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Accidental Islanding of Distribution Systems with Multiple Distributed Generation Units of Various Technologies

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SUMMARY

The system response to accidental islanding and effect on anti-islanding detection of distribution feeders with multiple distributed generation (DG) technologies (synchronous machine and inverter-based units) is one major utility concern associated with increasing penetration of DG. Studies have been conducted to evaluate the performance of anti-islanding detection through use of conventional voltage and frequency protection elements, and a non-detection zone (NDZ) defined in terms of real and reactive power mismatch scenarios. However, this NDZ applies to only synchronous generator DG technology, and efforts to characterize system behaviour and performance of anti-islanding detection for systems with mixed inverter and machine units have been limited. This paper investigates the effect of adding inverter-based DG to the system under various real and reactive power mismatch scenarios.

A realistic three-phase 21.6kV distribution feeder with one synchronous generator and multiple inverter DG units is modelled in PSCAD/EMTDC. The generator is always run at full MW capacity (2.85 MW). Real power mismatch is achieved through varying the output power of the inverters, and reactive power mismatch is provided by three switchable shunt capacitors spread throughout the system. Feeder load is adjusted at the minimum daytime load. It is assumed that all DG units operate at unity power factor. Anti-islanding protection is provided by under/over voltage and frequency protection elements, as well as a proposed power factor variation element at the generator intertie.

The real power mismatch is defined as the percentage of real power flow at the substation feeder outlet with respective to the total resistive load of the feeder and losses. At higher mismatch percentages, the inverter contribution is relatively low, and the system response is dominated by the synchronous generator. At lower mismatches, the inverter contribution is higher, and the effect of the inverters on the system response becomes greater.

The synchronous generator intertie protection tripped on underfrequency or overfrequency under downstream reactive power flow conditions. During a low generation to high load mismatch conditions, and synchronous generator-dominated scenarios, the system frequency decreased following islanding, as the generator uses up its spinning energy to compensate for the missing real power. In contrary, under inverter-dominated scenarios and similar power mismatch conditions, the system frequency increased from the greater effect of the inverters response to shortage of reactive power within the island. In between the two extremes, the conflicting frequency response of the

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generator and inverters balanced out, resulting in a flatter frequency curve and longer tripping times. When the system had an excess of reactive power, the generator absorbed the reactive power following islanding, causing a large voltage spike. In all cases, due to voltage exceeding 1.2 pu level, the overvoltage protection tripped very quickly (less than 10 cycles) before the frequency response of the generator or inverters came into effect.

It was found that under downstream reactive power flow scenarios, faster protection operation times are exhibited in the cases where the response is highly dominated by either generator or inverters. For the cases of upstream reactive power flow, the trip times are always very short (less than 10 cycles) regardless of real power mismatch. It is therefore a suggested practice to ensure that there is excess reactive power within a potential islanded system with multiple generators.

KEYWORDS

Distributed generation, voltage and frequency protection, anti-islanding detection, inverters, non-detection zone

INTRODUCTION

The rapid increase in global electricity consumption and environmental awareness has presented a significant opportunity for deployment of alternative and renewable energy resources in the form of distributed generation (DG) units. Inverter-based renewable energy sources, such as photovoltaic (PV), are regarded as key technologies in the proliferation of DG systems on distribution systems. However, as an emerging technology, distributed generation is at an early stage of development and the system response under transient scenarios when there are multiple DG technologies on the same feeder is not well understood. In particular, the detection of accidental islanding and DG disconnection from the main grid in a timely fashion is one major utility concern associated with increasing penetration of DG.

Studies have been conducted evaluating the performance of anti-islanding detection through use of conventional voltage and frequency protection elements. In [1] and [2], the anti-islanding detection capability under various real and reactive power mismatch scenarios is expressed in terms of a non-detection zone (NDZ) – a region where islanding is not detected through conventional protection elements which is determined by load type, generation controls, and protection scheme. However, the NDZ outlined only applies to synchronous generator DG technology. In addition, the certification tests (example, UL1741) and published data by vendors primarily address anti-islanding provision under a single DG operation. There has been limited effort to characterize system behaviour and performance of anti-islanding detection schemes for a utility distribution system with multiple DG units of various technologies.

This paper investigates the effect of adding inverter-based DG technologies on the detection of accidental islanding scenarios and the NDZ. A realistic three-phase medium-voltage balanced distribution system is modelled in PSCAD/EMTDC. Real power mismatch is varied through adjustment of the PV inverter outputs while the generator is always run at full power. Reactive power mismatch is varied through the connection of the capacitors on the feeder.

1. STUDY SYSTEM AND DG MODELING AND CONTROLS

The distribution feeder utilized in the study is a 21.6kV balanced three-phase feeder with three PV inverter-based DG and one synchronous generator (landfill gas). Reactive power compensation is provided by three switchable shunt capacitors spread throughout the system. The system is islanded by the opening of a breaker at the substation. A one-line diagram of the system is provided in Figure 1. The load locations are not shown on the diagram. The arrows show the downstream load without the DG contribution.

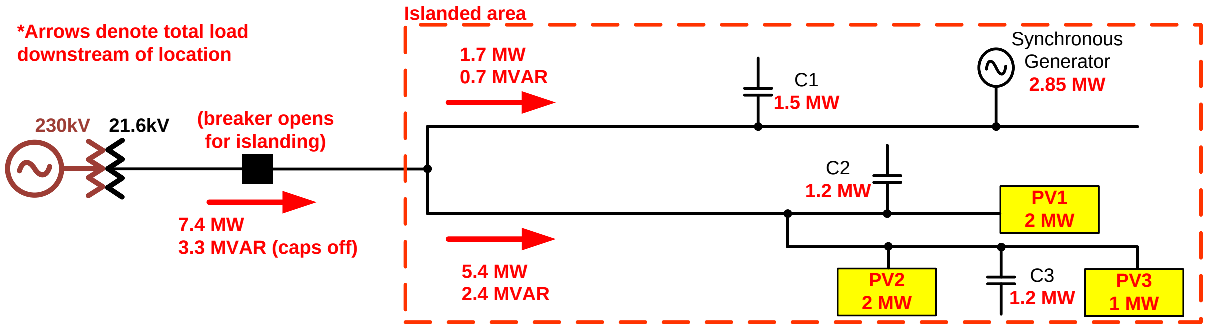

Figure 1 - Study system single line diagram

The synchronous generator is rated at 2.85MW and is connected through a step-up transformer to the distribution feeder. A turbine governor operating with speed-droop control is employed to respond to load variations and adjust the power frequency of the generator. The excitation system, controlled by an Automatic Voltage Regulator (AVR) and reactive power compensation controller, regulates the terminal voltage to output the desired reactive power - within a limited power factor range (± 0.95) agreed by the local utility. The generator parameters are given in [3]. Generator protection consists of over and under voltage protection, as well as over and under frequency protection, as specified by IEEE 1547 and California Rule 21 [4]. Generator intertie protection parameters are defined in Table 1.

Table 1 - Generator intertie protection

Frequency (measured at terminal)				
Indicator	**Condition**			**Delay (s)**
OF1	f	>	63 Hz	0.50
UF1	f	<	57 Hz	0.10

Voltage (measured at terminal)				
Indicator	**Condition**			**Delay (s)**
UV1	VrmsA or VrmsB or VrmsC	<	0.80 pu	0.50
OV1	VrmsA or VrmsB or VrmsC	>	1.2 pu	0.50

PV systems use multiple parallel grid-tie inverters per facility for power conversion. The PV inverters are modelled as voltage controlled current sources with internal protections. The models are validated based on generic characteristics of typical commercial PV inverters available in the market [5]. The PV inverter response to an islanding case is highly influenced by the phase angle measurement and synchronization schemes of the grid-tie inverters based on Phase-Locked Loop (PLL) design. Detailed investigations through laboratory examination and comparison with field measurements were performed to achieve a realistic response of the PLL block for the purpose of this evaluation [5].

2. CASE STUDIES

In this study, the benchmark system and DG units are modelled in PSCAD/EMTDC. Anti-islanding detection is provided by the intertie protection of the generator facility that uses voltage and frequency protection schemes. Intertie protection disconnects the synchronous machine from the system when tripped. In order to determine transient responses and protection performance, it is assumed that the PV inverter protection elements (including possible active anti-islanding schemes) operate in alarm mode only, without taking action to disconnect the PV inverters. The anti-islanding detection capability is investigated for realistic levels of both real and reactive power mismatch in the system:

a) real power flow mismatch at the substation - the level of mismatch adjusted by varying PV inverter outputs (representing expected generation level at different time of day), and

b) reactive power flow mismatch at the substation, varied through addition of the capacitors.

The real power mismatch is defined as the percentage of real power flow at the substation with respect to the total resistive load of the feeder and losses (about 7.4MW). For all mismatch scenarios, the generator is run at full MW capacity and the PV inverter outputs are adjusted to give the desired real power flow at the substation. The cases under consideration are: 55%, 50%, 45%, 35%, 20%, 10%, 5%, 0% and -5%, where positive mismatch is defined as power flowing into the feeder (the -5% would be power flowing back upstream to the substation).

Higher real power mismatches exhibit relative low PV inverter output and the synchronous generator characteristics dominate the system response. The PV inverter output is greater for low mismatch scenarios, and the inverter characteristics dominate the system response.

Reactive power compensation is provided by the connection of the three capacitors (C1, C2, C3) to the distribution feeder. Four reactive power scenarios are investigated: a) no capacitor compensation (3.2MVAR flow downstream at substation), b) single capacitor compensation (1.5MVAR flow), c) two capacitor compensation (no MVAR flow), and d) three capacitor compensation (1MVAR flow upstream). It is assumed that PV inverter units and the synchronous generator operate at unity power factor in normal condition.

2.1 Anti-islanding detection

Considering the standard two second trip requirements, the generator protection trip times are classified into three categories: a) fast detection under 1s, b) slow detection between 1.0s and 1.5s, and c) very slow detection greater than 1.5s. Detection time slower than 1.5 second may be considered a failed trip due to the possible delays introduced by measurements and switching response. This is primarily due to the fact that, circuit breaker operation time and differences among vendor-specific devices or designs are not included in the trip time.

The trip times for generator voltage and frequency protection in response to accidental islanding are given in Table 2, with color coding for the three categories. It is observed that in the cases of positive reactive power flow, the real power operating conditions, where system response is highly dominated by either synchronous generator or PV inverter, exhibit shorter trip times. In the case of negative reactive power flow, the trip times are always very short (less than 10 cycles) regardless of real power mismatch scenario.

Table 2 - Trip times for synchronous generator protection in response to accidental islanding

Trip times for Generator Protection in Response to Accidental Islanding (seconds)													
MVAR at Substation		Mismatch in Real Power at Substation (%)											
		-5%	0%	5%	10%	15%	20%	30%	35%	40%	45%	50%	55%
0 Cap	3.2	0.91	0.91	0.93	0.96	1.01	1.07	1.26	1.38	1.60	1.77	1.29	0.65
1 Cap	1.5	1.03	1.04	1.06	1.12	1.22	1.35	1.87	3.01	0.67	0.56	0.42	0.38
2 Cap	0.0	0.67	2.03	1.99	2.40	0.89	0.64	0.46	0.42	0.38	0.36	0.32	0.29
3 Cap	-1.0	0.13	0.12	0.11	0.11	0.11	0.10	0.10	0.09	0.09	0.09	0.09	0.09

The trip times indicated in Table 2 are used to develop a non-detection zone diagram for a multiple DG system, as shown in Figure 2. It is worth noting that the regions do not follow any of the suggested NDZ areas in the existing literature [1-2].

Based on the study observations, a suggested practice would be to ensure there is excess reactive power within a potential islanded system.

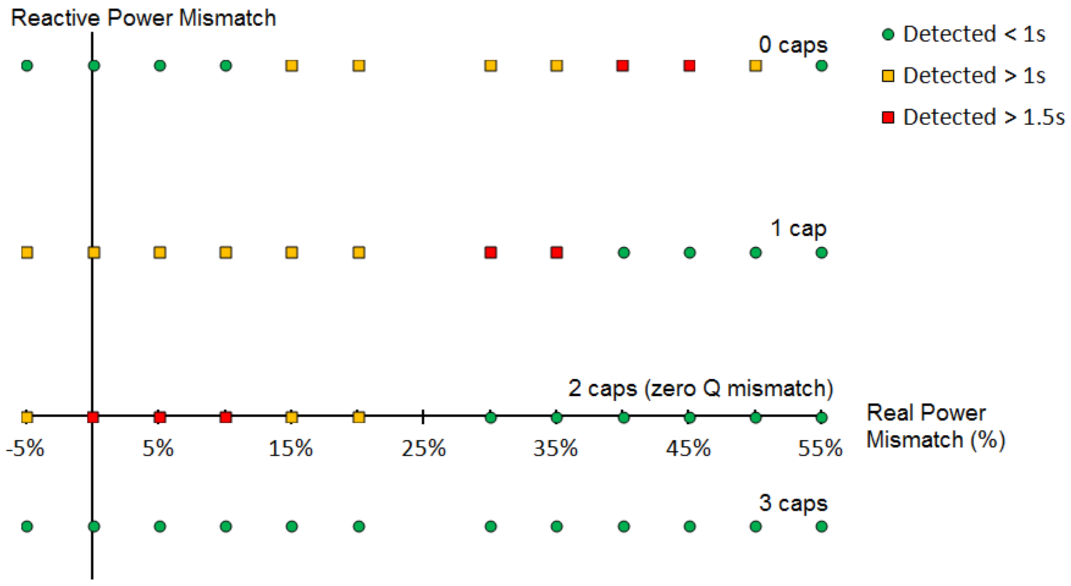

Figure 2 - Non-detection zone with synchronous generator and PV inverter DG types

2.2 Real Power Mismatch

For the cases reported in this section to examine effect of real power mismatch, all capacitors are disconnected, resulting in a downstream reactive power flow prior to islanding. The system is islanded at t = 0s by opening the circuit breaker at the substation. The system frequency response to the islanding is shown in Figure 3, with generator trip times for each mismatch case indicated by a dashed vertical line.

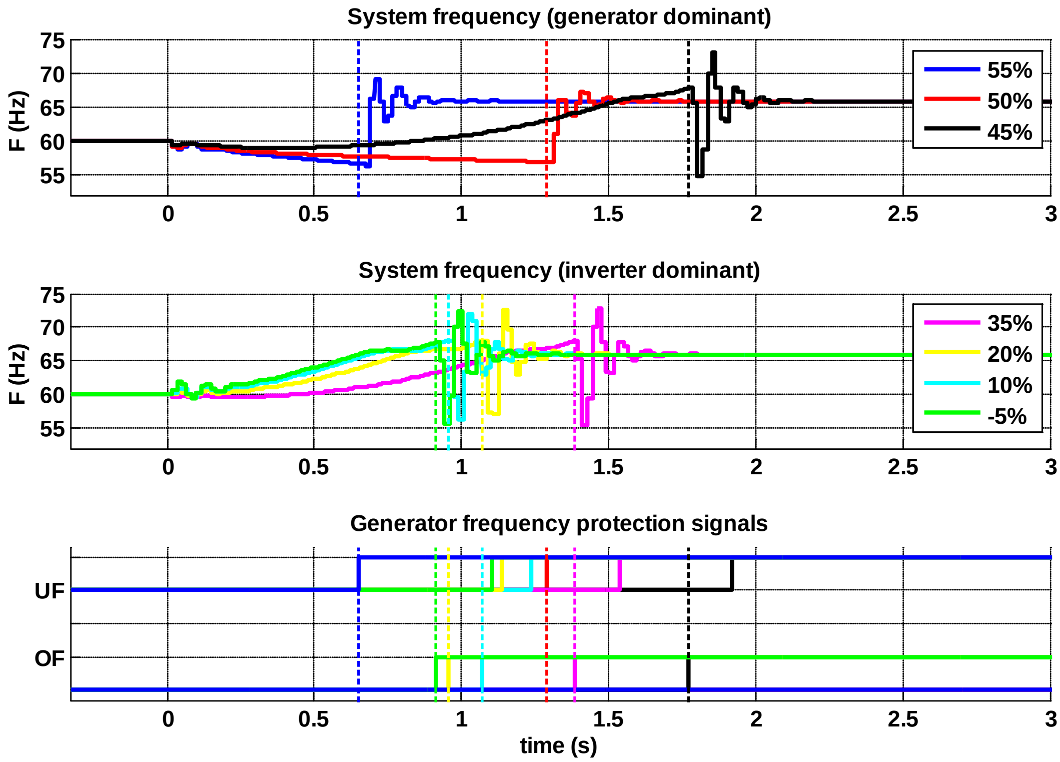

Figure 3 – System frequency and generator trip times in response to islanding

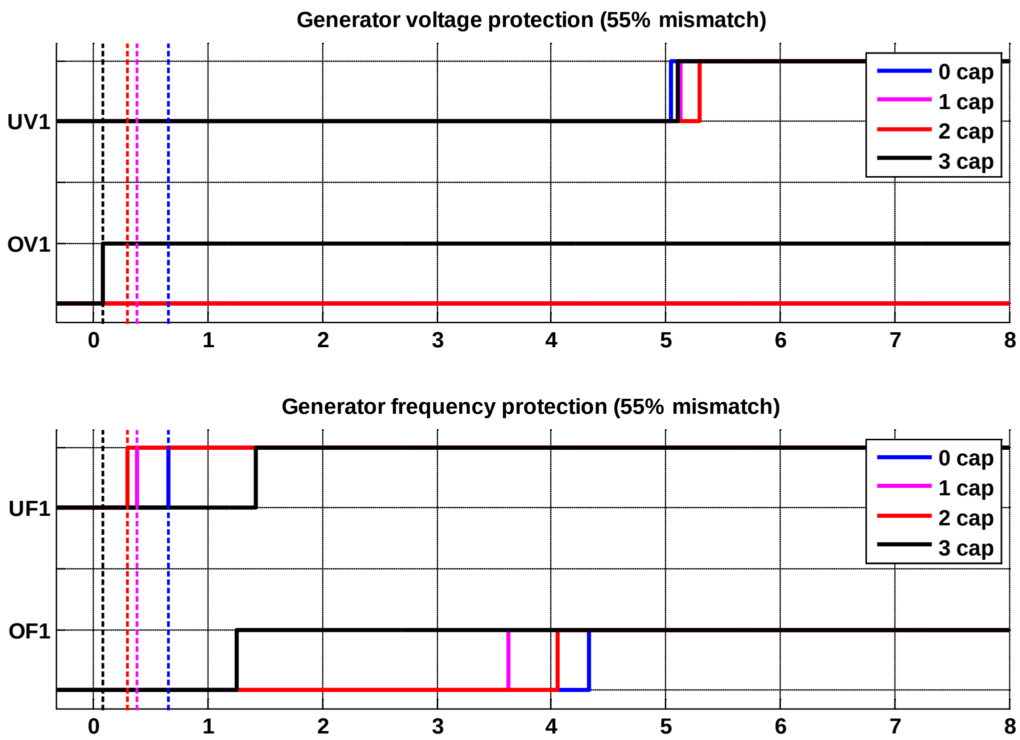

Figure 4 - Generator tripping times for islanding with reactive power compensation (55% mismatch)

It is observed that system frequency increases or decreases depending on the mismatch scenario. The frequency response of synchronous machines is inversely coupled to the real power output due to the presence of droop control in the machine's governor [6]. A positive real power mismatch upon islanding where resistive load in the system is greater than generation would result in the generator increasing output power to compensate and decreasing machine speed and system frequency. In the case of inverters, based on the current source behaviour, real power is decoupled from frequency while the reactive power is inversely affected. If there is shortage of reactive power in the system, the inverter frequency will increase [7]. The net effect of the two contradictory behaviours is dependent on the relative output of the PV inverters and synchronous generator.

The system response at higher positive mismatches (relatively small PV inverter contribution and greater portion of load supplied by the grid) is dominated by the synchronous generator and a decrease in frequency is observed. Lower mismatch scenarios (larger PV inverter contribution) are dominated by the response of the inverters and show an increase in frequency. The 45% mismatch scenario shows the contradicting frequency responses of the generator and PV inverters, with a longer flatter curve and longer trip time than the other cases.

Generator tripping is based on frequency, with generator-dominated scenarios tripping on underfrequency protection, and inverter-dominated scenarios tripping on overfrequency protection. It is noted that the trip times increase as the contradictory frequency responses of the generator and inverters balance out – the 45% mismatch scenario with the flattest curve exhibits the longest trip time.

2.3 Reactive Power Compensation

In this case, two real power mismatch scenarios are considered: a) 55% mismatch representing generator-dominated response, and b) 0% mismatch representing inverter-dominated response.

The generator tripping times for the 55% mismatch are shown in Figure 4 and the generator output and system parameters are shown in Figure 5. Upon islanding, the generator increases real power output to compensate for the loss of grid and reactive power depends on the reactive power compensation scenario. In the case of 0 and 1 capacitors, the reactive load on the feeder is positive, resulting in the generator increasing reactive power output on islanding and consequently decreasing voltage and frequency. For these cases, and the 2 capacitor scenario, the generator is disconnected due to underfrequency protection. In the case of 3 capacitors, the reactive power flows upstream at the substation, and the machine absorbs the excess reactive power, causing a voltage spike and disconnection of the generator due to overvoltage protection.

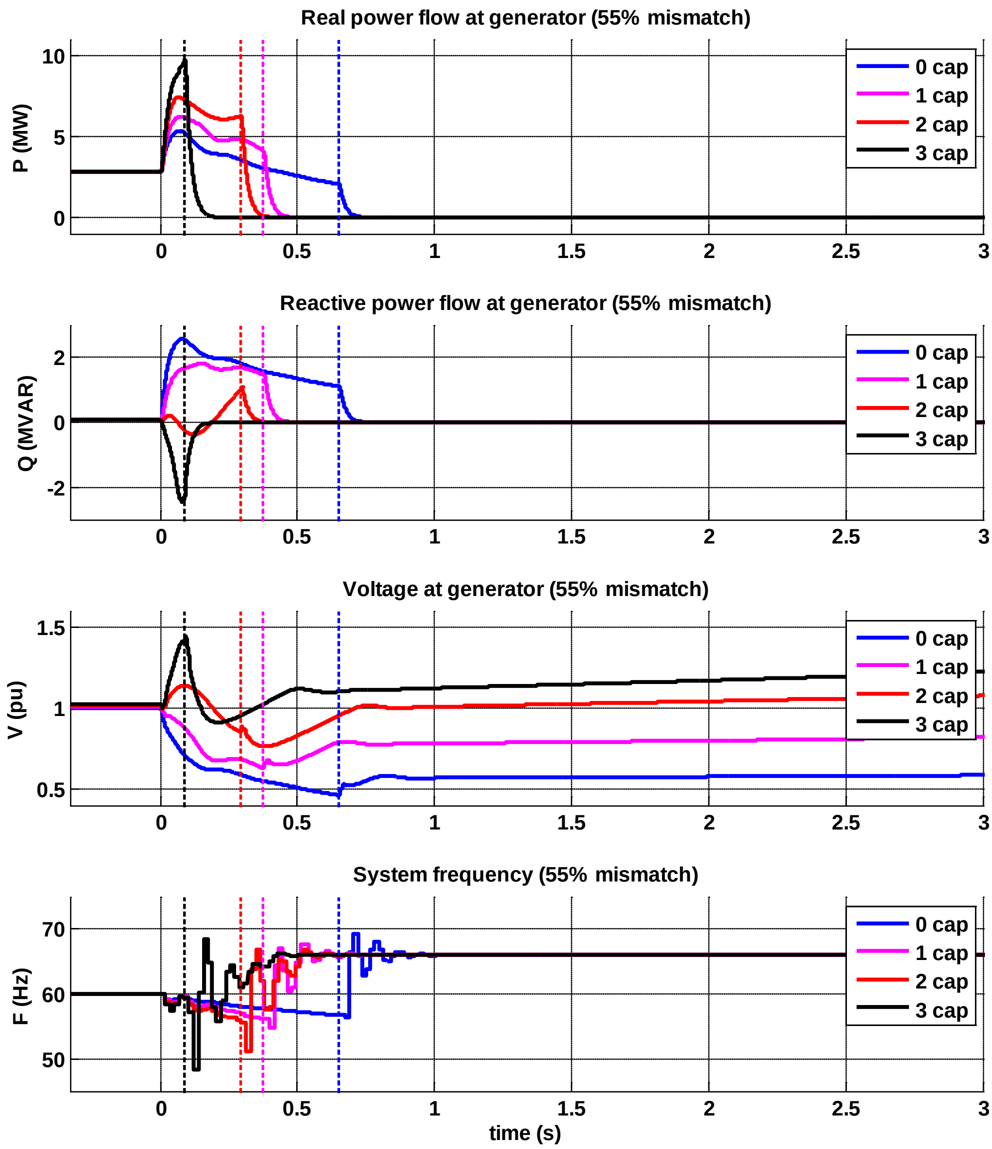

Figure 5 - Generator response to islanding with reactive power compensation (55% mismatch)

The generator tripping times for 0% mismatch and system frequency are shown in Figure 6. Upon islanding, the generator increases real power output to compensate for the loss of grid. Reactive power output depends on the reactive power compensation scenario; in the case of 0 and 1 capacitors, the reactive load on the feeder is positive, resulting in the generator increasing reactive power output on islanding and consequently decreasing voltage. In the case of 3 capacitors, the reactive power flows upstream at the substation, and the machine absorbs the excess reactive power, causing a voltage spike and disconnection of the generator due to overvoltage protection.

The influence of the PV inverter is seen in the system frequency, which increases in response to the islanding. The conflicting frequency response of the inverters and generator results in longer tripping times for the 0 capacitor, 1 capacitor, and especially the 2 capacitor (where downstream reactive power flow prior to islanding is close to zero) cases.

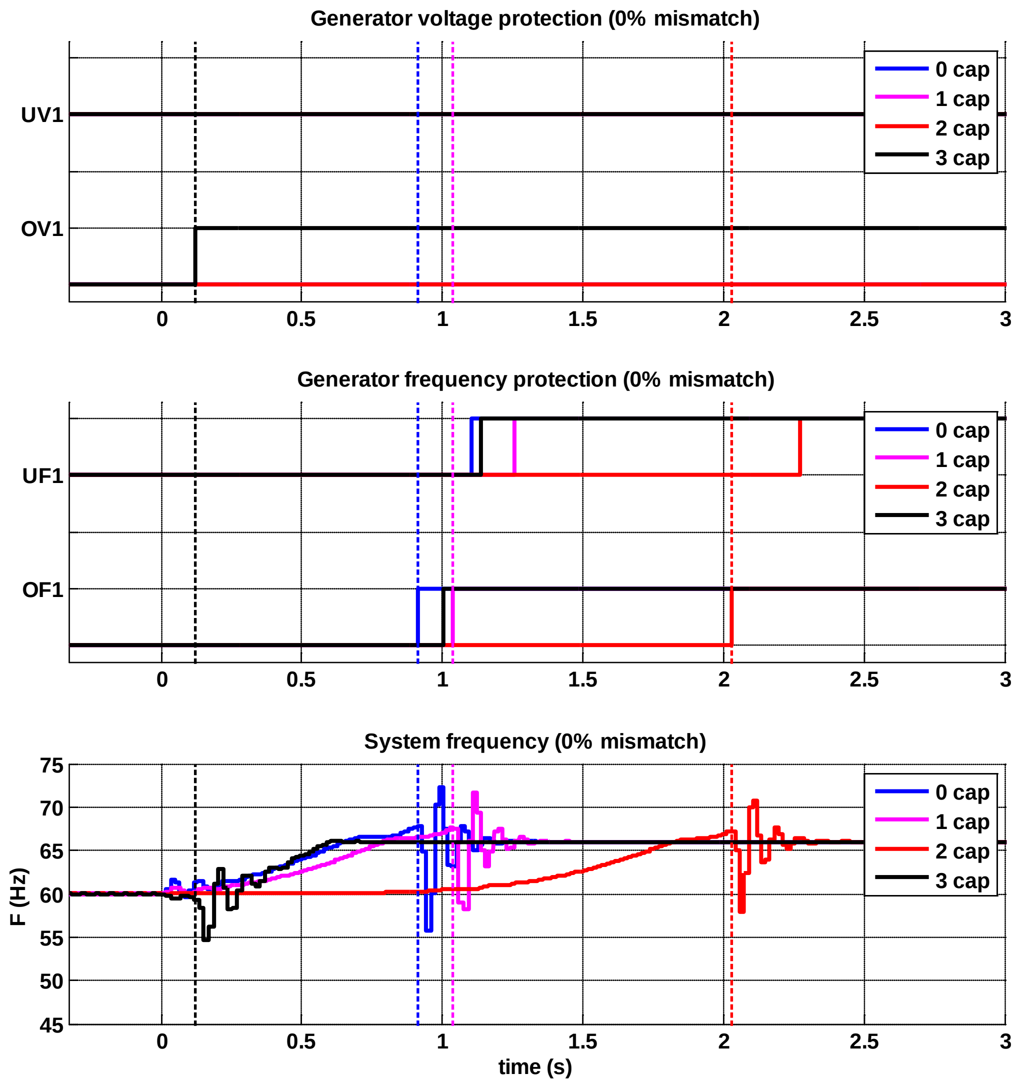

Figure 6 - Generator tripping times for islanding with reactive power compensation (0% mismatch)

3. CONCLUSION

This paper has investigated the effect of multiple DG technologies on anti-islanding detection using conventional voltage and frequency protection. It was demonstrated that the frequency response of the synchronous generator and the PV inverters are contradictory, with frequency increasing during inverter-dominated power mismatch scenarios and decreasing during generator-dominated scenarios. The protection trips faster when the frequency response is more dominated by either the generator or inverter. In between the two extremes, the contradicting frequency responses achieve a balance, resulting in longer detection times. In the case of upstream reactive power flow, the generator absorbs the excess reactive power, causing a voltage spike and fast disconnection from the feeder by overvoltage protection.

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