series

capacitor compensation from increasing to levels known to cause SSR. The plant status signals monitor generator conditions known to promote SSR.

The RAS controllers send the series capacitor insertion permit signals when the following four conditions are met:

- The protective relays used for SSR detection must be in service.
- The generator excitation systems must be in service (they damp out low-frequency oscillations on the turbine generators by varying the generator field current).
- All the on-line generators must be operating above a critical power threshold.
- The total plant power output must be above another threshold.

If these conditions are met, the RAS controllers communicate the signal to the remote terminals to permit the final segments of series capacitors to be inserted at each location. The permit insert signal must be maintained to keep the capacitors in service.

B. Scheduling Limit Functionality

Corridor capacity limits are dynamically changing and are often difficult for PacifiCorp Operations to track. The state of the power system (lines in or out of service) strongly impacts corridor capacity limitations.

The RAS controllers use the known line and equipment outages (J states) to first come up with the system state. The system state is then used to derive the scheduling limit for the Jim Bridger West Corridor. This is done in a fashion similar to

arming level calculations, by using a weighted equation of gains to evaluate the system state and come up with a single scheduling limit number for the Jim Bridger West Corridor.

IV. RAS ARCHITECTURE

Fig. 3 is an overview of the major systems in the Jim Bridger RAS. RAS Systems C and D are identical, triple redundant systems with full two-out-of-three voting. Each input/output (I/O) point to the field is wired to three independent I/O points on both systems. Each half of the RAS I/O is separately wired to terminal blocks, and all RAS controllers and wetting voltages are powered by separate dc battery systems. This creates a system of two completely autonomous control systems, hence the system is considered “dual primary.”

Within each RAS system (C and D), there are three autonomous IEC logic controllers with fully independent I/O modules. These three controllers perform two-out-of-three voting via high-speed communications links. A single substation-hardened computer provides a user interface (human-machine interface, HMI), sequence of events viewing (SERviewer Software), and event report viewing (oscillography). Another hardened computer is used as an engineering workstation and contains the development environment for all hardware (IEC 61131-compliant programming).

Each RAS system (C and D) has its own protocol gateway for communication to the PacifiCorp energy management system (EMS). These gateways communicate the necessary status, metering, and controls to and from the SCADA (supervisory control and data acquisition) masters via serial DNP3.

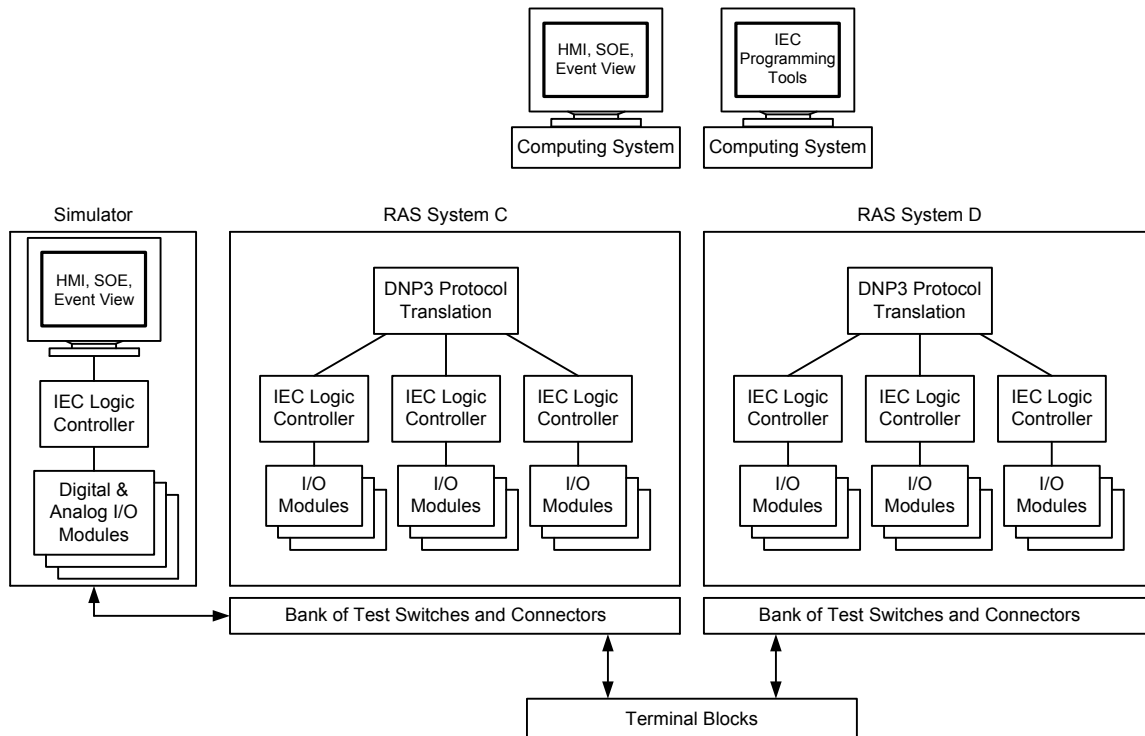


Fig. 3. System Architecture Overview

RAS Systems C and D are completely isolated on separate networks, and all logic on each system runs without any knowledge of the other system. The router between the two systems is configured to prohibit all traffic between the two RAS systems. The router limits communication from the RAS systems only to the HMI, engineering workstation, and supervision systems.

A. SCADA Communication

The SCADA gateway systems function as the intermediary for receiving data from the PacifiCorp EMS that will be used in the RAS system calculation algorithms. These gateways are also used for providing data to the EMS regarding the status and operating characteristics of the RAS system. The tasks performed by the gateways are as follows:

- Receive status and analog values from PacifiCorp and Idaho Power and make them available to the IEC controllers.
- Validate that each redundant data stream contains identical data (status and analog values) that are returned from the three controllers. Select the data source (controller) that represents the best quality data, and pass this on to the EMS.
- Flag and alarm any and all data not consistent within each redundant data stream.
- Identify and alarm any and all communications path failures via a watchdog routine.
- Code using the IEC 61131-3 programming system in a library that can be accessed from any program.

Each IEC controller performs integrity comparisons of data set points coming from the two PacifiCorp EMS front-end processors. One front-end processor is located in Casper, Wyoming, and the other is located in Salt Lake City, Utah. Based upon quality indicators, the controllers select which data source (gateway) to use. Because the code (library) running in each controller is identical, the decisions will be identical. The quality indicators used to decide data source selection include:

- Loss of communications watchdog to the EMS.
- Loss of communication between the gateway and controller.
- Alarm contact assertion on the gateway.
- Unchanging or high latency data from the EMS.

B. Simulator Design

The test simulator for the RAS control system simulates all RAS external inputs, including digital status, control inputs, analog data, and DNP3 data streams. The test simulator contains a user interface (HMI) from which an operator can perform all system tests. All systems run autonomously from the RAS.

The test simulator has the following two operating modes:

- Static simulator. This mode provides the operator the ability to drive each individual input to the RAS to a desired value. For example, the system is used to set EMS set points, set breaker status conditions, and detect generator trips from the RAS. This is extremely

useful for testing all I/O points and creating any desired power system scenarios for presentation to the RAS controls.

- Playback simulator. In this mode, the simulator is used to replay one or more event report files to the RAS system. There are two types of playback files:
 - Playback of RAS system recordings of actual events. This is identically analogous to replaying an event report created by a relay back to that very same relay. The only difference is that the response of the RAS in the recorded event is deleted for the playback, and the test simulator emulates the power system response to the output of the in-test RAS, changing the inputs to the in-test RAS.
 - Playback of recordings created by the engineers. These test records are similar to the RAS report records but are for events that the RAS has never seen before. The records cover a series of events over a period of time. The test simulator again emulates the power system changes that would occur as a result of the RAS unit tripping.

Both RAS subsystems have separate disconnect equipment (test switches) for all status, control, and low-level analog signals. The test simulator plugs into either RAS C or D for testing purposes. When under test, the RAS will not receive any inputs other than the conditions supplied by the test simulator.

The test simulator was used extensively during factory acceptance testing and on-site commissioning and will be used for future verification and maintenance testing.

C. Rugged Design Characteristics

All hardware in the Jim Bridger RAS is protective relay-class, substation-hardened equipment with extended temperature range, physical shock resistance, electromagnetic immunity, and static discharge capabilities.

The control algorithm resides on a substation-hardened controller running an embedded real-time controller engine. This engine is programmable in all IEC 61131 programming languages. There are no fans and no spinning hard drives in any equipment. All components run off of the substation battery (dc). No ac power is used in the RAS panels.

All outputs are Form A, trip-rated dry contacts; there are no interposing relays in the system. These outputs are therefore failsafe (i.e., they remain open unless a tripping scenario has occurred).

Additionally, every zone of the RAS hardware, firmware, and software contains continuous self-diagnostics. This guarantees the detection of catastrophic failures of any component(s) in the system. Every device in the RAS design has a normally closed, watchdog alarm contact that will assert if any device is powered down or has a hardware or firmware failure. These contacts are crosswired to other devices for monitoring, which guarantees that a failure in one device will not propagate further.

The logic, settings, and configurations installed on each hardware system are developed and tested to be fault tolerant,

meaning that bad computations are intentionally rejected. For example, if a line metered value is out of range or coming from a failed device, an alarm will be asserted, and the logic will declare that specific data as bad. All logic, settings, and configurations are set up to automatically reject bad data and reselect available (good) data. Bad data will not be used to make decisions.

A dual Ethernet communications network completely replaces the need for failure-prone, backplane technologies present in most industrial PLCs. The traditional technique for TMR systems is to use three central processing unit (CPU) controller modules on a single backplane, making the backplane the inherently weak point of the design. The Jim Bridger RAS TMR system uses dual redundant Ethernet hardware and redundant communications lines to eliminate this single point of failure.

The result of these design decisions is a RAS that requires four carefully selected, simultaneous hardware failures to prevent RAS operation.

V. COORDINATION WITH NEIGHBORING RAS

The Jim Bridger RAS is tightly integrated with a neighboring RAS system on the Idaho Power transmission system. These two RASs are designed to complement each other with intertripping and coordination, a nontrivial task for any RAS crossing company boundaries.

The Jim Bridger RAS receives two digital inputs (Level 1 and Level 2 trips) from the RAS located at the Idaho Power Midpoint Substation. For Level 1 and Level 2 trips, the Jim Bridger RAS is expected to trip two selectable levels of generation (Level 1 and Level 2). Based on the loss of key facilities in Idaho and prefault conditions, the Idaho Power Borah West RAS will send transfer trip signals to the Jim Bridger RAS for the processing and tripping of predetermined generation amounts. Idaho Power can trip up to two units (Level 2) within a 30-minute window; further trips are blocked during this time to prevent Idaho Power from tripping more power than necessary from the PacifiCorp Jim Bridger Power Plant. The transfer trip signals are sent via high-speed, protective relay communications channels. The Jim Bridger RAS also monitors some key facilities in Idaho. Some data required for monitoring these facilities are sent from the Idaho Power Borah West RAS to the Idaho Power EMS system. These data are shared between the Idaho Power and PacifiCorp EMS systems.

VI. RAS DESIGN

The RAS scheme implemented at Jim Bridger dynamically calculates the generation needed to be shed for each of the pre-identified events and then selects generators to shed, based on a generation selection algorithm. The main requirements of the RAS are as follows:

- Available
- Reliable
- Deterministic
- Fast (operation must be less than 20 milliseconds)

The RAS should be available under all circumstances. Having dual primary systems (RAS C and D) satisfies this requirement. The two systems are independent of each other, which gives the flexibility to disable RAS C or D for testing or maintenance and keep at least one RAS available at all times. Having a triple modular system, two-out-of-three voting, and independent communications paths in each RAS greatly increase system availability. The other two concerns are speed and determinism. Once a contingency is detected, the RAS is required to process the inputs, perform two-out-of-three voting, and trigger remedial action in less than 20 milliseconds. It has to be deterministic under all circumstances. Failure of the RAS to respond within 20 milliseconds may lead to blackouts. To make the RAS fast and deterministic, the RAS logic needs to be efficient. The RAS logic has two parts: data acquisition and processing of the RAS algorithm.

A. Data Acquisition

The RAS needs to gather analog and digital information from the field. Both high-speed and low-speed serial lines are used to gather the data. The dual TMR RAS implemented at Jim Bridger is replacing an existing RAS scheme, so a portion of the I/O required for the RAS was already available. Of the remaining I/O, some had to be wired from the field, and some had to be brought in from remote locations.

Not all data need to be fast. Some of the data are needed in detecting contingencies and some to calculate the RAS actions. This leads to the classification of the required data into two categories: high-speed and low-speed data.

1) High-Speed Data

The communication and input voting logic required to detect contingencies (N events) are accomplished in less than 8 milliseconds. The output voting logic, communication, and contact closure required to energize the trip coils are accomplished in less than 9 milliseconds. The total loop time of the system is therefore less than 17 milliseconds. If the detection of a contingency is delayed, the power system may collapse into a blackout. A proprietary communications protocol was used for high-speed data communication. This protocol provides data with deterministic, 2-millisecond updates of digital I/O to the logic processing units.

2) Low-Speed Data

Low-speed data are processed every 200 milliseconds. These data are used in determining the power system state (J states), determining the appropriate arming levels, and calculating the remedial actions for all the predefined contingencies. Data from the EMS system, analog data, breaker statuses, and out-of-service conditions fall under this category. Once the arming levels and actions for each contingency are calculated, they are fed into a crosspoint switch (CPS). The high-speed input data are then cross-multiplied with the CPS to issue digital output signals (trips).

B. RAS Algorithm and Logic Processing

The RAS algorithm is shown in the flow chart in Fig. 4. The following subsections discuss the different sections of the RAS algorithm.

1) Two-out-of-Three Voting

All data inputs, control outputs, and internal data in each RAS go through two-out-of-three voting. Specifically, all input data (slow and fast) are voted, all internal computations are voted (slow and fast), and all outputs are voted (fast).

For example, in RAS C, there are three logic processors that run similar logic. The data are fed to all the processors, and the processors share the data between them. Processor 1 now has three sets of data, and it performs two-out-of-three voting. At least two sets of data need to agree for the data to be considered valid. Fig. 5 shows the two-out-of-three voting logic.

2) N Events

Any event in the power system that may require a RAS action is identified as an N event (contingency). The following

is the digital information (in order of preference) required to identify an N event:

- Line relay trip signals
- Fault severity signals (single-line-to-ground, phase-to-phase severe and nonsevere, and three-phase severe and nonsevere)
- Breaker auxiliary contact status
- Breaker disconnect switch status
- Lockout relay status
- Transfer trip receiver outputs

Not all of the above data are required for every N event. It all depends on what the end user can provide. Trip signals come first, because they are fast. The line loss status is then maintained for the breaker auxiliary contact status. All of the data required to detect N events must be high-speed data.

3) J State

Any event that changes the configuration of the power system is identified as a J state. Most N events become J states in the RAS after a fixed amount of time. For example, a

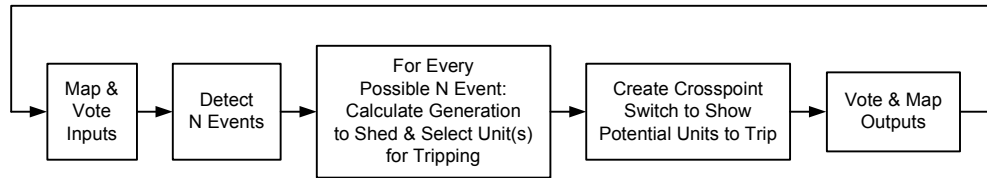


Fig. 4. Basic RAS Algorithm

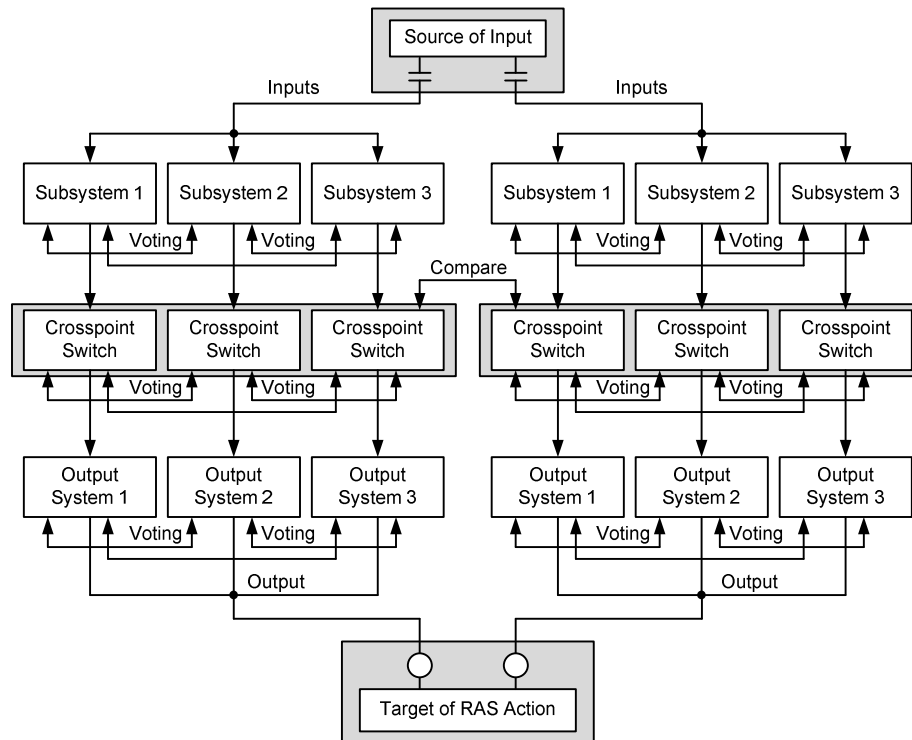


Fig. 5. Two-out-of-Three Voting on All Data

remote phase-to-phase fault on the Jim Bridger – Borah line is an N event. This N event becomes the J state that the Jim Bridger – Borah line is out of service. But J states are not limited to just N events. The outage of each power network element that is critical to the flow of power from the Jim Bridger Power Plant to the west is a J state.

A change of a J state will not require a RAS action but will change the configuration of the power system. Other examples of J states are the outages of synchronous condensers, transformers, shunt capacitors, and transmission lines. J state data do not need to be high speed.

4) *System State*

The combination of J states is called a system state. For example, in an instance when there are two lines open and a capacitor is out of service, three J states are identified in the system. These three states converge to a system state, and this system state determines the limits of the system. In other words, the system state actually mimics the present condition of the power system. The RAS uses the system state to determine which gain constants need to be used in the action-determining calculation.

5) *Arming Level and Generation-to-Shed Calculation*

The RAS uses the arming level equation and calculates up to 64 arming levels every 200 milliseconds. The arming level equation is basically a polynomial equation that uses measured real and reactive power generation (local inputs), compensation level of the 345 kV lines (remote inputs), several path flows (local and remote inputs), and eight gain factors that define system sensitivity. Data are gathered from local and remote systems, and all the J states that are active in the system are identified. The identified J states are mapped to a new system state. This system state identifies which gain factors need to be used in the arming level calculation equation. A total of eight gain factors can be loaded from a lookup table, and there are four lookup tables that represent each season (spring, summer, autumn, winter). These gain factors define the system sensitivity to each component in the arming equation and are developed from system studies.

6) *Generator Selection Algorithm*

The arming level calculation logic calculates an arming level for each contingency. This arming level will be used in the generation-to-shed calculation equation (1) for each contingency, which results in a generation-to-shed value for each contingency. The values will be zero if no generation needs to be shed. For all values greater than zero, the generator selection algorithm will determine which of the four generators needs to be shed. Operators are given preference in selecting units to shed. If no unit is selected by the operators, the algorithm will select the optimum units. At any point of time in one scan, the RAS is allowed to trip only two units. This restriction prevents the RAS from tripping all the units for contingencies detected in one scan.

The following is the generation-to-shed calculation equation:

$$G = K_{nj} \cdot (F_{nj} - AL_{nj}) - X \tag{1}$$

where:

- AL_{nj} = calculated arming levels from previous logic.
- K_{nj} = coefficient that changes with facility outage and fault type. These are predetermined values that reside in a lookup table. In most cases, the value equals 1.
- F_{nj} = either net Jim Bridger generation or net Jim Bridger flow, which depends on the preexisting outage combination *j* and fault type *n*. The selection of Jim Bridger generation or Jim Bridger flow is predetermined by system planning.
- X = generation dropped by the RAS in the last 5 seconds.

7) *Crosspoint Switch*

The CPS is the final result of the RAS algorithm. The CPS shows the N event and the actions. The results from the generator selection algorithm are used to populate the CPS. The CPS is preloaded and will give operators information on how the RAS is going to respond for each contingency. As soon as an N event is detected, the RAS knows which actions it needs to take and triggers the actions. Fig. 6 shows a typical CPS.

		Ns															
Actions		N ₁	N ₂	N ₃	N ₄	N ₆₄
Trip Gen1	I ₁	X			X									X			
Trip Gen2	I ₂		X		X							X					
Trip Gen3	I ₃							X			X						
Trip Gen4	I ₄		X					X									
.	.	X			X												
.	.		X								X						
I ₁₆	I ₁₆	X						X									

Fig. 6. Crosspoint Switch

8) *RAS Logic Processing*

The logic processing in the RAS controllers is done as multithread processing, which provides flexibility in dividing the tasks into groups, based on how fast they need to be computed. This also makes the RAS algorithm deterministic and prevents time-consuming tasks from delaying the RAS actions. The RAS algorithm is arranged into three schedulers: 1-millisecond, 8-millisecond, and 1-second tasks.

The Jim Bridger RAS has dual primary systems running in parallel. The two systems are independent of each other and come up with their own trip remedial actions. Theoretically, both systems are running the same logic, and if all communications paths are good and the data fed to both systems are the same, the decisions of both systems will

match. However, in foreseeable situations, the decisions made by the RAS Systems C and D may be different due to the following reasons:

- The analogs are fed from different transducers and have measuring discrepancies.
- There can be failed communications paths or equipment that may force a RAS to make a different decision.

VII. SUPERVISION SYSTEM

The analog differences seen in each RAS can cause each RAS to come up with different decisions for a contingency. This is especially dangerous because different decisions increase the chance of shedding more generators than required. To overcome this problem, a supervision system was designed to monitor the crosspoint discrepancies between the systems. In the case of discrepancies, the supervision system will assess the overall quality indicators of the system and decide which RAS should be allowed to operate. The quality indicators are the weighted average of the system communications and hardware alarms. Primary and backup supervision units are designed for redundancy and use different technology hardware, software, and communications protocols to further ensure reliability.

Testing has shown that the RAS systems quite often come up with different decisions, caused primarily by analog transducer scaling discrepancies. This is especially frequent as analogs create arming levels around preset tripping thresholds. Note that direct digital communication to the power measurement devices eliminates many of these problems.

VIII. MULTIPLE N EVENTS AND CLOSELY TIMED EVENTS

There are two special logic timers used in the RAS logic. Any contingency that happens in the power system creates a disturbance. For example, a line is tripped. Due to this line loss, the power is redistributed across different paths, or there are power swings, causing the gathered analog data to fluctuate as the power system settles towards a steady-state condition. During this time, if the gathered analog data are used in the arming level calculation, it may result in poor-quality decisions. To prevent these disturbances from affecting RAS decisions, all generation-to-shed values calculated prior to this event are frozen for a certain period of time, in this case, 5 seconds. At the end of the analog freeze, the N events are transitioned to J states. If a second event happens during this time, the timer is reset, and the 5-second counter starts again.

If the CPSs in RAS C and D are different, the supervision system decides which system is allowed to operate for the next contingency. However, it takes around 12 milliseconds to send the CPS to the supervision unit and receive a decision from it. During the 12 milliseconds after the first contingency, the RASs can have different CPSs, which may lead to different decisions if a second contingency happens in this 12-millisecond window. The closely timed event logic is used to prevent these cases. Once a first contingency (that sheds

generation) happens, a 16-millisecond timer is started. During this timer duration, if a second or additional events happen, all of these events are queued and evaluated at the expiration of the timer. This gives the supervision unit enough time to evaluate the CPSs, make a decision, and prevent the RASs from making different decisions for closely timed events.

IX. FAST RECALCULATE ALGORITHM

If an event happens and a line is tripped, the RAS detects the contingency, verifies the generation-to-shed values, and trips a generator. The 5-second timer starts, and the generation-to-shed values are frozen. If, after some time (e.g., 100 milliseconds), the RAS detects another contingency, it will overtrip if it does not take into account the loss of line and generator tripping that happened during the last scan. This is because the generation-to-shed values are frozen and have not yet updated. They are waiting for the 5-second timer to expire. The fast recalculate code is designed to address these issues.

As soon as a contingency is detected, if the RAS detects another contingency in the next 5 seconds, the fast recalculate code is run, which modifies the generation-to-shed values based on how much generation was shed for the previous contingency. X in (1) serves this purpose. It deletes the generation shed by the RAS in the last 5 seconds, yields fewer generation-to-shed values, and prevents overtripping.

X. GRAPHIC INTERFACES

A. RAS HMI

The RAS HMI runs on a substation-grade computer. Although it is designed to run continuously, it is not necessary for the RAS to operate. The HMI is only necessary for changing the settings used for the RAS computations. These settings are stored in nonvolatile memory in the individual RAS controllers, making the RAS operations independent of the HMI.

The RAS HMI station serves as the user interface to all RAS controllers and subsystems. The functionality includes:

- Status display of live power system data on a summarized one-line screen.
- Status display for every system input and output, including data shared through the EMS system.
- Ability to change and view adjustable settings and gains loaded in the RAS controllers.
- Real-time view of the CPS matrix that shows the action to be taken for every contingency.
- Communications and alarm screens that reflect current device and communications alarms.
- Sequence of events (SOE) gathering, archiving, and viewing.
- Historical alarm and event viewing. The event files can be played back to the RAS through the test simulator.

The HMI collects data from all six RAS controllers and the four EMS interfaces. Screens exist to view the data individually for verification that they agree and to view the one-line screen that reflects the system status as determined by the

two-out-of-three voting logic. The data set for the one-line screen is picked by the same algorithm that is present in the supervision logic. The one-line and I/O screens are critical for factory acceptance testing, site acceptance testing, and commissioning purposes, because they provide visual verification of what occurs during each test.

Due to the immense amount of data required to fill the system adjustable gains, a database file was created to hold these large matrices. There are eight matrices that are of the dimensions 64 x 1,000 x 4 (256,000 gains) and several other matrices of smaller sizes. When edits are made to any one of the 256,000 gains, the controllers detect that new settings are available and issue a signal that the loaded settings are old. At this point, the database file is compacted into several binary files; these files are then transferred to the RAS controllers at the operator's request. These binary files are stored in non-volatile memory on the RAS controllers and are viewable in tables through the HMI.

Each RAS controller creates SOE logs, event report logs (oscillography), and OPC (Object Linking and Embedding [OLE] for Process Control) alarm tags. There are two main ways to view alarms on the HMI: through the communications and alarm screens (OPC point) and through the SERviewer Software (SOE logs). The communications and alarm screens show the active state of major device, communications, and diagnostic alarms. If an alarm clears but was not acknowledged, there is still an indication that the alarm was not viewed by an operator. The SERviewer shows all alarm points time-stamped as to when any changes occurred. All data in the SERviewer are time-stamped with 1-millisecond accurate resolution.

Event reports are in a flat file format, similar to COMTRADE format. Event report viewing on the HMI is performed using special software that displays all digital and analog information before and after each event. The event report logs contain the status of every I/O point in the RAS, sampled at 2-millisecond intervals. The event report logs contain data for 2 seconds prior to each event and 4 seconds after every event. This allows for easy diagnostic evaluation of what occurred during the event. Also, the event file can be replayed to the RAS from the test simulator.

B. Simulator HMI

The simulator HMI has two modes of operation: operator controlled and file playback. The operator-controlled mode allows the user to interactively change any digital or analog system input from the default value. The user can then trigger a contingency and observe the results on the RAS connected to the simulator. File playback allows user-generated files or actual event reports from the RAS to be fully simulated. This allows the RAS gains to be easily adjusted for desired operation.

Additionally, the simulator has controls for biasing the analog values to test the voting logic. Discrepancies between the redundant analog inputs are the most likely source of differing inputs to the RAS, due to the maintenance required on transducers to keep them calibrated. The controls to bias

the inputs allow for skewing the analog inputs to each RAS subsystem. Running tests this way verifies that two out of three systems agree before an action is taken. Controls are also present to skew the analog signals between RAS C and D for verifying the supervision logic when testing both RAS systems.

C. Event and System Diagnostics

The RAS has complete diagnostic capability that automatically pinpoints any faults or errors within the system (hardware and software) to a failure location within a hardware device or a software module. Every N event, input, and output occurring in the RAS system is also tracked by these tools. All SOEs and event reports are saved as flat *.csv files and saved in nonvolatile, flash-type memory on the substation-hardened computers.

There are three types of diagnostic tools for these purposes:

- HMI displays. This is generally the first place to look. The HMI describes failures pictorially by color changes on the HMI screen. This provides a high-level view of the system. These data are provided through an OPC data link out of each controller.
- SOE logging and viewing. SOEs from both systems are simultaneously logged. These events are viewable with the SERviewer and are time-tagged at 1-millisecond accuracy. Alarms are given descriptions detailed enough to specify the faulted device or software module.
- Oscillography logging and viewing. These oscillography reports (event report logs) capture the system conditions monitored by the controllers. The reports are generated on the controllers and passed to the computers for long-term storage and viewing. These oscillography files have an identical structure to the event reports created by all of the protective relays used for fault discrimination in the RAS. For this reason, these log files are called event reports.

D. Sequence of Events Logger

The SOE logger contains raw, digital I/O, internal digital values of great interest in the controller, and all system alarms (e.g., data disparities, equipment failures). The SOE logger is responsible for detecting, identifying, and making available to file the SOEs of selected, critical variables. The main features of the logger include:

- Monitoring of up to 512 digital variables.
- Detection of up to 4,000 events per minute on a continuative basis with no data loss.
- Detection of up to 2,000 events over 160 milliseconds (simulation of a fault with clearance time of proximally 10 cycles) with no data loss.
- Visualization of the SOE file with the SERviewer or any text reader.
- Multiple SOE file creation when the end of the file is reached or problems are encountered during the writing process.
- Minimal CPU consumption.

E. Oscillography

Any N event contingency will cause an event report to be gathered. The event report records all control outputs, all digital inputs, all analog inputs (in engineering units), all data provided through the SCADA interface, the contents of the CPS, the J states, the current state, the arming levels, and the generation to shed. Some of the main features of the event report logger include:

- The event report library has the capability to store 320 Boolean values (10 DWORDS) and 64 analog (REAL) values.
- Each analog and Boolean quantity has a textual name associated with it. This name is saved in the event report file (*.csv). The analog and Boolean variable names are each limited to 15 characters.
- Each event stores up to 6 seconds of data. The 6-second time is a combination of the pre-event and post-event length.
- The CPU usage is minimal.
- The event report library is designed to log data every 2 milliseconds.
- The event report library has the capability to store at least five event reports triggered in a 2-millisecond time gap.
- The file written to the storage location is readable with off-the-shelf COMTRADE-viewing software.
- There is no limit to the number of files that can be stored on the substation computer. The limit is purely the maximum free space left on the compact flash.

XI. TESTING

A. Test Simulator

The test simulator was designed to play back power system events into one of the redundant RASs (C or D). Through a pair of interconnection panels and software interlocks, the test simulator can be isolated and connected to either RAS C or D. Because of the sensitivity of the RAS system to changes in gain files used in the RAS algorithm, it is necessary to test modifications in a fully functional, triple redundant system prior to applying them to a live system. The hardware and software designs implemented within the Jim Bridger RAS satisfy this requirement.

A playback simulator is used to easily simulate system conditions and events. This allows the creation of text files that contain analog and digital data reflecting specific scenarios to be sent to the RAS system. The files are sent through an algorithm that separates each value in time, thereby properly compensating for the communications delays of the various test simulator components. Several hundred playback files are then queued up for automatic playback, one after another. In this fashion, engineers can observe the reaction of the RAS algorithm to hundreds of different scenarios in a few hours.

The test simulator uses hard-wired analog and digital signals to communicate to the RAS. The test simulator also communicates to the RAS with serial links, emulating the

EMS DNP3 interface. All RAS and test signals are sent through an interconnect panel, which allows for easy insertion of the test simulator signals into the RAS. By using test paddles and isolation test blocks, the signals from the live power system are disconnected from the RAS while simultaneously inserting the test signals.

Once a contingency occurs, the RAS system records each event for a period of 2 seconds before and after the event, for a total of 4 seconds. By doing this, the RAS can capture key information within the event and place that data within a .cev file. This file is then sent to the main HMI, where it can be transferred back to the test simulator for playback. The file structure is exactly the same as those created by PacifiCorp engineers, as described earlier. In this way, each event recorded on the power system can quickly be played back into the RAS and observed with no interruption to the performance of the RAS. This allows PacifiCorp to quickly evaluate the control system response with new settings for all known and recorded events.

B. Project Execution

A primary design objective of the RAS was to allow future modifications to occur with little interruption to the performance of the RAS. The hardware design allows for interconnect panels so either RAS C or D can be disconnected from the live power system and reconnected to a series of simulated signals. This not only allows for quick changes to occur within the RAS but also for expansion and other maintenance corrections without taking the entire system out of service. With one of the two systems connected to the test simulator, there is still a triple redundant RAS operating normally.

The test simulator and dual RAS design proved very valuable during the validation phase of the project. Engineers were able to interact with both systems and observe all levels of performance within the RAS systems.

It was discovered during the design phase that a close working cooperation between PacifiCorp and the supplier's engineers was critical. Instant feedback for the specific requirements and performance of the RAS system proved to be valuable. It is important for the PacifiCorp engineers to have a full understanding of the algorithms and logic within the RAS. This understanding allows for timely analysis of events once the system is fully operable. Their understanding of the power system provided critical information that modified the design of the control system algorithms. It became possible to incorporate very specialized solutions to past problems with the existing system. It was necessary for PacifiCorp and the supplier's engineers to spend no less than two months working in close cooperation at one location during final software implementation of the RAS.

C. Quality Control

Several forms of testing were involved in maintaining a high level of quality and ensuring that the integrity of the complete RAS control system was upheld throughout the RAS development and implementation. Unit testing was completed within the software, hardware, and communications designs. This involved isolated testing to detect failures prior to

integrating the components into the system. Using a peer review process to fully inspect each other's designs allowed each component to assimilate into a compatible scheme.

A series of internal validation tests were then completed to ensure the integrity of the system as a whole. This involved pushing the system past the ordinary limits described by initial specifications and was effective at capturing potential failures that were unforeseen at the component level. This testing was immediately followed by external validation in the form of factory acceptance testing prior to delivery. This process was repeated several times throughout the project as problems and solutions were discovered.

D. Timing Results

The throughput time of the RAS system is less than 17 milliseconds; this is the measured total time from an input voltage asserting to 90 percent of full voltage to an output point fully conducting. This includes the time required to accomplish both I/O voting schemes. All output contacts are rated for tripping; therefore, interposing relays were not used. All contact outputs used are a high-speed, high-current interrupting design; this design closes an output in less than 10 microseconds and can interrupt up to a 30 A inductive current.

XII. COMMISSIONING

The process of commissioning a system of this magnitude is highly critical and involved many groups within PacifiCorp, including protection engineering, field service technicians, planning, operations, dispatch, communications, and technicians. Because of this dynamic, it was key to have a primary individual or small group of individuals responsible for the coordination of each independent group's efforts.

Once the system was delivered to the substation, the immediate task was to coordinate efforts from each group to allow the system to be integrated in parallel with the existing system. This had to be accomplished without interruption to the existing system.

A checklist was created prior to commissioning that systematically checks each input and output of the RAS. This ensures that each individual component is operable. Once this is completed, the previous functionality from the factory acceptance test will be preserved.

A one-time site acceptance test involving the test simulator connected to both RAS C and D was performed in order to again prove the functionality of the entire system. Because the system was designed with the test simulator flexibility discussed earlier, this was possible.

Careful steps were taken to avoid unnecessary generation shedding at Jim Bridger. Each and every item within the checklist contained a specific method for testing and was described within the commissioning documentation. By doing this, everyone involved could gain an understanding of the reasoning behind the process. Upon completion of the checklists, all parties signed their approval.

Communication between the RAS and the PacifiCorp EMS is another critical piece. Information regarding system alarms and history is provided to the EMS through four SCADA machines, and likewise, data from the EMS are passed to each of the four SCADA components. Commissioning these systems depends on first establishing reliable communications circuits between the source and destination of each circuit. It also relies heavily on any DNP3 protocol conversion and settings involved in the communication. There was a very high dependence on having a constant working relationship between the engineers and technicians out in the field and those involved with the DNP3 master.

XIII. IN-SERVICE PERFORMANCE

At the time of writing this paper, the Jim Bridger RAS was undergoing final site commissioning. Presenters will share their experiences on system performance during the presentation of this paper.

XIV. BIOGRAPHIES

Dean Miller is a principal engineer in Protection & Control Engineering at PacifiCorp and an adjunct professor at Portland State University, teaching a course on power system relaying. He received his Bachelor's degree in Electrical Engineering from the University of Idaho. During his 36 years at PacifiCorp, Dean has held a variety of positions in the engineering and operations organizations. He holds a patent in the area of distribution automation. Dean is a senior member of IEEE, an active member of the Power System Relaying Committee of IEEE, and a registered professional engineer in the State of Oregon.

Robert Schloss is an automation engineer for the Engineering Services Division of Schweitzer Engineering Laboratories, Inc. (SEL). Robert received his Bachelor of Science degree in Electrical Engineering from the University of Idaho and has been with SEL since 2004. He has experience in power system automation, specifically with remedial action schemes, load shedding, voltage control, and generation control.

Scott Manson is a supervising engineer for the Engineering Services Division of Schweitzer Engineering Laboratories, Inc. (SEL). He received a Masters in Electrical Engineering from the University of Wisconsin-Madison and his Bachelors in Electrical Engineering from Washington State University. Scott worked at 3M Corporation as a control system engineer for six years prior to joining SEL in 2002. Scott has experience in designing and implementing control systems for electrical utility customers, high-speed web lines, multi-axis motion control systems, and precision machine tools. Scott is a registered professional engineer in Washington, Alaska, North Dakota, and Louisiana.

Sai Raghupathula is an automation engineer for the Engineering Services Division of Schweitzer Engineering Laboratories, Inc. (SEL). He received a Masters degree in Electrical Engineering from the University of Idaho. Sai has been employed with SEL since 2004 and has experience in designing and implementing control systems for utility and industrial customers.

Trent Maier is an automation engineer for the Engineering Services Division of Schweitzer Engineering Laboratories, Inc. (SEL). Trent received his Bachelor of Science degree from Michigan State University and spent five years within the automotive industry prior to joining SEL in 2007. He has experience in control system design and application within power systems, conveyor systems, and robotics.

System Islanding Using a Modern Decoupling System

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System Islanding Using a Modern Decoupling System

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Abstract—The Gulf Petrochemical Industries Company (GPIC) plant in Bahrain produces ammonia, methanol, and urea. The GPIC process load is primarily steam driven; however, 24 MVA of critical loads are electrical, including the ammonia plant. One on-site combustion gas turbine is run in parallel to a connection to the local utility for a highly reliable power system configuration.

GPIC requires the ammonia and methanol plants to be islanded as soon as possible for external system disturbances. The loss of the ammonia plant for any reason leads to automatic shutdown of the entire petrochemical complex. The existing decoupling system misoperated once and had very limited system analysis capability. GPIC selected a new dual-primary redundant automatic decoupling system (ADS) to island their system for external system disturbances. Using the ADS, it is possible to analyze system events using the built-in tools of Sequential Events Recorder (SER) and event records, in addition to monitoring power system operating conditions. Since installation, the ADS has operated several times to island the GPIC system correctly for external system disturbances.

I. INTRODUCTION

Because of grave safety and financial consequences related to the uncontrolled shutdown of the Gulf Petrochemical Industries Company (GPIC) petrochemical facility, the critical loads are fed by a redundant power scheme. The GPIC facility uses a dual feed to the national grid owned and operated by the Ministry of Electricity and Water (MEW), as well as a 24 MVA combustion gas turbine (CGT) generator for redundancy. Either one of the feeders or the generator is capable of supplying the entire process electrical load. See Fig. 1; T114 and T115 are the redundant feeds, and MG6401 is the CGT.

The urea plant relies solely on power imported from the MEW national grid. The ammonia and methanol plants are normally fed from the CGT running in parallel with the grid connection. From a process point of view, the loss of the ammonia plant leads to the automatic shutdown of the urea plant. The electrical system is thus designed so that the loss of either the CGT or the MEW network is acceptable, but a loss of both sources results in the shutdown of the entire petrochemical complex [1] [2] [3].

The CGT has a history of sensitivity to disturbances in the national grid. To ensure the reliability of the GPIC network, a decoupling device was installed during the original commissioning of the complex in 1985. While only a single incident in a span of 22 years was attributed to the malfunction of the original decoupling device, GPIC proactively opted to replace the original device with a modern automatic decoupling system (ADS) that can cater to the ever-

increasing system disturbances emanating from the drastic expansion of MEW.

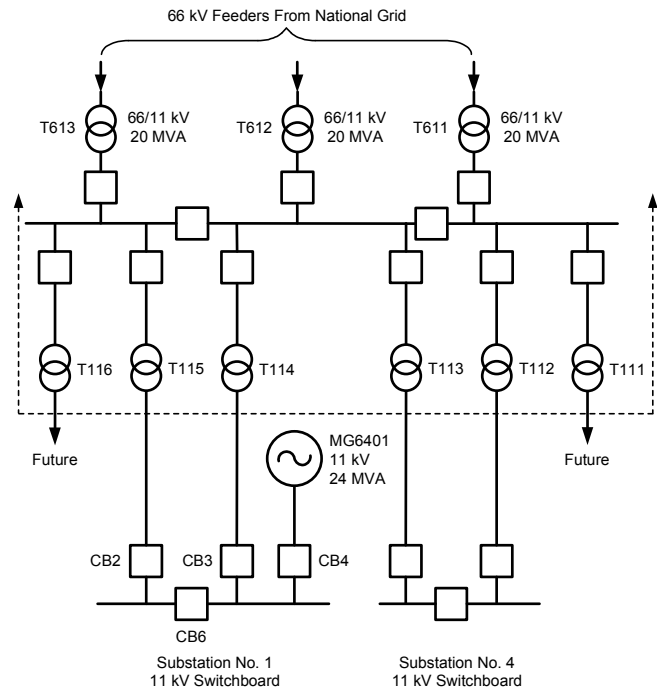


Fig. 1. Feeding arrangement to petrochemical complex

The new ADS isolates (or islands) the GPIC CGT from MEW during external system disturbances. The system uses several protection elements to achieve this goal. Each of these elements and devices is explained in this paper. The new, state-of-the-art ADS also added several engineering diagnostic features that enable both operations and maintenance personnel to quickly diagnose and understand an islanding event.

II. THE POWER DISTRIBUTION NETWORK

The single-line diagram in Fig. 1 shows the feeding arrangement to the petrochemical complex. The 11 kV switchboard in Substation No. 1 feeds essential loads at the ammonia and methanol plants. The switchboard is supplied via two feeders (T114 and T115) and a CGT (MG6401), any of which are sufficient to supply all the power required at Substation No. 1 (approximately 15 MW).

During normal operation, the gas turbine MG6401 supplies the bulk load while the two infeeds from the national grid are kept at 0.5 MW each. The net 1 MW import keeps the

frequency deviation and process disturbance minimal in case of an opening of the utility ties. A guaranteed import of power also makes selection of a reverse power element pickup quite simple.

The new ADS trips Circuit Breakers CB2 and CB3 at the Substation No. 1 switchboard, islanding the most critical loads in the plant. The ADS monitors the current and voltages at T114 and T115, calculates quantities required for analysis, and initiates a trip to island the GPIC system based on the quantities monitored at the interface point.

On the other hand, the 11 kV switchboard at Substation No. 4 provides electrical power exclusively for the urea plant and relies solely on power imported from the grid (approximately 10 MW).

III. CRITERIA FOR REPLACEMENT OF THE DECOUPLING DEVICE

The initial automatic decoupling device was commissioned together with the power network in 1985. The original device provided basic protection against the following:

- Directional overcurrent
- Undervoltage
- Underfrequency
- Delayed overcurrent
- Instantaneous overcurrent

In 2007, the old device was replaced for the following reasons:

- Several near misoperations
- No diagnostics for device health
- Need for reliable power source for the whole complex
- Obsolescence of spares
- Need for improved monitoring and alarms
- Need for improved maintainability
- Facilitation of fault and operation analysis

The old decoupling device did not provide any system operation details, event report analysis data, system alarms, or Sequential Events Recorder (SER) reports. In the absence of such functions, it is difficult to analyze any disturbances or the system operation. The old decoupling device also did not communicate to supervisory control and data acquisition (SCADA) for information or control. It was not capable of providing new protection functions, such as phase angle and rate of change of frequency (df/dt). With the new ADS and digital relays, the protection systems are time-synchronized and have automatic archival of events (with analog and digital signals), continuous SER monitoring, and remote SCADA monitoring and control.

In 2010, GPIC will replace the open-delta potential transformer (PT) on the 11 kV switchgear with three-phase PTs. As part of this retrofit, the ADS logic has been modified to have the following:

- Directional overcurrent protection to isolate GPIC even faster
- Phase angle detection logic on a per-phase basis
- The ability to measure reverse power on each phase separately

More features were added to the logic for enhancements, such as enabling synchrophasors to detect df/dt and enabling a loss-of-potential feature to block all voltage protection elements in case of PT fuse failure conditions.

IV. HISTORY OF SYSTEM DISTURBANCES

System disturbances are common occurrences on the MEW network. The GPIC electrical system can become unstable or settle at a new set point after a disturbance is over. The GPIC system has a history of instability due to one or more of the following system disturbances:

- System fault
- Disconnect of any large load
- Trip of any large MEW generator
- Erroneous system operation or failure of control system
- Lack of reactive power (low system voltage)
- Reverse active power (low system frequency)

The disturbances are known to cause one or more of the following problems at the CGT and Substation No. 1:

- Unstable swing and out-of-step relaying trip
- Overwhelmed synchronous generator reactive power capability
- Machine overspeed/underspeed
- Turbine thermal limit protection
- Underexcitation
- Unnecessary motor load tripping
- Machine vibration trips

Some disturbances may also result in local plant mode, interarea mode, or control mode oscillations if corrective action is not taken. The GPIC system is connected via high-impedance, step-up transformers to the MEW system to reduce the fault current in the system. However, this results in a very large phase angle difference between the GPIC and MEW electrical systems. A reversal of power on the MEW intertie therefore can exhibit itself as a significant disturbance to the CGT synchronous generator rotor angle, further exacerbating the disturbance seen by the CGT.

Fig. 2 shows the equivalent two-machine model of the GPIC and MEW systems. Simplified power transfer equations are also indicated in Fig. 2. Power transfer between the two systems is dependent on the angle between the two systems in addition to other parameters (i.e., system voltages and impedance).

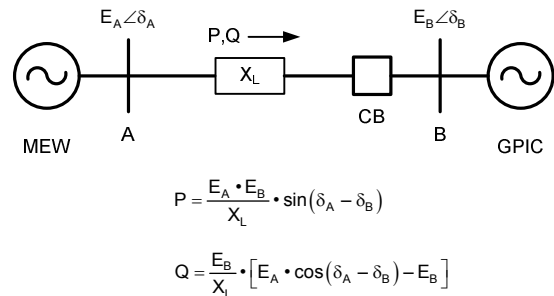


Fig. 2. Simplified two-machine model

Fig. 3 shows the power transfer at different machine internal angles.

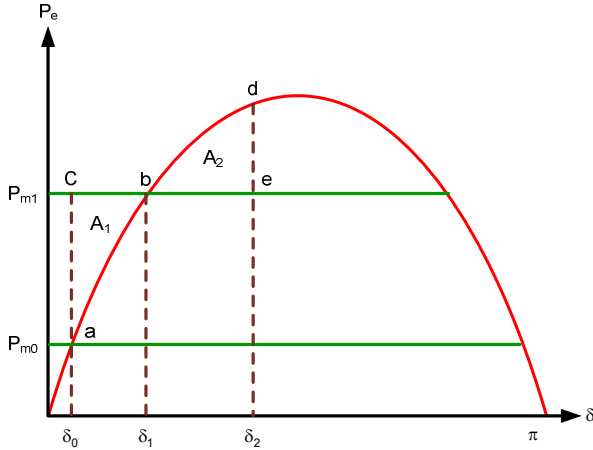


Fig. 3. Maximum power and equal area

The system may settle at a different stable point if the system configuration changes because of system disturbance and if the system is properly damped. If the system is transiently unstable, it will cause large separation generator rotor angles, large swings of power flows, and large fluctuations of voltages and currents. This eventually leads to a loss of synchronism, resulting in large variations of voltages and currents [4].

V. SYSTEM DESIGN

A. Communications Architecture

Fig. 4 shows the communication between components in the GPIC ADS. Decoupling relays 51A and 51B (microprocessor-based bay control relays) are identical in functionality. Each relay simultaneously performs decoupling protection for both breakers; therefore, this is considered a “dual-primary” protection scheme [5].

The ADS includes an engineering station (labeled “computing platform”), which provides a graphical interface to view sequence of event (SOE) and oscillography (digital fault recording [DFR]) of system disturbances, alarms, and decoupling actions. All SOE and DFR data are archived on nonvolatile flash memory in the engineering station. The DFR recorded protection data include sampled currents and voltages, status of input/output contacts, relay elements, relay settings, and programmable logic stored in the relay at the time of the event.

System parameters, including voltage, MW, MVAR, frequency, equipment diagnostic alarms, and incident alarms, are monitored via a Modbus® communications link to the SCADA master. All devices (computing platform, communications processor, 51A, and 51B) are time-synchronized to the IRIG-B satellite clock for accurate time stamps.

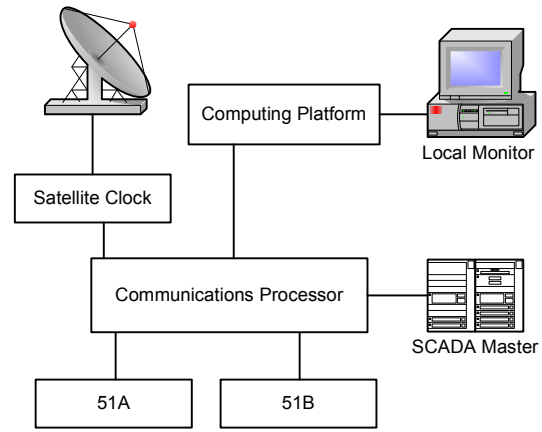


Fig. 4. Decoupling panel communications diagram

B. Protection Systems

The ADS provides system islanding based on the following elements:

- Phase angle deflection
- Reverse power
- Directional overcurrent
- Circulating current
- Undervoltage/overvoltage
- Df/dt operation
- Underfrequency/overfrequency

Both relays independently measure these quantities for both tie lines. The settings for each protection element are listed in Table I. Having three-phase PTs in the GPIC system allows for more sensitive settings of the phase angle element.

TABLE I
SETTINGS FOR THE DECOUPLING DEVICE

Protection Element	Alarm		Trip	
	Set Point	Time Delay	Set Point	Time Delay
Three-phase reverse power (when both breakers CB2 and CB3 are in service)	80% of trip	15 cycles	−1.0 MW	15 cycles
Three-phase reverse power (when only one of the breakers is in service)	80% of trip	15 cycles	−1.5 MW	15 cycles
Single-phase reverse power (when both breakers CB2 and CB3 are in service)	80% of trip	15 cycles	−0.5 MW	15 cycles
Single-phase reverse power (when only one of the breakers is in service)	80% of trip	15 cycles	−0.75 MW	15 cycles
Reverse overcurrent	No	No	65 A	10 cycles
Angle separation A-, B-, C-phase	6°	10 cycles	7°	10 cycles

As shown in Fig. 5, each relay has high- and low-side PT connections of both T114 and T115; this is for phase angle measurement. Now, a three-phase PT is available from GPIC and three-phase wye PT voltage from MEW. The phase angle set point is selected to detect the phase shift between GPIC and MEW on a per-phase basis. Phase shift due to wye/delta power transformers and load flow angle are also considered.

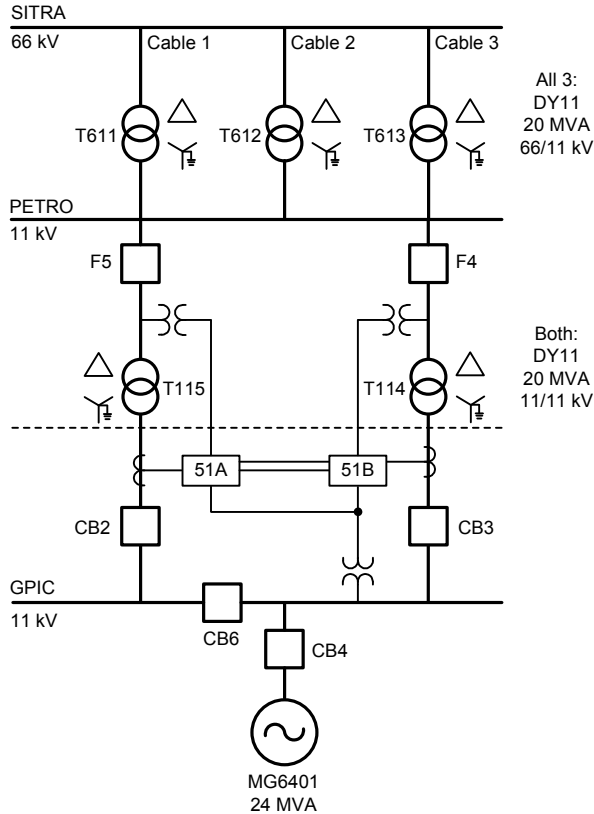


Fig. 5. New ADS for GPIC

Based on if one or both tie breakers (CB2 and CB3) are closed, different settings for reverse power are selected (refer to Table I). The reverse power protection function is blocked for 60 cycles after the operation of any main breaker within

the GPIC system, enabling the ADS to ride through any disturbances caused by GPIC.

Reverse power is assigned with two levels. GPIC can operate the system in two modes: when one interconnecting transformer (T114 or T115) at GPIC is in service or when both transformers at GPIC are in service. Reverse power flow monitored by the relay will be different depending on whether one or both transformers are in service.

Reverse MVAR is synonymous with circulating current protection and most commonly occurs during misoperations and failures of the load tap changer.

Tripping from the decoupling device is disabled when GPIC generation is out of service. Tripping is also wired in the block close circuit of GPIC Breakers CB2 and CB3. A trip to Breakers F4 and F5 indicates a trip to the MEW system, if MEW agrees to enable tripping based on the ADS. However, continuous monitoring of the decoupling device is also available to monitor and improve system performance by adjusting the settings. Protection logic is also programmed for the other protection functions using the freeform logic capability of the ADS.

Df/dt protection logic is set up with a combination of digital filtering and rated detection logic. No time delay was selected for the df/dt settings; rather, the filtering was adjusted to avoid spurious trips. Df/dt settings were selected to avoid system operation during system transients.

System trips and block close outputs from the relays are latched until manually reset by an operator, making the ADS act as a lockout relay.

Overfrequency protection is employed to decouple from MEW for a major loss of load on MEW. Df/dt detection was studied in detail for various system disturbances on the real-time system simulation.

Angle separation protection is the same as applying synchrophasor data to calculate the angle difference between GPIC and MEW in real time. With the advances in synchrophasor technology, it is also possible to calculate the damping factor and oscillation frequency using modal analysis to perform faster system islanding [6] [7].

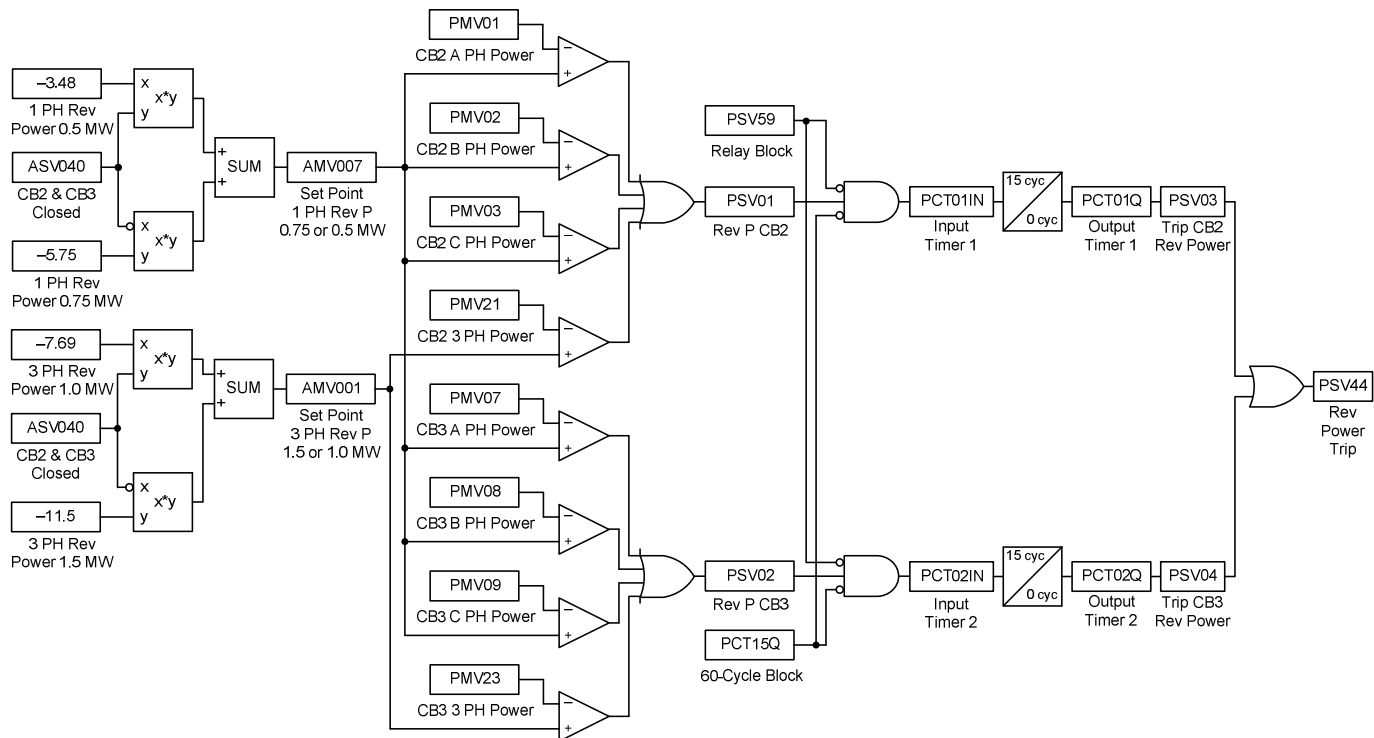


Fig. 6. Reverse power logic (refer to the appendix for terminology definitions and Section VII, Subsection C for a discussion of the selected settings)

Fig. 6 shows the reverse power logic for alarm and trip, programmed using the freeform logic capability of the ADS. For reverse power, the alarm set point is selected at 80 percent of the trip settings.

VI. SYNCHROPHASOR TECHNOLOGY

A. Introduction

Synchrophasor data allow us to determine the voltage and current phase relationship between multiple relays in different locations on a power system. Years ago, synchrophasor measurement capabilities were available only in standalone instruments called phasor measurement units (PMUs). In the last ten years, synchrophasors have become a standard capability of protective relays, meters, and recorders, as well as PMUs.

IEEE C37.118 has been widely accepted as the preferred method for exchanging synchrophasor measurement. Fast data rates are useful in observing the electrodynamic nature of the power system, such as power swings. Special-purpose computers called phasor data concentrators combine the streaming data from multiple sources to communicate the data to a central point for display, storage, or processing.

Locally, a system only needs a common time source, such as a clock, to synchronize all measurement devices. When more than one location is involved, Global Positioning System (GPS) clocks are a solution, because they can produce time signals accurate to a microsecond virtually anywhere in the world. Fig. 7 shows system voltages at different locations with the same time reference and provides a quick snapshot of the overall system.

In the future, the software installed on the ADS will provide a method to record and archive synchrophasor data in comma-separated value (CSV) and COMTRADE formats.

This software will be installed on the computing platform shown in Fig. 4 and will accept data from both the 51A and 51B protective relays, using IEEE C37.118 protocol.

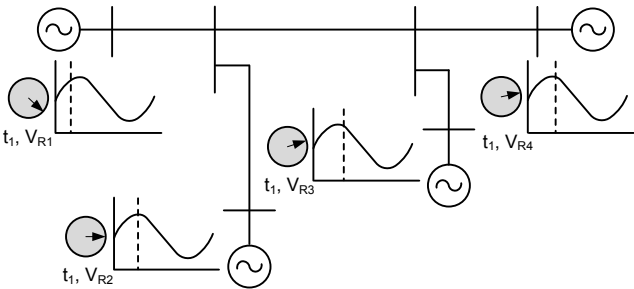


Fig. 7. Phasors with same time reference

B. Synchrophasor Future Application in GPIC

GPIC management wanted a future solution to monitor the MEW network voltage and frequency with a high sampling rate to identify and archive the sags and swells of voltage and df/dt . In addition, synchrophasor technology is also proposed to be used for future expansion of the GPIC plant, including new generation synchronization and control.

The proposed solution includes engineering station human-machine interface (HMI) screens to provide a snapshot of the GPIC system, as shown in Fig. 8. All relevant synchrophasor information will be automatically archived for future reference and any system disturbance analysis. This technology also provides continuous recording and archiving of df/dt .

The 51A and 51B relays have synchrophasors as a standard feature. Among many other signals, the synchrophasor df/dt element was configured to be recorded.

GPIC will use synchrophasors to monitor the MEW voltage waveform, and any sag or swell will be easily observed.

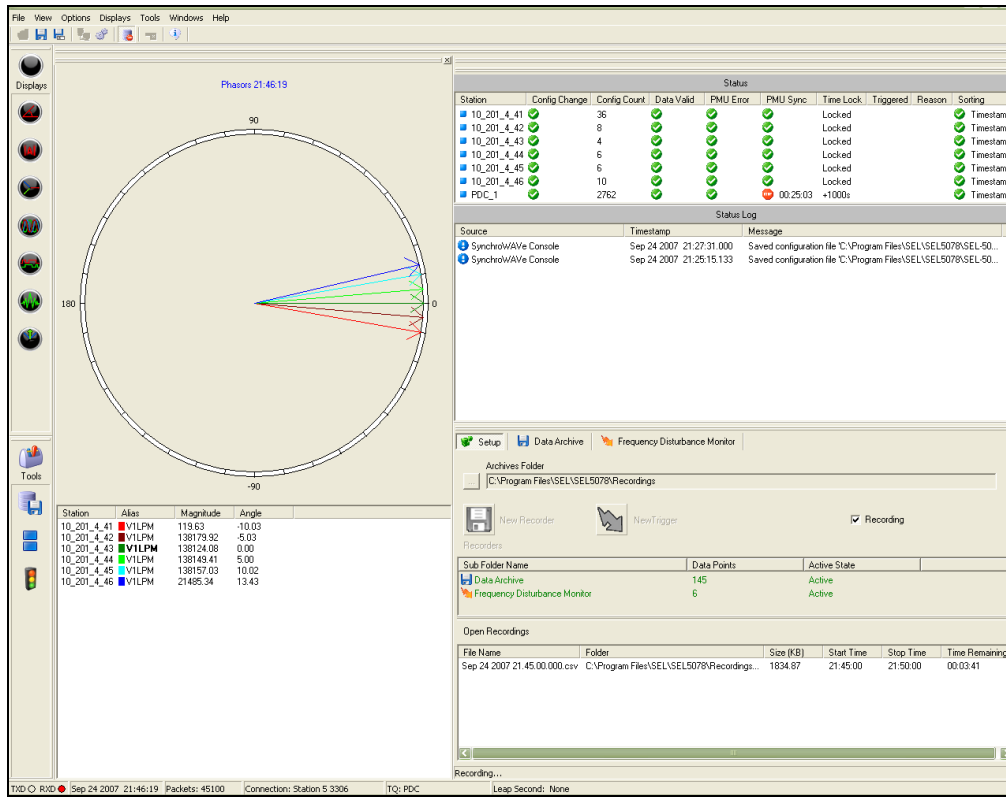


Fig. 8. Synchrophasor snapshot

These data will be continuously recorded, compressed, and saved to a CSV file, and the data can be sent to an existing SCADA system.

Slower data rates, such as once per second or even less, are easier to communicate and process and are useful in directly measuring the state of the power system. This is better than state estimation, because it is simpler, costs less, requires less processing, has no convergence issues, is less dependent on system data, and is faster.

VII. SYSTEM MODELING AND VALIDATION

The scope of work discussed in this section includes:

- Model development
- Validation of ADS operation
- Live modeling validation

A. Model Development

A detailed power system dynamic model was prepared for the GPIC and MEW systems. A summary of the dynamic simulation model for the ADS is shown in Fig. 5.

Fig. 9 illustrates the GPIC and MEW system model built into the real-time digital simulation system. There are several generators in the MEW system near GPIC that require detailed simulation in the dynamic model. Two generators in MEW, G1 and G2, are modeled with detailed exciter and governor models. The G3 machine is modeled as the equivalent machine to represent the rest of the MEW system with an appropriately large inertia. The GPIC machine MG6401 is also modeled with detailed exciter and governor models to represent actual system operation. Equivalent loads L1 and L2 at the local bus and L3 and L4 at the GPIC bus are modeled as

lumped static and induction motor loads. Large motors at the GPIC bus are also modeled independently.

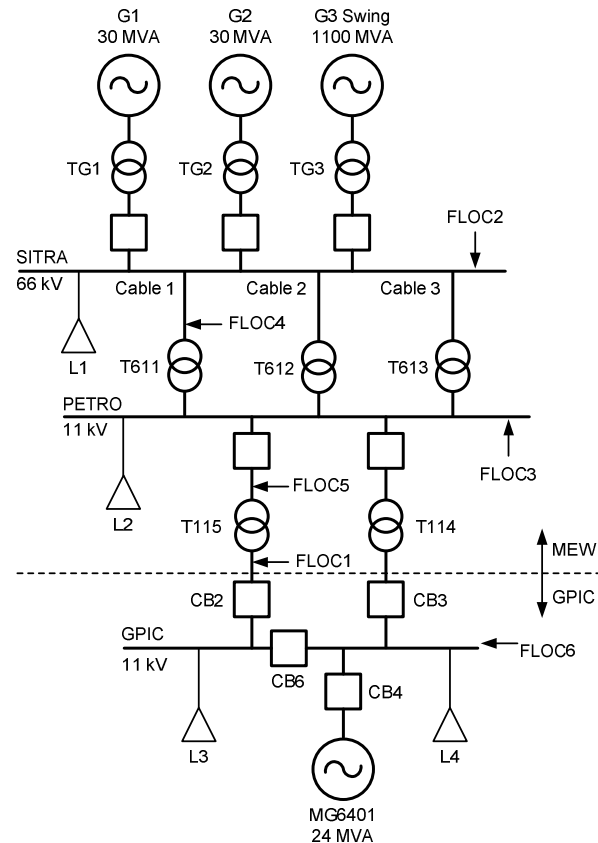


Fig. 9. Simplified model of GPIC and MEW

66 kV Cables 1, 2, and 3 connect the Sitra 66 kV bus and Petro 11 kV bus via 66/11 kV transformers T611, T612, and T613, respectively. The length of these cables is more than 9 kilometers, making them a significant source of reactive power during normal operating conditions. Transformers T611, T612, and T613 feed the Petro 11 kV bus, which connects the GPIC substation via 11/11 kV T114 and T115 transformers.

The GPIC CGT governor operates in droop mode when the GPIC system is connected to the MEW grid. The governor changes to isochronous mode as soon as it is islanded from the MEW system. Governor mode control was accurately modeled and validated using simulations.

The CGT governor and exciter modeling were the most difficult (and critical) parts of system modeling and validation. To get governor and exciter tuning parameters to represent the GPIC system, a 50 percent step in load was utilized to evaluate the GPIC system response, including the exciter and governor. Fig. 10 shows the GPIC generator response for the step load, which was held on for 75 cycles. Final governor and exciter model performance was fine-tuned to match actual data gathered from several field step-load tests. The procedure used for data gathering and model assessment is outlined in a recent technical paper [8].

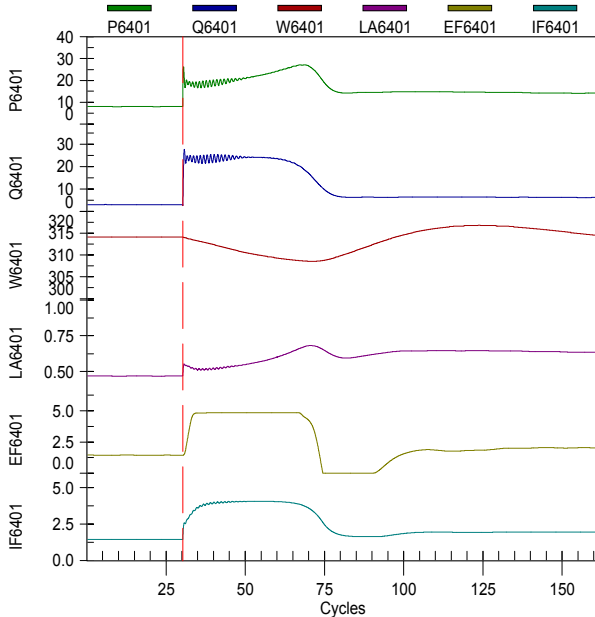


Fig. 10. 50 percent step load on the MG6401 generator

The CGT and associated mechanical fuel valves were modeled in a simplified manner. All major mechanical assemblies were modeled. Performance was validated against data from field step-load tests.

A full synchronous machine model (based on Park's equations) was used for the generator attached to the CGT. Parameters were from nameplate and manufacturer test data. Performance was validated against transient and subtransient short-circuit data from the machine manufacturer.

Transformers T114 and T115 were modeled as on-load tap changers to study the circulating current and reactive power. These transformers were modeled an equivalent of 16 taps

with a total voltage variation of ± 10 percent. The tap position of the transformers was changed to study the circulating current between the two tie transformers and select the settings for circulating currents; the automatic load tap changer algorithm was also included in the dynamic study.

The completed system model was validated using the following means:

- Governor and exciter model responses were compared against step-test data gathered from the field.
- Load flow data from the live facility were compared against steady-state conditions on the simulation.
- Short-circuit studies from several prior studies were compared against short-circuit conditions simulated in the live simulation system.
- Motor starting data from several prior studies were compared to simulated results.

B. Validation of ADS Operation

After model validation, the ADS was connected to the live, real-time modeling system. The ADS panel was tested by connection to the system modeling hardware, as shown in Fig. 11. The system operation was tested for faults at all locations, including tie lines close to the GPIC and MEW systems and for generation or load loss at GPIC/MEW, including possible system contingencies.

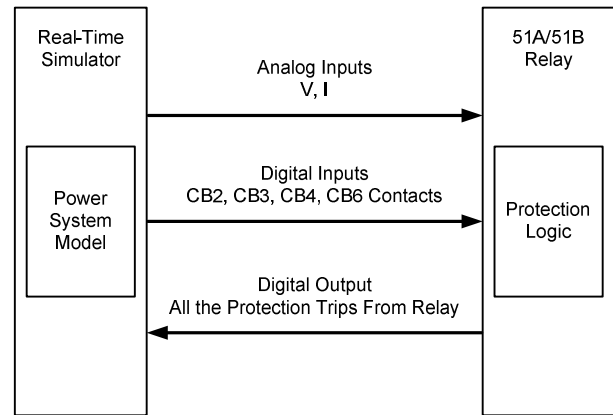


Fig. 11. ADS connected to real-time simulation for validation testing

Motor starts and trips at GPIC were simulated. Additional analysis was performed to determine the sensitivity of reverse power to avoid the decoupling system operation on reverse power for a major motor bus fault in the GPIC system.

C. Explanation of Settings

Undervoltage, underfrequency, and overfrequency were selected based on the history of normal operation for the MEW and GPIC systems. The selected settings were also coordinated with the existing settings of protective relays on the GPIC system.

Circulating current thresholds were selected based on an acceptable transformer tap difference between the two main incomer transformers, T114 and T115.

Phase angle separation was selected such that if the voltage angle between GPIC and MEW was greater than 10 degrees, tripping was initiated. Angle selection was based on the

normal operating point of 1 MW and the transformer impedance.

Normal, minimum, and maximum power flow and various possible system contingency conditions were tested using live simulation to ensure the system did not become islanded for normal system operation. A pickup time delay of 10 cycles was selected to ensure that the ADS allows primary protection systems in MEW and GPIC time to operate.

D. Live Modeling Results

This section is a shortened summary of the ADS reaction to several fault types. These data were gathered with the final settings shown in Table I. All data for this section were collected from the ADS while connected to the real-time modeling system.

Fig. 12 indicates the line-to-line fault at FLOC1 (Fault Location 1). All the fault locations that were analyzed for this study are shown in Fig. 9. The fault is an A-C (R-B) phase fault. The results indicate that phase angle and undervoltage (UV) operate and correctly island GPIC.

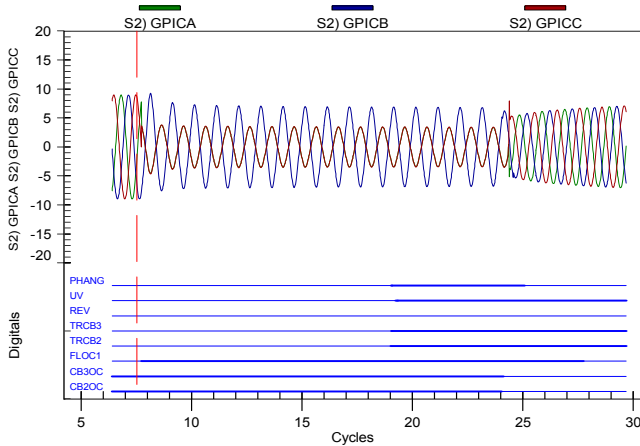


Fig. 12. FLOC1, line-to-line fault – PHANG (phase angle) and UV trip

This testing shows the ADS set points to be insensitive to the tripping of one 30 MW unit at the local MEW generation station. The pickup set points for all elements were selected for this criterion, because stability studies indicated that the GPIC system will survive this outage. The ADS will island GPIC for a loss of more than one unit at Sitra in the MEW system.

From the results of this study, it was concluded that the decoupling system will operate in less than 0.5 seconds for all fault conditions.

Note that primary protection should operate before the ADS for most severe faults. However, because the protection of the MEW is outside the control of GPIC, the ADS acts as a GPIC-owned backup method of preventing cascading outages, should primary protection fail.

VIII. GPIC DECOUPLING PANEL OPERATION DETAILS

The ADS has recorded and operated for several events since its installation in November 2007. The following is a summary of an event that occurred on March 5, 2008. On that day, the decoupling panel tripped the breakers (CB2 and CB3)

because of reverse power element operation. GPIC was islanded from an electrical disturbance on the MEW side.

Fig. 13 shows the waveforms and relay reverse power element operations for this event, where:

PSV01 represents reverse power CB2 start.

PSV02 is reverse power CB3 start.

PSV03 is reverse power CB2 trip after 15 cycles.

PSV04 is reverse power CB3 trip after 15 cycles.

PSV44 is reverse power trip.

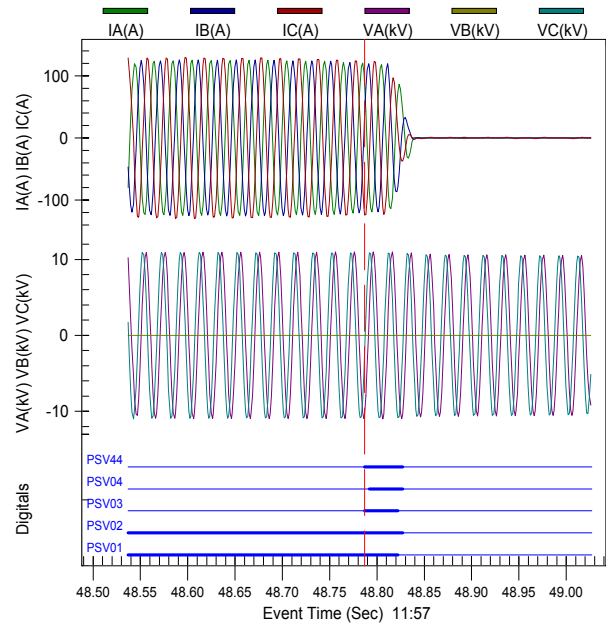


Fig. 13. March 5, 2008 event report

Fig. 14 shows the phasor diagrams of the voltages and currents during the events.

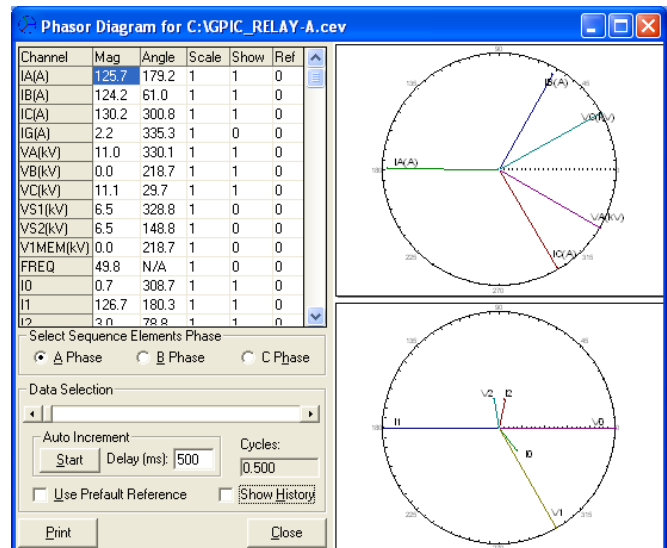


Fig. 14. Phasor diagrams showing voltages and currents

The event report details indicate the reverse power alarm and trip operations for Breakers CB2 and CB3. The reverse power alarms operated at 11:57:48:732 and 734. The reverse power trip for CB2 and CB3 operated at 11:57:48:787, and

relay LO asserted at the same time. Because the disturbance was in the external system, the ADS recorded reverse power flow on the tie lines. Because the alarm was selected at a lower setting, the reverse power alarm operated first, and then the reverse power trip operated. The ADS successfully operated and islanded the GPIC system for an external disturbance.

IX. CONCLUSION

This decoupling panel for GPIC was supplied in 2007, has operated several times, and has islanded the GPIC system correctly. The ADS has never misoperated, nor has any equipment failed. These successes are attributed to the use of ultra-reliable protection components, extensive modeling, and validation of system performance prior to system installation.

ADS testing provided critical insight into the system operation and set-point selection. Live system testing allowed engineers an experimental test bed to greatly refine set-point selections.

In 2010, the logic was modified, and the synchrophasor element was enabled to detect df/dt and monitor the utility network voltage waveform.

X. APPENDIX: TERMINOLOGY DEFINITIONS FOR FIG. 6

ALT	Automation freeform latch bits
AMV	Protection control equation math variables
AST	Automation freeform sequencing timers
ASV	Automation control equation variables
PCT	Protection freeform conditioning timers
PLT	Protection freeform latch bits
PMV	Protection control equation math variables
PST	Protection freeform sequencing timers
PSV	Protection control equation variables

XI. ACKNOWLEDGMENT

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XIII. BIOGRAPHIES

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Ahmed El-Hamaky is an application engineer with Schweitzer Engineering Laboratories, Inc. He received a bachelor's degree in electrical engineering from Cairo University, Egypt. Ahmed has extensive experience in the application of protection schemes for different voltage level substations, fault analysis, testing, and troubleshooting of protective relays.

Idaho Power RAS: A Dynamic Remedial Action Case Study

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Idaho Power RAS: A Dynamic Remedial Action Case Study

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Abstract—Two separate remedial action scheme (RAS) algorithms reside on a single set of hardware at a transmission substation located in Idaho. The substation is the terminus of three 345 kV, one 230 kV, and one 500 kV transmission circuits. This substation transports power from power plants in the Rocky Mountains to load centers in Oregon, Idaho, and Utah. When one or more of the high-voltage circuits are lost, overloading can occur on the remaining lines across the path.

The primary function of this RAS is to protect lines against thermal damage, while helping optimize the transfer across critical corridors. The secondary function of the RAS is to dynamically predict power flow scheduling limits on critical transmission lines and corridors.

Idaho Power Company contracted with a supplier to build a state-of-the-art RAS that can trip generation units, bypass series capacitors, insert shunt capacitors at remote substations, or take any combination of these actions. To most effectively determine which level of remediation should occur, a user-configurable set of action tables is used alongside a dynamic arming calculation. A user-configurable nomogram and logic are used for the simpler RAS for lines flowing into Oregon.

I. BACKGROUND

A. Introduction

As the demands placed on a power system grow, maintaining the stability, reliability, and security of the power system becomes a balancing act for engineers. As consumers, we continually find ourselves embracing more and more power-consuming technology, which increases demand for power and further stresses our installed infrastructure. Owners of electrical power transmission systems constantly juggle the need to build more power plants and transmission lines with how much they cost and when the right time is to invest those costs. Because it is so expensive to build more plants and lines to make our systems more robust, we need to operate the installed infrastructure closer to its operating limits and at higher utilization levels. It is a constant conundrum. Where and when do we spend money to operate systems at their most cost-effective levels?

Another inherent problem of highly stressed power systems is that they will degrade in an unrecoverable cascading fashion when certain significant events occur. The solution to this is millisecond-speed (subcycle) identification and control actions to keep the problems from growing larger, commonly referred to as a remedial action scheme (RAS) or special protection scheme (SPS). Without these schemes in place, permanent damage to electrical and mechanical power system equipment will happen. The more significant the event, the greater the potential damage and, therefore, cost that could be incurred.

The revenue dollars lost while system repairs are made further compounds such problems.

A RAS becomes a necessary and cost-effective solution when a power system is not robust enough to accept failures or outages of components without some subsequent response. When a primary protective relay system operates to protect individual components or portions of a power system, a RAS monitors the effect to the larger overall system. If conditions exist that are detrimental to the operation of the larger system or to adjoining systems, then actions are taken by the RAS to remediate the effects. A RAS is the safety control system that monitors and protects a larger power system from additional problems when something within the power system fails.

A fast (subcycle) RAS can double the power transfer capacity across an existing transmission grid [1]. Operating speed, determinism, expandability, processing power to run complex algorithms in milliseconds, and data capture for post-event analysis are key factors that need to be addressed in these schemes.

As shown in Fig. 1, the RAS supports loads served in Idaho and Oregon. Without the RAS in operation, it is generally necessary to lower the operational transfer limit (OTC) of the path when contingencies or operations and maintenance activities remove key lines from service. When demand is high enough and the RAS is in operation, the OTC does not have to be lowered. This allows Idaho Power Company and PacifiCorp to operate path flows (MW) at higher levels throughout the year. Both RAS algorithms meet the Western Electricity Coordinating Council (WECC) requirements, while allowing maximum power transfer across related paths during changes in the system topography.

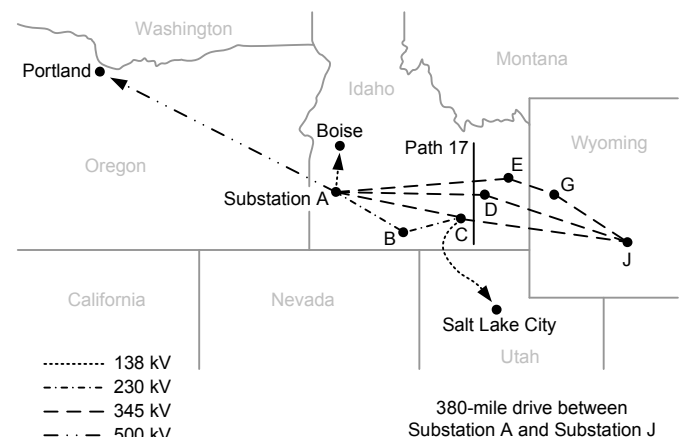


Fig. 1. Geographic area involved

The RAS system described in this paper cost a fraction of what it would have cost to build a new transmission line or to bring a new power plant online, allowing those major costs to be postponed. The RAS allows increased operating revenues during normal maintenance or repair operations and during emergency operations when key system components fail. It also allows Idaho Power Company to be good neighbors with adjoining utilities by preventing problems from propagating out into other systems. With the relatively small investment of the RAS, Idaho Power Company gains more secure and reliable operations, as well as higher utilization levels for key system components, resulting in higher profits and more cost-effective delivery of power to customers.

B. History

The RAS was installed to replace a series of aging and limited systems that worked independently to accomplish a similar, yet much more limited, generation-shedding scheme.

The previous RAS consisted of a collection of discrete contacts, power flow monitoring devices, timers, and tripping relays that had the ability to initiate a very limited response to a small number of conditions. The previous RAS had only two outputs, a Level 1 or Level 2 trip. It could only consider input on conditions from the local substation. It was not adaptive and had to be manually adjusted in order to respond to different system conditions. As such, its functionality and area of influence no longer matched the needs of the system. This initial RAS had to be manually disabled or adjusted whenever related lines were taken out of service for maintenance or repair. During those maintenance or repair activities, the flows across the monitored path had to be drastically reduced to safe operating limits, which translated to reduced revenues. Therefore, a new RAS was needed to meet all operating requirements and to optimize path utilization.

RASs are applied to solve credible single- and multiple-contingency (event) problems. RASs in the Western Electricity Coordinating Council (WECC) supplement ordinary protection and control devices (fault protection, reclosing, automatic voltage regulators, power system stabilizers, governors, automatic generation control, etc.) to prevent violations of the North American Electric Reliability Corporation (NERC) and WECC reliability criteria for Category B and more severe events.

The previous RAS did not meet current WECC design requirements, as outlined in the WECC "Remedial Action Scheme Design Guide" dated November 28, 2006. Also, when a RAS is in place, its operation must be monitored and analyzed to ensure proper response. When a RAS has to be taken out of service, the path flows need to be reduced to safe levels. If a RAS is found to have misoperated, it must be taken out of service and repaired or corrected within the described time frame. Otherwise, the RAS owner could face penalties and fines. These requirements are found in WECC Standard PRC-004-WECC-1 – Protection System and Remedial Action Scheme Misoperation, dated April 16, 2008. The WECC requirements mandate a more complex RAS with high

availability, continuous self-monitoring, and the ability to automatically capture data for later analysis.

The new RAS has the ability to monitor much more data and different classes of data inputs from very widely dispersed locations. It can rapidly consider changes to system data and make decisions and effect responses that mitigate further problems, while allowing optimized use of the system. This RAS senses when key system components are removed from service and automatically adjusts its responses as needed. This new system is also redundant, providing very high levels of reliability and availability. It is self-monitoring and captures time-stamped data for analysis and evaluation that are accurate to 1 millisecond. These captured data can be replayed in the original captured form back to the RAS via the playback simulator.

C. Cross Company Boundary Complications

Idaho Power Company owns the RAS equipment that is described in this paper, and is part owner of another RAS installed in Wyoming. The major transmission lines flowing into Oregon are owned by PacifiCorp, but they originate at a substation owned by Idaho Power Company. This cross company ownership of assets makes for a great deal of complication in a RAS. These RASs communicate together over hundreds of miles to form a cohesive control system. Both RASs were designed specifically to protect the interests of both companies.

II. RAS CONTROLLER REQUIREMENTS

A. Timing Requirements

The majority of the system is thermally limited, meaning that upon outages of key resources, overload conditions can occur on other resources. This requires a response time on the order of minutes.

Certain system contingencies for a portion of the system require remediation for voltage stability concerns. This requires a much faster response time. When the typical fault detection, communications time, and unit breaker opening time are excluded from the total time budget, the RAS is left with 20 milliseconds of operating time in which it must operate for certain contingencies. Table I shows the installed RAS throughput time, which meets Idaho Power Company requirements. The RAS total throughput time is the total measured time from an input voltage asserting to 90 percent to an output (trip-rated contact) fully conducting.

TABLE I
RAS TIME BUDGET

Item	Time (ms)
I/O module input debounce	2
I/O module output contact closure	0.01
RAS controller central processing unit (CPU) processing time	2
Communications transmit and receive signals	<8
Total throughput time	<12

B. Reliability Requirements

WECC design guidelines do not require absolute redundancy as long as the failure of nonredundant components does not result in the interconnected transmission system violating its performance requirements. Alternatives to redundant design can also be implemented as long as the resulting response meets system requirements. This is based on an evaluation of the consequences of nonredundant component failure. In most areas, the new RAS implements full redundancy. Some aspects are not redundant, but are monitored and alarm upon failure. All the RAS equipment was designed and hardened to operate and survive in a substation environment.

C. Functional Requirements

WECC monitors a transmission path that lies just east of a key substation. This substation, located in south central Idaho, is the terminus of one 230 kV transmission line and three 345 kV lines coming in from the east that bring power from one of the larger power plants in Wyoming. When one or more of these lines are lost, overloading can occur on remaining lines across the path. This RAS exists to protect against thermal damage to any of these lines, while helping optimize transfer of power across the path.

Much of the power from the power plant in Wyoming is then sent on to Oregon via another path monitored by WECC. This RAS monitors availability of and power flow on the related transmission lines flowing into Oregon. The RAS takes action as needed to maintain voltage stability and protect against thermal damage to underlying circuits in the event that one of those transmission lines open under particular conditions.

Under some circumstances, particularly the loss of the 345 kV lines, the 138 kV line can become overloaded. In order to alleviate overloads on these lines and keep overloads from occurring on surrounding transmission lines, it is preferable to open breakers at remote stations. A transfer trip signal from a thermal overload element programmed in a microprocessor-based multifunction distance relay on the overloaded 138 kV line is sent to the remote breaker that best alleviates the overload condition. This is incorporated into the communications infrastructure of the system.

Three existing RASs were replaced by the new RAS. These RASs performed the following actions:

- Generator dropping scheme for loss of the 345 kV lines.
- Generator dropping scheme for loss of the 500 kV line.
- Line overload RAS for the 138 kV lines.

The first of the three original RASs was initially installed in the 1980s, the last in 1995. Though they have been reliable and have served their purpose, they were very limited in design and were no longer able to meet current and future needs. These RASs were replaced with new, state-of-the-art redundant systems that improve the reliability and maintainability

of the transfer paths. This replacement project allows for optimized power transfers across both WECC paths during equipment outages.

The RAS was required to provide a set of fast, reliable, automatic controls to monitor power flow in the system components and monitor ambient air temperatures. The controls are also required to sense changes in the system configuration, determine the optimized response for maximum power transfer and minimum generation tripping, and transmit an output (such as a trip signal to the remote RAS in Wyoming) in less than 20 milliseconds from input detection to output trip initiation (total throughput time). The scheme needed to be reliable and secure with very high levels of availability.

Failure of this scheme to operate correctly could result in damage to the transmission lines, unnecessary tripping of generators, or expansion of disturbances into adjacent systems. Thus redundancy is implemented in this system.

D. Events and Actions

The N events or contingencies that can result in remediation being taken by this RAS are the following:

- The loss of one or more lines from service.
- An overload condition sensed in one of the monitored lines or transformers.

The control actions the RAS can take are the following:

- Add shunt capacitors.
- Bypass series capacitors.
- Shed generation at the power plant.

The RAS was designed to respond to multiple closely timed or simultaneous events; this functionality is key to the optimization of the system with this RAS control strategy.

Table II shows that the RAS logic is all performed at the main substation, whereas digital and metering status information is gathered at six remote substations and control actions are made at eight substations. Many of these substations are hundreds of kilometers from the RAS controller at the main substation. This makes for a system that depends heavily on communication.

TABLE II
SUBSTATION SUMMARY CHART

Substation	Detection	Logic	Action
A	X	X	X
B	X		X
C	X		X
D	X		X
E	X		
F	X		X
G			X
H	X		X
J			X

III. RAS DESIGN

A. System Architecture

Fig. 2 is an overview of the major systems in the RAS. Notice that the right side of this image is a mirror of the left side. This critical equipment duplication creates a system of two completely autonomous control systems; hence the system is considered dual primary redundant. Dual primary redundant schemes have no failover time because both RAS controllers are running at all times. This is in stark contrast to many of the failover or standby redundant schemes employed with outdated programmable logic controllers (PLCs). Dual primary technology is used extensively in transmission protection schemes in North America.

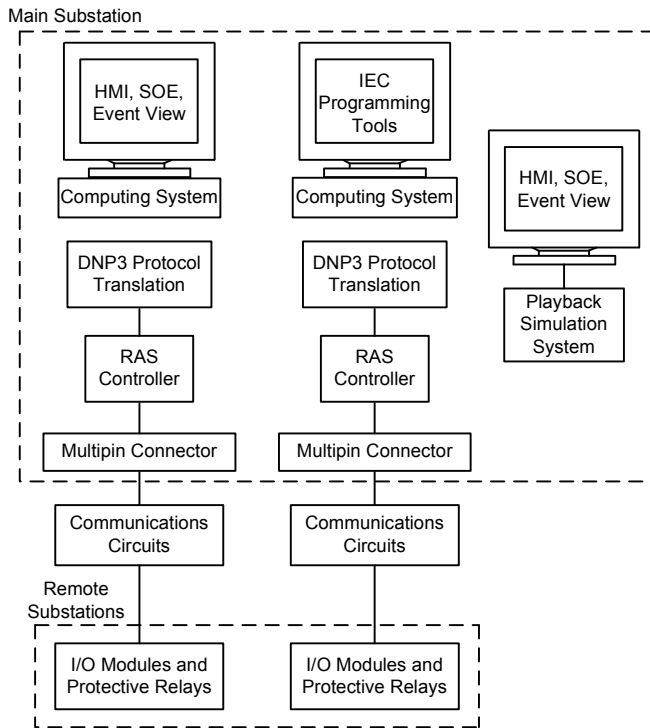


Fig. 2. System architecture overview

Within each RAS system, a single substation-hardened computer provides a user interface (human-machine interface [HMI]), sequence of events (SOE) viewing (SERviewer Software), and event report viewing (oscillography). Another hardened computer is used as an engineering workstation and contains the development environment for all hardware (including the IEC 61131-compliant programming).

Each RAS system (A and B) has its own protocol gateway for communication to the Idaho Power Company energy management system (EMS). These gateways communicate the necessary status, metering, and controls to and from the supervisory control and data acquisition (SCADA) masters via serial DNP3.

RAS Systems A and B are completely isolated on separate networks, and all logic on each system runs without any knowledge of the other system. The decisions taken by the two RAS systems are monitored by a supervision system. If the control actions are identical, both RASs are allowed to

operate. If the two RASs come up with different control actions, only the system with the best overall health is allowed to operate.

The router between the two systems is configured to prohibit all traffic between the two RAS systems. The router allows communication from each independent RAS system to the HMI, engineering workstation, and supervision systems.

Not shown in Fig. 2 is a multifunction playback test simulator designed to test the RAS in all system conditions. Modifications or improvements to the RAS can be tested easily by forcing one RAS to test mode and connecting it to a test simulator, while keeping the other RAS online.

B. SCADA Communications

The SCADA gateway systems function as the intermediary for receiving data from the PacifiCorp EMS that will be used in the RAS system calculation algorithms. These gateways are also used for providing data to the EMS regarding the status and operating characteristics of the RAS system.

The RAS can run autonomously from the EMS. This is because all data used by the RAS are provided through independent communications channels.

C. Rugged Design Characteristics

All hardware in the RAS is protective relay-class, substation-hardened equipment with extended temperature range, physical shock resistance, electromagnetic immunity, and static discharge capabilities.

The control algorithm resides on a substation-hardened controller running an embedded real-time controller engine. This engine is programmable in all IEC 61131 programming languages. There are no fans and no spinning hard drives in any equipment. All components run on the substation battery (dc). No ac power is used in the RAS panels.

All outputs used on remote I/O modules are hybrid Form A, trip-rated dry contacts; there are no interposing relays in the system. These outputs are therefore fail-safe (i.e., they remain open unless a tripping scenario has occurred). The hybrid outputs feature submillisecond closing times; this saves approximately 5 milliseconds on the total throughput time of the RAS. These hybrid outputs can also interrupt up to 30 A of inductive current while opening.

Additionally, every zone of the RAS hardware, communications system, firmware, and software contains continuous self-diagnostics. This guarantees the detection of a catastrophic failure of any component in the system. Every device in the RAS design has a normally closed, watchdog alarm contact that asserts if any device is powered down or has a hardware or firmware failure. These contacts are crosswired to other devices for monitoring, which guarantees that a failure in one device will not propagate further.

Communications systems are continuously monitored with protocols that detect the loss of a single serial packet. Additionally, watchdog counters are implemented on all programmable intelligent electronic devices (IEDs), then transmitted to other IEDs, and thus used to detect communications failures.

The logic, settings, and configurations installed on each hardware system are developed and tested to be fault tolerant, meaning that bad computations are intentionally rejected. For example, if a line metered value is out of range or comes from a failed device, an alarm asserts, and the logic declares that specific data as unusable. All logic, settings, and configurations are set up to automatically reject bad data and reselect available (good) data or default to a more conservative value.

A dual Ethernet communications network completely replaces the need for failure-prone, backplane technologies present in most industrial PLCs. The RAS system uses dual redundant Ethernet hardware and redundant communications lines to eliminate all single points of failure in communications between the EMS gateways and RAS controllers.

The result of these design decisions is a RAS that requires two carefully selected, simultaneous hardware failures to prevent RAS operation.

The design considerations for such RASs are nearly identical to those of the industrial power management and control systems regularly deployed by the supplier [2].

IV. RAS ALGORITHM

To make the RAS fast and deterministic, the RAS logic needs to be efficient. The RAS logic has two parts: data acquisition and RAS algorithm processing.

A. Data Acquisition and Communications Systems

Not all data used within the RAS need to be fast. High-speed data are needed to detect contingencies, whereas low-speed data, such as metering (MW) information, can be used to calculate the RAS actions. This leads to the classification of the required data into two categories: high-speed and low-speed data. This type of data segregation has been proven by the vendor to provide excellent performance on both large and small RASs, industrial load-shedding systems, generation control schemes, and automatic decoupling projects [3] [4] [5] [6].

Between the main substation and all remote substations, there are both high-speed and low-speed data communications streams. Making all the data high speed would require T1 or faster data connections; these were not available or necessary.

Both high-speed and low-speed serial lines are multiplexed together at the remote substation and then transmitted to the RAS over a variety of media, such as devoted fiber optics, leased lines, and microwave. Path diversity was used to reduce the likelihood of simultaneous communications failures to a single location. Statistical multiplexing satisfies the requirement of a fast, deterministic, high-speed data stream and simultaneously passes the large volume of low-speed data over a single low-bandwidth data communications line.

1) High-Speed Data

A proprietary communications protocol was used for high-speed data communications. This protocol is the dominant serial communications protocol used for pilot protection schemes in North America. At 19200 bps, this protocol

provides data with deterministic, 4-millisecond updates of digital I/O to the controllers. The protocol itself is built for operational security and therefore is an excellent choice for digital communication for a high-speed RAS. Because of its low-bandwidth usage, it works naturally with bridge multiplexers and microwave equipment. These high-speed data are used to detect N states and will be explained in detail in later sections.

2) Low-Speed Data

Low-speed data are processed every 200 milliseconds by the RAS. These data are used in determining the power system state (J states), determining the appropriate arming levels, and calculating the remedial actions for all the predefined contingencies. These low-speed data include data from the EMS, analog data (such as MW and MVAR), breaker statuses, and out-of-service conditions. Every 200 milliseconds, the RAS decides on the actions that must take place for each contingency, should it occur. These actions are fed into a crosspoint switch (CPS). The high-speed input data are then cross-multiplied with the CPS to issue digital output signals (trips).

B. RAS Logic Processing

The following subsections discuss the major components of the RAS algorithm logic.

1) Data Source Validation and Selection

Digital and analog data selections are accomplished by selecting the data that are deemed the fastest and most reliable, while filling an entire data set with one source. The data selection monitors communications failures with different levels of equipment to select the best data path available. In the RAS, the data are sent through two separate communications processors, as well as the EMS. The RAS operates with a single set of data for all decision-making processes. The single set is determined with this data selection logic. The data validation logic follows the data selection logic and is used to determine whether the analog data selected are valid. This is accomplished by comparing sets of data with those not chosen to ensure that neither is outside of a given threshold from one another. If a single value from two equally healthy data sources exceeds a 5 percent difference, the more conservative (larger) value is used for all generation-shedding calculations.

2) Detect N Events

Any event in the power system that may require a RAS action is identified as an N event (contingency). All of the data required to detect N events must be high-speed data. Two closely timed N events are treated as N-minus-two events, and the RAS is designed to take higher-level actions for these N-minus-two events. The RAS currently has 64 N states. With simple modification, it can be expanded to any number of N states. The following are some of the N states identified in the RAS:

- Substation D to C 345 kV line out
- Substation D to A 345 kV line out
- Substation A to C 345 kV line out

- Substation E to A 345 kV line out
- Substation C to B 230 kV line out
- Substation F to C 138 kV line out

3) J State

Any event that changes the configuration of the power system is identified as a J state. Most N events become J states in the RAS after a fixed amount of time. For example, a loss of a line is an N event. After a period of time, this N event transitions to a line-out-of-service J state. The following are some of the J states identified in the RAS:

- None (system normal)
- Substation E to C #2 345 kV line out
- Substation A to E 345 kV line out
- Substation C to A #1 345 kV line out
- Substation A to C #2 345 kV line out
- Substation C to B 230 kV line out
- Substation F to C 138 kV line out

A J state change does not require a RAS action but changes the configuration of the power system, which forces the RAS system to load a new set of gains into the arming level calculations. Other examples of J states include the outages of synchronous condensers, transformers, shunt capacitors, and transmission lines. J state data do not need to be high speed. The RAS is designed to accommodate 64 J states and, with simple modification, can be expanded to any number of J states.

4) System State

The combination of J states is called a “system state.” For example, in an instance when there are two lines open and a capacitor is out of service, these three J states are identified in the system. These three states converge to a system state, and this system state determines the gains used in the calculation of the arming level calculation. In other words, the RAS determines the power system state to categorize every combination of possible scenarios that can exist on the power system.

The RAS uses the system state to determine which gain constants need to be used in the action-determining calculation. A set of user-entered tables selects which system state comes out of each cross-combination of J states. With 64 J states, a total of 64! (64 factorial) system states are possible, but not all system states are valid or possible. Considering future expansions and valid states, a total of 1,000 system states is provided within the system.

The present system state identifies which gain factors need to be used in the arming level calculation equation. These gain factors define the system sensitivity to each component in the arming equation and are developed from system studies.

5) Arming Level Calculation

The dynamic calculation and action tables used for the RAS are a novel way of providing remediation to a power system under stress. These techniques add considerable flexibility and intelligence to the power grid and achieve a RAS throughput time of less than 12 milliseconds.

The arming level equation is basically a polynomial equation that is a function of ambient temperature conditions, local area load and generation, initial loading of the underlying 138 kV and 230 kV lines, compensation level of the 345 kV and 500 kV lines (remote inputs), and seven gain factors that define system sensitivity. The RAS uses the arming level equation and calculates 32 arming levels every 200 milliseconds for each N state identified in the system. These 32 arming levels calculated for an N state are associated with a unique index number that identifies a specific set of actions that need to be taken if that contingency were to occur. The 32 arming levels for each N state are arranged in descending order, and the current path flow is compared to arming levels for each N state. The arming level that is slightly below the current path flow is chosen, and the RAS is armed with the actions associated with the index number of the arming level for that N state.

There are a total of seven matrices that are of the dimensions 64 x 1,000 x 32 x 4. This adds up to a total of 57,344,000 gains, not including several other matrices of smaller sizes. Table III summarizes all the major matrices used in the RAS.

TABLE III
GAIN TABLE ARRAY STRUCTURE

Table	N State	J State	System State	I State
Action index	N/A	N/A	N/A	32
N actions table	64	N/A	N/A	32
N actions reference	N/A	N/A	1000	N/A
Kgins	64	N/A	1000	32
Kloadins	64	N/A	1000	32
Kgenins	64	N/A	1000	32
Kpre138ins	64	N/A	1000	32
Kpre230ins	64	N/A	1000	32
Ktins	64	N/A	1000	32
Kaconstins	64	N/A	1000	32
Two J lookup table	N/A	64, 64	N/A	N/A
PostXX	64	N/A	1000	32
Critical element table	64	N/A	1000	32
Miscellaneous settings	N/A	N/A	N/A	N/A

The RAS also calculates the OTC limit. This limit determines the maximum permissible path flow limit, while not exceeding the permissible overload on the parallel circuits under various overload mitigating actions, line outages, and system configurations.

The path OTC limit for each predetermined outage N and facility out of service J can be expressed by the following equation:

$$\begin{aligned}
 BW_{anj} = & K_{ganj} \cdot JB_{Gen} + K_{tanj} \cdot AT + K_{loadanj} \cdot \\
 & LALoad + K_{genanj} \cdot LAGen + K_{pre138anj} \cdot Pre138 + \\
 & K_{pre230anj} \cdot Pre230 + K_{constanj}
 \end{aligned} \quad (1)$$

6) Action Table Prioritization

The RAS implemented for the 500 kV line to Portland dynamically calculates 32 action levels that need to be satisfied for each of the preidentified events. These “I actions” consist of combinations of multiple control actions to restrict the system from not exceeding the permissible overload on the parallel circuits. Through the action table technique, the RAS optimizes various overload mitigating actions for all possible line outage and system configuration (system state) combinations.

Using the action table prioritization has many advantages. Its main advantage is to provide a larger number of possible remediating actions out of a handful of actual possible actions. For example, 10 total actions can provide 10! (3,628,800) total possible combinations of actions. This provides more flexible use of various assets, minimizes impact on the system and customers, and prevents over-remediation of events. Because the action table combinations are entered by the user on the HMI, they are easy to understand. Most importantly, this action table lookup technique provides a simple, elegant, and deterministic solution to a complicated problem.

7) Crosspoint Switch

The CPS is the final result of the RAS algorithm. The CPS is a two-dimensional array with indices of N events and actions. The results from the action table selection algorithm are used to populate the CPS. The CPS is loaded dynamically every 200 milliseconds by the RAS. The CPS gives operators information regarding how the RAS will respond for each N event. As soon as an N event is detected, the RAS knows which actions must be taken and triggers the actions. Fig. 3 shows a typical CPS.

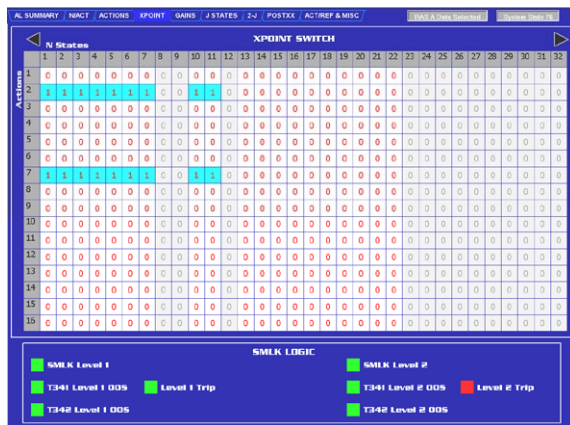


Fig. 3. RAS status screen—CPS tab on RAS HMI

V. MULTIPLE, CLOSELY TIMED EVENTS

There are several logic timers used in the RAS logic. Any contingency that happens in the power system creates a disturbance. Consider, for example, a line is tripped. Because of this line loss, the power is redistributed across different paths, or there are power swings causing the gathered analog data to fluctuate as the power system settles toward a steady-state condition. During this time, if the gathered analog data are used in the arming level calculation, it may result in poor-quality decisions.

To prevent these disturbances from affecting RAS decisions for closely timed N events, all values calculated after the first event are frozen for a certain period of time. At the end of the analog freeze timer, the N events are transitioned to J states. If a second event occurs during this time, the timer resets and the process repeats.

VI. RAS HMI

The RAS HMI runs on a substation-grade computer. The HMI is not critical to RAS operation; it is only necessary for changing the settings used for the RAS computations. A complete failure in the HMI will not affect the RAS functionality. All settings inserted by the user at the HMI are stored in nonvolatile memory in the individual RAS controllers.

The RAS HMI station serves as the user interface to all RAS controllers and subsystems. The functionality includes the following:

- Status display of live power system data on a summarized one-line screen.
- Status display for every system input and output, including data shared through the EMS.
- Ability to change and view adjustable settings and gains loaded in the RAS controllers. See Fig. 4 for an example.
- Real-time view of the CPS matrix that shows the action to be taken for every contingency.
- Communications and alarm screens that show the active state of major devices, communications, and diagnostic alarms.
- SOE gathering, archiving, and viewing. All data in the SERviewer Software are time-stamped with 1-millisecond accurate resolution.
- Oscillography event viewing. Event files are saved in a flat file format, similar to COMTRADE format. Equivalent to a digital fault recorder (DFR) in size and sampling rate, these files can be replayed to the RAS from the test simulator. The reports are generated on the controllers and passed to the computers for long-term storage and viewing.

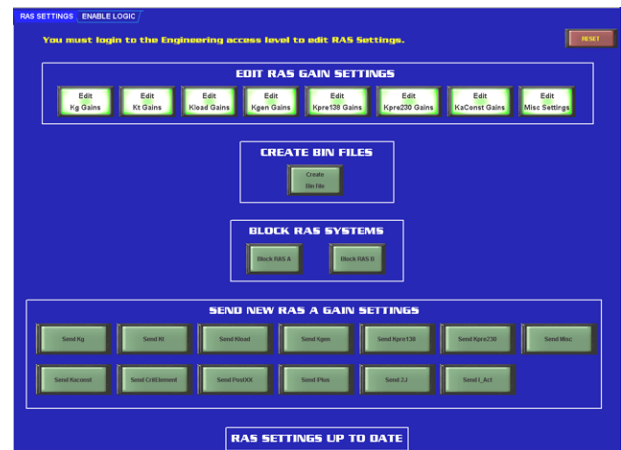


Fig. 4. Sample RAS HMI screen

Database files were created to hold the large number of gain matrices. When edits are made to any one of the gain matrices, the controllers detect that new settings are available and issue a signal that the loaded settings are old. These files are then transferred to the RAS controllers at the request of the operator.

VII. TESTING SIMULATOR

The dual primary systems (RAS Systems A and B) are independent of each other. This gives the flexibility to disable either RAS for testing or maintenance and keep at least one RAS available at all times. As shown in Fig. 5, the test simulator communicates to the RAS with serial links, emulating both the EMS DNP3, low-speed, and high-speed serial data streams.

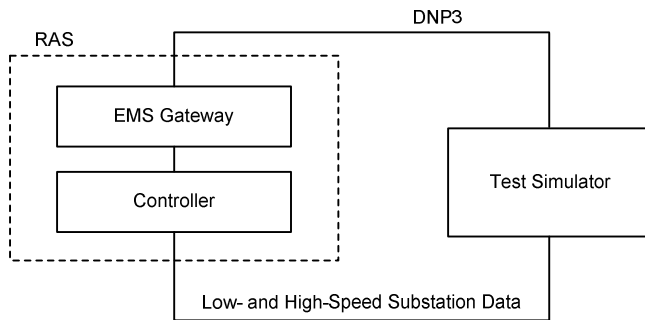


Fig. 5. RAS playback simulator

The test simulator for the RAS simulates all RAS external inputs, including digital statuses, control inputs, analog data, and DNP3 data streams. The test simulator contains an HMI user interface from which an operator can perform all system tests. The test simulator has the following two operating modes:

- **Static simulator.** This mode provides the operator the ability to drive each individual input to the RAS to a desired value. For example, the system configures EMS set points, set breaker status conditions, and detects generator trips from the RAS. This is extremely useful for testing all I/O points and creating any desired power system scenarios for presentation to the RAS controls.
- **Playback simulator.** In this mode, the simulator is used to replay one or more event report files to the RAS system. The simulator can play back real RAS system event report recordings of actual events. This was valuable during factory acceptance testing because playback files created by Idaho Power Company could be played back to the system. This is an especially valuable tool for a live RAS because it allows engineers to fine-tune RAS gains for desired operation, with no risk to maintaining power system stability.

Both RAS subsystems are connected to all field I/O through communications lines. For the simulator to actively interact with one of the RASs, large, multipin military-style

connectors are used to “unplug” the RAS from live field data and to “plug in” the simulator. When a RAS is connected to the test simulator, the RAS will not receive any inputs or send any outputs to field equipment.

The test simulator has a feature to hold several hundred playback files, which are then queued up for automatic playback, one after another. In this fashion, engineers can observe the reaction of the RAS algorithm to hundreds of different scenarios in only a few hours. This is extremely useful for factory and site acceptance testing.

VIII. CONCLUSIONS

The RAS was successfully commissioned in July 2009 and, with outputs disconnected, allowed to run in parallel with the existing RAS over a period of six months. The RAS responses to several events during this monitoring period were analyzed, and the system performed perfectly. Therefore, the RAS went live in November 2009.

The RAS is designed to allow future modifications to occur with little interruption to the performance of the RAS. The hardware design allows for RAS Systems A or B to be disconnected from the live power system and connected to a test simulator. This not only allows for quick changes to occur within the RAS but also for expansion and other maintenance corrections without taking the entire system out of service.

Considering the complexity of the RAS, it was identified that a close working relationship between Idaho Power Company engineers and supplier engineers was crucial. Idaho Power Company engineers spent nearly two months at a supplier site to fully test system performance. Idaho Power Company engineers brought site-specific experience to the factory acceptance testing, proving that all problems on the old RAS were overcome by the new RAS.

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X. BIOGRAPHIES

Michael Vaughn is a project manager for Idaho Power Company. Mike has a Bachelor of Science degree in Electrical Engineering from the University of Idaho and is registered as a Professional Engineer in the state of Idaho. Mike has 26 years experience working in the power/systems/facilities engineering realm working for the U.S. Air Force, Power Engineers, the Idaho National Laboratory, and Idaho Power Company.

Robert Schloss is an automation engineer for the Engineering Services Division of Schweitzer Engineering Laboratories, Inc. (SEL). Robert received his Bachelor of Science degree in Electrical Engineering from the University of Idaho and has been with SEL since 2004. He has experience in power system automation, specifically with remedial action schemes, load shedding, and generation control.

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Wind Farm Volt/VAR Control Using a Real-Time Automation Controller

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Wind Farm Volt/VAR Control Using a Real-Time Automation Controller

Michael Thompson, Tony Martini, and Nicholas Seeley, *Schweitzer Engineering Laboratories, Inc.*

Abstract—Wind generating facilities often require significant reactive power support to maintain voltage and power factor within operating limits prescribed by the transmission grid entity. Many installations include multiple stages of switched capacitor and reactor banks for this purpose. Coordinated control of these capacitor and reactor banks, which are often connected to the point of interconnection via multiple step-up transformers, requires a centralized control system.

This paper discusses a reactive power control system that utilizes a central automation controller to regulate both power factor and voltage at the point of utility interconnection. This controller includes the capabilities of a complete communications processor to exchange voltage, power flow, and status information along with control commands to microprocessor-based relays throughout the system. It also includes a powerful IEC 61131-3-compliant soft programmable logic controller (PLC) logic engine to execute the control algorithms. The system is easily adaptable and scalable to nearly any configuration.

The challenge when controlling both power factor and voltage is to prevent hunting due to conflicts between the two control requirements. An adaptive algorithm is utilized to deal with this challenge. The controller also includes a sophisticated sequencing algorithm to ensure that both reactors and capacitors are not in service at the same time, to optimize power factor through multiple step-up transformers to reduce losses, and to even out switching operations between reactive banks.

I. INTRODUCTION

Wind generating facilities often require significant reactive power (VAR) support to maintain voltage and power factor within the operating limits prescribed by the transmission grid entity that supplies the tie to the grid. VAR support is often provided by multiple capacitor and reactor banks connected to wind farm collector buses that can be switched in and out.

This paper discusses an integrated control system that utilizes a central automation (CA) controller to regulate both power factor and voltage at the point of utility interconnection. The control system measures voltage, active (P) and reactive (Q) power flow, and power factor and controls the multiple reactive power devices (RPDs) of capacitor and reactor banks.

II. OVERVIEW OF THE CONTROL SYSTEM

Fig. 1 shows a simplified single-line diagram of the system. The metering device measures power flow at the point that the facility ties to the utility system. It measures three-phase voltage and power factor (ratio of apparent power, S , to active power, P) at the point of interconnection (POI), as well as active and reactive power flowing towards the utility system. The transformer relays measure active and reactive power flow through the transformers. These measurements are used to optimize power factor, thereby minimizing losses through

each transformer. The RPD relays monitor positive-sequence voltage on the collector bus. The collector bus sensing is used to determine the status of the collector bus and to determine the expected ΔQ per step for RPDs connected to it.

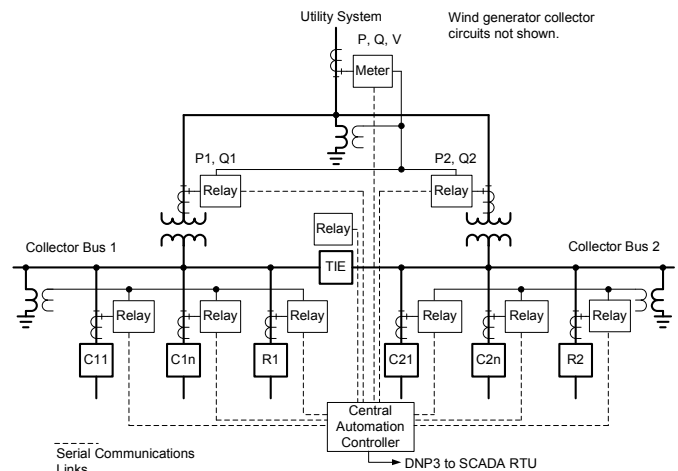


Fig. 1. Control system simplified one-line diagram

The functions of the CA controller and RPD relays are described in more detail in the following sections.

A. Central Automation Controller

The CA controller monitors and controls the relay for each RPD via a serial communications link. The CA controller analyzes the system status and sends control commands to each relay. The need to send control commands in order to add or remove RPDs is determined by a priority sequencing algorithm, which maintains the voltage between upper and lower limits and the power factor between leading and lagging limits. When either condition is out of band, the algorithm requests the addition or removal of an RPD. However, the control commands are supervised and reevaluated if the two measurements (voltage and power factor) are in conflict and it is predicted that a command to improve one will also adversely affect the other.

If the power factor and voltage criteria are in conflict, voltage control has priority. For example, if the facility is consuming too many VARs supplied by the utility, resulting in the power factor being out-of-band leading, the CA controller will want to add capacitors. But, if the voltage is out-of-band high, the controller will want to remove capacitors. Under this condition, the controller will remove capacitors to correct the voltage and let the power factor stay out of band.

A previous volt/VAR control system included logic to allow the voltage versus power factor priority to be user settable [1]. However, it was discovered that users always selected voltage priority, so that logic was not carried forward in this new control system.

Alarms are provided to indicate if the regulated parameters are outside of band limits. The alarms also assert if the regulated parameters are out of band but the CA controller cannot add or remove RPDs because there are none available to switch. The alarms are provided to the utility supervisory control and data acquisition (SCADA) system.

The controller also includes loss-of-voltage detection for each bank. When a relay senses dead bus voltage, the controller removes that bank from operation in the system.

B. RPD Relays

In addition to providing primary protection for the RPD or banks of RPDs, each RPD relay informs the CA controller of the status of its corresponding RPD(s). This information is used in the controller sequencing algorithm. If a relay receives a command to add or remove an RPD, it opens and closes its respective RPD breaker or RPD vacuum switch.

An RPD breaker must be in automatic mode before it can be available for automated addition or removal. The RPD breaker control mode is set to automatic or manual via pushbuttons on the relay front panel.

The CA controller monitors a timer in each capacitor RPD relay, which prevents a capacitor RPD from being available to add for a user-settable dead time (configured in the relay) after being removed to allow the capacitors to discharge.

III. OVERVIEW OF RPD CONTROL FUNCTIONS

A. Control of Reactive Power Supply

The reactive power supply at a facility is important to the reliable and economical operation of the power system. In many cases, utility system operators charge power factor penalties if a facility is consuming too much reactive power. Reactive power support helps control the voltage on the interconnected power grid. Increasing the VAR supply raises the local bus voltage, while decreasing the VAR supply lowers the local bus voltage. Voltage support is necessary for power transfer.

The VAR supply can come from dynamic sources, such as rotating machine excitation systems and static compensators (STATCOMs), or from static sources, such as switched capacitor banks. Often, there is a combination of these sources. External sources of reactive power are commonly required for wind generation—the primary application for which this system was developed.

The CA controller monitors voltage and power factor at the POI and regulates both parameters. As long as the two control parameters are not in conflict, either control function can add or remove RPDs.

B. Regulation Challenges

In the PQ plane, active power (P) and reactive power (Q) are quadrature components. The hypotenuse of the power triangle is the apparent power (S). For this application, one of the regulated quantities is the power factor (PF). PF is the ratio of P/S. However, the controlled quantity is discrete steps of Q. The step size is based upon the size of each switched RPD and the voltage on the collector bus. PF is a ratio, so at low active power flow, the ΔQ from one step can overshoot the opposite band limit, which would result in hunting. So, the power factor regulation limits must be modified as active power flow approaches zero.

Another complicating matter in designing the regulation characteristics is that the expected ΔQ from a switching operation varies by the square of the bus voltage. For this reason, it is desirable to measure the voltage on each collector bus so the controller can adjust its regulation characteristics based upon the actual expected ΔQ , instead of using the nominal VAR rating of the RPD.

For voltage regulation, the change in voltage (ΔV) associated with a step change in local VAR support is a function of the equivalent source impedance to that bus. High source impedance will magnify the rise associated with a step addition in reactive power.

Other devices, such as wind generator control systems or a load tap changer (LTC) on the step-up transformer, may also make control responses to regulate the voltage on a bus. The ΔV resulting from an RPD switching operation may cause a converse reaction in these other voltage control systems. For this reason, it is necessary to consider other control systems at the wind farm facility that may respond to power factor and voltage. Hunting may result if various control systems interact [1].

IV. ADD/REMOVE RPD LOGIC

A. Voltage Regulation

The CA controller uses the voltage read from the POI revenue meter and operator-configurable upper and lower voltage limits to regulate the system.

The upper and lower voltage limits are set by the user via SCADA. These values are in turn sent to the CA controller for use in selecting and blocking control requests. When voltage and PF are not in conflict and the voltage is out-of-band high, the controller removes capacitor RPDs or inserts reactor RPDs. If the voltage is out-of-band low, the controller will perform the opposite of the aforementioned operation.

B. Power Factor Regulation

Fig. 2 illustrates the power factor control characteristics in the P/Q plane.

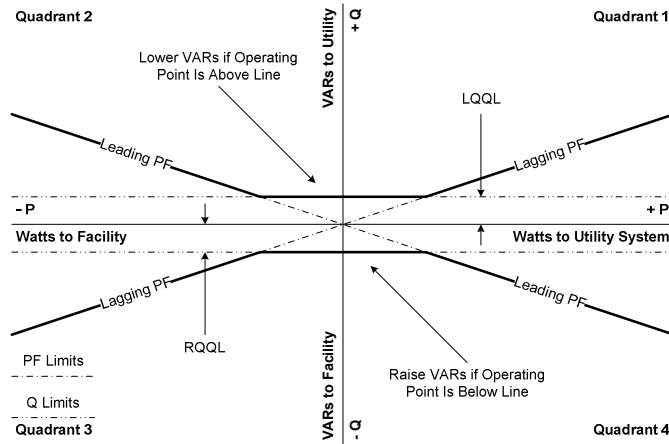


Fig. 2. Power factor regulation characteristic

The CA controller has separate leading and lagging power factor limits. The limit in effect depends upon the quadrant where the power system is operating. Because power factor is a ratio of P/S (active power over apparent power) and the controlled quantity is Q, the power factor band limits are cut off when the expected ΔQ overshoots the opposite power factor band limit. Equations (1) and (2) describe the limits.

$$LQQL = \frac{MAX\Delta Q_{NextAdd} \cdot Rmv \cdot Margin}{2} \quad (1)$$

$$RQQL = \frac{MAX\Delta Q_{NextAdd} \cdot Rmv \cdot Margin}{2} \quad (2)$$

where:

LQQL is the lower VAR reactive power limit.

RQQL is the raise VAR reactive power limit.

$MAX\Delta Q_{NextAdd} \cdot Rmv$ is the maximum ΔQ expected between the next RPD to be removed or added, per (3).

Margin is the ΔQ margin setting.

C. ΔQ Next RPD Step Function

The VARs supplied by an RPD vary by the square of the voltage at its terminals. The CA controller adjusts the nominal Q rating of the RPD based upon the measured voltage, as shown in (3) and (4). This is the value used to determine the expected ΔQ for the next RPD to operate. This value, shown in (5), is used in (1) and (2).

$$\Delta Q_{NextRmv} = VNR_{PU}^2 \cdot Q_{NOM} \quad (3)$$

$$\Delta Q_{NextAdd} = VNA_{PU}^2 \cdot Q_{NOM} \quad (4)$$

$$MAX\Delta Q_{NextAdd} \cdot Rmv = \max(\Delta Q_{NextAdd}, \Delta Q_{NextRmv}) \quad (5)$$

where:

$\Delta Q_{NextRmv}$ is the delta Q expected from the next RPD to be switched to lower VAR supply.

VNR_{PU} is the per-unit voltage associated with the next RPD to be switched to lower VAR supply.

$\Delta Q_{NextAdd}$ is the delta Q expected from the next RPD to be switched to raise VAR supply.

VNA_{PU} is the per-unit voltage associated with the next RPD bank to be switched to raise VAR supply.

Q_{NOM} is the nominal three-phase MVAR rating setting for each RPD.

The sequencing logic function determines which RPD will be the next to be added or removed and from which bus. This function is described in Section V.

The CA controller receives the bus voltage measurement from each relay and converts it to per unit based upon the nominal RPD voltage rating. The nominal RPD voltage is the voltage at which the nominal VAR rating will be supplied by the RPD. If the capacitor bank nominal voltage rating differs from the reactor bank nominal voltage rating, it is necessary to convert the VAR and voltage ratings to a common voltage base when setting up the control.

D. V Priority Logic

If voltage and power factor regulation criteria are in conflict, voltage has priority. The controller uses logic, described in Table I, to mediate conflicts between the two control parameters. See Fig. 3 and Fig. 4 for the blocking limit characteristics. The control action of the power factor control parameter is blocked when performing that action would cause voltage to be out of band.

TABLE I
V PRIORITY LOGIC

Control Function	Supervision Logic	Figure
Add capacitor or remove reactor on PF	But not if $V > V$ priority raise Q limit	Fig. 3
Remove capacitor or add reactor on PF	But not if $V < V$ priority lower Q limit	Fig. 4

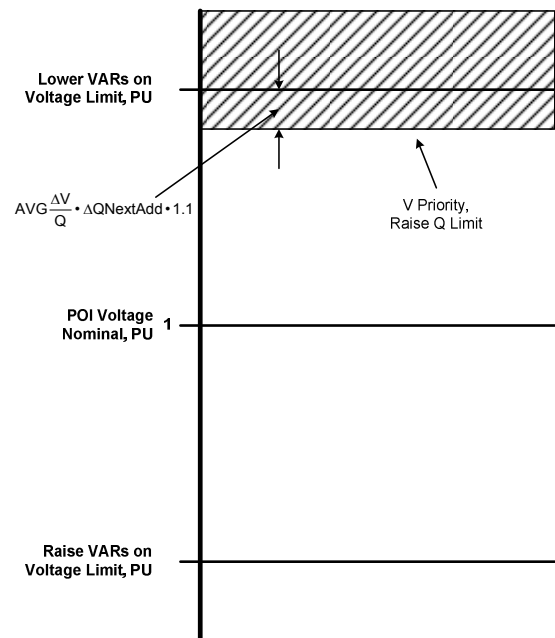


Fig. 3. V priority, raise VARs on Q blocking characteristic

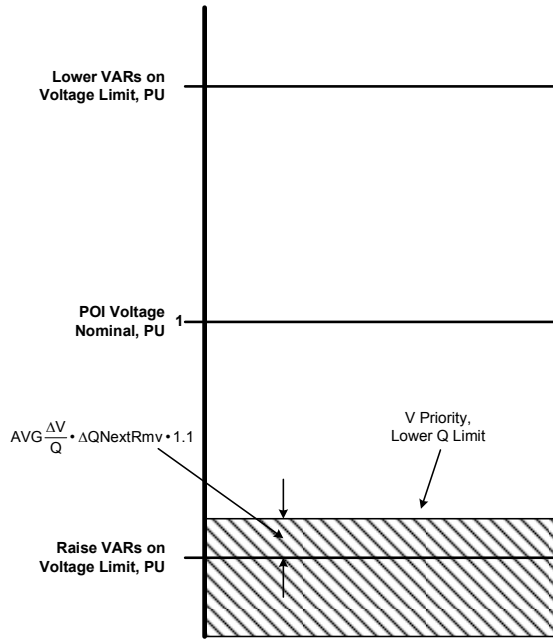


Fig. 4. V priority, lower VARs on Q blocking characteristic

The regulation limit is offset by the average $\Delta V/Q$ from the most recent six switching operations multiplied by ΔQ next raise or ΔQ next lower multiplied by a margin of 1.1. The averaging function uses the previous six samples or, in cases where the CA controller has yet to issue six operations, the actual number of operations the controller has issued. See the average $\Delta V/\Delta Q$ function discussion in the next subsection.

E. Average $\Delta V/\Delta Q$ Function

Because the ΔV associated with each step is expected to vary based upon system conditions, the CA controller performs a learning function by recording the observed ΔV and ΔQ associated with each switching operation in two six-register first in, first out (FIFO) memory buffers and averages the $\Delta V/\Delta Q$ for use by the V/Q priority logic. The memory buffers are reset to zero upon initial enable of automatic control. See Fig. 5 and Fig. 6.

Each ΔV that is recorded is divided by its corresponding ΔQ . The resulting ratio indicates the expected change in voltage per VAR to be added or removed from the system. These values are used in conjunction with the logic, as described in Section IV, Subsection D, to determine the upper and lower limits for switching operations based upon the expected ΔV resulting from a switching operation.

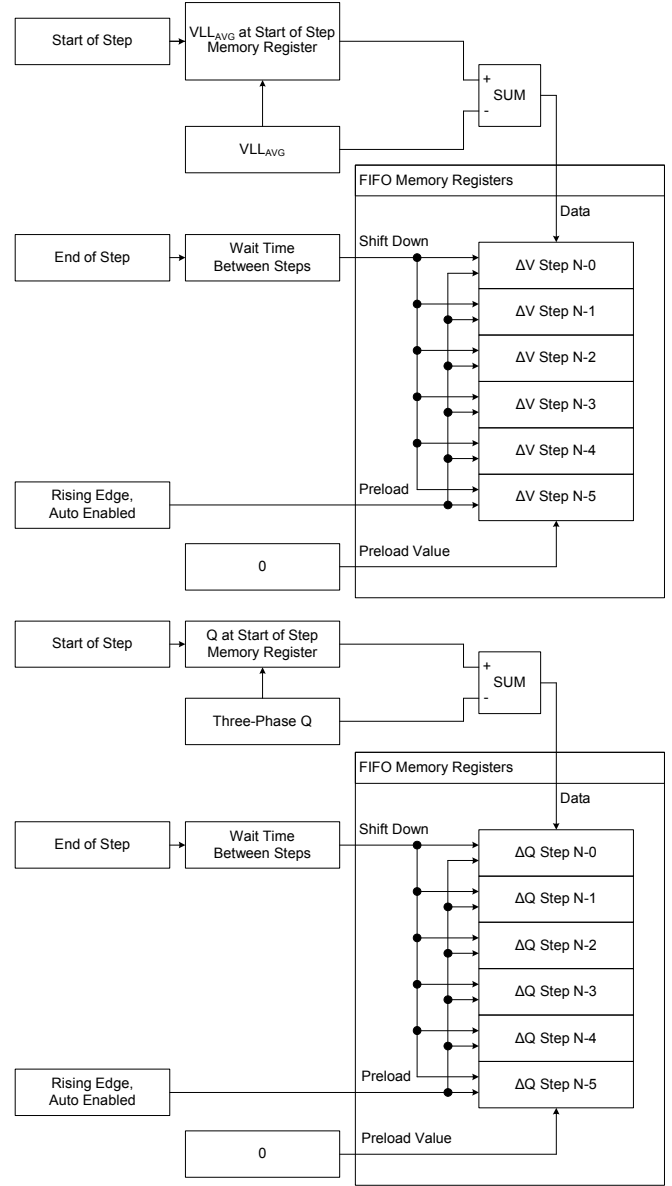


Fig. 5. FIFO memory

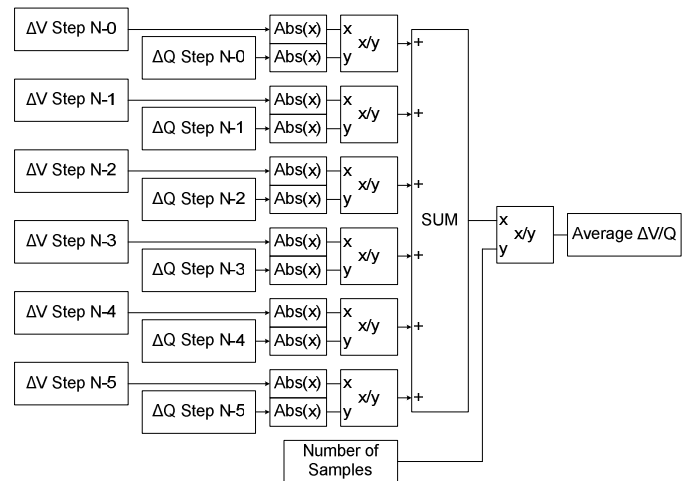


Fig. 6. Average $\Delta V/Q$ function

V. AUTOMATIC SWITCHING LOGIC

The automatic switching logic handles routing of switching commands to the appropriate RPD relay and monitoring for alarm conditions. It includes logic to prevent both reactors and capacitors from being in service, to reduce losses in the step-up transformers, and to even out operations between RPD switching devices. The following subsections describe these functions in more detail.

A. Insert and Remove Process Logic

Fig. 7 shows the flow chart for the automatic switching logic. When the control parameters call for switching an RPD, the CA controller sends an add or remove command to the designated relay. The relay starts a timer to wait for the feedback input from the RPD breaker (the 52A contact). If the timer expires before the feedback input is detected, the relay sets a fail-to-open/close alarm for that RPD. The CA controller sees this input and proceeds on to the next RPD in the sequence.

When a single switching process ends (either by fail to open/close or successful operation), the time-between-steps timer delays the next step for a user-settable time. When the time-between-steps timer expires, the logic updates the ΔV and ΔQ registers and then checks to see if the condition that caused the switching operation has been satisfied.

The time-between-steps timer allows the LTC to adjust the bus voltage back inside its regulation band before measuring the ΔV and ΔQ from that switching operation. For example, if the switching operation raises the reactive power supply from that collector bus, the collector bus voltage will rise and the VAR supply will be temporarily higher (and therefore the POI voltage will be higher) compared with after the LTC lowers the collector bus voltage back down to its regulated level. If time is not allowed for the LTC to settle before measuring ΔV and ΔQ and the control parameter is still out of band, it is possible for the control interaction to cause hunting.

If the out-of-band condition still exists, then the sequencing process starts from the beginning without additional delay and a new RPD is added or removed. Otherwise, the CA controller stays active and waits for the voltage or power factor to go out of band to initiate another switching operation.

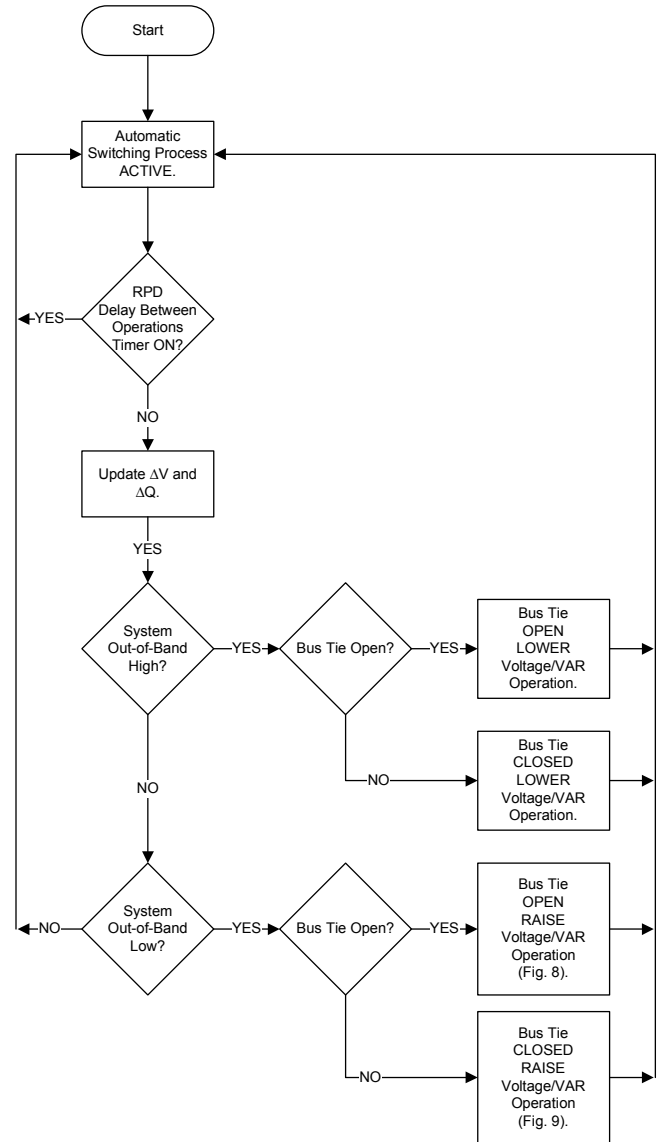


Fig. 7. Automatic switching process flow chart

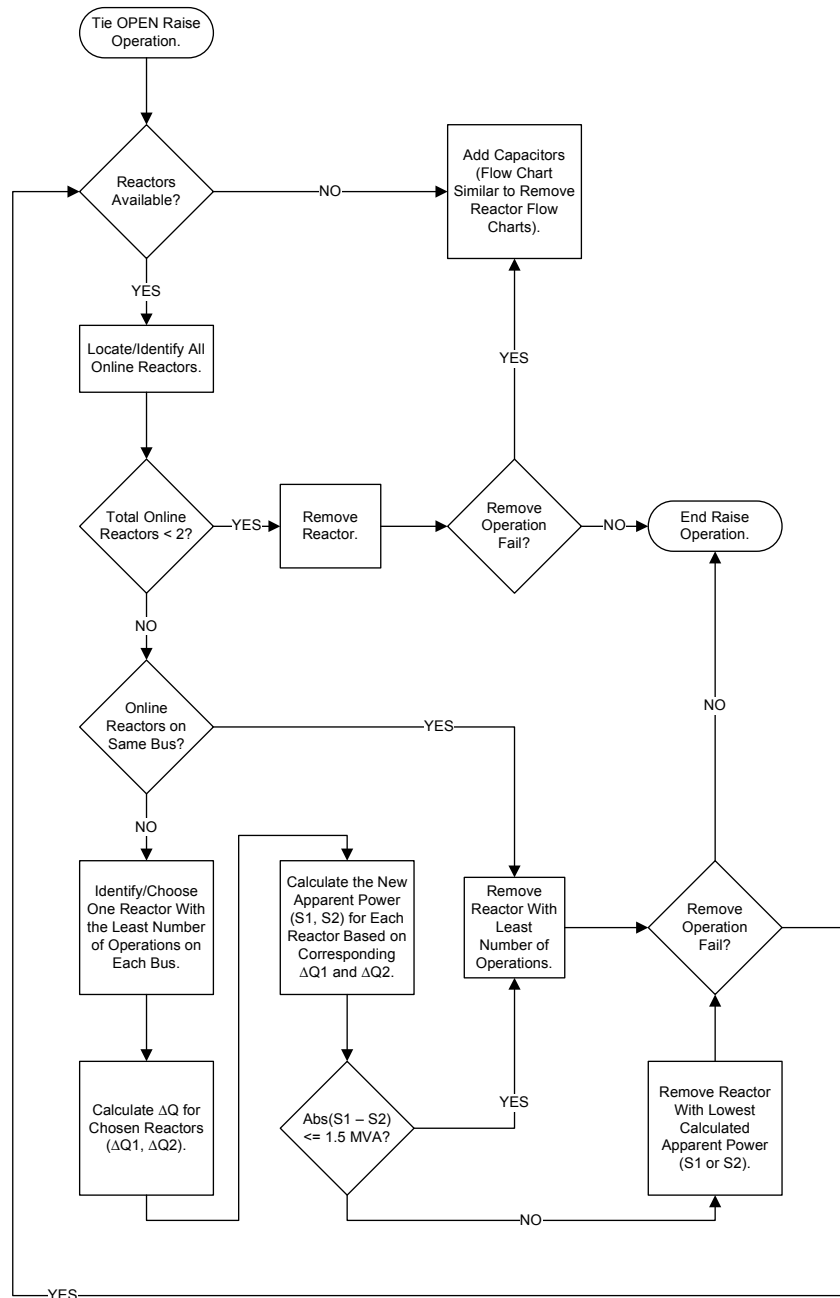
B. Sequencing Logic

The sequencing logic is an important feature of the controller. This function determines which RPD has the highest priority when multiple RPDs are available to switch. The reactor switching portions of the raise voltage/VAR flow charts are detailed in Fig. 8 and Fig. 9 to illustrate the concepts. The other flow charts are similar.

The controller considers the number of RPDs available on each bus and the operations counter value for each available RPD when selecting the next RPD to operate in an attempt to equalize the operations between switching devices. The sequencing algorithm also includes logic to optimize the VAR flow in each transformer when the collector system bus tie is open to reduce I^2R losses. To do this, the controller calculates the expected total apparent power (S) in the two banks if it sends the next switching command to an RPD on each bus. The scenario that results in the lowest total expected apparent power has priority. This reduces losses because S is directly proportional to I when the two transformers are bused together (V is equal) at the high side. To simplify the logic, it is assumed that any difference in R between the two transformers is relatively insignificant.

As seen in Fig. 7, the bus tie status determines which flow chart to use to select the RPD with the highest priority for switching. The sequencing algorithm includes logic to optimize the load flow power factor in each transformer when the collector system bus tie is open to reduce I^2R losses. If the bus tie is closed, active and reactive power flow divides evenly between the two transformers (assuming the impedances are similar), so there is no need to choose between RPDs on different collector buses.

Fig. 8 shows the flow chart for selecting which RPD to switch to raise voltage/VARS. When the tie is open, the controller first checks to see if there are reactors available to remove. If there are no reactors available, it looks to add a capacitor. If there is only one reactor available to remove, the controller removes it.



If there are multiple reactors available to remove, the controller checks to see if the reactors are on the same bus. If they are, it selects the reactor with the fewest operations to remove. This helps to even out the number of operations on the reactor breakers. If the reactors are on different buses, the controller calculates the expected ΔQ from removing a reactor on Bus 1 versus removing a reactor on Bus 2. From that, it can determine the expected apparent power flow in each transformer. If the apparent power flow difference between the two scenarios is insignificant (less than 1.5 MVA), the controller selects the reactor with the fewest operations. If the difference in apparent power flow is significant, the controller selects the reactor that will result in the optimal power factor through each transformer.

Fig. 9 shows the flow chart for selecting a reactor to remove when the bus tie is closed. In this case, the controller simply has to remove the reactor with the fewest operations.

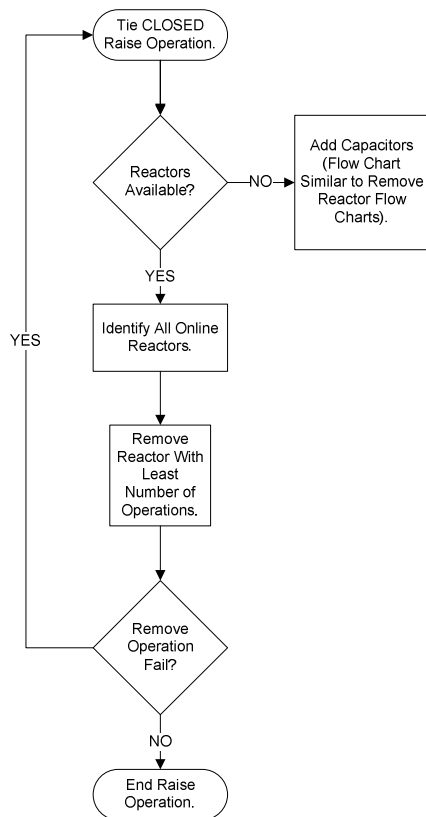


Fig. 9. Bus tie closed, raise voltage/VAR reactor switching flow chart

VI. STATIC VAR CONTROL WITH DYNAMIC VAR CONTROL

While the majority of wind farms use a dynamic VAR control solution throughout normal operation, the static VAR control solution can complement the dynamic control solution by acting as a backup. In cases that the dynamic VAR control system should fail or be offline, the static control system takes over by automatically switching the capacitor and reactor banks according to the logic presented previously.

The dynamic VAR controls associated with doubly fed induction generators (Type 3 machines) and full converter

generators (Type 4 machines) are able to control the VAR production or consumption of each generator in the wind farm dynamically and temporarily boost VAR supply up to 1.5 to 2 times the current limits of the power electronics during short circuits to aid ride-through capability. These systems can be centrally controlled or controlled on an individual basis. Static compensators also have the ability to dynamically boost VAR output to aid ride-through capability.

The total available VAR output from the wind farm is the collective contribution from each active static compensator and generator with dynamic capability within the system. As the wind farm nears its collective VAR limits, the dynamic VAR system can insert or remove capacitor or reactor banks as required, allowing each machine to back off of its respective limit and operate more comfortably within its VAR limits.

While the dynamic VAR controller is in operation, the static VAR controller can remain aware and continue to monitor the capacitor and reactor bank switching activity. As the dynamic VAR controller switches capacitor and reactor banks, the static system can continue to monitor and calculate the $\Delta V/\text{VAR}$ as well as the number of switching operations to which each capacitor and reactor bank has been subjected. The static controller uses the $\Delta V/\text{VAR}$ calculation and switching operations performed during dynamic operation to populate its learning algorithm. As the dynamic VAR controller becomes unavailable, the static VAR system can shift from standby to active and operate optimally immediately upon taking control.

The authors have encountered some dynamic VAR controllers that have a limitation. The dynamic VAR controller disables VAR production and consumption when the wind slows to a speed where the wind farm is unable to produce active power. The underground cable lines connected to the collector bus add a capacitive load, which affects the voltage at the collector bus. The static VAR controller was modified to include simple logic to identify when the wind farm was not producing power because of low wind speed and subsequently entering a mode of operation where it tried to maintain zero VAR flow at the POI. The resolution of control of the VAR flow in such cases is limited to the size of the capacitor and reactor banks. Large capacitor and reactor banks will produce large shifts in reactive power. As such, maintaining zero VAR flow at the intertie is often not achievable. However, such operation may be desired, or even required, by the transmission operator.

Coordinating dynamic VAR control with static VAR control presents many challenges. Dual control, if not coordinated properly, can result in the two control systems fighting each other as each controller tries to drive the system to potentially different set points. As such, in the absence of detailed investigation into the operational philosophy of the dynamic control system, it is best to leave the static control system in standby while the dynamic controller is in service. The static VAR controller is best suited as a low-cost backup controller in a system where a dynamic VAR control system can perform higher-resolution VAR control.

VII. SUMMARY

Reactive power support for wind farms is critical to the successful integration of wind generation to the grid. The system this paper describes demonstrates a simple, centralized, and integrated system that can control a very large number of capacitor and reactor banks.

The system for this project is unique in that it can handle simultaneous regulation of both power factor and voltage at the point of utility interconnection. The system is in service on several wind farms and has been field proven to be a practical and useful solution using a central automation controller that manages communications and centralized logic processing all in one rugged device.

VIII. REFERENCE

- [1] M. Thompson and D. Kopf, "Reactive Power Control System for Wind Farm Application Using IEC 61850," proceedings of the 11th Annual Western Power Delivery Automation Conference, Spokane, WA, April 2009.

IX. BIOGRAPHIES

Michael J. Thompson received his BS, magna cum laude, from Bradley University in 1981 and an MBA from Eastern Illinois University in 1991. He has broad experience in the field of power system operations and protection. Upon graduating, he served nearly 15 years at Central Illinois Public Service (now AMEREN), where he worked in distribution and substation field engineering before taking over responsibility for system protection engineering. Prior to joining Schweitzer Engineering Laboratories, Inc. (SEL) in 2001, he was involved in the development of several numerical protective relays while working at Basler Electric. He is presently a principal engineer in the SEL engineering services division, a senior member of the IEEE, a main committee member of the IEEE PES Power System Relaying Committee, and a registered professional engineer. Michael was a contributor to the reference book *Modern Solutions for the Protection, Control, and Monitoring of Electric Power Systems*, has published numerous technical papers, and has a number of patents associated with power system protection and control.

Tony Martini received his BS from the University of Cincinnati in 1995. He has automation and control experience in manufacturing and power system operations. He joined Schweitzer Engineering Laboratories, Inc. in 2009 as an automation engineer in the engineering services division. He is a member of IEEE and IEEE PES.

Nicholas Seeley graduated from the University of Akron in 2002 with a BS in electrical engineering. After graduation, he began working at American Electric Power in Columbus, Ohio, for the station projects engineering group, where he focused on substation design work. In June 2004, he was hired at Schweitzer Engineering Laboratories, Inc. in the engineering services division as an automation engineer involved in the development, design, implementation, and commissioning of numerous control-based projects specifically geared towards power management solutions. He currently works as a lead power engineer in research and development, focusing on development of power system control solutions. He is a member of IEEE and IEEE IAS.

Case Study: Simultaneous Optimization of Electrical Grid Stability and Steam Production

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ABSTRACT: SIMULTANEOUS OPTIMIZATION OF ELECTRICAL GRID STABILITY AND STEAM PRODUCTION

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Abstract—Steam production and electric power system stability are often competing interests in an industrial refinery. Optimal control of steam production is required to meet plant process operating requirements, and electrical grid stability is required to prevent power system blackouts. For many industrial plants connected to a utility grid, both operating criteria cannot be met simultaneously, placing the power system in serious jeopardy of a blackout.

Steam turbines, which are controlled to produce a desired tonnage per hour of steam, can hinder the ability of a power system to avoid blackouts. This issue occurs at any facility in which electric power is derived from steam turbines running in extraction flow or pressure control modes.

The issue is explained using modeling and in-field results from a refinery with several three-stage extraction turbines, a large refinery load, and several utility grid interconnections. The implications of running these turbine governors in pure extraction priority, pure power priority, or mixed extraction and power priorities are explored in this paper.

A comprehensive electric dispatch control strategy used at the facility is shared. This control system optimizes electrical grid stability throughout the facility while simultaneously interfacing with a steam optimization system.

Index Terms—Steam optimization, grid stability, droop, blackout prevention, dynamic disturbance rejection, real-time modeling, turbine load sharing.

I. INTRODUCTION

The first part of this paper explains the basics of how steam turbines (STs) produce power, how they are controlled for extraction and droop, and how governors provide dynamic disturbance rejection in an electric power system. The authors discuss and explain the contradiction between steam control and a stable electric power system. The topic of islanded frequency control is shared to clarify this often-debated point.

In the second part of the paper, the specifics of the case study project at a refinery are shared. This discussion includes a review of frequency control, adaptive boundary controls, and autosynchronization. The paper also reviews the modeling of the case study facility, which included performing

model validation, modeling a three-valve turbine and governor, and examining system performance data.

II. POWER PRODUCTION IN STEAM TURBINES

STs operate across a pressure differential, producing power as the mass flow of steam flows across the turbine blades. Equation (1) states that the rotational mechanical power output of an ST is proportional to the mass flow rate of steam in tons per hour. This equation holds true assuming that the pressure and moisture content of each pressure header remain constant.

$$\text{Turbine Power Output (MW)} \propto \text{Steam Flow (tons/hr)} \quad (1)$$

As shown in Fig. 1, steam is produced at the high-pressure (HP) header by some type of boiler.

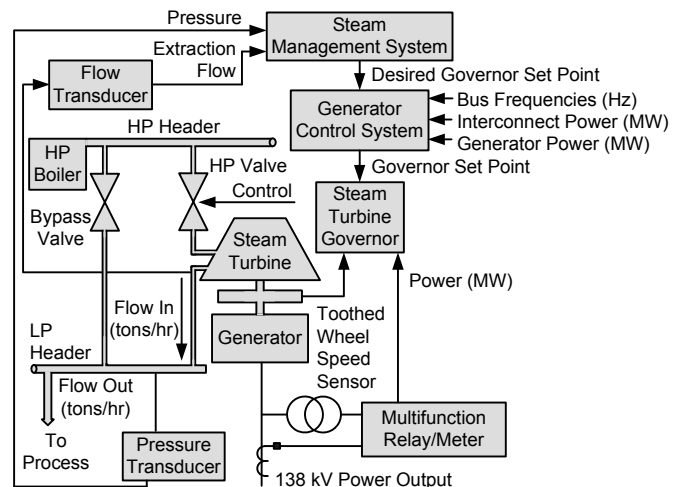


Fig. 1 Typical Industrial Steam and Turbine Control System

Boilers convert the thermal energy of a burning substance, such as coal, oil, or gas, into HP steam. The ST exhausts steam to the low-pressure (LP) header. This LP steam is commonly used throughout an industrial process to drive loads, such as dryers, heaters, and rotating turbines. These process loads consume steam in tons per hour. The

difference in steam production and consumption mass flow rates determines the pressure in a header, as shown in (2).

$$\text{Pressure} \propto \text{Time} \int (\text{Steam Flow In [tons/hr]} - \text{Steam Flow Out [tons/hr]}) \quad (2)$$

Equation (2) shows that for the pressure to rise, there must be more steam going into the header than leaving it. For the pressure to fall, there must be more steam leaving the header than going in. Thus a system controlling header pressure has to gain control of the steam flow into or out of the header.

STs in industrial process facilities are commonly set to produce steam using one of the following two methods:

- Extraction control. The ST is controlled to produce a constant amount of steam in tons per hour.
- Pressure control. The ST is controlled to produce a constant pressure (kPa) at the LP header.

For both of these schemes, the steam management system (SMS) accomplishes extraction and/or pressure control by sending a desired governor set point to a generator control system (GCS). The GCS then evaluates the set point, determining if the requested value is acceptable to maintain electrical grid stability. If it is acceptable, the set point is passed on to the ST governor.

Steam extraction or pressure control loops commonly exist in the SMS, GCS, or governor. Regardless of where they exist, these extraction or pressure control loops operate at slow time constants of 60 seconds or slower. These time constants are defined by the rate at which the LP header changes pressure in response to changes in flow caused by new governor set points.

For this discussion, STs running in extraction or pressure control mode are constant power devices for time constants above 60 seconds. For the LP header to stay at a constant pressure, the ST power output must be directly proportional to the average process steam consumption in tons per hour. Thus, to maintain LP header pressure, the long-term droop characteristics of the ST are overridden by process steam consumption on the LP header.

III. GENERATOR FREQUENCY CONTROL

Electrical motors and generators must operate in a narrow frequency range. Frequencies outside of this range can cause motor damage through overheating or excessive internal mechanical stresses on the motor windings and/or steel laminations. (Note that most rotating loads, such as compressors, fans, conveyors, and crushers, are very resilient when it comes to speed variations.) The synchronous generators converting mechanical power to electric current and voltage must also operate within these strict frequency boundaries for a large host of reasons [1]. Protective relays are used to trip the motors and generators if the measured frequency of the voltage is outside of this range. Therefore, some type of speed (frequency) control system is required to keep a power system online.

Turbine governors indirectly control power system frequency. Turbine governors control the rotating speed of a turbine to within a tolerable range during disturbances such as

a sudden loss of electrical load or generation. The generator creates a voltage with the same frequency as the rotating speed of the turbine. Electromagnetic forces in the air gap between the generator stator and rotor keep the generator rotor (and turbine) in synchronism with the power system frequency. Thus a governor controls power system frequency by changing the mechanical power output of the turbine.

Governors modify their turbine valve control signal as a function of both speed (frequency) and power; this is called droop. The following are two ways to accomplish droop in a governor:

- Active power control with a speed droop term.
- Speed control with an active power droop term.

These two methods provide the same steady-state relationship between active power and speed (frequency). The droop relationship between power and frequency is plotted as the solid line in Fig. 2.

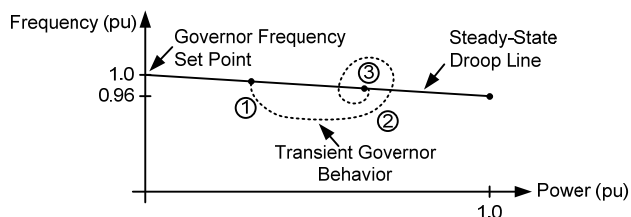


Fig. 2 Steady-State and Transient Droop Characteristic

The dotted line in Fig. 2 illustrates what happens to the power system frequency when a load is suddenly added to an islanded power grid. At Point 1, the starting of the motor extracts kinetic energy from the rotating mass of the ST, generator, and all other spinning loads, slowing down the power system frequency. The governor then responds (typically in less than 1 second) by increasing the turbine power, as shown with Point 2. The power and frequency commonly oscillate, eventually converging onto the steady state at Point 3. The droop line in a governor defines the steady-state operational point of the electric power system. However, inertia, tuning, and load composition define the transient relationship between frequency and electric power consumption in Fig. 2.

It is worthwhile to note that the frequency set point in Fig. 2 is raised or lowered by the GCS to maintain the long-term system frequency at nominal.

IV. DYNAMIC DISTURBANCE REJECTION

Properly tuned governors prevent unstable frequency runaway and, hence, maintain electric power system frequency stability. Because not all governors run in droop mode, it is worthwhile to categorize the possible relationships between frequency and power in a governor. Fig. 3 shows the droop, isochronous, unstable, and constant power modes of operation.

To quantify the ability of a governor-turbine combination to maintain system frequency, a simple scenario is used to evaluate each of the characteristics shown in Fig. 3. Consider for a moment a scenario where the electrical load increases from Point A to Point B.

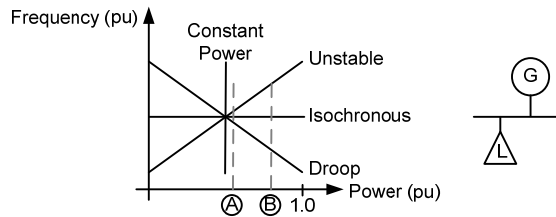


Fig. 3 Frequency and Power Characteristics

The increase in electrical load causes a drooped governor to increase power output, thus preventing a cascading fall in frequency. A governor configured for isochronous control also increases its power output in this scenario. Thus both droop and isochronous governors increase the turbine power output to compensate for the increase in load. This tends to keep the power system frequency stable. A governor rejects disturbances when the power system frequency is kept relatively constant in this manner.

The result of increasing electrical load on a constant power governor is quite different. Because the governor constantly forces a specific power output from the turbine, the frequency of the power system falls catastrophically if the load exceeds the constant power production set point. The same occurs, but to a lesser extent, for the unstable line. Note that steam extraction and pressure control are effectively constant power modes of operation, and thus they cannot reject long-term disturbances or keep islanded power system frequency constant.

To prevent a steam extraction turbine from destabilizing a power system, the governors are kept in droop mode operation, with slow outer-loop ST extraction and pressure control, as shown in Fig. 4. The outer extraction or pressure loops are tuned to be very slow (60 seconds or slower, commonly). This allows the drooped characteristic to maintain short-term transient stability, as shown in Fig. 2. Thus, in a time domain, the droop line is obeyed for a few seconds, but the constant power and flow rate are obeyed after several minutes. In other words, the governor droop control saves the electric power system from frequency decay for a few seconds, but the ST extraction loop drops the power system frequency a few minutes later.

Thus the constant power mode behavior of extraction turbine controls creates long-term frequency instability when a plant is islanded from the utility grid.

V. CONTROL TIME CONSTANTS

It is problematic that constant steam extraction and robust speed control cannot be satisfied simultaneously in a power system. This problem is resolved in the short term by cascading loop control systems with different time constants of control within each cascading loop (see Fig. 4). It is important to understand the control time constants of each of the control loops shown in Fig. 4.

The unit megawatt control, tie flow control, and frequency control in the GCS control loops are typically set 10 times slower than the governor closed-loop speed and droop control time constant. With most ST governors tuned to approximately 1 second, the GCS unit megawatt control is typically set to 10 seconds or slower.

The SMS steam extraction and pressure control loops are set approximately 5 to 10 times slower than the GCS controls; therefore, time constants of 60 seconds or greater are common.

VI. THE CONTRADICTION

If an industrial power system is connected to a large electric utility, the power system frequency changes little. However, once the industrial power system is islanded, the frequency becomes heavily dependent on the tuning of the governor, load composition effects, machine droop, and disturbances.

It is during these islanded conditions that the contradiction between steam production and power system stability occurs most dramatically. The drooped governor speed regulator is sent new set points by the slower extraction control system, which has the sole purpose of keeping a constant tonnage per hour of steam production and therefore a constant electric power production level. This extraction control system raises or lowers the governor speed set point to achieve the required steam flow, regardless of what is happening to the power system frequency. Changes in process steam consumption can run a power system frequency too high or low, causing a frequency-induced blackout of the electric power system.

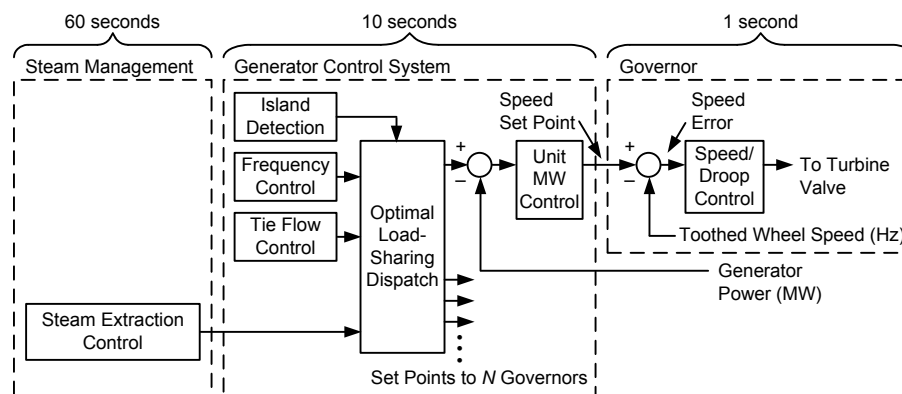


Fig. 4 Steam, Power, and Frequency Control Loops

To avoid a frequency-induced blackout during islanded conditions, the outer extraction control loops controlling the generator set points must be removed. To maintain the header pressures, the SMS therefore switches from controlling the generator set points to controlling the bypass valve between the HP and LP headers (see Fig. 1). Thus, in an islanded mode, the process load (not the turbines) must be throttled up or down to maintain steam header pressures. Steam load shedding and valve feed-forward control are commonly employed to preserve header pressures should the bypass valve provide insufficient control for the SMS.

VII. KEEPING GENERATOR OUTPUTS BALANCED

Islanded or not, the output from parallel-connected generators must be balanced in some way. The riskiest place to operate a turbine is at its upper or lower limit because the likelihood of tripping a turbine offline increases substantially. For example, should a disturbance in the form of a motor trip occur, a turbine close to zero output is likely to trip on reverse power as the governor correctly tries to close the control valve and prevent frequency overshoot. It is for these reasons that a turbine balancing system is used in a GCS.

For utility-connected generators, the need to balance turbine loading is less critical, unless it is possible that an islanded condition could happen at any moment. Generators that are expected to operate while separated from a utility grid (islanded) should always be load-balanced to minimize the possibility of tripping during transient conditions that may occur after islanding.

Balancing the loads of multiple turbines becomes more complicated when multiple differently rated units are connected in parallel on an industrial power system. For example, if a 20 MW unit is on the same grid section as a 100 MW unit, both units cannot possibly be dispatched to the same power output. Instead, the technique of equal percentage load sharing between generation units is used.

The concept of equal percentage load sharing is a matter of loading all the units on a grid to the same percentage loading factor. To further complicate matters, it is common for turbines to have unstable operational areas or undesirable areas of operation (for example, low NO_x emission lines in combustion turbines). The solution to these problems is to create artificial upper and lower limit boundaries that are user-settable, as shown in Fig. 5.

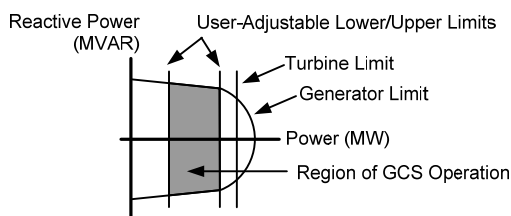


Fig. 5 GCS Operational Conditions

A fully functional GCS must accomplish the following simultaneously:

- Keep a generator and turbine within the region of GCS operation shown in Fig. 5.

- Satisfy equal percentage load sharing between turbines of different ratings and technologies.
- Keep an islanded power system at nominal frequency by raising or lowering the power output of all turbines in the island.
- Keep a grid-connected power system at a nominal intertie power flow by raising or lowering the power output of all turbines that are electrically connected to the tie line.
- Dispatch turbines to the SMS set points when connected to the grid.
- Ignore SMS turbine set points when islanded.
- Send feed-forward signals to the bypass valves and trip the steam loads to prevent steam header pressure problems during islanded conditions.

VIII. GOVERNOR MODES AND ISLANDED FREQUENCY CONTROL

There are many options to control system frequency on an islanded power system with multiple generators. These options are often debated and worth explanation. In each of these cases, an outer-loop controller (such as a GCS) is required to keep one or more units within their limits. The control scheme for each option is detailed in the following subsections.

A. All Governors in 0 Percent Droop (Isochronous)

A 0 percent droop turbine (also known as an isochronous unit) keeps the power system at a constant frequency. With multiple parallel-connected isochronous governors, it is very common for a small disturbance to cause units to oscillate in megawatts unnecessarily. Generators have been known to trip when paralleled in this mode. Governor tuning and some isochronous-sharing control strategies can reduce these effects. The authors consider parallel-connected isochronous turbines to not be naturally stable and to be difficult to tune robustly.

Parallel-connected isochronous turbines require a high-speed isochronous sharing control system to dispatch the governors simultaneously and provide interturbine electrical oscillation damping. The central controller and associated power supplies, wiring, and communications cabling become points of failure. If any of these fail, the turbines will oscillate dangerously and, commonly, the electric power system will also fail.

The authors do not recommend this method for any power system.

B. One Unit Isochronous, Remainder in Droop

Some small, low-inertia power systems with very tight frequency requirements can take advantage of operating one unit in isochronous mode and the remainder in droop mode. Grid operation with one unit in isochronous mode is commonly used by power system utilities to start up a grid after a system-wide blackout.

In this scenario, the isochronous unit keeps the power system at a constant frequency. The remaining droop units

must therefore be redispatched by the GCS load-sharing algorithm to keep all the units equally sharing load. The strategy is to push the isochronous unit to equal percentage load sharing with the droop units by raising or lowering the droop unit set points. Without continuous load sharing, the isochronous unit will commonly run to a maximum or minimum, often resulting in the isochronous unit tripping. Should multiple islands form, the GCS must force one generator on each island into isochronous mode. The loss of GCS load sharing is not catastrophic to the power system.

The authors recommend this method as a viable second-choice scheme for governor-mode control of islanded industrial facilities.

C. All Units in Droop

Most power systems throughout the world operate with all units in droop mode. However, droop mode is sometimes not appropriate for low-inertia power systems with very tight frequency requirements.

In this mode, all turbine speed governors are set to the same droop. This mode of operation is suitable for large systems because the system inertia (the spinning mass of all its generators and loads) of a large system makes the natural rate of decay of frequency slow enough for the combined efforts of a GCS and drooped governors to effectively regulate frequency within reasonable limits. Without a GCS dispatch, the frequency is not constant and can deviate from nominal by several hertz.

In droop mode, a GCS adjusts the governor set points of all units simultaneously to keep the power system at nominal frequency. Equal percentage load sharing is accomplished simultaneously with nominal frequency control. Droop mode is always recommended by the authors as the first-choice scheme for governor-mode control of islanded industrial facilities. This mode is considered the most robust frequency control scheme because there are two layers of backup load sharing and frequency control, thereby eliminating single points of failure. The loss of GCS frequency regulation and load sharing is not catastrophic to the power system because parallel units operating in droop naturally provide limited amounts of frequency regulation and load sharing. The case study facility this paper describes is set up with all of its governors in this mode.

IX. CASE STUDY CONTROL SYSTEM

A simplified one-line diagram of the case study plant is shown in Fig. 6.

Several issues make the plant unusually complex in regard to simultaneous optimization of steam and electricity, including the following:

- The plant uses three different governor controllers and three different turbine technologies.
- The system has three three-stage STs.
- The plant has a very complex electrical topology. Six different potential power system islands must be tracked concurrently.
- The plant has been in service for approximately 30 years. This made the installation, wiring,

commissioning, and testing of the control system complicated and time-consuming.

- Significant modeling effort was required to accurately predict the dynamic response of this large facility. This included significant load composition modeling and customized governor models.
- This system is known to exhibit both voltage- and frequency-induced power system collapses. The supplied control system corrected both problems.

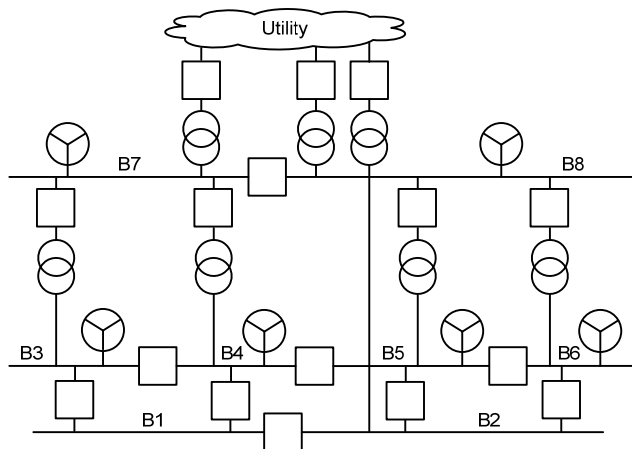


Fig. 6 Simplified Plant One-Line Diagram

A. Control System Design

The detailed functional design of the plant control system is itemized in a voluminous proprietary document; therefore, this section can only serve to provide a high-level overview of the major control systems put into place at the facility. Many details of these systems are omitted, such as voltage control, VAR control, on-load tap changer (OLTC) control, load shedding, and generator tripping. Only controls related to power and steam are explained here because they are pertinent to the conclusions in this paper.

The supplied control system is a *separate, survive, and synchronize* type of scheme, which is described as follows:

- **Separate.** Automatically separate the system from a failing utility grid.
- **Survive.** Shed load or generation to rebalance the electric power system. Simultaneously control system frequency, generator power output, generator VAR output, and bus voltage of the entire islanded facility.
- **Synchronize.** Upon operator initiation, quickly and automatically resynchronize after the adjacent grid recovers.

B. Islanded Frequency Controls

The case study power system shown in Fig. 6 can be broken into six independent and simultaneously operational islands. The GCS was therefore designed to detect and track six different possible island formation combinations. Should any of these islands form, the controls automatically switch each of the three-stage governors out of extraction priority into droop. The GCS automatically creates new control

arrangements for each of the multiple islanded systems. For example, in the condition where six islands exist, six completely simultaneous and autonomous solutions are required for active GCS control.

The GCS simultaneously controls the dispatch of any number or combination of parallel-connected turbines to equal percentage load sharing and the frequency set point criterion. Load sharing keeps the positive and negative reserve margin allocation between turbines to an identical percentage loading. Identical percentage load sharing optimizes the spinning reserve of all the units operating in parallel in the same island. By keeping each unit equally loaded as a percentage of its total capability, the controls ensure that each unit has an equalized percentage of spinning reserve.

C. Adaptive GCS Operational Boundary Conditions Based on Steam Condensing Valve Positions

The user-entered upper and lower boundaries of the generic GCS algorithms shown in Fig. 5 were found to be insufficient for the three-stage governors in the case study facility. During nonislanded conditions where the GCS was to control intertie flows with the utility, only the third valve (condensing valve) was available for active power dispatch control. This was because the governor controlled Valves 1 and 2 (V1 and V2) to meet steam extraction requirements at the intermediate-pressure (IP) and LP headers (see Fig. 7). During nonislanded conditions, this particular governor gave clear priority to the needs of the plant for continuous steam extraction flow.

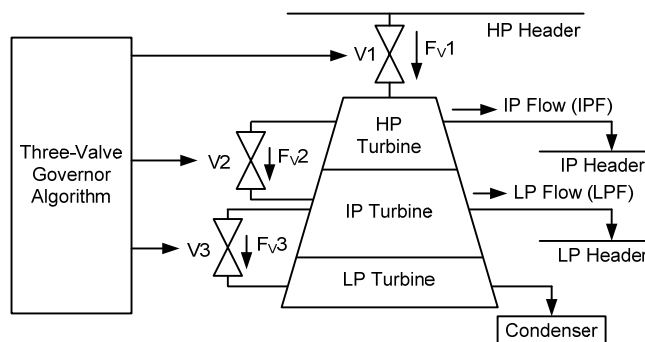


Fig. 7 Three-Valve Turbine System Model

The third valve (condensing valve) was discovered to supply approximately 14 percent of the turbine power output as the third valve varied from fully closed to fully open. The governor algorithm used the third valve to provide a 4 percent droop characteristic over this 14 percent power swing range. This created a scenario where the lower operational boundary for generator power dispatch was defined by the position of the extraction valves of both pressure headers (as shown by Line A in Fig. 8). The upper operational boundary was created by the 14 percent power contribution limit of the third valve (as shown by Line C in Fig. 8). Thus the GCS derived the upper and lower operational boundaries of the three-stage turbines by tracking the position of the third valve (condensing valve) and the unit extraction.

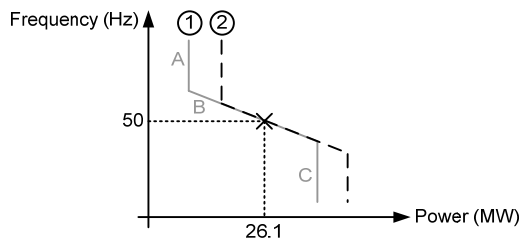


Fig. 8 Graphical Depiction of the Droop Line for a Change in IPF Set Point From 100 (Line 1) to 105 (Line 2) Tons Per Hour

D. Nonislanded Tie-Line Controls

The GCS was designed to detect hundreds of possible tie-line and grid-connected plant configurations (topologies). The GCS automatically creates new control arrangements for each of the multiple tie lines. For example, in the condition where three grid sections are fed by three different tie lines, three completely autonomous solutions are required for active GCS tie-line megawatt control. Simultaneous to controlling the three tie lines, load sharing keeps the positive and negative reserve margin allocation between turbines to an identical percentage loading.

Alarms are generated should any two generators or incoming transformers be paralleled together at Busbars B1, B2, B3, or B4 (see Fig. 6). This condition is not allowed because the combined fault duty exceeds breaker ratings.

E. Island Autosynchronization

The autosynchronization systems for the facility measure voltage and frequency on all possible combinations of islanded and utility-connected grid sections. The systems send proportional correction pulses to adjust the governors and exciters of multiple parallel-connected units on each bus section as necessary. The close supervision relay automatically closes the breaker upon identifying satisfactory conditions of slip, voltage, and slip-compensated advanced angle [2].

X. CASE STUDY MODELING

A custom governor and turbine model was built to accurately depict the nonlinear extraction mode characteristic of these three-stage turbines and associated governors. This nonlinear characteristic provides for an easily controllable steam generation system for the on-site process; however, this same characteristic provides very limited dynamic stabilization for the electric power system.

The model was specifically developed to validate the functionality of the *separate, survive, and synchronize* control system described previously. The control systems were connected to simulation hardware, with a real-time software model loaded onto it, to enable closed-loop testing of the control systems during factory acceptance testing.

A closed-loop real-time simulation, as depicted in Fig. 9, minimizes commissioning time for large control and protection systems. The authors modeled the dynamics of the plant power system with a simulation time step sufficiently fast to

test all closed-loop control and protection systems. Thousands of test cases were run with the automated capability of the modeling equipment, providing plant personnel with a great amount of confidence that all systems would react as expected under the most adverse scenarios.

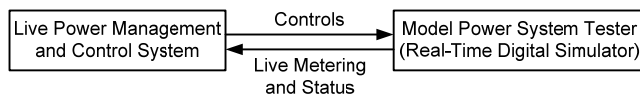


Fig. 9 Closed-Loop Real-Time Simulation

A. Model Validation

Once a model is constructed, it must be validated. A methodical validation process was used to prove that the created model was an accurate representation of the plant power system.

The following subsections outline the model validation methods.

1) Short-Circuit Validation

Fault current magnitudes between the real-time model and the values provided by plant personnel were compared. This confirmed that the transient and subtransient impedance values were correct. Saturation modeling was validated in this process as well. Real fault currents from protective relays are the best source of data for this validation method if the records can be correlated with system topologies and units.

2) Load Flow Validation

For standard islanded and nonislanded conditions, the active and reactive power flow and voltage magnitudes were compared to field experience. This confirmed that steady-state impedances and load values were correct in the model.

3) Generator, Turbine, and Governor Transient Validation

Standard IEEE models are rarely adequate to provide any realistic validation results. IEEE models are built to categorize different types of governing systems used in the industry, but they do not represent the actual detailed models required to create an accurate dynamic model. To overcome the shortcomings of these oversimplified models, custom models are used. Custom models can be acquired from some governor and turbine manufacturers, but these are often oversimplified and have inaccurate or unknown tuning constants. The only way to truly model the dynamics of a combined governor, turbine, and generator unit is to use a detailed back-to-basics mathematical derivation of the system. The system model parameters are derived from mechanical designs, operational experience, and observational data [3].

To validate the transient behavior of a power system, it is critical to first validate the individual governor, turbine, and generator sets. Step response data captured from the real-time digital simulator model are compared to field experience in this exercise. The outcome of these tests validates the generator, turbine, and governing system models. Inertia, damping constants, and slew limiters are all confirmed to be accurate in this exercise. This is the most rigorous and time-intensive form of validation. It also requires the largest amount of skill and experience to properly evaluate.

During the validation of the case study plant extraction turbine and governor model, it was discovered that the relationship among steam, droop, and controls was nonlinear and data from the site could not be reconciled with model output. Therefore, a custom model was designed, built, and validated to simulate the three-stage steam extraction turbines and their associated governors.

B. Load Validation

Due to the limitations of the number of loads that can be modeled, all of the plant loads in the facility were lumped into one of five categories: induction motors connected to pumps, induction motors connected to conveyors, synchronous motors connected to compressors, pulse-width modulated variable speed drives, or constant current variable speed drives.

Sheddable and nonsheddable lumped loads from one or more of the five categories were added to every load bus to enable real-time tripping of sheddable loads. A total of 123 lumped load models were derived from approximately 500 total plant loads.

Load inertia was calculated for all load types. Inertia was not counted for some loads because the high gearbox ratios connecting the induction motor to the belt made the transferred inertia to the electric power system insignificant.

Lumping the direct-on-line (DOL) load models was challenging due to the greatly varying starting and running torque versus speed characteristics of the different types of DOL loads in the plant. The double-cage induction motor model shown in Fig. 10 was selected as the lumped DOL induction motor model for all locations. The model shown in Fig. 10 was adapted to model all single and double rotor bar-constructed motors throughout the plant. The equivalent resistance and reactance parameters of the lumped double-cage induction machines were derived through a proprietary process.

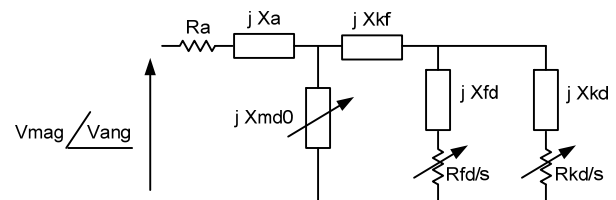


Fig. 10 Equivalent Circuit of the Double-Cage Induction Motor

C. Three-Valve Turbine and Governor Model

The authors created a new three-valve turbine and governor model (see Fig. 7) to accurately represent the following:

- The turbine governor controls both power production and steam production simultaneously.
- Two modes of control are possible: droop priority and extraction priority.
- In droop priority mode, the droop line is met as the first priority, and IP and LP extraction set points are

followed if possible. Fig. 2 depicts this mode of operation.

- In extraction priority mode, IP and LP extraction set points are met as the first priority, and the droop line is met if possible. Fig. 8 depicts this mode of operation.
- In extraction priority mode, a limited 4 percent droop line is accomplished, as shown in Fig. 8.
- The three valves are simultaneously controlled to simultaneously follow extraction set points from the SMS and power set points from the GCS.

D. Validation of Three-Valve Turbine and Governor Model

Fig. 11 shows the typical response characteristics of a three-valve turbine governor set.

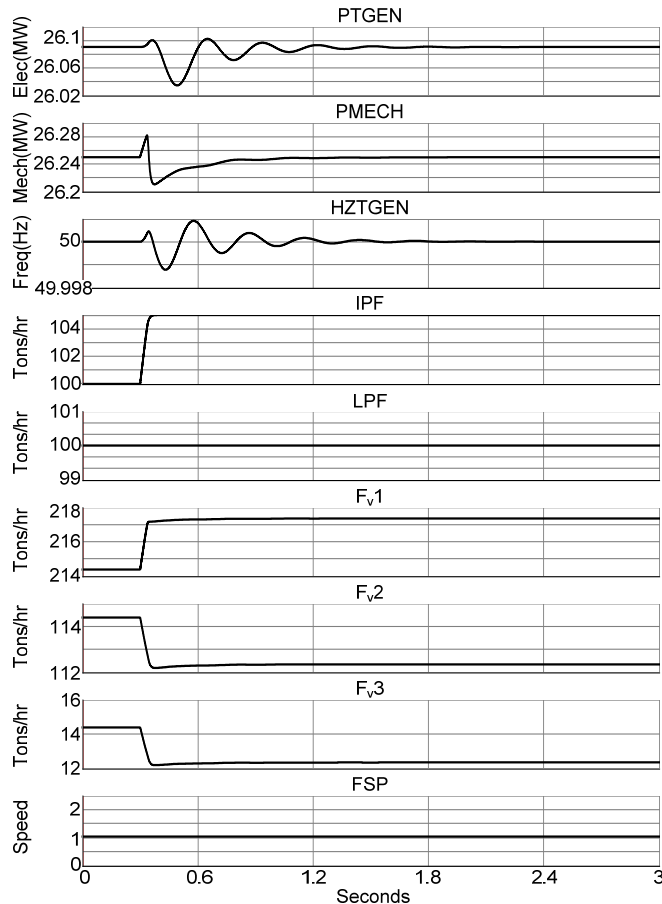


Fig. 11 Changing IPF Set Point From 100 to 105 Tons Per Hour

The plot in Fig. 11 represents a case whereby the IPF set point was changed (without a ramp rate limiter) from 100 to 105 tons per hour of steam flow. There are a number of critical items to point out from Fig. 11, including the following:

- IPF followed the new set point of 105 tons per hour.
- LPF stayed at 100 tons per hour throughout the disturbance.
- Valve 1 (V1 in Fig. 7) opened, causing the flow in Valve 1 (F_{v1}) to increase.

- Valves 2 and 3 (V2 and V3 in Fig. 7) closed, causing the flow in Valves 2 and 3 (F_{v2} and F_{v3}) to decrease.
- The power produced by the turbine was momentarily disturbed, but it regained its steady-state set point after about 1 second.

Fig. 8 shows the movement of the droop line for the event shown in Fig. 11. The change in IPF rates adjusted the low power limit upward, as signified by the movement from Line 1 to 2. Simultaneously, the droop line did not move; however, its upper and lower limits were adjusted by the new IPF rates.

XI. SYSTEM PERFORMANCE

Fig. 12 shows the case study plant (from Fig. 6) broken into six different islands without the GCS. Each island had one generator and multiple loads. As expected, each island settled to off-nominal frequency.

Fig. 13 shows the same situation as Fig. 12 but with the GCS enabled. The GCS simultaneously regulated all six islands to a nominal frequency of 50 Hz. Both Fig. 12 and Fig. 13 were captured from closed-loop real-time simulation with the GCS.

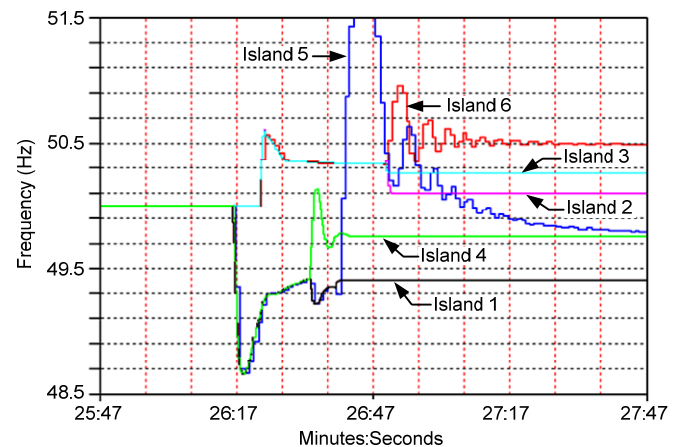


Fig. 12 Six Islands Without GCS

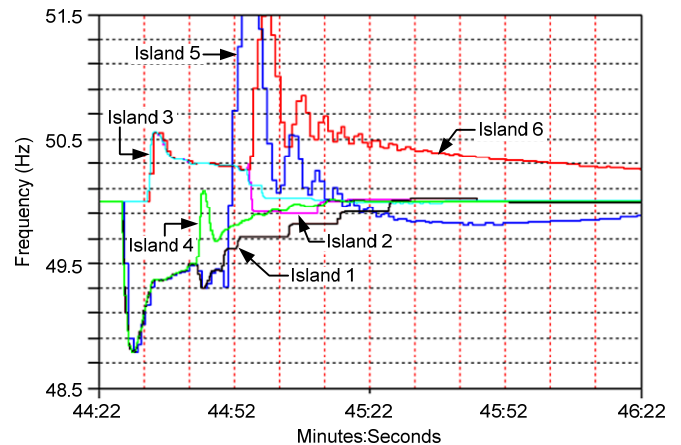


Fig. 13 Six Islands With GCS

XII. CONCLUSIONS

During nonislanded conditions, the following conclusions can be made:

- GCS schemes can simultaneously dispatch the generators to equal percentage turbine loading and tie-line power dispatch set points.
- The GCS must use adaptive boundary conditions based on steam extraction flows and third-valve (condensing) position measurements.
- As long as the ST extraction and pressure controls are tuned to be very slow (60 seconds or slower, commonly), the natural stabilization of the governor droop control is not compromised for transient conditions.
- Three-stage turbines in extraction mode meet most interconnect standards for droop control only if V3 (shown in Fig. 7) is not fully open or closed.

During islanded conditions, the following conclusions can be made:

- ST generators must be switched out of steam extraction to droop priority control mode to support the electric power grid from collapse.
- GCS schemes must focus on frequency dispatch and equal percentage turbine loading.
- Governors are switched from extraction to droop mode when a plant is islanded to improve electrical disturbance rejection.
- An SMS without a GCS can cause an electric power system blackout during islanded conditions.
- A GCS may have to send feed-forward signals to bypass valves and trip loads to prevent header pressure problems during islanded conditions.

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XIV. VITAE

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Best Practices for Motor Control Center Protection and Control

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BEST PRACTICES FOR MOTOR CONTROL CENTER PROTECTION AND CONTROL

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Abstract—Low-voltage motor control centers (MCCs) are numerous and consume a large portion of maintenance and operator interaction in an industrial power distribution system. The extensive human interaction with these low-voltage (less than 1,000 V) circuits makes a low-voltage MCC a location of significant potential hazard. The large number of low-voltage MCC circuits results in significantly more human interface time with low-voltage MCC equipment than with medium-voltage MCCs and switchgear.

Modern protection and control systems derived from medium-voltage (1,000 V to 38 kV) and high-voltage (38 to 765 kV) power systems have much to offer low-voltage MCC systems. Proactive maintenance indicators based on load characteristics, motor start characteristics, and thermal measurements are described. Time synchronization, modern Ethernet-based protocols, sequence of events records, oscillography (COMTRADE), monitoring and alarming for protection functions, and other previously standard features in medium- and high-voltage protective relays are available in modern low-voltage MCC protective relays. Increased safety in the form of advanced protection elements and arc-flash detection are now also available.

This paper focuses on the philosophy of a comprehensive low-voltage MCC protection and control system.

Index Terms—Reliability, motor control center (MCC), safety, arc-flash hazard, protection, automation, multifunction microprocessor-based relays.

I. INTRODUCTION

We do not have to look farther than the dashboard on a modern automobile to see opportunities for practical advancements in industrial motor control and protection. A simple turn of the ignition key begins a series of self-diagnostics on devices and systems critical to personal safety and vehicle reliability. Dashboard indicators provide the status of the antilock braking system, dual-master brake cylinder, and tire pressure. There are indicators for failures in safety-related light bulbs, including headlights, brake lights, turn signal indicators, and side lamps. Other indicators monitor lubrication oil and coolant levels, which are critical to preventing costly failures. An automobile mechanic can

connect instrumentation to immediately download diagnostic data and failure codes to pinpoint the need for maintenance or corrective action. These advancements in sensors and instrumentation that enable continuous monitoring, self-diagnostics, and event logging are embedded in millions of automobiles on the road today and are helping make automobiles safer and more reliable. The technologies found in automobiles are making their way into industrial applications to enable advancements in safety and reliability, improve energy and raw material use, and reduce the costs and improve the effectiveness of maintenance resources.

These advancements are especially applicable toward improving the reliability of protective devices essential for arc-flash hazard mitigation. The recognition of arc flash as a unique electrical hazard has led to a new expectation for circuit protection devices: the safeguarding of personnel from the hazards of thermal burns and explosive blasts. Arc-flash hazards have changed the design rules for the analysis and protection of power systems. This has also led to a different expectation for electrical equipment maintenance: the assurance that overcurrent protective device pickup and trip characteristics used as the basis for arc-flash hazard analysis and the selection of hazard control measures, including personal protective equipment, perform exactly as designed. If these protective devices do not function as designed, the thermal and blast energy exposure can be orders of magnitude greater than expected. Unfortunately, early generations of protective devices can fail. The failure can go undetected until the next scheduled maintenance inspection. If an arc-flash event occurs, the thermal energy released can be orders of magnitude greater than anticipated. Technologies that enable the remote monitoring of current, voltage, contactors, and overload devices impact more than arc-flash mitigation. These technologies also help reduce exposure to electrical shock hazards by decreasing the need to troubleshoot and perform other maintenance tasks that place workers in close proximity to potentially hazardous voltages.

This paper describes a comprehensive low-voltage (LV) protection and control system for motor control centers (MCCs). This system is designed to provide increased safety, more selective protection, advanced event diagnostics, reduced cost, and higher reliability than previous technologies.

II. BACKGROUND

Prior to the 1990s, MCC units were electromechanical in design and typically included a contactor, thermal overload elements, and short-circuit protection. Local and remote indications were provided through hard-wired lights and signals to a programmable logic controller (PLC). The PLC then sent the state of the MCC buckets to the process control system (PCS). Status and control messaging between the MCC buckets and PLCs required extensive cabling between the MCC, PLC, and PCS for start and stop control and monitoring. It was not uncommon to need 16 control and metering wires per motor starter unit. Hence an MCC with 30 units could have required 480 wires, 960 terminations, sufficient terminal blocks, and a separate distributed control system (DCS) marshalling cabinet in the building.

Between 1990 and 2010, the concept of smart MCCs was developed by many manufacturers. The features of these systems mainly revolved around improving diagnostics, reducing wiring, and removing personnel from the immediate vicinity of dangerous voltages [1]. These MCC designs substantially reduced wiring by placing intelligent electronic devices (IEDs) in the MCC bucket and by using digital communications instead of hard-wired signals. At the core of these older, smart MCC designs were PLCs communicating via industrial protocols. The protection, metering, and control IEDs used in these older designs (from the last 20 years) were simple microprocessor-based multifunction devices with very limited capabilities.

The reliability, functionality, programmability, flexibility, and intelligence of these older, smart MCC protection, metering, and control IEDs were very limited when compared with modern medium-voltage (MV) and high-voltage (HV) microprocessor-based multifunction protective relays. Simultaneous to the evolution of the smart MCC systems, a vastly more sophisticated set of electronics, software tool sets, diagnostics, reporting, and communications methods were developed for the MV and HV electric power protection industry throughout the world. These more sophisticated protection IEDs have been used since 1982 in the MV and HV protection industry (1,000 V to 765 kV). These transmission-grade IEDs are subjected to severe environmental testing and reliability requirements, such as temperature, shock, and electromagnetic interference. The mean time between failures of these transmission-grade systems and products exceeds 300 years [2].

The features and reliability of the HV transmission and MV-grade products are becoming the new standard for LV protection and control products. It is in the best interest of industry professionals to bring the reliability, safety, and reduced cost of these transmission- and distribution-grade products and integration philosophies into LV systems.

A. Historical LV Motor Protection

Historically, the protection of LV motors was done with thermal overload elements and short-circuit interruption devices. Motor thermal overload elements were most commonly melting alloy overload relays. The motor current was routed through this alloy, and if the current exceeded a

time-overcurrent threshold, the alloy melted. The melting of the alloy allowed an internal ratchet wheel to turn and open a set of contacts, thus opening the motor contactor. There was also some reset time, which was required to allow the alloy to cool and harden. This equated to the motor cooldown time.

Short-circuit current interruption was typically accomplished with a type of magnetic circuit breaker (or circuit protector) capable of interrupting cable fault currents. The fault current levels that the circuit breaker must interrupt were often larger than what a motor contactor (starter) could interrupt, so the circuit breaker had to directly interrupt the fault current on its own. Note that many magnetic circuit breakers were rated only to interrupt full fault current one time. After full fault current was interrupted, there was no guarantee that these circuit breakers would function correctly again.

B. What Is a Protective Relay?

The primary purpose of any protective relay is to identify events worthy of interrupting the flow of current. The following three classes of relays exist in the world today [3]:

1. Electromechanical relays that are constructed of wire, magnets, springs, dashpots, and steel components to detect anomalous events.
2. Solid-state relays that are constructed of silicon-based components built up as analog circuits (e.g., operational amplifiers) to detect anomalous events. All signals remain analog. No signals are digitized in these devices.
3. Microprocessor-based multifunction relays that convert analog currents and voltages to digital signals, which are processed to detect anomalous conditions. Only microprocessor-based relays have advanced diagnostic and communications features.

III. CHARACTERISTICS OF A MODERN LVMR

This section explains the basic characteristics and feature set of the modern microprocessor-based low-voltage motor relay (LVMR). Fig. 1 shows the typical implementation of the LVMR for a direct-on-line (DOL) started motor application.

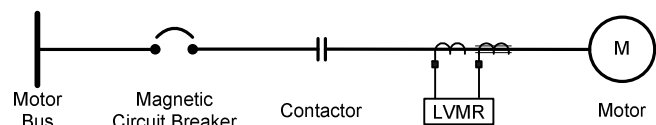


Fig. 1 Direct-Start Motor Application

A. Features of LVMRs

Many features differentiate the modern microprocessor-based multifunction LVMRs from older technologies. These features include the following:

1. Detailed event diagnostic reporting features, such as sequence of events (SOE), oscillography, motor start and stop reports, and load profiling. These features replace strip charts and oscilloscopes.
2. Onboard time-stamping of all events and settings changes. Simple Network Time Protocol (SNTP) time

synchronization is used to keep all the LVMRs time-synchronized.

3. An integrated power supply, which can be powered from 24 to 250 Vdc or 110 to 240 Vac sources (eliminating auxiliary power supplies in the cabinets).
4. Onboard arc-flash detection (AFD).
5. A small form factor. The devices must fit into the smallest LV MCC buckets.
6. Multiple Ethernet and serial ports. A clear demarcation line between process and electrical systems is easy to achieve on products with multiple communications ports.
7. IEC 61850 Generic Object-Oriented Substation Event (GOOSE) and Manufacturing Message Specification (MMS) protocols to take advantage of the simplicity and cost savings of Ethernet-based communication.
8. Communications protocols built directly into the main board of the unit. Firmware (not hardware) can be updated to enable new protocols.
9. Direct terminal block connections for temperature measurement, analog outputs, digital outputs, and optoisolated digital inputs. All digital outputs should be dry contacts because transistorized outputs are unsuitable for trip circuits.
10. Complete onboard diagnostics to determine if the power supply, microprocessor, memory, analog-to-digital converters, and other components are functioning properly.
11. Conformal-coated boards for the dirty and corrosive environments common in industrial LV applications.
12. A simplified setup from a web-based human-machine interface (HMI) mounted on the bucket front door.
13. Built-in metering with fundamental and harmonic data.
14. Complete onboard diagnostics to determine if the power supply, microprocessor, memory, analog-to-digital converters, and other components are functioning properly.
15. Programmability similar to a miniature PLC, including Boolean logic, analog mathematics, timers, counters, and programmable discrete and analog outputs for custom control and protection schemes.
16. Security in the individual LVMR that must include (at a minimum) multilevel password login and strong password protection schemes.

B. Direct-Start Motor Protection

The protection features of the modern microprocessor-based LVMR (see Fig. 2) commonly provide the following functions [4]:

1. DC offset and harmonics removal inherent with modern ac signal filtering techniques [5].
2. Full real-time symmetrical components in polar form phasors (magnitude and phase angle) and the metering of voltages (V_0 , V_1 , and V_2) and currents (I_0 , I_1 , and I_2).
3. Undervoltage and overvoltage (27 and 59) elements.

4. Underfrequency and overfrequency (81U and 81O) elements.
5. Load loss detection (37CP) element.
6. Power factor (55) element.
7. Phase reversal (47) element.
8. Loss-of-potential (60) element.
9. Instantaneous and time-overcurrent (50 and 51) elements.
10. Thermal (49T and 49P) elements.
11. Locked rotor detection (50PLR) element.
12. Load jam detection (50PLJ) element.
13. Current unbalance detection (46) element.
14. Breaker failure protection.
15. Motor lockout.
16. Negative-sequence overcurrent (50Q and 51Q) elements.
17. Motor starting and running (14 and 66) elements.
18. Variable frequency drive (VFD) protection.
19. Arc-flash detection (AFD) element.

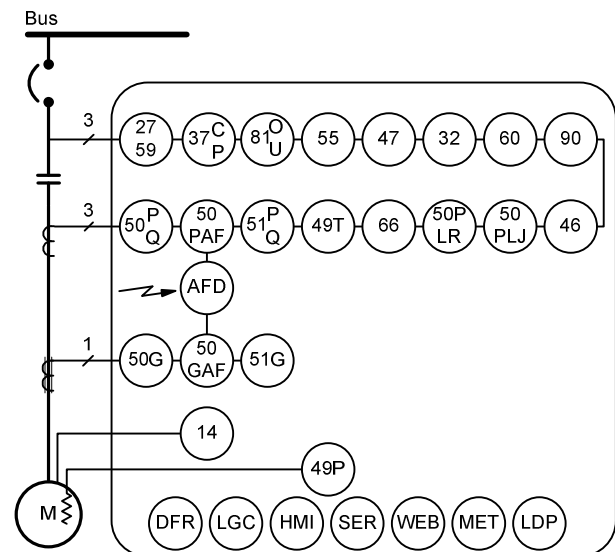


Fig. 2 Modern LVMR Functionality

C. Lighting Circuit Protection

LVMRs can also be used for lighting circuit or feeder protection. Note that in the list in Section III, Subsection B, the protection elements are provided for basic feeder protection schemes. These include phase, ground, and negative-sequence overcurrent protection; phase, ground, and negative-sequence time-overcurrent protection; and directional power and AFD elements.

Of particular interest is the opportunity to improve relaying sensitivity to prevent human electrocution and injury. Sophisticated protection schemes designed to prevent human electrocution, such as those mentioned in prior IEEE papers [6], can now be implemented by any user. These schemes can be implemented by using programmable logic in the LVMR, high-speed relay-to-relay communication, and sensitive zero-sequence elements.

D. Variable Frequency Drive Protection Enhancements

Many low-cost VFDs do not have sufficient motor protection, metering, automation, controls, or communications capabilities. Modern microprocessor-based LVMRs fill these gaps. A typical one-line diagram for such a system is shown in Fig. 3.

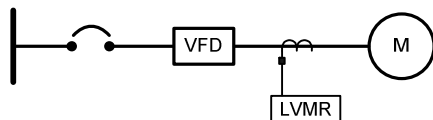


Fig. 3 Enhancing VFD LV Motor Protection

In the VFD operating mode, the thermal model and overcurrent protection elements use root-mean-square (rms) current magnitudes that include both the fundamental and harmonic content. This is in contrast to normal motor and feeder protection modes that only use the fundamental frequency magnitudes via the long-standing method of cosine filtering [5].

With self-cooled motors, a reduction of the motor speed also reduces the cooling air flow. Sustained reduced-speed operation can result in the motor overheating. Modern LVMRs provide thermal protection throughout the VFD speed ranges.

E. Arc-Flash Protection

Electrical hazards that can result in human injury or death commonly come in two forms: arc flash and electric shock. For the maximum in personnel safety, there are a large number of schemes available that use the positive (I_1), negative (I_2), and zero-sequence (I_0) quantities calculated in an LVMR.

The AFD element in a protective relay can provide a significant reduction in the hazardous incident energy from an arc fault [7]. The light produced by an arc flash provides a large-magnitude signal that is used in conjunction with overcurrent sensing to securely and reliably detect an arc fault. Upon detection of the arc-fault condition, the relay initiates the high-speed tripping of an upstream breaker to minimize the arc-fault duration and resultant incident energy. In the system we describe in this paper, the LVMR is capable of providing the entire arc-flash protection function, including light sensing, overcurrent sensing, and high-speed tripping.

The typical MCC implementation is vulnerable to arc faults upstream of the LVMR (e.g., on the contactor, fuse, busbar, or breaker). Consequently, it is also advantageous to sense the arc-fault overcurrent on the incoming feed to the motor bus while still sensing the light flash within the MCC bucket. Furthermore, LV MCCs typically use fuses, motor circuit protectors, or thermal magnetic circuit breakers within the buckets that are not tripped by a protective relay (only the contactor is opened by a relay). As a result, it is necessary to trip the incoming motor bus breaker to reliably clear the arc fault.

When a light flash is detected in an MCC bucket, high-speed IEC 61850 GOOSE messaging is sent from the LV

protective relay to an upstream relay associated with the motor bus circuit breaker (52). If the upstream relay detects an overcurrent condition coincident with the MCC bucket light flash, a high-speed trip is initiated on the motor bus circuit breaker to minimize the arc-fault duration. A typical scheme for such a system is shown in Fig. 4.

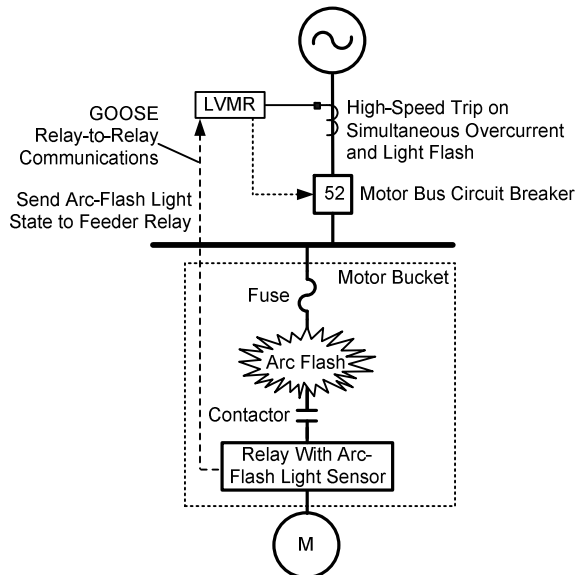


Fig. 4 Use of Relay-to-Relay GOOSE Messaging for Arc-Flash Protection

Tests during live arc-flash events with multiple relays prove that the careful design of relays is required for them to survive the harsh environment of the arc-flash plasma cloud. This environment includes very high temperatures, bright light, ionized air, strong magnetic fields, flying molten metal, and mechanical shock. Table I shows the end-to-end detection and trip times measured during arc-flash testing at a high-current laboratory. The test methodology is similar to that described in [8] but with an LVMR instead of a feeder relay.

TABLE I
SUMMARY OF GOOSE ARC-FLASH TRIP TIMES

	Trip Time (milliseconds) From Application of Current
Minimum	4
Maximum	13

The microprocessor-based LVMR must survive an arc-flash event long enough to trip upstream breakers. The LVMRs must be designed and tested to survive an arc-flash event if they are to effectively sense an arc flash and trip an upstream breaker. This is an onerous task that requires ruggedized design principles that far exceed the norm in the industry.

Significant testing of the relays must be done in real arc-flash environments to ensure survival. Typical testing methods

are shown in Fig. 5. Field tests have proven that even in a catastrophic arc-flash test event, at least four GOOSE messages indicating the arc-flash event are sent within 16 milliseconds. The total time from the start of fault conditions to an upstream relay having trip-rated contacts fully closed and conducting is shown in Table I. The variance between 4 to 13 milliseconds is caused by the asynchronous processing cycles of the microprocessor-based relays.

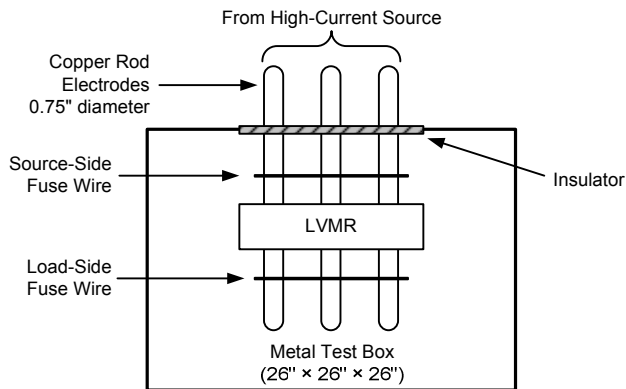


Fig. 5 Arc-Flash Test Box

F. Configuration and Commissioning of LVMRs

Operator handle interlocks may not allow a bucket door to be opened while live voltages exist in the bucket. This means that the front of the relay may not be available for configuration while it is in an energized state. All configuration can be done through the communications network when the bucket door is closed and the circuits are energized. This makes it imperative that simple, reliable, time-proven, and diverse methods exist to configure and test the microprocessor-based LVMR. Modern devices are configured and commissioned through one or more of the following:

1. Simple, user-friendly, embedded web server.
2. Remote configuration through the communications network.
3. Diverse communications media options, such as serial terminal session, File Transfer Protocol (FTP) Transmission Control Protocol/Internet Protocol (TCP/IP) file transfer, or Telnet TCP/IP.
4. Full configuration without any software through a menu-driven bucket-mounted HMI.
5. Portable hand-held device settings transport.
6. Global relay settings software management tools.
7. Manual configuration using the command prompt (via Ethernet or serial communication).

G. Hardened Equipment Specifications

LVMRs are applied in harsh physical and electrical environments; thus, they must withstand vibration, electrical surges, fast transients, and extreme temperatures. The type-test standards that the devices must meet include the following:

1. 15 g vibration resistance (IEC 60068-2-6:1995).
2. Shock resistance (IEC 60255-21-2:1988).

3. Cold tolerance at -40°C for 16 hours (IEC 60068-2-1:2007).
4. Steady-state damp heat (IEC 60068-2-78:2001).
5. Cyclic damp heat (IEC 60068-2-30:1980).
6. Dry heat (IEC 60068-2-2:2007).
7. High-potential dielectric (IEC 60255-5:2000 and IEEE C37.90-2005).
8. 15 kV electrostatic discharge immunity (IEC 61000-4-2:2008 and IEC 60255-22-2:2008).
9. Radiated radio frequency immunity (IEC 61000-4-3:2008 and IEC 60255-22-3:2007).
10. 2.5 kV common-mode surge withstand capability immunity (IEC 60255-22-1:2007).
11. IEEE C37.90 and IEC 60255 protective relay standards.

Additional organizations that commonly affect LVMR installations are the International Organization for Standardization (ISO), Underwriters Laboratory (UL), Canadian Standards Association (CSA), and the European Commission (CE).

H. Internal Self-Testing and Diagnostics

Modern microprocessor-based LVMRs must advise monitoring systems when they are having internal problems, such as failures in internal memory, power supply problems, input/output (I/O) board failures, current transformer (CT) or voltage transformer (VT) board failures, clock inaccuracies, or processing vectoring errors. Ultimately, the greatest advantage of any protection IED is that it can continuously confirm whether it is functioning properly.

LVMRs continuously run self-diagnostic tests to detect out-of-tolerance conditions. These tests run simultaneously with the active protection and automation logic and do not degrade the device performance.

The LVMR reports out-of-tolerance conditions as a status warning or a status failure. For conditions that do not compromise functionality yet are beyond expected limits, the LVMR declares a status warning and continues to function normally. A severe out-of-tolerance condition causes the LVMR to declare a status failure and automatically switch the device into a device-disabled state. During a device-disabled state, the LVMR suspends protection elements and trip/close logic processing and de-energizes all control outputs.

LVMR internal diagnostics must discern between hardware, firmware, or software alarm conditions. User-initiated events, such as settings changes, access level changes, and unsuccessful password entry attempts, must also be logged.

I. Event Diagnosis

The ability to diagnose and understand motor overloads, short-circuit trips, motor starts, and all other relay operations has proved critical in the protection industry. Having synchronized time signals to all IEDs in the LV MCC and throughout an industrial plant provides the ability to have comparable power system fault and disturbance event reports (oscillography), Sequential Events Recorder (SER) records,

and time-accurate reporting for supervisory control and data acquisition (SCADA) analog and state-change records (SOE).

Being able to perform time-deterministic root-cause analysis of system events and combine report data from different microprocessor-based relays to calculate in real time the timing between occurrences related to the same incident has proved invaluable.

The types of event records commonly provided by an LVMR include the following:

1. Oscillographic recording using a built-in oscilloscope. Every event has an oscillography report for postmortem analysis.
2. Trip event reports, including special oscillographic reports of every trip or stall event.
3. SOE capture. The binary state of change of inputs, outputs, and internal digital variables.
4. Total harmonic distortion (THD) measurement.
5. Load profile report, which stores the metering quantities captured every few seconds into nonvolatile memory. This replaces slow-sample, long-duration strip chart recording devices.
6. Event summaries, which are shortened, simplified versions of oscillography reports (typically used for nontechnical management).
7. Event histories, which provide summaries of all recent load trips or jams.
8. Motor operating statistics report. This includes summarized information such as running data, start data, and alarm and/or trip data.
9. Motor start trending, which is a simple summary of all motor starts.
10. Motor start report, which provides a special oscillographic recording of every motor start.

J. Data Processing for Protection IEDs

Protection techniques based on the rms calculated values of current and voltage are inadequate for motor start applications. For example, rms calculated values do not reject dc and harmonic offsets due to transformer inrush. Techniques used in HV relays, such as the cosine filtering of sampled data, must be used to prevent nuisance misoperation of LV relays due to spurious dc and harmonics present in all power systems [5].

IV. CENTRALIZED SMART MOTOR CONTROL SYSTEM

A centralized smart motor control system (CSMCS) is recommended to provide a fully integrated, preconfigured LV MCC protection and control package. The CSMCS simplifies the configuration, commissioning, and testing of large numbers of LVMRs. The CSMCS is a preconfigured engineered solution for MCCs. The CSMCS replaces extensive cabling between relays, PLCs, remote terminal units (RTUs), and other controllers with a minimum count of industrially hardened, devoted-purpose LVMRs. Communication to each LVMR is done with a single Ethernet

cable, implementing IEC 61850 GOOSE and MMS messaging from each relay to a centralized managed switch.

The CSMCS shown in Fig. 6 provides users with immediate real-time information on motor performance, centralized touchscreen HMI access to IEDs throughout the LV MCC lineup, and historical reporting and analysis. This networked CSMCS solution integrates the latest LVMR and incoming feeder relay for advanced motor protection, control, metering, and process automation.

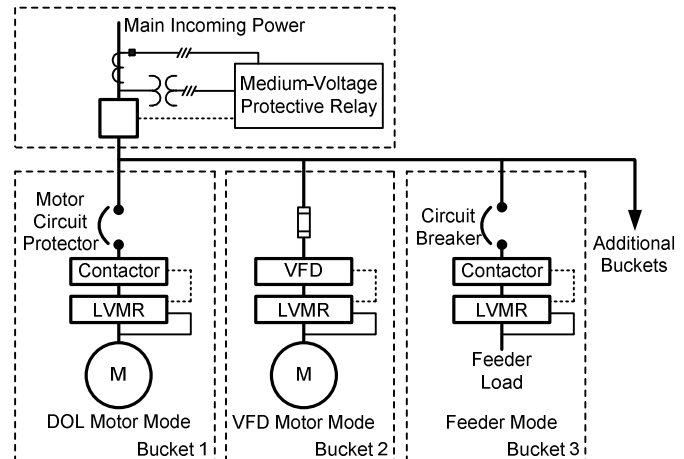


Fig. 6 CSMCS One-Line Drawing

Valuable motor and MV and LV system process data are automatically gathered, consolidated, and made available simultaneously to the PCS, power management systems (PMSs), and asset management systems. Fig. 7 shows the simplified communications hierarchy of the CSMCS.

The CSMCS is also a complete protection, control, and monitoring solution for an MCC. It provides process diagnostics that simplify maintenance by allowing users to detect and correct problems before they become critical, preventing damage and minimizing process downtime.

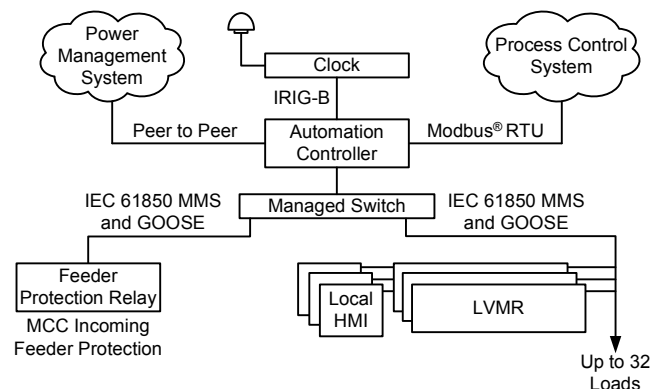


Fig. 7 CSMCS Concept

A. CSMCS Functions and Performance

The CSMCS uses standard integration and communications techniques that have been refined based on

decades of utility and industrial electric power protection experience. Some of the attributes of the CSMCS include the following:

1. AFD that signals to initiate an upstream breaker trip signal less than 13 milliseconds from the detection of an arc-flash event anywhere in the MCC.
2. Ethernet communication between LVMRs.
3. HV- and MV-grade feeder protection at the main incoming section.
4. Control and monitoring of individual loads.
5. Complete status and metering data from each load and the entire motor bus.
6. Preconfigured bidirectional communication and interface to the plant PMS and PCS.
7. Preconfigured HMI systems, which provide basic system visibility via several options.
8. Factory preconfigured and programmed relays, controllers, and managed switches specifically for the CSMCS application.
9. Automatic configuration of the IEC 61850 configuration of IEDs when they are placed on an Ethernet network.
10. Remote PMS monitoring capability.
11. Subcycle remote trip operation response from remote PMS load-shedding schemes.
12. Engineering access to every IED on the Ethernet network.
13. Centralized event diagnostic software.
14. Instantaneous power metering from every relay to give real-time feedback about process operations.
15. Metering for tracking process energy costs and improving energy usage.
16. Standard data that include system faults, annunciation, motor thermal capacity used, motor load current, bus voltage, power, energy and percentage loading, motor operating statistics, motor start reports, and relay-stamped SER.

B. Multilevel HMI Annunciation

Critical for the long-term maintenance of an MCC are multiple levels of system annunciation. Should a central HMI fail, the local HMI on the front of the bucket is available. Installations requiring minimal visualization and diagnostics may have only a simple front-panel indicator. Installations requiring maximum visualization and diagnostics typically use a centralized HMI system. The three most typical HMI annunciation methods are as follows:

1. A small individual bucket HMI that provides cost-effective interface capabilities (see Fig. 8).
2. A medium individual bucket HMI that provides extensive and cost-effective interface capabilities (see Fig. 9).
3. A system-wide HMI (viewed on a local, remote, or portable computer) that provides system-level and drill-down status viewing and control for each load (not shown).

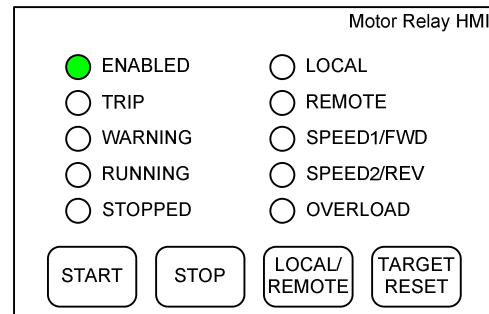


Fig. 8 Small Bucket Individual LVMR HMI

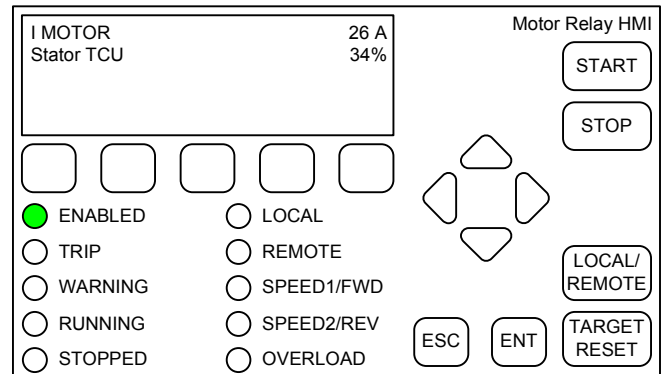


Fig. 9 Medium Bucket Individual LVMR HMI

C. Communications Architectures

In order to reduce cost, it is recommended that all LVMR devices support at least a daisy-chain Ethernet solution, as shown in Fig. 10. For maximum network redundancy and reliability, the preferred solution is for the LVMR to communicate to dual switches in a dual-star arrangement, as shown in Fig. 11. Dual-star networks are common for extremely critical functions, such as load shedding [8].

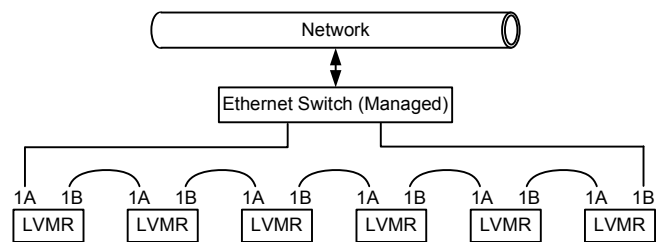


Fig. 10 Daisy-Chain Architecture for Minimum Cost

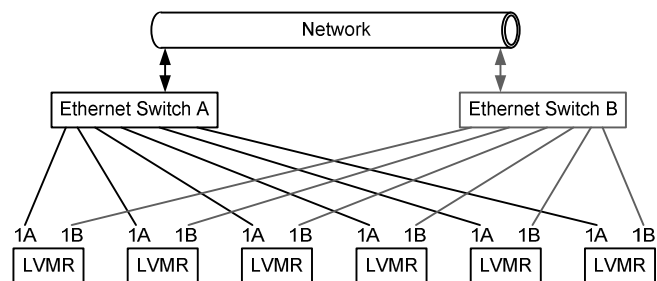


Fig. 11 Dual-Star Architecture for Maximum Reliability

V. LABOR AND ECONOMIC CONSIDERATIONS

Due to the volume of LVMRs installed in many plants, the total cost of ownership must be factored into any decision to use new LVMR or CSMCS technologies. There are several proven strategies, concepts, and technologies that should be considered in any economic or return-on-investment calculation. These include the following:

1. What is the warranty for the equipment and components?
2. What is the field measured product reliability and quality?
3. What is the total cost to production and maintenance for a failed LVMR?
4. What is the reputation and history of the manufacturer supplying the system?
5. Is it possible to order components installed with the default configurations and logic of the end-user facility?
6. What is the historical failure rate of similar components in the end-user facility?
7. What has been the customer support response time?
8. Are there sufficient diagnostic tools available to help find the root cause of problems?
9. Will the system prevent injuries to personnel?
10. How does the technology fit into the safety program?
11. Are there skilled personnel available locally to set the devices?
12. What do long-term maintenance agreements cost?

VI. STANDARDIZATION AND SIMPLIFICATION

Industries with limited engineering talent do not commonly have the resources to devote to designing a detailed CSMCS solution. The experience required to adequately design a full solution can be significant. Skills in communications systems, protection schemes, and programmable logic are required. These skills within an organization are often better devoted to larger tasks. To address this issue, many corporations have chosen a standardization program to simplify the design, ordering, manufacturing, testing, installation, and commissioning of such systems.

To facilitate the needs of end users to standardize, CSMCS solution providers must be able to order all the affiliated equipment with standard settings that meet specific end-user needs. These settings are usually sufficient for an MCC manufacturer with no additional engineers to pass a full factory acceptance test without having to adjust any settings in any devices.

Once these factory-ordered solutions are delivered and installed in a plant, commissioning the system per true field conditions is required. For fast and basic protection, it is most convenient to enter motor nameplate data directly into the basic settings display. For more complex protection requirements, which are typical of large or unusual motors, it is appropriate to use more flexible and advanced methods. For example, the web-based interface is a convenient and

easy method for electricians and technicians to configure, commission, and monitor the LVMRs.

VII. CONCLUSION

The following points capture the essential takeaways about a comprehensive LV MCC protection and control system:

1. Comprehensive feature sets in the LVMR increase reliability, improve safety, and reduce the operating costs of LV MCC systems.
2. The system reduces motor failures with advanced protection elements.
3. Direct-start motors, lighting circuits, and VFD-driven motors are protected by a single LVMR model.
4. Arc-flash detectors built directly into the LVMR and advanced protection strategies are used to reduce the incident energy of events.
5. Simple, reliable, and time-proven methods of configuring, commissioning, and communicating with the LVMR must be supported.
6. Ruggedized designs and thorough type-testing of LVMRs improve the reliability of an LV MCC system and reduce process downtime.
7. An LVMR with internal testing and onboard diagnostics immediately identifies if the protection and control system is functioning.
8. LVMRs with several different types of event records aid in the diagnosis of motor overloads, short-circuit trips, and motor starting problems.
9. Cosine filtering of sampled data in an LVMR prevents spurious events caused by rms calculation techniques.
10. End users save money and time with a preconfigured, standardized CSMCS solution.
11. Due to the volume of LVMRs installed in many plants, the total cost of ownership must be factored into any decision to use new LVMR or CSMCS technologies.

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IX. VITAE

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Case Study: An Adaptive Underfrequency Load-Shedding System

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CASE STUDY: AN ADAPTIVE UNDERFREQUENCY LOAD-SHEDDING SYSTEM

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Abstract—Underfrequency (UF) schemes are implemented in nearly every power system and are deemed critical methods to avert system-wide blackouts. Unfortunately, UF-based schemes are often ineffective for industrial power systems.

Traditional UF schemes are implemented in either discrete electromechanical relays or microprocessor-based multifunction relays. Individual loads or feeders are most commonly shed by relays working autonomously. The UF in each relay is set in a staggered fashion, using different timers and UF thresholds. Sometimes, $d\omega/dt$ elements are used to select larger blocks of load to shed. Unfortunately, no traditional schemes take into account load-level changes, system inertia changes, changes in load composition, governor response characteristics, or changes in system topology.

This paper explains an adaptive method that overcomes known UF scheme problems by using communication between remote protective relays and a centralized UF appliance. This method continuously keeps track of dynamically changing load levels, system topology, and load composition. The theory behind the improved scheme is explained using modeling results from a real power system.

Index Terms—Reliability, dynamic stability, blackout, incremental reserve margin, generation shedding, spinning reserve, load shedding, ICLT.

I. INTRODUCTION

Power unbalances of power supply versus load in ac electric power systems often lead to blackouts. Blackouts affect utilities, ships, refineries, mines, data centers, industrial processes, military installations, and basically every power system in the world. A historical method for detecting power unbalances is to detect a fall or rise in the frequency of the power system voltage fundamental. The crossing of a level of underfrequency (UF) or overfrequency (OF) in a power system is then used to trigger the shedding (dropping) of loads or generators to rebalance the power system. Several present day methods exist for such UF load-shedding and OF generation-shedding schemes. This paper explains a new method of providing a unified UF load-shedding and OF generation-shedding system for any power system size. The algorithm used operates by monitoring time-synchronized

measurements of angle and frequency to identify any number of islands in a power system. Load-shedding processing is based on the total inertia of each islanded system, combined with the frequency rate of change. For the purposes of this paper, this new scheme is designated as an inertia compensation and load-tracking (ICLT) system. This approach has made practical the development of an ICLT appliance for use on power systems around the world. The new system is easy to use for all engineers, even those with minimal experience.

II. BACKGROUND

In order to explain the impact of the new method, this section discusses the basis of the problems associated with load-shedding systems today.

A. Island Tracking

Island tracking is also known as “topology tracking.” Load-shedding systems must track the power system topology to relate the trigger (UF or otherwise) to sheddable loads. Fig. 1 illustrates the problem with topology tracking. UF triggers are derived from the 132 kV busbars. However, the sheddable loads are downstream at the 13.8 kV, 4 kV, and 480 V busbars. Because this facility can be broken into multiple islands, a load-shedding system must track the status of all the breakers and disconnects between the 132 kV, 13.8 kV, 4 kV, and 480 V busbars in order to constantly compute the real-time topology.

Fig. 1 includes an example topology configuration showing two possible simultaneous islands, one black and one gray. Many more island combinations exist in this buswork, namely if lower-voltage bus-tie breakers are closed and incoming breakers are opened. For a medium-sized installation, topology tracking scenarios number in the tens of thousands.

The effort and cost of tracking the topology of a complex plant can be significant. Take into account that I/O modules must be placed throughout the plant to track the open and close status of all breakers and disconnects. These I/O modules require fiber-optic communication to travel the long distances between substations, which can commonly be several kilometers away in a petrochemical, natural gas liquid (NGL), or refinery facility. The user must also take into

account the cost of engineering and technician labor to configure, install, test, maintain, and monitor the equipment.

The ICLT method eliminates the need for any topology tracking, thereby greatly reducing the complexity, cost, and maintenance and greatly increasing the reliability of load-shedding systems.

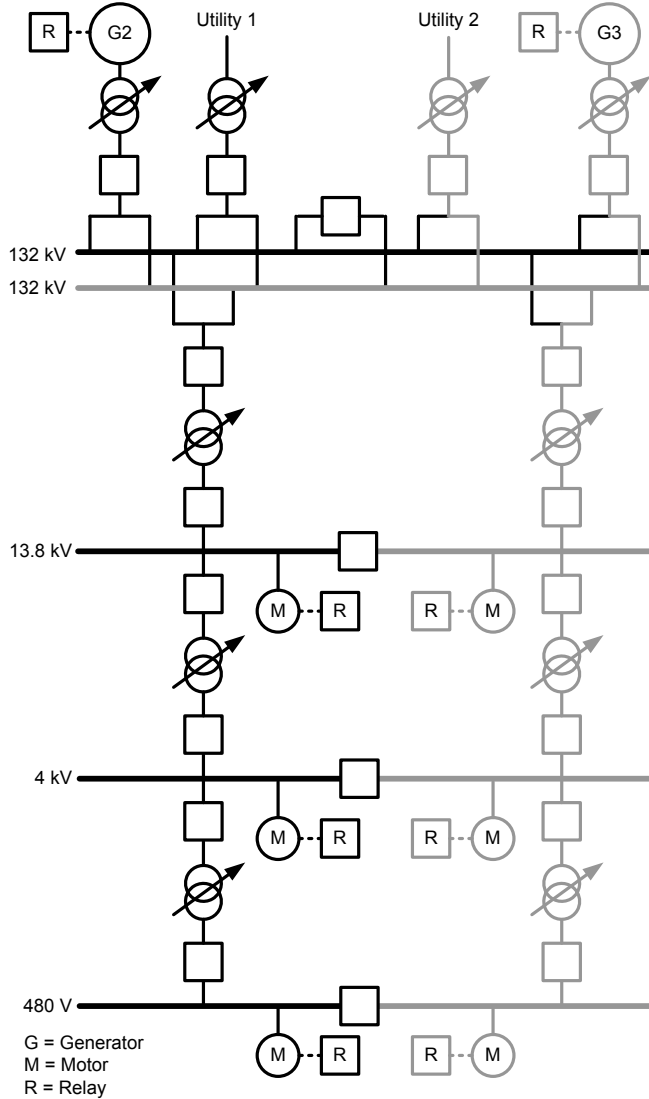


Fig. 1 Topology Tracking Example

B. System Inertia “H” Tracking

Rotating inertia, J , as taught in basic physics, is the effect of mass spinning at a radius. It is described by the following equation:

$$J = \text{mass} \cdot \text{radius of rotation squared} \quad (1)$$

where:

J is expressed in units of $\text{kg} \cdot \text{m}^2$.

Mass is expressed in kilograms.

Radius of rotation squared is in meters^2 .

The inertia of electric power system apparatus, such as generators, motors, and turbines, is defined as:

$$H = \frac{J \cdot \omega_{om}^2}{2 \cdot VA_{rating}} \quad (2)$$

where:

H is expressed in seconds.

ω_{om} is the rated machine speed (in radians per second).

VA_{rating} is the total rating of the machinery or system. It is used to put H in terms of per unit (pu).

H is most commonly used to describe the relationship between generator speed, the mechanical power from a turbine, and the electric power out of a generator per (3). The units of H are sometimes also referred to as seconds.

$$2H\omega \cdot \frac{d\omega}{dt} = P_m - P_{elec} = P_{acc} \quad (3)$$

where:

ω is the generator speed expressed in pu of the rated speed.

P_m is the mechanical power out of a turbine (in pu).

P_{elec} is the electric power out of a generator (in pu).

P_{acc} is the acceleration power of the combined turbine and generator system.

For a generator and turbine combination, H becomes the time (in seconds) required for a machine to change 1 pu speed given full mechanical power from the turbine and a short-circuit condition on the generator terminals. Note that short-circuited generators supply no electric power, and thus the generator and turbine rotational speed (and hence electric frequency) accelerates. Considerations must be made in any inertia calculation to include generator pole count and mechanical gearing between a turbine and generator (such as is common in some microturbines). For the remainder of this paper, assume direct shaft coupling and that all electric machines are four-pole construction.

Note that (3) identifies the general power balance equation that must be satisfied by any load-shedding system. After an event, an optimal load- and/or generation-shedding system will trip enough load or generation such that the P_{acc} term is equal to near zero.

Table I quantifies large, medium, and small system relative inertias from the authors' experience. It is interesting to note that many large and small electric machines and utility grids have similar H values but radically different J values. For example, per Table I, the inertia of a large utility power system, as shown in (4), can easily be 160 times bigger than that of a large oil refinery. Note that the $2/\omega_{om}^2$ term is omitted in (5) because the variables cancel each other out.

$$J = \frac{H(2 \cdot VA_{rating})}{\omega_{om}^2} \quad (4)$$

$$\frac{8 \cdot 10,000}{4 \cdot 125} = 160 \quad (5)$$

TABLE I
REPRESENTATIVE INERTIA VALUES FOR
ELECTRIC POWER SYSTEMS

System	H (seconds)	MVA _{rating}
Direct-on-line (DOL) induction motor (IM) and compressor	1	0.15
DOL IM and conveyor	0.6	0.15
DOL synchronous motor (SM) and compressor	1	0.6
Variable speed drive (VSD)	0	0.5
Pipe heaters	0	NA
Lighting	0	NA
Single-shaft industrial gas turbine (GT) and steam turbine (ST)	4.5	100
Aero-derivative industrial GT and ST	2.5	15
Diesel generator set	2	5
Steam extraction turbine and ST	3.5	35
Combined cycle and ST	5.5	150
Dynamic positioning vessel	2.5	15
Offshore oil rig	3	25
Large fertilizer plant	4	200
Large oil refinery	4	125
Large utility	8	10,000

Total power system inertia greatly impacts the performance of any UF load-shedding system. As shown in (3), the power disparity (mismatch) and inertia of a power system define how fast the frequency falls. For example, consider that the power system in Fig. 1 is a large oil refinery with total on-site generation of 125 MW and a total electric system inertia as shown in (6).

$$J = \frac{2 \cdot 4 \text{ seconds} \cdot (125 \cdot 10^6 \text{ VA})}{(2 \cdot \pi \cdot 60 \text{ radians per second})^2} = 7,036 \text{ kg-m}^2 \quad (6)$$

It is noteworthy that the cumulative sum of on-site generators, their turbines, motors, loads, and the like adds to the overall inertia of a power system. Assuming the utility tie is opened while importing 25 MW, the expected rate of change of frequency ($d\omega/dt$) decay is shown in (7). Note that (7) is a manipulation of (3), and 25/125 puts P_{acc} into pu.

$$\frac{d\omega}{dt} = \frac{\left(\frac{25 \text{ MW}}{125 \text{ MVA}} \right)}{2 \cdot 4 \text{ seconds}} = 0.025 \text{ pu per second} \quad (7)$$

For a 50 Hz system, this translates to:

$$0.025 \text{ pu per second} \cdot 50 \text{ Hz} = 1.25 \text{ Hz per second} \quad (8)$$

Now, consider the same power system split in two under the same condition. With half the inertia but the same power unbalance, the decay rate is double, or 2.5 Hz per second. With half the inertia and double the decay rate, a load-shedding system must still trip 25 MW of load to operate correctly.

Some load-shedding schemes implemented today shed more load (MW) with higher $d\omega/dt$ rates. However, without tracking H , they all would misoperate under one of the two scenarios described. For example, a traditional $d\omega/dt$ scheme set up for an inertia of 7,036 kg-m² could be properly configured to shed 25 MW at 1.25 Hz per second. However, the same scheme would erroneously shed 50 MW at 2.5 Hz per second. Traditional UF systems do not track H and therefore will commonly misoperate. It is important to note that a contingency-based load-shedding system does have this information. Contingency-based schemes are vastly more sophisticated, complicated, and costly than UF-based schemes and are therefore not in the scope of this paper. The ICLT scheme presented in this paper replaces contingency-based systems for many locations. In other locations, this ICLT scheme acts as a backup to a contingency-based system.

The ICLT method explained later in this paper is revolutionary because it is the first load-shedding system in the world that adaptively tracks power system inertia.

C. Changing Load Levels

Many UF load-shedding schemes do not adjust tripping based upon present measured load levels. To do so would increase the complexity of the system to an unmanageable level. For example, most utility UF schemes trip load feeders at predetermined frequency levels. They do not shed more feeders or fewer feeders should feeder loading (MW) conditions change. This commonly results in serious overshedding or undershedding of megawatts, thereby not correctly balancing (3). Because of system inertia and frequency decay rates, this is sometimes an acceptable solution for massive power utilities. However, it is rarely an acceptable solution for islanded industrial power systems.

The ICLT method explained in this paper selects an amount of load to shed (MW) based upon the P_{acc} term. This megawatts-to-shed number is then used to select an appropriate amount of load based upon real-time load megawatt measurements. This is done with priority or action table techniques, similar to contingency load-shedding processor (CLSP) schemes. The unique innovations of this new solution are its elegance and simplicity, which make it affordable and easy to apply.

D. Load Composition

After H , governor and prime mover characteristics and load composition are the next largest contributors to system frequency decay characteristics. Governor and prime mover responsiveness is a topic for other papers, but basically, UF schemes must be coordinated with these devices. The new

adaptive method does not provide any significant improvement in this coordination because this coordination is dependent on the skill of the protection engineer configuring the system. Load composition, however, is tracked in the new method.

The frequency versus power consumption characteristic of a load predates how far the frequency falls in a power system for a load disparity. Therefore, this load characteristic determines how hard a governor must work to correct for off-nominal frequency conditions.

Electronic loads such as VSDs continue to consume full power as the frequency falls; therefore, VSDs make a governor work harder and increase frequency excursions. Spinning loads attached to DOL IMs and SMs reduce their power consumption as frequency decays; therefore, these items naturally keep the power system frequency constant and reduce the burden on governors.

Fig. 2 shows a simple case in which the governors controlling the turbine (shown later in Fig. 4) were prevented from acting upon frequency excursions by placing them in locked valve control. The tie line was then opened while exporting 25 MW. Three cases were then run: mostly DOL IMs, mostly VSDs, and an equal mixture of VSD and DOL IM loads. As expected, the VSD-dominated load caused the largest frequency excursion. Note that Fig. 2 was obtained for analysis purposes with all network and machine protection disabled.

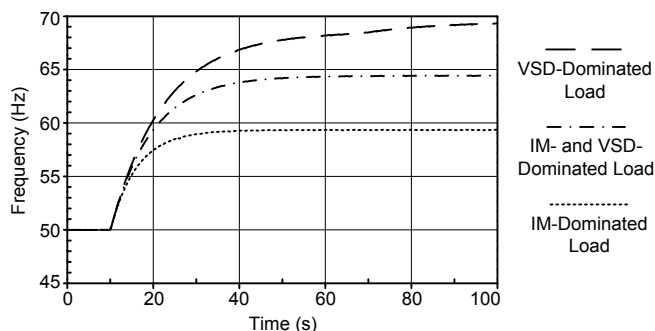


Fig. 2 Frequency Response Load Composition Influence

III. SYSTEM RELIABILITY

This section summarizes the most modern methods available to create a physical load-shedding system, starting with design principles and progressing on to describe the architecture and data flow for a load-shedding scheme at a large refinery. This background is necessary to understand state-of-the-art systems and their limitations. It also helps the user understand the simple elegance of the new ICLT method.

A. Reliability Design Principles

A properly designed load-shedding system incorporates the principles of design described in the following subsections. An ICLT system addresses all of these principles.

1) Simplified User Interface

Most important for the long-term maintainability and operation of any complex system is a simple and elegant user interface. This user interface must be capable of providing all troubleshooting for the communications and hardware health of all subsystems. It must also provide event diagnostic tools, such as log files, to capture each load-shedding event and sequence of events. Both event records and log files must have 1-millisecond-or-better accuracy and 0.1-millisecond-or-better resolution of all events. Log files must include enough information for the manufacturer to debug all of the systems, and they must also contain a simple-to-read summary of every event action that is easily understandable to untrained operators or maintenance personnel.

The load-shedding systems must work without the user interface functioning. No critical path components should be based on Windows® operating systems due to performance restrictions, processing jitter, and cybersecurity vulnerabilities. All critical path components must be embedded controllers with strong security measures taken to prevent misoperation.

2) Commissionability

Load-shedding systems are often commissioned with live plants, generators, and utility ties. The reputations of some companies have been damaged by having a single trip contact in a load-shedding system close incorrectly on a live plant during test. It is therefore critical that all trip output contacts have blade disconnects. It is also imperative that the system design prevent all possible communications hardware failures, I/O hardware failures, processor failures, power supply failures, and the like from causing a misoperation.

3) Expandability

As plants grow, their load-shedding system must also grow. Any reliably designed system must be capable of expansion with zero process outages to the existing in-service plant. The controllers and relays must never be taken out of service to perform upgrades. New settings should be downloaded with little or no gap in protection during the download process, just like with any other modern protective relay.

4) Testability

The system architecture must allow a controller sitting on an engineering desk to be fully tested under all scenarios. With the ICLT system, large numbers of panels populated with racks of I/O and relays are not necessary as part of a complete factory acceptance test. Rather, a comprehensive factory acceptance test can include two controllers being fed data by simulation equipment, which actively produces real-time scenarios for the controller.

5) Redundancy

Redundancy should never be less than dual primary. Hot standby is inadequate for a blackout prevention scheme. Dual primary redundancy is the world standard for transmission-level protection, and therefore, the user should require a set of controllers that are constantly active and racing each other (i.e., dual primary redundancy). No controller should ever be used in a master or slave mode.

6) Minimal Equipment

The larger the equipment count, the lower the overall system reliability. This stems both from the increase in unavailability through fault tree analysis and from the eventual cost-cutting measures of adding low-cost, unmonitored equipment into the scheme.

Noteworthy unreliable equipment includes items such as low-level transducers and interposing relays; neither should ever be allowed in a modern system. All outputs to trip load breakers must be initiated by direct hard-wiring to trip-rated output contacts embedded into protective relays or I/O modules. No interposing relays should be allowed in any circuit. Low-level signals do not contain the necessary quality of information; therefore, all systems must employ only modern digital metering equipment with direct communication to the central decision-making controller.

B. System Self-Monitoring

All equipment in a system must be monitored to prevent hidden failures. It is best to remove all devices without self-diagnostics to eliminate hidden failures. Each self-diagnostic device should identify its health status to the master controller. Any equipment without self-monitoring must be monitored with additional equipment. Adding diagnostics and monitoring information for all equipment in a large system adds significant complexity, furthering the rationale for reducing the equipment count.

C. Architecture and Data Flow for an ICLT System

To accomplish the reliability design principles outlined in Section III, Subsection A, the ICLT scheme is to operate as a standalone scheme or as a completely independent backup to a contingency-based scheme. It is necessary for the ICLT system to function on independent hardware, protocols, and communications channels and to function with a completely different algorithm from contingency-based load-shedding systems. This is accomplished with the physical architecture shown in Fig. 3.

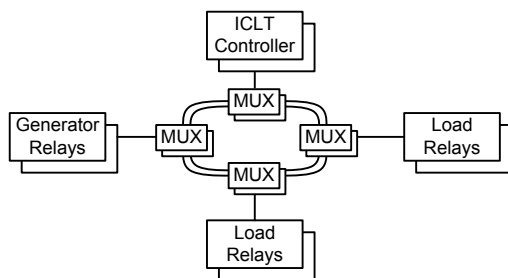


Fig. 3 System Architecture of Dual Primary ICLT System

It is noteworthy that the ICLT controller communicates directly to the generator relays and sheddable load relays. Every generator and load on the system must have a relay or mitigation device communicating to the ICLT controller.

A modern, encrypted MUX is used to route point-to-point direct communication from the relays to the ICLT controller. This allows the ICLT controller, generator relays, and load

relays to be thousands of kilometers apart without any degradation in timing or performance. Note that two MUXs and their associated rings are used to avoid single points of failure.

Logic for tripping is performed within relays, and the status is extracted directly from relays, so there is a significant danger of the system being disabled mistakenly if the relay settings are modified by personnel who are not aware of the tight integration with the load-shedding system. In the new ICLT method, this is prevented by having relay settings templates, which make critical load-shedding settings available only to administrative users.

D. Factory Acceptance Testing

Comprehensive factory acceptance tests are required to create a reliable contingency-based load-shedding system. The tests must include dynamic simulation of the power system in question in a real-time environment. The load-shedding controllers in the test must therefore be attached directly to the real-time simulation with real data updated to the controller at intervals of 1 millisecond or less.

If both a contingency system and UF load-shedding system are to operate on a power system, a dynamic simulation is mandatory. For some situations that require only a UF-based system, dynamic simulation is not required when the new ICLT adaptive method is used. Traditional UF-based schemes must be simulated extensively. Because modeling and simulation are not required, the new method provides a tremendous cost savings to some users.

E. Contingency Versus Underfrequency

For all power systems, a UF load-shedding system only detects a frequency decay after the initiating condition of a power deficit. As shown in [1], this delayed response time can frequently result in a cascading blackout. For this reason, most industrial end users require a contingency-based scheme.

Various signals have been used over the years to initiate a load-shedding contingency. These signals include breaker contacts (52a and 52b contacts), 86 lockout contacts, current thresholds, out-of-step (OOS) conditions, protective relaying trip signals, synchrophasor phase angle deflection [2], thermal limits on generators, transformer overloads, voltage depressions, and more. All of these terms are collectively called "contingencies" in order to differentiate them from UF techniques. Each of the aforementioned contingency-triggering conditions has an impact on the overall system shedding time and the operational security of the overall scheme.

A UF load-shedding scheme is commonly employed in industrial power systems as a backup to a contingency-based load-shedding system. In addition to transient inhibit periods, maintenance issues, such as equipment failures, broken wiring, shorted current transformer (CT) windings, and dc battery failures, can cause a contingency-based load-shedding protection system to fail to operate when needed. Clamping and slew rate limiters in governors, fuel problems, or air flow problems are other situations in which a

contingency-based load-shedding protection system will not operate. Improper installation or commissioning of protection equipment can also cause a contingency-based system to not react when needed. All of these reasons make it mandatory that a backup UF-based load-shedding system be employed to supplement a contingency-based system.

Unfortunately, there are severe limitations in traditional UF load-shedding protection systems, primarily because this type of system only reacts after the system is in a state of decay due to overload. These limitations have caused load-shedding systems to gain the bad reputation of being untrustworthy.

It is the authors' experience that systems based on single-function UF relays have an approximately 50 percent likelihood of rescuing a power system from decay. The new adaptive UF-based system is calculated to improve the success rate of UF load shedding significantly.

F. $d\omega/dt$ Elements

$d\omega/dt$ elements require supervision from pure UF elements to prevent spurious misoperations. Calculations of $d\omega/dt$ within a digital relay must include very sophisticated infinite impulse response (IIR) and finite impulse response (FIR) digital filtering methods and off-nominal frequency elimination techniques, such as cosine filtering [3]. All the aforementioned methods must match unerringly between the digital relays, and therefore, identical relays must be used.

IV. CASE STUDIES OF MULTIPLE IN-SERVICE LOAD-SHEDDING SCHEMES

This section relates experiences from dozens of facilities and blackouts into simple, tangible, easy-to-understand dynamic stability phenomena. The intent of this section is to show the philosophy of setting systems for a wide variety of end users. The new ICLT system easily adapts to all of these situations.

A. UF System Acting as a Backup Steam Load-Shedding System

At one facility, on-site exothermic processes were used as the primary steam providers for two on-site 75 MW steam turbines. These steam turbine-driven generators provided electric power to the entire facility, and at times, power was sold to the local utility grid. Fig. 4 shows the system.

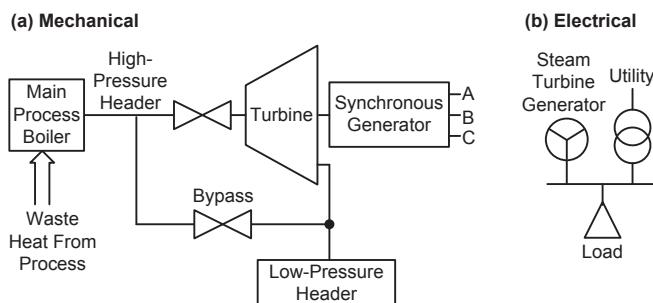


Fig. 4 Typical Fertilizer Plant

Fig. 5 identifies the settings and behavior of the on-site load-shedding system. At frequencies above 61.5 Hz and below 58 Hz, the generators trip offline for self-preservation. Under scenarios of exporting power, the grid tie line opens and the system naturally drives to OF. This happens because the main governor control valve only closes after a frequency disturbance occurs and the time constant on this is approximately 1 second. To prevent this, the steam bypass valve shown in Fig. 4 is opened within 100 milliseconds, thereby quickly diverting the steam flow around the turbine and preventing overspeed (OF) of the electric grid.

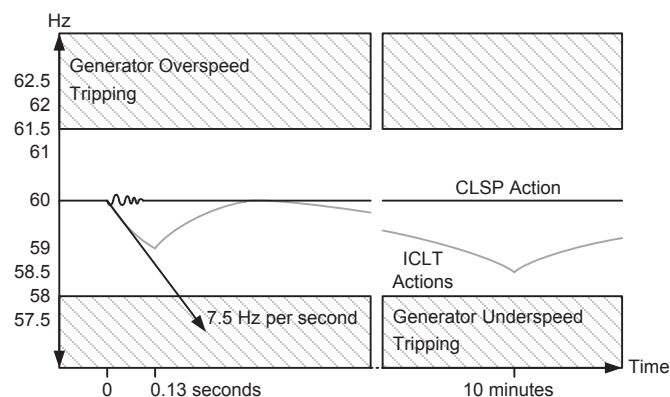


Fig. 5 Fertilizer Plant Recovery With an ICLT System

For scenarios where the plant is importing power from the utility grid, the worst-case frequency descent was determined to be 7.5 Hz per second, as shown in Fig. 5. Also shown on the plot in Fig. 5 are the system responses in frequency to CLSP and ICLT load-shedding operations. Note that the CLSP action has minimal effect on frequency and the power system permanently recovers.

An ICLT action assumes there has been no contingency action. Therefore, there is an initial system frequency recovery as the governor opens its control valve wide open and load is shed at the first UF level of 59 Hz. Of note and concern is the slow decay several seconds after the ICLT operation. This is caused by the main high-pressure header reducing in pressure because the turbine is extracting more steam than what is being produced by the exothermic process. This occurs because the ICLT scheme does not perfectly balance the P_{acc} term and the steam header pressure starts decaying as the tons per hour consumed by the turbine exceed that produced by the process.

This slow decay is arrested by further ICLT load-shedding tripping at the second level of 58.5 Hz. In this way, the electric load is reduced, thereby reducing the requirements for steam demand from the primary boilers. ICLT load shedding therefore acts as a boiler or steam preservation backup system.

In this facility, excessive load shedding is acceptable because OF situations are dealt with quickly with a fast turbine valve closing and the opening of the steam bypass valve. Because the system handles OF conditions so well, the loads selected for tripping for each level are customarily set larger than normal.

B. Load-Shedding Scheme at a Large Refinery

A classic problem is having UF triggers at multiple central locations and having hundreds of sheddable loads spread out at low-voltage locations. In one facility from the authors' experience, shown in Fig. 6, six different island scenarios can occur, each with sufficient generation to support the islanded loads.

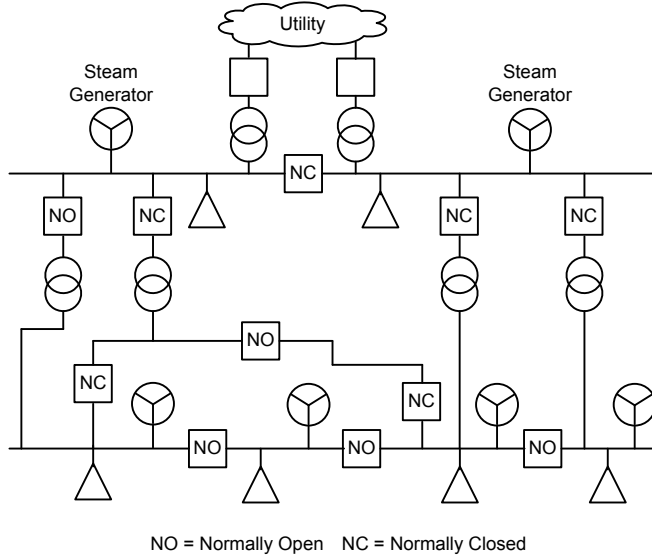


Fig. 6 Complex Topology Tracking

The sheddable loads have dozens of paths from which power can flow at these UF locations. This creates the unenviable problem of having to keep track of thousands of disconnects and breakers in order to properly select loads on the correct bus. To accomplish this, topology tracking algorithms are employed to monitor every island occurrence and then allocate all sheddable loads to each island. As can be expected, this requires extensive equipment, processing power, code, and testing [4] (and was previously referred to as a topology tracking problem). Because the UF triggers had to be combined with a topology tracking algorithm typically reserved for CLSPs, this form of UF load shedding is referred to as hybridized UF. The ICLT method provides superior functionality for sites such as this and can provide labor and cost savings.

V. ICLT ALGORITHM

This section explains how the ICLT method works.

In Fig. 1, identical multifunction relays are located at each generator and sheddable load. All multifunction relays are set with the same UF and OF set points and time delay, which means that all relays have identical UF and OF settings.

There are two UF levels, two OF levels, three $d\omega/dt$ negative levels, and three $d\omega/dt$ positive levels, as shown in Table II (and later in Fig. 7). All relays communicate the detection of any UF event to a centralized ICLT controller. Inside this controller, all UF events are queued and buffered into an array and then examined by their time of event. The

subsequent events are sent to a load reduction calculation. Because the load-shedding scheme must be able to operate in a few power system cycles, this scheme necessitates that all UF trigger information be updated at the controller at a minimum sample frequency of 250 Hz (4-millisecond sample time). The UF events must also be time-tagged by the multifunction relays, and all the relays must be time-synchronized to 1 millisecond or better.

TABLE II
DISCRIMINATION TABLE

Supervision Level	$< (d\omega/dt)d1$	$< (d\omega/dt)d2 \text{ \& } > (d\omega/dt)d1$	$> (d\omega/dt)d2$	$< (d\omega/dt)u1$	$< (d\omega/dt)u2 \text{ \& } > (d\omega/dt)u1$	$> (d\omega/dt)u2$
UF1	K	J	I	NA	NA	NA
UF2	N	M	L	NA	NA	NA
OF1	NA	NA	NA	H	G	F
OF2	NA	NA	NA	E	D	C

The theory of this operation is based on the principle that the decay rates of islanded segments of power systems are all different. For example, if a power system islands into two pieces, the probability of both pieces decaying identically in frequency is remote because this requires perfectly matched generation and load difference. Often, one island goes up in frequency and the other down. If both islands decrease in frequency, their rate of change is different. The likelihood of both systems crossing the same UF boundary at the same millisecond time interval is even more remote. Thus, through proper time-stamping and rapid data acquisition, the centralized controller discriminates which loads are together on the same island. Therefore, this system provides guaranteed identification of loads and allocation to the proper island.

To make the allocation of loads to the proper island guaranteed, time-synchronized phasor measurements, such as IEEE C37.118 synchrophasors, are optionally used. Thus the synchrophasor angle of each load is sent to the centralized controller, and all the power system islands are positively identified [5]. This island discrimination technique further supervises the selection of loads to shed in the controller. Synchrophasor load angle is mandatory for a large utility application of this new scheme because of the large impedance, power transfers, and inertias involved. Smaller islanded power systems do not typically require this additional sophistication. This ICLT method expands the already large usage of synchrophasor technology [2].

H tracking of the power system is estimated by the summation of the inertia of the largest-inertia devices in a system. The H of a power system is grossly dominated by the inertia of the generators and large sheddable loads. By positively identifying which generator and load are attached to each islanded grid section, the algorithm determines the approximate power system inertia and then solves (3) based upon the trigger information coming from the protective relay.

Load composition tracking is accomplished by user-entered percentages of load type (IMs, SMs, VSDs, electronics, and so on), which are further allocated to each sheddable load. The accumulation of sheddable loads that are triggered then identifies the average load composition.

Incremental reserve margin (IRM) values from each generator are accumulated to determine a total IRM value for the island in question. This allows the algorithm to shed less load than that required to satisfy (3) and still guarantee frequency recovery. The concept of IRM is especially critical for many industrial power systems [1].

Two implementations of this ICLT scheme are available: a digital formulation and a hybrid synchrophasor formulation. The remainder of this paper focuses on the digital formulation of the controller because the synchrophasor formulation will more commonly be used at the utility level and the digital at the industrial level.

Note that only a small amount of data is required: eight status bits from relays monitoring generators and six status bits from relays monitoring sheddable loads. Relays at the generators have two UF levels for H tracking of load shedding. They also have three $d\omega/dt$ elements that are supervised by two OF elements for generation shedding. Relays at the sheddable loads have three $d\omega/dt$ levels that are supervised by two UF levels. All relays have a single trip signal coming from the ICLT controller.

The load reduction calculation then takes into account the amount of load to be shed (MW) for each level based on the solution of (3). Once the amount of load (MW) to shed is selected for any event, the load to shed is selected based upon the priority of loads and the current power consumption of each load (MW). The user can alternatively enter MW values into the algorithm should dynamic metering not be possible (as is common in partially commissioned plants that are just starting up). From this calculation, an array of loads is selected to be shed and the loads are tripped by communicating back to the relays that detected the UF or OF. The whole sequence of operation, from event detection to tripping contacts closed, takes less than 20 milliseconds for most systems.

Generation shedding and/or the runback decision process is similar to that of load shedding, with the exceptions that action table techniques instead of direct priority lists are most commonly used and that OF instead of UF triggers are employed.

A. Practical Setting of $d\omega/dt$ and 81 Elements for an Islanded Power System

Fig. 7 depicts the most common method for setting this ICLT appliance. These settings are for an industrial power system with a utility tie and on-site generation.

Above 62.5 Hz and below 57.5 Hz, generators, VSDs, and large DOL motors trip offline. Between 59 Hz and 61 Hz, the connection to the utility is maintained and no load shedding is desired. Below 59 Hz and above 61 Hz, the industrial plant separates from the utility and goes into a self-imposed island condition. This relies on the ICLT appliance to shed or run back generation between 61 Hz and 62.5 Hz (labeled A in

Fig. 7). This also relies on the appliance to shed load between 57.5 Hz and 59 Hz (labeled B).

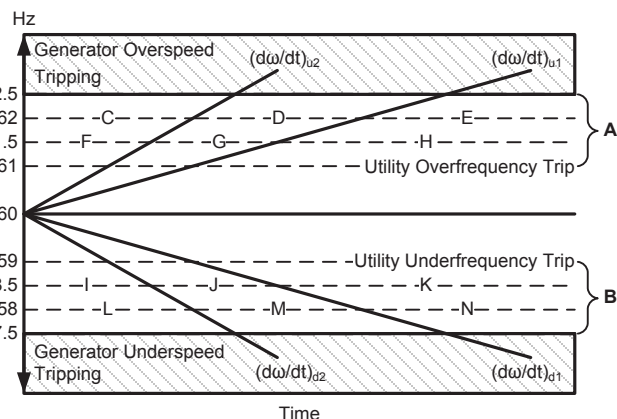


Fig. 7 Typical Industrial Settings for the ICLT Appliance

As shown in Table II and Fig. 7, the UF and OF zones are segmented by three $d\omega/dt$ zones each. More are possible, but they do not add much value, in the authors' experience. Based on practical limitations in the certainty of the $d\omega/dt$ measurement, these three zones need to be equally spaced apart (the $d\omega/dt$ levels must not be close to each other).

Generic $d\omega/dt$ settings are provided for large-, medium-, and small-sized facilities; however, these $d\omega/dt$ settings can be highly refined by dynamic stability studies. Detailed guidelines for setting UF and $d\omega/dt$ levels are provided by the ICLT system manufacturer.

There are two UF thresholds and two OF thresholds to prevent misoperation and to drive frequency lockouts. These thresholds are best selected to be equally spaced in the A and B windows of operation shown in Fig. 7. The supervision levels must not be close to the upper or lower boundaries of operation, and they cannot be close to each other.

Note that large numbers of UF and OF threshold levels are appropriate for large-inertia, slow-moving systems only. Industrial systems with fast frequency decay rates gain nothing by having more than two levels, especially considering the inertia and load composition tracking of the algorithm.

B. Implementation at Medium-Voltage (MV) and Low-Voltage (LV) Buswork and VSD

Each large, multimewatt DOL machine has a significant protective relay with UF and $d\omega/dt$ elements. This protective relay should be used to protect the machine and provide ICLT protection.

For LV loads, load metering has become increasingly less expensive with the recent innovations in smart motor control center (MCC) devices. Better-quality, more programmable LV relays are increasingly available on the market. Use LV relays to gather load MW information, and use a single relay at each LV incoming bus to capture the UF and $d\omega/dt$ signals.

VSDs at both MV and LV are common sheddable loads. Place a protective relay upstream from the VSD to monitor frequency and $d\omega/dt$. A trip contact output from this relay is

then wired directly to the emergency “stop” input command on the VSDs. Should the user have a field-oriented controlled VSD with regenerative braking, the load energy can be added into the IRM availability calculation within the controller.

C. Relay Selection

For the scheme to work reliably, all relays used to trigger the UF signals must come from a single manufacturer and from a single generation of relaying product. The filtering and frequency tracking of relays from different manufacturers, and even between products from a single manufacturer, can be very different. Results from the authors’ past relay evaluations are typified in Fig. 8.

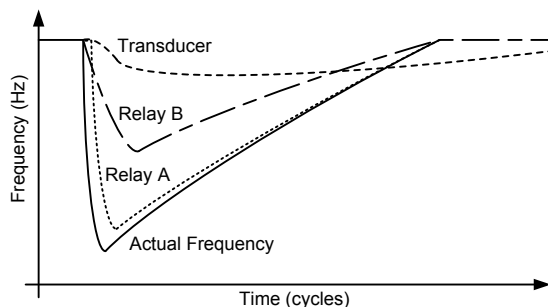


Fig. 8 Example of How Frequency Tracking Varies by Manufacturer

VI. CONCLUSION

The following points capture the essential takeaways about the ICLT method for preventing blackouts:

- The total cost of an ICLT system is significantly less than a comparable contingency-based scheme.
- An ICLT scheme universally sheds load and generation as required to prevent blackouts.
- All UF, OF, and $d\omega/dt$ elements and pickup times are identical in all of the relays. They never need coordination or changing.
- An ICLT system requires no topology tracking because of frequency-based island detection.
- Modifying the priority of loads and generators to shed is a simple matter.
- An ICLT system accurately determines load- and generation-shedding amounts with dynamic inertia and load composition tracking.
- An ICLT system acts as a steam load-shedding preservation system.
- Placing protective relays at every sheddable load and generator provides a complete ICLT system.
- An ICLT system uses completely independent algorithms and hardware from contingency-based load-shedding schemes.
- Industrial facilities that require minimal frequency deviations still require a contingency-based load-shedding scheme.
- An ICLT scheme is acceptable as a standalone load- and generation-shedding scheme for an end user that can tolerate larger frequency swings.

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VIII. VITAE

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Complete Power Management System for an Industrial Refinery

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COMPLETE POWER MANAGEMENT SYSTEM FOR AN INDUSTRIAL REFINERY

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Abstract—Islanded power systems for critical facilities require a robust, secure, and reliable power management system that can respond to system disturbances and avoid blackouts to ensure process survivability. A facility in Saudi Arabia with four gas-oil separation plants and one natural gas liquids recovery facility operates with a total installed generation capacity of approximately two gigawatts and no utility interconnections. This paper discusses power management system components, such as automatic generation control (power and frequency), volt/VAR control systems (reactive power and voltage), intertie power factor control, high-speed generation shedding and runback, and high-speed load shedding, along with an overview of the overall system architecture and the state-of-the-art dual-ring time-division multiplexing synchronous optical network communications networks at this facility. High-speed generation-shedding and load-shedding systems are designed with overfrequency- and underfrequency-based secondary backup protection schemes to provide additional system reliability. This paper also introduces a transient-level computer model of the facility power system, which is used for functional testing of the power management system components.

Index Terms—Power management, generation shedding, runback, load shedding, frequency and voltage stability, autosynchronization, blackout prevention, microgrids.

I. INTRODUCTION

One of the key requirements of an islanded (isolated) power system (also known as a microgrid) is a complete power management system (PMS) to avoid system outages and ensure load availability and reliability. This paper discusses a fully redundant PMS for a major oil field in Saudi Arabia with a production capacity of 750,000 barrels of oil per day. This facility is composed of five plants: a natural gas liquid plant (Plant 1, 230 kV) and four gas-oil separation plants (Plant 2 [115 kV and 230 kV], Plant 3 [69 kV], Plant 4 [230 kV], and Plant 5 [230 kV]). The original plant consisted of Plant 3, Plant 4, and Plant 5; Plant 1 and Plant 2 are the latest additions. Thirteen tie lines connect the five stations using overhead and underground cables. Plant 1 contains eight combustion-gas turbine generators (CGTGs), Plant 2 contains

six CGTGs, and Plant 3 contains four CGTGs. The total generation capacity of all the on-site generation is approximately two gigawatts. Fig. 1 shows a simplified diagram of the plant without the load represented.

This facility, with no utility connections, can split into ten viable islands. The PMS was designed and tested to track any combination of islands and is equipped with thirteen autosynchronization schemes to synchronize the islands as required.

II. POWER MANAGEMENT SYSTEMS

Similar to the utility grid, an islanded power system needs control systems to maintain system frequency and voltage within allowable limits. A PMS for an islanded power system is similar to utility energy management systems and remedial action schemes. A PMS combines low-speed functions, such as automatic generation control (AGC), volt/VAR control systems (VCSs), and tie line control, with high-speed functions, such as load shedding and generation shedding. A PMS also requires autosynchronization systems that can synchronize generators and system islands. All of these systems operate in a coherent fashion to control the system during all manner of low-speed and high-speed disturbances.

Islanded industrial systems have much less inertia than utility systems. Disturbances such as short-circuit conditions therefore cause larger changes to rotor angles and system frequency. These islanded power systems therefore require faster load- and generation-shedding systems to preserve system stability. Fig. 2 shows a simplified architecture of the PMS used to protect and control the power system shown in Fig. 1.

III. COMMUNICATIONS ARCHITECTURE

Modern PMSs are a complete integration of protection, control, and automation devices. These include devices such as protective relays, embedded computers, logic controllers, I/O modules, and communications and engineering tool sets.

The capability and determinism of such PMSs are heavily dependent on the communications networks and devices involved. Multiplexer technology was used to improve the reliability and determinism of the facility wide-area

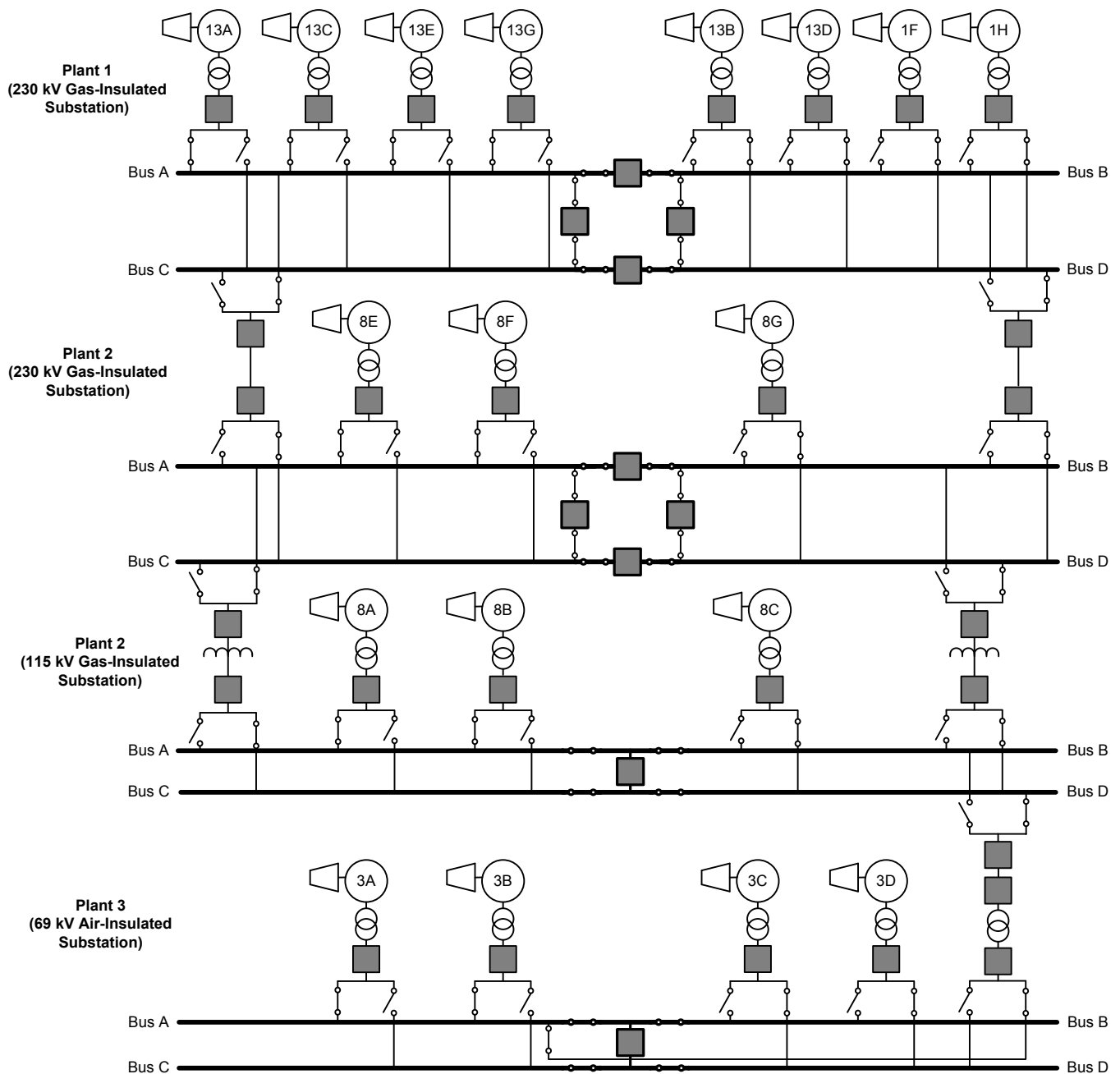


Fig. 1 Simplified One-Line Diagram of Power Generation and Transmission Systems

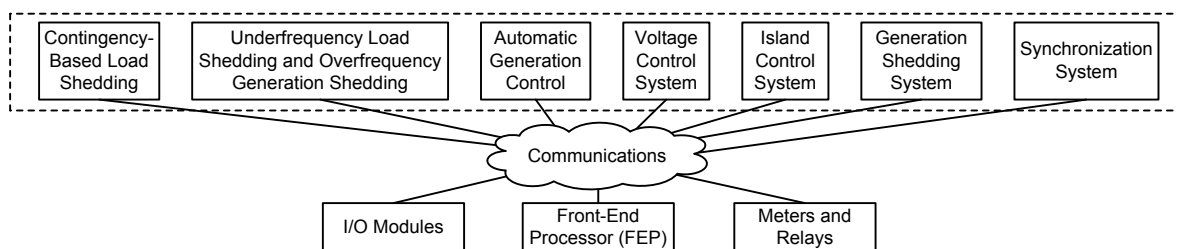


Fig. 2 Simplified PMS Architecture

network (WAN). This was crucial for high-speed applications, such as load and generation shedding, that protect the overall integrity of the system.

As shown in Fig. 3, the communications architecture at the facility uses a fully redundant time-division multiplexing-based network connecting all five plants. The multiplexers and the fiber connections between them represent the WAN. The WAN links the local-area networks (LANs) of the plants together. The WAN network provides the advantages of determinism, reliability, and data segregation via time-division multiplexing pipes [1]. Reliability is improved through fast network healing times; WAN traffic is interrupted for less than 5 milliseconds for a fiber break in the system. Table I shows the typical protocols used in such PMSs.

TABLE I
PMS PROTOCOLS

Application	Protocols
High-speed controls (load shedding, generation shedding)	IEC 61850 Generic Object-Oriented Substation Event (GOOSE), IEEE C37.118 synchrophasors, proprietary peer-to-peer protocols
Low-speed controls (supervisory control and data acquisition [SCADA], data monitoring)	DNP3, Modbus® TCP/IP, IEC 61850 Manufacturing Message Specification (MMS)

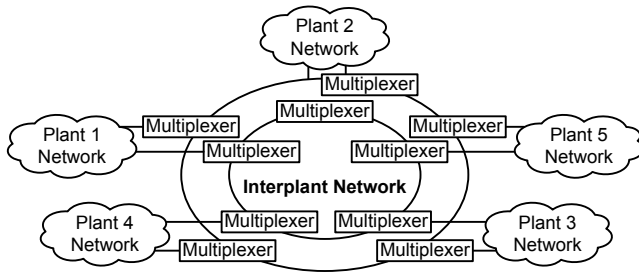


Fig. 3 Simplified Communications Architecture

IV. SLOW-ACTING REBALANCING CONTROL SYSTEMS

The generation control system (GCS) described in this section operates in seconds or minutes to slowly correct the system frequency, voltage, active and reactive power flows, power factor, and more.

A GCS controls the active and reactive power flow from generators. This is done to maintain generator bus voltage

and system frequency by controlling the exciter and governor of the CGTG. A GCS also participates in system synchronization efforts because it has control of every governor and exciter.

A typical GCS includes functions such as AGC, a VCS, and an island control system (ICS). Such control systems are connected to the generator unit controller using an interface device that sends and receives control and status signals.

A. Automatic Generation Control

AGC dispatches turbine governor set points for equal-percentage real power load sharing, while simultaneously maintaining the system frequency and the real power flow across tie lines. Tie line control follows user-defined set points for maintaining the real power flow.

Fig. 4 shows the overall control strategy of the AGC algorithm. The algorithm is basically a four-stage cascaded advanced control system. The controls are all feed-forward and use observer-based strategies based on decades of power system experience.

Inside the AGC system a unit megawatt controller keeps the CGTG real power output to a desired megawatt set point. The megawatt set point for each generator is determined by the optimal load-sharing controller. The optimal load-sharing controller receives bias commands from either the frequency or tie flow controller algorithms. The island detection logic in the ICS determines which of these algorithms is activated.

Of the 24 different possible power-wheeling buses at the facility, only 16 can have generators attached. As such, there are 16 unit megawatt control subsystems, 16 frequency control systems, and 5 tie flow control subsystems. The AGC can simultaneously control 16 different islands and 5 different tie lines or any combination of these, as required.

In the system, 5 intertie lines are controlled for active power flow by the PMS: 2 tie lines between Plant 1 and Plant 2 (230 kV), 2 tie lines between Plant 2 (230 kV) and Plant 2 (115 kV), and 1 tie line between Plant 2 (115 kV) and Plant 3.

The PMS simultaneously controls the island frequency and voltage and maintains the real power flow across the tie lines. As soon as the tie control is enabled, the ICS designates the swing and power buses based on the system topology and islanding scenarios in the system. The swing bus controls the island frequency, and the power bus controls the real power flow across tie lines. As the system separates into multiple islands, these swing and power buses are dynamically reconfigured to maintain the tie flow.

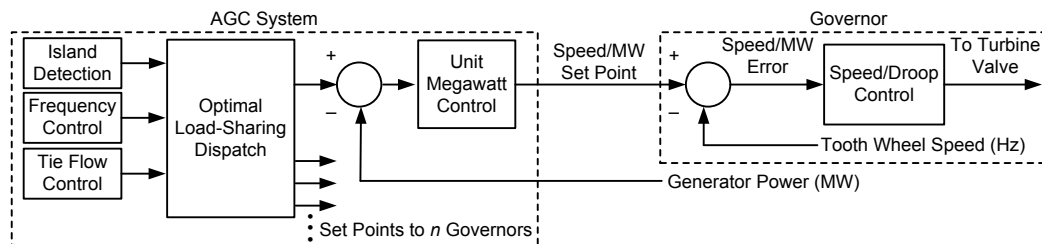


Fig. 4 AGC System

B. Volt/VAR Control System

The VCS dispatches exciter set points for equal-percentage reactive power load sharing and maintains the generator terminal voltages within acceptable limits. Fig. 5 shows the overall control strategy of the VCS algorithm.

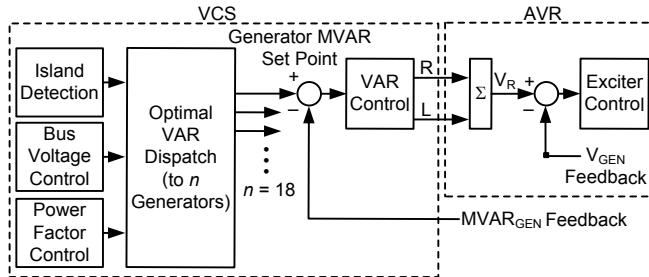


Fig. 5 VCS Strategy

As shown in Fig. 5, the VAR control sends voltage set points to each of the exciters through raise/lower (R/L) commands. The VAR control keeps the generator MVAR output at a desired set point. The optimal VAR dispatch (load-sharing controller) sends the set points to the unit VAR controls and performs equal-percentage sharing between the collocated generators. The optimal VAR dispatch receives bias commands from the bus voltage control or power factor control algorithms. The island detection logic in the ICS determines which of these algorithms is activated for each island and bus configuration.

The VCS contains 16 unit VAR controls and 16 optimal VAR dispatch subsystems. If the entire system is connected as a single grid, then 3 different voltage control subsystems are active for 3 different voltage levels (230 kV, 115 kV, and 69 kV). The VCS can simultaneously control 16 different islands and 5 different tie lines or any combination of these, as required.

C. Island Control System

The ICS controls the modes (droop and isochronous [ISO]) of the governors and the modes of the exciters (volt/VAR), and selects the AGC and VCS dispatch algorithm modes. The ICS also tracks the number of electrical islands within the system and all of the CGTGs connected to those islands. Using this information, the ICS dynamically creates individual AGC and VCS control loops for each island, thereby allowing the control systems to adapt to all electrical grid conditions.

D. Allowable Operation Region

The GCS uses a continuously adapting allowable operational region algorithm to track the CGTG real and reactive power limits. The controllers are not allowed to dispatch a generator outside the boundaries of this region. This region is used to calculate real and reactive power spinning reserves for use in the AGC and VCS.

Fig. 6 shows two different operational scenarios for the allowable operational region algorithm. Fig. 6a shows an example where the operator-entered regulation limits are within the generator capability curve but outside the turbine

capability. The allowable operational region is indicated by the shaded region.

Fig. 6b shows an example where the regulation limits are outside the generator capability curve, the turbine capability, and the underexcitation limit of the turbine (10 percent reduced capability). As shown by the shaded region, the turbine line is used for part of the allowable operational region. The generator capability curve is used for the upper-right corner of the operational region boundary, whereas the underexcitation limit is used for the lower excitation boundary.

Because the generator capability curves can change during system operation, the allowable operational region needs to be dynamically adjusted depending on the curve and the fixed operator-entered regulation limits.

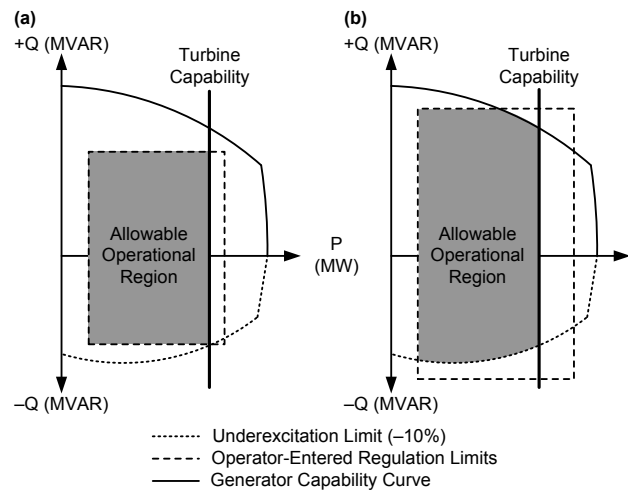


Fig. 6 Regulation Limits Within and Outside the Generator Capability Curve

E. Megawatt and MVAR Equal-Percentage Load-Sharing Algorithm

AGC turbine load sharing is critical to prevent turbine operation at or near turbine and generator capability limits. The VCS exciter load sharing is critical to prevent generator operation at or near exciter and generator capability limits. By keeping all of the machines in the same quadrant, no single machine can become underexcited.

The philosophy of an equal-percentage load-sharing method is to load the turbines equally so that the turbine governors have maximum flexibility to move turbine control valves during disturbances. Having one turbine operating near its upper limit while other units are less loaded means that the most loaded unit will not be able to actively participate in rejecting a disturbance. This technique is also commonly referred to as optimal stability dispatch. The system also adapts to all forms of steam control and provides optimal steam dispatch, if required [2].

The AGC and VCS calculations take into consideration boundaries such as dynamic real-time turbine derating, dynamic real-time synchronous generator curve derating, the underexcitation limit of the exciter, an operator-entered boundary condition, and an operator-entered preferred operating point.

The operator-entered preferred operating point allows experienced users to set a CGTG at the best-known or normal operating point. The AGC and VCS algorithms then adjust the real and reactive dispatch as close as possible to this value. The units cannot typically be sent to the exact operator-entered operational point because the active and reactive power from the units must be adjusted by the AGC and VCS to meet bus voltage, frequency, and tie line power and power factor control set points.

Operator-entered upper and lower regulation limits on real- and reactive- power allow an experienced user to prevent a unit from operating in a known region of dangerous operation. For example, a governor region of operation known to be unstable can be avoided with these upper and lower limits. Also, the limits can be used to keep the unit within a low-nitrous oxide (low-NOX) emission level. The AGC and VCS will not dispatch a CGTG outside of the operator-entered boundaries (upper and lower limits on active and reactive power output).

F. Autosynchronization System (A25A)

A25A systems are required at generators, tie lines, and bus couplers. Unit-autosynchronization systems are used to synchronize individual generators to power grids. Island-autosynchronization systems are used to synchronize and reconnect power system islands. These systems are required to function automatically with minimal human supervision because they must dispatch multiple generators simultaneously to reduce slip and voltage differences at the interconnection point [3].

A25A systems replace analog synchroscopes and manual breaker closing. This creates less damage on generator windings and provides better reporting features, such as sequence of event (SOE) reports and oscillography. These systems adapt to changing bus topologies without external switching of voltage transformer signals. They also feature protection-class equipment and high-speed (subcycle) communications over long distances.

At the facility, the autosynchronization systems measure the voltage and frequency on both sides of several breakers (bus couplers, bus ties, and tie line breakers) to send proportional correction pulses for adjusting the governor and exciter as necessary to automatically close the breaker. This process enables safe, secure, unattended synchronization of the generators connected to one bus and the generators on the opposing bus.

V. FAST-ACTING REBALANCING CONTROL SYSTEMS

Disparities between turbine power output and electric power consumption occur as the power system becomes slightly unbalanced. The unbalance causes the power system frequency to change as kinetic energy is extracted from (or inserted into) the rotating inertia of the turbines, generators, motors, and loads. The control schemes described in this section attempt to balance the mechanical power input with the electric power consumption.

A. Contingency-Based Load-Shedding System

A contingency-based load-shedding system (CLS) is a protection algorithm that sheds load to maintain the power balance between the prime movers and the electric power system loads. This is done by reducing the total plant electrical load to less than the calculated available turbine and generator capacity after a contingency occurs. Because of the power system net rotating inertia, the CLS operates fast enough that loads are shed prior to any significant decay in frequency.

A contingency is any event that results in the loss of power to a grid section (island). Contingencies can occur when a tie line, bus coupler, sectionalizer, or generator breaker opens under load. A contingency can also be the overload of a transformer, cable section, or generator. The CLS operates by making load-shedding decisions based on topology statuses (breaker 52A [close status], 52B [open status], and disconnect switch 89A and 89B statuses), contingency statuses and metering (breaker 52A and 52B statuses and active power values measured on contingency breakers), and load statuses and metering (breaker 52A or 52B statuses and the megawatt values measured on sheddable load).

When an event occurs that would cause a contingency situation, the 52A and 52B contacts of the contingency breaker change state. This state change is detected by I/O modules. These modules transmit the 52A and 52B status signals to the CLS controller. The CLS controller then determines the loads to shed based on the contingency statuses and metering, user-defined load-shedding priorities, user-defined incremental reserve margin values, topology statuses, and load statuses and metering. The CLS sends the load trip signals to I/O modules, and output contacts on these modules trip breakers.

The CLS algorithm is depicted in Fig. 7. For further details regarding load-shedding systems, refer to [4], [5], and [6].

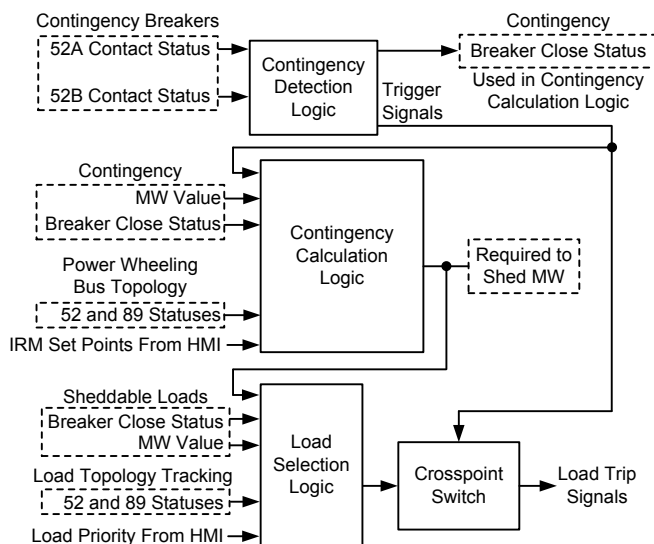


Fig. 7 CLS Algorithm

B. Generation-Shedding and Runback System

A generation-shedding system (GSS) keeps the steady-state frequency of the power system at nominal during a major loss of load. By keeping the frequency at nominal, the turbine revolutions per minute (rpm) are also stabilized, thus keeping turbine generators online and preventing system power outages (blackouts). A secondary goal of the system is to minimize disturbances to generation during these shedding and runback events. This generation-shedding and runback system is the primary protection for excess generation, which tends toward overfrequency.

The GSS is a fast, contingency-based algorithm that sheds and runs back generators to maintain the power balance between the loads and the generation. This is done by reducing the total island generation to make it approximately equal to the running load of the island after a contingency occurs. Because of the power system net rotating inertia, the GSS operates fast enough that generation sheds prior to any significant overshoot in frequency.

A GSS contingency is any event that results in excess generation on an island. Contingencies can occur when a tie line or bus coupler breaker opens under load.

Similar to CLS, the GSS operates by making generation-shedding and/or runback decisions based on three basic categories of information: contingency statuses and metering, topology statuses, and generator statuses and metering.

When the GSS controller detects a contingency breaker open condition, it determines the generation to shed or run back based on the contingency status and metering, user-defined generator-shedding and runback priorities, user-defined decremental reserve margin (DRM) values, topology statuses, and generator statuses and metering. Then the GSS sends the generator trip and runback signals to I/O modules. Output contacts on these modules trip breakers, send digital signals to enable runback control mode, and send an analog megawatt set point (runback level) to the turbine generator controller.

The system performs pre-event calculations to dynamically determine which generator to shed or run back and to build a generation-shedding and runback table. The system monitors contingency trigger signals and generates generation-shedding and runback signals based on the generation-shedding and runback table when a trigger is detected.

1) Generation Runback Philosophy

Generation runback is used to quickly reduce CGTG output and avoid having to trip a CGTG. The governor regulates the speed and active power output of a CGTG, but it is inherently limited in its ability to quickly reduce output. This limit in reducing output is caused by a number of factors, including PID tuning constants, measurement time lags, filtering, and ramp rates. In a generator runback scheme, the governor PID is bypassed and runback set points are directly injected into valve control set points, as shown in Fig. 8. This runs the CGTG output directly to the real power required within the response time of the valve and associated valve controls.

Runback schemes like the one in Fig. 8 can respond in less than one second, whereas governor PID speed controls typically respond in one to five seconds. The runback is

coordinated with the GSS based on the plant load, total generation runback capacity, and the amount of excess power on the system. Governor runback responses in a CGTG are limited by flame-out restrictions on fuel valve movement, while runback in steam generation has no such limit.

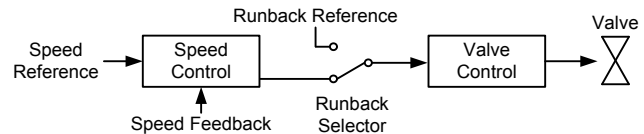


Fig. 8 Runback in a CGTG Speed Governor

Generation runback at the facility works as follows. First, the GSS calculates the runback target load set point for each generator. The runback target load set point indicates the desired megawatt operating set point of the CGTGs. When a contingency is detected, the runback target load set point and runback control mode enable signals are sent to the CGTG governor controller. The CGTG governor controller, on receipt of the runback signals, processes these signals as follows:

1. Change the control fuel valve position to the output real power (in megawatts) to match the runback target load set point from the GSS.
2. Change the mode of operation of the CGTG, if required, based on the runback target load set point.
3. Maintain the generator megawatt set point at the runback target load set point.

Fig. 9 explains the runback target load set point and how this set point should be treated by the CGTG governor controller.

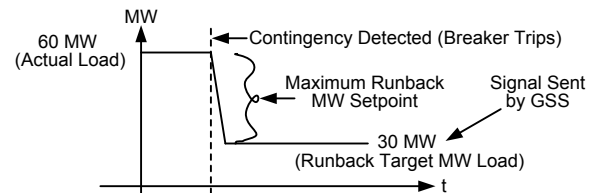


Fig. 9 Generator Runback Target Load Set Point

2) System DRM

The GSS and runback algorithm uses the DRM in the calculation of the excess generation (in megawatts). Unit DRM is the amount of step decrease in generation a turbine can provide within the tuning time response of the governor (typically one second). The same effect can be described as the load rejection capability within frequency stability margins. There is no recognized industry standard for this characteristic. DRM is the reverse of the incremental reserve margin described in [6].

System DRM is the accumulated total of the DRM of all online generators. Island DRM is the accumulated total of the DRM of all online generators connected to a given island. The user-defined DRM is limited by the lower regulation limit set for the AGC.

DRM values must be coordinated with overfrequency GSS tripping levels. The GSS reduces the amount of generation selected for shedding or runback by accounting for DRM in its calculation. This limits the impact of GSS on the user's process. Another effect of incorporating the DRM into the

GSS calculation is that the frequency commonly increases following a GSS generator-shedding event. The level of this frequency increase is a function of the tuning in the governor, the user-defined DRM, system inertia, and generation composition. The larger the DRM the user enters, the more the frequency increases for a GSS generator-shedding event. This is because the DRM calculation forces the governors to tap into power decay to keep the frequency at nominal. It is for this reason that DRM values must be coordinated with overfrequency GSS tripping levels.

DRM is also commonly used to compensate for poor governor tuning. Reducing the DRM set point can limit large frequency swings (overshoot) to drop generation resulting from improper tuning.

Following events such as short circuits or breaker openings, control systems receive measurements with oscillatory and or aliased data. For the first event, the controllers can use steady-state pre-event data. To avoid reacting to poor quality data, GSS, runback, and CLS algorithms must have several safeguards. Common safeguards (such as modal detection, data filtering, data freeze, and state estimation) are used to prevent misoperation.

C. Underfrequency Load-Shedding and Overfrequency Generation-Shedding Systems

The overall reliability of the load- and generation-shedding systems is improved with redundant controllers using different algorithms. These different algorithms are the underfrequency load-shedding (UFLS) and overfrequency generation-shedding (OFGS) systems.

The UFLS algorithm is designed to be a load-shedding protection system secondary to the CLS controller. Because the UFLS requires the frequency to decrease, underfrequency triggers happen later than a CLS contingency trigger. The CLS scheme minimizes process, frequency, and power disturbances. UFLS events are therefore commonly associated with power swings and process disturbances.

The time difference between a power disparity event and the UFLS trigger is dominated by the physics of a power system. Net power system inertia and power deficits predicate the rate-of-change of frequency via (1).

$$2H\omega \cdot \frac{d\omega}{dt} = P_m - P_{elec} = P_{acc} \quad (1)$$

where:

ω is the generator speed (in per unit [pu] of the rated speed).

H is the inertia constant in MW/MVA.

P_m is the mechanical power output of a turbine (in pu).

P_{elec} is the electric power output of a generator (in pu).

P_{acc} is the acceleration power of the combined turbine and generator system.

In the event of a sudden loss of load, the CGTGs must reduce their output to prevent the frequency from rising unacceptably. Excessive system frequency causes protection equipment to trip off generators and other sensitive power

apparatus. Once protection equipment starts to trip on frequency, power systems commonly deteriorate into a power outage (blackout).

Similar to UFLS, the OFGS algorithm is designed to be a generation-shedding and runback protection system secondary to the GSS and runback algorithm

VI. TRANSIENT-LEVEL SYSTEM MODEL FOR CLOSED LOOP SIMULATIONS

A simulation tool for system modeling allows engineers to model the dynamics of the power system with a time step sufficiently fast to test relay protection schemes, fast-acting control algorithms, and slow-acting control algorithms. The simulation tool derives dynamic power system information, such as current and voltage, by solving multiple simultaneous differential and algebraic equations. A completed simulation model incorporates real-time inputs and outputs with the control or protection system under test. For example, a load-shedding trip command should be able to go directly into the model running on the simulation hardware.

Testing requires an accurate, dynamic model of the power system under test, including both mechanical and electrical subsystems such as governors, turbines, exciters, motors, busbars, generator parameters, power system stabilizers, inertia of loads, nonlinear load mechanical characteristics, electrical component impedances, magnetic saturation of electrical components, transient and subtransient reactance, and more. This level of modeling provides an accurate depiction of frequency, voltage, current, turbine speed, generator rotor angle measurements, and governor response characteristics. Model development includes the collection of data required for modeling different power system components, such as generators, transformers, transmission lines, distribution lines, and loads. After model development is complete, validation ensures that the model is sufficiently accurate for live testing of the PMS. Details of how the models are built and the response characteristics of the power distribution system, governor, loads, and exciters are discussed in the remainder of this section.

A. Simulation Model

For the facility under discussion, the full power system model was used to successfully predict events that could cause voltage and frequency collapse. The model consisted of 18 synchronous generators, generator exciters and associated power system stabilizers, turbine governor controls, 50 sheddable synchronous and induction motor loads, 41 on-load tap changer controls, 5 high-voltage overhead transmission lines, 4 underground cables, and 33 nonsheddable loads represented as lumped induction motors.

This model, running on real-time simulation hardware, was connected in a closed loop with the PMS algorithms for testing and validation. The model communicates with the controllers via industry standard protocols, such as IEC 61850 GOOSE and DNP3. The model also has hard-wired connections to the PMS to send and receive analog signals.

Due to the real-time nature of the simulation hardware and communications involved, the control systems under test cannot tell whether they are connected to a simulator in the lab or to the actual electrical system in the field.

B. Validation and Full Model Tests

The first step before creating a full model is individual component validation. This involves individually validating components, such as generators, loads, transformers, and so on. Generator validation involves performing load rejection, load acceptance, and step tests on generator controllers. Transformer validation includes validating the on-load tap changer controls for step tests. Load validation includes synchronous motor power factor correction and voltage control tests.

Once the individual validations are complete, the full model is tested for load flow convergence, short-circuit comparison, and dynamic stability comparison. Typically, the comparison is done against any available field data or the user software model. Short-circuit comparison involves comparing fault currents for several single-phase and three-phase faults. Dynamic stability comparison involves comparing critical fault-clearing times, frequency excursion limits, and so on.

C. Closed Loop Simulations

For performing closed loop simulations, several Ethernet-based, hard-wired communications are set up between the simulation model (running on real-time hardware) and the PMS. This enables the testing of the PMS for round trip times, critical fault-clearing times, and so on.

Such closed loop testing also allows the user to perform point-to-point testing of several PMS input and output signals before the start of field commissioning.

After full model validation, closed loop simulations are primarily divided into two categories. The first category is functional testing of individual PMS functions (unit testing). Functions such as load shedding, generation shedding, autosynchronization, and so on are individually tested to validate their performance according to system requirements.

Once unit testing is successful, the functional testing proceeds to the integrated system phase. Integrated testing involves evaluating all PMS functions simultaneously for several system scenarios. During this testing, all of the functions are enabled, and the interactions between various functions are evaluated for system-wide performance. For example, integrated system testing shows how a CLS trips load to keep frequency within bounds after a generator trip, which is followed by the slow redispatch of governors by the AGC.

VII. CONCLUSIONS

The full suite of PMS functions is critical for the safe and reliable operation of the entire facility. Such PMSs play a critical role in ensuring process survivability when it comes to islanded power systems. Low-speed controls assist in

everyday operations to preserve stability margins. High-speed controls, such as load-shedding systems and GSSs, operate during disturbances to preserve system stability.

Some of the key points to take away from this paper include the following:

1. The complexity of the power system required the AGC, VCS, and ICS to simultaneously control 16 different islands and 5 different tie lines or any combination of these.
2. The AGC and VCS control the swing bus to a constant frequency and the inter-tie lines to real power and power factor set points.
3. The ICS controls the modes (droop and ISO) of the governors and the modes of the exciters (volt/VAR), and selects the AGC and VCS dispatch algorithm modes.
4. A25A schemes are required at generators, tie lines, and bus couplers.
5. CLS algorithms shed load to maintain the power balance between the prime movers and the electric power system loads.
6. GSS algorithms shed generators to maintain the power balance between the prime movers and the electric power system loads.
7. Runback algorithms quickly redispatch turbine governors to prevent overfrequency events.
8. DRM values must be coordinated with overfrequency GSS tripping levels. Incremental reserve margin values must be coordinated with UFLS levels.
9. Common safeguards (such as modal detection, data filtering, data freeze, and state estimation) are used to prevent misoperation of the CLS, runback, and GSS algorithms.
10. The power system must be modeled with a time step sufficiently fast to test relay protection schemes and fast acting control algorithms.
11. The real-time simulation model and closed loop testing of the system allowed the plant operators and engineers to effectively test the PMS for various operating conditions.

As of the writing of this paper, the system is operating in Plant 2 and Plant 3, while systems for Plant 1, Plant 4, and Plant 5 are still being commissioned. Plant 2 and Plant 3 have had several power management system operations, and all of these operations resulted in correct decisions by the system to optimize plant processes and ensure load survivability. When fully commissioned, the system will be one of the largest microgrids ever built, with a state-of-the-art PMS monitoring and controlling the entire plant.

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IX. VITAE

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PacifiCorp

JIM BRIDGER PLANT, WYOMING, USA

Remedial Action Scheme (RAS), SEL POWERMAX® Dual-Primary Triple Modular Redundant (TMR) Control Scheme

The primary function of the Jim Bridger RAS is to maximize power transfer and ensure power system stability of the transmission system adjacent to the Jim Bridger generation station in Wyoming. This RAS allows PacifiCorp to operate their system very close to the stability limit, thus increasing the amount of low-cost power that can be shipped from Jim Bridger to Portland, Oregon, and Salt Lake City, Utah. The RAS protects the power system from subsynchronous resonance (SSR) by bypassing one or more series capacitors, thereby changing the damped natural frequency of the electric grid around Jim Bridger away from several shaft modes of the generators in the PacifiCorp system. This protects the shafts from damage during situations that are known to cause SSR. It also sheds generators at Jim Bridger (one or more 500 MW units) in response to changing system conditions to prevent the generation at Jim Bridger from exceeding the dynamic stability limits of several major transmission corridors.

SEL Engineering Services provided a POWERMAX Power Management and Control System RAS control scheme, configured as a triple modular redundant (TMR) control scheme. This system is similar to systems used in an emergency shutdown and the nuclear power industry. It employs a full two-out-of-three voting architecture (input and output voting) for all analog inputs (MW and MVAR), digital inputs (statuses), control outputs (output trips), and the SEL Crosspoint Switch Advanced Application Logic. Two TMR systems were provided, making it a dual-primary TMR scheme. The maximum response time from input assertion to output contacts was less than 16 milliseconds. A simulator was designed and delivered to the customer to test the functionality of the RAS. A supervision system was designed to monitor the decisions of the two TMRs and to perform contingency-based suppression or a complete TMR suppression when the RASs do not agree.



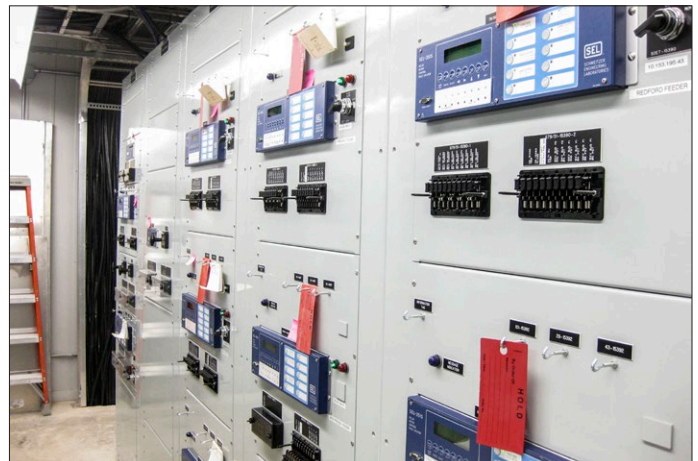
American Electric Power

PRESIDIO, TEXAS, USA

Presidio NaS Substation Automation Control and Protection System

SEL provided integration, controls, and protection of a 24 MW-hour sodium sulfur system and surrounding distribution systems. The scope of work included:

- Controls for capacitor/reactor banks
- Battery management
- Automatic transfer and load splitting
- Detailed functional design document
- Single-line diagrams and communications drawings
- AEP standard substation automation controller panel layouts and wiring schematics
- All distributed network protocol settings for SEL controllers to interface to S&C PCS controller
- Design of SEL static simulator
- Factory acceptance testing, training, and commissioning assistance
- Instruction manual and training power points
- Coordination study
- Model power system testing
- Relay settings



Ma'aden Phosphate

SAUDI ARABIA

SEL POWERMAX® Power Management and Control System

SEL Engineering Services was contracted by Hanwha Engineering & Construction in Seoul, South Korea, to provide a POWERMAX Power Management System for the Ma'aden Phosphate Complex in Saudi Arabia. Hanwha Engineering & Construction was the engineering, procurement, and construction contractor, and Worley Parsons was the engineer for the owner.

The scope of work was to provide a complete load-shedding, protection, and supervisory control and data acquisition (SCADA) system. SEL provided gateways to allow their process control system to monitor the POWERMAX System. The load-shedding scheme provided subcycle load shedding should the local utility connection be lost. The SCADA system included full metering, remote control, and historical archiving of plant-wide electrical events. Communications to SEL relays were handled via the IEC 61850 Manufacturing Message Specification protocol and third-party metering systems through a Modbus® RTU. The protection scheme used IEC 61850 GOOSE for two- and three-way automatic transfer schemes, bus lockout, and breaker failure schemes between SEL relays.



Tengizchevroil

TENGIZ, KAZAKHSTAN

SEL POWERMAX® Power Management and Control System to Provide a Fast Load-Shedding System

A POWERMAX contingency-based load-shedding system was designed, tested, and commissioned ahead of schedule for Chevron's Tengiz oil refining and extraction plant in Kazakhstan. This project was a cooperative effort between engineers from Chevron's headquarters in Houston, Texas; SEL's Engineering Services in Pullman, Washington; and Tengizchevroil engineers in Tengiz, Kazakhstan.



Motor Oil Hellas

HELLAS REFINERY, CORINTH, GREECE

Services Contract for a Comprehensive SEL POWERMAX® Power Management and Control System for an Oil Refinery With Onsite Generation and a Utility Tie

SEL Engineering Services provided a comprehensive protection, automation, monitoring, and control solution for all of the electric power systems within the refinery. Protective relays and supervisory control and data acquisition (SCADA) for 14 substations, four generators, two utility ties, and numerous motors and distribution feeders were provided. The SEL high-speed, flexible load-shedding solution, using the SEL-2032 Communications Processor, SEL-2100 Logic Processor, and SEL-3351 System Computing Platform human-machine interface, was implemented to maintain system stability when generation, utility tie lines, or internal ties are tripped. Process control provided dynamic control of the prioritization of over seventy 6 kV and 380 V loads for the load shedding. The SEL automatic generation control, voltage control, and megavolt-ampere reactive control systems maintained utility interconnection schedules, provided automatic economic dispatch of local generation, maintained busbar voltages, and maintained system frequency during islanded conditions.



Black Hills Power

RAPID CITY, SOUTH DAKOTA, USA

DC-Intertie Runback Remedial Action Scheme (RAS)

Black Hills Power (BHP) approached SEL Engineering Services to provide the architecture for implementation of a Remedial Action Scheme (RAS) on their 200 MW ac-dc-ac intertie. The scheme's purpose was to monitor the status of the BHP transmission system, area generation, and area load, matching the combination of these parameters to the power transfer capability of the installed 200 MW ac-dc-ac intertie station that connects the Eastern U.S. and Western U.S. power grids. The RAS limits or runs back the intertie's power transfer capability based on the output of the logic scheme.

The SEL products in the architecture included the SEL-2506 Rack-Mount Remote I/O Module, SEL-734 Advanced Metering System, SEL-2100 Logic Processor, and SEL-2032 Communication Processors. SEL developed special application logic in the logic processor to accommodate the complex scheme. In addition, SEL also provided real-time monitoring, event viewing tools to monitor the system conditions, and the runback signals. SEL also assisted the customer onsite with the system installation.



Saudi Aramco

SHAYBAH PLANT, SAUDI ARABIA

SEL POWERMAX® Power Management and Control System for the Shaybah Gas Separation Facility

The full suite of POWERMAX power and load management tools were employed at the Shaybah gas-oil separation plants (GOSP-2 and GOSP-4) in Shaybah, Saudi Arabia. This included SEL's contingency-based load-shedding controls, automatic generation control, frequency control, a wide-area volt/VAR control system, a small SCADA-like metering system, a complete protection system, automatic synchronization, and a full suite of engineering and diagnostic tools. Hyundai Heavy Industries was the prime contractor on the job, and SEL was hired as the power management system expert.

A dual-primary load-shedding system for the new and old plants was provided. High-speed load-shedding communication between the new and old plants occurred over a RUGGEDCOM® Ethernet network. Load shedding over Ethernet to the old GOSP2 plant used IEC 61850 GOOSE messaging. The worst-case total loop time for a load-shedding contingency at GOSP2 was 42 milliseconds, which included contact closure time. The high-speed load-shedding communication within the new GOSP4 green field plant used SEL MIRRORRED BITS® communications. Load-shedding response times for events in GOSP-4 and loads shed in GOSP-2 were measured at 12 milliseconds, including trip contact closure.

Tie-line control (MW and MVAR) between the new and old plants was provided while simultaneously dispatching generation of three 100 MVA generators. System-wide Sequential Events Recorder and event records (oscillography) were collected from SEL protective relays mounted throughout the customer's power system.

SEL used a Real Time Digital Simulator (RTDS®) to model and validate all system controls. The RTDS was also employed as a dynamic simulator to show real-life performance of the SEL control systems during factory acceptance tests.



Gulf Petrochemical Industries Company

MANAMA BAHRAIN

SEL POWERMAX® Decoupling Control System for Gulf Petrochemical Industries Company (GPIC) With Dynamic Real Time Digital Simulator (RTDS®) Study and Commissioning

GPIC uses natural gas to produce ammonia, urea, and methanol. GPIC hired SEL to provide decoupling to island the GPIC system from the external utility in case of an external disturbance.

For this project, SEL programmed two SEL-451 Protection, Automation, and Bay Control Systems in a dual-primary scheme to island the GPIC system for external disturbances. System validation was performed using the RTDS model during factory acceptance testing. SEL also provided an SEL-3351 System Computing Platform engineering station configured for sequential events recording and viewing, and automatic event retrieval using ACSELERATOR Report Server® SEL-5040 Software. An SEL-2032 Communications Processor was also provided preconfigured as a Modbus® gateway interface to the customer's distributed control system.

These systems have been in service continuously since November 2007 and have operated twice (correctly) to island the GPIC power system.



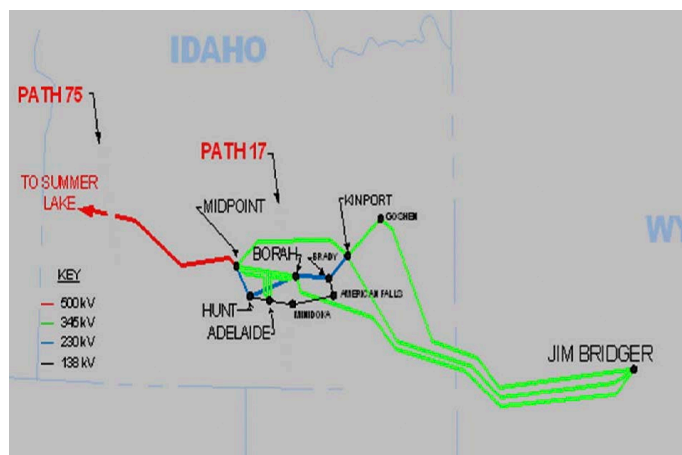
Idaho Power Company

BORAH TRANSMISSION STATION, IDAHO, USA

SEL POWERMAX® Power Management and Control System With a Dual-Primary Remedial Action Scheme (RAS)

The Borah West Remedial Action Scheme (RAS) was designed to maximize operating transfer capability, while protecting against cascading outages, on several key transmission corridors in Idaho Power's grid under normal and derated operating conditions. By remotely monitoring the state of all associated lines, transformers, and capacitors (shunt and series) for the specified path, the control system takes predetermined actions to prevent overloading transmission lines beyond their design level for all credible outages impacting the transfer capability of the path. The algorithm uses present system state information to continually adapt the control's response for every possible future contingency, making it one of the most advanced RAS algorithms in place in the world today. The RAS trips generators, inserts shunt capacitors, and bypasses series capacitors throughout Idaho Power's transmission system in response to the present system state and major system events (such as faults and line outages). SEL-2506 Rack-Mount Remote I/O Modules are used to collect breaker status and communicate via MIRRORING BITS® communications back to the RAS logic processors (SEL-1102 Computing Platform for Value-Added Resellers) located in the Borah West substation. The SEL-2506 is also used for output trips to remote substations.

SEL provided a POWERMAX RAS control scheme, configured in a dual-primary redundant control scheme. The maximum response time from input assertion to output contact is less than 20 milliseconds, transferred over several hundred kilometers.



Jacobs Engineering Group

SHAYBAH PLANT, SAUDI ARABIA HOUSTON, TEXAS, USA

Motiva Refinery Generation Control System

SEL Engineering Services was contracted by Jacobs Engineering in Houston, Texas, to provide a complete generation and load management system for the Motiva Refinery in Port Arthur, Texas. Jacobs was the engineering, procurement, and construction (EPC) contractor and owner's engineer.

The scope of work included dual redundant SEL POWERMAX® Generation Control System (GCS) hardware, a ClearView-based human-machine interface system running on an SEL-3354 Embedded Automation Computing Platform, and an SEL-2407® Satellite-Synchronized Clock at the main substation. SEL-3530 Real-Time Automation Controllers (RTACs) were used as data gateways to gather data from the existing SEL-2032 Communications Processor and SEL relays located throughout several substations. Included in the GCS was an automatic synchronization control system; redundant SEL-451 Protection, Automation, and Bay Control Systems were used to automatically resynchronize the plant back to the local utility grid. SEL-2411 Programmable Automation Controllers mounted in small wall-mounted racks were placed adjacent to the GE Mark VI governor and exciter controls. These SEL-2411 Controllers provided a hardwired interface for the POWERMAX System to dispatch set points and monitor the status of the GE governor and exciters.



Chevron Gorgon

BARROW ISLAND, AUSTRALIA

SEL POWERMAX Power Management and Control System

This project consisted of a POWERMAX generation control system, a load-shedding system, and a full simulation system.

SEL was contracted by KBR in London, England, to provide a POWERMAX System for the Chevron Gorgon LNG (liquefied natural gas) facility on Barrow Island, Australia.



East Bay Municipal Utility District

OAKLAND, CALIFORNIA, USA

SEL POWERMAX® Power Management and Control System for Load-Shedding and Protection

This project consisted of a complete load-shedding, SCADA, and protective relaying system for the East Bay Municipal Utility District (EBMUD) wastewater treatment plant.

SEL provided a comprehensive protection, automation, monitoring, and control solution for all of the electric power systems within the treatment plant. Protective relays and SCADA for three substations, four generators, two utility ties, and distribution feeders were provided. Load shedding for islanding of segments of the plant was provided. Real-time digital simulation was provided to validate the entire control system. SEL also provided autosynchronization and main-tie-main systems.



North American Oil Platform

GULF OF MEXICO

SEL POWERMAX® Power Management and Control System

In early 2010, SEL's client was looking for a solution for a modern, fast power-monitoring and load-shedding system for the design of an oil platform. The project was designed by the end user and a consulting firm. The present SCADA and load-shedding systems were required to be functioning as one system in order to simplify the day-to-day operation and increase accessibility. The load-shedding system is fast enough to issue trip commands to a list of user-prioritized loads within 70 milliseconds. The preferred SCADA human-machine interface (HMI) package was Wonderware InTouch® and was required to minimize the maintenance effort. Data concentration to several non-SEL devices and systems was required to be in the scope of the power management and load-shedding (PMLS) system vendor (SEL) scope. Automatic synchronization for the emergency generator buses and hurricane generator buses was required to be incorporated into the PMLS system. SEL Engineering Services participated in the front-end engineering design (FEED) stage of the project and officially kicked off the project in early 2011. Later in 2011, our client approved the scope expansion to have SEL provide protective relays.

SEL implemented a Wonderware InTouch-based SCADA system, including one-line screens, breaker detail screens, alarm screens, trending screens, and load-shedding screens. The HMI system monitors the live data of the power distribution system and displays them in an easy-to-understand fashion with the assistance of graphic animation and color codes. It also provides a historical, discrete-alarm database and analog trending screens. Five user levels were defined on the HMI system to grant different privileges to individual users. The breaker control function is not only protected by a user credential, but also supervised by electrical building location. Besides SEL intelligent electronic devices (IEDs), the SCADA system also integrates non-SEL devices, such as turbine control panels, 480 V MCCs, 480 V solid-state trip units, UPSs, HRGs, and others. The system provides two redundant Modbus® interfaces to process the automation system and also provides onshore connectivity for remote monitoring and event analysis at the client's onshore control center.

SEL delivered the contingency-based fast load-shedding system. The dual, hot-redundant SEL-1102 Computing Platform for Value-Added Resellers load-shedding processors provide reliable operation of the system. The 2-millisecond processor interval and the pre-event calculation feature ensure minimal time used in detecting, analyzing, and the system taking action. IEC 61850 GOOSE protocols are used for fast data communication.

SEL designed and constructed the PMLS communications panels, which are located in every electrical building. Two desktop computers were configured as engineering workstations. The workstations provide an HMI screen, manage a relay settings database, provide remote access to SEL IEDs, and allow users to manage and modify HMIs, add/edit/delete users, analyze events, etc.

An offline static simulator was configured for the project. The simulator is ideal for new operator training and engineering study of system behavior.

There were three automatic synchronization systems implemented on the project: one for the 13.8 kV bus-tie breaker main generator switchgear bus, one for the 480 V emergency generation system, and one for the 480 V hurricane generation system. The automatic synchronization system allows the operator to select which breaker to synchronize and matches the voltage magnitude, phase angle, and frequency by adjusting the corresponding generator. Custom logic was built into the SEL-451 Protection, Automation, and Bay Control System to meet the unique logic scheme requirements for this project.

SEL also provided the protective relay settings database according to the customer ETAP® system study and coordination report.



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