AEMC

RULE CHANGE

Australian Energy Market Commission

CONSULTATION PAPER

National Electricity Amendment (Demand side obligations to bid into central dispatch) Rule 2015

Rule Proponent(s)

Snowy Hydro Limited

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Inquiries

Australian Energy Market Commission
PO Box A2449
Sydney South NSW 1235

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

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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.

Contents

1 Introduction

On 10 June 2015, Snowy Hydro Limited (Snowy) submitted a rule change request to the Australian Energy Market Commission (AEMC or Commission). The rule change request seeks to amend clause 2.3.4 of the National Electricity Rules (NER) in relation to scheduled loads.

Under Snowy's proposed rule, all market customers with market loads[1] 30 Megawatts (MW) or greater that are responsive to, or intend to be responsive to, the electricity spot price[2] would be required to become scheduled loads and participate in the central dispatch process operated by the Australian Energy Market Operator (AEMO). Snowy is not proposing any changes to the requirements or obligations associated with being a scheduled load, including but not limited to, submitting bids, conforming to good faith bidding requirements and complying with dispatch instructions.[3]

This Consultation Paper has been prepared to facilitate public consultation on the rule change proposal, and to seek stakeholder submissions on the rule change request.

This paper:

- sets out the background, and summary of, the rule change request;
- sets out the proposed assessment framework to be used by the Commission in assessing the rule change request;
- identifies a number of questions and issues to facilitate public consultation on the rule change request; and
- outlines the process for making submissions.

While the Commission has not yet determined that there is a material issue to be addressed through a change to the rules, given the technical requirements and obligations associated with scheduled loads and the need for input from stakeholders, it may be necessary to extend the standard timeframe associated with the Commission's rule making process in relation to Snowy's rule change request if the Commission proposes to make a rule.

Submissions to this consultation paper are to be received by 3 December 2015. Details on how to lodge a submission are contained in Chapter 6 of this consultation paper.

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1 For the purpose of this consultation paper a market customer with a market load is also referred to as a market load.

2 The spot price is the price in a trading interval for one megawatt hour of electricity at a regional reference node. Prices are calculated for each dispatch interval (five minutes) over the length of a trading interval (a 30-minute period). The six dispatch prices are averaged each half hour to determine the price for the trading interval. See: http://www.aemo.com.au/Glossary/Glossary-S

3 The rule change request is available on the AEMC's website: www.aemc.gov.au

2 Background

This chapter sets out the following background information in relation to the rule change request:

- an overview of the relevant aspects of the design of the wholesale electricity market;
- demand forecasting in the wholesale electricity market; and
- the current rules relating to scheduled loads.

2.1 The wholesale electricity market

The National Electricity Market (NEM) operates in Queensland, New South Wales, Victoria, South Australia, Tasmania and the Australian Capital Territory. Electricity is traded through AEMO's central dispatch process between generators (supply) and consumers (demand). AEMO is responsible for balancing the supply with demand in real-time through its dispatch process.

2.1.1 Generation in the NEM

Generators are either a market generator or a non-market generator. A market generator is one that sells the electricity it produces into the spot market through AEMO's central dispatch process. A non-market generator is one that sells its electricity directly to a retailer or customer at the generator's connection point (therefore, the electricity is not transmitted through either the transmission or distribution network). For the purpose of this consultation paper, references are to market generators only.

Each market generator is classified as either scheduled, semi-scheduled or non-scheduled generating units. A generator with a nameplate rating of 30 MW or more that has the technical capability to participate in the central dispatch process is generally classified as a scheduled generator.[4] A generator with a nameplate rating of less than 30 MW but more than 5 MW[5], may be granted an exemption by AEMO from the requirement to be registered as a scheduled generating unit if the generator exports less than 20 GWh in any 12-month period or there are extenuating circumstances.[6]

4 NER, clause 2.2.2

5 Generally, there is a standing exemption applied by AEMO in relation to generators with a nameplate rating of less than 5 MW

6 See AEMO Guide to NEM Generator Classification and Exemption: http://aemo.com.au/About-the-Industry/Registration/How-to-Register/Exemption-and-Classification-Guides

A semi-scheduled generator is a generating unit with a nameplate rating of 30 MW or more but which has intermittent output, such as a wind or solar farm.[7] A semi-scheduled generator can supply electricity into the market up to the generator's maximum capacity unless AEMO limits its output due to network constraints.[8]

A non-scheduled generator is generally a generating unit where the amount of electricity sent out to the market is less than 30 MW or the generator does not have the technical capability to participate in AEMO's central dispatch process.[9]

2.1.2 Loads in the NEM

Most consumers in the NEM do not buy electricity directly from the spot market. They contract with a retailer and the retailer purchases electricity on their behalf in the electricity spot market. The retailer may also hedge its exposure to the spot price through the purchase of derivative contracts. For many of these customers, the price they pay for electricity does not reflect the actual spot prices that the retailer paid for the electricity but rather reflects the retail tariff in the customer's retail contract. That said, it may be the case that the customer (usually a very large customer), as part of its retail contract, has contracted for some direct exposure to the spot price. Under the current rules, customers with loads that are settled through retail contracts are not market loads and are not scheduled.

In addition to customers who contract with a retailer to purchase electricity, there are also customers who purchase electricity directly from the spot market. These customers are market customers and their loads are market loads. Market loads may either be scheduled or non-scheduled under the current provisions of the NER. The choice of being scheduled or non-scheduled lies with the market customer. If a load becomes a scheduled load, it will participate in AEMO's central dispatch process.

A load also generally operates as "normally-on" or "normally-off". A "normally-on" load is one where the customer generally operates and consumes electricity, unless or until some event occurs. For example, during a high spot price event, a "normally-on" load may reduce its demand by turning off. A "normally-off" load is one that generally does not consume electricity, unless or until some event occurs. For example, during a low spot price event, a "normally-off" load may increase its demand by turning on.

2.1.3 The central dispatch process

In the NEM, the settlement price is based on the average of the six five-minute dispatch interval prices over the 30-minute trading interval. Market participants that participate in AEMO's central dispatch process include scheduled and semi-scheduled generators, scheduled loads and scheduled network service providers. Each participant is required

7 NER, clause 2.2.7

8 A network constraint occurs when the electricity flowing through an element of the network, whether transmission or distribution, is limited in order to maintain system security.

9 NER, clause 2.2.3

to submit initial price/quantity offers for each of the 30 minute trading intervals to AEMO by 12:30 pm the day before the trading day.

The bids specify the quantities at which each participant is willing to supply or consume electricity at nominated prices. For generators, bids specify the prices and the corresponding quantities that the generator is willing to supply. For scheduled loads, the bids specify the prices and the corresponding quantities that the load is willing to pay and consume. The bids submitted may reflect conditions under which the load will turn on, generally, when the prices are low, or turn off, generally, when prices are high.

Bids can contain up to ten price bands with each band representing an incremental quantity of supply or demand. Although a scheduled participant has to put its initial bids in the day before the trading day, a scheduled participant does have the ability to submit a rebid. Rebidding can be undertaken at any time following the submission of the initial bid up until the relevant five-minute dispatch interval. The only timing constraint on the submission of rebids is a practical limitation of approximately three or four minutes for rebids to be incorporated in the NEM dispatch process and reflected in the dispatch merit order. The re-bid allows market participants to alter the quantities of electricity it will supply or consume in the various price bands of its initial offer.

AEMO uses the information contained in all of the individual bids to create a bid stack representing the known supply and demand intentions of scheduled participants. AEMO also prepares a demand forecast which forecasts the demand of all customers who are not scheduled. Once the bid stack has been created, AEMO uses the information to dispatch generators or loads every five-minutes to balance the supply and demand of the electricity market in real-time.

The price at which the generator or load is dispatched (the dispatch price) is calculated by reference to the bid submitted by the marginal or last market participant dispatched to balance supply and demand. In the NEM, each of the six regions has its own regional spot price that is determined based on the supply and demand conditions in that region.

2.2 The importance of demand forecasting in the NEM

In balancing supply and demand in the NEM, given that the majority of demand is non-scheduled, AEMO must forecast the amount of electricity demand that will occur in the market for each of the trading intervals. Accurate forecasting of electricity demand is an important feature of an efficient market. Market participants may also use the demand forecast information prepared by AEMO in making business or process decisions and therefore the accuracy of this demand forecast may play an important role in achieving efficient market outcomes:

- AEMO may use demand forecasts to inform its operational decisions and processes relating to:
  - the process by which the quantity and price of electricity generation or scheduled load is dispatched;
  - the requirements for Frequency Control Ancillary Services (FCAS);[10]
  - procurement decisions, such as when to procure services through the Reliability and Emergency Reserve Trader (RERT)[11] procedures.
- other energy market stakeholders may use demand forecasts to inform aspects of their decision-making that relates to, for example, generation levels, consumption levels, network planning and regulatory purposes.

AEMO creates a variety of forecasts for electricity demand in the NEM which are used for different purposes. One forecast of electricity demand prepared and published by AEMO is the pre-dispatch schedule. The pre-dispatch schedule examines the scheduled and semi-scheduled generation, scheduled load and projected demand for all trading intervals (30-minute periods) covering the period from the current trading interval up to and including the last trading interval for which participants have provided bids. The pre-dispatch schedule attempts to maximise the value of spot market trading within each trading interval of the pre-dispatch schedule. Maximum trading value is achieved by minimising the cost of meeting forecast regional demand, subject to various constraints considered by AEMO in its central dispatch process (for example, transmission capability constraints).

In forecasting demand, AEMO uses the most probable energy demand for a particular trading interval based on half-hourly historical metering records of as-generated demand which includes the electricity consumed by "normally-on" scheduled loads, among other things. AEMO is then required to back out the scheduled load demand from its demand forecast.

The pre-dispatch schedule does not specifically take into account any historic or projected increases or decreases in demand that may result from a non-scheduled load which is price-responsive to a high or low price event. As a result, the demand forecast does not necessarily reflect the true intentions of demand participants. This may result in a difference between the pre-dispatch supply and demand conditions and the actual supply and demand conditions. This may contribute to a difference in the spot price forecasted in the pre-dispatch schedule and the real-time spot price. The greater the variance between the demand forecast in the pre-dispatch schedule and actual

10 AEMO manages key technical characteristics of the power system, such as frequency and voltage, through ancillary services which it purchases from market participants.

11 Clause 3.20.2 of the NER provides that AEMO must take all reasonable actions to ensure reliability of supply and, where practicable, take all reasonable actions to maintain power system security by negotiating and entering into contracts to secure the availability of reserve under reserve contracts (known as RERT).

real-time demand, the less weight the market may assign to the signals provided in the pre-dispatch schedule. This may lead to inefficiencies in the market.

2.3 Current rule requirements for scheduled loads

Currently, upon request by the market customer, and the market customer having adequate communication and/or telemetry systems to support dispatch instructions, AEMO must classify the market load as a scheduled load.[12]

If a market load is classified as a scheduled load it must submit dispatch bids in accordance with Chapter 3 of the NER[13] and must comply with AEMO's dispatch instructions.[14] The AEMC is currently examining a rule change request relating to compliance with dispatch instructions which, depending on the outcome of the rule change process, may have an impact on scheduled loads.[15]

A scheduled load must adhere to the following requirements or obligations, among others, in relation to its bids submitted as part of AEMO's central dispatch process:

- must specify whether the load is "normally-on" or "normally-off";
- may contain up to ten price bands;
- must specify for each of the 48 trading intervals (30-minute intervals):
  - an incremental MW amount for each price band specified in the dispatch bid; and
  - an up ramp rate and a down ramp rate.
- prices associated with each band which must increase monotonically with an increase in available MWs.[16]

A scheduled load must also comply with the other requirements and obligations set out in the NER related to participation in the central dispatch process. This includes, but is not limited to, compliance with the bidding in good faith provisions and the information provision requirements needed to allow AEMO to prepare the short and medium term projected assessment of system adequacy. The AEMC is currently assessing a rule change request related to the bidding in good faith provisions in the NER which may have an impact on loads if they were to become scheduled.[17]

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12 NER, clause 2.3.4(e)

13 NER, clause 2.3.4 (f)

14 NER, clause 2.3.4(g)

15 The rule change request related to compliance with dispatch instructions is available on the AEMC's website at http://www.aemc.gov.au/Rule-Changes/Compliance-with-dispatch-instructions.

16 NER, clause 3.87

17 The rule change request related to the bidding in good faith provisions is available on the AEMC's website at http://www.aemc.gov.au/Rule-Changes/Bidding-in-Good-Faith

3 Details of the rule change request

This chapter provides detail on the Snowy rule change request.

3.1 Overview of Snowy's proposed rule

Snowy's rule change request includes a proposed rule (clause 2.3.4) which would:

- require a market customer to classify its market load as scheduled if that load is 30 MW or greater and varies, or may vary, its market load in respect to changes in the spot price of electricity;
- allow a market customer to request AEMO to classify its market load as scheduled even if the load is less than 30 MW or if the load does not vary its consumption based on the spot price of electricity;
- require a market customer whose market load has been classified as a scheduled load to submit bid and offer validation data to AEMO;[18]
- require a market customer whose market load is scheduled to have adequate communications and/or telemetry to support the issuing of dispatch instructions and the audit of responses; and
- require a market customer to submit dispatch bids in respect of scheduled loads.[19]

3.2 Rationale for the proposed rule

In its rule change request, Snowy provides its rationale for the proposed changes to the NER. Snowy indicates that the main impetus for its rule change request is to improve the efficiency of the price discovery process.

In the rule change request, Snowy considers that access to information about supply and demand side intentions underpin the efficient price discovery process but at present only scheduled participants, usually only scheduled and semi-scheduled generators, provide this information to AEMO. Therefore, the majority of demand, which is currently unscheduled, does not provide information on its intentions to the market.

Snowy provides that the different treatment between scheduled and non-scheduled participants leads to material inefficiencies in the price setting process, including:

- **Reduction in confidence in pre-dispatch prices**: pre-dispatch prices reflect the supply and consumption intentions of scheduled market participants and

18 The bid and offer validation data is the standard data requirements for the verification and compilation of dispatch bids and dispatch offers on the trading day schedule.

demand forecasts prepared by AEMO. However, given that price sensitive loads can change their consumption without informing the market, the pre-dispatch price does not reflect this change in demand;[20]

- **Inaccurate reserve forecasting by AEMO:** non-scheduled loads may impact AEMO's function of ensuring adequate reserves for the reliable supply of electricity. This is because AEMO is not aware of when non-scheduled loads may reduce demand and hence, AEMO has to forecast its reserve requirements without any information regarding how the non-scheduled load will behave;[21]

- **Impedes AEMO's ability to manage the central dispatch process:** non-scheduled loads impact on the central dispatch system as they reduce the effectiveness of AEMO's transmission constraint equations which set the operational boundaries for secure and reliable system operation;[22]

- **Incorrect pricing of financial contracts**: non-scheduled loads result in incorrect pricing of financial contracts in both the short and long term. In the short term, day ahead outage cover could be incorrectly priced. The pricing error is caused by high pre-dispatch forecast prices but lower actual spot prices when demand management is not taken into account in the pre-dispatch price. In long term financial contracts, prices don't reflect underlying supply and demand and therefore, may impact new entrant timing decisions.[23]

Snowy indicates that the proposed rule would improve transparency in the NEM resulting in more confidence that the price signals from AEMO's central dispatch process reflect the actual underlying supply and demand conditions.

3.3 Snowy's National Electricity Objective assessment

Snowy argues that the rule change request will contribute to the achievement of the National Electricity Objective (NEO) as a result of:

- **More efficient operations:** more predictable prices will improve spot market operations;[24]

- **More accurate forecasting of reserve requirements and more efficient management of the central dispatch process:** more accurate forecasting of reserve requirements helps AEMO maintain a reliable and secure system. Further, the proposed rule would mean AEMO could rely on scheduled bids, from generators and loads, to more accurately forecast:

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19 Snowy rule change request, Appendix A

20 Snowy rule change request, pp.7 & 8

21 Snowy rule change request, pp. 8 & 9

22 Snowy rule change request, p.9

23 Snowy rule change request, pp. 9 & 10

24 Snowy rule change request, pp. 12 & 13

- loading on interconnectors;
- the expected loading for each scheduled generating unit; and
- to fulfil its general system security and reliability obligations.[25]

- **More efficient pricing of financial products in the contract markets:** the prospect of asymmetric or non-transparent information available only to some market participants has an adverse impact on market liquidity and contracts would incorporate a higher risk premium to factor in increased risk. In the long term, spot and contract prices which are reflective of underlying supply and demand conditions will help inform efficient investment of capital in the system.[26]

3.4 Expected costs, benefits and impacts of proposed rule

Snowy indicates that the following entities may be impacted as a result of the rule change request:

- Generators: the proposed rule would improve the allocation of scarce resources;
- Financial intermediaries: would be better able to price contracts with more accurate forecasts of supply and demand;
- Consumers: would be able to make more informed consumption decisions; and
- Australian Energy Regulatory (AER): the proposed rule would remove administration costs in investigating price spikes or price floors caused by sudden changes in non-scheduled demand.

Snowy provides that the expected costs for the impacted market loads associated with implementing the proposed rule would be the result of:

- setting up communication channels to send telemetered (4 second) consumption information to AEMO and receive dispatch targets; and
- setting up a trading platform to allow submitting of bids.

Snowy indicates that it is inherently difficult to quantify the impact of non-scheduled load on the efficiency of the price-setting process, AEMO's functions to maintain a reliable and secure power system, and the incorrect pricing of financial contracts. That said, the qualitative assessment of how the proposed rule would better fulfil the NEO suggests there would be significant net benefits from the proposed rule by improving the efficient price discovery process.[27]

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25 Snowy rule change request, p. 14

26 Snowy rule change request, p. 14

27 Snowy rule change request, p.15

Question 1 The rule change request

(a) Is the lack of participation of market loads as scheduled loads in AEMO's central dispatch process, a material issue, in relation to the price discovery process or any other aspect of the market's operation?

(b) Has the problem related to lack of participation by market loads as scheduled loads in AEMO's central dispatch process been correctly identified in the rule change request?

(c) If no, what problem or issue, if any, arise as a result of market loads not participating in AEMO's central dispatch process as scheduled loads?

(d) Does Snowy's proposed rule address the issue identified in the rule change request?

(e) If no, are there other ways to address the issue identified in the rule change request?

4 Assessment Framework

The Commission, in its assessment of the rule change request, must consider whether the proposed rule will, or is likely to, contribute to the achievement of the NEO, as set out under section 7 of the National Electricity Law (NEL).

The NEO is:

> "The objective of this Law is to promote efficient investment in, and efficient operation and use of, electricity services for the long term interests of consumers of electricity with respect to-
>
> (a) price, quality, safety, reliability and security of supply of electricity, and
>
> (b) the reliability, safety and security of the national electricity system."

The most relevant aspects of the NEO appear to be the efficient investment in, and efficient operation and use of electricity services for the long-term interests of consumers with respect to the price of supply of electricity, and the safety and reliability of the national electricity system.

An approach for assessing whether the proposed rule is likely, to promote the NEO is set out below. Stakeholders feedback on the proposed approach outlined in this consultation paper is welcome.

To determine whether the proposed rule, if made, is likely to promote the NEO, the following factors may be considered as part of the AEMC's assessment:

- **Prices that reflect the marginal cost of supply and value of its use:** the potential of the proposed rule to better inform electricity spot prices by including both supply and demand side information, thereby increasing the accuracy of AEMO's pre-dispatch schedule and the price discovery process, potentially leading to better investment and operational decisions by market participants and other energy market stakeholders;

- **Prices of financial derivatives:** impact on the pricing of financial derivatives in the market as a result of increased information available to all parties in respect of the intentions of scheduled loads, decreased unexpected price volatility and reduced reliance on forecast inputs into the pricing of the derivatives;

- **Improvements in market operation:** the potential of the rule change request to impact the decisions of AEMO in relation to the amount of FCAS required to ensure the safe and reliable operation of the electricity system resulting from loads' behaviour at various spot prices being known in advance;

- **Planning:** the potential of the rule change to assist AEMO in planning and procuring other market services required to ensure the safe and reliable operation of the electricity system over the medium and long-term;

- **Impact on market participants:** the impact of the rule change on:
  - the incentives and disincentives of market loads to participate in AEMO's central dispatch process under the NER;
  - the degree to which the proposed rule creates an obligation on parties to participate in the central dispatch process;
  - how the obligation impacts market loads' incentives to respond to price signals and participate in the spot market; and
  - the resulting impacts on the long-term interests of consumers.

  The qualitative, and where possible, quantitative information on the potential costs and benefits incurred by market participants as a result of the proposed rule, including the allocation of costs and benefits among the various participants, are proposed to be examined.

- **Potential regulatory and administrative burden:** the potential regulatory and/or administrative burden on market participants, and in particular market customers with market loads, that may arise if the proposed rule where to be implemented.

The proposed rule will be assessed against the relevant counterfactual of not making the proposed changes to the NER. That is, against the current situation whereby market customers with market loads have the option, but not the obligation, to be registered as a scheduled load and participate in the central dispatch process.

5 Issues for Consultation

Taking into consideration the assessment framework set out in Chapter 4, a number of issues that appear to be relevant to this rule change request have been identified for consultation.

In particular some issues affecting the implementation of the proposed rule and alternative options to address the issues raised in the rule change request are canvassed. These questions have been posed to inform further consideration of the proposal, if the Commission concludes that there is a material problem to be addressed.

The matters are outlined below and are provided for guidance only. Stakeholders are encouraged to provide written submissions to the AEMC on them, as well as any other relevant aspects of the rule change request or this paper.

5.1 Participation of market loads in the NEM

Under the current rules, a market customer with a market load may elect to become a scheduled load and participate in AEMO's central dispatch process. To date, with the exception of a few pump storage facilities, no such customers have elected to become or remain a scheduled load.[28]

As a result of most market loads being non-scheduled, AEMO's pre-dispatch process does not explicitly take into account any intentions of these market loads to respond to price signals by turning off (where the load is "normally-on") or turning on (where the load is "normally-off") as a result of spot prices. This is due to the fact that a non-scheduled load has no obligation to provide AEMO with its firm intentions relative to its demand consumption over the trading day.

Non-scheduled market loads may impact the spot price or other market participants through increasing or decreasing the demand, when certain conditions are present. For example, a "normally-off" load may turn on when certain conditions are present, i.e. low-prices or network constraints, which may have an impact on AEMO's ability to dispatch generation according to the bid stack. The AER in its *Special Report Market outcomes in South Australia during April and May 2013*[29] provided:

> "... In a condition where a region is importing at or close to the interconnector limit, a change in demand can only be managed by ramping generators in that region. In South Australia around one quarter of conventional generation is fast start peaking plant that can start up in less than 30 minutes (but which cannot start in five minutes). When there are relatively few generators online, small changes in demand cannot be met

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28 It is our understanding that when the NEM first started a few market loads where scheduled, but those market loads subsequently requested that they no longer be classified as a scheduled load.

29 AER, *Special Report Market outcomes in South Australia during April and May 2013* July 2013

by ramping generation in merit order, which can cause high priced offers to be dispatched setting very high five minute dispatch prices ...[30]"

Market participants having information on the intentions of scheduled loads, in situations like the one discussed above and other, may impact on the outcome of the dispatch process, such as the one discussed above, and may provide market participants with the ability to incorporate this information into their decisions regarding their own behaviour in the market.

Further, as non-scheduled market loads do not currently provide bids into the central dispatch process, but rather may turn off or on based on an examination of the costs of various inputs into its business (including the spot price of electricity), economic conditions and contractual requirements, the forecast demand on which AEMO bases its dispatch process, in some cases, may not equal actual demand. This may result in less accurate information being provided to the market. Further, this may require AEMO to balance the actual supply and demand conditions through the use of FCAS to maintain the electricity system in a safe and reliable condition.

Other longer term market services obtained by AEMO or network service providers to provide a safe, secure and reliable system may be impacted by the behaviour of non-scheduled market loads.[31] For example, Network Support and Control Ancillary Services (NSCAS) may be obtained by AEMO to maintain system security and reliability, and to maintain or increase the power transfer capability of the transmission network. In determining the NSCAS needed, AEMO would examine the best available information; however, this information currently would not include bid information from most market loads. The requirement for a market load to become scheduled would allow AEMO to take into account the intentions of scheduled loads and may impact its decisions regarding NSCAS and other market services.

Snowy has stated in its rule change request, that as spot prices are derived from AEMO's central dispatch process and that this process provides price signals to participants to respond to actual supply or consumption intentions, inaccurate information leads to inefficiencies for market participants and may negatively impact decisions made by various parties in the market. An accurate central dispatch process, in Snowy's view, is essential for efficient price discovery and access to timely and accurate information about supply and demand side intentions underpins this process. Currently, only scheduled or semi-scheduled participants have to provide information to AEMO which, in Snowy's view, leads to inefficiencies in the price discovery process and therefore in the market.

Under Snowy's proposed rule, the lack of information regarding demand intentions would be addressed through an obligation on market loads 30 MW or greater that are, or intend to be, price responsive to bid into the central dispatch process. By consequence, this would mean that all other demand would not have to become scheduled. Given that, it may be necessary to consider the impact of, what may be a

30 AER, *Special Report Market outcomes in South Australia during April and May 2013* July 2013, p. 30

31 See Snowy's rule change request, pp. 8 & 9

relatively small percentage of total demand becoming scheduled, on the price discovery process and the overall operation of the central dispatch process.

Question 2 Market Impacts

(a) What would be the impacts, positive or negative, on the behaviour of market loads if they were required to become scheduled?

(b) What would be the impacts, positive or negative, on the behaviour of market participants, such as scheduled, semi-scheduled and non-scheduled generators, if market loads were required to become scheduled?

(c) What would be the impacts, positive or negative, on the price signals in the pre-dispatch and dispatch periods and the half hour trading intervals if market loads were required to become scheduled?

(d) What are the impacts, positive or negative, in relation to the procurement and use of FCAS by AEMO as a result of market loads being non-scheduled?

(e) Are any negative impacts related to the procurement and use of FCAS by AEMO mitigated if market loads are scheduled?

(f) What other market services obtained and used by AEMO to ensure system safety and reliability are impacted as a result of the market loads being non-scheduled?

(g) What are the impacts, positive or negative, in relation to the other market services as a result of market loads being non-scheduled?

(h) Are any negative impacts related to the other market services obtained and used by AEMO mitigated if market loads are scheduled?

Question 3 Obligation on market loads

Although the Commission has not yet concluded that there is a material problem which needs to be addressed, if a material problem does exist what are stakeholders' views on the following:

(a) Is 30 MW or greater, the appropriate threshold for mandatory participation of market loads as scheduled loads in AEMO's central dispatch process?

(b) If not, how should the threshold for mandatory participation of scheduled loads be determined?

(c) Given that market loads do not have a nameplate rating (whereas generators do), how should the size of a market load be determined (eg. average consumption, maximum consumption, single connection point)?

(d) Should a market load only be required to participate in the central dispatch process if it is, or intends to be, responsive to the electricity spot price?

(e) If the obligation to participate in AEMO's central dispatch process as scheduled loads, should only apply to price responsive market loads, how should it is be determined if a market load is, or intends to be, responsive to the electricity spot price?

(f) What requirements or obligations are necessary to ensure that market loads do not change their behaviour so as to avoid the requirements associated with the mandatory obligation to participate in AEMO's central dispatch process?

5.2 Incentives and obligations

Under the current rules, a market load may have an economic incentive to respond to the electricity spot price. The market load may consider the costs of various inputs into its business, economic conditions and contractual requirements and determine when it might be economical to reduce or increase its electricity demand. One of the considerations customers with loads may have is whether to become a market load (buying directly from the electricity market) or to engage a retailer to buy on its behalf. Currently, a market load is not required to consider the costs associated with being a scheduled load, including the upfront and ongoing costs to comply with the various requirements or obligations to participate in the central dispatch process.

A market load may have an incentive to respond to spot prices, but may not, under the current rules, have an incentive to become a scheduled load. This is evidenced, in part, by the fact that currently very few market loads operate as a scheduled load. The overwhelming incentive for market loads appears to be to minimise the cost of electricity by changing demand. As market loads can currently change their demand at any time, the additional incentives for the market load to become scheduled and incur the upfront and ongoing costs associated with being scheduled are not evident. However, incentives may exist for market loads which could provide a basis for them to become scheduled.

Regardless of whether there are incentives for market loads to become scheduled, there may be benefits to the whole market from a market load being scheduled.

In circumstances where a mandatory obligation requires a party to do something where an incentive may not exist, it is necessary to examine whether the mandatory obligation creates any disincentives or reduces the effectiveness of the incentives that already exist. In this case, Snowy's proposed rule imparts a mandatory obligation on some market loads to become scheduled. It will be necessary to assess whether this mandatory obligation would impact market loads' incentive to be price responsive and if so, to what degree. If a mandatory obligation creates a disincentive, it is important to examine what, if anything, could be done to ensure that the positive behaviour continues regardless of the mandatory obligation and to minimise any disincentives.

Question 4 Incentives and obligations

(a) Do any incentives currently exist for market loads to become scheduled loads?

(b) If no, could incentives be created in the market to encourage market loads to participate in the central dispatch process as scheduled loads without creating a mandatory obligation on market loads to become scheduled?

(c) If a mandatory obligation is created requiring market loads to become scheduled, how may this impact the behaviour of market loads in the electricity spot market?

(d) If a market load's incentives are impacted by a mandatory obligation how can market loads behaviour be aligned with the intentions of the proposed rule?

5.3 Provision of information

Snowy indicates in its rule change request that as a result of pre-dispatching prices only reflecting the supply and demand intentions of scheduled participants, the pre-dispatch price ignores a significant portion of demand; namely the price-sensitive market loads.[32] AEMO currently uses supply bids, demand bids (where provided), and historic and other information to forecast demand to create the pre-dispatch schedule and operate the central dispatch process.

Due to the nature of the demand forecast and pre-dispatch process currently used by AEMO, it is difficult to incorporate historic price response information from market loads. For example, if historic decreases in demand were incorporated into the demand forecast, then the forecasted spot price may reflect a lower price as the supply and demand would be balanced at a lower price in the bid stack. However, at this lower price, the market load would not decrease demand and the demand forecast would have underestimated demand which may result in a higher actual real-time spot price.

If a market load is required to be scheduled, then the supply and demand bid information, together with the demand forecast (which would no longer include the scheduled market loads) would be used by AEMO in its pre-dispatch schedule and in the central dispatch process. Given that these would now be based on more bid information and less forecasted information, the result may be a measure of supply and demand conditions that more accurately reflect the actual real-time supply and demand conditions. This may have an impact on the price discovery process.

There is a possibility that the provision of additional information from market loads, including their firm intentions regarding increasing or decreasing consumption based on specific electricity spot prices, may be possible without the requirement of a mandatory obligation for market loads to become scheduled. However, a requirement

32 Snowy's rule change request, p. 7

to provide information would not oblige the relevant load to consume at the intended level. A risk may arise that the actions of the load will not reflect the information they have provided in relation to their intentions. Therefore, this may have an impact on the usefulness of the information provided.

Question 5 Provision of information

(a) Is it possible to address the issues raised by Snowy in its rule change request, through the provision of further information from market loads in relation to their intentions to increase or decrease their consumption at specific spot prices?

(b) If yes, what form would this additional information take?

(c) If additional information were to be provided, what mechanisms or incentives could be used to ensure that the information provided and updated by market loads reflects the market loads true intentions relative to its consumption under various spot prices?

5.4 Implications on the derivatives market

Many market participants, including generators, retailers and market customers with market loads, use financial derivatives to protect from a high or low electricity spot price, which is often referred to as market risk.

There are generally three main types of financial derivatives being swaps, options and futures, which may be used to manage market risk. There are also variations of these three main types of derivatives that may be available in the market, in addition to other derivative products where the terms and prices are negotiated between two parties (and which are generally referred to as over-the-counter products).

Generally, derivatives are traded at prices that reflect various market conditions including the volatility of the underlying commodity, in this case electricity. As extra information provided by market loads participating in the central dispatch process may result in fewer inputs into derivative pricing having to be forecasted, less uncertainty may be built into the pricing of the derivatives themselves. We will examine the impact of the rule change request on derivative pricing and the short and long term impacts on consumers as a result.

Further, as derivatives may be used to manage market risk, it is necessary to also examine the incentive of market loads to limit their exposure to high price events by using derivatives rather than increasing or decreasing their actual demand. If a market load is fully hedged against prices (which means it faces no exposure to high prices), then it may not decrease demand in the event of a high price. This may impact other market participants whereby they may face prices different than they would have if the market load had not been fully hedged and had responded to the spot price. This may result in higher spot prices being paid by other market participants, and potentially their customers. Alternatively, other market participants may themselves obtain further derivative products to further hedge their risk against high price events. This may impact on their costs or may eventually flow through to their customers.

Question 6 Implications on derivatives market

(a) What are the costs and/or benefits to the derivatives markets (both exchange traded and over-the-counter) of market loads becoming scheduled?

(b) If so, what are these costs and benefits?

(c) Are there costs and/or benefits to the various market participants of increased participation by market loads in the derivatives market?

(d) What types of over-the-counter derivatives products are used by market participants to mitigate market risk under the current arrangements?

(e) How would these other derivative products be impacted, either positively or negatively, by market loads becoming scheduled?

5.5 Technical requirements

Under the current rules, a market load may either be scheduled or non-scheduled. If scheduled, the market load must comply with all of the requirements and obligations associated with being scheduled, which are generally the same requirements and obligations associated with being a scheduled generator.

The requirements and obligations of a scheduled generator are different than the requirements and obligations associated with being a semi-scheduled generator. These differences arose as a result of numerous market and non-market considerations which resulted in a new class of generator being created to take into account the differences, capabilities and limitations of semi-scheduled generators. It may be appropriate to examine, in depth, the technical requirements and obligations associated with being a scheduled load to determine if all market loads can comply with all of the requirements and obligations that under the current rules would be applicable to scheduled loads or if specific requirements related to some or all market loads would be more appropriate.

The types of issues that may need to be resolved, include, but are not limited to:

- the minimum communication and/or telemetry requirements needed for market loads to participate in the central dispatch process;
- possible ramp up and ramp down rates associated with market loads and whether there are any issues specific to market loads that need to be considered in relation to ramp rates;
- how base load or uncontrollable load components of a market loads' total load is accounted for under the requirements and obligations associated with being a scheduled load; and

- bid structure for market loads including if it is necessary to take into account the load's ability to only step up or step down consumption in block increments.

While the Commission has not yet determined that there is a material issue that must be resolved, the problem identified involves numerous technical requirements and obligations. If the Commission considers that there is a material problem to be addressed, it may be necessary to form a technical working group to explore the technical requirements associated with a new class of scheduled load. If this is to occur, the timing for the draft rule determination may be affected such that the standard rule making process timeframe will have to be extended.

Question 7   Technical requirements

(a) Are stakeholders aware of any technical limitations of market loads which would not allow, or make it difficult for, market loads to comply with the requirements and obligations that currently exist for scheduled loads that participate in the central dispatch process?

5.6 Costs and Benefits

Under the current arrangements, a market load can decide if and when, it will respond to movements in the spot price. If a market load determines it will decrease its demand, the market load will generally benefit from this decision through electricity cost savings. The main cost of a market load deciding to reduce its consumption is generally the opportunity cost of foregone operational outcomes due to the reduction in electricity demand. A business will assess the benefit and the costs to it and determine when, if ever, it is appropriate to decrease its electricity demand. This assessment may change over time depending on factors particular to the business, such as cost of other inputs into the business, contractual obligations and general economic conditions.

However, given that the market, and generators in particular, have no advance notice of a non-scheduled market load's intention to reduce or increase demand, decisions made based on the best available information, including the pre-dispatch schedule, may be impacted as a result of decisions made by non-scheduled market loads. For example, as raised by Snowy in its rule change request,[33] based on the pre-dispatch schedule, the bid stack and forecasted demand, a peaking generator[34], whether scheduled or non-scheduled, may ramp up to meet the forecasted demand at a particular price but may not be dispatched. As a result, the peaking generator may not be able to recover the costs associated with ramping up its generator. If the peaking generator is not able to recover its costs it may become uneconomical for the peaking generator to continue to operate in the market. Other impacts may also result on

33 Snowy rule change request, p.8

34 A generator may operate as either a base load or peaking generator. Base load generation provides steady power flows into the electricity system, and generally only stops for repairs or maintenance. Peaking generation provides electricity into the market at times of increased demand, and therefore, generally during high price events.

generators and other market participants as result of no advance notice being provided by non-scheduled market loads.

Further, when there is an unexpected decrease or increase in demand, AEMO must manage the safety and reliability of the system by deploying FCAS. The deployment of FCAS comes at a cost to the market. AEMO must forecast how much FCAS is necessary in the market to address numerous contingencies in the system, including the contingency associated with an unexpected decrease or increase in demand. If market loads were scheduled, the decision made by AEMO in relation to the procurement and use of FCAS may be affected.

The inclusion of bid information from market loads into the central dispatch process may impact on the level of price volatility in the spot market overall. The impacts of price volatility on the market and its participants generally, will be examined.

Requiring market loads to bid into the central dispatch process would result in costs being borne by market customers with market loads. These costs relate to the installation and operation of the required telecommunication and/or telemetry equipment, additional personnel and other costs associated with meeting all the requirements or obligations associated with being scheduled.

Question 8 Costs and benefits

(a) Under the current arrangements in the NER, what are the qualitative and/or quantitative costs and benefits associated with the current operation of the market given market loads are not generally scheduled, including but not limited to the market loads' ability to respond to changes in the spot price, the pre-dispatch process including the demand forecast, the central dispatch process, and system safety and reliability with respect to:

- **market customers with market loads;**
- **generators, both base load and peaking generation;**
- **AEMO;**
- **retailers and their customers;**
- **other parties who participate in the market?**

(b) Under the proposed rule, what are the qualitative and/or quantitative costs and benefits associated with the operation of the market given market loads requirement to become scheduled, including but not limited to the market loads ability to respond to changes in the spot price, the pre-dispatch process including the demand forecast, the central dispatch process, and system safety and reliability with respect to:

- **market customers with market loads;**
- **generators, both base load and peaking generation;**
- **AEMO;**
- **retailers and their customers;**
- **other parties who participate in the market?**

6 Lodging a Submission

The Commission invites written submission on this rule change proposal[35]. Submissions are to be lodged online or by mail by 3 December 2015 in accordance with the following requirements.

Where practicable, submissions should be prepared in accordance with the Commission's Guidelines for making written submissions on Rule change proposals.[36] The Commission publishes all submissions on its website subject to a claim of confidentiality.

All enquiries on this project should be addressed to Shari Boyd on (02) 8296 7869.

6.1 Lodging a submission electronically

Electronic submissions must be lodged online via the Commission's website, www.aemc.gov.au, using the "lodge a submission" function and selecting the project reference code ERC0189. The submission must be on letterhead (if submitted on behalf of an organisation), signed and dated.

Upon receipt of the electronic submission, the Commission will issue a confirmation email. If this confirmation email is not received within 3 business days, it is the submitter's responsibility to ensure the submission has been delivered successfully.

6.2 Lodging a submission by mail or fax

The submission must be on letterhead (if submitted on behalf of an organisation), signed and dated. The submission should be sent by mail to:

Australian Energy Market Commission
PO Box A2449
Sydney South NSW 1235

The envelope must be clearly marked with the project reference code: ERC0189.

Alternatively, the submission may be sent by fax to (02) 8296 7899.

Except in circumstances where the submission has been received electronically, upon receipt of the hardcopy submission the Commission will issue a confirmation letter.

If this confirmation letter is not received within 3 business days, it is the submitter's responsibility to ensure successful delivery of the submission has occurred.

35 The Commission published a notice under section 95 of the NEL to commence and assess this rule change request.

36 This guideline is available on the Commission's website.

Abbreviations

AEMC	Australian Energy Market Commission
AEMO	Australian Energy Market Operator
AER	Australian Energy Regulatory
Commission	See AEMC
FCAS	Frequency Control Ancillary Services
MW	Megawatts
NEL	National Electricity Law
NEM	National Electricity Market
NEO	National Electricity Objective
NER	National Electricity Rules
NSCAS	Network Support and Control Ancillary Services
RERT	Reliability and Emergency Reserve Trader
Snowy	Snowy Hydro Limited