Improving Transmission System Resilience Using an Automation Controller and Distributed Resources

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***Abstract*—As the transmission network has evolved over time, it has been operated closer to its limits and as a result lacks the ability to handle severe contingencies such as extreme weather, natural disasters, major generation failure, loss of transmission lines, or cyber-attacks. Depending on the timing of the event, these conditions could lead to cascading problems which can bring down an area larger than that directly affected by the event if they are not handled properly. Recent technological advancements in lower cost communication and control plus the increased use of distributed generation, gives an opportunity to break the transmission network into independent networks supplying local critical loads beyond the break points used by regional transmission operators. This paper demonstrates the concept with a relatively simple transmission system model and utilizes a commercial automation controller to partition the system. The local generators are able to supply the local critical loads. An algorithm is proposed to detect the abnormal situations and to isolate the system into independent networks. The isolated systems can supply the local critical loads under stable operating conditions following generator shedding or shedding of less critical loads. The entire system is modeled in a Real Time Digital Simulator (RTDS) along with an automation controller which communicates with model using the IEC 61850 standard protocol. The entire operation can be monitored and controlled with the help of a Human Machine Interface developed for the project.**

***Index Terms*—RTDS, HMI, IEC 61850, GOOSE, EMTP, DER, Resiliency**

I. Introduction

A system can be said to be more resilient if it can maintain an acceptable level of normalcy during larger disturbances or threats or can recover toward optimum performance in a shorter period of time [1]. Reliability, with its focus on keeping the lights on, can be described as the end goal of the power grid. In order to meet this goal in the case of evolving cyber-threats the power grid needs to be more resilient. The concept of resiliency is illustrated notionally in the Disturbance and Impact Resilience Evaluation Curve (DIREC) in Fig. 1. The difference between a resilient and un-resilient system can be observed by considering time as the metrics basis in DIRE curve.The DIRE curve shows the more resilient system is better able to withstand the disruptive event compared to the less resilient system. For a power system the time element comes into play when the time to reconfigure following an event is long enough to have an undesirable impact on critical loads. The importance of resilience in power system came into picture with experiences of blackouts across the world. The last decade has seen many blackouts due to natural disasters such as the Hurricane Katrina, 2011 Japan Earthquake, and Hurricane Sandy [2]. It is interesting to note that the resulting blackouts did not cascade significantly beyond the areas of direct impact. The overall transmission system was resilient. The goal to improve resilience is both to be able to ensure that future events dont lead to cascading blackouts and to be able to provide power to critical loads in the areas directly affected. There has been considerable progress in advancing methods for analyzing the natural disaster related issues in the last decade. These events cause damage to power system components that effect their operation and reliability.

The report on the August 2013 blackout in the US by the

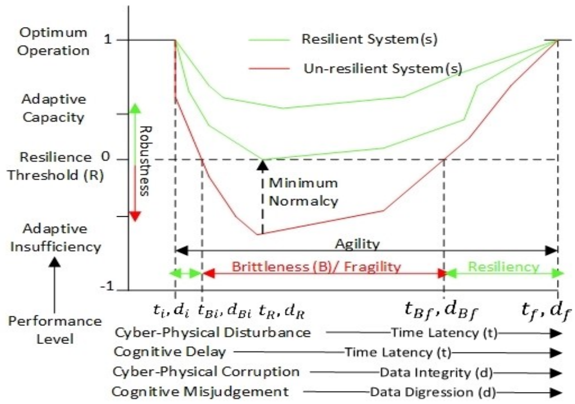

Fig. 1. Resilience base metrics DIRE curve [1]

United States-Canada System Outage Task Force [3] describes how lines tripped by the line protection equipment under high loading conditions leading to blackout. Another blackout was caused by a software bug in the alarm system at a control room. The current control and monitoring systems lack the inherent ability to analyze unexpected failures and take necessary remedial action to stop the propagation of the outage. They lack the resilient framework which can bring the system to normalcy [4].

The existing power system network still depends to a significant extent on centralized control, resulting in an increasing complex system. We cannot afford the failures on such a large scale system, so decentralization of the power grid can make it resilient [6]. Electric grid modernization, through smart grid development, provides an opportunity to incorporate resilient control system architectures. The increased use of Distributed Resources (DR) can improve resiliency with appropriate islanding detection monitors and controls applied. In an abnormal situation, the DRs can serve the local loads reducing the outage. In order to overcome the challenges in maintaining the stability, we can design an automation controller, which can make decisions and send commands to the local generating units or the loads. By designing for resilience from start instead of considering it as an afterthought, the power system can be made more resilient.

To demonstrate these concepts and to check the system metrics in DIRE curve against physical, cyber and cognitive classes of disturbances, we deployed our system using RTDS. Section 2 in this paper addresses the conventional techniques to detect the islanding situations in case of distributed generation systems. Section 3 discusses the simulation model, and Section 4 presents the proposed algorithm. Results of the study are presented in Section 5.

II. Islanding with Distributed Resources

A. Intentional Versus Unintentional Islanding

Islanding is defined as a condition in which a portion of an area of an electrical power system is energized solely by one or more local generation resources when that portion is electrically separated from the rest of the network [7]. There are two different types of islanding, one is a scheduled transition which is intentional islanding and the other is an unscheduled event called unintentional islanding. In the case of intentional islanding, the time and duration of the island is properly planned, so the transition would be smooth. Unintentional islanding occurs when a fault or abnormal condition on a utility inter-tie and circuit breaker action isolates part of the system, which has sufficient load generation to supply the load. In such a case, the generator controls are not designed for islanded operation, and voltage and frequency regulation are compromised.

When DR is connected to the utility grid, the IEEE 1547 standard [8] recommends the desired interconnection system response for abnormal voltage and frequency as shown in Table 1. These specifications help in setting up the protection elements monitoring the system.

TABLE I
Distributed generation islanding transition requirements [7]

IEEE 1547 Standard			
Voltage Response		Frequency Response	
Voltage Range (pu)	Max. Islanding Time (sec)	Frequency Range (Hz)	Max. Islanding Time (sec)
$V < 0.5$	0.16	$f > 60.5$	0.16
$0.55 \leq V < 0.8$	2	$57 \leq f < 59.8$	0.16 to 300
$1.1 \leq V < 1.2$	1	$f < 57$	0.16
$V \geq 1.2$	0.16		

If a planned DR system is to be operated in islanded mode, it needs to be designed to supply real and reactive power to the local loads within the island [9]. It should be able to regulate the voltage and frequency within the agreed limits (as per ANSI/NEMA C84.1-2006). There should also be adequate reserve margin for load variations available with DR. The transient stability should be maintained during the step changes of loads. In case of the island mode, sometimes even the protective device coordination should be modified. There should also be coordination between different DR units if there are more than one in order to have a sustained island. To balance the load and generation, various techniques are used among which the load shedding and generator shedding are most common ones.

B. Islanding detection techniques

If a fault occurs on the interconnection between the utility and distributed resource, the protection device will open breakers on the tie line,creating a possibility to form an island. If the load and generation are different within the island, then there will be rapid changes appearing in voltage and frequency. If load and generation are close enough to be nearly balanced, detection of the islanded condition is difficult. It is very important to detect the islanded condition as it would cause a potential threat to safety, also other problems such as out of phase reclosing and degradation of power quality can occur. Therefore the current employed process is to disconnect all the distributed generators supplying the loads in the island immediately after the islanding detection. Typically a distributed generator should be disconnected within 2 to 3 sec after loss of the main supply according to IEEE 1547 standards [7]. To achieve this goal, each distributed generator should be equipped with an islanding detection device. However, as per the IEEE 1547.4, if the systems automation controllers are capable of handling the parameters then DG system can be run in island condition.

To improve the resiliency of the system, we need to operate at a minimum maintain supply to critical loads while islanding condition exists. A strategy of controlled load or generator shedding applied by algorithms within the automation controller will maintain normal operations to the extent possible within the islanded system. There are many islanding detection techniques discussed in [10], [11], [12]. Two of the techniques are demonstrated in this paper:

1. Direct Transfer Trip (DTT)

In this approach a signal is being sent by the utility side protection equipment to notify the DR side about the breaker opening and indicating possible islanding condition. There are many communication methods and protocols practiced in the industry for this purpose [7].

2. Local Islanding Detection Techniques

There are active and passive detection schemes under the local detection techniques [10]. Active detection schemes use low-frequency interharmonic current injection technique to identify the islanding condition. However, this paper will only concentrate on passive detection schemes. The transition to an island with mismatch between generation and load leads to frequency variations. In addition, reactive power imbalances lead to voltage magnitude variations. The performance of the frequency and rate of change of frequency

df/dt elements depends on the real power mismatch between the local generation and the local load. In the similar way, the performance of the voltage elements depends on the reactive power mismatch. The passive detection schemes typically use the frequency and voltage elements available in generator and /or feeder relays protecting the distributed generators. Moreover these methods are more resilient to communication breakdowns or data integrity.

a) Voltage based detection: Deviation from nominal voltage would be an indication of islanding conditions. As the voltage changes occur faster than the frequency changes [10] an undervoltage or overvoltage could result in case of an islanded condition.

b) Frequency based detection: Frequency increases if generation exceeds load and it decreases when load exceeds generation. Prior to islanding, the power grid regulates frequency, which is typically at 60 Hz $\pm$ 20 mHz or 50 Hz $\pm$ 20 mHz. Frequency deviations from nominal along with df/dt elements are good indicators of an islanding condition [10].
There are many other techniques such as detection based on rate of change of frequency, including wide area based detection schemes which are discussed in the references mentioned above. These are out of scope of this paper.

C. Load shedding and Generator shedding

Load shedding is a process to identify and curtail non-critical loads based on the operator's preset preference. It includes different schemes for determining the amount of load to be shed. Conceptually, the load shedding system is divided into two functional categories - pre-event calculations and event actions. The system performs pre-event calculations to dynamically determine which loads to shed and to build a load shed table. The system monitors contingency trigger signals and generates load shed signals when a trigger is detected based on the load-shed table [10].
Generator shedding is a process to manage the output from the generators within the system. It sheds the generators based on the excess generation and runback capability of the distributed generators. Also over frequency thresholds serve as a backup in this case. The generators are selected for shedding based on operator selectable priorities on the user interface and power system topology [10].

III. System Model

In order to demonstrate the resilience in case with distributed generation connected to utility grid, a network is designed and then modeled in a Real Time Digital Simulator (RTDS). Two different distributed generators a lumped into Gen 1 and Gen 2 as shown in Fig. 2. These represent an aggregation of smaller generators. The distributed generators are able to supply 100MW power in this model. These distributed generators are connected to aggregated dynamic loads: Load 1 (100 MW), Load 2 (25 MW), and Load 3 (25 MW) at Bus-2 and Load 4 (100 MW), Load 5 (25 MW), and Load 6 (25 MW) at Bus-3. The two buses are considered to be at a 220kV level in order to have a simplified model within the resources of the available RTDS. These two different buses import 100MW power from utility grid at Bus 1 via two long transmission lines represented as Line 1 and Line 2. There are normally closed circuit breakers numbered B1 to B14 modeled as shown in the Fig. 2.

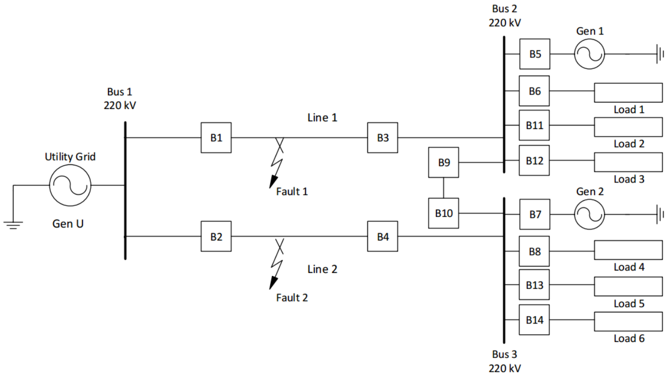

Fig. 2. Simplified model of the power system network

An automation controller is added which is programmed to identify the islanding condition by monitoring the voltage and frequency values at Bus 2 and Bus 3. The automation controller also receives the binary status of the breakers on utility side to identify the islanding condition. The communication between the physical automation controller and the RTDS model takes place through an Ethernet cable via IEC 61850-GOOSE messages[13]. Two protection relays are utilized, which collect the metering data at Bus 2 and Bus 3 and send it to automation controller through a proprietary protocol of the relay vendor via serial communication. A Human Machine Interface (HMI) is applied to replicate the exact model with breaker status and analog values. The HMI fetches the data from automation controller and displays information intuitively. A block diagram representing this setup is shown in Fig. 3.

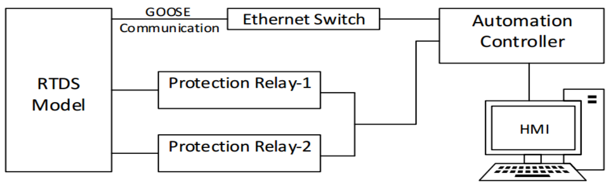

Fig. 3. Block diagram of the hardware setup

The GOOSE communication protocol is used to send/receive the breaker statuses in the model. Typically transfer time of a GOOSE message is in a range of 3-4 ms.

IV. Study Scenarios

A. Case-1: Fault on Line-1

Fig. 4 shows the flow of events occurring when a fault occurs on Line-1. The protective relay on transmission line (Line-1) will open the breakers B1 and B3 for any fault on that line (Fig. 2). In this case, the power flows from utility grid to loads connected at Bus 2 and Bus 3 through Line-2.

Under ideal conditions, the two lines carry 50MW in each. Any violation of active power limit would load the line to the thermal limit and cause a violation of reactive power limits may cause corresponding voltage loss. The automation controller detects this situation and reduces the power flow in Line-2 around 50MW by curtailing the non-critical loads Load-3 and Load-6 (Fig.2). In this way, it will bring back the system under normal conditions of operation. Suppose that if

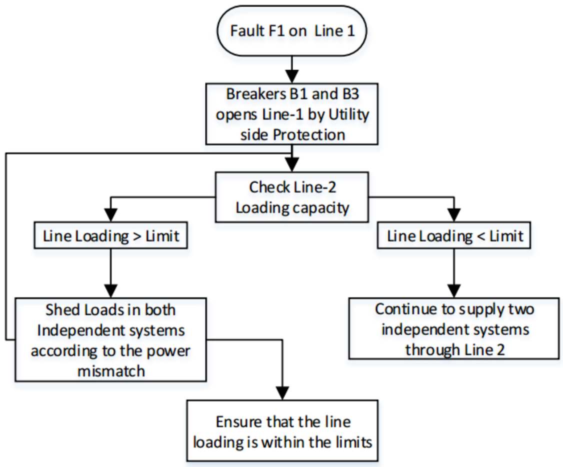

Fig. 4. Flowchart representing the case-1 process

instead we island Gen 1 independent of the grid in this case. The Gen 2 system will still be grid connected by supplying the local loads. But the Gen 1 system will start oscillating based on active and reactive power mismatch. The corresponding controls established in automation controller will regulate the voltage and frequency of the network by shedding the loads or generators. It is advisable to run two independent systems in grid connected mode by load shedding provided the connected source is stiff or else it would be better to run them in island mode. If both the Generators are connected together that increases the inertia of the system and hence increases its ability to respond to any further abnormalities.

B. *Case2: Fault on Line-1 and Line-2*

Fig. 5 shows the events occurring in the system if a fault occurs on Line-2 when Line-1 is already out of service. The automation controller detects this situation by monitoring the breaker statuses or the voltage and frequency variations. It will send load shedding signals to isolate the non-critical loads 3 and 6. This will balance the generation and load within the system and bring them into normal conditions. In case the system doesnt attain stability even after this, then it would be ideal to island both Gen 1 and Gen 2 as independent systems to bring them to stable operating conditions. The tie breakers B9 and B10 would trip and island those systems. It will send load shedding signals to isolate the other non-critical loads. We can also synchronize these two systems if needed for any power exchange after they both attain stability separately.

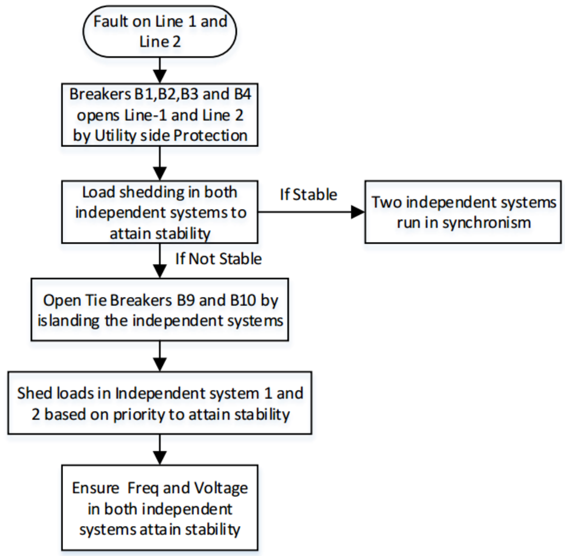

Fig. 5. Flowchart representing the case-2 process

V. Simulation Results

A. *Case-1: Fault occurred on Line-1*

The simulation is run in this case by applying a fault on Line-1 in which the breakers B1 and B3 open to isolate the fault. In this case, the loading in Line-2 crosses the limits. As per the logic discussed in Section-IV, the controller curtails the non-critical loads Load 3 and Load 6. So, it brings back the loading in Line-2 within the limits. The simulation results in Fig. 6 show the breaker B3 status (BRK12), it goes from logic 1 to 0 showing that the breaker is open. Frequency (FGen1) at generator-1 operating at 60Hz, drops down when fault occurred and attains stability after few seconds. Voltage (VBUS1) at Bus-2 which is at 1 per unit, fluctuates and attains stability as well. The loading on Line-1 (PLine1) drops to 0 MW, whereas in Line-2 (PLine2) reduces to 50MW which is the ideal limit. The abscissa of the plots below represents time in seconds. In case of a fault on Line-2, we can see a similar response in terms of loading on Line-1, based on the limits of Line-1, load shedding would reduce the loading well within the limits.

B. *Case2: Faults occur on both Line-1 and Line-2*

The simulation is run in this case by applying a fault on Line-2 when the Line-1 is already out of service. As per the logic discussed earlier, the automation controller will perform load shedding to bring the system to stable condition. Two scenarios are simulated, one in which the system is not able to reach stability after initial load shedding. In the other scenario, islanding of the two independent systems help to attain stability. In the first scenario results as shown in Fig. 8 the Line-1 breaker status (BRK12) is 0, showing that the breaker is already open. The Line-2 breaker status (BRK22) goes from 1 to 0 representing it is open at that instance. The output frequencies of Gen 1 (FGen1) and Gen 2 (FGen2)

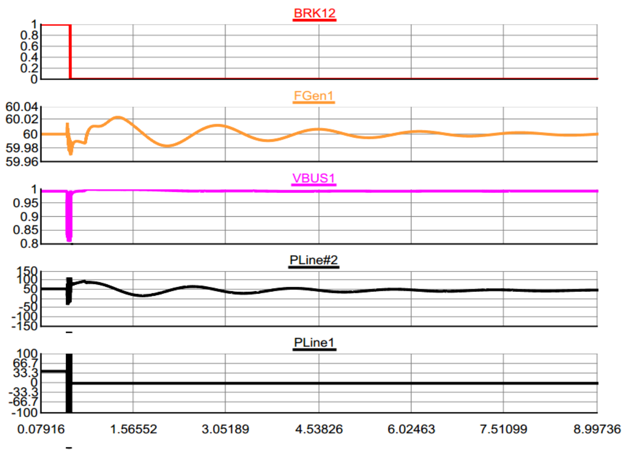

Fig. 6. Response for fault on Line-1 with load shedding

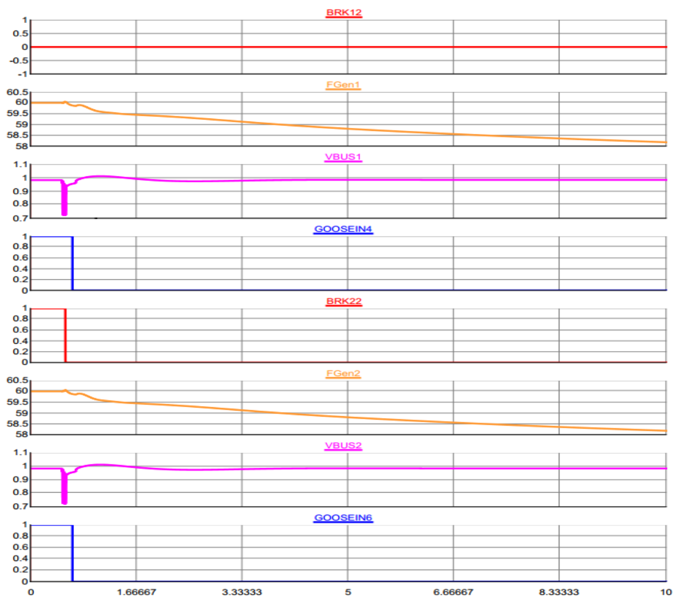

Fig. 7. Response for fault on Line-1 and Line-2 with initial load shedding

drops down even after initial load shedding soon after the fault occurred. The voltage magnitude at Bus2 (VBUS1) and Bus 3 (VBUS2) fluctuates and reaches stable point as the generators are set to maintain the voltage at 1 per-unit. The GOOSE trip signal for the non-critical loads 3 and 6 are shown by GOOSEIN4 and GOOSEIN6. The initial load shedding isnt able to stabilize the system, this can be observed by identifying the frequency of both generators ramping down after the fault on the line as shown in Fig. 8.

As shown in Fig.8, as the system doesnt attain stability even after initial load shedding in first scenario, it will island into two independent systems by opening the tie breakers B9 and B10, then it curtails the other non-critical loads 2 and 5 to stabilize the two individual systems intelligently. In this case, both the generators attained stability within reasonable time which can be observed in frequencies of Gen 1 (FGen1) and

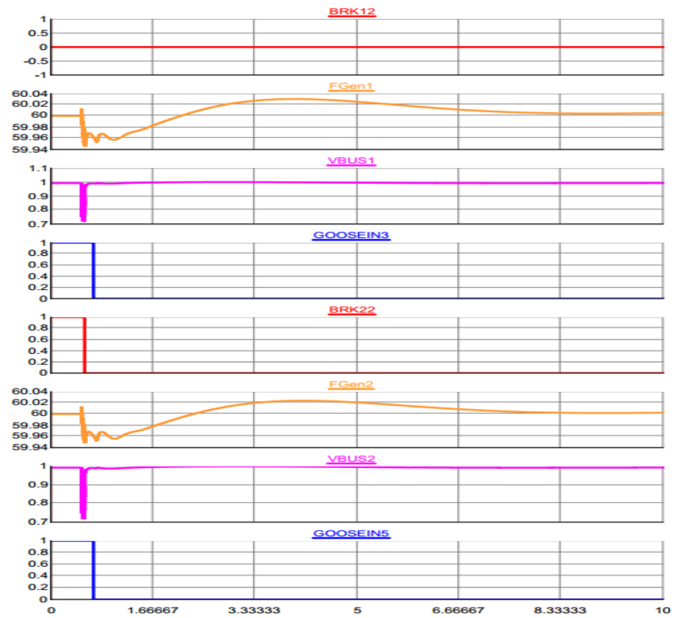

Fig. 8. Response for fault on Line-1 and Line-2 with Islanding

Gen 2 (FGen2) attaining 60Hz after the contingency.

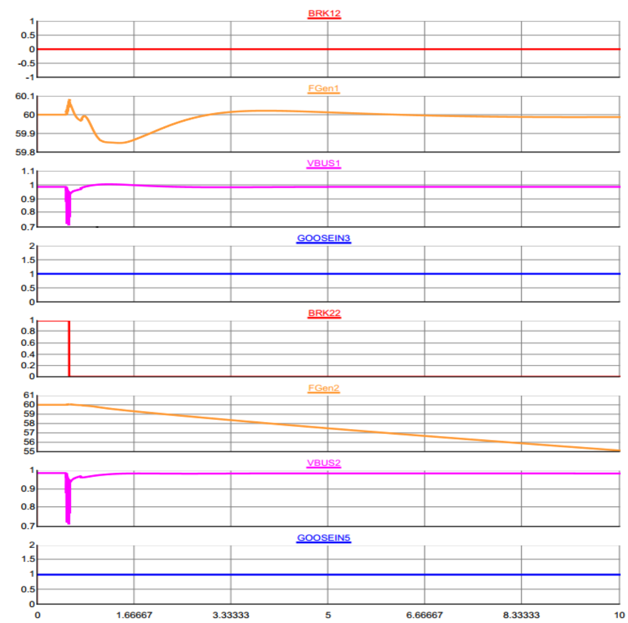

Fig. 9. Response for fault on Line-1 with communication failure

C. *Case-3: Communication failure*

In Case-1, if we consider that if there is a communication failure while transmitting the breaker trip command through GOOSE protocol, the loading on Line-2 would cross 100MW which is shown in Fig. 9. In Case-2, when the two systems are islanded by opening the tie breakers, if there is a communication failure or a breaker misoperation, either or which would lead to instability. This case is simulated considering the communication failure while transmitting the GOOSE message to Gen 2 independent system. This can be observed in the Fig. 10 which shows that the frequency of Gen-1 attains stability due to load shedding, whereas the Generator-2 becomes unstable by drop in the frequency.

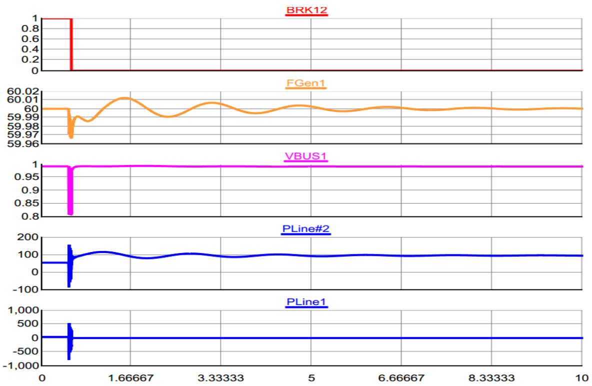

Fig. 10. Response for fault on Line-1 and Line-2 with communication failure

D. Other cases

Other cases were simulated to identify the system behavior, by considering different scenarios of communication failure, but are omitted here for space considerations.

This model can be further extended to study system behavior under different scenarios, including the other methods for detecting islanding conditions. Possible methods include using rate of change of frequency, angle change, and wide area synchronized phasor based islanding detection schemes. As the scheme presented relies on communication, we can consider cyber-attacks and data integrity as well. The frequency mismatch in case of disturbances can be fed to a resilient PID controller which will have the desired frequency as set point, and which can send set points to generator to attain stability faster. These will help to identify the different areas where we can improve the resilience of the system by implementing new architecture or upgrading the existing infrastructure.

VI. Conclusion

A system model containing distributed resources connected to utility grid is designed and then simulated using Real Time Digital Simulator which is integrated with a commercial automation controller and commercial protective relays. Though the system looks redundant, it is not entirely resilient without the programmed automation controller. The automation controller has the flexibility to view the scheme operation in a Human Machine Interface developed considering the human factors for system operators. The model developed provides opportunity to simulate different cases that might occur in the power systems and develop controls to increase resilience.The three classes of disturbances are simulated and issues related to the time latency are addressed by the GOOSE communication. With the advances of distributed resources, it is possible to decentralize the system into small islands which are similar to microgrids, but larger in scope than what is common in the literature. The results show that by implementing the load shedding or generator shedding schemes when we have distributed generation we have a possibility to run the system as islands in case of severe contingency. This model can be further extended by implementing the advanced methods of islanding detection and load shedding schemes. Due to the diversity in distributed generation coming up in future, different control logic may be required in each different case. With the experiences of blackouts in the past, it is advisable to go towards the direction of resilience architecture. The transition might take long time, if we do not start soon, the option will slip away.

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