30th May 2019

Mr John Pierce AO
Chair
Australian Energy Market Commission
Level 6, 201 Elizabeth Street
Sydney NSW 2000

Submitted at www.aemc.gov.au

Dear Mr Pierce,

Re: Amendment to National Electricity Rules Clauses <3.15.6A, 4.3.1, 4.9.4, 5.20B.5, S5.2.5.11, S5.2.5.14, 10>

Please find attached a rule change request seeking amendment of clauses 3.15.6A, 4.3.1, 4.9.4, 5.20B.5, S5.2.5.11, S5.2.5.14 and 10 of the National Electricity Rules, to improve frequency control within the National Electricity Market (NEM) in alignment with the National Electricity Objective.

Frequency control deterioration has been cited by many sources over the past few years, however, many open questions remain. The system separation event which occurred on 25th August 2018 highlighted continuing system control issues, weakening power system security.

This rule change request seeks to mandate the provision of primary frequency control within the NEM. Ensuring a predictable system dynamic response would *improve* power system security – a requirement of the National Electricity Law – whilst also providing benefits regarding system operation and planning.

Any queries concerning this rule change proposal should be directed to Peter Sokolowski on 03 9925 1182 or peter.sokolowski@rmit.edu.au.

Yours sincerely,

Dr Peter Sokolowski

FIEAust CPEng NER APEC Engineer IntPE(Aus) SMIEEE RPEQ

Rule Change Request – Amendment to National Electricity Rules Clauses <3.15.6A, 4.3.1, 4.9.4, 5.20B.5, S5.2.5.11, S5.2.5.14, 10>

1. Name and Address of Rule Change Proponent

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2. Summary of Proposed Rule Change

Gradual deterioration of frequency control within Australia's National Electricity Market (NEM) has been observed since the *Ramp Rates, Market Ancillary Service Offers, and Dispatch Inflexibility* rule change was implemented in National Electricity Rules (NER) version 27 commencing 31st March 2009. This deterioration and its effects has been well documented [1-3], and, this issue has stemmed from several potential causes. *The Independent Review into the Future Security of the National Electricity Market: Blueprint for the Future* (*Finkel Review*) highlighted many international 50 Hz power systems which have tighter frequency operating standard (FOS) and tighter governor deadbands than the NEM, and that having more generators in the NEM contributing to frequency control would be beneficial [4].

Submissions to the Finkel Review[1] proposed tighter deadbands, *improving* the capacity to maintain network security[2]. However, the NEM's frequency control issue have not been solved by implementation of the Finkel Review's recommendations to date. Accordingly, many open questions regarding recent degradation of frequency control currently exist within the NEM. The need for resolution of the frequency control issue was compounded by the separation event on 25th August 2018 which highlighted a reduction in system security and resilience.

Frequency control issues can stem from market signals overriding the technical requirements of the power system, inactive governors and large governor deadbands. This rule change request details changes to the NER version 121, with the aim of improving power system security and the provision of frequency control within the NEM.

If degradation in frequency control is allowed to continue, reliability and security of supply implications exist, and power system security is neither maintained nor improved. Minimal changes to the NER are proposed to address this issue:

a) **Clause 3.15.6A** is updated to include modification of active power by the local system frequency according to droop and deadband settings.

[1] from GE and Pacific Hydro
[2] GE's submission

b) **Clause 4.3.1** is updated to include the words "and improve" in alignment with the National Electricity Law.

c) **Clause 4.9.4** is updated for scheduled and semi-scheduled generating units using local power system frequency to provide automatic frequency response.

d) **Clause 5.20B.5** is updated to include fast frequency response from inverter-connected plant.

e) **Clause S5.2.5.11** is updated to mandate the provision of primary governor response.

f) **Clause S5.2.5.14** is updated to govern active power control through the use of local frequency.

g) **Clause 10** is updated to align with newer generation technologies.

The above changes are in alignment with the National Electricity Objective, providing benefits to market participants and consumers.

3. Issues with Existing Rules and Rationale for the Rule Change

Since the *Ramp Rates, Market Ancillary Service Offers, and Dispatch Inflexibility* rule change implemented in NER version 27 commencing 31st March 2009, time-series NEM data [5] (illustrated in Figure 1) shows there has been a gradual deterioration in the regulation of system frequency. A range of sources have cited this degradation in primary frequency control as contributing to power system instability [1-4, 6, 7].

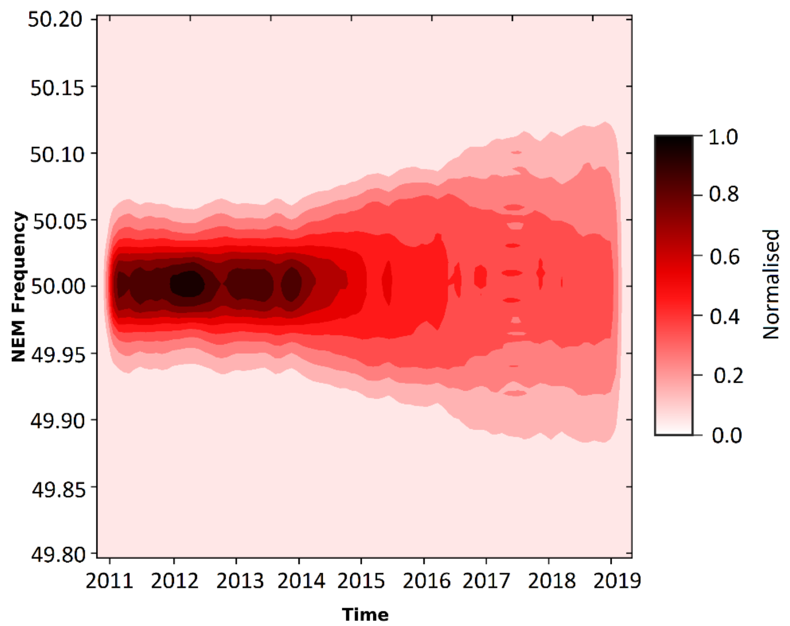

Figure 1: Contour plot of NEM frequency data from 2011-2019.

Since 2009, numerous changes have occurred within the NEM leading to questions surrounding the source of this degradation:

1) *Are market frameworks overriding the technical design of the system resulting in deterioration of frequency control?*

2) *Are large governor deadbands on synchronous generating units (coupled with wide Frequency Operating Standards) contributing to frequency control issues?*

3) *Is energy transition planning contributing to deterioration in frequency control?*

4) *Is governor inactivity degrading the provision of primary frequency control?*

Frequency control issues may be perpetuated from numerous issues, including, but not limited to:

- Market signals taking precedence over the technical requirements of the system, contributing to a reduction in frequency control and stability.

- Large governor deadbands and inactive governors, contributing towards a reduction in primary frequency control [6].

- Loss of dynamic response from synchronous machines to changes in system frequency.

This is of concern because the relatively wide control of power system frequency can cause a range of issues as detailed by Engineers Australia, including, but not limited to [7]:

Safety and reliability issues

- blades on synchronous turbines may be damaged;

Reliability issues

- wear and tear on generator governing equipment;
- inefficient operation of generators resulting in increased emissions;
- stable control of synchronous machines may be compromised;

Security issues

- system stability may be compromised;
- impedance measurement may affect stable control of voltage;
- feedback through stabilisers may affect voltage;
- interconnectors may deviate from their dispatch targets and during a contingency may lead to cascading failure;
- measurements of quantities that require a certain level of accuracy may be compromised;

Price issues

- dispatch of energy and interregional loads may no longer be optimised owing to measurement error;
- local measurement and its billing may be affected;

Quality issues

- harmonic dependent measurement devices may be affected; and
- harmonic filter efficiency.

Operating a power system with wide frequency bounds has an economic effect across the whole system, which exposes the system to increased risk of equipment failure and increases safety hazards to power plant operations crew. Continuing operation with the above issues present is operating contrary to the principles of the NEO as they negatively impact upon the price, quality, safety, reliability and security of the supply of electricity and the reliability and security of the national electricity system.

The current arrangement of allowing generation plant to switch on or off their frequency control in accordance with market dynamics adds to the level of uncertainty of how the power system will react in response to power system events and market dispatch instructions.

i. If primary frequency control is mandated, power system modelling can provide accurate estimates of system frequency trajectories, which greatly simplifies the identification and quantification of system constraints and improves system responsiveness to NEMDE dispatch instructions.

ii. It has been recently demonstrated that the power system is difficult to control after system breakup events[3]. This has a significant economic cost - the longer a region is left disconnected from the main grid, the longer the economic benefits that the flow of power across the relevant interconnector must be foregone. The separated components of the system are also exposed to greater risk the longer they remain disconnected.

Under the current rules, there may be a reliance on load shedding to arrest frequency decline after a loss of a generating unit because there is no guarantee that sufficient governor control will be enabled to prevent a sustained frequency decline (or rise) for even minor system disturbances.

The system separation event that occurred on the 25th August 2018 is mentioned briefly to highlight the consequences of poor frequency control, impacting power system security. For further details about this event the *Final Report – Queensland and South Australia System Separation on 25 August 2018* should be consulted [2].

[3] i.e. events where one or more regions are separated from the NEM.

A relatively minor power mismatch of 835 MW between QLD and NSW resulted[4] following a double circuit fault on the Queensland-New South Wales Interconnector (QNI). Queensland's frequency rose following its separation from the rest of the NEM, owing to 835 MW of surplus generation. Conversely, the remainder of the system (NSW, VIC, SA and TAS) had a deficit of 835 MW which caused its collective frequencies to fall. Figure 2 provides the time-series frequency data for the event.

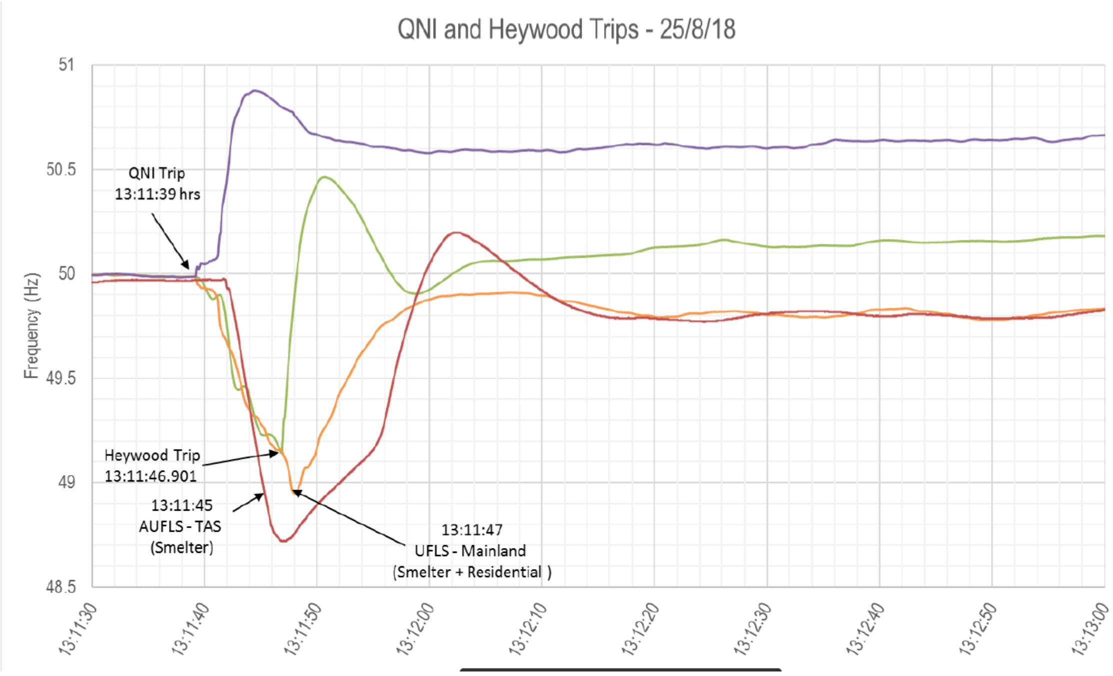

Figure 2: Regional frequency during the separation events on 25th August 2018 (Figure 4 from AEMO Preliminary report: Queensland and South Australia separation on 25th August 2018 – published 7th September 2018).

By control system standards, the rate of decline and rise in regional frequency was relatively slow[5] - well within a modern, automated governor control system's response capability. However, in this case many governors on the operating plant did not respond appropriately due to current practices. Tighter control of system frequency could have ensured greater system security.

Prior to the event on 25th August 2018, the previous time QLD separated from the NEM was on 28th February 2008 (before the *Ramp Rates, Market Ancillary Service Offers, and Dispatch Inflexibility* rule change commencing 31st March 2009).

[4] 835 MW is "minor" because it is of the same order of magnitude as the loss of a single largest generator which is 650 MW, which is not an infrequent event on the NEM.

[5] It took 8 seconds for the main system to decline to approximately 49 Hz ((50-49)/8 = 0.125 Hz/s on average), and 4 seconds for Queensland frequency to rise ((50.9-50)/4 = 0.225 Hz/s on average).

Table 1: Comparison between consecutive QLD separation events.

	28th February 2008	**25th August 2018**
Total loss of power transfer	1091 MW	870 MW
Additional regions separated	None	South Australia
Under-frequency load shedding	None	997 MW
QLD Frequency	50.62 Hz	50.9 Hz
Remaining NEM frequency	49.55 Hz	48.95 Hz

Table 1 illustrates that in the most recent QLD separation event, a smaller total loss of power transfer occurred; however, additional NEM regions separated, and under-frequency load shedding and larger frequency excursions resulted, i.e., power system security has declined (or has not been maintained nor improved) between events.

The proposed rule change request seeks to bring the NEM's frequency control into alignment with established international practice [8], literature and clause 49(1)(e) of the National Electricity Law (NEL).

4. Description of Proposed Rule Change

Appendix A details the proposed rule change through mark-ups of the NER. The major changes proposed are detailed below.

a) **Clause 3.15.6A:** updated to include modification of active power by the local system frequency according to droop and deadband settings.

b) **Clause 4.3.1:** updated to align with the National Electricity Law.

c) **Clause 4.9.4:** updated for scheduled and semi-scheduled generating units using local power system frequency to provide automatic frequency response.

d) **Clause 5.20B.5**: updated to include fast frequency response from inverter-connected plant.

e) **Clause S5.2.5.11:** updated to mandate the provision of primary frequency control (governor response).

f) **Clause S5.2.5.14** is updated to govern active power control through the use of local frequency.

g) **Clause 10:** definition of inertia is corrected to reflect the changing energy mix.

5. How the Proposed Rule Change Addresses the Current Issues

The proposed rule change introduces key points that generator dispatch should take into account:

i. The local system frequency (i.e. the frequency at the generator frequency measuring point, which is usually the generator terminals).

ii. The agreed generator governor droop characteristic.

iii. The agreed governor response.

Currently, these effects are not accounted for in the rules or market design. As a result, generators currently have an incentive (if they do not wish to participate in the frequency control ancillary services (FCAS) market) of detuning their governor control systems to be non-responsive to frequency changes, so as to follow their dispatch targets and avoid disturbance to their internal processes. The proposed rule change removes this incentive and requires generators to always respond to frequency changes in a pre-agreed manner, thus maintaining or improving power system security.

The proposed changes with respect to inertia support activities recognise that fast frequency response services available from inverter connected plant can be seen to be effectively equivalent to inertia support.

6. How the Proposed Rule Change Contributes to the National Electricity Objective

The National Electricity Objective (NEO) as stated in the National Electricity Law (NEL) is:

"to promote efficient investment in, and efficient operation and use of, electricity services for the long term interests of consumers of electricity with respect to:

- *price, quality, safety and reliability and security of supply of electricity*
- *the reliability, safety and security of the national electricity system."*

The proposed change to clause **4.3.1** seeks to ensure that the NEM's power system security is continually improved, which is in the long term interests of electricity consumers regarding both supply of electricity and the national electricity system as a whole.

Mandating governor control, as detailed within clause **S5.2.5.11**, contributes to the NEO through improvement in the price, reliability and security of the supply of electricity, as well as the reliability, safety and security of the national electricity system. It will assist in the provision of necessary dynamic response (clause 4.3.1 (k)), reducing the magnitude of frequency deviations which promotes efficient operation and use of network assets for the long term interests of consumers. Additionally, clauses **3.15.6A, 4.9.4 and S5.2.5.14** are updated to align with the changes of **S5.2.5.11,** improving the dynamic response of the system.

The proposed changes to clauses **5.20B.5** and **10** contribute to the NEO by promoting efficient investment in and use of electricity services with respect to reliability and security of the supply of electricity. These contributions are achieved by highlighting the ability of inverter-connected plant in providing inertia support activities.

7. Impacts to Existing Market Participants

Large deviations in frequency can produce additional wear and tear on generating units, which existing market participants can potentially be exposed to owing to reduced frequency control [1]. Primary control actions are currently implemented at the bounds of the Normal Operating Frequency Band (NOFB), which increases the likelihood of frequency not being held around its nominal value. Maintaining the power system frequency close to 50 Hz ensures that all the control systems within the power system have a reference for their control. This is undesirable as it can lead to unnecessary loss of load which has a direct economic impact whilst exposing the power system to greater risk. The rule change seeks to improve frequency control which would be beneficial to existing market participants regarding wear and tear, safety, security and reliability. Improvements in system security and reliability which could be realised would be greatly beneficial to all market participants and consumers.

As the provision of primary frequency control is proposed to be mandated, market participants could be affected owing to reduced FCAS payments. However, broader benefits potentially exist for market participants and consumers through implementation of the rule changes, in combination with reform of the causer pays system. The causer pays system, as it is currently operated, is relatively opaque in nature which, contrary to the NEO, can discourage efficient investment in electricity services. Difficulties exist for generators to limit their exposure to these charges as the calculation[6] requires access to information that is only accessible to the centralised dispatch system (NEMDE). As the causer pays methodology is not specifically defined in the NER, this necessary reform would need to take place independently of the rule changes detailed in this rule change request.

Returning to the 25th August 2018 example where power system security has declined, the economic impact of the outworking of FCAS market design appears to be as follows:

a) The Heywood interconnector tripped unnecessarily resulting in loss of revenue for surplus generation available in South Australia, (and made load shedding more likely for New South Wales, Victoria and Tasmania, and placed the overall system at greater risk).

[6] How the calculation is carried out is unclear to many market participants despite several publications explaining the methodology. No generation or scheduled load participant is able to estimate their liability for FCAS charges.

b) Load shedding occurred in New South Wales, Tasmania and Victoria which included both industrial and some suburban loads – better governor frequency control is likely to have made this unnecessary.

Queensland was placed in a situation of high risk because its frequency went high, and only a reduction of generation arrested the rise in power system frequency. A greater power surplus or further lack of generator responsiveness to frequency changes could have resulted in a state-wide blackout, which would have had significant consequences for market participants, consumers and the overall economy, alike.

Acknowledgements

The proponent thanks and expresses his sincere gratitude to all those who have in some way contributed to the preparation of this rule change request. Insights from across the profession have provided depth in knowledge and know-how that have been invaluable in addressing the fundamental objectives of the NEO.

The proponent thanks the following individuals for their significant contributions:

- Dr Lasantha Meegahapola SMIEEE
- Professor Xinghuo Yu FIEEE FIET FACS FAICD FIEAust CPEng EngExec NER APEC Engineer IntPE(Aus)
- Mr Jack Bryant GradIEAust
- Mr Bruce Miller
- Ms Kate Summers FIEAust
- Dr Mahdi Jalili MIEAust CPEng
- Mr Ryan Ghanbari.

References

[1] DIgSILENT Pacific, 'Review of frequency control performance in the NEM under normal operating conditions', Tech. rep. (2017).

[2] AEMO, 'Final report – Queensland and South Australia system separation on 25 August 2018', Tech. rep. (2019).

[3] AEMC, 'Final report: frequency control frameworks review', Tech. rep. (2018).

[4] A. Finkel, 'The independent review into the future security of the national electricity market: blueprint for the future, Commonwealth of Australia 2017, available at: https://www.energy.gov.au/sites/default/files/independent-review-future-nem-blueprint-for-the-future-2017.pdf

[5] AEMO, 'Market data NEMWEB', n.d., available at: http://www.nemweb.com.au/

[6] J. Bryant, P. Sokolowski, L. Meegahapola, 'Impact of FCAS market rules on Australia's power system stability', in: 2019 IEEE 20th International Conference on Industrial Technology.

[7] Engineers Australia, 'Frequency control frameworks review', Tech. rep., (2018).

[8] CIGRE, 'Ancillary services: An overview of international practices', Tech. rep., CIGRE (2010).

Appendix A – Proposed Amendments to NER Clauses

The following NER clauses are proposed to be changed as shown in the mark-ups below.

3.15.6A Ancillary service transactions

(5) a *Registered Participant* which has classified a *scheduled generating unit*, *scheduled load*, *ancillary service generating unit* or *ancillary service load* (called a **Scheduled Participant**) will not be assessed as contributing to the deviation in the *frequency* of the *power system* if within a *dispatch interval*:

(i) the Scheduled Participant achieves its *dispatch* target at a uniform rate <u>(subject to modification of the *active power* by the *local frequency* in accordance with the agreed generator governor droop characteristic (including provision for control deadbands));</u>

(ii) the Scheduled Participant is *enabled* to provide a *market ancillary service* and responds to a control signal from *AEMO* to *AEMO's* satisfaction; or

(iii) the Scheduled Participant is not *enabled* to provide a *market ancillary service*, but responds to a need for *regulation services* in a way which tends to reduce the aggregate deviation;

4.3.1 Responsibility of AEMO for power system security

The *AEMO power system security responsibilities* are:

(a) to maintain <u>and improve</u> *power system security*;

(b) to monitor the operating status of the power system;

(c) to co-ordinate the *System Operators* in undertaking certain of its activities and operations and monitoring activities of the *power system;*

(d) to ensure that *high voltage* switching procedures and arrangements are utilised by *Network Service Providers* to provide adequate protection of the *power system;*

(e) to assess potential infringement of the *technical envelope* or *power system operating procedures* which could affect the security of the *power system;*

(f) to ensure that the *power system* is operated within the limits of the *technical envelope*;

(g) to ensure that all *plant* and equipment under its control or co-ordination is operated within the appropriate operational or emergency limits which are advised to *AEMO* by the respective *Network Service Providers* or *Registered Participants;*

(h) to assess the impacts of technical and any operational *plant* on the operation of the *power system*;

(i) to arrange the *dispatch* of *scheduling generating units, semi-scheduled generating units*, *scheduled loads*, *scheduled network services* and *ancillary services* (including *dispatch* by remote control actions or specific directions) in accordance with the *Rules*, allowing for the dynamic nature of the *technical envelope*;

(j) to determine any potential *constraint* on the *dispatch* of *generating units, loads, market network services* and *ancillary services* and to assess the effect of this *constraint* in the maintenance of *power system security*;

(k) to assess the availability and adequacy, including the dynamic response, of *contingency capacity reserves* and *reactive power reserves* in accordance with the *power system security standards* and to ensure that appropriate levels of *contingency capacity reserves* and *reactive power reserves* are available:

 (1) to ensure the *power system* is, and is maintained, in a *satisfactory operating state;* and

 (2) to arrest the impacts of a range of significant multiple *contingency events* (affecting up to 60% of the total *power system load*) or *protected events* to allow a prompt restoration or recovery of *power system security*, taking into account under-*frequency* initiated *load shedding* capability provided under *connection agreements*, by *emergency frequency control schemes* or otherwise;

(l) to monitor demand and *generation* capacity in accordance with the *reliability standard implementation guidelines* and, if necessary, initiate action in relation to *relevant AEMO intervention event;*

(m) to publish as appropriate, information about the potential for, or the occurrence of, a situation which could significantly impact, or is significantly impacting, on *power system security*, and advise of any *low reserve* condition for the relevant periods determined in accordance with the *reliability standard implementation guidelines*;

(n) to refer to *Registered Participants*, as AEMO deems appropriate, information of which *AEMO* becomes aware in relation to significant risks to the *power system* where actions to achieve a resolution of those risks are outside the responsibility or control of *AEMO*;

(o) to utilise resources and services provided or procured as *ancillary services*, *system strength services* or *inertia network services* or otherwise to maintain or restore the *satisfactory operating state* of the *power system*;

(p) to procure adequate *system restart ancillary services* in accordance with clause 3.11.9 to enable *AEMO* to co-ordinate a response to a *major supply disruption*;

(1) to coordinate the provision of *emergency frequency control schemes* by *Network Service Providers* and to determine the settings and intended sequence of response by those schemes;

(2) to determine the boundaries of *inertia sub-networks* and the *inertia requirements* for each *inertia sub-network* and to *enable inertia network services;*

(3) to determine the *system strength requirements* for each *region* and to *enable system strength services;*

(q) to interrupt, subject to clause 4.3.2.1(1), *Registered Participant connections* as necessary during emergency situations to facilitate the re-establishment of the *satisfactory operating state* of the *power system*;

(r) to issue a *direction* or *clause 4.89 instruction* (as necessary) to any *Registered Participant;*

(s) to co-ordinate and direct any rotation of widespread interruption of demand in the event of a major *supply* shortfall or disruption;

(t) to liaise with *participating jurisdictions* should there be a need to manage an extensive disruption, including the use of emergency services powers in a *participating jurisdiction;*

(u) to determine the extent to which the levels of *contingency capacity reserves* and *reactive power reserves* are or were appropriate through appropriate testing, auditing and simulation studies;

(v) to investigate and review all major *power system* operational incidents and to initiate action plans to manage any abnormal situations or significant deficiencies which could reasonably threaten *power system security*. Such situations or deficiencies include without limitation:

(1) *power system frequencies* outside those specified in the definition of *satisfactory operating state;*

(2) *power system voltages* outside those specified in the definition of *satisfactory operating state*;

(3) actual or potential *power system* instability; and

(4) unplanned/unexpected operation of major *power system* equipment; and

(w) to ensure that each *System Operator* satisfactorily interacts with *AEMO*, other *System Operators* and *Distribution System Operators* for both *transmission* and *distribution network* activities and operations, so that *power system security* is not jeopardised by operations on the *connected transmission networks* and *distribution networks*.

4.9.4 Dispatch related limitations on Scheduled Generators and Semi-Scheduled Generators

A *Scheduled Generator* or *Semi-Scheduled Generator* (as the case may be) must not, unless in the *Generator's* reasonable opinion, public safety would otherwise be threatened or there would be a material risk of damaging equipment or the environment:

(a) send out any *energy* from the *generating unit*, except:

(1) in accordance with a *dispatch instruction;*

(2) in response to remote control signals given by AEMO or its agent;

(3) in connection with a test conducted in accordance with the requirements of this Chapter or Chapter 5; or

(4) in the case of a *scheduled or semi-scheduled generating unit;*

i. in accordance with the *self-commitment* procedures specified in clause 4.9.6 up to the *self-dispatch level;* or

ii. as a consequence of operation of the *generating unit's* automatic *frequency response mode* to local *power system frequency* conditions;

Note

This clause is classified as a civil penalty provision under the National Electricity (South Australia) Regulations. (See clause 6(1) and Schedule 1 of the National Electricity (South Australia) Regulations.)

(b) adjust the *transformer tap position* or *excitation control system voltage* set-point of a *scheduled generating unit* or *semi-scheduled generating unit* except:

(1) in accordance with a *dispatch instruction;*

(2) in response to remote control signals given by *AEMO* or its agent;

(3) if, in the *Generator's* reasonable opinion, the adjustment is urgently required to prevent material damage to the *Generator's plant* or associate equipment, or in the interests of safety; or

(4) in connection with a test conducted in accordance with the requirements of rule 5.7;

Note

This clause is classified as a civil penalty provision under the National Electricity (South Australia) Regulations. (See clause 6(1) and Schedule 1 of the National Electricity (South Australia) Regulations.)

(c) *energise* a *connection point* in relation to a *generating unit* without obtaining approval from *AEMO* immediately prior to *energisation*;

Note

This clause is classified as a civil penalty provision under the National Electricity (South Australia) Regulations. (See clause 6(1) and Schedule 1 of the National Electricity (South Australia) Regulations.)

(d) *synchronise* or *de-synchronise* a *scheduled generating unit* with a *nameplate rating* of 30 MW or more, without prior approval from *AEMO* or other than in response to a *dispatch instruction* except;

(1) *de-synchronisation* as a consequence of the operation of automatic protection equipment; or

(2) where such action is urgently required to prevent material damage to *plant* or equipment or in the interests of safety;

Note

This clause is classified as a civil penalty provision under the National Electricity (South Australia) Regulations. (See clause 6(1) and Schedule 1 of the National Electricity (South Australia) Regulations.)

(e) change the *frequency response mode* of a *scheduled generating unit* without the prior approval of *AEMO*; or

Note

This clause is classified as a civil penalty provision under the National Electricity (South Australia) Regulations. (See clause 6(1) and Schedule 1 of the National Electricity (South Australia) Regulations.)

(f) remove from service or interfere with the operation of any *power system* stabilising equipment installed on that *generating unit*.

Note

This clause is classified as a civil penalty provision under the National Electricity (South Australia) Regulations. (See clause 6(1) and Schedule 1 of the National Electricity (South Australia) Regulations.)

5.20B.5 Inertia support activities

(g) *AEMO* may at the request of an *Inertia Service Provider* approved activities (*inertia support activities*) under this clause and agree corresponding adjustments to the *minimum threshold level of inertia* or the *secure operating level of inertia* for the purposes of clause 5.20B.4(b) where the activities:

(1) are to the undertaken by the *Inertia Service Provider* or provided as a service to the *Inertia Service Provider*;

(2) are not *inertia network services*; and

(3) *AEMO* is satisfied the activities will contribute to the operation of the *inertia sub-network* in a *satisfactory operating state* or *secure operating state* in the circumstances described in clause 4.4.4(a) or (b) as applicable.

Note

If approved by *AEMO* under paragraph (a), inertia support activities may include installing or contracting for the provision of *frequency* control services, installing emergency protection schemes or contracting with *Generators* in relation to the operation of their *generating units* in specified conditions, including fast frequency response from inverter-connected plant.

S5.2.5.11 Frequency control

(a) For the purpose of this clause S5.2.5.11:

droop means, in relation to *frequency response mode*, the percentage in *power system frequency* as measured at the *connection point*, divided by the percentage change in *power transfer* of the *generating system* expressed as a percentage of the maximum operating level of the *generating system*. Droop must be measured at *frequencies* that are outside the deadband and within the limits of *power transfer*.

maximum operating level means in relation to:

a. a *non-scheduled generating unit*, the maximum *sent out generation* consistent with its *nameplate rating;*

b. a *scheduled generating units* or *semi-scheduled generating unit*, the maximum *generation* to which it may be *dispatched* and as provided to *AEMO* in the most recent *bid and offer validation data;*

c. a *non-scheduled generating system*, the combined maximum *sent out generation* consistent with the *nameplate ratings* of its in-service *generating units*; and

d. a *scheduled generating system* or *semi-scheduled generating system,* the combined maximum *generating* to which its in-service *generating units* may be *dispatched* and as provided to *AEMO* in the most recent *bid and offer validation data.*

minimum operating level means in relation to:

(1) a *non-scheduled generating unit*, its minimum *sent out generation* for continuous stable operation;

(2) a *scheduled generating unit* or *semi-scheduled generating unit*, its minimum *sent out generation* for continuous stable operation;

(3) a *non-scheduled generating system* the combined *minimum operating level* of its in-service *generating units*; and

(4) a *scheduled generating system* or *semi-scheduled generating system,* the combined minimum *sent out generation* of its in-service *generating units.*

Automatic access standard

(b) The *automatic access standard* is:

(1) a *generating system's power transfer* to the *power system* must not:

i. increase in response to a rise in the *frequency* of the *power system* as measured at the *connection point*; or

ii. decrease in response to a fall in the *frequency* of the *power system* as measured at the *connection point*; and

(2) a *generating system* must be capable of operating in *frequency response mode* such that it automatically provides a proportional:

i. decrease in *power transfer* to the *power system* in response to a rise in the *frequency* of the *power system* as measured at the *connection point*; and

ii. increase in *power transfer* to the *power system* in response to a fall in the *frequency* of the *power system* as measured at the *connection point*,

sufficiently rapidly and sustained for a sufficient period for the *Generator* to be in a position to offer measurable amounts of all *market ancillary services* for the provision of *power system frequency* control.

Minimum access standard

(c) The *minimum access standard* is:

(1) for a *generating system* under relatively stable input energy, *power transfer* to the *power system* must not:

i. increase in response to a rise in the *frequency* of the *power system* as measured at the *connection point*; and

ii. decrease more than 2% per Hz in response to a fall in the *frequency* of the *power system* as measured at the *connection point*; and

(2) a *generating system* must be capable of operating in *frequency response mode* such that, subject to energy source availability, it automatically provides:

i. a decrease in *power transfer* to the *power system* in response to a rise in the *frequency* of the *power system* as measured at the *connection point*; or

ii. an increase in *power transfer* to the *power system* in response to a fall in the *frequency* of the *power system* as measured at the *connection point*,

where the change in *active power* is either proportional or otherwise as agreed with *AEMO* and the *Network Service Provider*.

[Deleted]

(d) **[Deleted]**

(e) **[Deleted]**

(f) **[Deleted]**

Mandatory requirements

(g) Each *synchronous generating unit* must have enabled and responsive speed *governor systems* with deadbands no greater than 50 mHz (to avoid doubt +25 mHz to – 25 mHz) providing primary frequency control and maintaining nominal rotational speed of the *generating unit* in steady state conditions and contribute to system response for *contingency events*.

(h) *Asynchronous generating systems* must have enabled frequency droop control with deadbands no greater than 50 mHz (to avoid doubt +25 mHz to – 25 mHz) providing frequency response in steady state conditions and contribute to the system response for *contingency events*.

General requirements

~~(g)~~(i) Each *control system* used to satisfy this clause S5.2.5.11 must be *adequately damped*.

~~(h)~~(j) The amount of a relevant *market ancillary service* for which the *plant* may be registered must not exceed the amount that would be consistent with the *performance standard* registered in respect of this requirement.

~~(i)~~(k) For the purposes of subparagraph (b)(2), and with respect to a *negotiated access standard* proposed for the technical requirements relevant to this clause S5.2.5.11:

(1) the change in *power transfer* to the *power system* must occur with no delay beyond that required for stable operation, or inherent in the *plant* controls, once the

frequency of the *power system* as measured at the *connection point* leaves a deadband around 50 Hz;

(2) a *generating system* must be capable of setting the deadband and droop within the following ranges:

(i) the deadband referred to in subparagraph (1) must be set within the range of 0 to ± 1.0 Hz. Different deadband settings may be applied for a rise or fall in the *frequency* of the *power system* as measured at the *connection point*; and

(ii) the droop must be set within the range of 2% to 10%, or such other settings as agreed with the *Network Service Provider* and *AEMO*;

(3) nothing in subparagraph (b)(2) is taken to require a *generating system* to operate below its minimum operating level in response to a rise in the *frequency* of the *power system* as measured at the *connection point*, or above its maximum operating level in response to a fall in the *frequency* of the *power system* as measured at the *connection point*;

(4) a *generating system* is required to operate in *frequency response mode* only when it is enabled for the provision of a relevant *market ancillary service*; and

(5) the *performance standards* must record:

(i) agreed values for maximum operating level and minimum operating level, and where relevant the method of determining the values, and the values for a *generating system* must take into account its in-service *generating units*; and

(ii) for the purpose of subparagraph (b)(2), or a *negotiated access standard* offering measureable amounts of *market ancillary services* under this clause S5.2.5.11, the *market ancillary services*, including the performance parameters and requirements that apply to each such *market ancillary service*.

S5.2.5.14 Active power control

(a) The automatic access standard is a generating system must have an active power control system capable of:

(1) for a scheduled generating unit or a scheduled generating system:

(i) maintaining and changing its active power output subject to *local frequency* in accordance with its dispatch instructions;

(ii) changing ~~ramping~~ its active power output subject to *local frequency* ~~linearly~~ from one level of dispatch to another; and

(iii) receiving and automatically responding to signals delivered from the automatic generation control system, as updated at a rate of once every 4 seconds (or such other period specified by AEMO as required);

(2) subject to energy source availability, for a non-scheduled generating unit or non-scheduled generating system:

(i) automatically reducing or increasing its active power output subject to *local frequency* within 5 minutes, at a constant rate, to or below the level specified in an instruction electronically issued by a control centre, subject to subparagraph (iii);

(ii) automatically limiting its active power output subject to *local frequency*, to below the level specified in subparagraph (i); and

(iii) not changing its active power output within 5 minutes by more than the raise and lower amounts specified in an instruction electronically issued by a control centre; and

(3) subject to energy source availability, for a semi-scheduled generating unit or a semi-scheduled generating system:

(i) automatically reducing or increasing its active power output subject to *local frequency* within 5 minutes at a constant rate, to or below the level specified in an instruction electronically issued by a control centre;

(ii) automatically limiting its active power output subject to *local frequency*, to or below the level specified in subparagraph (i);

(iii) not changing its active power output within 5 minutes by more than the raise and lower amounts specified in an instruction electronically issued by a control centre;

(iv) changing ~~ramping~~ its active power output subject to *local frequency* ~~linearly~~ from one level of dispatch to another; and

(v) receiving and automatically responding to signals delivered from the automatic generation control system, as updated at a rate of once every 4 seconds (or such other period specified by AEMO as required).

Minimum access standard

(b) The minimum access standard is a generating system must have an active power control system capable of:

(1) for a scheduled generating unit or a scheduled generating system:

(i) maintaining and changing its active power output [subject to *local frequency*] in accordance with its dispatch instructions; and

(ii) receiving and automatically responding to signals delivered from the automatic generation control system, as updated at a rate of once every four seconds (or such other period specified by AEMO as required);

(2) for a non-scheduled generating system:

(i) reducing its active power output [subject to *local frequency*], within 5 minutes, to or below the level required to manage network flows that is specified in a verbal instruction issued by the control centre;

(ii) limiting its active power output [subject to *local frequency*], to or below the level specified in subparagraph (i); and

(iii) subject to energy source availability, ensuring that the change of active power output in a 5 minute period does not exceed a value agreed with AEMO and the Network Service Provider; and

(3) subject to energy source availability, for a semi-scheduled generating unit or a semi-scheduled generating system:

(i) maintaining and changing its active power output [subject to *local frequency*] in accordance with its dispatch instructions;

(ii) not changing its active power output within five minutes by more than the rise and lower amounts specified in an instruction electronically issued by a control centre; and

(iii) receiving and automatically responding to signals delivered from the automatic generation control system, as updated at a rate of once every 4 seconds (or such other period specified by AEMO as required).

Negotiated access standard

(c) A negotiated access standard may provide that if the number or frequency of verbal instructions becomes difficult for a control centre to manage, AEMO may require the Generator to upgrade its facilities to receive electronic instructions and fully implement them within 5 minutes.

(d) The negotiated access standard must document to AEMO's satisfaction any operational arrangements necessary to manage network flows that may include a requirement for the generating system to be operated in a manner that prevents its output changing within 5 minutes by more than an amount specified by a control centre.

(e) **[Deleted]**

General requirements

(f) Each control system used to satisfy the requirements of paragraphs (a) and (b) must be adequately damped.

(g) Each control system used to satisfy the requirements of paragraphs (a) and (b) must be frequency sensitive and must not respond to oppose the *local frequency*.

10. Glossary

Inertia

Contribution to the capability of the *power system* to ~~resist~~ oppose changes in *frequency* by means of an inertial response from a *generating unit*, *network element* or other equipment that is ~~electro-magnetically~~ coupled with the *power system* and *synchronised* to the *frequency* of the *power system*.