Energy Management Systems for Islanded Industrial Facilities

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Presented at the
5th IEEE GCC Conference & Exhibition
Kuwait City, Kuwait
March 17–19, 2009

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Abstract — **For completely islanded industrial facilities, a stable and robust power system is absolutely essential. Such facilities are not able to rely on an interconnection to a utility grid to provide stability or act as a safety net in the event of large, on-site generation disturbances. Knowing the ramifications of operating an islanded facility, Saudi Aramco has taken great care to help design a complete power management system for its new Gas Oil Separation Plant (GOSP) in Saudi Arabia. This power management system performs automatic, intelligent generation and voltage control to keep the on-site generation operating within its ideal range under normal conditions and within range in abnormal conditions, where the plant may be separated into individual islands. In addition to the voltage and generation control, which is used to keep the system running optimally for day-to-day operations, a high-speed load-shedding system provides dynamic, intelligent, protection-speed corrective action, based on user-defined load priority tables, for any major system contingency that could occur. Together, these systems provide a complete solution for power system management.**

Index Terms — **Load shedding, power generation, power system protection, power systems, voltage control.**

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. Active system controls within a PMS system include automatic generation control (AGC) and voltage control, while reactive systems normally involve frequency- or contingency-based load shedding. In previous decades, contingency-based 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.

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

where:

J = combined moment of inertia
ωm = angular velocity of the rotor
Tm = mechanical torque
Te = 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).

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

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 (Ta), as shown in (3), will be present on the system, and the frequency will begin to decay.

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

where:

Ta = Tm – Te = 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.

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.

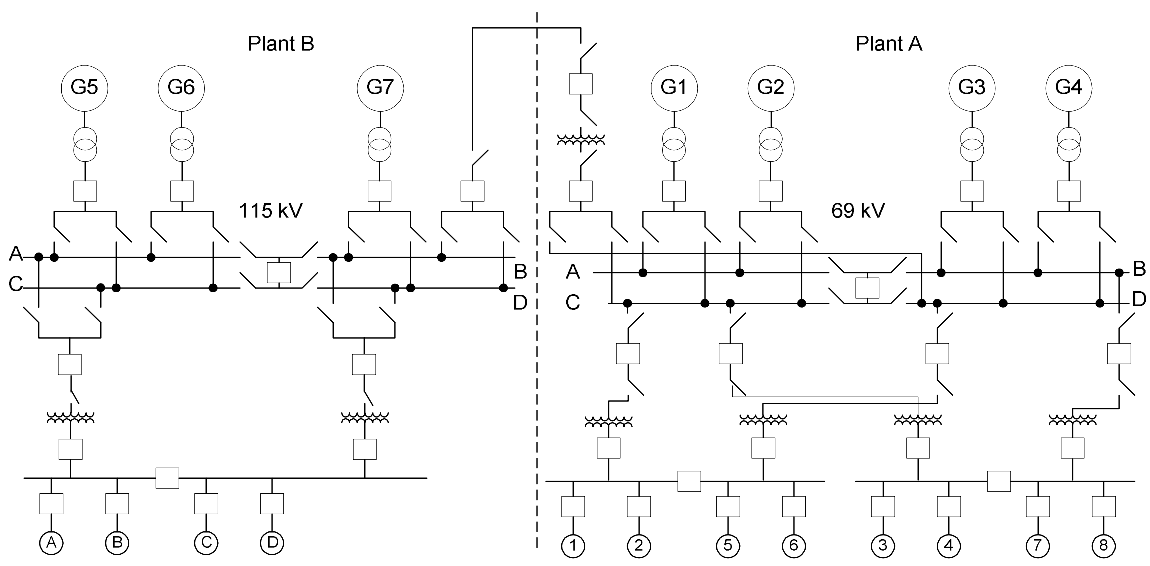

Fig. 1. Electrical network under review

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.

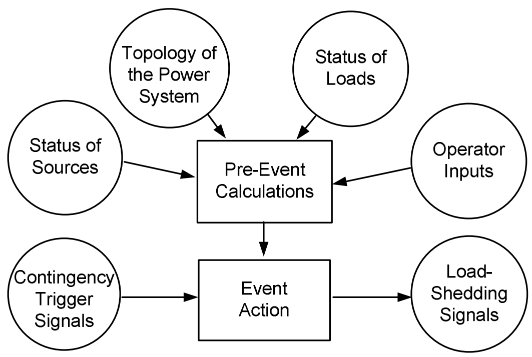

Fig. 2. Conceptual architecture

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)

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. 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. 3 for the Ethernet system architecture.

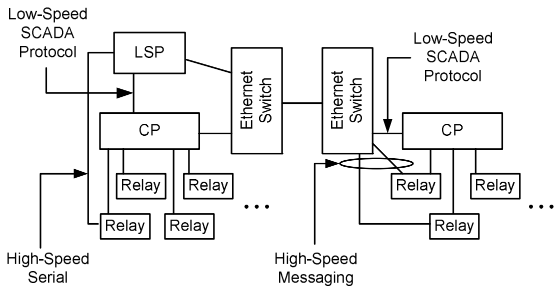

Fig. 3. Ethernet system architecture

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. 4 is typical of the local substation where the high-speed serial communications are used.

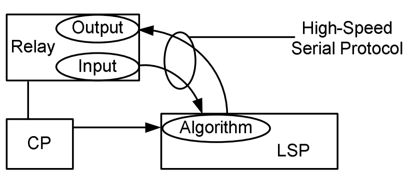

Fig. 4. Basic function of the LSP

Fig. 5 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 (see Table I for Ethernet-based time tests).

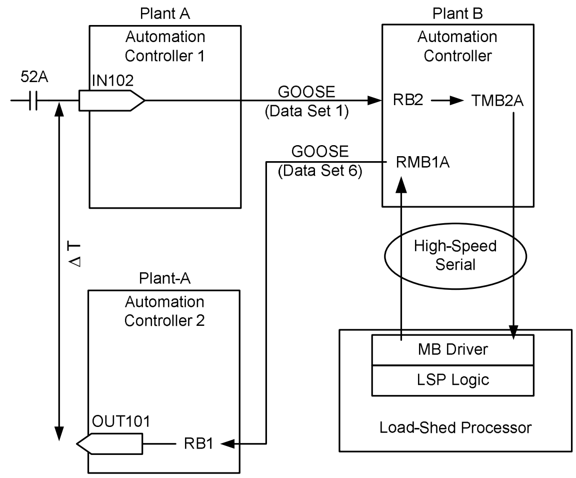

Fig. 5. General architecture

TABLE I
ETHERNET PATH
(REFER TO FIG. 5. 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 II, we eliminated the Ethernet side of the communications and rely completely on the serial communications. See Fig. 4 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 II
SERIAL PATH
(REFER TO FIG. 4. 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

V. AUTOMATIC GENERATION CONTROL AND VOLTAGE CONTROL

The primary goal of AGC and a voltage control system (VCS) on any system is three-fold:

- Increase longevity of equipment by keeping the system running at optimal set points
- Reduce the need for operator intervention, thereby reducing possible operator induced error
- Keep all units running with maximum margin, thus minimizing the effects of system faults

Considering these objectives, implementing AGC and a VCS involves gathering the appropriate data needed to perform the necessary calculations. As described briefly above, the LSP is run in parallel and uses much of the same data. This enables AGC and the VCS to share data with the LSP, thereby eliminating the need for additional communications networks. This point is significant in that the differentiation between AGC, the VCS, and the LSP is merely categorical. These three systems are actually subsystems of the PMS and, in many cases, can reside on the same controller.

AGC and the VCS are only integrated into the new plant (Plant B in Fig. 1). The AGC/VCS subsystem is therefore only tied to generators G5, G6, and G7 and interfaces with the original equipment manufacturer (OEM) governor and exciter packages. Considering this limitation, the AGC/VCS is controlling the output of each generator, the bus voltage and frequency, and the MW and MVAR tie flow to Plant A.

A. Island Mode Detection

Within the AGC/VCS subsystem, it is important to detect the number of islands into which the system may be separated. The most obvious instance of islanding would occur if the Plant A to Plant B tie line opened. Currently, the AGC/VCS subsystem runs all units at Plant A in isochronous mode. In the event that the two plants are islanded from each other, one of the requirements of this AGC/VCS subsystem is to shift one generation unit at Plant B to isochronous mode. The AGC continuously monitors Plant B to detect island conditions, and if an island is created, one unit is shifted into isochronous mode based on individual islands within Plant B, as well as islanding from Plant A.

B. Operator Interface

Control of the AGC/VCS subsystem is done via a graphical user interface (GUI) on the human machine interface (HMI) system for the PMS. This is the same interface that is used to set the LSP parameters. Operators have the ability to control specific set points related to the AGC/VCS subsystem. Generator operating set points and droop set points are entered on the screen and are limited to values that are acceptable to the AGC/VCS subsystem. If values outside of these limits are entered, the AGC/VCS subsystem restricts the inputs to a maximum or minimum value and warns the operator of the condition.

VI. CONCLUSION

This paper highlighted a complete PMS 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.

AGC and the VCS are important tools in maintaining balance and efficiency across the power system. Each unit is being controlled in a manner that optimizes operating margin, which leads to a more robust power system.

The combination of these PMS subsystems provides excellent proactive and reactive protection for the power system. The AGC/VCS subsystem maintains optimal system performance, and the LSP responds quickly and accurately in order to minimize disturbances.

VII. Biographies

Musaab M. Almulla graduated from King Fahd University of Petroleum & Minerals in 1998 with a BS 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 dis-tribution at Saudi Aramco facilities, focusing mainly on relay coordination studies and generation control. In 2002, Musaab graduated from Arizona State University with a MS 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.

Mohammed A. Fazil graduated from the Osmania University in 1999 with a BS in electronics and communication. After graduation, Mohammed began working for Schneider Electric's Automation division, where he was responsible for providing solutions for substation automation and industrial applications through system design, integration, and commissioning activities. In March 2008, Mohammed was hired at Schweitzer Engineering Laboratories, Inc. as an integration application engineer, where he is involved in supporting the development, design, implementation, and commissioning of substation-automation-based projects.

Nicholas C. Seeley graduated from the University of Akron in 2002 with a BS 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 specifically geared towards power management solutions.

Further Reading

N. Seeley, "Automation at Protection Speeds: IEC 61850 GOOSE Messaging as a Reliable, High-Speed Alternative to Serial Communications," proceedings of the 10th Annual Western Power Delivery Automation Conference, Spokane, WA, April 2008. Available at http://www.selinc.com/techpprs.htm.

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20090123 • TP6368