Anti-Islanding Today, Successful Islanding in the Future

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***Abstract*—Distributed generation (DG) is gaining popularity in the United States and across the world. The Florida Public Service Commission recently passed rules encouraging the use of renewable resources. Integrating DG with the utility network poses challenges for anti-islanding schemes. These schemes detect islanding conditions and trip the DG. Fig. 1 shows a typical network configuration for DG installations.**

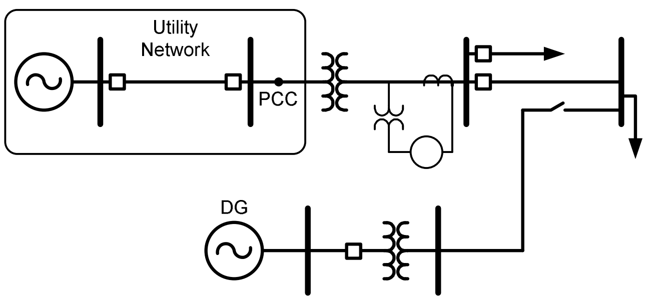

Fig. 1. DG interconnection with a utility network

Failure to trip islanded generators can lead to problems such as threats to personnel safety, out-of-phase reclosing, and degradation of power quality.

This paper discusses a wide-area measurement-based islanding detection scheme (IDS_WA) that uses time-synchronized measurements to calculate the slip frequency and acceleration between two systems to detect islanded conditions. The proposed scheme has significant advantages compared to traditional anti-islanding schemes, specifically when the power mismatch is minimal. Local-area measurement-based schemes (IDS_LA) complement the IDS_WA. The paper also discusses the use of a real-time digital simulator to model DG along with the rest of the system to validate the proposed anti-islanding scheme. The paper shows the performance of the scheme for different system configurations and load flow conditions. The paper presents a successful islanding scheme that monitors the system power exchange, takes remedial actions when islanding occurs, and maintains quality of service in the islanded system.

I. Introduction

Reliable energy supply is paramount in modern society. It is important to balance economic, environmental, and social factors and integrate them into a strategy for energy development.

One strategy is the use of landfill gas (LFG) as an energy source. In the past, it was common to flare LFG to the atmosphere. In 1994, the Environmental Protection Agency (EPA) created the Landfill Methane Outreach Program (LMOP) to encourage the use of LFG for energy production. More recently, the Florida Public Service Commission passed rules encouraging investor-owned utilities to use renewable resources. In fact, more than 30 states include LFG in their renewable portfolio standard. The EPA estimates that far more than 500 new landfill sites have energy resources available to generate electricity to power several hundred thousand homes.

There are two types of generators for distributed generation (DG) applications: inverter-based and rotating machines. LFG generation sites, classified as DG facilities, are usually connected at the distribution level and operated in parallel with the utility using rotating machines. These sites typically range in size from 1 to 10 MW. The number of generators connected at a site also varies widely. For example, some sites consist of a single 2 MW generator, whereas other proposed sites consist of thirty 335 kW generators running in three parallel banks of ten generators each. The proximity of the DG site to a substation also varies widely. Some may be as close as a few thousand feet from the distribution substation, while others are several miles from the substation.

Generating electricity from LFG offers economic and social benefits, but there are also challenges for utilities. Some of the challenges include feeder protection, exceeding fault current levels beyond the breaker interruption rating, and islanding detection. Utilities require detailed studies related to power quality, short-circuit analysis, the interrupting capabilities of equipment, and system configuration for some DG installations.

II. Utility Practices for DG Connection

In addition to the protection system installed by the DG owner, utilities require an interconnection protection system (IPS) to connect DG to their power system. Utilities apply an IPS at the point of common coupling (PCC) and then dictate the required protection system according to state regulations. The utility typically installs and maintains the interconnection equipment. The IPS main objectives are the following:

- Protect customer equipment from DG that operates outside nominal voltage and frequency limits.
- Protect utility equipment from adverse effects caused by the DG response to faults within the utility system.

In addition to the IPS, utilities generally require an anti-islanding protection system. The goal of the anti-islanding scheme is to detect loss of interconnection with the utility and disconnect the DG so it does not operate independently of the grid. If the DG output closely matches the feeder loading when the local network is disconnected from the utility, an islanded condition could occur in which the DG operates independently.

Typically, islanding is not a desirable operating condition. There are hazards to utility workers if power lines remain energized when the utility interconnection is lost. Additionally, voltage and frequency may fall outside acceptable levels, resulting in poor power quality for utility customers. Lastly, the DG must disconnect from the system faster than the automatic reclosing time that the utility uses. If it is not fast enough, damage to equipment may result when synchronism check is not present. IEEE 1547 Standard for Interconnecting Distributed Resources with Electric Power Systems provides technical specifications and requirements for DG interconnections [1]. At this time, most utilities do not allow islanded operation of DG.

For the purposes of this paper, we will focus on methods of islanding detection that utilities have used in the past as well as an innovative method that uses time-synchronized measurements.

III. Traditional Islanding Detection Techniques

A. Local Detection Schemes

Local detection schemes are divided into two categories: passive detection schemes and active detection schemes [2]. Passive detection schemes use voltage, frequency, and rate of change of frequency (ROCOF or df/dt) to identify islanding conditions. The performance of the frequency and df/dt elements depends on the real power mismatch between the local generation and the local load. The voltage element performance depends on the reactive power mismatch. Passive schemes typically use frequency and voltage elements available in generator and/or feeder relays protecting DG. Active schemes typically inject signals into the system and detect islanding conditions by measuring system response to the injected signal.

1) Passive Detection Schemes

Passive detection schemes detect islanding conditions based on measured voltage and current signals.

a) Voltage-based detection

Based on the reactive power mismatch prior to an islanding condition and the reactive power reserve capability of the DG, an undervoltage or overvoltage condition could result in an islanded system. Deviation from nominal voltage could be an indication of islanding conditions. A voltage relay, typically part of the DG protection scheme, detects this condition. Voltage-based detection complements frequency-based detection. Additionally, because voltage changes occur faster than frequency changes, voltage-based detection offers faster response than frequency-based detection.

b) Frequency-based detection

Frequency-based detection schemes are widely used for islanding detection. Frequency increases if generation exceeds load, and it decreases when load exceeds generation. Prior to islanding, power system controls regulate frequency, which is typically at 60 Hz ± 20 mHz or 50 Hz ± 20 mHz. Frequency deviations from nominal and df/dt are good indicators of an islanding condition.

(1) Frequency Relay

Frequency relays measure the voltages at the DG terminals and calculate the system frequency. These relays issue trip commands based on user-configurable thresholds and timers. Typical thresholds are 59.8 Hz for the underfrequency elements and 60.2 Hz for the overfrequency elements (60 Hz nominal system) with a typical delay of 10 to 12 cycles.

(2) Df/dt Relay

The df/dt relay measures the rate of change of frequency and asserts the trip contact if df/dt exceeds a user-configurable threshold. A common threshold for df/dt is 2.5 Hz/s.

(3) Vector Shift Relay

The vector shift or vector surge relay is based on the phase shift of the voltage signal that the relay measures at the DG terminal relative to a reference signal. Because the relay calculates frequency based on the phase angle difference, the performance of the vector shift relay is comparable to the frequency relay. Some relay implementations use vector shift to enable the df/dt or ROCOF relay.

2) Active Detection Schemes

One of the active detection schemes injects low-frequency interharmonic current at the generator terminals. Active detection schemes calculate the impedance from voltages and currents measured at the generator terminals [3]. During normal system conditions, the impedance at the generator terminals is small. The calculated impedance increases following an islanding condition. The logic detects the change in impedance to identify islanding conditions. Active detection scheme performance does not depend on the power mismatch level in the island. However, the additional cost for an injection system, effects on load, and interference resulting from multiple DG sites decrease the appeal of this scheme.

B. Communications-Based Detection Schemes

Traditional communications-based detection schemes use the statuses of circuit breakers and disconnects to identify an islanded condition. A central processor or logic controller monitors the breaker and disconnect statuses and determines an islanding condition based on a predefined logic condition. These schemes are basic and easy to implement; however, the schemes depend on the topology of the power system. The logic should adapt to the topology changes.

For DG installations with a dedicated feeder, islanding detection employs a multifunction relay at each end of the interconnection line with transfer trip between the two line breakers. Since no other customers are connected, it is possible to use a dedicated feeder without islanding being a concern. This solution is effective, but dedicated feeders are so costly that requiring their use could deny low-capacity distributed generators access to the grid.

IV. Islanding Detection Using Local-Area and Wide-Area Measurement Solutions

The proposed solution uses a combination of IDS_LA and IDS_WA. The IDS_LA uses conventional voltage and frequency elements and also an element based on frequency and df/dt measurements to detect islanding conditions. The IDS_WA uses time-synchronized measurements from the DG location and a remote source to detect islanding conditions.

A. Local-Area Measurement-Based Detection Scheme

The IDS_LA detection scheme uses conventional protection elements. Table I shows the thresholds and the pickup timer values for these conventional elements.

TABLE I
CONVENTIONAL PROTECTION ELEMENT SETTINGS FOR IDS_LA

Protection Element	Threshold	Qualifying Times
Overfrequency	61 Hz	10 cycles
Underfrequency	59 Hz	10 cycles
Overvoltage	1.15 pu	10 cycles
Undervoltage	0.85 pu	10 cycles

The IDS_LA also uses a special element to detect islanding conditions. This element provides faster response relative to the conventional frequency elements. The scheme blocks the output of the characteristic for 30 cycles under fault conditions. The fault detection logic includes overcurrent and undervoltage elements. Fig. 2 shows the characteristic along with fault detection and the blocking logic.

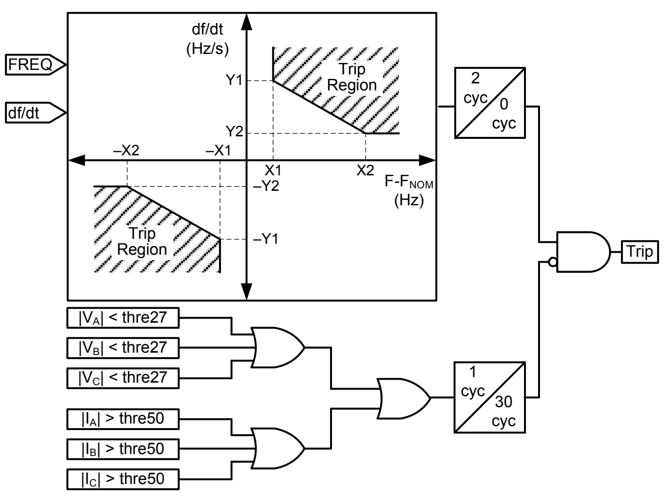

Fig. 2. Islanding detection scheme using local measurements

B. Wide-Area Measurement-Based Detection Scheme

The IDS_WA uses time-synchronized measurements from a remote source and the DG to detect islanding conditions. It employs two detection methods that we describe below.

1) Angle Difference

The angle difference element operates if the phase angle difference between the positive-sequence voltage phasors at the two buses (DG and remote source) exceeds a programmable threshold for a specified duration.

2) Slip Frequency and Acceleration Characteristic

This characteristic is based on slip frequency and acceleration [4]. The scheme measures slip frequency based on the rate of change of the angle difference with respect to time; acceleration is the rate of change of the slip frequency with respect to time. The characteristic detects how the two systems are slipping against each other, as well as how fast they are slipping. Based on preset thresholds, the characteristic declares islanded conditions. Fig. 3 shows the normal operating and islanding regions of the characteristic.

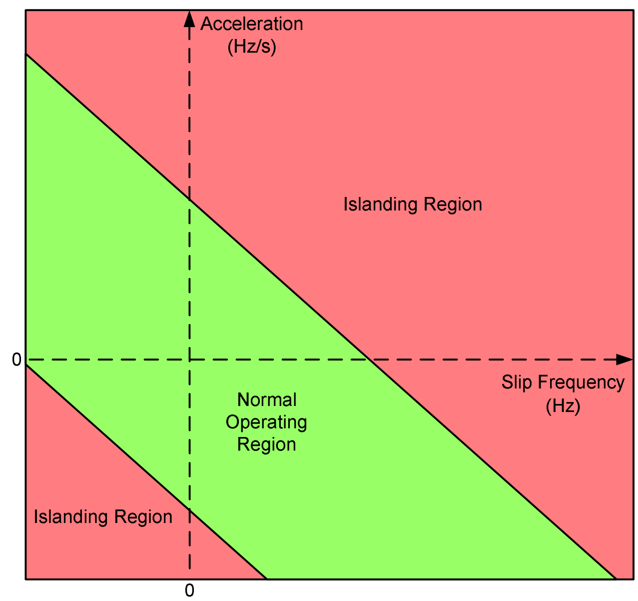

Fig. 3. Islanding detection characteristic using wide-area measurements

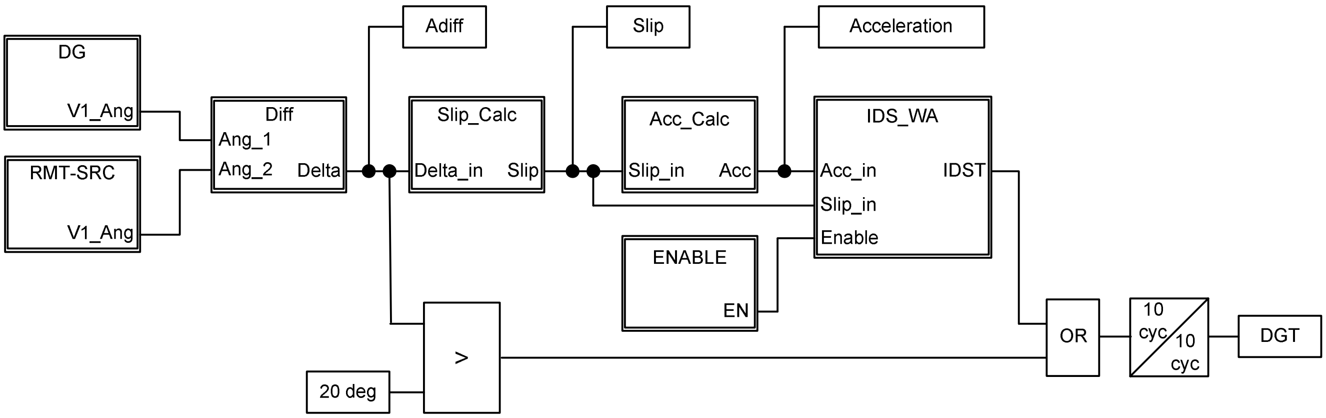

Fig. 4. Islanding detection logic based on local and remote time-synchronized measurements

Fig. 4 shows the logic for implementing the IDS_WA. A real-time logic processor receives time-synchronized positive-sequence voltage angle measurements from both the DG site and the remote source. This processor calculates the angle difference, slip frequency, and acceleration. It issues the DG trip command if the angle difference exceeds the threshold (e.g., 20 degrees) or if the operating point is in the islanding region of the characteristic in Fig. 3.

This scheme, based on wide-area measurements, operates for islanding conditions during all power transfer conditions. However, power mismatch dictates how fast or slow two systems slip against each other. Therefore, the response time is dependent on power mismatch. The scheme takes a longer time to detect the island when power mismatch is minimal because the systems are slipping slowly against each other. Because the proposed IDS_WA scheme is not dependent on system topology, we could use the scheme across different network configurations.

V. Scheme Validation Using Dynamic Simulations

To validate the proposed schemes, we developed a power system model, based on a typical distribution system, in the Real Time Digital Simulator (RTDS®). We connected phasor measurement and control units (PMCUs) to the simulator to receive the voltage and current signals from the DG terminal and the remote source. The PMCU at the DG site included the IDS_LA detection scheme discussed in Section IV. We implemented the IDS_WA detection scheme in a synchrophasor vector processor (SVP) [5] that received the phasor measurements at 60 messages per second, executed the logic discussed in Section IV, and sent a control command back to the PMCU based on the logic output. The contact on the PMCU was wired back to the simulator to trip the DG. Fig. 5 and Fig. 6 show the test setup and system model that we used to validate the proposed scheme.

We modeled the transmission network as an infinite source. The model of the DG included synchronous machine dynamics and an excitation control system. We locked the governor control of the generator to apply fixed torque to the synchronous machine.

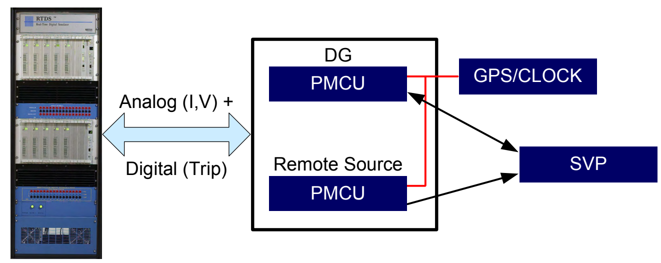

Fig. 5. Test system to verify the operation of the islanding detection schemes

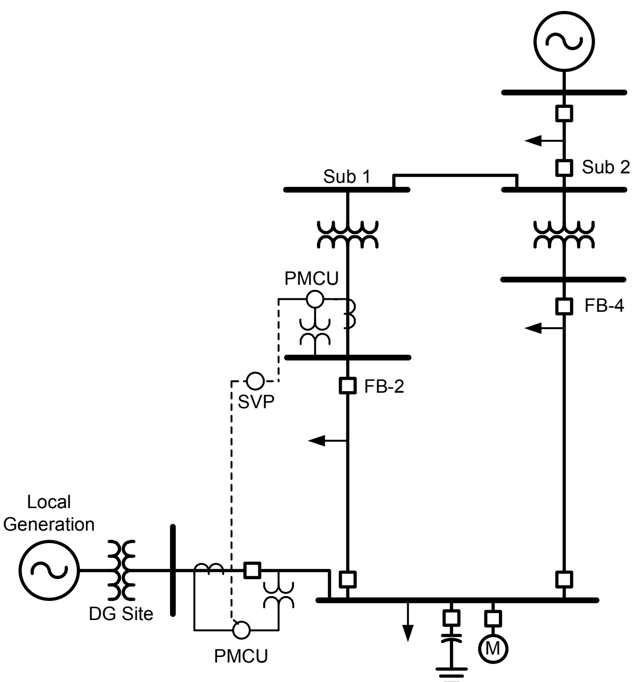

Fig. 6. Power system model

We set up the following active power load flow conditions (reactive power is closely matched) prior to the fault/dynamic simulations:

- DG greater than the connected feeder load
- DG less than the connected feeder load
- DG closely matching the connected feeder load

The dynamic simulation cases included the following:

- Three-phase and single-phase-to-ground faults
- Manual opening of the tie breaker leading to an islanding condition
- Load and generation switching
- Capacitor bank switching
- Induction motor switching

We did not trip the DG breaker in order to compare the response times of the different schemes. The test cases in this paper are associated with the manual opening of the tie breaker FB-2, with FB-4 normally open. We archived time-synchronized messages for each test case.

A. Test Case 1: Distributed Generation Greater Than the Connected Feeder Load

Fig. 7 shows the A-phase voltages at the DG site and at the remote source. Following the islanding condition, the local generation is greater than the local load, so frequency started to increase. Thus, the overfrequency element detected the islanded condition. The IDS_WA is relatively slow because of communications and filtering delays.

B. Test Case 2: Distributed Generation Less Than the Connected Feeder Load

In this test case, the local generation is less than the connected local load. The frequency decreases after breaker opening (Fig. 8), triggering operation of the underfrequency element. In Cases 1 and 2, the IDS_LA scheme responded faster than conventional frequency elements.

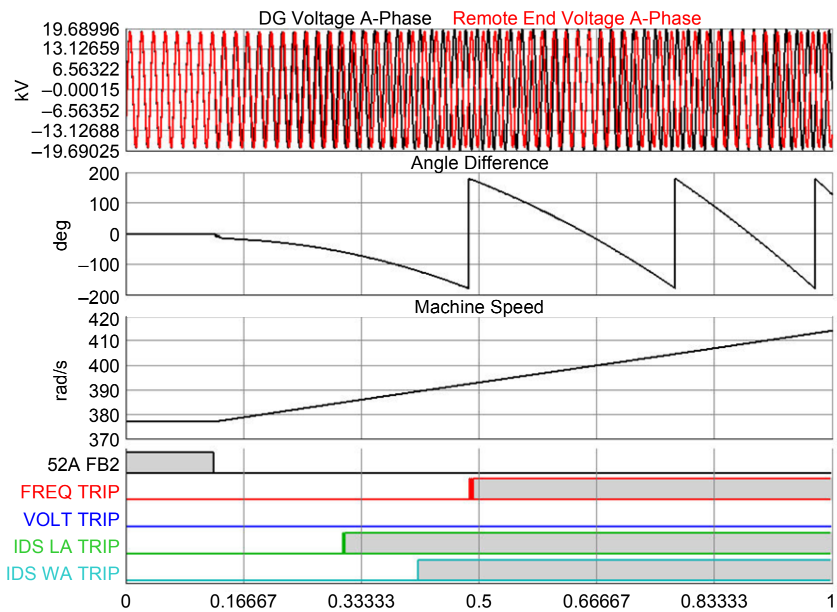

Fig. 7. Local-area measurement-based elements detected the islanded condition for export power

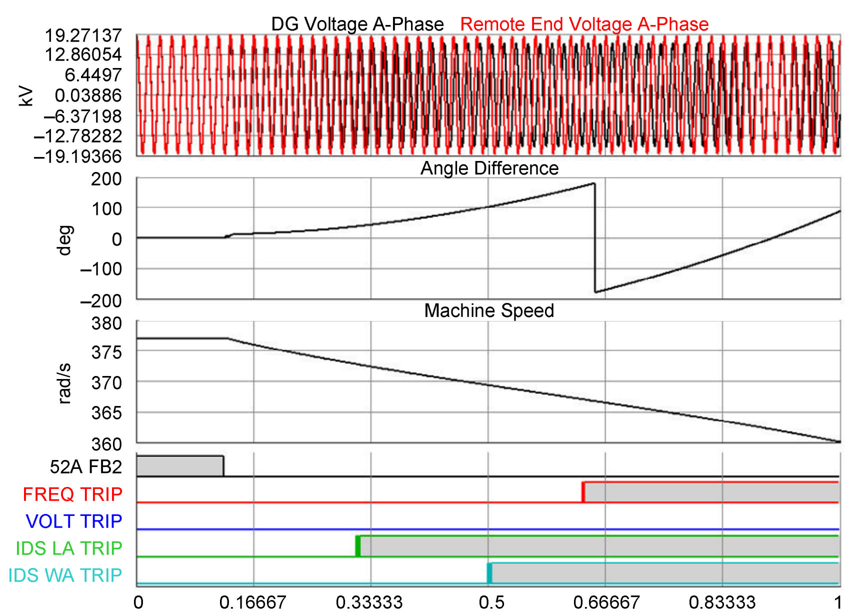

Fig. 8. Local-area measurement-based elements detected the islanded condition for import power

Fig. 9 shows the IDS_WA characteristic. The operating point is inside the characteristic during normal conditions. Following the islanded condition, the two systems start slipping against each other, and the operating point enters the islanding detection region.

C. Test Case 3: Distributed Generation Matches the Connected Feeder Load

An islanded system does not move to a new operating point when local generation and local load are tightly matched. Therefore, the IDS_LA and conventional elements could not detect this islanding condition in a timely manner. Fig. 10 shows that the IDS_WA detection scheme operates under this condition. As the previous section explained, the operating time of the IDS_WA scheme depends on how fast the two systems slip against each other. Element response times can be slow, so to prevent automatic reclosing out of synchronism, a synchronism-check element should supervise the breaker close.

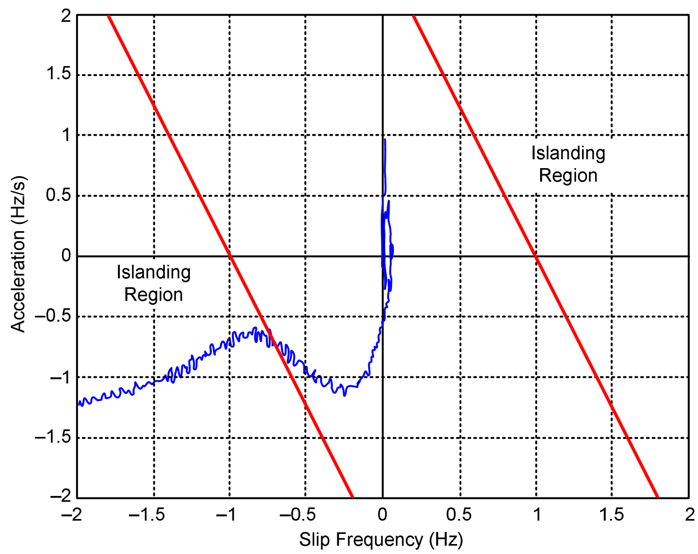

Fig. 9. The operating point enters the islanding region for import power exchange

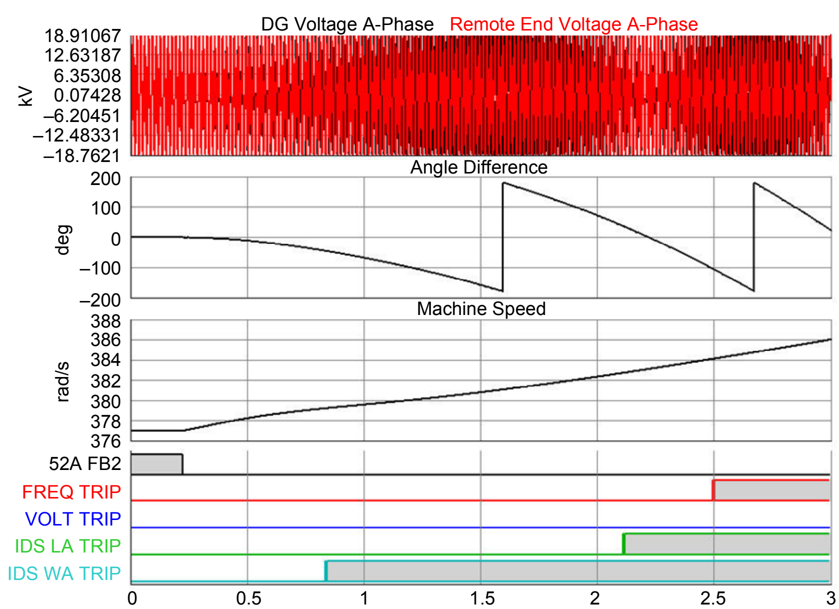

Fig. 10. The IDS_WA scheme detected the islanded condition for minimal power exchange

D. Test Case 4: Islanding Detection System Security

We tested the security of the proposed scheme. The tests included load and generation changes, induction motor switching, and capacitor bank switching. The scheme did not operate for any of these tests. For example, Fig. 11 shows that the elements restrained from operating during the motor starting condition.

E. Test Case 5: Multiple Power Exchange Conditions

We then ran a series of tests to study the response of the IDS_LA and IDS_WA schemes for different load-to-generation active power ratios. In the model, the total local generation (P_G) was 11.3 MW, and the local substation load (P_L) increased gradually from no local load to 22.6 MW. Fig. 12 shows the response times of generator protection, IDS_LA, and IDS_WA with respect to the load-to-generation active power ratio. The results show that IDS_LA responds faster than the conventional protection elements.

From the simulation results, we conclude the following:

- The IDS_LA scheme detects islanding faster than the IDS_WA scheme for conditions where the load-to-generation ratio is less than 0.8 or greater than 1.3.
- The IDS_LA scheme does not operate in a timely manner for conditions where the power mismatch is negligible. The IDS_WA scheme detects islanding under these conditions.
- Test cases with manual or intentional islanding are challenging to detect relative to transient fault test cases. When a transient fault initiates the islanding condition, the system is already perturbed, so conventional elements can detect the condition faster.

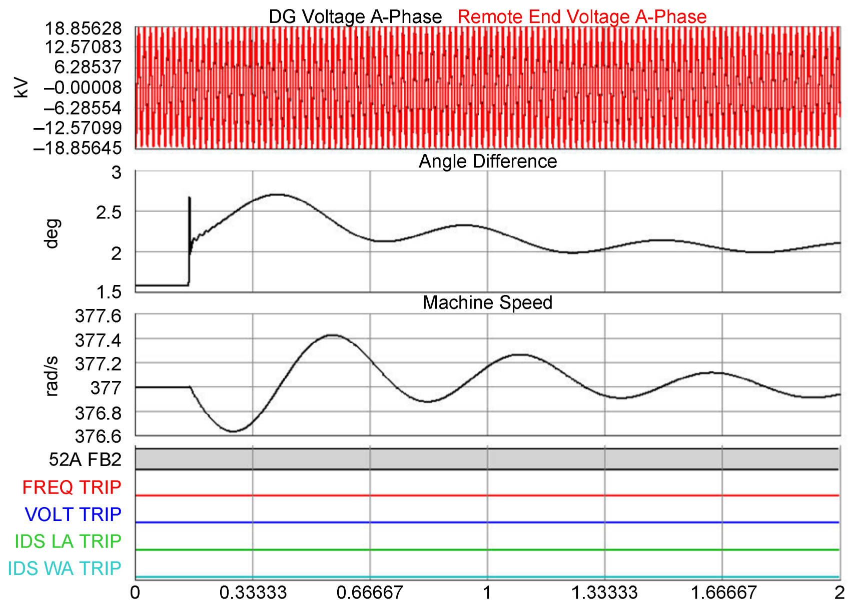

Fig. 11. Islanding detection elements are stable during induction motor switching

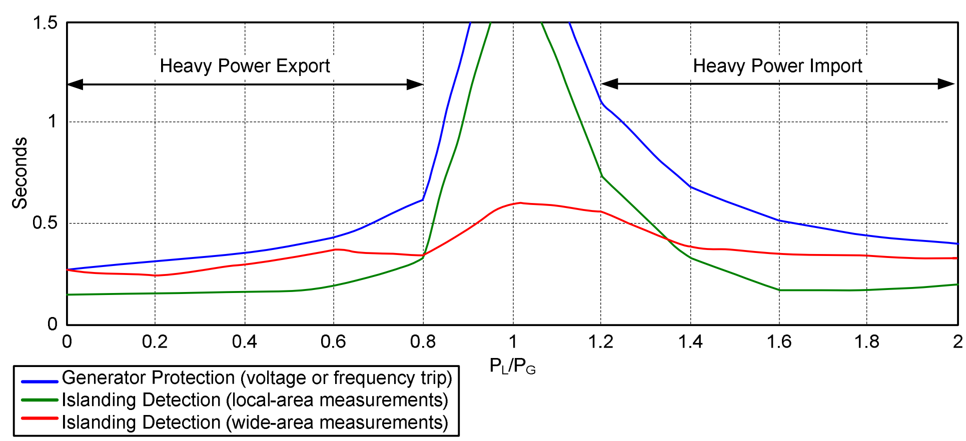

Fig. 12. Operating times of generator protection and local- and wide-area islanding detection schemes for different power exchange conditions

VI. Successful Islanding

IEEE 1547 requires tripping the DG following an islanding condition. However, customers prefer continuity of power even during islanded conditions, and it is common to run power systems while islanded. This section describes an adaptive load-shedding scheme (ALSS) that uses time-synchronized messages, along with local generation reserve margins and load priorities [6]. It is a typical practice to initiate predetermined load shedding following an islanded condition. To optimize power delivery, however, it is best to trip only the load necessary for the system to maintain stability. The ALSS calculates the amount of power to be shed (P_{SD}) in real time according to (1).

$$P_{SD} = \sum_{n=1}^{k} P_T - \sum_{n=1}^{m} \left(P_{GMax} - P_G \right) \quad (1)$$

where:

P_T = real power from the intertie connections.

k = number of intertie connections.

$P_{GMax}–P_G$ = MW reserve in each local generator.

m = number of local generators.

The load-shedding processor calculates P_{SD} and, based on load priorities and the power demand of the load feeders, initiates load-shedding actions.

To improve crew safety under islanding conditions, operational procedure modifications are necessary to use this scheme.

VII. Conclusions

1. Utilities require islanding detection and DG disconnection to avoid threats to personnel safety, out-of-phase reclosing, and degradation of power quality.
2. Islanding detection schemes that use local measurements detect islanding conditions reliably when there is a significant power exchange between the DG and the utility. However, they cannot detect islanding conditions in a timely manner when there is minimal power exchange.
3. The element that uses local frequency and df/dt information is the fastest to detect islanding during operating conditions with heavy power exchange.
4. Wide-area measurement-based schemes detect islanded conditions independent of the amount of power exchange.
5. Adaptive load-shedding schemes avoid unnecessary tripping of loads while maintaining system stability and power quality in the islanded area.

VIII. References

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IX. Biographies

John Mulhausen, P.E., received his BSEE from the University of Louisiana at Lafayette. He has more than 30 years of experience in protection and control systems. He is presently working as the manager of Design & Standards at Florida Power & Light Company and is a registered licensed professional engineer in the state of Florida. He is a member of IEEE and of the NERC System Protection and Control Subcommittee.

Joseph Schaefer received his BSEE from the University of Florida in 1986 and joined Florida Power & Light Company in 1987. Joe has worked as a protection and control field engineer and as a staff engineer designing and testing protective relay systems for generation, transmission, and distribution applications. In his current role, Joe reviews and develops distributed generation interconnects at the transmission and distribution level. Joe is a member of IEEE and PES.

Mangapathirao (Venkat) Mynam received his MSEE from the University of Idaho in 2003 and his EEE from Andhra University College of Engineering, India, in 2000. He joined Schweitzer Engineering Laboratories, Inc. (SEL) in 2003 as an associate protection engineer in the engineering services division. He is presently working as a lead research engineer in SEL research and development. He is a member of IEEE.

Armando Guzmán received his BSEE with honors from Guadalajara Autonomous University (UAG), Mexico. He received a diploma in fiber-optics engineering from Monterrey Institute of Technology and Advanced Studies (ITESM), Mexico, and his MSEE from the University of Idaho, USA. He lectured at UAG and the University of Idaho in power system protection and power system stability. Since 1993, he has been with Schweitzer Engineering Laboratories, Inc. in Pullman, Washington, where he is presently research engineering manager. He holds several patents in power system protection and metering. He is a senior member of IEEE.

Marcos Donolo received his BSEE from Universidad Nacional de Rio Cuarto, Argentina, in 2000, and his masters degree in electrical engineering (2002), his masters degree in mathematics (2005), and his Ph.D. in electrical engineering (2006) from the Virginia Polytechnic Institute and State University. Since 2006, he has been with Schweitzer Engineering Laboratories, Inc. in Pullman, Washington, where he is presently a research engineer. He is a member of IEEE.

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