HOW TO SAFELY ISLAND A CHEMICAL FACILITY

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Abstract—In a chemical plant facility with excess generation, it is not only beneficial to export excess power, but essential to support the utility's load by maintaining a certain minimum power export. A chemical plant's electrical stability is of highest importance because downtime and unplanned events pose potential risks to the plant, personnel, and environment.

This paper describes how rate-of-change of frequency (ROCOF) detection is used to safely island a chemical plant from a utility. This is followed by runback and generation shedding. Decoupling protection design, benefits, and limitations are explored with results from hardware-in-the-loop (HIL) testing. The ping-pong effect between sheddable loads and generators is discussed and underfrequency-based load shedding as back up is also introduced.

Index Terms—Decoupling, generation shedding, generator runback, inertia, HIL testing, rate-of-change of frequency (DFDT) (ROCOF), load shedding.

I. INTRODUCTION

A. System Overview

The chemical facility power system is a combined heat and power facility that has steam and power generation sources across the facility at different voltage levels separated into three main areas as illustrated in Fig. 1. Area 1 has four gas turbine generators (GTGs) and one steam turbine generator (STG) connected to the 230 kV breaker-and-a-half substation. This is the largest power generation area where power is distributed to the remainder of the chemical production facility and the utility. The facility is almost always exporting power, which is about half the total generation capacity, to the utility during normal operation through three utility tie lines. The power export to the utility is nearly the same across the three utility tie lines, and each has the capacity to carry the entire power export from the facility. The facility *can* decouple if the frequency-based protections on the line operate and trip all tie lines together. The three lines serve as redundant connections where one or more lines could be isolated for maintenance routinely.

Area 2 has two GTGs and two synchronous condensers (SCs) to provide VAR support to the 15 kV bus. This area imports additional power from a 230 kV system through step-down Transformers T1, T2, and T3 (230/15 kV) as illustrated in Fig. 1. Area 2 also sends power to Area 3 through two interconnecting tie lines. Area 3 has four GTGs that provide power to the loads connected at this area of the facility.

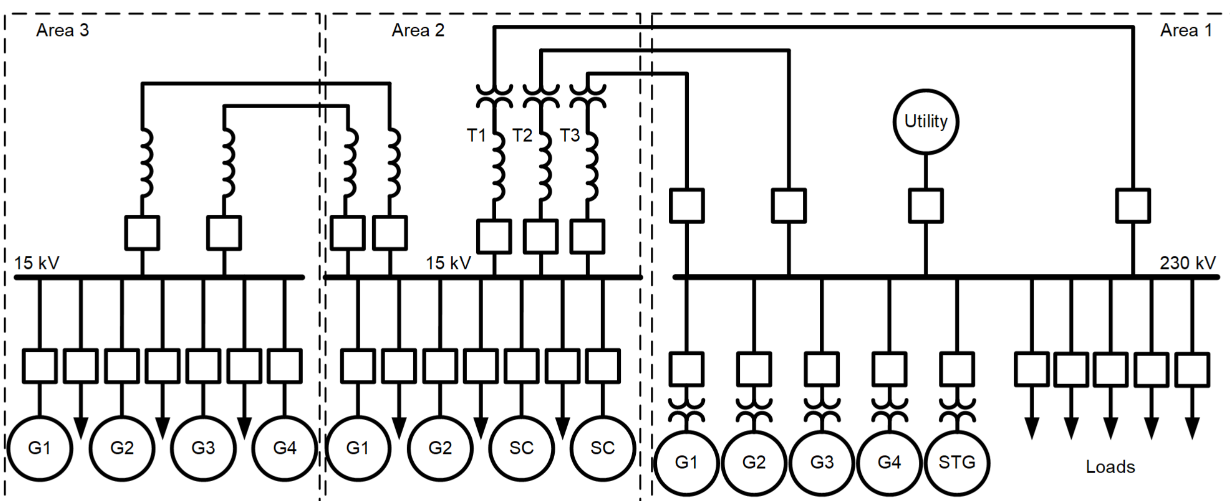

Fig. 1 Simplified One-Line Diagram of the Facility

The major loads for the plant are connected at the generator supported buses in Area 2 and Area 3. The 15 kV power distribution switchgear has many series reactors that are used to limit the short-circuit current and regulate power flow.

B. Problem Statement

This power system can produce more power than the required load within its plant. This excess power is exported by the facility to the utility for distribution to its customers. The facility is primarily in export mode, where a portion of its generation capacity is exported under normal conditions. In a situation where the system is suddenly disconnected from the utility due to an undesirable condition, the excess generation needs to be reduced and balanced with the system load to maintain system stability.

This paper discusses solutions implemented in the facility using protection and microgrid control systems for the detection of unstable conditions, isolation from the utility, and resolution for system instability.

C. Power Swing Equation and Critical Clearing Time (CCT)

The CCT is the maximum time interval by which the fault must be cleared to preserve the system stability [1]. The CCT is essential to evaluate the system performance but is impacted by many factors. The CCT in the plant, recorded through simulation studies, is the maximum time a three-phase fault at the intertie needs to clear before the generators in the plant lose complete synchronism. The CCT was used as a reference in performing transient stability tests on the system and in the design of the decoupling protection system.

Fig. 2 depicts an example equal area criteria illustration. The most critical fault for system stability is the three-phase fault. In general, fault types involving more phase conductors are more critical for stability.

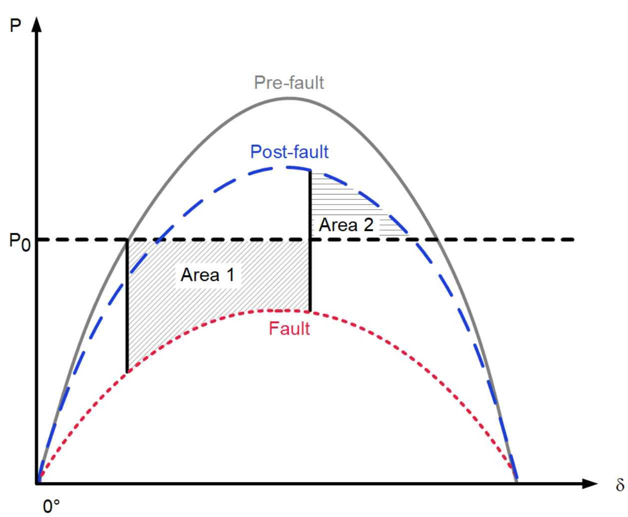

Fig. 2 Equal Area Criteria

When a fault occurs on the transmission system, the power flow is predominantly reactive due to the dominant inductive impedances of the transformers and lines. 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 prime movers driving the generators are continuing to produce real power, the generator accelerates due to the law of conservation of energy. 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. 2 shows Area 1 as the accelerating area and Area 2 as the decelerating area. This figure depicts an unstable system. Slow fault clearing causes a large accelerating area, which cannot be compensated by a corresponding decelerating area. The equal area criteria method helps determine stability of a system without the need to solve the swing equation. This method is applicable for one machine connected to an infinite bus or for two machines. Using this method, the CCT is determined for the facility.

II. DECOUPLING PROTECTION DESIGN

A decoupling scheme detects disturbances in the utility power system and intentionally islands the microgrid. Disturbance detection settings for such intentional decoupling systems should be carefully set to avoid being too sensitive and to prevent nuisance tripping [2].

Decoupling protection is essential for safely islanding the facility and triggering other important actions within the facility, such as generator shedding, load shedding, and generation control. This section introduces the decoupling characteristics and how the sensitivity of the decoupling protection is set.

Equation (1) is from [3]:

$$\Delta f_{PU} = \frac{\Delta P_{PU}}{2H} \tag{1}$$

where:

Δf_{PU} is change in frequency in pu.

ΔP_{PU} is change in frequency in pu • seconds.

H is inertia in seconds.

During a transient in the system, the deviation in frequency without the interference of any control system (which is usually the first few cycles after an event) is a consequence of the power exchange and system inertia.

The decoupling design is based on two factors:

1. The power exchange with the utility
2. The total system inertia

The worst-case scenario is when the breakers upstream on the utility side are opened unintentionally and the system responds to the sudden mismatch of the overall generation and load within the facility. This condition is considered to be the worst case since any connection to the utility would just add more inertia. This test condition is set up for all further discussions regarding decoupling in this section. Since the facility is always exporting power, a positive DFDT condition is the focus of the adverse frequency condition.

A. The 81RF Element Characteristics

The 81RF element provides a faster response compared with the frequency (81O and 81U) and ROCOF (81R) elements. The faster response times make the 81RF element suitable for detecting islanding and system disturbance conditions with critical time requirements.

Fig. 3 shows the 81RF characteristic. This element uses frequency deviation from nominal frequency (DF = FREQ – FNOM) and ROCOF to detect islanding conditions.

Under steady-state conditions, the operating point is close to the origin. During separation from the utility, depending on the frequency difference and the ROCOF, the operating point enters the operating region of the characteristic. If the system is accelerating, the operating point enters Trip Region 1, and if the system is decelerating, the operating point enters Trip Region 2.

Fault-blocking logic is used to restrain the element under fault conditions or other conditions where the frequency measurements are not reliable. At the same time, if the fault is not cleared within the CCT, the decoupling should not be blocked, and a trip signal must be issued. The logic unblocks and arms the decoupling if the fault persists for more than eight cycles. The timing is determined based on the CCT of the facility.

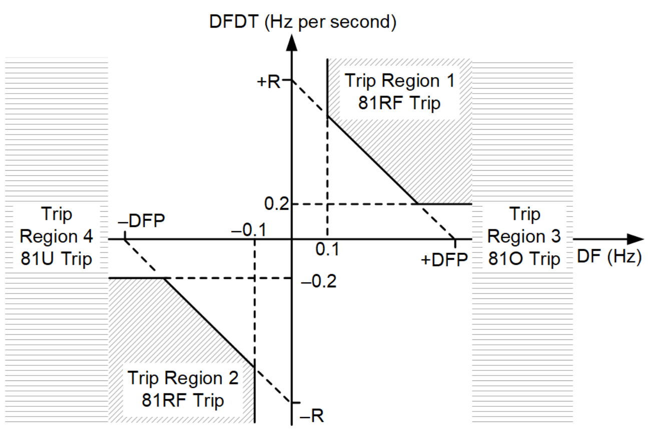

Fig. 3 Decoupling Scheme Characteristics

The 81RF element should be secure so it does not operate in conditions of faults and other spurious switching events. The slope of the 81RF characteristic is the equation of a line, as shown in (2).

$$y = m \bullet x + c \tag{2}$$

where:

y is DFDT.

m is the slope of the line.

x is df (slip frequency).

c is the y intercept.

If the DFDT of a frequency swing is known, it is easy to calculate the frequency at which the decoupling protection triggers when the slope and *y* intercept are known. The same applies if the DFDT of the event is calculated based on the slip frequency (df) where decoupling happens. A faster DFDT can result in quick detection for 81RF protection and a slower DFDT picks up the 81RF event slower, as demonstrated in the following sections.

B. Power Export and 81RF

This system usually exports 50 percent of its total generation capacity, which is also about 75 percent of its total export capability. In a high-export condition, the *ΔP* is high enough to create a fast DFDT. In a condition when the upstream breaker is opened, a DFDT of about 4.13 Hz/second is observed.

Similarly, a low-export condition is at 20 percent of the total generation capacity, which is also about 30 percent of its total export capacity. In a condition when the upstream breaker is opened, a DFDT of about 2.36 Hz/second is observed.

Fig. 4 shows a comparison of the frequency response of the system in a high-export and a low-export condition, respectively. It can be noted here that the decoupling protection islands the system faster in a high-export case with a faster DFDT than the low-export condition.

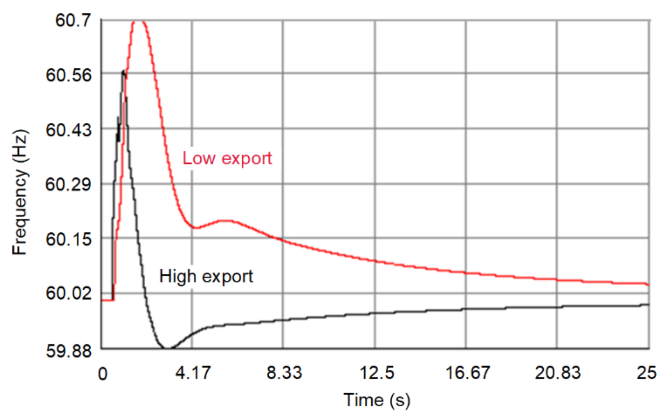

Fig. 4 Impact of Power Exchange on Decoupling

C. System Inertia and 81RF

The inertia of a machine is calculated as the combination of the rotating masses that store kinetic energy. It is represented as inertia constant (*H*) with the units MWs/MVA or just seconds. In practical terms, it represents the time in seconds a machine takes to respond to one pu change in speed in terms of acceleration or deceleration [3].

In a system like this one, the combination of multiple machines connected directly online (generators or loads) provides cumulative system inertia. To find the cumulative *H* of the system, the inertia of each machine is measured against a common base and summed. For a conservative design of the system, the inertia contribution from any load machines is ignored. In many cases, inertia contributions from loads are insignificant in comparison to big generators.

The decoupling protection is as sensitive to inertia as it is to the power exchange with the utility. With a higher inertia, a DFDT recorded by the decoupling relay is smaller than the DFDT recorded with a lower inertia in the facility. The combined inertia of the machines online store kinetic energy during a transient, thereby dictating the DFDT of the facility.

Fig. 5 shows the frequency response of the system in a high-inertia and a low-inertia condition, respectively. In both cases, the amount of power exported is the same, at 30 percent export of the total plant capacity. It is seen from the plot that decoupling is not triggered in a high-inertia condition. It is more beneficial to run fewer machines in a lower export condition for a successful decoupling.

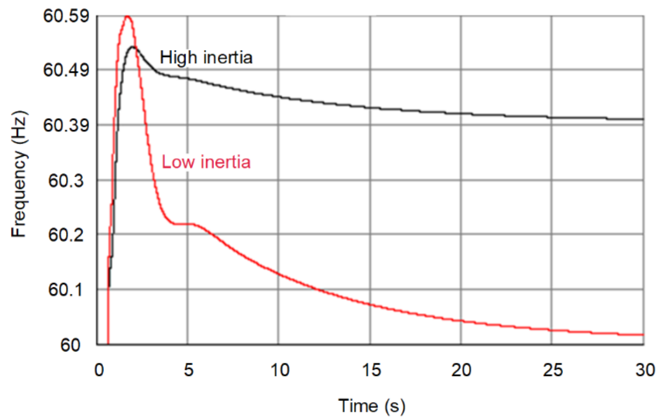

Fig. 5 Impact of Inertia on Decoupling Protection

III. MICROGRID CONTROLLER SOLUTIONS

After a safe decoupling event, facilities with significant exports and imports with a utility need a controller that is able to detect the event as a contingency and take action to maintain their system's stability. This system requires a controller that can act on a generation-shedding system (GSS) contingency as well as a load-shedding system (LSS) contingency, depending on whether the system is connected to a utility or islanded. Decoupling from the utility triggers a GSS contingency, and the controller takes action by shedding some generators and issuing runback to other generators. Once in an islanded system, the same controller now monitors the system for LSS contingencies, such as loss of generation or tie lines and bus couplers within the facility through which power transfer is occurring. The microgrid controller's primary goal is to always monitor the system for power imbalance between the source and load and take appropriate action by shedding generators or loads to maintain the stability of the system.

A. GSS Introduction

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, making 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 defined as any event that results in excess generation on an islanded system. Contingencies can occur when a tie line or bus coupler breaker opens under load. The GSS algorithm then determines the generation to shed and run back based on the contingency status and metering information, user-settable generator-shedding and runback priorities, user-settable decremental reserve margin (DRM) values, topology status, and generator status. The GSS sends the generator trip signals to corresponding generator breakers and runback signals to respective generator controllers with analog MW set point (runback level).

B. Generator DRM

DRM is defined as the capacity of a generator to reject load without affecting its frequency and stability. Unit DRM is the amount of step decrease in generation that a generator can provide within the tuning time response of the governor (typically one second). Manufacturers describe this as the "load rejection capability within system stability margins."

System DRM is the accumulated total of the DRM of all online generators available in a system. Island DRM is the accumulated total of the DRM of all online generators connected to a given island.

When the system is islanded from the utility, one of the generators goes to isochronous (Isoc) mode to maintain the frequency that reduces the overall system DRM to the difference between the present power of a generator before islanding and the minimum MW level of this Isoc unit. The Isoc unit at a steady state rejects the total excess load after islanding, and the droop machine's steady-state loading is back to its original loading. Hence, the maximum system DRM equals the Isoc machine's MW power output just before islanding—the minimum MW limit of the Isoc machine.

The system DRM should be capped well above the Isoc unit's minimum MW limit to avoid stability issues with the Isoc machine. Some manufacturers of turbine controllers do not allow the governor to instantaneously respond to deviation in load rejection at a user-settable DRM value. The DRM used by the GSS is the lesser of two values: the minimum MW limit set in the controller (five MW) and a user-enterable maximum DRM. The GSS uses DRM only when the DRM on an island is greater than the excess generation. If the excess generation in an island is greater than DRM on an island, then DRM is not considered in the calculations.

C. Generator Runback

Generator shedding works in coordination with the generator runback. Upon detection of a contingency (loss of tie line or loss of a large load), the controller calculates the excess generation value on the exporting island and selects the generator to shed to ensure that the frequency of the system quickly recovers to the rated 60 Hz. Because generator shedding and runback must work together, both functions are part of the GSS. The decision to shed generators and to run back generators depends on the plant load, the amount of excess generation on the system, and the generator runback capacity.

Generator runback is used to quickly reduce the generators' output to bring the system frequency back to nominal. The generator runback characteristics (frequency versus time) are typically similar to the generator load rejection characteristics.

The GSS calculates the runback target load set point for each generator. The runback target load set point indicates the desired MW operating set point of the generators. Refer to Fig. 6.

The GTG governor controllers, on receipt of the runback signals, process these signals the following way:

1. Change the control fuel valve position to the output MW power to match the runback target load set point from the GSS.
2. Change the mode of operation of the GTGs, if required, based on target runback set point.
3. Maintain the generator MW set point at the runback target load set point.

The operational philosophy described previously is also shown in Fig. 6.

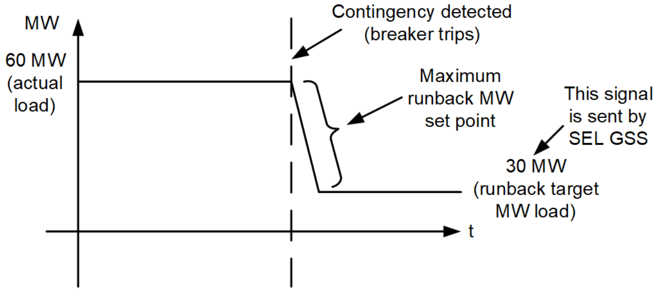

Fig. 6 Generator Runback Target Load Set Point

The GSS algorithm and logic, as shown in Fig. 7, explains how the generation-shedding and runback logic works and takes action based on a contingency. It is important that GSS does not overshed generation so that the runback is used to balance the shedding and keep it to a minimum. Generator runback and shedding together create a robust response to stabilize the system in case of a utility line outage contingency when the facility is exporting power.

D. HIL Test Setup

HIL testing is an excellent tool for validation of a control system or protection and helps in validating design, troubleshooting errors, and preparing for all scenarios without the need to test in the field, thereby avoiding downtime and potential hazards. IEEE 2030.8 [4] recommends testing the microgrid controller system (MGCS) with control HIL (cHIL) and the protection relays with protective HIL (pHIL).

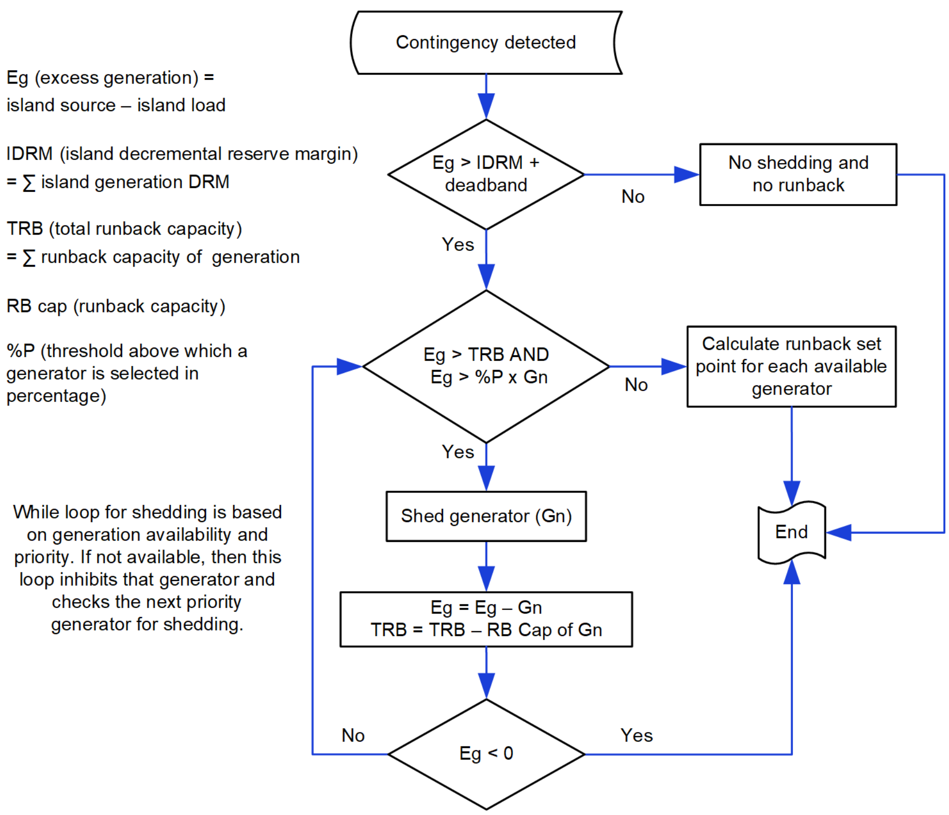

Fig. 7 GSS Control Logic

Fig. 8 shows the testbed considered for evaluating the decoupling protection and the microgrid control system. In HIL setup, voltage and current signals from the real-time digital simulator (RTDS) are hardwired to decoupling relays through an I/O cube. The microgrid controller receives all the data from the RTDS through the front-end processor using communication protocols like DNP3 and GOOSE. The RTDS provides real-time data to the microgrid controller and decoupling relays similar to the field data; hence, this setup helps to test the system in a close-to-field conditions. This sort of HIL testing and validation improves the confidence in the algorithm and logic of the microgrid controller.

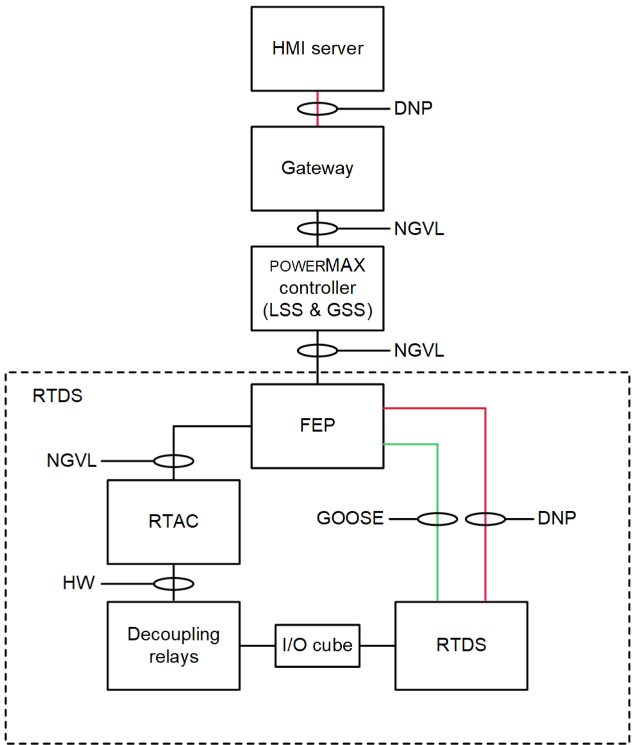

Fig. 8 HIL Simulation Test Bed

E. Simulation Results for Decoupling and GSS

Various scenarios with different power export conditions, different generators online, and different plant load conditions were tested using RTDS to validate the decoupling settings and microgrid controller response for several permutations of system conditions.

The result discussed here is from the high-export case shown in Fig. 4. Fig. 9 is an expanded view of that high-export case. T1 shows the time at which the decoupling relays detected and tripped the tie line breakers, followed by subsequent generator-shedding action within two to three processing cycles (10–15 milliseconds) of detecting the decoupling event. T2 shows the time at which generator runback signals were sent. The delay between T1 and T2 is due to the generator interface device converting the set point from the microgrid controller into an actual 4 to 20 mA signal to send it out through one of its analog outputs to the generator. A command to change one of the generators to Isoc mode is also sent out at Time T2. After these actions are taken, the system frequency stabilizes and recovers to a nominal value over the next 25 seconds, as seen in Fig. 4. From the moment of utility disconnection, it takes less than 200 milliseconds for the microgrid controller to safely decouple and take control action by shedding generators and issuing a runback signal. The speed of operation of the microgrid controller after detecting is key in quickly stabilizing the system after such an event.

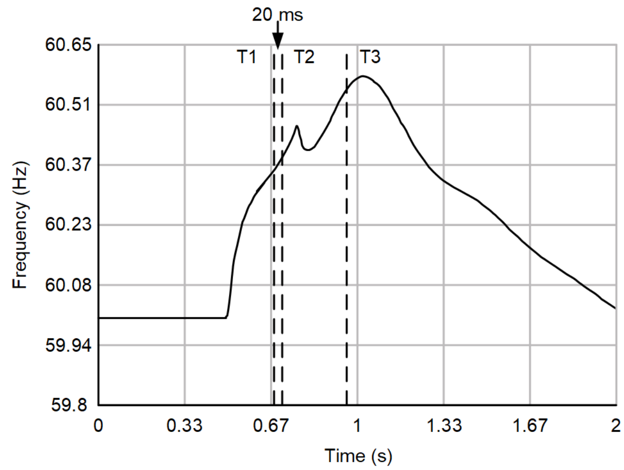

Fig. 9 Generator Runback Simulation Results for Decoupling and GSS

In the microgrid controller with GSS and LSS algorithms, it becomes critical to make sure that one algorithm does not trigger the other, as the action taken by one of them becomes a contingency trigger for the other. For example, as a result of GSS action, if generators are shed it can trigger a contingency for the LSS, and similarly, when the contingency-based load-shedding (CLS) system sheds a load, it could become a GSS contingency. Hence, to avoid such ping-pong-style action, both the GSS and CLS systems are logically coordinated such that the algorithms can monitor and detect each other's actions and contingencies, and they act only in cases of individual triggers and not based on each other's action. This is crucial, as incorrect algorithm supervision can result in back-and-forth shedding of generators and loads leading to a blackout.

F. CLS and Coordination

The fast CLS algorithm sheds load to maintain the power balance between the prime movers and the electrical power system loads. This is done by reducing the total plant electrical load to less than the calculated available turbine and generator capacities after a contingency occurs. Because of the power system net rotating inertia, the CLS operates fast enough so that loads are shed prior to any significant decay in frequency.

The primary goal of this LSS is to keep the steady-state frequency of the power system at nominal during a major loss of generation. 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). The secondary goal of the system is to minimize disturbances to loads during load-shedding events.

The conceptual architecture and the underlying algorithm for LSSs have been discussed in multiple papers for further reading [5] [6] [7] [8].

The CLS reduces the amount of load selected for shedding by accounting for incremental reserve margin (IRM) in its calculation. This limits the impact of the CLS. Another effect of incorporating IRM into the calculation is that the frequency commonly decays following a load-shedding event. This frequency decay level is a function of tuning in the governor, user-entered IRM, system inertia, and load composition. The larger the IRM the user enters, the greater the frequency decay for an LSS load-shedding event. This is because the IRM calculation forces the governors to tap into power reserves to keep the frequency at nominal.

G. Underfrequency Load Shedding (UFLS) and Coordination With Other Frequency-Based Protection

The UFLS is a backup protection system for the CLS that relies on the measurement of the system frequency from protection relays. This backup protection serves situations such as an out-of-service CLS, gradual decay of frequency, tripping of an alarmed breaker, load-shedding failure due to wiring or trip coil issues, and incorrect load metering values [9]. Fig. 10 shows the frequency line diagram used for coordination with other protections in the facility.

The UF Level 1 and Level 2 protections are derived after detailed underfrequency coordination and IRM study of the system. This study examined capabilities of the facility to accept step change in load, due to loss of some generation and coordination with other protections. Boundary operating conditions, normal operating conditions, detailed models of each generator governor, generator inertia, load inertia, and frequency protection settings are required to evaluate the most optimal solution for such protection.

Equation (3) shows a simple conversion of a machine's inertia constant to a common base.

$$H_{NEW} = H_{OLD} \bullet \frac{\text{MVA base}_{NEW}}{\text{MVA base}_{OLD}} \quad (3)$$

Using a boundary condition, the total inertia of the islanded system is calculated using (3) and the DFDT is estimated for a change in power (ΔP) using (1). Using these equations, several combinations of generators online are considered to estimate the lowest DFDT within the system. The following steps can be followed for estimating frequency deviation after loss of generation.

1. Calculate total inertia at common base MVA (excluding the generator that is simulated to be lost).
2. Record ΔP as loss of generation.
3. Calculate DFDT in Hz/second using (3).
4. Calculate Δf in one second.
5. Coordinate with other protection settings as in Fig. 10.
6. Repeat steps for other generation combinations and find boundary operating conditions for successful underfrequency protection.

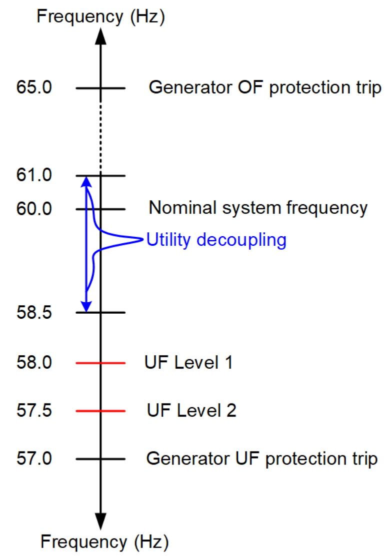

Fig. 10 Sample Frequency Line Diagram for Coordination

IV. CONCLUSION

This project design illustrates a complete solution for detecting unintended isolation of a utility, islanding the facility from the utility, and stabilizing the facility's frequency by balancing the generation and load. Using protection relays and microgrid controllers, this facility can be safely islanded and protected in its own islanded operation from adverse frequency instabilities due to sudden loss of generation or load.

It has also been demonstrated how HIL testing is helpful in validating the microgrid controller algorithms and decoupling protection design before any live testing on field. Simulation results showing a decoupling and GSS action have been discussed and illustrate how the fast-acting microgrid controller stabilizes the system within 200 milliseconds (including detecting of decoupling and taking GSS action).

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VI. VITAE

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