AEMC

RULE CHANGE

Australian Energy Market Commission

DRAFT RULE DETERMINATION

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

Rule Proponent

Australian Energy Regulator

28 August 2014

For and on behalf of the Australian Energy Market Commission

Inquiries

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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.

Summary of draft rule determination

The Australian Energy Market Commission (AEMC or Commission) has determined to make a more preferable draft rule to rationalise the existing requirements on scheduled and semi-scheduled generators to specify the minimum rates at which they may increase or decrease output.

This more preferable draft rule has been made following the Commission's consideration of a rule change proposed by the Australian Energy Regulator (AER), which would require that ramp rates reflect the maximum technical capability of generating plant. The AER has 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.

The Commission has not been convinced that a change as extensive as that proposed by the AER is warranted, and has concerns that the proposed rule might be difficult to apply in practice. However, in examining and consulting on the rule change request, the Commission has concluded that the existing provisions governing ramp rates risk distorting competitive market outcomes and investment signals. The Commission's more preferable draft rule refines the current arrangements to address these issues.

The Commission's more preferable draft rule would require that ramp rates provided by generators should be at least one per cent of maximum generation capacity per minute.

The revised requirements would be applied consistently and proportionately, regardless of generator size, plant configuration or technology type. This would promote more efficient wholesale market outcomes and generation investment, in the long term interests of consumers.

Commercial incentives as a driver of efficient investment

The provision of system security requires that generators provide ramping capability to the market. Ramp rates are specified by generators as a component of their offers and govern the manner in which generation dispatch levels can be physically changed through time.

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 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 the Australian Energy Market Operator (AEMO) to efficiently manage the security of the electricity system.

Therefore, under the current market design, there is a need to place a regulatory obligation on generators to provide a minimum level of ramping capability.

The Commission’s more preferable draft rule

The existing rules require that generators specify a minimum ramp rate greater than or equal to three megawatts per minute (MW/minute), or three per cent of maximum capacity for generators below 100 MW, unless there is a technical limitation on their plant.

The Commission considers that under the existing arrangements, the burden of system ramp rate capability is not applied consistently for all generating units, and is disproportionately borne by smaller generators, non-aggregated generators, and those with a larger number of generating units. The Commission considers that the number of generating units or levels of aggregation are not an appropriate basis on which to determine ramp rate capability, and 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.

The Commission’s more preferable draft rule would require that the ramp rate provided by a generator at any time is equal to at least one per cent of its maximum generation capacity per minute.

Determining minimum required ramp rates as a percentage of a generating unit’s capacity treats different technology types and power station configurations on the same basis. This would promote technology neutrality and therefore the efficient operation of electricity services when generators are required to reduce output through the market dispatch process. Such competitively neutral arrangements would promote more efficient wholesale market outcomes, while allowing AEMO to maintain the secure operation of the electricity system.

In addition, 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. Investment based purely on economic and commercial considerations should result in the least cost option to meet forecast demand, in the long term interests of consumers.

The Commission has assessed the impact of this change on the market and, based on advice receive from AEMO, is satisfied that one per cent of maximum capacity would maintain AEMO’s ability to manage the secure operation of the electricity system.

The Commission’s assessment of the AER's proposed rule

The Commission recognises the importance of the issues raised in the rule change request, but has not been convinced that a change as significant as that proposed by the AER is warranted. In particular, information provided by AEMO indicates that such an extensive increase in minimum required ramp rates is not necessary in order to efficiently manage system security.

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 due to higher wholesale price volatility. While agreeing that it would be desirable to minimise any such inefficiencies, the Commission notes that, 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 also risks creating a disincentive to invest in flexible plant, as generators that are able to provide greater ramp rate capability would be disproportionately impacted.

Finally, the Commission is concerned that the proposed rule may be difficult to apply in practice. The Commission's view is that a trade-off exists between ramp rate capability and costs incurred, and this would make it problematic for the AER to determine whether the ramp rates submitted by generators represent a true reflection of the technical capability of their generating units at any given time.

The Commission welcomes submissions on this draft determination, including its draft rule, by **9 October 2014**.

Contents

1 The Australian Energy Regulator's rule change request

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.

This 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.

The AER also notes that dispatch inflexibility profiles can be used by participants with fast-start plant to achieve commercial objectives and that this can also result in market inefficiencies.[1] The AER considers this issue can be addressed by requiring fast-start generators to submit dispatch inflexibility profiles that reflect the technical capabilities of their plant at the time.

1.2 Current arrangements

Clause 3.8.3A of the National Electricity Rules (NER) currently requires all scheduled generators, semi-scheduled generators or market participants with generating units, scheduled network services and/or scheduled loads that provide ramp rates to the Australian Energy Market Operator (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.

These participants must specify a ramp rate that is greater than or equal to three megawatts per minute (MW/minute), or three per cent of maximum capacity for generators below 100 MW, unless there is a technical limitation on their plant.

Clause 3.8.19(d) of the NER currently provides fast-start generators with the discretion to include a dispatch inflexibility profile as part of its dispatch offer. Dispatch inflexibility profiles are used by fast-start plant such as gas turbines, to inform the

1 Dispatch inflexibility profiles do not apply to slow start generating units. Slow start generating units are defined in clause 3.8.17 of the NER as units which are unable to synchronise and increase generation within 30 minutes of receiving an instruction from AEMO.

dispatch process of inflexibilities in respect of their units such as minimum start and stop times, and minimum safe operating levels.

Appendix B provides further detail on ramp rates and dispatch inflexibility profiles in the NEM.

1.3 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 network 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 and changes to dispatch inflexibility profiles. 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 or make changes to their dispatch inflexibility profiles 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 has not been sufficient to address market inefficiencies.[2] The AER maintains 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.

1.4 Solution proposed in the rule change request

The AER is seeking to place a greater restriction on the ability of generators to vary 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.

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

With respect to dispatch inflexibility profiles, the AER considers that the current rules are imprecise and that generators can change this parameter through the rebidding process for any reason, and may do so for commercial advantage. The AER is therefore seeking to require fast-start generators to submit a dispatch inflexibility profile that always reflects the technical limitations of their plant.

The AER proposes to align all of the rules related to ramp rates and dispatch inflexibility profiles to ensure they reflect the true technical characteristics of plant and cannot be manipulated for short-term commercial gain. The AER states that this would align the treatment of ramp rates and dispatch inflexibility profiles with the current treatment of other technical parameters in the NER, such as frequency control ancillary services parameters, which must reflect the technical capabilities of the plant.

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

To provide further clarity on how the proposed rule would operate in practice, and how the AER would enforce it, the AER has stated that it would amend its Rebidding and Technical Parameters Guideline.[3]

1.5 The Commission's rule making process to date

On 13 February 2014, the Commission published the AER's rule change request and a paper identifying specific issues and questions for consultation. The Commission also published a notice extending the timeframe for the publication of its draft determination to 28 August 2014. This extension of time was to allow for the analysis necessary to address the complex issues raised in the rule change request.

Submissions on this first round of consultation closed on 27 March 2014. The Commission received 16 submissions, which are available on the AEMC website.[4] A summary of the issues raised in submissions and the Commission's response to each issue is contained in **Appendix C**.

The Commission held a public forum on 5 May 2014 to provide an opportunity for stakeholders to share their views on the scope of the issues identified in the rule change request, the impact of the proposed rule, and any alternative solutions that may better address the identified problems. A copy of the presentations given at the public forum can be found on the AEMC website.

1.6 Consultation on the draft determination

The Commission invites submissions on this draft determination, including its draft rule, by **9 October 2014**.

3 The AER may amend or replace the guideline from time to time in accordance with clauses 3.8.3A(g), 3.8.19(b)(2) and 3.8.22(c)(3) of the NER.

Any person or body may request that the Commission hold a hearing in relation to the draft determination. Any request for a hearing must be made in writing and must be received by the Commission no later than **4 September 2014**.[5]

Submissions and requests for a hearing should quote project number "ERC0165" and may be lodged online at www.aemc.gov.au or by mail to:

Australian Energy Market Commission
PO Box A2449
SYDNEY SOUTH NSW 1235

4 www.aemc.gov.au

5 In accordance with section 101(1a) of the NEL. A public hearing is a formal requirement for the Commission to appear before the applicant to enable the applicant to make a presentation to the Commission.

2 Draft rule determination

The Commission has decided to make a more preferable draft rule to require that any up ramp rate and down ramp rate provided to AEMO is at least one per cent of maximum generation capacity on a MW/minute basis, rounded up to the nearest whole number.[6]

The Commission has concerns that the AER's proposed rule, to require generators to provide their maximum technical ramp rate at all times, may create a disincentive to invest in or to operate generating plant with more flexible ramp rate capability. Further, the Commission considers that, as the ramp rate capability of generating plant is not constant, the AER's proposed rule may be difficult to apply in practice and may increase the burden of compliance by requiring generators to continuously update their ramp rates to reflect the maximum technical capability of the plant at any given time. This would necessarily require the generator to make a trade-off between the level of ramp rate capability offered and the operational and maintenance costs to the plant.

This Chapter outlines:

- the Commission's rule making test for changes to the NER;
- the Commission's assessment framework for considering the rule change request; and
- a summary of the Commission's draft determination, including the reasoning for its decision.

Appendix A sets out further detail regarding the legal requirements for the making of this draft determination.

2.1 Rule making test

The Commission may only make a change to the NER if it is satisfied that the rule will, or is likely to, contribute to the achievement of the National Electricity Objective (NEO).[7]

The NEO states:[8]

> "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:

6 Maximum generation capacity refers to the maximum generation of the generating unit on a MW basis to which the generating unit may be dispatched as defined under schedule 3.1 of the NER.

7 See section 88 of the NEL.

8 See section 7 of the NEL.

(a) price, quality, safety, reliability and security of supply of electricity; and

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

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 contribute to the NEO.[9]

2.2 Assessment framework

The promotion of efficiency lies at the heart of the NEO, and the Commission considers that, where feasible, the use of competitive markets provides the best means of achieving this. This approach is most effective where the commercial incentives acting ongenerators are aligned with the long term interests of consumers.

In the NEM, prices generally signal to generators to either increase or decrease supply depending on whether this is valued by consumers, providing efficient market outcomes. However, this rule change request seeks to address concerns that the commercial incentives acting on generators in the NEM may not be aligned with the interests of consumers in all circumstances and can, on occasion, lead to outcomes which are not efficient with regard to the price or the reliability and security of supply of electricity.

For this rule change request, the Commission considers the relevant aspects of the NEO to be the efficient operation of electricity services and the efficient investment in electricity services.

The efficient operation of electricity services, or productive efficiency, can be attained when dispatch is optimised such that the production of electricity occurs at the lowest possible cost. Productive efficiency can be promoted by rewarding those generators who are able to vary output in response to changes in supply and demand at the lowest cost.

Efficient investment in electricity services, or dynamic efficiency, is promoted when productive (and allocative) efficiency occurs over time. In this context, dynamic efficiency can be achieved when generation investment results in the least cost option to meet demand over the long term.

In assessing this rule change request, the Commission has had to consider its likely effects in terms of both forms of efficiency. While the proponent has highlighted its concerns regarding productive efficiency, the Commission has to weigh this against any effects on dynamic efficiency, given the role of commercial incentives in driving efficient investment.

9 See section 91A of the NEL.

The Commission is also conscious that rules that seek to impose minimum requirements on generators in the interests of system security have the potential to diminish both productive efficiency and dynamic efficiency. Rules that are applied inconsistently may reduce productive efficiency if the dispatch process cannot be fully optimised. They may also reduce dynamic efficiency if the preferential treatment of certain types of participants impacts on investment decisions.

In consideration of maintaining the security and reliability of the electricity system, the Commission has considered the following matters in assessing whether making a change to the existing arrangements will, or is likely to, promote the NEO:

- the optimisation of the dispatch process such that the production of electricity occurs at the lowest cost;
- consistency of application in the rules such that investment decisions are not unduly influenced by arbitrary factors and are based purely on commercial and economic considerations; and
- the impact on investments in new generation technology such that forecast demand is able to be met over time through the least cost available options.

2.3 The Commission's draft rule determination

The Commission considers that commercial incentives are a key driver for the ramp rate capability of generators and that, for many generators, flexibility is necessary to provide energy to the market at times of highest value. Generators have an incentive to increase generation quickly when the spot price is high and reduce generation when the spot price falls below their operating costs. Generators may also have an incentive to maintain flexibility to support variations in their contract positions. Rules that attempt to prescribe fixed requirements on ramp rate capability have the potential to disrupt the efficient functioning of the market incentive framework.

However, 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 can compromise the ability of AEMO to efficiently manage the stability and security of the electricity system. Therefore, the Commission considers that the rules should require participants to provide a minimum level of ramp rate capability at all times, consistent with AEMO's ability to provide this system security.

The Commission considers that, while the AER's proposed rule would provide more than the required minimum level of ramp rate capability to manage the secure operation of the electricity system, it may also create a disincentive to invest in flexible plant by disproportionately impacting generators that are able to provide greater ramp rate capability. Over time, this may affect commercial investment decisions regarding the flexibility of plant, potentially resulting in inefficient price outcomes in the long term interests of consumers.

However, while not supporting the AER’s proposed rule, the Commission also has concerns in relation to the current arrangements. While the current minimum ramp rate requirements provide sufficient capability for AEMO to manage the secure operation of the electricity system, the Commission considers that the existing rules may prevent this from being achieved at the lowest cost.

The Commission considers that under the existing arrangements, the burden of system ramp rate capability is not applied consistently for all generating units, and is disproportionately borne by smaller generators, non-aggregated generators, and those with a larger number of generating units. The Commission considers that the number of generating units or level of aggregation are not an appropriate basis on which to determine ramp rate capability, and 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.

The Commission is satisfied that the more preferable draft rule to determine the minimum required ramp rate as a percentage of a generating unit’s maximum capacity will, or is likely to, contribute to the achievement of the NEO for the following reasons:

- Promoting the efficient operation of electricity services by treating different technology types and power station configurations on the same basis when generators are required to reduce output through the market dispatch process. This should promote the ability of AEMO to optimise the NEM dispatch process more efficiently, which will enhance the efficient operation of electricity services for the long term interests of consumers.

- Promoting the NER principle of technology neutrality by applying a consistent set of rules to all participants.[10] This will ensure that investment decisions are based on commercial drivers as signalled by the market, which should promote efficient outcomes in the long term interests of consumers.

Further information on the Commission's consideration of the issues raised in the rule change request and the AER's proposed rule is set out in Chapter 3. The Commission's reasons for its more preferable draft rule are provided in Chapter 4.

2.4 Strategic priority

Costs for consumers are likely to be minimised where market arrangements encourage efficient investment. This is the basis for the AEMC's third strategic priority for energy market development (the Market Priority). The strategic priorities underpin the Commission's work, helping to guide our advice to governments and our approach to rule making.

10 In this context, technology neutrality means that, to the greatest extent possible, the NER should not advantage one technology type over another. As set out in section 3.1.4(3) of the NER, one of the market design principles of the NEM includes “the avoidance of any special treatment in respect of different technologies used by market participants”.

The more preferable draft rule contributes to the Market Priority by ensuring that investment decisions made regarding the type of generation technology and aggregation of units are not influenced by the regulatory framework around the calculation of minimum ramp rates. This would ensure that, to the greatest extent possible, investors make decisions based on economic and commercial factors, which would promote the efficient operation of the market and contribute to efficient outcomes that minimise costs for consumers.

3 Issues raised in the rule change request and the AER's proposed rule

The AER has stated that there are a range of costs associated with the rebidding of ramp rates and changes to dispatch inflexibility profiles under constraint conditions to achieve commercial objectives.

The Commission notes that the nature of these costs can change depending on whether rebidding is undertaken through ramp rates and changes to dispatch inflexibility profiles, or through other forms including variations to price and volume. In the context of generator rebidding, the Commission has categorised the costs raised by the AER into those where the rebidding of ramp rates and changes to dispatch inflexibility profiles may be directly attributed and those where it may be a contributing or supporting factor but not necessarily the principal or underlying cause.

This Chapter outlines the Commission's considerations of the issues raised in the rule change request and its assessment of the AER's proposed rule.

3.1 System security and counter-price flows

This section sets out the Commission's considerations of the issues raised by the AER that, in the context of generator rebidding, may be more directly attributed to the rebidding of ramp rates and changes to dispatch inflexibility profiles, including the efficient management of system security and counter-price flows between NEM regions.

3.1.1 The AER's view

The AER considers that the ability of generators to rebid ramp rates and make changes to dispatch inflexibility profiles under constraint conditions to achieve commercial objectives may:

- compromise the ability of AEMO to determine an economically efficient dispatch arrangement while maintaining system security;[11] and
- reduce the effectiveness of interconnectors and increase network charges to consumers by causing counter-price flows between NEM regions.[12]

The AER considers that these outcomes are primarily driven by the priority afforded to ramp rates and dispatch inflexibility profiles when the optimal economic dispatch is calculated by the National Electricity Market Dispatch Engine (NEMDE).

11 AER, *Request for rule change - Requirement for ramp rates and dispatch inflexibility profiles to reflect technical capabilities*, 21 August 2013, p. 18.

12 Ibid, pp. 7-9.

In order to manage network congestion, NEMDE prioritises different technical aspects of generators and the network. Ramp rates and dispatch inflexibility profiles are considered to be the highest priority constraint types. This is because ramp rates can vary across a wide range and AEMO is not in a position to make assumptions about the capabilities of individual generators. As such, the possibility of causing damage to generating plant means that AEMO is dependent on what generators submit.

In order to determine the optimal dispatch arrangement, NEMDE must take into consideration the limitations imposed by different physical parameters of generators and the network. Some parameters are more flexible than others and NEMDE prioritises different parameters to manage network congestion.

Each physical parameter is assigned a constraint violation penalty (CVP) which represents a notional incremental cost incurred if a constraint equation that represents the parameter is violated.[13] To determine a feasible solution in a constrained condition, NEMDE allows constraint equations to be violated. NEMDE allows constraints with the lowest CVP to be violated first.

Table 3.1 shows CVPs for a number of different physical parameters. Satisfactory and secure network limits and the management of negative residues (clamping) have lower CVPs than ramp rates and dispatch inflexibility profiles. As such, a generator that rebids its ramp rates to low levels in order to maintain generation output under constraint conditions will be prioritised in the dispatch process over network limits and the management of negative residues.[14] This means that when generators rebid ramp rates to low levels or make changes to their dispatch inflexibility profiles, the effect may be to compromise the efficient management of system security or to potentially give rise to counter-price flows between NEM regions.

Table 3.1 Constraint violation penalties

	CVP
Ramp rates	1155
Dispatch inflexibility profiles	1130
Minimum and fixed loading level	380
Satisfactory network limit	360
Secure network limit	35
Negative residue management (clamping)	2

13 Ibid, p. 10.

14 AEMO uses reasonable endeavours to manage the accumulation of negative inter-regional settlement residues when the accumulation reaches $100,000. This is achieved by invoking constraints on the interconnector to "clamp" the flow of electricity from the high-price region to the low-price region.

Importantly, NEMDE will give priority to network limits over generator offers of price and volume but not over ramp rates and dispatch inflexibility profiles. Therefore, a potential distinction exists between the impact that ramp rates have on the ability for AEMO to manage system security compared to the impact of price and volume offers.

AEMO may step in to override generator offers by directing generators to change output in the interests of system security. However, directions to generators by AEMO are made irrespective of economic considerations and NEMDE's calculation of the optimal economic dispatch. Therefore, while AEMO always has the ability to provide directions to generators in an effort to maintain system security, generators reducing ramp rates under constraint conditions may compromise the ability for AEMO to determine an economically efficient dispatch arrangement while maintaining system security.

Similar to the management of system security, counter-price flows may also occur from generators engaging in other forms of rebidding under constraint conditions, such as the rebidding of price and volume. However, the costs associated with the rebidding of ramp rates have the potential to be more substantial. As with the management of system security, AEMO will override generator offers, including rebidding capacity into negative price bands, in order to limit counter-price flows but will ensure the management of generator ramp rates and dispatch inflexibility profiles takes precedence.

Counter-price flows lead to the accumulation of negative inter-regional settlement residues as retailers pay the low spot price in the importing region and generators receive the high spot price in the exporting region. This shortfall in spot market settlements is recovered from customers in the low-price region through network tariffs in the form of transmission use of system (TUOS) fees.

In its rule change request the AER cites a number of occasions where it considers that generator bidding at times of network constraints has resulted in significant counter-price flows between NEM regions.[15]

3.1.2 Stakeholder submissions

In its submission on the consultation paper, AEMO confirms that ramp rates are the highest priority constraint and that generator rebidding ramp rates as a means of maintaining high generation output would override network constraints. However, AEMO also confirms that the current minimum ramp rate requirements continue to be sufficient to manage the NEM power system under normal circumstances.[16]

A number of participants note that AEMO's powers to override generator offers by issuing directions to market participants constitute an additional tool that can be used

15 AER, *Request for rule change - Requirement for ramp rates and dispatch inflexibility profiles to reflect technical capabilities*, 21 August 2013, p. 8.

16 AEMO, submission on the consultation paper, p. 5.

to manage power system security and stability.[17] Snowy Hydro notes that AEMO has not used its power of direction to source more ramping capability to meet system security since the current minimum requirements were included in the NER in 2009.[18]

A number of stakeholders consider that counter-price flows undermine the efficient operation of the market and that a reduction in counter-price flows would improve efficient dispatch and price discovery.[19]

Snowy Hydro and the National Generators Forum (NGF) contend that counter-price flow events have predominantly occurred at times of multiple non-credible transmission outages, which has acted to significantly reduce the capability of the transmission network.[20] Snowy Hydro suggests that, of the total negative settlement residues noted by the AER in their rule change request,[21] the majority occurred at times of multiple and non-credible transmission outages, equivalent to 97 per cent on the Victoria to New South Wales interconnector and 91 per cent on the New South Wales to Victoria interconnector.[22] They suggest that, because generators have no control over this risk, it is at these times that generators must manage their exposure through the bidding process, which may inevitably result in the occurrence of counter-price flows between NEM regions.

In a report prepared by ACIL Allen, which accompanied Snowy Hydro's submission, it is argued that generators rebidding ramp rates to low levels at times of network congestion is a rational response to the absence of compensation for being constrained off.[23] The report contends that it is this lack of compensation rather than the response that should be addressed.

A number of participants further contend that the materiality of the issue has been overstated by the AER as a significant proportion of the total negative residues attributed to generator rebidding activities in the rule change request were accumulated in a few market events that were isolated in nature and are unlikely to be repeated again.[24]

17 See submissions on the consultation paper from: Origin Energy, p. 4; NGF, p. 3; Snowy Hydro, p. 6.

18 Snowy Hydro, submission on the consultation paper, p. 6.

19 See submissions on the consultation paper from: Alinta Energy, p. 3; Government of South Australia, p. 1.

20 See submissions on the consultation paper from: Snowy Hydro, p. 8; NGF, p. 4.

21 AER, *Request for rule change - Requirement for ramp rates and dispatch inflexibility profiles to reflect technical capabilities*, 21 August 2013, pp. 22-25.

22 Snowy Hydro, submission on the consultation paper, p. 8.

23 ACIL Allen Consulting, *Review of aspects of AER's rule change proposal*, report to Snowy Hydro, 27 March 2014, p. 3.

24 See submissions on the consultation paper from: Origin Energy, pp. 2-3; NGF, p. 4.

3.1.3 The Commission's assessment

The Commission agrees with the AER's view that, due to the occurrence of network congestion in the NEM, a minimum ramp rate capability must be provided by generators at all times in order to ensure the efficient management of system security.

The Commission notes that the minimum required ramp rate of 3 MW/minute was considered to be sufficient to manage the NEM power system under normal circumstances at the time of the previous rule determination in 2009, and that AEMO confirms that this continues to be the case.

While AEMO maintains the power to direct generators to change output in the interests of system security, the Commission is satisfied that such an occurrence is unlikely to occur under normal circumstances given the existing minimum requirements of 3 MW/minute. Indeed, the Commission notes that AEMO has never been required to direct a generator to change output due to the rebidding of ramp rates since the minimum requirement of 3 MW/minute was first enforced in 2009.

Therefore, the Commission does not support the AER's view that the current minimum ramp rate requirement of 3 MW/minute is insufficient in the current circumstances and that it is likely to compromise the ability of AEMO to efficiently manage the secure operation of the electricity system.

With regard to counter-price flows, the Commission notes the considerable divergence of views in submissions regarding the causes and materiality of the issue.

While acknowledging the AER’s concerns in relation to inefficient outcomes caused by the occurrence of counter-price flows, the Commission considers 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.

Further, the Commission recognises that there are a range of factors that can create the conditions in the market that give rise to counter-price flows. These conditions may include generators rebidding ramp rates or changing dispatch inflexibility profiles, but may also include other factors unrelated to generator rebidding that impact the capability of the network, such as the timing of network outages. The Commission notes the suggestions that, in a number of market events where substantial negative residues have been accrued, multiple network outages occurred simultaneously that may have had a significant bearing on the extent of counter-price flows.

Therefore, the Commission has not been persuaded that it would be appropriate to make a rule that requires generators to provide a greater minimum level of ramp rate capability that does not also address the range of other factors that may contribute to counter-price flows. The Commission notes that such issues could be addressed through the Optional Firm Access model currently being considered by the AEMC. Optional Firm Access would delink physical dispatch from financial outcomes in the wholesale market and so align the commercial incentives on generators with the promotion of more efficient market outcomes for consumers.[25]

3.2 Productive efficiency losses and risk management costs

This section sets out the Commission's considerations of the issues raised by the AER where the rebidding of ramp rates and changes to dispatch inflexibility profiles may be a contributing or supporting factor but for which other forms of generator rebidding may also be a cause. These issues include productive efficiency losses and higher risk management costs.

3.2.1 The AER's view

The AER considers that generators that engage in rebidding at times of network constraints may create productive inefficiencies by causing high cost plant to be dispatched in place of low cost plant.[26] This may occur not just through rebidding of ramp rates and dispatch inflexibility profiles but also through other forms of rebidding, such as the rebidding of generation capacity between price bands.

Based on generator offers received, NEMDE determines the optimal mix of plant to meet demand given the limitations placed by congestion in the network. Generators may change their offers to influence the outcomes that NEMDE chooses to achieve the optimal mix of plant. The AER considers that generator rebidding under constraint conditions changes the merit order of dispatched plant and may result in high cost generation being dispatched in place of low cost generation, thereby resulting in productive efficiency losses.

In addition, the AER considers that instances of rebidding of price and volume at times of network constraints can result in higher wholesale spot price volatility and reduce spot price predictability, and that the rebidding of ramp rates by generators at the same time can exacerbate the problem.[27]

The AER suggests that the higher price volatility is primarily caused by generators that are constrained off rebidding capacity into negative price bands in an effort to maintain generation output. While the price is initially set on the opposite side of the constraint by higher priced generation, the volatility is caused by the constrained off generator setting the price at negative levels when the constraint ceases to bind. The market may then revert to a higher price when the constraint binds again. As a consequence, spot prices may fluctuate between levels close to the price cap and levels close to the price floor over successive five-minute dispatch intervals. The AER considers that the

25 The Optional Firm Access model currently being considered could result in better coordination of transmission and generation investment with more transmission investment being driven by commercial decision-making on the part of generators.

26 AER, *Request for rule change - Requirement for ramp rates and dispatch inflexibility profiles to reflect technical capabilities*, 21 August 2013, p. 22.

27 Ibid, p. 14.

rebidding of ramp rates prolongs the effect by allowing the constrained off generator to further reduce the rate at which its dispatch levels are decreased.

Increased spot price volatility leads to an expectation of similar volatility in the future, which can lead to an increase in the risk premium on hedge contracts.[28] The higher risk profile may then flow through to consumers in the form of higher energy charges.

3.2.2 Stakeholder submissions

Snowy Hydro suggests that dispatch inefficiency caused by generators rebidding at time of network constraints is immaterial in total and with respect to the overall size of the NEM.[29] Snowy Hydro cites two separately commissioned studies that have attempted to estimate the total productive inefficiency at between $8 million and $10 million per annum. Further, Snowy Hydro contends that these estimates were based on all forms of generator bidding under constraint conditions and that generators rebidding ramp rates may only be responsible for a fraction of this.

The report prepared by ACIL Allen for Snowy Hydro contends that generator bidding in response to transmission congestion is not necessarily non-cost reflective.[30] Generator dispatch offers are opportunity cost reflective in that they take into account system and market conditions, including transmission constraints, and can be interpreted as the prices at which the generator is indifferent about having the relevant dispatch quantities dispatched or not.

The NGF contends that the focus on productive efficiency is misguided as generators' contract positions dictate their activities in the physical market.[31] As such, while the physical dispatch in the NEM on a day to day basis may not be productively efficient, the competitive process should result in efficient price outcomes in the long-term.

In relation to higher risk management costs, Snowy Hydro suggests that the extent to which higher risk premiums on hedge contracts are attributed to the use of ramp rates is difficult to discern from the impact of other forms of rebidding and is likely impossible to quantify.[32] Arrow Energy also notes that rebidding ramp rates should not be isolated as the sole issue causing inefficient price signals.[33] Alinta Energy considers that, in assessing effects on price volatility, the focus would need to be on the level of volatility above that which is reflective of the true underlying conditions of supply and demand.[34]

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28 Ibid, pp. 18-19.

29 Snowy Hydro, submission on the consultation paper, p. 7.

30 ACIL Allen Consulting, *Review of aspects of AER's rule change proposal*, report to Snowy Hydro, 27 March 2014, p. 9.

31 NGF, submission on the consultation paper, pp. 6-7.

32 Snowy Hydro, submission on the consultation paper, p. 10.

33 Arrow Energy, submission on the consultation paper, p. 4.

34 Alinta Energy, submission on the consultation paper, p. 3.

3.2.3 The Commission's assessment

The AER's view that generators rebidding ramp rates under constraint conditions leads to productive efficiency losses is predicated on an assumption that a generator's offers are representative of their operational costs. However, the Commission considers that a generator’s offers may also take into account a range of other factors, such as the opportunity costs of not being dispatched. As such, the rebidding of ramp rates by generators that inhibits a market dispatch arrangement in strict accordance with the ranking of price and volume offers does not necessarily imply a productive efficiency loss.

Further, the AER's view does not take into account the costs to generators that are implicit to the provision of ramp rate capability. An increase in operating and maintenance costs to generators from providing higher ramp rates should be considered alongside any potential gains in productive efficiency.

The Commission acknowledges the results of earlier studies undertaken to estimate the extent of productive efficiency losses arising from generator rebidding activities, which suggests these are likely to be small relative to total market turnover. These estimates were undertaken to assess the impact of all forms of generator rebidding at times of network constraints, and the rebidding of ramp rates is only likely to represent a portion of the overall estimate.

The Commission also recognises that the difficulty in discerning the impact of the rebidding of ramp rates from other forms of rebidding extends to the impact on price volatility and the possible consequent increase in risk premiums on forward hedge contracts. This is particularly the case given that higher price volatility is primarily caused by the rebidding of volume between price bands but that the rebidding of ramp rates prolongs the effect by allowing the generator to reduce the rate at which it is constrained off.

Similar to counter-price flows discussed in section 3.1.1, and in consideration of the fact that the rebidding of ramp rates is only one form of generator rebidding that may give rise to these outcomes, the Commission considers that such issues discussed above could be addressed through the Optional Firm Access model currently being developed by the AEMC. Optional Firm Access would align the commercial incentives on generators with the promotion of more efficient market outcomes for consumers.

3.3 The AER's proposed rule

This section sets out the Commission's considerations on the AER's proposed rule.

3.3.1 Summary of the proposed rule

The AER's proposed rule would require generators to always submit ramp rates that reflect their technical capability at the 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 AER's proposed rule would also place a greater restriction on dispatch inflexibility profiles by requiring fast start generators to submit a dispatch inflexibility profile that reflects the technical limitations of their plant.

Given the variable nature of ramp rates, the AER proposes to provide further clarity on how the proposed rule would operate in practice, and how the AER would enforce it, through amendments to the Rebidding and Technical Parameters Guideline.[35]

3.3.2 Submissions on the proposed rule

A number of participants support the AER’s proposed rule in submissions, considering that the treatment of ramp rates and dispatch inflexibility profiles in the NER should be aligned with the current treatment of other technical parameters, such as frequency control ancillary services parameters, which must reflect the technical capabilities of the plant.[36]

However, other submissions on the consultation paper note the significant level of ambiguity in the proposed rule with regards to how the maximum technical ramp rate would be defined.[37] Macquarie Generation contends that there are a number of factors that make it difficult to calculate an accurate ramping capability for the older coal-fired plant in the NEM, and that much is likely to rely on the knowledge and experience of control room operators in assessing the performance limits of a generating unit.[38]

The AER contends in its submission that participants are aware of their generator ramp rate capabilities based on the conditions of their plant and that, given a set of forecast conditions, a generator can predict, with reasonable certainty, what the ramping capability of the generator will be for a given level of output.[39]

The AER further notes that the intention would not be to scrutinise small differences between ramp rates offered by participants and some historical benchmark. Instead, when monitoring compliance, the intention would be to use extensive monitoring knowledge and 15 years of historical generator data to examine ramp rates that materially deviate from expected levels where market conditions create financial incentives to do so.

35 This guideline is available on the AER website. The AER may amend or replace the guideline from time to time in accordance with clauses 3.8.3A, 3.8.19(b)(2) and 3.8.22(c)(3) of the NER.

36 See submissions on the consultation paper from: Government of South Australia, p. 1; MEU, p. 3.

37 See submissions on the consultation paper from: InterGen, p. 1; Arrow Energy, pp. 4-5; Macquarie Generation, p. 2; AGL, p. 1; EnergyAustralia, p. 3.

38 Macquarie Generation, submission on the consultation paper, pp. 2-3.

39 AER, submission on the consultation paper, p. 3.

However, several participants maintain that enforcement and compliance with the AER's proposed rule would create material uncertainty and would increase the cost of participation in the NEM and that any rule should be sufficiently specific to not result in ambiguity when assessing compliance.[40]

Participants also cite the strong links that exist between ramp rates and commercial incentives.[41] GDF Suez notes that generators have an incentive to offer high ramp rates so that when the pool price exceeds their offer price, they can have their output increased quickly and thus maximise their pool revenue. Equally, when the pool price falls below the generator’s bid price, the generator would generally want to ramp down as quickly as possible, to avoid being dispatched beyond their desired market level.[42]

Participants suggest that the AER's proposed rule would be inequitable as it would impose greater requirements on those generators that are able to provide greater ramp rate capability.[43] Flexible units would be required to be ramped down to a greater extent in order to alleviate constraints in the network at times of congestion. ACIL Allen suggests in its report to Snowy Hydro that the possibility of being constrained off without compensation as a result of having a responsive plant and having to submit at all times the safe maximum ramp rate would seem to be a deterrent to investment in peaking generation.[44]

The importance of efficient market outcomes as an incentive to invest in flexible plant is emphasised by both Alinta Energy and GDF Suez.[45] Both participants note that ramping capability may become more valuable to the market over time as greater levels of intermittent renewable generation are introduced and the remaining thermal plant needs to continuously change generation patterns to cover the variations in supply.

3.3.3 The Commission’s assessment of the proposed rule

In consideration of the issues raised in the AER’s rule change request, and in light of submissions made by participants, the Commission does not support the AER’s proposed rule to require generators to provide the maximum ramp rate that they can safely attain at all times or to require fast-start generators to submit a dispatch inflexibility profile that always reflects the technical limitations of their plant.

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40 See submissions on the consultation paper from: Snowy Hydro, p. 15; Arrow Energy, p. 7; GDF Suez, p. 2; AGL, p. 1; EnergyAustralia, p. 2; NGF, p. 23.

41 See submissions on the consultation paper from: EnergyAustralia, pp. 2-3; GDF Suez, p. 2; Snowy Hydro, pp. 16-17.

42 GDF Suez, submission on the consultation paper, p. 2.

43 See submissions on the consultation paper from: Arrow Energy, p. 5; Snowy Hydro, p. 16; EnergyAustralia, p. 2.

44 ACIL Allen Consulting, *Review of aspects of AER's rule change proposal*, report to Snowy Hydro, 27 March 2014, p. 10.

45 See submissions on the consultation paper from: Alinta Energy, pp. 8-9; GDF Suez, pp. 3-4.

The Commission considers that ramp rate capability is strongly linked to commercial incentives. For many generators in the NEM there is a strong commercial incentive to have a highly flexible plant. The Commission considers that the AER's proposed rule has the potential to create a disincentive to invest in flexible plant as it may disproportionately impact generators that are able to provide greater ramp rate capability. By requiring generators to provide their maximum ramp rate at all times, the burden of ramp rate capability in the market would be shifted to more flexible plant. Over time, this may affect commercial investment decisions regarding the flexibility of plant, potentially resulting in inefficient price outcomes over the long term. The Commission considers that this is contrary to the NER principle of technology neutrality which provides that rules should not be made that apply special treatment in respect of different technologies used by participants.[46]

The Commission also considers that the proposed rule may impose a burden of compliance on generators to continuously review and update their maximum ramp rate requirements, thereby adding to operational and administration costs and increasing the level of uncertainty in compliance with the NER.

Further, the Commission is concerned that the proposed rule may be difficult to apply in practice as it would require the AER to determine whether the ramp rates or dispatch inflexibility profiles submitted by generators represent a true reflection of the technical capability of their generating units at any given time. Ramp rates and dispatch inflexibilities of generating plant are subject to a range of factors and the complexity of determining the maximum technical capability at any given time would involve a trade-off between capability and cost and may give rise to disagreements between the AER and generators.

46 See clause 3.1.4(3) of the NER.

4 The Commission's more preferable draft rule

Although the Commission does not support the AER's proposed rule, it does have concerns in relation to the current arrangements. While the current minimum ramp rate requirements provide sufficient capability for AEMO to manage the secure operation of the electricity system, the Commission considers that the existing rules may prevent this from being achieved at the lowest cost.

This Chapter discusses the Commission's objectives for determining the minimum required ramp rates and sets out the reasoning for its more preferable draft rule.

4.1 Commercial incentives and system security

Commercial drivers of ramp rate capability

In the NEM, decisions to invest in generating plant are based on a range of factors that determine the ability to obtain a return on capital investment. Amongst its considerations, a prospective investor is likely to take into account the possible geographic location of the new plant and its ease of access across the transmission network to receive the regional energy price. A further important influence on investment decisions relates to the design of the NEM as an energy-only market. As generators do not receive payment based on their available capacity, many generators rely on relatively high wholesale market prices at time of scarcity to provide a significant share of their required revenue. The ability of these generators to provide energy at these discrete times is determined, not only by their access across the transmission network, but also by the flexibility of their generating units.

A generating unit that can ramp up generation output at the times that the market signals it is needed will be rewarded. Equally, when sufficient low-price energy is provided to meet demand and the price falls below the operating cost of the generating unit, a fast ramp down rate will reduce the potential losses. Generators may also have an incentive to maintain flexibility to support variations in their contract positions. As such, for many generators in the NEM there is a strong commercial incentive to have a highly flexible plant.

Efficient wholesale market price outcomes rely on the ability of generating units to provide energy when it is of most value. Rules that restrict the operating flexibility of generating units may diminish the incentives for investment in flexible plant. Over time, this is likely to give rise to inefficient wholesale price outcomes which is not in the long-term interests of consumers.

However, the Commission recognises that market conditions do not always give rise to a consistent set of commercial incentives for greater flexibility. Congestion in the transmission network can mean that 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 that are likely to be constrained off have an incentive to rebid to reduce the rate that they can be ramped down in order to reduce the extent to which their dispatch levels will be decreased.

A requirement for minimum ramp rates

In 2009, the AEMC made a rule in relation to a request received from the AER, which placed requirements on generators regarding their minimum offered ramp rates.[47] The rule change request was precipitated by an AER investigation into the events of 31 October 2005. On that day, the National Electricity Market Management Company (NEMMCO), now AEMO, invoked network constraints to manage the impact of a transmission outage between Wallerawang Power Station and the Sydney South substation, which had the effect of constraining the dispatch of some generation in the vicinity. The AER found that some generators took action to minimise the commercial impact of these constraints by rebidding their ramp rates to very low levels. This limited the rate that NEMMCO was able to reduce the dispatch levels of those generators, thus hindering NEMMCO's ability to effectively manage power system security during that event.

The Commission's final determination on that rule change request imposed a minimum ramp rate of 3 MW/minute (or three per cent of capacity for generating units less than 100 MW) except where it could be demonstrated to NEMMCO that a lower ramp rate is required for technical or safety reasons. The rule required generating units that are aggregated to be treated as a single unit and provide a minimum ramp rate of 3 MW/minute.

The AER's 2008 proposed rule to change ramp rates to a minimum of 3 MW/minute was principally driven by the fact that the lack of restrictions on scheduled generators to rebid ramp rates undermined the ability of NEMMCO to determine an efficient dispatch arrangement while maintaining system security. The AER explained that the ability of generators to reduce ramp rates could hinder the ability of market systems to rapidly adjust power flows to respond to issues that emerge in the market. The AER noted that NEMMCO was of the view that 3 MW/minute should accommodate the vast majority of system security issues that may arise in the context of the NEM.[48]

The Commission acknowledges that, given the commercial incentives caused by conditions of network congestion, a minimum level of ramp rate capability must be provided in the NEM in order to maintain the efficient and secure operation of the dispatch process and to ensure that system security can be maintained.

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

48 The decision to use 3 MW/minute was based on an analysis of offers in 2007 which showed that all except a handful of generators offer at 3 MW/minute or greater most of the time. It was therefore determined that a level of 3 MW/minute minimum ramp rate would be sufficient for most generators.

4.2 Objectives for minimum required ramp rates

In determining the minimum required ramp rates to satisfy the efficient management of system security, the Commission considers that the efficiency of wholesale price outcomes will be influenced by the extent to which the commercial incentives for ramp rate capability are preserved.

The Commission considers that the impact on commercial incentives can be minimised if minimum ramp rate requirements are:

- applied consistently for all participants;
- distributed proportionately such that the burden of system ramp rate capability is shared across all 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.

Rules that are designed to meet these objectives should ensure that the minimum level of required ramp rate capability is provided at the lowest cost in the long term interests of consumers.

4.3 Assessment of the current rules

In seeking to determine minimum ramp rate requirements, the Commission considers that the current arrangements are limited in their ability to satisfy the Commission's objectives to provide commercial incentives for ramp rate capability.

The Commission considers that under the existing arrangements, the burden of system ramp rate capability is not applied consistently for all generating units. The Commission notes that:

- 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;
- the minimum required ramp rate is applied to each generating unit and so those generators with a greater number of generating units have a higher overall minimum ramp rate requirement;
- if generating units are aggregated for the purposes of the market dispatch process then the minimum required ramp rate of 3 MW/minute applies to all generating units combined; and
- 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, non-aggregated generators, and those with a larger number of generating units.

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 possible cost; and
- impact investment such that decisions on the number of generating units, size of units, and levels of aggregation are not based purely on commercial and economic factors.

The Commission considers that there is potential to improve the current rules such that the provision of the minimum required level of ramp rate capability is applied consistently and proportionately for all participants.

4.4 Reasons for the Commission's more preferable draft rule

The Commission has determined to make a more preferable draft rule by amending clause 3.8.3A(b)(1) to require that any up ramp rate and any down ramp rate provided to AEMO is at least one per cent of maximum capacity on a MW/minute basis, rounded up to the nearest whole number.

The Commission considers that the more preferable draft rule would contribute to the NEO by providing AEMO with a greater ability to optimise the NEM dispatch process more efficiently, which would enhance the efficient operation of electricity services for the long term interests of consumers.

- The requirements of the more preferable rule would apply uniformly across all participants. The current arrangements apply a separate form of the rules to generators with capacity less than 100 MW. The more preferable 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 more preferable rule 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 more preferable 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 more preferable rule would base minimum requirements on unit size and would ensure that aggregated and non-aggregated generators are treated on the same basis.

Table 4.1 sets out how the Commission's more preferable draft rule differs from the current rules in the treatment of three hypothetical generators. The table demonstrates how, under the current arrangements, three separate generators with the same maximum capacity can have significantly different minimum ramp rate requirements depending on the number of generating units or whether or not the generating units have been aggregated. The more preferable draft rule would improve the consistency and proportionately with which the minimum required ramp rates are determined.

Table 4.1 Minimum ramp rate requirements

	Generator A	Generator B	Generator C
Max. capacity	1500 MW	1500 MW	1500 MW
No. of generating units	4	4 (aggregated)	6
Min. ramp rate (current)	12 MW/min	3 MW/min	18 MW/min
Min. ramp rate (more preferable draft rule)	15 MW/min	15 MW/min	15 MW/min

The Commission also considers that the more preferable draft rule is likely to avoid the potential negative impacts that the AER's proposed rule may have had on the incentive to invest in generating plant with more flexible ramp rate capability. The more preferable draft rule would align the minimum ramp rate requirements with the size of plant and would be determined irrespective of generation technology. This would ensure that investment decisions are, to the greatest extent possible, based on commercial and economic factors, which would contribute to efficient investment in electricity services for the long terms interests of consumers.

Further, the minimum required ramp rate would be a constant that is not subject to variation, thereby minimising compliance costs. The Commission considers that this is 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 Commission's more preferable 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.

4.5 Application of the more preferable draft rule

The Commission's more preferable draft rule would require participants to provide an up ramp rate and a down ramp rate that is at least one per cent of maximum capacity on a MW/minute basis, rounded up to the nearest whole number.

The rule would apply to scheduled and semi-scheduled generators, scheduled loads and scheduled network services.

The Commission has assessed the impact of this rule on the market and, based on advice received from AEMO, is satisfied that one per cent of maximum capacity would maintain AEMO's ability to manage the secure operation of the electricity system. Table 4.2 shows how aggregate ramp rate capability would be affected for each region of the NEM.

Table 4.2 Regional change in aggregate minimum ramp rate requirements

Region	Current weighted average minimum (MW/min)	Draft rule weighted average minimum (MW/min)	Difference (MW/min)
New South Wales	3.0	7.3	4.3
Queensland	2.9	4.0	1.1
South Australia	2.7	2.6	-0.0
Tasmania	2.6	3.1	0.5
Victoria	2.9	5.7	2.8

The Commission has decided to require that minimum ramp rates be rounded up to the nearest whole number on the basis that:

- generators with capacity less than 50 MW should provide a minimum ramp rate capability of at least 1 MW/minute; and
- there are a significant number of smaller capacity generators in the NEM and rounding down (as under the current rules) would result in their contribution to minimum system ramp rate capability being materially diminished on aggregate.

Analysis undertaken using AEMO data suggests that individual generators should be able to meet their minimum requirements under the more preferable draft rule. However, if individual participants are unable to meet the minimum requirements, the draft rule would retain the existing provisions that allow the generator to provide a brief, verifiable, and specific reason to AEMO as to why the ramp rate provided is below the minimum required. The AER would retain the ability to seek additional information from participants to substantiate and verify the reasons provided. Further, generators may elect to change their maximum ramp rates provided to AEMO as part of bid and offer validation data in accordance with schedule 3.1 of the NER.

While the draft rule does not include any changes to the requirements in relation to dispatch inflexibility profiles, the Commission notes that the current requirements in the rules impose a degree of constraint on generators to make changes to time inflexibilities in their dispatch inflexibility profiles. The Commission considers that this has the potential to limit the extent to which generators can use dispatch inflexibility profiles to achieve commercial objectives at times of network congestion. A further discussion of dispatch inflexibility profiles is provided in **Appendix B**.

Abbreviations

ACCC	Australian Competition and Consumer Commission
AEMC or Commission	Australian Energy Market Commission
AEMO	Australian Energy Market Operator
AER	Australian Energy Regulator
CVP	constraint violation penalty
MCE	Ministerial Council on Energy
NEL	National Electricity Law
NEM	National Electricity Market
NEMDE	National Electricity Market Dispatch Engine
NEMMCO	National Electricity Market Management Company
NEO	National Electricity Objective
NER	National Electricity Rules
NGF	National Generators Forum
SRA	settlement residue auction
TNSP	transmission network service provider
TUOS	transmission use of system

A Legal requirements under the NEL

This appendix sets out the relevant legal requirements under the National Electricity Law (NEL) for the AEMC in making this draft determination.

A.1 Draft determination

In accordance with section 99 of the NEL the Commission has made this draft rule determination in relation to the rule proposed by the Australian Energy Regulator.

A.2 Power to make the rule

The Commission is satisfied that the Proposed Rule falls within the subject matter about which the Commission may make Rules. The Proposed Rule falls within section 34 of the NEL as it relates to the operation of the NEM (section 34(1)(a)(i)), the operation of the national electricity system for the purposes of the safety, security and reliability of that system (section 34(1)(a)(ii)), and the activities of persons (including Registered participants) participating in the NEM or involved in the operation of the national electricity system (section 34(1)(a)(iii)).

A.3 Commission's considerations

In assessing the rule change request the Commission considered:

- the Commission's powers under the NEL to make the rule;
- the rule change request;
- the fact that there is no relevant Ministerial Council on Energy (MCE) Statement of Policy Principles;[49]
- submissions received during first round consultation; and
- the Commission's analysis as to the ways in which the proposed rule will or is likely to, contribute to the NEO.

A.4 Power to make a more preferable rule

Under section 91A of the NEL the Commission may make a rule that is different (including materially different) from a market initiated proposed rule if the Commission is satisfied that, having regard to the issues or issues that were raised by

49 Under section 99(2)(a)(iv) of the NEL, the AEMC must have regard to any relevant MCE statement of policy principles in making a rule. The MCE is referenced in the AEMC's governing legislation and is a legally enduring body comprising the Federal, State and Territory Ministers responsible for Energy. On 1 July 2011 the MCE was amalgamated with the Ministerial Council on Mineral and Petroleum Resources. The amalgamated Council is now called the COAG Energy Council.

the market initiated proposed rule, the more preferable rule will or is likely to better contribute to the achievement of the NEO.

As discussed in Chapter 2, the Commission has determined to make a more preferable rule. The reasons for the Commission's decision are set out in Chapter 4.

A.5 Civil penalty provision

The Commission's more preferable draft rule amends clause 3.8.3A(b) of the NER. This clause is currently classified as a civil penalty provision under the National Electricity (South Australia) Regulations.

The Commission may recommend that clause 3.8.3A(b) be retained as a civil penalty provision, but must notify the COAG Energy Council of the policy rationale for taking this course of action. The Commission considers that clause 3.8.3A(b) should continue to be classified as a civil penalty provision because a breach of this clause could pose a risk to the secure operation of the NEM. In addition, the classification of clause 3.8.3A(b) as a civil penalty provision would encourage compliance by relevant parties with this provision.

A.6 Others

Under section 91(8) of the NEL, the Commission may only make a rule that has effect with respect to an adoptive jurisdiction if satisfied that the proposed rule is compatible with the proper performance of AEMO's declared network functions. The more preferable draft rule is compatible with AEMO's declared network functions because it does not affect AEMO's performance of those functions.

B Ramp rates and dispatch inflexibility profiles

This appendix provides a discussion of the current treatment and history of ramp rates and dispatch inflexibility profiles in the NEM.

B.1 Ramp rates

On 10 December 1997, the Australian Competition and Consumer Commission (ACCC) authorised amendments to the National Electricity Code (the Code) in preparation for the commencement of the NEM. In the final determination, the ACCC refrained from imposing any conditions regarding the rebidding of dispatch parameters, such as capacity, ramp rates, dispatch inflexibility and energy constraints.[50]

In April 2008, the AER proposed changes to the rules relating to the bidding and rebidding of ramp rates.[51] The AER contended that the rules permitted generators to rebid ramp rates in such a way to inhibit the market operator's ability to reduce the output of generators through central dispatch to manage system security.

In making the rule, the AEMC largely adopted the AER's proposal with some modifications. The AEMC's final determination changed clause 3.8.3A of the NER to require participants to submit a minimum ramp rate of 3 MW/minute except where it can be demonstrated that a lower ramp rate is required for technical or safety reasons.

The AER's proposed rule to change ramp rates to a minimum of 3 MW/minute was principally driven by the fact that the lack of restrictions on scheduled generators to rebid ramp rates undermined the ability of NEMMCO to manage system security in an economically optimal fashion. The AER cited events of October 2005 in New South Wales and October and November 2007 in Queensland where system security was compromised through the rebidding of ramp rates. The AER explained that the ability of generators to reduce ramp rates could hinder the ability of market systems to rapidly adjust power flows to respond to issues that emerge in the market.

In proposing a minimum ramp rate of 3 MW/minute, the AER analysed ramp rates from 2007 that showed all except a small number of generators offer at 3 MW/minute or higher. The AER therefore concluded that past ramp rate bidding indicated that a 3 MW/minute minimum ramp rate would not cause undue wear and tear on plant. Furthermore, the market operator at the time considered that 3 MW/minute should accommodate the majority of system security issues that may arise in the NEM.[52]

During consultation on the rule change request, stakeholders raised concern that a minimum fixed ramp rate of 3 MW/minute would place a disproportionate burden on

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50 ACCC, *Amendments to the National Electricity Code Changes to bidding and rebidding rules*, 4 December 2002, p. 5.

51 AER, *Request for rule changes – technical parameters*, 21 April 2008.

52 Ibid, p. 7.

smaller generators who would be required to change output at a rate equivalent to a higher relative proportion of their overall capacity.

To address this concern, the AEMC determined that the minimum ramp rate required by generators should be the lower of 3 MW/minute or 3 per cent of capacity rounded down to the nearest whole number. This implied that generators with a capacity less than 100 MW would be required to maintain a minimum ramp rate of either 2 MW/minute or 1 MW/minute.

Stakeholders also raised concern that a minimum fixed ramp rate would create incentives to aggregate generating units. Stakeholders suggested that commercial incentives could see generators aggregate units in order to diminish their aggregate ramping capability.

However, the AEMC noted that the rules provided NEMMCO with the ability to reject or place conditions on applications for aggregation if the approval of an application for aggregation would affect power system security or materially distort central dispatch. As such the AEMC determined that a minimum ramp rate of the lower of 3 MW/minute or 3 per cent of the registered unit size would apply to both aggregated and non-aggregated generating units (as opposed to individual physical generating units).

Under the NEL, the AER's enforcement role and powers allow it to investigate and take action against a possible breach of the rules. The AEMC determined that the requirement for generators to meet a minimum ramp rate of 3 MW/minute be a civil penalty provision. The AEMC also determined that the AER may request additional information from the relevant scheduled generator or market participant to verify a reason provided for a ramp rate below the minimum.

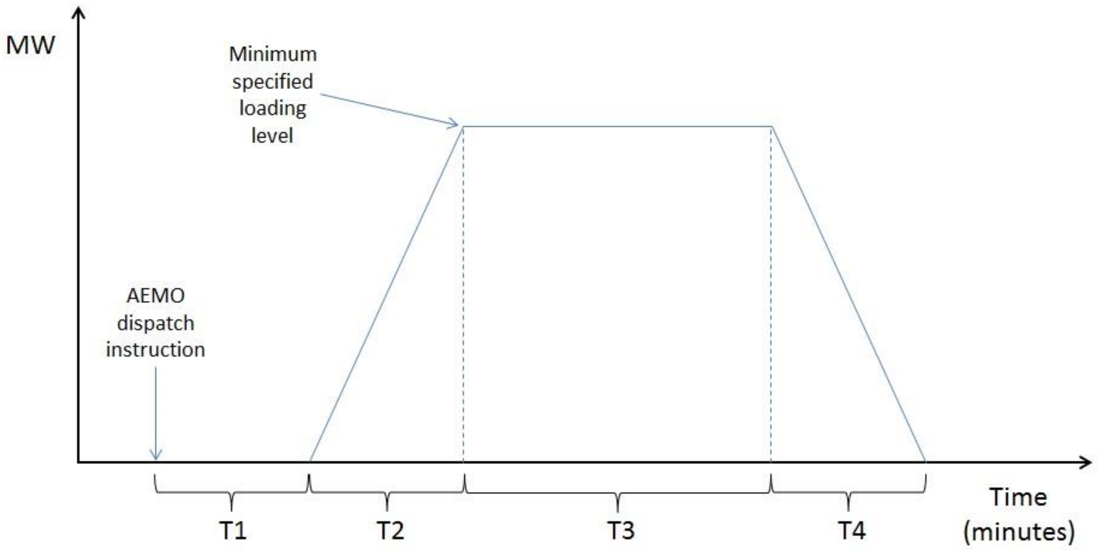
The Commission considered that the objective of the AER's rule change request was to provide NEMMCO with sufficient ramp rate capability for it to be able to manage power system security. The decision at the time to use 3 MW/minute as the minimum value was based on advice from NEMMCO that this would be sufficient to allow the effective management of system security incidents.

B.2 Dispatch inflexibility profiles

Dispatch inflexibility profiles are used by fast start plant such as gas turbines, to inform the dispatch process of inflexibilities in respect of their units such as minimum start and stop times, and minimum safe operating levels.

Clause 3.8.19(d) of the NER currently provides fast start generators with the discretion to include a dispatch inflexibility profile as part of its dispatch offer. As shown in figure B.1, a dispatch inflexibility profile must contain parameters to indicate its MW capacity and time related inflexibilities.

Figure B.1 Dispatch inflexibility profile



Along with a minimum specified MW loading level, the dispatch inflexibility profile must also include:

- the time following the issue of a dispatch instruction by AEMO to increase loading level from 0 MW (T1);
- the time the plant requires to reach the specified minimum loading level (T2);
- the time that the plant requires to be operated at or above its minimum loading level before it can be reduced below that level (T3); and
- the time following the issue of a dispatch instruction by AEMO to reduce loading from the minimum loading level to 0 MW (T4).

The NER places a number of constraints on the time related inflexibilities that can be provided in a dispatch inflexibility profile, including that:

- T1, T2, T3 and T4 must all be greater than zero;
- the sum T1+T2 must be less than or equal to 30 minutes; and
- the sum T1+T2+T3+T4 must be less than 60 minutes.

C Summary of issues raised in submissions on the Consultation Paper

Stakeholder	Comment	AEMC response
AER's rule change proposal		
AER	Proposed rule will not address all of the costs associated with disorderly bidding and its consequences, but it will reduce the likelihood and duration of such market outcomes, while improving the efficiency of the operation of the market more generally (p. 3).	The Commission has not been persuaded that it would be appropriate to make a potentially extensive change to generators' minimum ramp rate requirements that does not also address the range of other factors that may contribute to the costs raised. The Commission notes that such issues could be addressed through the Optional Firm Access model currently being considered by the AEMC.
GDF Suez	Review of generators acting to limit ramping capability is appropriate, however, not supportive of the proposal for generators to provide their maximum technical ramping capability at all times. Ramp rates are a commercial parameter as it is in a generator's commercial interest to ramp up and down with changing pool price. As such, GDF Suez does not support regulatory measures being imposed on the NEM which seek to mandate the provision of a product or service which is not a technical condition for generator connection. A requirement for generators to continually update their ramping capability, and for the regulator to monitor compliance, would be unnecessarily burdensome (p. 1).	The Commission considers that commercial incentives are a key driver for the ramp rate capability of generators and that, for many participants, flexibility is necessary to provide energy to the market at times of highest value. The Commission considers that the AER's proposed rule has the potential to create a disincentive to invest in flexible plant as it would disproportionately impact generators that are able to provide greater ramp rate capability. The Commission also considers that the proposed rule would impose a burden of compliance on generators to continuously review and update their maximum ramp rate requirements, thereby adding to operational and administration costs and increasing the level of uncertainty in compliance with the NER. See section 3.3.3.
Origin Energy	Origin Energy notes that the materiality of the problem the rule change is intended to solve has not been established. Both the	While acknowledging the AER's concerns in relation to inefficient outcomes caused by generators rebidding ramp

Stakeholder	Comment	AEMC response
	incidence and impact of the market outcomes are not of a sufficient magnitude to warrant the introduction of the proposed rule. Origin also note that imposing a requirement on generators to submit ramp rates reflecting their maximum technical capacity at all times would impose additional risk and increase operating and maintenance costs. (p. 1.)	rates to low levels at times of network congestion, the Commission considers 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.
Macquarie Generation	The proposed rule would require generators to constantly update their maximum technical ramp rate capability. This could dramatically increase the frequency of rebidding for coal-fired generators as plant conditions change and ramp rate capability moves up or down. Considers that the AER's proposal for an after-the-fact review of whether a generator has complied with ramp rates does not reflect reality. In practice, spot traders and control room operators need to make snap judgements at times of variable and sometimes volatile plant and market conditions (p. 4).	The Commission is concerned that the proposed rule may be difficult to apply in practice as it would require the AER to determine whether the ramp rates or dispatch inflexibility profiles submitted by generators represent a true reflection of the technical capability of their generating units at any given time. Ramp rates and dispatch inflexibilities of generating plant are subject to a range of factors and the complexity of determining the maximum technical capability at any given time would involve a trade-off between capability and cost and may give rise to disagreements between the AER and generators. See section 3.3.3.
Arrow Energy	Supports the need to ensure that system security is not at risk and that economically efficient price outcomes are achieved. Concerned about the implications of requiring generators to always offer and potentially run at their technical maximum ramp rate capability (p. 2).	The Commission considers that, while the AER's proposed rule would provide the required minimum level of ramp rate capability to manage the secure operation of the electricity system, it may also create a disincentive to invest in flexible plant by disproportionately impacting generators that are able to provide greater ramp rate capability. Over time, this may affect commercial investment decisions regarding the flexibility of plant, potentially resulting in inefficient price outcomes in the long term interests of consumers.
Determining and enforcing ramp rates		
AER	Given a set of forecast conditions, a generator can predict, with reasonable certainty, what the ramping capability of the generator will be for a given level of output. The rules currently	The Commission is concerned that the proposed rule may be difficult to apply in practice as it would require the AER to determine whether the ramp rates or dispatch inflexibility

Stakeholder	Comment	AEMC response
	require generators to provide the maximum ramp rate they can safely attain at the time when they offer a ramp rate below 3 MW/minute. The proposed rule would extend this to offer the maximum they can safely attain at all times. When monitoring compliance of ramp rates, the intention is to use 15 years of historical generator data to examine ramp rates that materially deviate from expected levels, where market conditions create financial incentives to reduce the ramp rate below the unit's maximum technical capability. Intention is not to scrutinise small differences between ramp rates offered by participants and some historical benchmark, nor analyse in detail when a participant's ramp rate is moving through a range of values, consistent with movements in output (pp. 1-3).	profiles submitted by generators represent a true reflection of the technical capability of their generating units at any given time. Ramp rates and dispatch inflexibilities of generating plant are subject to a range of factors and the complexity of determining the maximum technical capability at any given time would involve a trade-off between capability and cost and may give rise to disagreements between the AER and generators.
MEU	Each generator should be able to advise the maximum ramp rates for each individual generator in its fleet. These ramp rates should be interrogated by AEMO and the AER to ensure that the generators are not artificially de-rating the ramp rates that are technically achievable (p. 20).	
AER	It would not be appropriate for generators to use the ramp rate submitted in accordance with schedule 3.1 as a default ramp rate. This is only to be used for verification and compilation of dispatch bids and offers in the trading day schedule. It is not a regulatory provision but rather a tool for validation. Rather than submitting the maximum ramp rate as defined in the rules, the expectation would be for generators to submit ramp rates that reflect the maximum achievable under the conditions at the time, or expected output of plant under anticipated conditions in the forecasting horizons (p. 4).	The Commission is concerned that the proposed rule may be difficult to apply in practice as it would require the AER to determine whether the ramp rates or dispatch inflexibility profiles submitted by generators represent a true reflection of the technical capability of their generating units at any given time. See section 3.3.3.
AER, SA Government	Proposed rule brings ramp rates and dispatch inflexibility profiles into line with the other technical characteristics of an offer, for instance those related to ancillary services or when a	The Commission considers that ramp rate capability is strongly linked to commercial incentives. For many generators in the NEM there is a strong commercial

Stakeholder	Comment	AEMC response
	generator declares itself inflexible and is unable to follow dispatch instructions (p. 5, p. 1).	incentive to have a highly flexible plant. The Commission considers that the AER's proposed rule has the potential to create a disincentive to invest in flexible plant as it would disproportionately impact generators that are able to provide greater ramp rate capability. See section 3.3.3.
SA Government	Current requirement of 3 MW/minute was determined arbitrarily by reviewing previous bidding behaviour to address the fact that the lack of restrictions on scheduled generators to rebid ramp rates undermined the ability of NEMMCO to manage system security in an economically optimal fashion. While improving on the previous situation, the arbitrary 3 MW/minute limit has no technical basis and still results in unintended outcomes (p. 1).	The Commission acknowledges that, given the commercial incentives caused by conditions of network congestion, a minimum level of ramp rate capability must be provided in the NEM in order to maintain the efficient and secure operation of the dispatch process and to ensure that system security can be maintained. The more preferable draft rule would ensure that the rules that determine minimum ramp rate requirements are applied consistently and proportionately to all generators, which should provide for more efficient wholesale market outcomes in the interests of consumers.
Snowy Hydro	It is not valid to assume that generators would generally be able to operate at their maximum ramp rates submitted in accordance with schedule 3.1. In some circumstances Snowy Hydro's plant could achieve much higher ramping but at very significant increased cost and risk and in other circumstances much less ramping rates than those submitted in schedule 3.1. Cost differences associated with different levels of ramp rates are very material and sensitive between different generation technologies. There would be many technical issues and assumptions made to determine maximum ramp rates (p. 14).	The Commission recognises that in determining the ramp rates to apply to each of their generating units, generators currently take into account the costs associated with wear and tear and the risks of damage to plant. Therefore, each generator is likely to have a range of ramp rates that they consider to be typical of the technical capability of their generating units to which a range of costs may apply. As such, there is a trade-off that exists between the ramp rate capability provided and the costs to the generating unit. Therefore, the determination of ramp rates may not be a purely technical exercise as characterised by the AER.
Snowy Hydro	It would be sub-optimal and completely ineffectual for generators to negate wear and tear through bidding volumes within price bands. There is only limited ability to manage dispatch ramping in this manner. The proposal will	The Commission considers that commercial incentives are a key driver for the ramp rate capability of generators and that, for many participants, flexibility is necessary to provide energy to the market at times of highest value. The

Stakeholder	Comment	AEMC response
	considerably alter incentives on highly flexible generators. Energy constrained hydro generators are driven by the scarce energy resources to offer at the margin of the market. The AER seems to be proposing that these generators should vary the marginal priced energy offers to manage the commercial cost and risks of excessively high technical ramping impact on plant (p. 17).	Commission considers that the AER's proposed rule may create a disincentive to invest in flexible plant by disproportionately impacting generators that are able to provide greater ramp rate capability.
AGL	AGL considers there is merit in exploring applying the existing 3 MW/minute rule to individual physical generation units. This would provide additional ramping capability to NEMDE under certain network conditions. AGL has a number of aggregated units and would support changing the rules in this way (pp. 1-2).	The Commission considers that applying the existing 3 MW/minute to individual physical generating units would not entirely remove the arbitrary nature with which minimum ramp rate requirements are determined under the current rules. The more preferable draft rule would apply minimum ramp rate requirements consistently and proportionately to all participants, which should provide for more efficient wholesale market outcomes in the interests of consumers.
EnergyAustralia	Accept that the current arrangements may create a regulatory distortion that encourages generators to aggregate individual units to benefit from the fixed minimum of 3MW/minute. A pragmatic and administratively simple alternative to deliver a step change increase in ramp capability would be to apply the current limit to each unit (p. 3).	
GDF Suez	Support a minimum ramping requirement and it may be useful to reconsider if 3 MW/minute is still appropriate. However, the level should not be set to the maximum that is technically possible. A potential solution could be for the transmission network service provider (TNSP) to negotiate a form of network agreement with the relevant generator to provide additional ramping capability on a fee-for-service arrangement. Another potential solution is for the 3 MW/minute to be applied on a physical unit basis rather than applied to aggregated totals. Need to consider how ramping capability can be better valued as it becomes more valuable with the increasing presence of	The Commission considers that the rules should require participants to provide a minimum level of ramp rate capability at all times, consistent with AEMO's ability to provide system security. The Commission considers that the proposal to apply 3 MW/minute to individual physical units is likely to be workable in providing the necessary minimum level of ramp rate capability to ensure system security. However, the Commission considers that the proposal would still mean that generators with a greater number of generating units have a higher overall minimum ramp rate requirement.

Stakeholder	Comment	AEMC response
	intermittent renewable generation (p. 3).	
Origin Energy	Imposing a requirement to offer a maximum technical capacity at all times would impose additional risk on generators and increase operating and maintenance costs. Under congestion conditions or when constraints bind, many of the issues identified by the AER are likely to still occur even if the proposed rule was in place. It is therefore worth considering the likely effectiveness of the AER's proposed changes when considering the adoption or a rule that will limit the operations of NEM participants (pp. 4-5).	In consideration of the fact that the rebidding of ramp rates is only one form of generator rebidding that may give rise to the issues raised by the AER, the Commission considers that such issues could be addressed through the Optional Firm Access model currently being considered by the AEMC. Optional Firm Access would delink physical dispatch from financial outcomes in the wholesale market and so align the commercial incentives on generators with the promotion of more efficient market outcomes for consumers.
Arrow Energy	Propose that generators are required to offer two ramp rates – one a technical maximum and the other a lower technical limit or commercial level. The CVP that applies to the latter could be set at below that of system security allowing NEMDE to dispatch those units in advance of potentially increasing system risk. Could also consider separate ramp rates from the energy offer to allow transparent bidding and costing of ramp rates. This would allow generators with multiple ramp rate modes to recover increased costs for different rates. Could also consider limiting the ability to change ramp rates to once within a particular half hour (this would still require the ability to rebid ramp rates if not technically achievable) (p. 6).	The Commission considers that commercial incentives are a key driver for the ramp rate capability of generators and that, for many participants, flexibility is necessary to provide energy to the market at times of highest value. However, the Commission considers that a minimum level of ramp rate capability is necessary in order to provide AEMO with the flexibility to manage the secure operation of the electricity system. The Commission's more preferable draft rule would provide this ramp rate capability on a consistent and proportionate basis.
MEU	The need to use the maximum ramp rate only applies when there is a constraint. So the requirement to advise on ramp rates should have at least two features - one where the preferred ramp rate is advised where its cost reflects the usual operation of the equipment and a second where the technical maximum is advised, but only to be used when there is a constraint (p. 20).	

Stakeholder	Comment	AEMC response
MEU	The application of using a percentage of capacity would result in fast start gas turbines having lower ramp rates than large coal fired power stations. This approach is inconsistent with actual equipment performance (p. 24).	The Commission considers that a requirement for ramp rates to reflect technical capabilities would advantage certain technology types over others. Minimum required ramp rates that are equal to a proportion of the capacity of generating plant would ensure that the rules are applied consistently and proportionately to all participants, which would promote more efficient wholesale market outcomes.
Management of system security and stability		
Snowy Hydro	The 3 MW/minute was set by AEMO and has not been an issue for system security. Looking forward with the oversupply of the NEM and the decline in demand growth the current ramping requirement would continue to sufficiently meet AEMO's system security obligations. Furthermore AEMO has the safety net power of direction and if ramping capability was indeed compromising system security, then AEMO could propose an explicit market for the offering of this service (p. 6).	The Commission notes that the minimum required ramp rate of 3 MW/minute was considered to be sufficient to manage the NEM power system under normal circumstances at the time of the previous rule determination in 2009, and that AEMO confirms that this continues to be the case. See section 3.1.3.
NGF	The NEM has no problems with system security. AEMO can direct participants at any time to change dispatch rather than rely on the market dispatch should there be risk of an insecure operating state (p. 3).	While AEMO maintains the power to direct generators to change output in the interests of system security, the Commission is satisfied that such an occurrence is unlikely to occur under normal circumstances given the existing minimum requirements of 3 MW/minute. See section 3.1.3.
Origin Energy	Origin consider there is no network security issue. AEMO previously advised that 3 MW/minute was sufficient to manage system security incidents. AEMO's powers to override generator offers by issuing directions is an additional tool that can be used to manage power system stability and security (p. 4).	

Stakeholder	Comment	AEMC response
Productive efficiency losses		
SA Government	Generators using ramp rates to avoid volume risk from high prices is inconsistent with the objective of an efficient dispatch where the least cost generation is used to meet demand, thereby being inconsistent with the National Electricity Objective (p. 2).	A generator's offers may take into account a range of factors, such as the opportunity costs of not being dispatched. Rebidding of ramp rates by generators that inhibits a market dispatch arrangement in strict accordance with the ranking of price and volume might not always imply a productive efficiency loss. See section 3.2.3.
SACOSS	All avenues of efficiency losses should be closed off. An argument that the impacts of rebidding ramp rates may be minor compared to other forms of rebidding is not a justification for inaction (p. 5).	The rebidding of ramp rates is only one form of generator rebidding that may give rise to this outcome. As such, the Commission considers that the issue could be addressed through the Optional Firm Access model currently being considered by the AEMC.
Snowy Hydro	The current minimum ramp rate has a negligible impact on AEMO's ability to determine efficient dispatch. The rebidding of ramp rates and changes to dispatch inflexibility profiles is not the underlying cause of inefficient dispatch. Multiple and non-credible transmission outages taken at inappropriate times were the primary cause of the volatile market events in 17 of the 20 events highlighted in the AER Special Report released in December 2012 (p. 6).	The Commission recognises that there are a range of factors that can create the conditions in the market that give rise to inefficient dispatch. These conditions may include generators rebidding ramp rates or changing dispatch inflexibility profiles, but may also include other factors unrelated to generator rebidding that impact the capability of the network, such as the timing of network outages. The Commission notes that the issue could be addressed through the Optional Firm Access model currently being considered by the AEMC. See section 3.2.3.
Snowy Hydro	Dispatch inefficiency due to disorderly bidding (to which only a small quantum can be attributed directly to ramp rates) is immaterial in total as shown by two separately commissioned reports - AEMC 2008 (Frontier Economics) which showed $8m pa and NGF 2013 (Frontier Economics) which showed $10m pa. This is compared to a total market turnover of	The Commission acknowledges the results of earlier studies undertaken to estimate the extent of productive efficiency losses arising from generator rebidding activities, which suggests these are likely to be small relative to total market turnover.

Stakeholder	Comment	AEMC response
	approximately $9 billion (p. 7).	
Snowy Hydro	It is not valid to conclude that changes in the merit order of dispatch necessarily imply productive efficiency losses. While dispatch outcomes in the NEM might be expected in many cases to conform with the "merit order of dispatch" as the stacking of generator dispatch offers in increasing order of offer price, the optimisation of dispatch in the NEM is a co-optimisation of dispatch in the energy and ancillary services markets subject to a variety of constraints. The AER has not provided an estimate of productive efficiency losses attributable to rebidding of ramp rates (p. 9).	The AER's view that generators rebidding ramp rates under constraint conditions leads to productive efficiency losses appears to be predicated on an assumption that a generator's offers are representative of their operational costs. However, the Commission considers that a generator's offers may also take into account a range of other factors, such as the opportunity costs of not being dispatched. As such, the rebidding of ramp rates by generators that inhibits a market dispatch arrangement in strict accordance with the ranking of price and volume offers might not necessarily imply a productive efficiency loss. See section 3.2.3.
EnergyAustralia	Agree that the priority afforded to ramp rates in dispatch can lead to inefficient dispatch outcomes in certain circumstances. However, the materiality of the issue has not been established. Any response should be proportionate and ensure the benefits outweigh the costs (p. 2).	The Commission notes the results of earlier studies that have estimated productive efficiency losses to be small relative to total market turnover. The Commission notes that this issue could be addressed through the Optional Firm Access model currently being considered by the AEMC.
Arrow Energy	Ramp rates and dispatch inflexibilities may only be a symptomatic part of the underlying problem and that other factors may potentially have a greater bearing. Arrow does not see a significant difference between ramp rate bidding and other forms of bidding behaviour, and therefore does not believe that the proposed rule change would reduce the extent of productive efficiency losses (p. 3).	The Commission recognises that there are a range of factors that can create the conditions in the market that give rise to inefficient dispatch. The Commission notes that such issues could be addressed through the Optional Firm Access model currently being considered by the AEMC.
MEU	Efficient dispatch requires the lowest cost generator to be dispatched first and offloaded last. If this merit order is violated because of artificial ramp rates being imposed, then the	The Commission considers that a minimum level of ramp rate capability is necessary in order to provide AEMO with the flexibility to manage the secure operation of the electricity system. Determining the minimum required ramp

Stakeholder	Comment	AEMC response
	outcome is not efficient (p. 14).	rates as a percentage of a generating unit's capacity would promote the efficient operation of electricity services by not advantaging one technology type over another or benefiting aggregated units when generators are required to reduce output through the market dispatch process. This should improve the ability of AEMO to optimise the market dispatch process more efficiently while maintaining the secure operation of the electricity system, which would promote more efficient wholesale market outcomes in the interests of consumers.
Counter-price flows between NEM regions		
Snowy Hydro	The root cause of the counter-price flow events has been multiple non-credible transmission outages. This has equated to 97% of negative settlement residues for the VIC to NSW interconnector and 91% for the NSW to VIC interconnect. It should be noted that AER is responsible for administering the various TNSP incentive schemes that should in theory incentivise the TNSP to schedule planned transmission outages at benign market times (p. 8).	The Commission recognises that there are a range of factors that can create the conditions in the market that give rise to counter-price flows. These conditions may include generators rebidding ramp rates or changing dispatch inflexibility profiles, but may also include other factors unrelated to generator rebidding that impact the capability of the network, such as the timing of network outages. See section 3.1.3.
Origin Energy	Not convinced that counter-price flows create costs for customers as customers would benefit from the lower wholesale spot price in the importing region. Origin also note that the principle whereby customers in the importing region fund shortfalls brought on by negative residues was based on the assumption that these customers would benefit from the lower wholesale spot prices from the interconnector flows (p. 3).	

<table>
<tr><th>Stakeholder</th><th>Comment</th><th>AEMC response</th></tr>
<tr><th colspan="3">Effectiveness of inter-regional hedging</th></tr>
<tr><td>Snowy Hydro</td><td>The use of settlement residue auction (SRA) units is highly risky and unpredictable as a myriad of factors can impact the effectiveness of the SRA units. The majority of all contracting is done intra-regional with generators selling predominantly in their own pricing region. The loss of contract volume as a result of the proposed rule would not be replaced by generators remote from the region due to the increase risk of inter-regional trading and the imperfect nature of the SRA units. The net impact would be a decrease in the overall volume of contracts available to the market. This loss in contract market efficiency would be orders of magnitude greater than any incremental increase in dispatch efficiency (p. 13).</td><td rowspan="2">The Commission considers that commercial incentives are a key driver for the ramp rate capability of generators and that, for many participants, flexibility is necessary to provide energy to the market at times of highest value. Generators may have an incentive to maintain flexibility to support variations in their contract positions. Rules that attempt to prescribe fixed requirements on ramp rate capability have the potential to disrupt the efficient functioning of the market incentive framework. However, the Commission considers that the rules should require participants to provide a minimum level of ramp rate capability at all times, consistent with AEMO’s ability to provide system security. See section 2.3.</td></tr>
<tr><td>MEU</td><td>If one generator uses an artificial ramp rate to remain dispatched out of merit order then another generator is constrained off even though it has offered a lower price and should be dispatched. This is inequitable and reflects that the current rules allow some generators to maximise their profitability at the expense of other generators (pp. 21-22).</td></tr>
<tr><td>Snowy Hydro</td><td>The market has experienced much lower energy and peak demand growth and in this environment it is to be expected that SRA spot accruals would be lower as has been seen. As a result the SRA proceeds are lower. It is completely inappropriate to therefore attribute lower SRA proceeds on rebidding of ramp rates (p. 12).</td><td rowspan="2">The Commission recognises that there are a range of factors that can affect counter-price flows and the value of SRAs. The Commission has not been persuaded that it would be appropriate to make a rule that requires generators to provide a greater minimum level of ramp rate capability that does not address the range of other factors that may contribute to the issues raised. See section 3.1.3.</td></tr>
<tr><td>Origin Energy</td><td>Origin note that declining demand and the oversupply of generation in the NEM has lead to low, flat wholesale prices with minimal regional price differentials. It therefore means that</td></tr>
</table>

Stakeholder	Comment	AEMC response
	under current market conditions SRAs are likely to be low yielding which could help to explain any discount in their value as a hedging instrument (p. 3).	
	Dispatch inflexibility profiles	
Alinta Energy	Concerned fast start inflexibility profiles, including the minimum load and “T-times” entered into the bidding system do not actually reflect technical plant characteristics. Plant have been known to rebid and change their inflexibility profiles and minimum load when commercially beneficial. This has the effect of backing off other generation that would otherwise be dispatched. Fast start plant should not be able to arrange and change minimum load and T-times in a manner which distorts dispatch based on price and quantity. Supportive of a change that aligns all of the rules related to ramp rates and dispatch inflexibility profiles to ensure they at all times reflect the true characteristics of plant and cannot be manipulated for short-term commercial gain (p. 6).	While acknowledging the AER's concerns in relation to inefficient outcomes caused by rebidding ramp rates and dispatch inflexibility profiles at times of network congestion, the Commission considers 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. While the draft rule does not include any changes to the requirements in relation to dispatch inflexibility profiles, the Commission notes that the current requirements in the rules impose a degree of constraint on generators to make changes to time inflexibilities in their dispatch inflexibility profiles. The Commission considers that this has the potential to limit the extent to which generators can use dispatch inflexibility profiles to achieve commercial objectives at times of network congestion. See section 4.5.
NGF	The AER has provided little information to support the change other than a desire for consistency in the treatment of "technical" parameters in offers. While the submission has focussed primarily on ramp rates, our arguments against ramp rates being a technical parameter can similarly be applied to dispatch inflexibility profiles (p. 1).	
GDF Suez	Dispatch inflexibility profiles should be set one day ahead and only changed for technical reasons. The AER would have the ability to ask generators to confirm / demonstrate the legitimacy of any dispatch inflexibility profile rebids provided within 24 hours of dispatch time (p. 3).	