AEMC

RULE CHANGE

Australian Energy Market Commission

OPTIONS PAPER

National Electricity Amendment (Generator ramp rates and dispatch inflexibility in bidding) Rule 2014

Rule Proponent

Australian Energy Regulator

18 December 2014

Inquiries

Australian Energy Market Commission
PO Box A2449
Sydney South NSW 1235

E: aemc@aemc.gov.au
T: (02) 8296 7800
F: (02) 8296 7899

Reference: ERC0165

Citation

AEMC 2014, Generator ramp rates and dispatch inflexibility in bidding, Options Paper, 18 December 2014, Sydney

About the AEMC

The AEMC reports to the Council of Australian Governments (COAG) through the COAG Energy Council. We have two functions. We make and amend the national electricity, gas and energy retail rules and conduct independent reviews for the COAG Energy Council.

Executive summary

This paper seeks stakeholders' comments on a number of options being considered by the Australian Energy Market Commission (AEMC or Commission) in response to the generator ramp rates and dispatch inflexibility in bidding rule change request. These options have been developed in light of issues raised by stakeholders regarding the practical implementation of the more preferable draft rule made in the Commission's draft determination.

The more preferable draft rule

The more preferable draft rule was made following the Commission's assessment of a rule change proposed by the Australian Energy Regulator (AER), which would require that ramp rates reflect the maximum technical capabilities of generating plant. The AER raised concerns that, at times, generators use ramp rates to achieve commercial outcomes that can lead to inefficiencies in the wholesale market and in the management of system security.

In the draft determination, the Commission explained that it was not convinced that a change as extensive as that proposed by the AER would be warranted, and set out its concerns that the proposed rule might be difficult to apply in practice. However, in examining and consulting on the rule change request, the Commission concluded that potential changes to the existing provisions governing ramp rates may support more competitive market outcomes.

The current requirements for ramp rates, under which all generators with a capacity greater than 100 MW are required to provide ramp rates of at least 3 MW/minute, mean that the burden of system ramp rate capability is disproportionately borne by smaller and non-aggregated generators. The Commission's more preferable draft rule therefore sought to refine the current arrangements to address this issue.

The more preferable draft rule required that ramp rates should be at least one per cent of maximum capacity per minute. Such revised requirements would be applied consistently and proportionately, regardless of generator size, plant configuration or technology type, and would promote improved wholesale market outcomes by allowing AEMO to more efficiently manage the secure operation of the electricity system.

Submissions to the draft rule determination

On the whole, submissions to the draft determination were supportive of the Commission's more preferable draft rule in principle. However, some stakeholders provided evidence that compliance with the more preferable draft rule might not be practicable for some participants, particularly certain large thermal generating units. A number of stakeholders also suggested that the more preferable draft rule might lead to disproportionate or perverse outcomes in the specific case of aggregated units, as a ramp rate requirement of one per cent of the maximum capacity of the aggregated unit may not be achievable unless sufficient physical units are online at the time.

In light of these concerns, the Commission has developed two further options that would address the issues raised in submissions to the draft determination, while still better meeting the Commission's objectives for ramp rate requirements that can be applied more consistently and proportionately than the current rules. Requirements that meet these principles would be in the long term interests of consumers by allowing for the enhanced optimisation of the dispatch process and reducing, albeit marginally, the extent to which the regulatory framework might influence investment decisions.

The Commission will assess these options alongside the proposed rule and the more preferable draft rule, and against the possibility of not making a rule, which is always an option open to the Commission.

Options for consideration

The two new options presented in this paper for stakeholder comment are as follows:

- **Option 1** would require minimum ramp rates to be equal to the lower of one per cent of maximum capacity or 3 MW per minute. For aggregated units, the requirement would be the lower of 3 MW/minute applied to individual physical units or one per cent of aggregate available capacity.[1]

- **Option 2** would retain the current arrangements of minimum ramp rates equal to the lower of three per cent of maximum capacity or 3 MW per minute. For aggregated units, the requirement would apply to each individual physical unit.

Option 1 refines the more preferable draft rule, including through the introduction of a capping mechanism. The changes aim to address the issues raised in submissions in relation to large thermal generating units and aggregated units, while still allowing for arrangements that would contribute to the achievement of the objectives for more consistent and proportionate requirements.

Option 2 is based on the existing arrangements, but would increase the consistency and proportionality in the application of the current rule by applying the minimum ramp rate requirements equally to aggregated and non-aggregated generators. This approach has been supported by a number of stakeholders through the rule change process.

The Commission welcomes stakeholder comments on these options. Submissions are requested by **5 February 2015**.

1 Available capacity is defined in the National Electricity Rules as the total MW capacity available for dispatch by a scheduled generating unit, semi-scheduled generating unit or scheduled load.

Summary of proposed ramp rate requirements for generators

<table>
<tr><th></th><th>Current rule</th><th>More preferable draft rule</th><th>Option 1</th><th>Option 2</th></tr>
<tr><td>Non aggregated</td><td rowspan="2">Lower of three per cent of maximum capacity or 3 MW per minute, rounded down but no less than 1 MW/minute</td><td rowspan="2">One per cent of maximum capacity, expressed as MW/minute, rounded up</td><td>Lower of one per cent of maximum capacity or 3 MW per minute, rounded up</td><td>Lower of three per cent of maximum capacity or 3 MW per minute, rounded down but no less than 1 MW/minute</td></tr>
<tr><td>Aggregated</td><td>Lower of 3 MW per minute applied to individual physical units or one per cent of aggregate available capacity, rounded up</td><td>Lower of three per cent of maximum capacity or 3 MW per minute, rounded down but no less than 1 MW/minute, applied to individual physical units, then summed</td></tr>
</table>

Contents

1 Introduction 1

1.1 The rule change request 1

1.2 The draft determination 1

1.3 This options paper 2

1.4 Timeframes and next steps 2

1.5 Process for making a submission 2

1.6 Structure of this consultation paper 2

2 Rule change process to date 4

2.1 Background 4

2.2 Rationale for the rule change request 4

2.3 Solution proposed in the rule change request 5

2.4 The draft rule determination 5

2.5 Submissions 9

3 Options for consideration 14

3.1 Overview of the options 14

3.2 Option 1 15

3.3 Option 2 19

3.4 Comparison of impacts on regional ramp rate capabilities 22

Abbreviations 25

A Draft rule - Option one 26

B Draft rule - Option two 29

1 Introduction

1.1 The rule change request

On 21 August 2013, the Australian Energy Regulator (AER) submitted a rule change request to the Australian Energy Market Commission (AEMC or Commission) proposing a requirement that ramp rates and dispatch inflexibility profiles for generators in the National Electricity Market (NEM) should reflect their technical capabilities.

Ramp rates and dispatch inflexibility profiles are specified by generators as a component of their offers and govern the manner in which the generation output from power stations can be physically changed through time.

The rule change request is intended to address purported inefficiencies resulting from the incentives generators have to change their ramp rates to low levels at times when the capacity of the transmission network is constrained. The AER proposes this can be achieved by requiring generators to at all times specify the maximum technical ramp rate that their generating plant can safely achieve.

1.2 The draft determination

On 28 August 2014, the Commission made a draft determination to make a more preferable draft rule following its consideration of the AER's rule change request. Its decision to make a more preferable draft rule, as opposed to the proposed rule, reflected its view that a change as extensive as that proposed would not be warranted, and its concerns that there might be difficulty in applying the rule in practice.

However, in examining and consulting on the rule change request, the Commission identified that the burden of system ramp rate capability is disproportionately borne by smaller generators and non-aggregated generators. The Commission's more preferable draft rule therefore sought to refine the current arrangements to address these issues, and thereby support more competitive market outcomes.

The Commission's more preferable draft rule required that ramp rates provided by scheduled and semi-scheduled generators should be at least one per cent of maximum generation capacity per minute. Such revised requirements would be applied consistently and proportionately, regardless of generator size, plant configuration or technology type.

The Commission considers that the more preferable draft rule would promote more efficient wholesale market outcomes, while allowing the Australian Energy Market Operator (AEMO) to maintain the secure operation of the electricity system. Further, the Commission considers that rules that are applied consistently and proportionately to generators should ensure that the regulatory framework does not inadvertently influence investment decisions in favour of larger or aggregated units.

1.3 This options paper

The Commission received 14 submissions in response to the draft rule determination. Submissions were generally supportive of the Commission's more preferable draft rule in principle. However, some stakeholders provided evidence that compliance with the more preferable draft rule may not be practicable for specific generators. In light of these concerns, the Commission has instead developed two further options that would address the issues raised in submissions to the draft determination and meet the Commission's objectives for ramp rate requirements that can be applied more consistently and proportionately than the current rules.

The purpose of this consultation paper is to present these options, and to seek stakeholder comment on them. This will assist the Commission in determining the best way to address the issues that this rule change has identified and ensure that any changes to the existing frameworks will contribute to the achievement of the National Electricity Objective (NEO).

The Commission also notes that the potential to make no rule remains an option for consideration.

1.4 Timeframes and next steps

The Commission invites submissions on this options paper by 5 February 2015.

After considering submissions in response to this options paper, as well as submissions received in response to the draft rule determination, the Commission will make a final rule determination. The Commission intends to publish the final rule determination on 19 March 2015.

1.5 Process for making a submission

Submissions should quote project number "ERC0165" and may be lodged online via the Commission's website, www.aemc.gov.au, or by mail to:

Australian Energy Market Commission
PO Box A2449
Sydney South NSW 1235

All enquiries on this project should be addressed to Sebastien Henry on (02) 8296 7800.

1.6 Structure of this consultation paper

The remainder of this options paper is structured as follows:

- chapter 2 discusses the process to date, including the Commission's assessment framework, the more preferable draft rule and submissions received in response to this; and

- chapter 3 presents the options that the Commission is currently considering, and provides some commentary on these options with reference to the assessment framework and implementation issues.

2 Rule change process to date

2.1 Background

Clause 3.8.3A of the National Electricity Rules (NER) currently requires all market participants with generating units, scheduled network services and/or scheduled loads that provide ramp rates to AEMO to specify an up ramp rate and a down ramp rate for each 30-minute trading interval. Ramp rates can be changed (rebid) at any time during a trading interval with effect from the next 5-minute dispatch interval.

Market participants must specify a ramp rate that is at least three megawatts per minute (MW/minute), or the lower of 3 MW/minute and three per cent of maximum capacity for generators. In effect therefore, the three per cent requirement applies to generators with a capacity of less than 100 MW. Participants may provide a ramp rate lower than these minimum requirements if an event or other occurrence physically prevents such a ramp rate from being attained or makes it unsafe to operate in that manner.[2]

2.2 Rationale for the rule change request

The physical power system comprises a network of transmission lines that convey electricity from generating plant to customer load centres. The capacity ratings of these lines place limits on the transmission of electricity and may impact the extent to which electricity can be sourced from generators with the lowest offers. As such, generators have uncertain access to the market, in terms of their ability to be dispatched and receive the regional energy price. There is currently no mechanism that allows generators to hedge this risk. Instead, generators may attempt to reduce the risk of being constrained by varying their offers.

The AER's rule change request seeks to reduce the ability of generators to pursue commercial objectives at times of network congestion through the rebidding of ramp rates. In particular, the AER is seeking to address instances where generators that are likely to be constrained off may rebid to reduce their ramp rates to limit the extent to which their existing output levels can be decreased.

The AER considers that generator rebidding at times of network constraints has become increasingly prevalent and that the previous change made to the NER in 2009 which introduced the current requirements has not been sufficient to address market inefficiencies.[3] The AER suggests that the use of ramp rates and dispatch inflexibility profiles to achieve commercial objectives can be harmful both in terms of inefficient market outcomes and the ability for AEMO to manage system security in an economically optimal fashion.

---

2 Clause 3.8.3A(c) of the NER.

3 AEMC, *Ramp rates, market ancillary service offers, and dispatch inflexibility – final determination*, 15 January 2009.

2.3 Solution proposed in the rule change request

Through its rule change request, the AER is seeking to place a greater restriction on generator ramp rates and dispatch inflexibility profiles by requiring generators to always submit parameters that reflect the maximum technical operating capability of the plant at that time.

The ramp rate provided to AEMO would be the maximum the generator can safely attain. If, closer to the time of dispatch, a generator submits a ramp rate that is materially different from its previous technical maximum, then it would be required to accompany the rebid with a brief, verifiable, and specific reason relating to the relevant technical limitation on their generating plant.

The rule change would apply to all market participants required to submit ramp rates to AEMO, including scheduled and semi-scheduled generators, scheduled network services and scheduled loads.

2.4 The draft rule determination

The Commission published its draft rule determination on 28 August 2014. In its draft determination, the Commission determined to make a more preferable draft rule. This more preferable draft rule would require that ramp rates provided to AEMO be at least one per cent of capacity per minute,[4] rounded up to the nearest whole number expressed as MW/minute.

2.4.1 The Commission's concerns with the proposed rule

In the draft determination, the Commission explained that it was not convinced that a change as extensive as that proposed by the AER would be warranted, and set out its concerns that the proposed rule might be difficult to apply in practice. However, in examining and consulting on the rule change request, the Commission concluded that potential changes to the existing provisions governing ramp rates may support more competitive market outcomes.

The Commission recognises that the presence of network congestion can, at times, create a commercial incentive for generators to rebid their ramp rates to low levels, which could potentially compromise the ability of AEMO to efficiently manage system security. The Commission therefore considers that the rules should require participants to provide a minimum level of ramp rate capability at all times. However, information provided to the Commission by AEMO indicates that it would be unnecessary to require generators to offer ramp rates equal to the maximum technical capability of generating plant solely for system security reasons.

4 Either maximum generation, load or power transfer capacity, as applicable. This information is provided by participants to AEMO in accordance with the requirements of schedule 3.1 of the NER.

In its rule change request, the AER also raised concerns regarding other potential inefficient market outcomes, including the occurrence of counter-price flows between regions, productive efficiency losses from high cost plant being dispatched in place of low cost plant, and higher risk management costs for market participants due to higher wholesale price volatility. While agreeing that it would be desirable to minimise any such inefficiencies, the Commission notes that, there has been no compelling evidence produced to date that suggests that the costs to the market are likely to be material in the context of the NEM as a whole and, in most cases, ramp rates represent only one contributing factor.

To seek to resolve these issues by requiring generators to always offer the maximum technical capability of their plant risks creating a disincentive to invest in flexible plant, as generators that are able to provide greater ramp rate capability would be disproportionately impacted. Over time, this may affect commercial investment decisions regarding the flexibility of plant, potentially resulting in inefficient price outcomes that would not be in the long term interests of consumers.

The Commission is also of the view that a trade-off exists between the level of ramp rate capability offered and the costs incurred in doing so. The Commission has concerns that this would make it problematic for the AER to determine whether ramp rates submitted by generators represent a true reflection of the technical capability of their generating units at any given time.

2.4.2 Concerns with existing arrangements

In examining and consulting on the rule change request, the Commission identified that the burden of system ramp rate capability is not applied consistently and proportionately to all generating units.

The Commission considers that commercial incentives are, and should be, the key driver for generators investing in, and maintaining, ramping capability. Flexible generating plant can best respond to price changes that signal alterations in the value the market places on the provision of energy. In this way, the commercial incentives acting on generators are aligned with the interests of consumers. However, the presence of network congestion can, at times, result in a misalignment of these interests, and a commercial incentive can be created for generators to rebid their ramp rates to low levels. This may compromise the ability of AEMO to efficiently manage the security of the electricity system.

The rules therefore require generators to provide a minimum level of ramping capability. However, under the existing arrangements, the burden of system ramp rate capability is not applied consistently for all generating units.

The Commission has identified the following inconsistencies:

- A fixed requirement of 3 MW/minute for all generators above 100 MW means that the minimum required ramp rate as a proportion of plant capacity reduces as the capacity of the unit increases.

- Generating units that are aggregated for the purposes of the market dispatch process have a minimum ramp rate requirement of 3 MW/minute for all generating units combined, despite there being no difference in the ramping capability of these units compared to individually registered units.

  For example, a generating plant with 3 units of 200 MW each would have a combined minimum ramp rate requirement of 3 x 3 MW/minute = 9 MW/minute, whereas a decision to aggregate the 3 units would reduce the minimum ramp rate requirement to 3 MW/minute for all 3 units combined.

- A separate rule exists for generators with capacity less than 100 MW.

The Commission considers that system ramp rate capability is therefore disproportionately borne by smaller generators and non-aggregated generators.

By requiring certain generators to provide a disproportionately higher level of ramp rate capability, the Commission considers that the current rules have the potential to:

- inhibit AEMO's ability to optimise the dispatch process such that the production of electricity occurs at the lowest cost realistically possible; and
- impact investment decisions at the margin on the size of units and levels of aggregation.

The Commission therefore considers that there is potential to improve the current rules such that the provision of the minimum required level of ramp rate capability by market participants is applied on a more consistent and proportional basis.

2.4.3 Assessment framework

Having identified the inconsistencies in the current arrangements set out above, the Commission developed and applied a framework to assess whether it could identify a more preferable draft rule which it considered would contribute to the achievement of the NEO.[5]

The NEO states:[6]

> "The objective of this Law 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:
>
> (a) price, quality, safety, reliability and security of supply of electricity; and

5 Under section 91A of the NEL, the Commission can make a rule that is different from the proposed rule if it is satisfied that, having regard to the relevant issues in the rule change request, the more preferable rule will or is likely to better to contribute to the NEO.

6 See section 7 of the NEL.

(b) the reliability, safety and security of the national electricity system."

The assessment framework developed by the Commission is based on the relevant aspects of the NEO, which the Commission considers to be the efficient operation of electricity services and efficient investment in electricity services.

The Commission considers that, where feasible, the use of competitive markets provides the best means of promoting efficiency. This approach is most effective where the commercial incentives acting on market participants are aligned with the long term interests of consumers.

The need for minimum ramp rate requirements is reflective of the fact that, under the current market design, incentives may not always be aligned in this way. However, the Commission considers that the impact on commercial incentives of such regulatory requirements can be minimised if they are:

- applied consistently for all market participants;
- distributed proportionately such that the burden of system ramp rate capability is shared across all market participants and not borne by generating units of a particular size or technology;
- easily determined, unambiguous, and not subject to significant variation; and
- able to be applied easily in practice to minimise compliance costs.

Requirements that can be applied consistently and proportionately in line with these principles will allow for:

- the optimisation of the dispatch process, such that the production of electricity occurs at a lower cost; and
- investment in new generation which is not unduly influenced by arbitrary factors, such that forecast demand is able to be met over time through lower cost available options.

The Commission also intends to use this framework to assess the options set out in chapter 3 of this paper.

2.4.4 The more preferable draft rule

In light of the concerns identified with the existing arrangements, the Commission determined to make a more preferable draft rule that it considered better met the principles set out in the assessment framework above. This more preferable draft rule would amend clause 3.8.3A(b)(1) to require that any ramp rate provided to AEMO should be at least one per cent of maximum capacity on a MW/minute basis, rounded up to the nearest whole number.

The Commission considered that the more preferable draft rule had a number of advantages over the current arrangements:

- The requirements of the draft rule would apply uniformly across all market participants. The current arrangements apply a separate form of the rules to generators with capacity less than 100 MW. The draft rule would remove this inconsistency in the rules that treats participants differently based on an arbitrarily determined benchmark level of capacity.

- For generators with capacity greater than 100 MW, the current arrangements apply a fixed minimum ramp rate requirement of 3 MW/minute which places a greater relative proportion of the burden on smaller generating units. The Commission's draft would apply the same ramp rate requirements as a percentage of capacity to all participants and would thereby distribute the burden of system ramp rate capability more evenly.

- Minimum required ramp rates under the draft rule would be based on unit size alone and would not be arbitrarily influenced by the number of generating units or whether or not generating units have been aggregated. The Commission considers there to be no basis on which minimum ramp rates should be determined by the number of generating units or levels of aggregation. The draft rule would base minimum requirements on unit size and would ensure that aggregated and non-aggregated generators are treated on the same basis.

Aligning minimum ramp rate requirements with the size of plant would reduce, albeit marginally, the extent to which the regulatory framework might influence investment decisions. This would contribute to the achievement of the NEO by resulting in lower cost options to meet forecast demand, in the long term interests of consumers.

Further, the minimum required ramp rate would be a constant not subject to variation, thereby minimising compliance costs. The Commission considers that this would be preferable to the AER's proposed rule which would require ramp rates to be continuously updated to reflect the maximum technical capability of the plant at any given time.

The more preferable draft rule would provide certainty to generators and plant operators and would minimise the risk of enforcement issues. It would also minimise regulatory risk by providing investors with certainty in relation to the minimum required capability of generating plant, thereby reducing the potential costs of investment.

2.5 Submissions

The Commission received 14 submissions in response to the draft rule determination. Submissions were generally supportive of the Commission's more preferable draft rule in principle, but highlighted some specific concerns with its application in practice.

2.5.1 Support for the more preferable draft rule

GDF Suez considered that the more preferable draft rule would provide a reasonable compromise between ensuring sufficient ramping capability to maintain system security, without imposing unnecessarily onerous compliance obligations on generators. In addition, GDF Suez agreed that the more preferable draft rule would address the problem of imposing relatively high ramp rate obligations on small (less than 100 MW) units.[7]

EnergyAustralia agreed that the more preferable draft rule would more appropriately address the commercial aspects of generator ramp rates than the proposed rule, and that it would more fairly distribute the requirement to provide ramping capability to the market.[8]

Infigen suggested that the more preferable draft rule would further contribute to the achievement of the NEO through the requirement of a consistent and proportional level of ramp rate bidding regardless of generator size and plant configuration. This would deliver more efficient wholesale market outcomes and ensure that the regulatory framework does not unduly influence investment decisions towards one technology type or size over others.[9]

Origin Energy agreed, in principle, with the approach of the AEMC to be technology neutral in applying the more preferable draft rule,[10] and Snowy Hydro supported the principles underpinning the more preferable draft rule.[11]

2.5.2 Issues with aggregated units

Notwithstanding their in-principle support for the more preferable draft rule, a number of stakeholders suggested that its practical application might lead to disproportionate or perverse outcomes in the particular case of aggregated units.

GDF Suez noted that the capability for aggregated units to ramp up and down is a function of how many physical units are on line at the time, and that a ramp rate requirement of one per cent of the maximum capacity of the aggregated unit may not be achievable unless sufficient physical units are online. To overcome this issue, it suggested that the minimum ramp rate obligation be made equal to one per cent of the maximum capacity of the physical units that are on line at any point in time.[12]

Snowy Hydro provided examples in support of the argument that requiring aggregated units to provide ramp rates based on aggregate maximum capacity would

7 GDF Suez, Submission to the Draft Determination, p. 1.

8 EnergyAustralia, Submission to the Draft Determination, p. 1.

9 Infigen, Submission to the Draft Determination, p. 1.

10 Origin Energy, Submission to the Draft Determination, p. 3.

11 Snowy Hydro, Submission to the Draft Determination, p. 2.

12 GDF Suez, Submission to the Draft Determination, p. 2.

be disproportionate, drawing the analogy that when an individually registered unit is shut down or not on line there would be no ramping requirement. Snowy Hydro proposed that, for aggregate units, the minimum required ramping capability should be based on the maximum capacity of the physical units which are online and synchronised. It suggested that market data is available which would allow the AER to verify and monitor compliance with such a requirement.[13]

Origin Energy and AEMO also both suggested that the maximum capacity used to calculate ramp rate requirements for aggregated units should reflect the number of units in service,[14] with AEMO highlighting that it holds data on the number of units in service and would be able to make this available to the AER if required.

2.5.3 Issues with large thermal units

A further specific issue raised by stakeholders related to the ability of some large thermal generating units to comply with the more preferable draft rule on a consistent basis.

AGL stated that, under the more preferable draft rule, some of its large generating plant (in particular, the Bayswater and Liddell power stations) would be unable to sustain the required ramp rates without incurring a substantial increase in operations and maintenance costs, or risking plant availability. Maintenance issues that would be likely to eventuate include:[15]

- increased boiler tube leaks due to increased thermal stress caused by boiler over firing during higher ramp up conditions;
- increased risk of unit trips in both ramp up and ramp down modes;
- increased failure rates of high pressure and low pressure heaters with a flow on impact to unit efficiency and a faster deterioration in operating life; and
- increased requirements for intra-day mill grind outs, which would often occur at inconvenient times.

AGL further suggested that other thermal generators in the NEM would be likely to encounter similar issues in attempting to comply with the requirements of the draft rule.[16]

Similarly, EnergyAustralia highlighted the example of the Mt. Piper power station, which would have a minimum ramp rate requirement of 7 MW/minute under the draft rule. EnergyAustralia suggested that the station does not always have the ability

13 Snowy Hydro, Submission to the Draft Determination, pp. 2-3.

14 Origin Energy, Submission to the Draft Determination, p. 2; AEMO, Submission to the Draft Determination, p. 3.

15 AGL, Submission to the Draft Determination, pp. 1-2.

16 AGL, Submission to the Draft Determination, p. 2.

to ramp at 7 MW/minute, as ramp capacity is affected by coal quality, mill changes, generation level, and other physical constraints.[17]

CS Energy contended that the requirements of the draft rule may be excessive and that Kogan Creek power station, in particular, would not be able to attain a ramp rate of 7-8 MW/minute at higher generation levels, as the unit was not designed with the intention of fast ramping.[18] Origin Energy also suggested that the more preferable draft rule failed to recognise operational requirements for mill movements and plant impacts from increasing the thermal stress on units, with resulting increases in wear and tear costs and reductions in asset life.[19]

Both GDF Suez and Stanwell noted that the more preferable draft rule would provide relatively high ramping obligations on large generating units that could be difficult or costly for some units to meet,[20] and Hydro Tasmania raised concerns that the more preferable draft rule would lead to several permanent derogations for large machines which could not achieve the required ramp rates.[21]

2.5.4 The Commission's view

The feedback provided by stakeholders supports the Commission's view that there is merit in making a rule to address the issues discussed by the Commission in its draft determination. However, submissions have highlighted some challenges in relation to the implementation of the more preferable draft rule, particularly its impacts on some large thermal plant.

The Commission notes that the rules currently allow participants to provide a ramp rate lower than their minimum requirement if an event or other occurrence physically prevents such a ramp rate from being attained or makes it unsafe to operate in that manner.[22] However, the issues raised in regard of large thermal plant would not necessarily physically prevent them from attaining the requirements of the draft rule in the short-term, nor make it unsafe to do so; rather, consistently offering ramp rates at the required level on an ongoing basis would increase costs, with the potential to decrease efficiency over the longer term.

The Commission has considered whether it would be possible to amend the rules to allow for the requirements on affected large thermal units to be reduced on a case-by-case basis. However, given its view that a trade-off exists between the level of ramp rate capability offered and the costs incurred in doing so, the Commission has concluded that it would be difficult to formulate a mechanism that could allow for the

---

17 EnergyAustralia, Submission to the Draft Determination, p. 1.

18 CS Energy, Submission to the Draft Determination, p. 3-4.

19 Origin Energy, Submission to the Draft Determination, p. 4.

20 GDF Suez, Submission to the Draft Determination, p. 1; Stanwell, Submission to the Draft Determination, p. 3.

21 Hydro Tasmania, Submission to the Draft Determination, p. 2.

22 See clause 3.8.3A(c).

objective differentiation of cases where efficiency concerns did and did not exist, and for the determination of a specific minimum ramp rate in each instance where a lower requirement was deemed appropriate.

This conclusion reflects the Commission's earlier concerns that, under the proposed rule, it would be problematic for the AER to assess whether ramp rates submitted by generators represented a true reflection of the technical capability of their generating units at any given time. This view that generator ramp rates contain elements of both technical and commercial considerations was supported in submissions.[23]

In light of this conclusion, the Commission has sought to identify and develop practical options that would address the issues raised in submissions with the implementation of the Commission's more preferable draft rule, while still being likely to contribute to the NEO by meeting the Commission's objectives for ramp rate requirements that can be applied more consistently and proportionately than the current rules. These options are discussed in the next chapter.

Having identified the potential for improvements to be made to the current rules, it would seem preferable to consider options that can at least offer partial solutions to address the existing inefficiencies. However, the Commission's experience in developing potential solutions is that it is difficult to design requirements that are more proportionate without dramatically increasing the requirements for some participants or, alternatively, materially reducing the overall level of ramping capability that must be provided. Given these issues, the potential to make no rule therefore also remains an option for consideration.

23 Origin Energy, Submission to the Draft Determination, p. 1; Snowy Hydro, Submission to the Draft Determination, p. 1; Stanwell, Submission to the Draft Determination, p. 1.

3 Options for consideration

This chapter sets out the two further options that the Commission is currently considering, including a description of the design of each option and a discussion of the extent to which each option would meet the Commission's objectives and therefore the NEO. The chapter also presents a comparative analysis of the effect of each option on aggregate regional ramping capability (i.e. the change in the total minimum ramp rates for a region arising from each of the options).

3.1 Overview of the options

Option 1

Under Option 1, minimum ramp rate requirements would be as follows:

- for scheduled generating units, scheduled network services and scheduled loads, the lower of one per cent of maximum capacity or 3 MW per minute; and
- for scheduled generating units, scheduled network services and scheduled loads that are aggregated, the lower of 3 MW/minute applied to individual physical units or one per cent of aggregate available capacity.

All requirements would be expressed as MW per minute rounded up to the nearest whole number.

Option 2

Under Option 2, minimum ramp rate requirements would be as follows:

- for scheduled generating units, the lower of three per cent of maximum capacity or 3 MW per minute;
- for scheduled generating units that are aggregated, the lower of three per cent of maximum capacity or 3 MW per minute applied to individual physical units, then summed;
- for scheduled network services and scheduled loads, 3 MW/minute; and
- for scheduled network services and scheduled loads that are aggregated, 3 MW/minute applied to individual network services and individual loads, then summed.

All requirements would be expressed as MW/minute rounded down to the nearest whole number, but not less than one.[24]

24 For aggregated generating units, the rounding would occur for each individual physical unit.

Table 3.1 provides an example of how the minimum ramp rate requirements would be determined under both options in comparison to the current rules and the more preferable draft rule. The following sections describe the two options in further detail.

Table 3.1 Example of minimum ramp rate requirements

Example of a facility with 3 units of 60 MW each	Current rules	More preferable draft rule	Option 1	Option 2
If 3 units are not aggregated	3% of 60 MW rounded down x 3 units = **3** MW/minute	1% of 60 MW rounded up x 3 units = **3** MW/minute	1% of 60 MW rounded up x 3 units = **3** MW/minute	3% of 60 MW rounded down x 3 units = **3** MW/minute
If 3 units are aggregated	**3** MW/minute	1% of (3 x 60 MW) rounded up = **2** MW/minute	Lower of: 3 units x 3 MW/minute = 9 MW/minute 1% of max. availability, rounded up = **2** MW/minute[25]	3% of 60 MW rounded down x 3 units = **3** MW/minute

3.2 Option 1

3.2.1 Design of Option 1

Option 1 is similar to the more preferable draft rule with two key changes:

1. Capping the minimum ramp rate requirements for each individual generating unit at 3 MW/minute.
2. Adjusting the minimum ramp rate requirement for aggregated facilities according to an approximation of the number of individual physical units that are online at any given time.

Capping the minimum ramp rate requirements for each individual generating unit

For scheduled generating units, scheduled network services, and scheduled loads, instead of minimum ramp rate requirements being equal to one per cent of maximum

25 Assumes full availability of the aggregated facility.

capacity as under the more preferable draft rule, Option 1 would require minimum ramp rates to be equal to the lower of one per cent of maximum capacity or 3 MW per minute.

This would essentially place a cap on the minimum ramp rate requirements for any scheduled generating unit, scheduled network service or scheduled load of 3 MW/minute. For example, instead of a 600 MW generating unit having a minimum ramp rate requirement of 6 MW/minute under the more preferable draft rule (one per cent of maximum capacity), Option 1 would limit the minimum requirement to 3 MW/minute, consistent with the current requirements.

This should address concerns raised in response to the draft determination that the minimum required ramp rates under the draft rule would have been too high for a number of large thermal generating units to achieve without incurring considerable operational and maintenance costs, or investing in upgrades to plant and equipment. The Commission notes that a variation of this approach was supported by GDF Suez in its submission in response to the draft determination.[26]

Determining the minimum ramp rate requirement for aggregated facilities

For scheduled generating units, scheduled network services, and scheduled loads that are aggregated, the minimum requirements would be the lower of 3 MW/minute applied to each individual physical unit or one per cent of aggregate available capacity.

The application of minimum ramp rate levels to individual physical units may result in an increase to the minimum ramp rate requirements for very large aggregated facilities. This would address the distortion that currently exists, bringing the requirements for aggregated units to levels broadly commensurate with those for individually registered units.

In addition, the minimum ramp rate requirements at aggregated facilities would be adjusted by their level of available capacity, which would address the concerns that some stakeholders raised that the draft rule would impose disproportionately high minimum ramp rate requirements when a number of individual physical units were unavailable. The Commission considers this to be consistent with the treatment of non-aggregated generators in the NEM that effectively have a zero minimum ramp rate requirement when they are declared unavailable.

Use of maximum availability for aggregated facilities

The Commission has considered whether it would be possible to design Option 1 such that minimum ramp rate requirements would be based on the number and capacity of the individual physical units that are generating at any point in time. This would provide for minimum ramp rate requirements to more accurately reflect the change in physical capability of the aggregated unit when a number of individual physical units are not online.

26 GDF Suez, Submission to the Draft Determination, p. 2.

However, clause 3.8.3A of the NER requires that ramp rates are submitted to AEMO as part of a generator's offers or rebids, or as part of its notification of available capacity prior to dispatch. Given that the number of individual physical units generating is an outcome of the dispatch process, aggregated generators would be unable in practice to know their minimum ramp rate requirements at the time of submitting their offers.

As a consequence, the Commission has sought to use an alternative measure that is knowable ahead of time to determine the online status of individual physical units. One possibility considered was requiring aggregated generators to notify AEMO of the availability of their individual physical units through their market offers. However, it was concluded that this would place undue administrative burden on aggregated generators and would undermine the purpose of aggregating generators such that separate market offers do not need to be made for individual physical units and can be managed by the generators independent of AEMO's dispatch processes.

Option 1 therefore uses the maximum availability of the aggregated generator as notified to AEMO as a means of identifying the minimum ramp rate requirements ahead of time. Generators are required to submit their maximum availability as part of their offers for the aggregated generating unit. At the same time, an aggregated generator would be able to determine its minimum required ramp rate as the lower of 3 MW/minute for each individual physical unit or one per cent of total maximum availability.

The Commission recognises that the maximum availability of an aggregated generator does not precisely reflect the number of individual physical units that are available. However, the Commission considers that for practical purposes, the use of maximum availability is a measure that would sufficiently approximate the relative reduction in capability of an aggregated generator that would arise through a decrease in the number of individual physical units online.

Rounding requirements

Option 1 would require that all minimum ramp rate requirements be rounded up to the nearest whole number, as in the more preferable draft rule. In the draft rule determination, the Commission explained that there is a significant number of smaller capacity generators in the NEM and that rounding down (as in the current rules) would result in their contribution to minimum system ramp rate capability being materially diminished on aggregate. In addition, it was considered that generators with capacity less than 50 MW should provide a minimum ramp rate capability of at least 1 MW/minute.

3.2.2 Assessment of Option 1

Option 1 has been developed by the Commission as an alternative to the more preferable draft rule. Option 1 varies the more preferable draft rule such that the arrangements can be implemented in practice, while still contributing to the achievement of the objectives set out in the draft determination. This section applies this framework formed by these objectives to minimise the impact on the commercial incentives that drive ramp rate capability to discuss the merits of adopting Option 1.

Consistency and proportionality

Similar to the current arrangements, Option 1 would apply different arrangements to generators according to the capacity of the generating unit. Specifically:

- generating units with a capacity less than 300 MW would have a minimum ramp rate of one per cent of capacity (rounded up to the nearest whole number expressed as MW/minute); and
- units with a capacity greater than 300 MW would have a minimum ramp rate capped at 3 MW/minute.

A benefit of the Commission's more preferable draft rule was that it would apply the same ramp rate requirements as a percentage of capacity to all participants. This would distribute the burden of system ramp rate capability uniformly across all participants and would remove the inconsistency in the current rules that treats participants differently based on an arbitrarily determined benchmark level of capacity.

However, a completely even distribution across all participants of minimum required ramp rates based on capacity appears problematic to implement due to the undue costs that would be imposed on some large thermal generators. Option 1 would result in a decrease in the ramping capability being provided by some units in comparison to the more preferable draft rule. A fixed requirement of 3 MW/minute for all generating units above 300 MW means that the minimum required ramp rate as a proportion of plant capacity would reduce as the capacity of the unit increases.

Option 1 would, therefore, maintain a certain level of inconsistency, similar to that in the current rules. However, as the benchmark level of capacity would be set at 300 MW rather than 100 MW, Option 1 would represent an improvement over the existing arrangements as the inconsistent treatment would be applied to fewer generating units in the NEM. Option 1 would increase the number of generating units that are required to provide a minimum ramp rate that is proportionate to their capacity.

A further benefit of Option 1 is that it would apply minimum ramp rate requirements to individual physical units that make up aggregated generators. Consistent with the intent of the more preferable draft rule, the Commission considers that the rules should be applied consistently to generators irrespective of their levels of aggregation.

Under Option 1, aggregated generators would be treated slightly differently to non-aggregated generators, through the use of the maximum availability measure to determine minimum ramp rate requirements. However, the Commission considers that this is likely to be a necessary inconsistency in order to ensure that aggregated generators are not disproportionately burdened with high minimum ramp rate requirements when a number of individual physical units are not available.

Optimisation of the dispatch process

While Option 1 would result in a small decrease in total minimum ramp rate capability in comparison to the more preferable draft rule, the Commission has undertaken analysis that shows that this decrease would, to some extent, be offset by an increase in ramp rate capability associated with extending the minimum requirements to individual physical units that make up aggregated facilities.[27]

The Commission considers that Option 1 is consistent with the expected benefits provided by the more preferable draft rule in terms of addressing the risk that disproportionately high minimum ramp rates for smaller generators and current low minimum requirements for some aggregated generators has the potential to inhibit AEMO's ability to optimise the dispatch process such that the production of electricity occurs at the lowest cost.

Effect on investment in new generation technology

The Commission's more preferable draft rule applied the same minimum ramp rate requirements as a percentage of capacity to all participants and as such would have reduced to the extent to which investment decisions would be influenced by the size of generating units or levels of aggregation, rather than based purely on commercial and economic factors.

Holding all other factors constant, Option 1 would still result in units above 300 MW receiving relatively lower minimum ramp rate requirements as a proportion of total capacity, and therefore has the potential to influence investment decisions around the size of generating units, albeit that this may only have a marginal effect. Nevertheless, Option 1 would represent an improvement over the current arrangements where the inconsistency is applied to all capacities above 100 MW and would therefore be likely to better contribute to the achievement of the NEO.

3.3 Option 2

3.3.1 Design of Option 2

Option 2 is similar to the current arrangements with one key change. As with Option 1, minimum required ramp rates for aggregated facilities would be determined according to the number of individual physical units. For scheduled generating units that are aggregated, the minimum requirements would be the lower of 3 MW/minute or three per cent of maximum capacity applied to each individual physical unit. For scheduled network services and scheduled loads that are aggregated, the minimum requirements would be 3 MW/minute applied to each individual network service or individual load.

Option 2 is therefore essentially the same as the current rules, with the exception that the minimum requirements would also apply to each individual physical unit that

27 See section 3.4.

make up aggregated facilities. The Commission notes that this approach has been supported by a number of stakeholders through this rule change request process.[28]

As discussed for Option 1, the application of minimum ramp rate levels to individual physical units would result in an increase to the minimum ramp rate requirements for larger aggregated facilities, thereby bringing the requirements for aggregated units to a level more commensurate with those for individually registered units.

For example, under the current rules a generating plant with 3 individually registered units of 200 MW each would have a combined minimum ramp rate requirement of 3 x 3 MW/minute = 9 MW/minute, whereas the minimum ramp rate requirement on the basis that the units are aggregated would be only 3 MW/minute for all 3 units combined. Option 2 would increase the minimum ramp rate requirement of the aggregated generator to 9 MW/minute, consistent with the treatment of individually registered units.

However, in contrast to Option 1, Option 2 would not vary minimum ramp rate requirements according to the level of availability of the aggregated facility. It is not possible to include a mechanism that uses maximum availability as a measure to approximate the relative reduction in capability of an aggregated facility in the same way as for Option 1. Applying a three per cent requirement to maximum availability would, in many instances, provide a minimum ramp rate requirement that is significantly higher than the 3 MW/minute requirement per physical unit. A substantial reduction in maximum available capacity would therefore be required in order to result in a minimum ramp rate requirement that more accurately reflects the change in physical capability of the aggregated unit when a number of individual physical units are unavailable.

Under Option 2, the current minimum ramp rate requirements would be retained for non-aggregated facilities. As such, this should address concerns raised by stakeholders in response to the draft determination that minimum required ramp rates under the more preferable draft rule may be too high for some large thermal generating units.

Rounding requirements

In contrast to Option 1, Option 2 would require that all minimum ramp rate requirements be rounded down to the nearest whole number but not less than 1 MW/minute. As Option 2 is only changing the minimum ramp rate requirements for aggregated facilities, the Commission does not consider it appropriate or necessary to change the existing rounding arrangements for non-aggregated facilities.

28 AGL, Submission to the Draft Determination, p. 3; EnergyAustralia, Submission to the Draft Determination, p. 2; Origin Energy, Submission to the Draft Determination, p. 5.

3.3.2 Assessment of Option 2

Option 2 retains most elements of the current arrangements but applies changes to the treatment of aggregated generators that would contribute to achieving the objectives set out in the draft determination.

Consistency and proportionality

By largely retaining the current arrangements, Option 2 would not distribute the burden of system ramp rate capability as proportionately as the more preferable draft rule, or indeed Option 1. Option 2 does not ultimately address the problem that the current rules set minimum ramp rates with reference to a fixed parameter, and that minimum required ramp rates do not vary with unit size.

In addition, Option 2 retains the inconsistency in the current arrangements that sees a separate form of the rules applied to generators with capacity less than 100 MW.

However, Option 2 would increase the consistency and proportionality in the application of the rule in comparison to the current arrangements by applying the minimum ramp rate requirements equally to aggregated and non-aggregated generators. By effectively applying minimum ramp rate requirements to individual physical units that make up aggregated generators, the burden of system ramp rate capability would no longer be disproportionately borne by non-aggregated generators.

Optimisation of the dispatch process

A benefit of Option 2 is that it can only result in a net increase in the minimum ramp rate capability available to the market. While minimum ramp rate requirements for non-aggregated generators would remain the same as under the current arrangements, the minimum requirements for aggregated generators would increase.

Given this additional level of minimum ramp rate capability, the adoption of Option 2 would therefore extend the set of feasible dispatch solutions, and so is likely to improve the efficiency of dispatch outcomes.

Effect on investment in new generation technology

The Commission considers that the decision to aggregate or disaggregate units should not be influenced by minimum ramp rate requirements. Option 2 would establish minimum ramp rates that were consistent across aggregated and disaggregated units, and therefore would remove favourable minimum ramp rate requirements from the decision of whether or not to aggregate units.

However, the Commission notes that when investing in new generation plant, the decision of whether to aggregate a set of units is likely to be a relatively minor consideration. Any resultant increase in dynamic efficiency from the application of revised rules might therefore be relatively marginal.

Option 2 would also not address the bias that currently exists towards allocating minimum ramping requirements to smaller units. Beyond 100 MW, any additional unit capacity will not attract a higher minimum ramp rate. Holding all else equal, this option would result in the persistence of the current, albeit marginal, incentive for generators to invest in larger units, and so reduce their proportionate ramp rate requirements.

3.4 Comparison of impacts on regional ramp rate capabilities

This section sets out a comparison of the impacts on regional ramp rate capabilities under each option. Tables 3.1 sets out the aggregate regional ramp rate capability that would arise under Options 1 and 2 compared to the status quo. Aggregate regional ramp rate capabilities for each region under the more preferable draft rule are also provided.

Table 3.1 Change in aggregate ramp rate capability for each region[29]

Aggregate ramp rate capability (MW/min)										
Jurisdiction	Current rules	More preferable draft rule	Difference from current rules		Option 1	Difference from current rules		Option 2	Difference from current rules	
NSW	91	124	33	36%	101	10	11%	129	38	42%
QLD	124	129	5	4%	114	-10	-8%	133	9	7%
SA	61	57	-4	-7%	56	-5	-8%	80	19	31%
TAS	51	40	-11	-22%	37	-14	-27%	67	16	31%
VIC	94	114	20	21%	98	4	4%	140	46	49%

In the draft determination, the Commission noted that the more preferable draft rule would see a small reduction in minimum required ramp rates in South Australia and Tasmania.

Consistent with the Commission's findings, AEMO noted in its submission that the more preferable draft rule had the potential to reduce the available ramp rate capability in South Australia in some specific circumstances, including:[30]

- a potential disruption of supply should the Heywood interconnector trip at a time of high wind generation; and
- synchronous hot water switching at 23:30 each day, which requires a high ramp rate to maintain power system security.

AEMO noted that, in these circumstances, the need to direct participants is more likely under the draft rule than the current arrangements.

The estimated reduction in minimum required ramp rates in South Australia and Tasmania was also consistent with analysis undertaken by the AER.[31] In its

29 Assumes all generating units are available to provide minimum ramp rate requirements consistent with their capabilities. Assumes a zero contribution from wind farms.

30 AEMO, Submission to the Draft Determination, p. 2.

submission, the AER suggested that the more preferable draft rule would appear to reduce the market's operational envelope and could foreseeably result in an increase in price volatility and the opportunity to manipulate outcomes by withdrawing ramp rate capability.

While the Commission acknowledges that system ramp rate capability may be limited in the specific circumstances noted by AEMO, the Commission considers that in both cases the issues would be caused by a lack of ramp up capability which would also be likely to coincide with a high market price. The Commission's more preferable draft rule, and Options 1 and 2 discussed in this paper, do not place any limits on maximum ramp up capability and, as such, the Commission would expect the market price to create the necessary commercial incentive for generators to provide greater ramp rate capability to the market at these times.

In the case of Tasmania, the Commission notes the submission from Hydro Tasmania which suggests that there would be no system security issues in Tasmania even with a lower minimum ramp rate requirement than that proposed under the more preferable draft rule.[32]

Effect of Option 1

Compared to the current rules, Option 1 would see an increase in aggregate ramp rate capability in New South Wales and Victoria and a reduction in aggregate ramp rate capability in Queensland, South Australia and Tasmania. The increase in aggregate ramp rate capability in New South Wales and Victoria is due to higher minimum ramp rates from aggregated generators exceeding the reduced minimum ramp rates from generators less than 300 MW but greater than 100 MW. These generators would have a minimum ramp rate requirement equal to one per cent of capacity under Option 1 compared to a fixed requirement of 3 MW/minute under the current arrangements.

In the remaining regions, while the minimum ramp rate requirements for a number of aggregated generators would increase, this would be more than offset by an overall reduction in minimum ramp rate requirements by the number of units that are less than 300 MW. The differences in South Australia and Tasmania are similar to the Commission's more preferable draft rule and would appear to represent relatively minor reductions in aggregate ramp rate capability. With regard to Queensland, the reduction in aggregate ramp rate capability would also appear to be relatively minor in the context of the high overall level of existing ramp rate capability in that region.

Effect of Option 2

Under Option 2, there would be an increase in aggregate ramp rate requirements in all regions of the NEM. While minimum ramp rate requirements for non-aggregated generators would remain the same as under the current arrangements, the minimum requirements for aggregated generators would increase. The large number of

31 AER, Submission to the Draft Determination, pp. 3-9.

32 Hydro Tasmania, Submission to the Draft Determination, p. 2.

aggregated generators in New South Wales and Victoria would result in substantially higher aggregate ramp rate capability in these regions.

Abbreviations

AEMC	Australian Energy Market Commission
AEMO	Australian Energy Market Operator
AER	Australian Energy Regulator
Commission	See AEMC
NEL	National Electricity Law
NEM	National Electricity Market
NEO	National Electricity Objective
NER	National Electricity Rules

A Draft rule - Option one

Omit clause 3.8.3A(b) and substitute:

3.8.3A Ramp rates

(b) Subject to clauses 3.8.3A(c) and 3.8.3A(i), a *Scheduled Generator*, *Semi-Scheduled Generator* or *Market Participant* to which this clause 3.8.3A applies must provide an up *ramp rate* and a down *ramp rate* to *AEMO* that is:

(1) for each *generating unit*, *scheduled network service* and/or *scheduled load* that is not aggregated in accordance with clause 3.8.3, at least the lower of:

(i) 3MW/minute or 1% of the maximum *generation* in the case of a *scheduled generating unit or semi-scheduled generating unit*;

(ii) 3MW/minute or 1% of the maximum *load* in the case of a *scheduled load*; or

(iii) 3MW/minute or 1% of the maximum *power transfer capability* in the case of a *scheduled network service*;

provided in accordance with clause 3.13.3(b), expressed as MW/minute rounded up to the nearest whole number; and

(2) for each *generating unit*, *scheduled network service* and/or *scheduled load* that is aggregated in accordance with clause 3.8.3, at least:

(i) in the case of a *scheduled generating unit*, or *semi-scheduled generating unit*, the lower of:

(A) the amount equal to the product of 3MW/minute and the number of individual *generating units* (and for the avoidance of doubt clause 3.8.3 does not apply to this clause 3.8.3A(b)(2)(i)(A)); or

(B) 1% of *available capacity* as notified to *AEMO* in accordance with clause 3.8.4(c) or as varied in accordance with clause 3.8.22,

(ii) in the case of a *scheduled load*, the lower of:

(A) the amount equal to the product of 3MW/minute and the number of individual *scheduled loads* (and for the avoidance of doubt clause 3.8.3 does not apply to this clause 3.8.3A(b)(2)(ii)(A); or

(B) 1% of *available capacity* as notified to *AEMO* in accordance with clause 3.8.4(d) or as varied in accordance with clause 3.8.22,

(iii) in the case of a *scheduled network service*, the lower of:

(A) the amount equal to the product of 3MW/minute and the number of individual *scheduled network services* (and for the avoidance of doubt clause 3.8.3 does not apply to this clause 3.8.3A(b)(2)(iii)(A); or

(B) 1% of *available capacity* as notified to *AEMO* in accordance with clause 3.8.4(e) or as varied in accordance with clause 3.8.22,

expressed as MW/minute rounded up to the nearest whole number; and

(3) for each *generating unit*, *scheduled network service* and/or *scheduled load*, at most the relevant *maximum ramp rate* provided in accordance with clause 3.13.3(b).

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.)

Changes to definitions in Chapter 10

available capacity

(a) In relation to a *scheduled generating unit*, *semi-scheduled generating unit* or *scheduled load*, the total MW capacity available for *dispatch* by (i.e. maximum plant availability) or, in relation to a specified *price band*, the MW capacity within that *price band* available for *dispatch* (i.e. availability at each price band).

(b) In relation to a scheduled network service, a MW capacity profile that specifies the *power transfer capability* in each direction available by a *scheduled network service* (i.e. maximum *power transfer capability* availability) or, in relation to a specified *price band*, the *power transfer capability* in each direction available within that *price band* (i.e. availability at each price band).

scheduled generating unit

(a) A *generating unit* so classified in accordance with Chapter 2.

(b) For the purposes of Chapter 3(except clause 3.8.3A(b)(2)(i)(A)) and rule 4.9, two or more *generating units* referred to in paragraph (a) that have been aggregated in accordance with clause 3.8.3.

scheduled load

(a) A *market load* which has been classified by *AEMO* in accordance with Chapter 2 as a *scheduled load* at the *Market Customer's* request. Under Chapter 3, a *Market Customer* may submit *dispatch bids* in relation to *scheduled loads*.

(b) For the purposes of Chapter 3 (except clause 3.8.3A(b)(2)(ii)(A)) and rule 4.9, two or more *scheduled loads* referred to in paragraph (a) that have been aggregated in accordance with clause 3.8.3.

scheduled network service

(a) A *network service* which is classified as a *scheduled network service* in accordance with Chapter 2.

(b) For the purposes of Chapter 3(except clause 3.8.3A(b)(2)(iii)(A)) and rule 4.9, two or more *scheduled network services* referred to in paragraph (a) that have been aggregated in accordance with clause 3.8.3.

B Draft rule - Option two

Omit clause 3.8.3A(b) and substitute:

3.8.3A Ramp rates

(b) Subject to clauses 3.8.3A(c) and 3.8.3A(i), a *Scheduled Generator*, *Semi-Scheduled Generator* or *Market Participant* to which this clause 3.8.3A applies must provide an up *ramp rate* and a down *ramp rate* to *AEMO* for each *generating unit*, *scheduled network service* and/or *scheduled load* that is:

(1) at least:

(i) in the case of a *scheduled network service* or *scheduled load* that is not aggregated in accordance with clause 3.8.3, 3MW/minute; or

(ii) in the case of a *scheduled network service* or *scheduled load* that is aggregated in accordance with clause 3.8.3, the amount equal to the product of 3MW/minute and the number of individual *scheduled network services* or individual *scheduled loads* (and for the avoidance of doubt clause 3.8.3 does not apply to this clause 3.8.3A(b)(1)(ii); or

(iii) in the case of a *scheduled generating unit, or semi-scheduled generating unit* that is not aggregated in accordance with clause 3.8.3, the *generating unit minimum ramp rate requirement*; or

(iv) in the case of a *scheduled generating unit, or semi-scheduled generating unit* that is aggregated in accordance with clause 3.8.3, the sum of the *generating unit minimum ramp rate requirements* for each individual *generating unit* (and for the avoidance of doubt clause 3.8.3 does not apply to this clause 3.8.3A(b)(1)(iv)); and

(2) at most the relevant *maximum ramp rate* provided in accordance with clause 3.13.3(b).

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.)

New Clause 3.13.3(b1)

(b1) In addition to the information provided to *AEMO* in clause 3.13.3(b), all *Scheduled Generators*, *Semi-Scheduled Generators* and *Market Participants* which have aggregated their *scheduled loads*, *scheduled network services* and *generating units* in accordance with clause 3.8.3, must provide *AEMO* with:

(A) the maximum *generation* of each individual *scheduled generating unit, or semi-scheduled generating unit* to which the individual *scheduled generating unit, or semi-scheduled generating unit* may be dispatched;

(B) the number of individual *scheduled loads* that have been aggregated in accordance with clause 3.8.3; or

(C) the number of *scheduled network services* that have been aggregated in accordance with clause 3.8.3.

Changes to definitions in Chapter 10

scheduled generating unit

(a) A *generating unit* so classified in accordance with Chapter 2.

(b) For the purposes of Chapter 3(except clause 3.8.3A(b)(1)(iv)) and rule 4.9, two or more *generating units* referred to in paragraph (a) that have been aggregated in accordance with clause 3.8.3.

scheduled load

(a) A market load which has been classified by AEMO in accordance with Chapter 2 as a scheduled load at the Market Customer's request. Under Chapter 3, a Market Customer may submit dispatch bids in relation to scheduled loads.

(b) For the purposes of Chapter 3 (except clause 3.8.3A(b)(1)(ii)) and rule 4.9, two or more scheduled loads referred to in paragraph (a) that have been aggregated in accordance with clause 3.8.3.

scheduled network service

(a) A network service which is classified as a scheduled network service in accordance with Chapter 2.

(b) For the purposes of Chapter 3(except clause 3.8.3A(b)(1)(ii)) and rule 4.9, two or more scheduled network services referred to in paragraph (a) that have been aggregated in accordance with clause 3.8.3.

New definition in Chapter 10

generating unit minimum ramp rate requirement

(a) in relation to a *generating unit* that has not been aggregated in accordance with clause 3.8.3, the lower of 3MW/minute or 3% of the maximum generation provided in accordance with clause 3.13.3(b); or

(b) in relation to a *generating unit* that has been aggregated in accordance with clause 3.8.3, the lower of 3MW/minute or 3% of the maximum generation provided in accordance with clause 3.13.3(b1);

expressed as MW/minute rounded down to the nearest whole number except where this would result in the nearest whole number being zero, in which case the generating unit ramp requirement is 1MW/minute.