Hardware-in-the-Loop Testing of Electrical Protection and Control Systems

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HARDWARE-IN-THE-LOOP TESTING OF ELECTRICAL PROTECTION AND CONTROL SYSTEMS

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Abstract**—**Tying a large greenfield plant to an existing and fully operational brownfield facility requires complex planning and modeling. Protection, load shedding, turbine load sharing, synchronization, and other key functionalities must be tested during all phases of the cutover sequence to successfully merge the greenfield and brownfield systems. To validate the effectiveness of these functionalities, a real-time, hardware-in-the-loop, digital simulation can be applied using actual control systems. This paper describes the design, technology, model development, and overall validation of such a hardware-in-the-loop simulation at the largest oil and gas project in the world. This project includes a 1 GW power system distributed over a large geographic region that must run in an islanded configuration when not connected to the local utility of equivalent size. Lessons learned and results from recent hardware-in-the-loop testing are shared.

Index Terms—Hardware-in-the-loop testing, closed-loop testing, simulation, testing, power management system.

I. INTRODUCTION

In hardware-in-the-loop (HIL) simulations, a power system model interacts with protection and control system hardware in a closed-loop fashion. HIL testing validates the algorithms deployed in new and existing control systems. Islanded power systems (e.g., those used for oil fields) employ power management systems (PMSs) to perform critical actions like load shedding, generation shedding, generation control, autosynchronization, decoupling, and islanding detection [1].

This paper discusses a state-of-the-art HIL simulation system developed to fully test and validate the control algorithms deployed at a Eurasian oil and gas facility. At the oil field, a new greenfield system is being tied into an existing brownfield system. Fig. 1 shows the topology of the brownfield plant, which will transition through nine stages of cutover to reach the final topology shown in Fig. 2. In the final system, the 110 kV gas-insulated switchgear located in the main substation will include two tie lines connected to a local utility grid with a similar MVA size. The local utility connects to a much larger utility grid in a neighboring country with a weak link. The main substation will connect four generation substations, as shown in Fig. 2.

Plant 1 has four generators (TG6.1–6.4), Plant 2 has three generators (TG6.5–6.7), Plant 3 has two generators (TG9.1 and 9.2), and Plant 4 has five generators (TG9.3–9.7). The greenfield system uses breaker-and-a-half substations, and it comprises a total of 26 power-wheeling buses that can support up to 9 simultaneous electrical islands. The power system contains 12 adjustable-speed drives (ASDs) connected at the 110 kV level. The soon-to-be-deployed PMS employs algorithms to track all the possible bus combinations of system islands and utility-connected grid sections.

II. POWER MANAGEMENT SYSTEM

The PMS, shown in Fig. 3, mainly consists of slow- and high-speed rebalancing control systems. These systems work together to preserve the overall dynamic stability of the electrical system while operating the system at the desired limits. Slow-speed control systems include automatic generation control, volt/VAR control, island control, progressive overload shedding, and autosynchronization [2]. High-speed control systems include load shedding, generation shedding and runback, decoupling, and islanding.

The load- and generation-shedding systems ensure high-speed power balance during the loss of any source or load in the system. Typical source losses include generation loss, utility loss (while importing power), and the formation of islands with a generation deficit as the result of inadvertent breaker-open conditions. Typical load losses include losing one or more ASDs, utility loss (while exporting power), and the formation of islands with a load deficit. These systems primarily operate to shed load and/or generation based on the opening of a contingency breaker (a breaker is a contingency breaker when it creates a power deficit within an island when opened). Backup control systems use a centralized frequency and rate-of-change-of-frequency approach. Compared with the contingency-based schemes, the backup schemes take longer to stabilize the power system due to their feedback-based control.

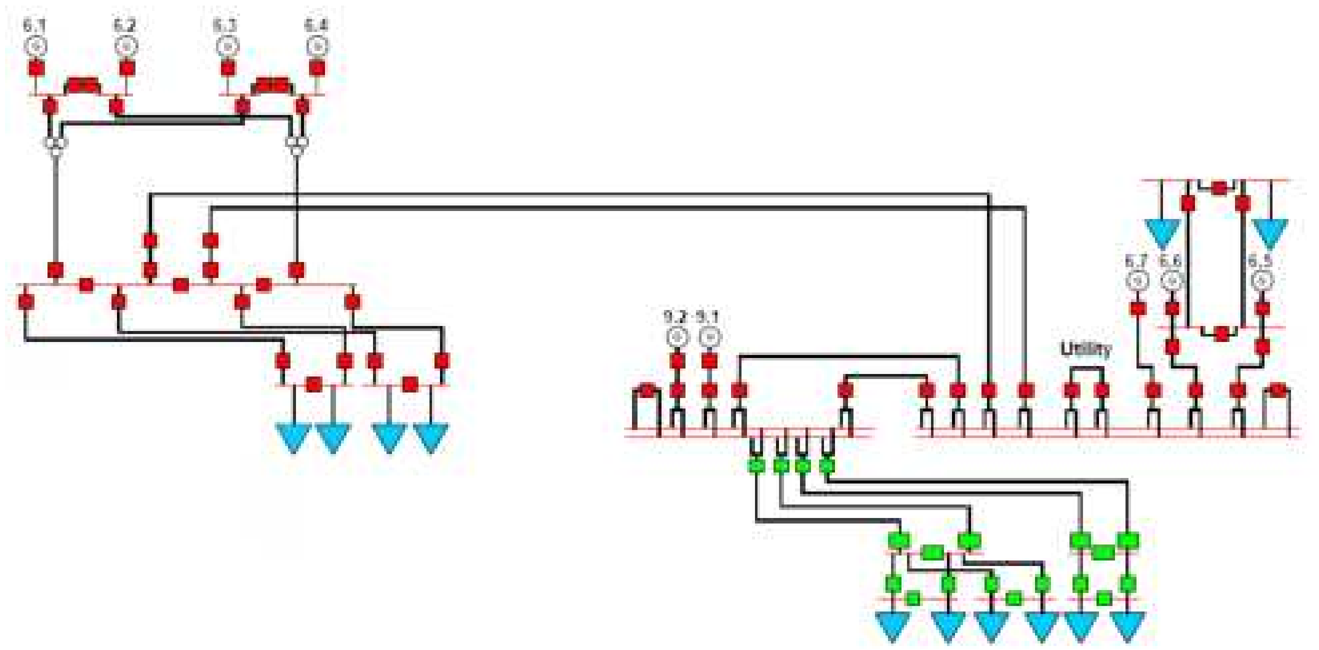

Fig. 1 One-Line Diagram of the Existing System

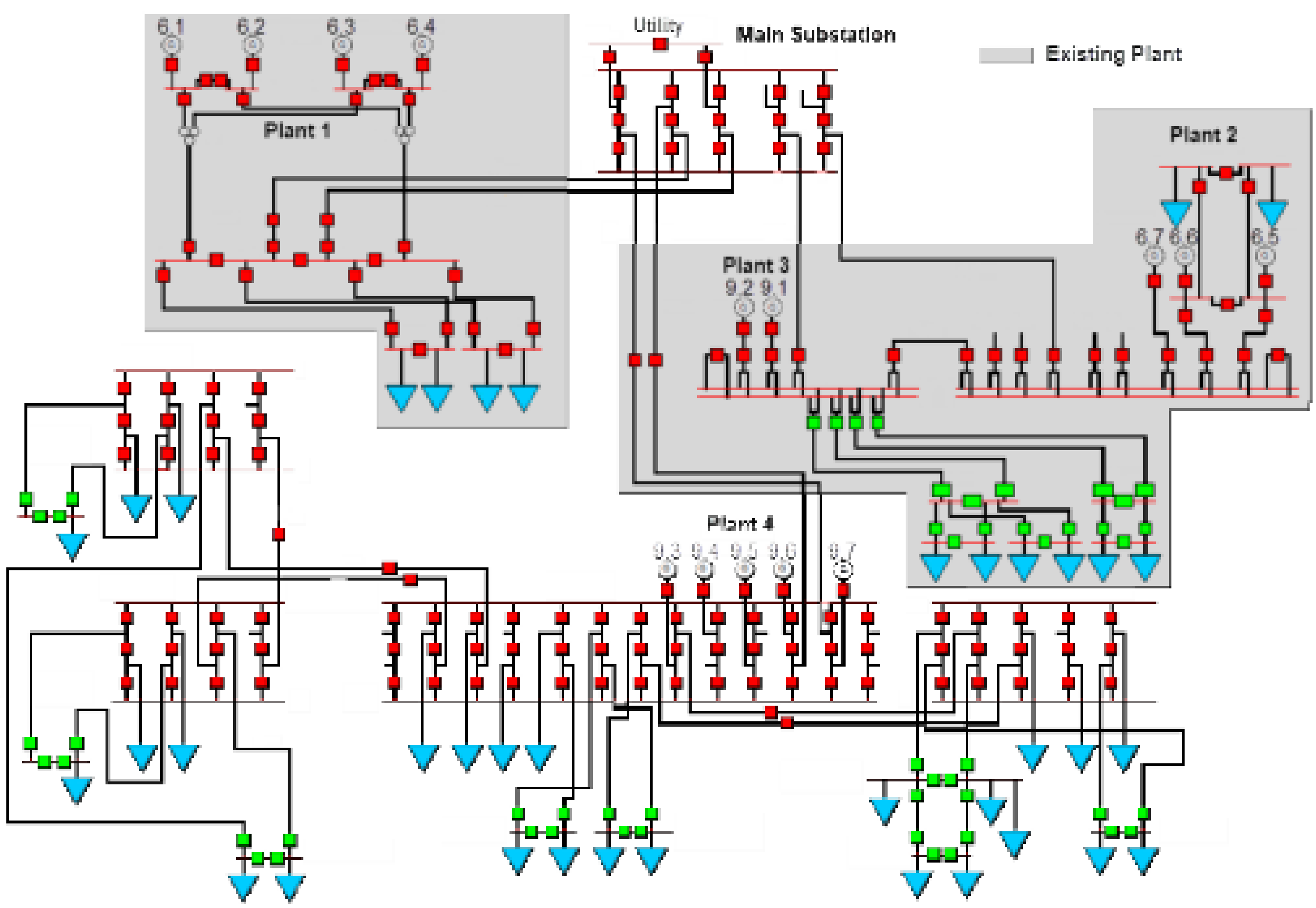

Fig. 2 One-Line Diagram of the Planned Final System

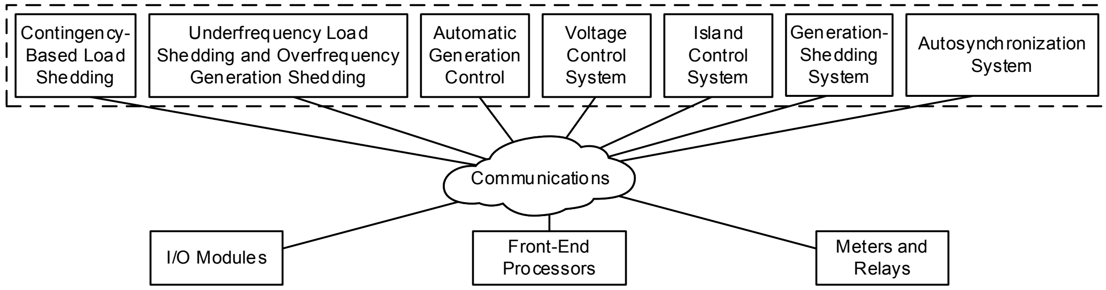

Fig. 3 Simplified PMS Architecture [1]

The decoupling scheme implemented at this oil field employs modern techniques to detect internal and external disturbances, intentionally island the plant, and stabilize it. As shown in Fig. 4, the decoupling system measures voltage and frequency on Bus 1 and Bus 2 at the 110 kV main substation, measures currents on the two utility tie lines, receives incremental reserve margin (IRM) [3] and decremental reserve margin (DRM) values from the load- and generation-shedding systems, and sends trip commands to decouple the power system from the utility grid under predefined system conditions. The decoupling scheme uses power, frequency, rate-of-change-of-frequency, and IRM/DRM elements.

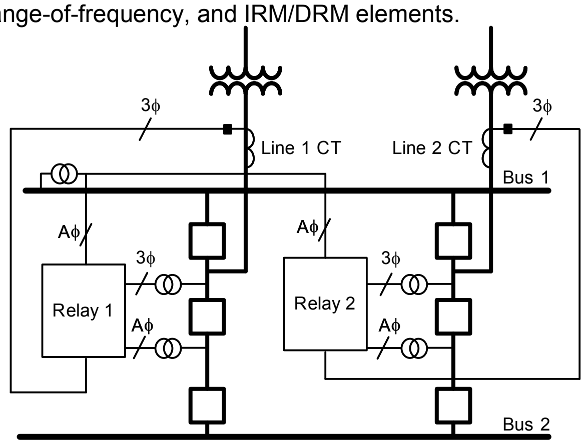

Fig. 4 Decoupling Relays on the Main Substation Utility Connections

The decoupling scheme is divided into primary and secondary schemes. The primary scheme uses a power-supervised 81RF element [4], and the secondary scheme uses traditional underfrequency (81U) and overfrequency (81O) elements. For the power-supervised 81RF element, power flow at the utility tie lines is monitored. Changes in this power flow during a disturbance are used to determine whether the disturbance is internal or external. For an external disturbance, only the power-supervised 81RF element is used, whereas the internal disturbances are further supervised by IRM and DRM values. The traditional underfrequency and overfrequency elements are used independently to guarantee decoupling under all power flow conditions. Fig. 5 shows the characteristics of the implemented decoupling scheme.

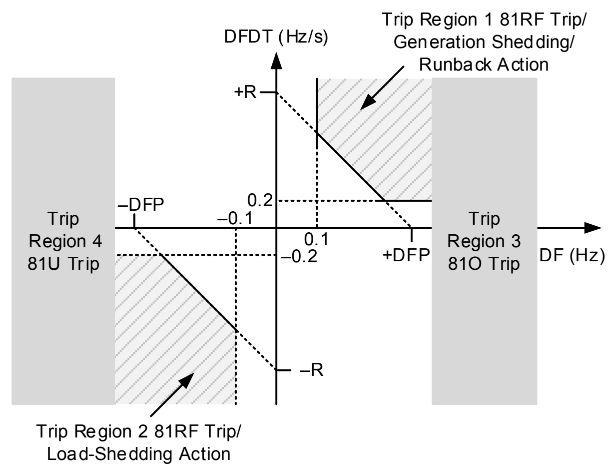

Fig. 5 Decoupling Scheme Characteristics

In addition to the relay-based decoupling system, the load-shedding system can also intentionally island from the utility if doing so results in fewer loads shed than staying connected with the utility. Fig. 6 shows the decoupling logic implemented within the load-shedding system.

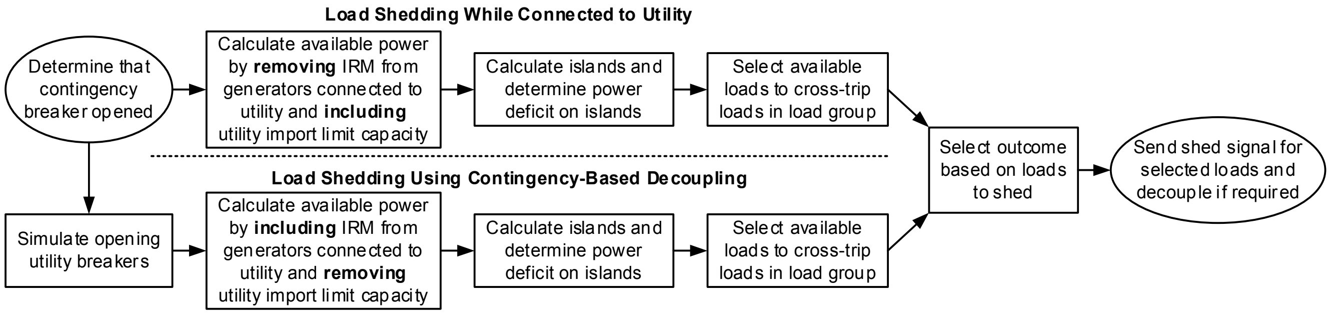

Fig. 6 Decoupling Logic Implemented Within Load-Shedding System

III. SIMULATION SYSTEM AND HIL TESTING PROCEDURE

The authors designed and developed a state-of-the-art simulation system to test and validate the PMS for both the brownfield and greenfield systems. The test bed comprises a digital real-time simulator (DRTS), panels with PMS equipment (replicas of the actual equipment being deployed in the field), and extensive interfacing of measurement and control signals using hardwired connections and industry-standard communications protocols.

The simulation system tests all the control functions of the PMS through each cutover phase as well as the final phase of the greenfield integration.

The PMS panel contains devices that emulate the load-shedding, generation-shedding and runback, decoupling, autosynchronization, electrical control, and generation control systems. Each control system runs concurrently and interacts with the DRTS power system model through statuses and commands sent and received in real time.

Fig. 7 shows the high-level setup of the closed-loop simulation of different controllers. The power system model in the DRTS receives signals from the simulator controllers (PMS control systems). The actual voltages, currents, and digital I/Os are wired to the autosynchronization and decoupling relays. Users can start a simulation, run closed-loop tests, perform studies, or train personnel on each controller.

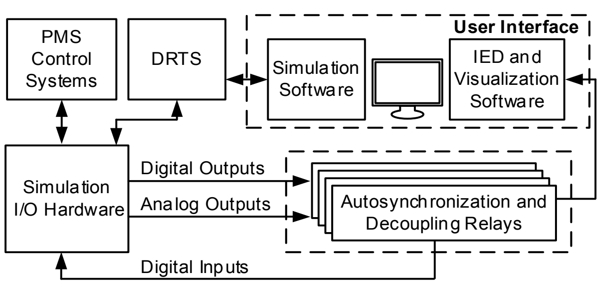

Fig. 7 Closed-Loop Simulation Setup

A. *Overview of Plant Simulation System Applications*

The power system model in the DRTS includes generators, governors, exciters, transformers, synchronous motors, induction motors, ASDs, utility equivalents, distribution lines, on-load tap changers, and sheddable and nonsheddable loads. All governors, exciters, and other power system component responses are monitored in real time. Table I lists the closed-loop tests and studies that can be performed with the DRTS and the overall simulation system.

TABLE I
APPLICATION CAPABILITIES OF THE SIMULATION SYSTEM

Closed-Loop Tests	Studies Using DRTS
Dynamic, high-speed load shedding, generation shedding, and runback	Short-circuit analysis using configurable fault controls
Slow-speed automatic generation control	Transient stability studies for different scenarios
Slow-speed voltage control	Load flow studies for various plant operational scenarios
Decoupling	Voltage stability tests for motor startup
Autosynchronization	Transformer inrush studies for specific loading conditions
Round-trip time evaluation	Frequency coordination studies
Electrical control system (SCADA) simulation	IRM and DRM calculation studies

Key abilities of this simulation system include the following:

1. Simulating power system scenarios in real time using dynamic models. These scenarios are observed and responded to by the controllers, which are connected in a closed-loop fashion. This provides a much better representation of reality than the “open-loop” playback systems typically used for testing protection systems.
2. Saving and restoring power system scenarios. Live plant load-flow data can be saved with a snapshot feature and loaded into the DRTS. This save-and-restore feature can be used for contingency or post-event analysis.
3. Aiding operator decision making by testing changes and procedures before they are applied to a live power system. Some examples include:
   - Modifying underfrequency settings for the backup load-shedding system.
   - Modifying IRM set points and verifying load-shedding functionality for different contingencies.
   - Verifying undervoltage load-tripping settings.
   - Confirming the expected outcome of a switching operation.

4. Assisting with plant operator and dispatcher training. Operators can:
   - Be trained on the different control system actions and the resulting power system dynamics.
   - Learn system contingencies, alarming, and required set points.
   - Learn about the interaction and signal exchange between SCADA and generation control systems.
   - Be trained without affecting the live plant.
   - Be trained on the autosynchronization and decoupling systems.
   - Select breakers to initiate, complete, or abort synchronization.
   - Understand the decoupling system and practice the actions required during events.
5. Observing interactions between various control systems and the associated dependencies. An example is understanding the effect of load-shedding trips on the generation control system.

In addition, controllers, gateways, and HMI components in the simulation system can later be used as spares for the installed field system.

B. Steps for Running Closed-Loop Simulations

Closed-loop testing and control system validation require a model of the power system that accurately represents reality. The following steps describe the process of developing a model in the DRTS and using it for HIL testing.

1) Model Development

In this step, a dynamic model of the power system is developed including both mechanical and electrical subsystems. These components include governors, turbines, exciters, motors, busbars, generator parameters, power system stabilizers, load inertias, nonlinear-load mechanical characteristics, electrical component impedances, magnetic saturation of electrical components, transient and subtransient reactance, and others. All data required for modeling the different power system components are extracted from sources such as equipment data sheets and computer models.

2) Model Validation

Before using the power system model, validation tests are performed to ensure accuracy and to match the model responses with the field and/or manufacturer's expected responses. In this step, details such as how the model was built and the response characteristics of the power system, turbines, governors, exciters, loads, and so on are documented. Typical validation tests include:

1. Generator governor load acceptance/rejection tests.
2. Generator exciter reference step change and full-speed, no-load tests.
3. Power system short-circuit tests for matching fault contributions.
4. Power system dynamic tests for matching transient and dynamic responses, including minimum and maximum values.

3) Power System Studies

In this step, studies are performed on the finished and validated power system model to derive controller set points. The IRM of each generator and connected utility is calculated, the frequency response characteristics of the system are plotted, relay underfrequency load-tripping levels are coordinated with IRM values, and automatic decoupling settings are determined. These studies allow operators to understand the voltage, frequency, and power response characteristics during various events.

4) Interfacing of Simulator and Devices Under Test

In this step, the DRTS and its interfacing hardware are configured to communicate control and status information. Hardwired and Ethernet connections are made according to the controller requirements. Interfacing is matched to the field setup to properly consider delays and round-trip times. I/O points are confirmed between devices.

5) HIL Testing

Set points are programmed into the controllers, and HIL tests are performed on the interfaced hardware under various scenarios using the power system model. Test scenarios range from modular tests to fully integrated system tests. Typical objectives of this step are to:

1. Validate the performance and effectiveness of control systems to guarantee power system stability and reliability.
2. Identify the strengths and weaknesses of the power system to understand boundary conditions.
3. Understand the interaction between new and existing control systems to ensure smooth plant operation and to avoid unplanned back-to-back events.
4. Understand round-trip times, network delays, and processing delays.
5. Validate and explore design changes to tune algorithms and add new elements.

IV. DYNAMIC SIMULATIONS

Hundreds of closed-loop simulations were performed as part of factory acceptance testing to validate the PMS algorithms for the oil field. Each control system was connected with the simulation system to test its performance against the design requirements. Each system was subjected to numerous scenarios, including generation loss, load loss, utility loss, overload conditions, motor startup, unintentional islanding, and fault conditions. For each test, the description, pre-event conditions, event trigger, expected controller actions, observed controller actions, and results were documented. Results included plots of power system responses (voltage, frequency, power, speeds, breaker statuses), pre- and post-event controller statuses, HMI screenshots, and event reports that include the sequence of events. This testing included hundreds of scenarios, resulting in several gigabytes of plot data. Since it is not practical to present all of the HIL testing results in this paper, some example test cases are provided.

A. Case 1

Case 1 shows the load-acceptance behavior of a Plant 4 gas turbine generator (with IEEE GGOV1 governor model) for three different acceptance values. This test was conducted during the model validation stage for verifying individual generator responses. Fig. 8 shows the plotted machine speed, mechanical power, and bus frequency values. These results were compared to the manufacturer's expected responses to tune the governor models. Overall, they compared well, and minimal tuning was required to bring them closer.

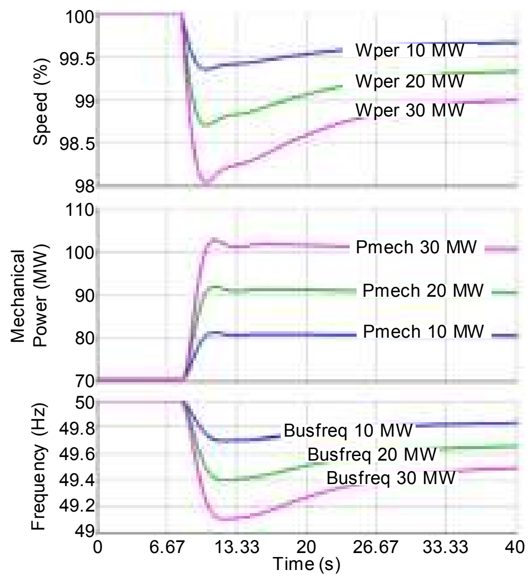

Fig. 8 Load Acceptance Responses for a Plant 4 Generator

B. Case 2

Case 2 represents a situation where a local generator was tripped while the plant was still connected to the utility. Most of the load was picked up by the utility, with a 0.14 Hz deviation in system frequency (see Fig. 9). During this test, the utility tie lines reached 95 percent of their power flow capacity and came very close to being decoupled. This test was conducted during the model validation stage for verifying the overall power system dynamic response.

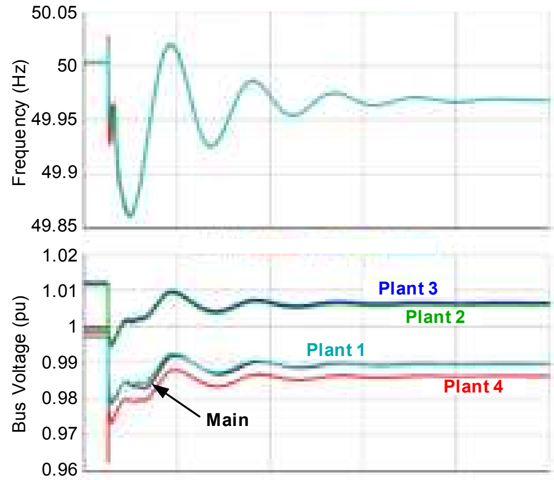

Fig. 9 Loss of Local Generator While Connected to Utility

C. Case 3

Case 3 represents a bolted fault condition on the 110 kV bus located in the main substation. The fault was applied for various durations, and 170 ms was determined to be the critical fault clearing time when the system is connected to the utility. The speed response of the generators and the synchronous motors was observed in various plants for this fault condition. Fig. 10 shows the loss of synchronism for two large motors when a 180 ms fault condition occurs. This test was conducted during the power system studies stage to determine the maximum allowed round-trip times for various island configurations.

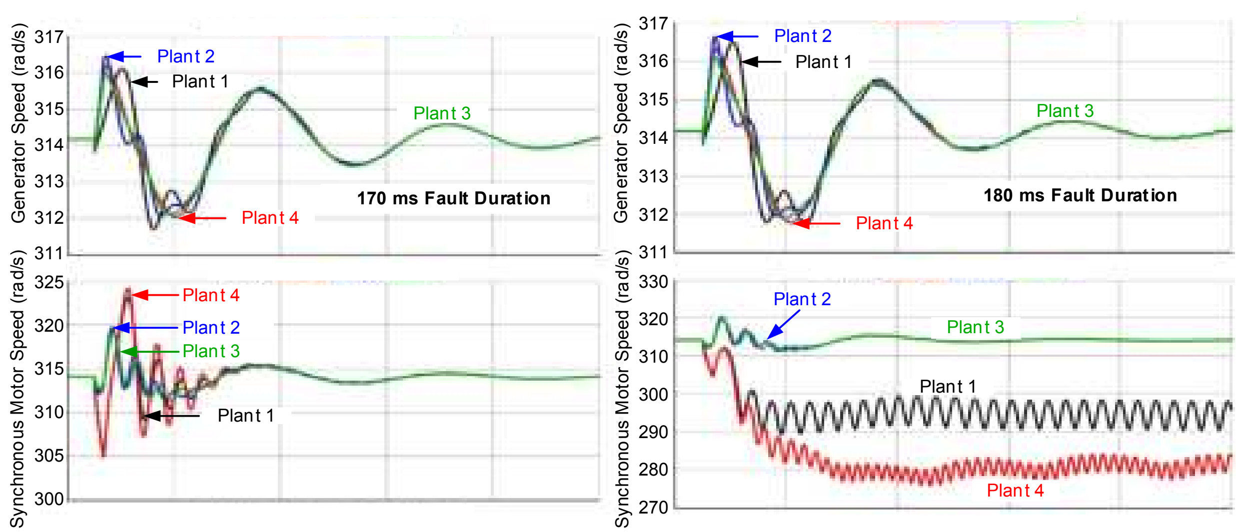

Fig. 10 Determination of Fault Clearing Time

D. Case 4

Case 4 (see Fig. 11) represents an HIL test where the load-shedding system shed load for the loss of a generator and quickly stabilized the power system during a summer operating case. In this case, all the generators were operating at their full capacity (pre-event) and the plant would have separated at the utility connection if a load-shedding action did not occur. The separation of the plant is undesired in this case because it would create a generation deficit that could collapse the island. This test was conducted during the HIL testing stage to validate the performance and effectiveness of the load-shedding system.

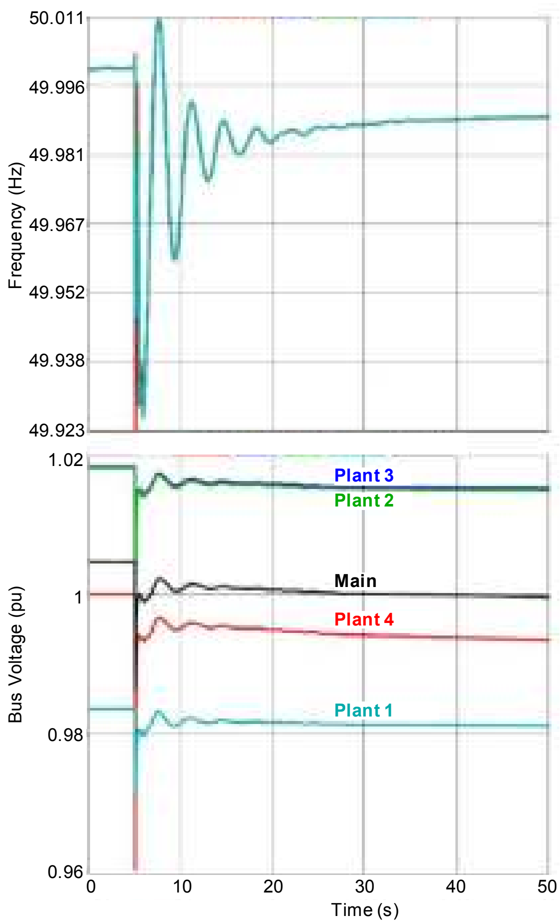

Fig. 11 Load-Shedding Operation to Preserve System Stability

Overall, the authors performed more than 100 HIL tests to validate control system performance during project development and factory acceptance testing. Some of the key lessons learned from the HIL testing include the following:

1. HIL testing provides a mechanism to understand the power system's dynamic response to control actions.
2. For optimized load shedding within the plant, compensate the decoupling scheme with IRMs and DRMs. This allows for proper classification of events and appropriate high- or low-speed actions.
3. To obtain a better frequency response during islanded conditions, revise the relay-based underfrequency set points to better coordinate with the centralized frequency-based load shedding.
4. To reduce the inherent risks of generation shedding and runback control, a grouped runback of generators is recommended in addition to an optimal combination of generators for shedding.
5. To prevent inadvertent overloading of a single utility tie line, combine the IRM and DRM set points for the overall utility connection.
6. Use rate-of-change of frequency in addition to the static frequency thresholds when developing underfrequency load-shedding schemes for a reliable backup scheme.

V. CONCLUSIONS

HIL tests play a critical role in testing control systems before they are deployed in the field. Through HIL tests, the performance and effectiveness of PMS controls can be studied for both typical cases and corner cases that cannot be verified in the field. Also HIL testing reduces overall commissioning time and is great for brownfield integration projects where production disruption can be critical. This paper discusses the theory and steps involved in developing a simulation system using a DRTS and actual field controllers. The architecture, applications, and key features are detailed to help describe the implementation. Key takeaways include the following:

1. Protection and control systems should be thoroughly tested and proved before they are deployed in the field. Closed-loop tests allow for true continuous interaction with the power system.
2. To meet HIL testing objectives, proper dynamic models must be developed and validated prior to testing. Also, proper protection and control system set points should be programmed into the model to represent existing field conditions.
3. The simulation system architecture should closely represent the field setup, including the interfacing protocols. This ensures proper consideration of delays and other nonlinearities.
4. Simulation systems can aid operator decision making before field modifications are implemented.
5. HIL testing helps identify vulnerabilities within the power system for better protection.

VI. ACKNOWLEDGEMENT

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VIII. VITAE

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