Managing frequency in low inertia grids

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Abstract—**Australia and other electricity grids are facing many issues with the increase of asynchronous generation commonly associated with renewable energy. One of the concerns is that renewables will displace synchronous plant and associated inertia.**

Demand-supply imbalance is compensated by rotational energy stored using inertia. As inertia is reduced in the power system, the rate of change of frequency (RoCoF) following a system contingency or fault increases and at some point, the existing frequency standards cannot be maintained. Fast RoCoF has the potential to compromise the stability of the power system. Some reasons for this include:

- **Mechanical torque on rotors increases for rapid changes in frequency, which may cause damage or a turbine trip and this further exacerbates frequency control problems**

- **Historical frequency control mechanisms such as load shedding and turbine governor control may be inadequate in low inertia systems due to their relatively slow speed of response in comparison to the rate of change of frequency**

The transition from the current operating regime to low inertia power systems poses challenges and many utilities around the world including Australia are seeking to mandate minimum system inertia to ensure the grid continues to operate as it always has. Whilst this is one way to solve the problem, it incurs economic costs on all users of the power system and there are likely to be alternative solutions.

As inverter-based generation systems are able to rapidly increase or decrease active power, they could potentially be made to respond quickly to frequency variations. Faster frequency control plant may be able to provide sufficient 'synthetic inertia' or act as an alternative for inertia.

In terms of load response, fast communications systems could potentially be used to assist in load shedding when the detection of rapid rate of change of frequency is too slow. Inverter controlled load such as air conditioners, pumps and fans could also be programmed to respond to frequency variations and provide load relief that would otherwise not be available.

This paper investigates the operation of a low inertia grid to examine the impacts on the frequency standard, system operations and viable options to ensure continued operation of the interconnected power system as inertia is reduced.

The authors seek to investigate what would be required to operate a practical power system, consisting of a variable mix of new and old technology generation, with very low inertia compared with current levels. An interconnected 2 region grid will be configured to resemble a practical real-world example.

The objective of the paper is to facilitate economic generation deployment and grid operation by offering an alternative to mandatory rotational inertia levels provided by synchronous machine technology.

Keywords-Variable Renewable Energy; frequency control; ancilliary services; reserves.

I. Introduction and Australian Context

The National Electricity Market (NEM) operates one of the world's longest interconnected power systems between Port Douglas, Queensland and Port Lincoln, South Australia with an end-to-end distance of more than 5000 kilometres, and 40,000 circuit kilometres [1] along the South and East Coast of Australia serving the population centres in the country. Dispersed throughout the NEM are various generators including Coal, Gas, Hydro, Wind and Solar PV. Prevalent societal and political attitudes have precluded the development of nuclear power in Australia. The NEM has a total electricity generating capacity, including Rooftop solar PV, of approximately 54 GW (December 2017) [1].

As is occurring worldwide there is a shift in the generation mix in Australia. Based on announced withdrawals and assumed operating life, some 16 GW of coal-fired generation capacity is expected to leave the NEM by 2050 [2]. Due to available resources and environmental factors, there is strong interest in solar resources particularly in the north of the grid and likewise a strong interest in wind generation in the south of the grid. Historically the north and south ends of the grid have had generation available from synchronous machines, however of concern to the system operator is the development of low inertia sub regions at these 2 extremities of the NEM, that are at the moment relatively weakly interconnected with the central regions.

Operator concerns are also heightened because of a system black event in 2016 in South Australia [3]. There are several contributors to the cause of this event including a fast moving storm front initiating multiple faults and contingencies, sudden loss of generation, separation of the interconnector and ultimately insufficient frequency regulation reserves in the islanded system. This event caused significant economic and massive political fallout and triggered the construction of a 100 MW grid connected battery backup system [4] (at the time the biggest battery in the world) in the hope that similar events could be avoided in the future. This battery now provides arbitrage for a nearby wind farm and ancillary services in the NEM including rapid response for high flows on the South Australia main interconnector [5].

Frequency control in the NEM has been managed by ancillary services for frequency control called Regulation FCAS and Contingency FCAS [6]. There are 6 contingency FCAS categories, the fastest being 6 seconds raise and 6 seconds lower FCAS. The system operator has become concerned about the rapid development of inverter connected equipment and the reduction in inertia which can "increase the susceptibility of the system to rapid changes in frequency that arise as a result of system disturbances, which can lead to blackouts" [7]. This leads to the conclusion that Contingency FCAS is no longer enough to provide sufficient frequency control to maintain power system security and the Australia Energy Market Operator (AEMO) are investigating the provision of faster FCAS services [8].

The concerns are not unfounded. Fig. 1 shows the historical minimum inertia in South Australia from 2013/14 to 2016/17.

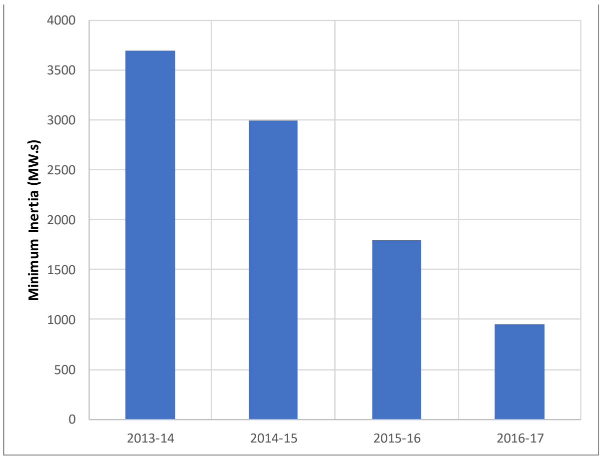

Figure 1. Historical minimum inertia in South Australia [10]

II. FREQUENCY CONTROL IN A SYNCHRONOUS MACHINE DOMINANT GRID

Before investigating the effects of removing synchronous generation, it is important to understand the characteristics of synchronous machines and in particular how those characteristics aid in power system stability.

The swing equation of rotating machines is given as

$$J\, d\omega/dt = Tm - Te \tag{1}$$

where Tm and Te are the mechanical and electrical torques and ω is the rotational speed of the rotor and J is the inertia of the rotor. The voltage of the machine terminals is nearly constant for moderate changes in external load, therefore increasing the electrical load on the machine causes additional current to flow in the stator, increasing stator flux and this increases the electrical torque. From equation (1), without adjusting the mechanical torque the rotor will decelerate. Turbine governors monitor the speed of the rotor and then to adjust the control of the fuel source to regulate the machines speed.

If there is a large sudden change in demand or generation, there is a change in torque on all machines and the average system frequency will change until supply and demand are balanced again.

The power system frequency should be kept within certain operational bands following the single largest contingency and the Rate of Change of Frequency (RoCoF) should be no greater than a specified value to avoid damage to the rotating components of synchronous machines caused by excessive torques.

A. *Effect of inertia*

As inertia in the system decreases, the RoCoF increases. For a generation trip, as the level of inertia is reduced and without faster governor controls, there is less injection of additional power into the grid prior to the frequency nadir and this causes a lower value of the nadir.

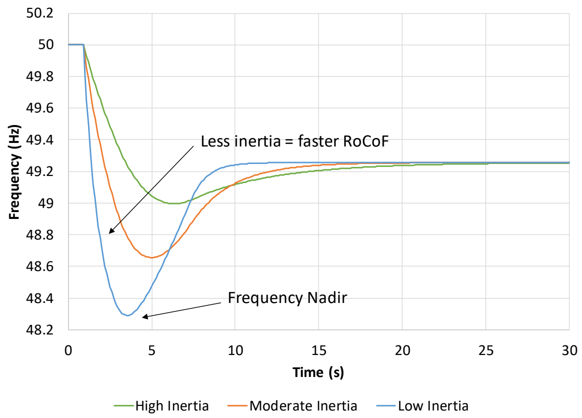

Figure 2. Effect of inertia on RoCoF and frequency nadir

B. *Effect of load*

Some types of equipment change their loading level in response to frequency changes. For example, induction motor load decreases with decreasing frequency whereas motors controlled by variable speed drives (VSDs) do not change output with small changes in frequency. The combined frequency response from all loads is dependent on the mix of loads at the time however a typically load relief factor would be between 1 and 2%.

III. AUSTRALIAN GRID CODE

The frequency operating bands for the NEM mainland as specified within the Mainland Frequency Operating Standards.

TABLE I. AUSTRALIAN MAINLAND FREQUENCY OPERATING STANDARDS

Term	Normal range (Hz)	Island range (Hz)	Supply scarcity range (Hz)
Normal operating frequency band	49.85 to 50.15	49.5 to 50.5	49.5 to 50.5
Normal operating frequency excursion band	49.75 to 50.25	49.5 to 50.5	49.5 to 50.5

Term	Normal range (Hz)	Island range (Hz)	Supply scarcity range (Hz)
Operational frequency tolerance band	49.0 to 51.0	49.0 to 51.0	48.0 to 52.0
Extreme frequency excursion tolerance limit	47.0 to 52.0	47.0 to 52.0	47.0 to 55.0

The frequency operating standard further specifies that these limits can be adjusted for a contingency that results in an islanded region and in the state of South Australia the frequency containment bands following an islanding contingency is 47 to 52 Hz [9].

The grid code in Australia is captured in a document called the National Electricity Rules (version 111 includes 1,698 pages). The NER provides a framework for negotiation of generator performance standards, between minimum and automatic access standard levels. For each technical requirement, the performance of a generating system may not be below minimum access standard level and is not required to be above automatic access standard level. Negotiated performance standards can be agreed between the generator, the network service provider and the AEMO, at levels between minimum and automatic access standard level.

Of interest in this paper is the requirements for generators to withstand frequency disturbances captured in S5.2.5.3. In this clause, the automatic access standard for RoCoF withstand is 4 Hz/s for more than 0.25s, and minimum access standard for RoCoF withstand is 1 Hz/s, for a period of one second. This has implications for an interconnected power system where there is a potential mix of generators with different access standards including generators with higher and lower RoCoF withstand capability.

A. Inertia service providers

On 19 September 2017, a change to the grid code placed an obligation for Transmission Network Service Providers (TNSPs) to provide minimum inertia services to manage power system security in response to credible contingencies, protected events, and when operating a network as an island [7]. The inertia requirements are specified as the minimum level of inertia required to operate an inertia sub-network in a secure operating state and a satisfactory operating state when the inertia sub-network is islanded.

Furthermore, Inertia is defined by AEMO as the "Contribution to the capability of the power system to resist changes in frequency by means of an inertial response from a generating unit, network element or other equipment that is electromagnetically coupled with the power system and synchronised to the frequency of the power system." [1]. This definition appears to preclude inverter connected plant from being able to provide such services. The authors feel that it is important to note that from a power system point of view, rotational inertia is not a requirement. Rather, voltage and frequency regulation standards are requirements. Inertia is only a consequence of the presence of many synchronous machines on existing power systems.

IV. INVERTER TOPOLOGY AND CONTROL

Since we have described from a high level how synchronous machines through inertia help to stabilise the grid, it is worthwhile similarly understanding the inverter connected equipment which is rapidly replacing synchronous machines.

Whilst there are several inverter topologies, they all work on basically the same premise and that is switching of semiconductors at hundreds or thousands of Hz to convert a DC voltage to an AC voltage using pulse width modulation (PWM). PWM works by comparing a 50 Hz voltage reference with a high frequency modulation signal known as a carrier. There are many different topologies that have been developed to maximise some aspect of the inverter such as the efficiency or harmonic content including multilevel designs. A reactor is connected to the output of the inverter to smooth the current at the output of the inverter.

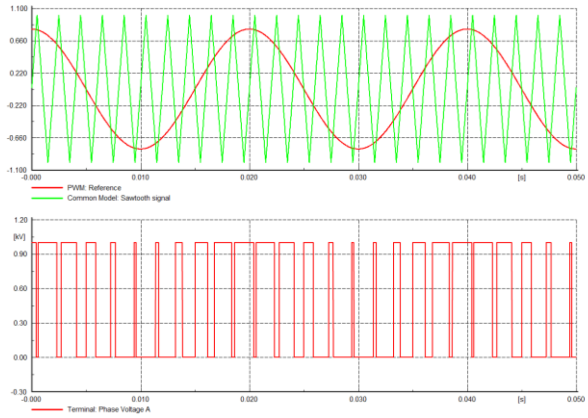

Figure 3. Basic PWM control

It can be shown that the real and reactive power transfer to the grid can be controlled by varying the magnitude and phase of the reference voltage with respect to the grid voltage. Whilst inverter-based generators are absent rotational mass, it is possible to control these devices to behave in a similar way if necessary or potentially with more optimal response. In terms of frequency control, however, a source of energy is required. Examining the prevalent renewable sources, wind and solar, wind turbines are capable of injecting additional active power into the grid by extracting the energy stored in the rotating mass of blades and generators however this causes the turbine to slow down, decreasing its efficiency, and it does not restore power until the turbine has had time to accelerate. PV inverters can provide inertia-like response only if curtailment is utilized. Note that in the NEM approximately 12% curtailment is required for PV plant for continuous uninterrupted operation compliance purposes [11] hence there is potentially a source of energy available which could be utilised for inertia in this market. Batteries are able to provide a dispatchable source of power without the same requirement for curtailment.

There are broadly two different types of control used to develop the voltage reference, current mode control and voltage mode control. The control mechanism is sometimes used to more generally refer to inverters as grid following and grid forming where current mode control is employed by the former and voltage mode control the later. Most commercial inverters connected to large interconnected power systems to date are grid following inverters.

A. Current mode control

Current mode or grid following controllers represent the most prevalent type of control strategy for grid-connected PV and wind inverters. A grid-following controller utilizes a phase-locked loop (PLL) to estimate the instantaneous angle of the sinusoidal voltage at the inverter terminals. The sinusoidal voltage reference signal is adjusted to inject a controlled current into the grid that tracks the terminal voltage. Grid following inverters work under the presumption that a "stiff" ac voltage with minimal amplitude and frequency deviations is maintained at its terminals such that it can simply follow its local voltage and inject a controlled current.

Almost all inverters connected to the transmission grid are presently controlled in a grid-following mode. In relation to frequency control, converters with this mode of control first need to measure the grid frequency before they can provide compensating active power introducing a control delay. For very low inertia systems with high RoCoF, such a control strategy will be unsuitable due to this measurement delay.

Whilst current mode control is different to the inertial response of synchronous machines, the control of active power can potentially be faster than governor action of coal or gas generation plant. Hence grid following plant can offer a fast frequency response service subject to resource availability (sun, wind) and operation with a margin from maximum output.

B. Voltage mode control

Whilst the concept of voltage control mode or grid forming inverters is not new, there has been much recent active research into the integration of grid forming inverters into large interconnected power systems [12] [13] [14]. In this mode of control, the voltage reference is internally maintained by the inverter controls and the current injected into the grid is then a function of the network conditions in response to a changing converter voltage.

As the equivalent circuit represents a voltage source behind an impedance, grid forming inverters can be made to behave almost identically to conventional synchronous generators. The 'inertia' of the inverter can be determined by a current droop gain parameter. In this mode of control, the MW response is directly proportional to the angular acceleration of the grid voltage rather than determined from measurement of grid frequency. With a simulated inertia, the inverter reference frequency is adjusted analogous to a synchronous machine whereas the machine speed increases or decreases in proportion to the difference between a reference active power (mechanical torque from the prime mover) and the electrical power (electrical torque from the stator circuit).

V. CASE STUDY

With increasing penetration of inverter-based generation, to maintain power system stability, the control of voltage and frequency for balancing reactive and active power demand has to come from either the introduction of additional synchronous plant (such as synchronous condensers), or from inverter-based generators. A case study has been developed to examine the interaction of the different aspects of frequency as grid inertia and governor response provided by synchronous generation is decreased and how this can be effectively managed through the introduction of inertia controls in grid forming inverters.

The example is a simplified equivalent interconnected, two region system which might represent the connection between the a potentially low inertia northern or southern regions of the Australian NEM that can potentially form an island (denoted region I) interconnected with a central mainland region (denoted region M).

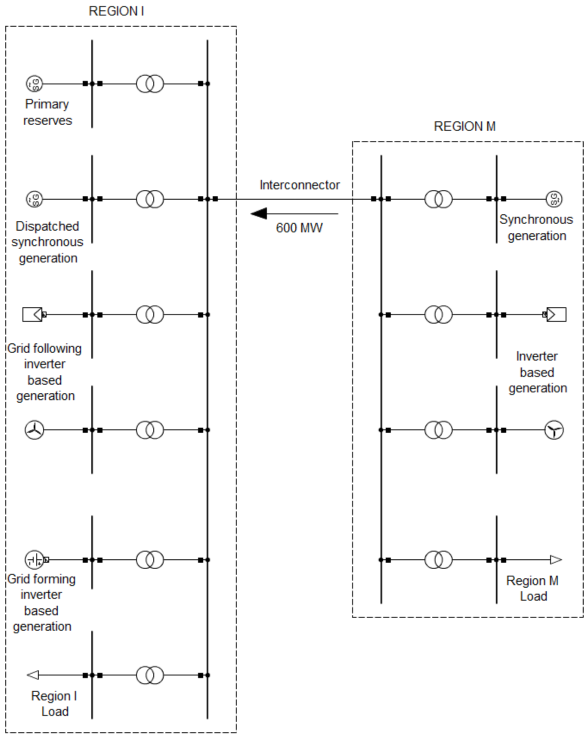

Figure 4. Example two region interconnected system

The scenario has been developed in the DIgSILENT PowerFactory software with the following main characteristics:

- 600 MW pre-contingent interconnector flow into region I
- Region I demand of 3,000 MW – load relief is 1.5%
- 600 MW primary reserves available tuned to full output in Case 1 in approximately 6 seconds. Reserve generator has been set with low inertia of 20 MWs to minimise inertial response and controlled using IEEEG1 governor with typical parameters.
- Grid following inverter-based plant represented using a mixture of WECC WT Control System Type 4 and WECC Large-scale PV Plant dynamic models and typical parameters
- Grid forming inverter-based plant represented using dynamic model developed by DIgSILENT with parameters as described in [15]
- The frequency standard for the region I to be consistent with the SA islanding frequency following interconnector contingency of 47 Hz and the maximum RoCoF equal to 4 Hz/s (this is the automatic access standard in the NEM).

A. *Impact of variable generation mix*

The scenarios considered to assess the impact with a varying mix of synchronous generators, grid following inverters and grid forming inverters are shown in Table II and the results of frequency nadir and maximum RoCoF are provided in Table III. RoCoF is calculated as the frequency deviation from nominal, 200 ms following the disturbance.

TABLE II. CONFIGURATION OF SIMULATION SCENARIOS

Scen.	Synch. Gen. (MW)	Inertia (MWs)	Grid follow gen. (MW)	Grid forming gen. (MW)	Grid forming capacity (MW)
1	2,400	24,000	0	0	0
2	2,000	20,000	400	0	0
3	2,000	10,000	400	0	0
4	400	2,000	2,000	0	0
5	400	2,000	1,800	200	1,500
6	400	2,000	1,800	200	2,000
7	400	2,000	1,000	1,000	1,500
8	0	10	1,400	1,000	1,500
9	0	10	0	2,400	3,000

TABLE III. SIMULATED FREQUENCY RESPONSE OF ISLAND FOLLOWING DISTURBANCE

Scenario	Frequency nadir (Hz)	Max. RoCoF Hz/s
1	47.1	1.00
2	47.0	1.64
3	46.7	2.79
4	44.4	5.51
5	46.8	3.39
6	46.9	2.85
7	47.2	3.25
8	47.0	5.50
9	47.3	3.00

As would be expected, these scenarios show that as inertia provided by synchronous machines decreases, the frequency performance also decreases. It is shown that this performance can be improved with enough inertia-like response provided by grid forming inverters. It is noted that the grid forming controller had minimal tuning. Adjustment of parameters should be able to yield a better performance, whereas the inertial response of the synchronous generator, while very fast, cannot be adjusted. It was found using the simple model that the “inertial reserve” required when this service is provided by grid forming inverters is approximately equal to the size of the contingency as shown in scenario 8 and 9.

The following plots show an interesting comparison of the response of the various plant in scenario 1, 5 and 9.

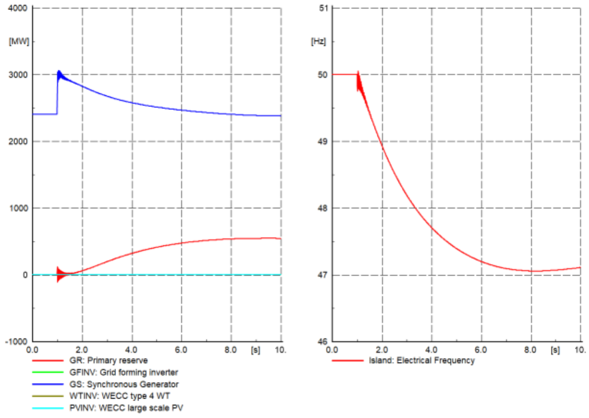

Figure 5. Scenario 1 active power and frequency response

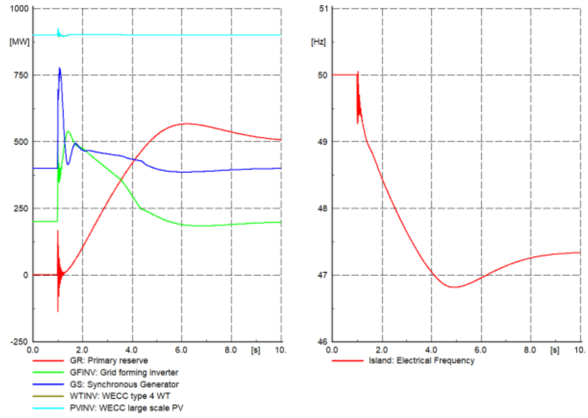

Figure 6. Scenario 5 active power and frequency response

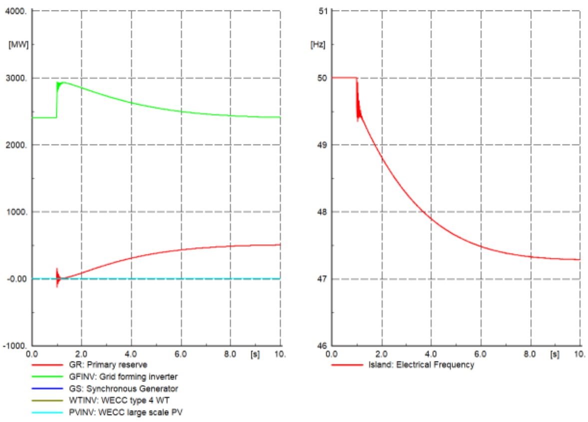

Figure 7. Scenario 9 active power and frequency response

The simulations show that the grid forming inverter can be made to deliver a response nearly identical to the synchronous generator. It is observed however that there is more of a frequency step for scenarios with lower inertia.

As the inverter response is controlled it has the following potential benefits:

- The response of an inverter can be controlled to achieve full output at a defined RoCoF, this allows the sizing and response of inverters with inertial response to be optimised.

- The controller could be potentially altered so that during frequency recovery, energy is not extracted from the system until the frequency recovers to 50 Hz and this would reduce primary and secondary control effort.

The simulations results for scenario 4 and 5 show that the frequency performance is diminished compared to the synchronous generation dominant scenarios and the grid following inverter-based generation dominant scenarios. From observation of the MW response immediately following interconnector separation, scenario 5 shows approximately 500 MW generation increase in the islanded region as opposed to almost 600 MW in scenario 1 and 9. This shows that, at least in this simulation, there are differences in the speed of response of the synchronous generation and the grid forming inverters. Potentially the inverter-based generation controls can be tuned to more quickly respond but it is more likely that additional generation capacity of either kind will be required to achieve the frequency objective. Scenario 6 includes 500 MW additional grid forming inverter capacity compared to scenario 5 and shows some improvement in performance to the point where the frequency objective of 47 Hz nadir and RoCoF of less than 4 Hz/s is almost met.

In the initial period following the separation event in the simulations some high frequency oscillations in the frequency and active power are observed. Similar behavior is observed in real interconnected systems [16] and represents the multi-modal swings of interconnected generators. In a larger transmission system, more than the two bus equivalent studied, frequency varies with location where generators furthest from the disturbance will see a lower RoCoF than those closer to the disturbance. This has not been investigated further in this paper but is an area of potential future investigation.

B. *Fast Frequency Response*

It is evident that an inertial response from either synchronous machines or other sources such as grid-following inverters is integral to power system frequency control. Some international jurisdictions such as Hydro-Québec already mandate requirements for non-synchronous plant to provide inertia-like frequency responses. Should synchronous generation capacity reduce in the future, this could be replaced by synchronous condensers with mass added to the rotor.

Fast frequency response (FFR) measures from inverter-based generation may be capable of delivering additional benefits for grid frequency regulation in comparison to convention generation technology. Whilst inverter-based generation may provide FFR, fast tripping of loads can also be similarly utilised. There are several issues with FFR, however, including accurate detection of the frequency derivative in very short timeframes using Phase Locked Loops (PLLs).

The influence of FFR was analysed in the study case by adding an outer loop controller to regulate the active power output of the wind and solar PV grid following inverter-based generation as a function of the frequency measured by a PLL. Such an outer loop control represents a power park controller that adjusts the output of a wind or solar farm based on grid measurements at the connection point.

In the simulations, the maximum output of the grid following wind and solar PV power plant was set at 1,200 MW each with a pre-event curtailment of 300 MW each to align with scenario 5. The outer loop controller was set to provide a 100 ms delayed measurement of frequency and a subsequent 500 ms was allowed for the plant to reach full output which is expected to be an achievable event detection and response time for FFR. The intention of the simulation is to assess if curtailment and control of the grid following generation can be used as a valid replacement of the 600 MW primary reserve assumed in the previous scenarios and the primary reserve is therefore excluded in the FFR scenarios.

Three additional scenarios were analysed as shown in Table IV. Plots of the system response are shown in Fig. 8, Fig. 9 and Fig. 10 and frequency nadir and RoCoF calculation results are provided in Table V.

The results indicate that FFR provided by grid following inverters can replace primary reserve and provides improvement in frequency nadir however there exists challenges with high RoCoF as can be seen in the results for scenario 10, which is a case without grid forming inverter support and in the results for scenario 12 which is an inverter only case. Scenario 12 represents the worst case out of all scenarios studied with and without FFR in terms of RoCoF due to the low total inertial response. The high RoCoF result is particularly pronounced in Fig. 10 and may be an issue for some users of the power system that are sensitive to high RoCoF.

TABLE IV. CONFIGURATION OF SIMULATION SCENARIOS WITH FFR

Scenario	Synchronous. Generation (MW)	Inertia (MWs)	Grid follow generation (MW)	Grid following capacity (MW)	Grid forming generation (MW)	Grid forming capacity (MW)
10	600	2,000	1,800	2,400	0	0
11	400	2,000	1,800	2,400	200	1,500
12	0	0	1,800	2,400	600	1,500

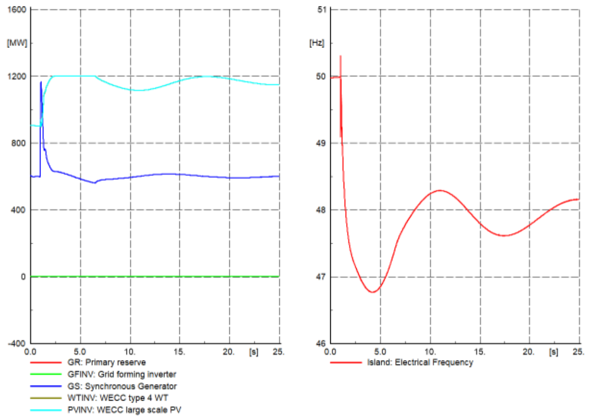

Figure 8. Scenario 10 active power and frequency response

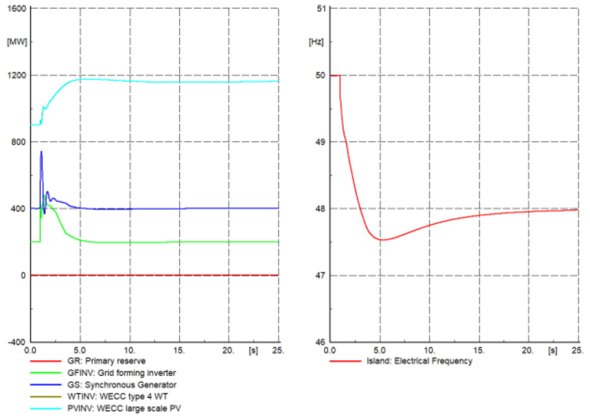

Figure 9. Scenario 11 active power and frequency response

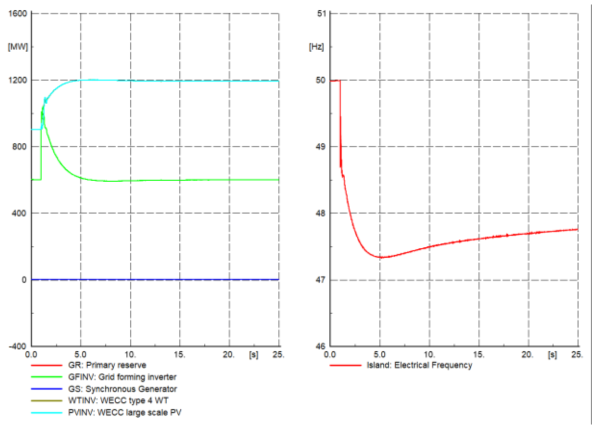

Figure 10. Scenario 12 active power and frequency response

TABLE V. SIMULATED FREQUENCY RESPONSE OF ISLAND FOLLOWING DISTURBANCE WITH FFR

Scenario	Frequency nadir (Hz)	Max. RoCoF Hz/s
10	46.8	5.45
11	47.5	3.14
12	47.3	7.15

VI. Conclusions

In this paper we have discussed the trends in generation in Australia and, in response to decreasing levels of inertia provided by synchronous machines, the new requirements for Australian TNSPs to provide system inertia services.

The flexible nature of inverter controls enables possible operation that mimics the response of synchronous machines and the analysis conducted in this paper demonstrates a possible future grid where inertial requirements are provided entirely from curtailed inverter connected renewables and/or batteries.

Whilst grid forming inverter technology has been shown as a potential solution, the fleet of existing grid following inverters cannot easily be changed to grid forming control. The future coordination of inertia, load response and ancillary services needs careful consideration and appropriate market mechanisms to enable the required services with economic efficacy. Both market signals and grid code requirements will ultimately drive the sources from which future frequency control including inertial response is provided.

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