RULE CHANGE

AEMC

Australian Energy Market Commission

DRAFT RULE DETERMINATION

National Electricity Amendment (Non-scheduled generation and load in central dispatch) Rule 2017

Rule Proponent(s)

ENGIE
Snowy Hydro Limited

20 June 2017

Inquiries

Australian Energy Market Commission
PO Box A2449
Sydney South NSW 1235

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

Reference: ERC0203

Citation

AEMC 2017, Non-scheduled generation and load in central dispatch, Rule Determination, 20 June 2017, Sydney

About the AEMC

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

Summary

The National Electricity Market (NEM) is undergoing significant transition. Technological developments are impacting on generation and consumption decisions, a trend which is likely to continue into the foreseeable future.

The Australian Energy Market Commission (AEMC or Commission), the Australian Energy Market Operator (AEMO) and others are undertaking work to examine the issues raised by this transition. These projects are looking at what, if any, changes may be required for efficient generation and consumption of electricity while maintaining power system security.

It is in this context that the AEMC considered two rule change requests which would require additional participants to participate in the central dispatch process. Specifically, the rule change requests sought to alter the way:

- price responsive loads with maximum demand greater than 30 MW, and
- non-intermittent non-scheduled generators with nameplate generation capacity 5 MW or greater

participate in the market by making it mandatory to participate in central dispatch processes.

The principle issue raised in the two rule change requests relates to pre-dispatch demand and price forecasting inaccuracy. In particular, that the behaviour of non-scheduled generation and price-responsive load cause forecasting inaccuracies that leads to inefficiencies in the electricity market.

The Commission has decided not to make a draft rule. The Commission is of the view that the materiality of the issue raised by the rule change requests is insufficient to warrant making the proposed changes. The Commission's analysis indicates:

- the proposed changes would only apply to a limited number of generators and loads, and would have limited impact on forecasting accuracy
- AEMO's demand forecasts are generally accurate at dispatch, and its price forecasts provide signals to the market to enable participants to plan and adjust their generation or consumption
- the proposed changes would place considerable costs and obligations on parties that are not justified by the limited benefits that may accrue
- AEMO has a range of powers to address forecasting issues and maintain system security, including security issues arising from market participation.

On this basis the Commission has determined that any change to the requirements to participate in the central dispatch process is not in the long-term interests of consumers

and will not, or is not likely to, contribute to the achievement of the National Electricity Objective (NEO) at this time.

Background

In the central dispatch process AEMO balances electricity supply and demand in five minute intervals. In order to achieve this balance AEMO receives information from scheduled participants on their generation and consumption intentions, and forecasts generation and consumption for the remainder of the market.

- Scheduled participants are generally non-intermittent generating units above 30 MW. They are required to submit price/quantity bids specifying their generation intentions, and must comply with dispatch instructions from AEMO
- Semi-scheduled generators are intermittent generators above 30 MW. AEMO forecasts their generation via specific wind and solar forecasting models. The semi-scheduled generators then specify prices for their generation. AEMO can require these generators to limit their output to a specific level if required
- Non-scheduled generators may be intermittent or non-intermittent and generally have a nameplate capacity between 5 MW and 30 MW. These generators are not required to provide information on their generation intentions. AEMO forecasts the output from this category, and generally does not constrain their generation output
- Unscheduled generators are intermittent or non-intermittent generating units that are less than the threshold 5 MW requirement for registration. These generators do not participate in central dispatch. AEMO forecasts the generation of this category, and does not constrain their output. They are not the subject of these rule change requests.

The 30 MW threshold for registration as a scheduled or semi-scheduled generator is contained within the National Electricity Rules (NER). The 5 MW threshold for registration exemption is contained in AEMO generator registration guidelines.

The rule change requests

The AEMC received two related rule change requests, from Snowy Hydro Limited (Snowy) and ENGIE, which relate to the obligations of market participants to participate in the AEMO's central dispatch process.

Snowy's rule change request proposed that price responsive loads over 30MW be required to participate in central dispatch as scheduled participants. The rule proponent's view is that unless all market participants provide AEMO with information about their supply and demand side intentions, an inefficient price discovery process could lead to market inefficiencies, including reduced confidence in pre-dispatch prices, inaccurate reserve forecasting by AEMO, a reduced ability for AEMO to manage the central dispatch process and an incorrect pricing of financial contracts. Snowy proposed that extending the scheduling requirement to price responsive loads would address these issues.

ENGIE's primary proposal was for non-intermittent non-scheduled generators greater than 5 MW to be scheduled. ENGIE's alternative proposals were for a new class of "soft-scheduled" generator to be created requiring these generators to provide information relating to their generation intentions, and that AEMO develop a process to estimate demand responsiveness and to provide this information to the market in the form of proxy bids.

ENGIE considers that all market participants capable of impacting market outcomes need to be equally obliged to inform the market of their intentions, and that the significant growth in non-scheduled generation in recent years is having a material impact on market outcomes, including causing generation inefficiency. ENGIE also considers that information asymmetries cause AEMO to take a more conservative approach to managing the security of the power system.

Market participants covered by the rule change requests

In November 2016, there were 96 registered non-scheduled generators with nameplate generation capacity of 5MW or greater in the NEM representing total capacity of 2,872MW. Only a third of these generators are potentially suitable for scheduling. That is:

- intermittent renewable generators such as wind and solar PV would be categorised as semi-scheduled generators and are not covered by the rule change request
- generators that produce electricity as a by-product of an industrial or commercial process rather than in response to electricity market conditions may not be suitable for scheduling.

Netting off these categories from total non-scheduled generation leaves 33 generators representing 771 MW of capacity that are potentially able to be scheduled. This represents less than 2% of the total registered generation capacity in the NEM. This breakdown is summarised in the following table.

Table 1 **Breakdown of registered non-scheduled generation, November 2016**

	Number	Share of total	MW	Share of total
Total non-scheduled	96		2,872	
Of which: intermittent renewable	23	24%	1,268	44%
Of which: industrial process	40	42%	828	29%
Remaining - potential for scheduling	33	33%	771	27%
NEM total			49,091	
Remaining as % of NEM total			1.6%	

Note: registered non-scheduled generators with a capacity 5 MW or greater

In relation to large loads, there are 36 unscheduled loads with maximum demand above 30 MW in the NEM. Together they account for approximately 18 per cent of average total load in the NEM. At a regional level, these loads represent varying proportions of average regional demand:

- in Tasmania, four loads represent 41 per cent
- in Queensland, 12 loads represent 26 per cent
- 20 loads in New South Wales, Victoria and South Australia represent between 12 and 15 per cent.

Of relevance to the rule change request is whether these loads are "price responsive"; that is, whether they vary their consumption in response to high or low spot market prices. Not all 36 large loads would be price-responsive in this sense and therefore subject to Snowy’s proposed rule.

The Commission engaged Ernst and Young to undertake a quantitative analysis to determine if loads (and non-scheduled) generators are spot price-responsive and if there is a link between spot price-responsive behaviour and forecasting accuracy. The conclusions of the study were limited by the unavailability of five minute metering data for the loads (and generators) studied, but included:

- in the majority of dispatch intervals with large forecast inaccuracy there is no observable relationship with spot price responsive behaviour
- for some loads (and generators) changes in consumption and generation aligned with forecast inaccuracy and were linked to spot price responsiveness

- other loads varied their consumption significantly in accordance with industrial and commercial requirements rather than in response to electricity spot market pricing.

Forecasting inaccuracy and causal links to load and non-scheduled generation

The rule change requests claimed large price responsive loads and non-scheduled generators cause forecasting inaccuracy. To understand the materiality of these claims, the Commission undertook a detailed analysis of AEMO's demand and price forecasting accuracy, and it looked for evidence of causation related to any forecasting inaccuracy.

In relation to the accuracy of AEMO's demand and price forecast accuracy, the Commission found:

- demand forecasts are historically generally accurate at dispatch, which results in an efficient amount of generation being dispatched

- while AEMO's price forecasts are not as accurate as the demand forecasts, this is to be expected as the price forecasts are a signalling mechanism to allow market participants to make and adjust their generation and consumption decisions ahead of dispatch. When spot prices are forecast to be above $300/MWh there is generally a market response that leads to actual spot prices being lower than forecast.

In relation to whether the forecast inaccuracy that does occur was caused by price responsive loads or non-scheduled generators, the Commission found:

- the actions of non-scheduled generators and large price responsive loads were clearly not the only or necessarily the primary cause of forecast error and not all non-scheduled generators or load contribute to forecast inaccuracy, in particular price error

- in relation to the causes of forecasting inaccuracy, the analysis indicated contributions from a number of sources, including: the actions of scheduled generators, in particular in relation to price forecasting; and, general forecasting issues related to the capabilities of AEMO's demand forecasting model and the accuracy of forecasts for intermittent generation and unregistered generation (ie that below the 5 MW registration threshold)

- as a point of reference, there is approximately 2.8 GW of intermittent semi-scheduled generation in the NEM, and approaching 6 GW of unregistered generation below the 5 MW registration threshold. AEMO must forecast the generation that would be provided by these units. The proposed changes would not change this

- given the limited number and size of participants captured by the rule change proposals and the variety of factors contributing to forecast error, it is far from clear that there would be a material improvement in forecast accuracy if these participants were scheduled.

Costs and net benefit assessment

There was limited information provided by stakeholders on the costs of scheduling and the estimates varied significantly. However the Commission considers that for loads, whose primary business is not related to electricity, and for smaller generators, the costs and requirements of scheduling would represent a significant impost.

Requiring non-scheduled generators to be scheduled would impose costs, change investment incentives, and change business models for these participants, but it would not necessarily improve demand and price forecasts materially. To the extent that benefits are uncertain and the costs may be inefficient and flow through to consumer pricing, the proposed changes will not, or are not likely to, contribute to the achievement of the NEO.

In relation to loads, while large price responsive loads can affect demand and price forecast accuracy, the Commission does not consider there is sufficient evidence to support the case for scheduling these loads at this time. The question of scheduling or not is different to questions around the information and visibility of these loads to the system operator.

The NEM is designed to enable, but not to require, loads to be scheduled. To date, most loads have elected not to be scheduled, which indicates they do not see a business advantage in doing so. If the opt-in nature of the market design was changed to require large price responsive loads to be scheduled, loads would have to incur the costs of establishing and operating communication and telemetry systems for bidding into the market and receiving dispatch instructions. These costs will vary depending on how active the load is in the market, but can be material.

Compliance costs may also be significant. In addition to ensuring bids conformed to requirements, and to the extent that industrial or commercial requirements meant dispatch instructions could not be followed, then additional costs would be incurred in AEMO or Australian Energy Regulator (AER) compliance processes. The Commission recognises that many businesses are already under financial pressure from high energy costs, and does not consider it reasonable to add additional costs when the benefits that may accrue from scheduling are uncertain.

On this basis, a decision to require loads to become scheduled will not, or is not likely, to contribute to the achievement of the NEO, given the costs and impacts on loads are more certain and therefore, in the Commission's view outweigh the possible benefits that may accrue from scheduling.

Other issues raised by the rule change proponents

Although the primary focus of the rule change requests was related to market transparency and the accuracy of the forecasting and dispatch processes, the rule change proponents raised issues that arise as a consequence of forecasting inaccuracy.

While noting that the materiality of the primary claim is not supported by the analysis undertaken, the Commission also considered the consequent issues raised including issues related to system security and the contracts market.

System security

In relation to system security the rule change proposals stated AEMO could achieve better reserves forecasting, that it could manage transmission constraint equations better, and that lower costs for frequency control ancillary services (FCAS) could be achieved, if large loads and non-scheduled generators were scheduled.

In its submission AEMO comments that:

> "In theory, any increase in the scope of generation covered by the central dispatch process would improve market efficiency and power system security, provided the additional generation has the ability to respond to dispatch instructions. The proposal would not alter existing exemptions from central dispatch for practical or technical reasons, so the main consideration is whether the remaining generation affected by the proposal will be material.[1]"

Given the Commission's analysis indicates that the majority of non-scheduled generation is either intermittent or the by-product of an industrial process, and the number of large loads that are price responsive is limited, the benefits that may accrue from scheduling these participants would also be limited.

The Commission recognises that the changes in generation and consumption technologies may result in new system security challenges. These challenges may require changes to market participation requirements or processes and the information and data available to the system operator. Implementing a broad mechanism affecting all generating units of a particular size may not be the appropriate answer in the absence of knowing what the specific system security issues are.

The Commission does not consider the rule change requests as the most appropriate method for addressing such issues.

Further, the Commission notes AEMO has powers to deal with system security issues that arise from the participants that could be affected by the Snowy and ENGIE rule change proposals, in particular:

- it can impose any terms conditions it considers reasonably necessary on participants at the time of registration, under cl. 2.2.3(c) of the National Electricity Rules (NER). This would enable it to apply specific requirements on certain types of participants, or on certain technologies (with particular attributes), if it considered this necessary for system security reasons

1 AEMO also commented that contingency FCAS would not be affected by the proposed rule, and regulation FCAS was unlikely to be affected. See AEMO submission to consultation paper, p 4.

- it has power under cl. 3.8.2(e) of the NER to require participants to participate in central dispatch to the extent necessary to ensure system security.

The Commission also notes emerging system security issues are being dealt with more broadly. The AEMC is undertaking the *System Security Market Frameworks Review* to assess the regulatory frameworks that affect system security in the NEM. Further, in its *Distribution Market Model Project* the Commission is exploring how the operation and regulation of distribution network may need to change in the future to accommodate increased distributed energy resources, like rooftop solar PV. AEMO is considering power system security challenges emerging in the market through its *Future Power Systems Security Program*, including a specific program on the visibility of distributed energy resources. The AEMC and AEMO have been working closely to consider, develop and implement changes to the market framework to facilitate the ongoing market transformation while maintaining the security of the system, and will continue to do so, including in relation to any additional specific security issues arising as a consequence of forecasting inaccuracy.

The contracts market

The rule change proponents claimed inaccurate price forecasting may impact on the efficiency of the contracts market. In the Commission's view, market participants value contracts on the basis of their particular circumstances, their expectations of the market, and their appetite for risk. Within this broad context the pre-dispatch price forecasts[2] are just one of a range of inputs that must be considered in contracting, and not necessarily the most significant factor.

Recommendations

The Commission recognises the technological change that is occurring is likely to result in increased amounts of small generation and more responsive loads. In order to maintain a transparent market with accurate information for participants, the requirements to participate in central dispatch may also need to change. Any such change should take account of a broad range of factors and market design options, and be informed by the outcomes of the reviews and rule change requests that are relevant to the central dispatch process and are currently underway.

At this time, the Commission considers the costs imposed on participants would outweigh the limited, if any, benefit that would arise under the proposed rules.

The Commission notes that AEMO's demand forecasting accuracy results indicate it has to date managed to adapt its forecasting methods to account for the increased quantity and proportion of non-scheduled generation in the market, and the actions of

2 AEMO publishes a range of forecasts. The five minute pre-dispatch demand and price forecast is available one hour before dispatch, covers the five minute dispatch interval, and is refreshed every five minutes. The 30 minute pre-dispatch demand and price forecast is available up to 40 hours before dispatch, covers the 30 minute trading interval, and is refreshed every 30 minutes. These forecasts are the focus of the rule change requests. AEMO also publishes a series of Projected Assessment of System Adequacy forecasts, for the short (six days), medium (two years) and long (10 years) terms.

loads. AEMO has regularly refined its forecasting methodology, is pursuing more information through its new demand side participation guidelines, and has power to require market participants to participate in the central dispatch process if it considers such participation is reasonably necessary for adequate system operation and the maintenance of power system security.

The Commission considers a more preferable course of action is for AEMO to continue to maintain and improve forecast accuracy by means of its existing powers. To the extent AEMO considers its powers are inadequate to manage system security issues or to continue to forecast with reasonable accuracy, the Commission will work closely with AEMO to examine the issues and develop appropriate mechanisms to ensure it has the necessary tools to operate the market.

Accordingly, the Commission recommends that AEMO:

- takes account of the findings of the demand forecast analysis, in particular those dispatch intervals where historically demand forecasting has been most inaccurate, and adopts a precautionary approach in relation to system reserve requirements where there is a congruence of factors that contribute to such results
- continues to improve its forecasting models and methodologies, including: addressing the deficiencies of the neural network model; assessing whether it can include existing information from the unconstrained intermittent generation forecast and the large non-scheduled generation forecast into its demand forecasts; and, incorporating additional information from implementation of the Demand Side Participation Information Guidelines[3] into its forecasts
- actively consider whether it has requirements that are beyond its existing information gathering and system security powers and, to the extent it considers it does, to work closely with the AEMC if considering to propose a rule change request or review in respect of these specific requirements.

3 The Demand Side Participation Information Guidelines enable AEMO to obtain information on demand side participation from registered participants in the NEM to develop and improve its load forecasting.

Contents

1 Introduction and Background

The Australian Energy Market Commission is considering amendments to the NER related to the obligations of market participants to participate in the central dispatch process operated by AEMO. The AEMC received two rule change requests[4]:

- Snowy Hydro Limited (Snowy) submitted a rule change request on 10 June 2015 related to obligations in respect of loads;[5] and
- ENGIE submitted a rule change request on 24 December 2015 related to the obligations of generators who are currently classified as non-scheduled.

Given the two rule change requests raise similar issues, on 21 April 2016 the Commission published notice that the two requests would be consolidated and considered together.

1.1 Background

This section sets out an overview of:

- the aspects of the design of the wholesale electricity market relevant to the rule change requests
- the role of demand forecasting in the wholesale electricity market
- the current rules in relation to scheduled load and generation
- other relevant rule change requests and reviews recently or currently being considered by the Commission.

1.1.1 The wholesale electricity market

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

---

4 The two rule change requests and submissions on the consultations published can be found on the AEMC website at: www.aemc.gov.au/Rule-Changes/Non-scheduled-generation-in-central-dispatch

5 The rule change request relates to imposing obligations on market customers with a market load to become scheduled. For the purposes of this draft determination we have referred to market customers with such loads as “loads”.

Generation in the NEM

A person who owns, controls or operates a generating system connected to a transmission or distribution network must register with AEMO as a generator, except where they meet AEMO's exemption criteria.[6] Currently, a person with a generating system with a nameplate capacity rating of less than 5 MW has been exempted by AEMO from the requirement to become registered. AEMO also considers registration exemption applications where a generating system is between 5 MW and less than 30 MW, if the generating system exports less than 20 GWh in any 12-month period or there are extenuating circumstances. Further, in exceptional circumstances, AEMO may consider a registration exemption application for generators with generating systems with a nameplate capacity rating of 30 MW or more.[7]

Registered generators are classified as either market or non-market generators. A market generator is one that sells the electricity it produces into the wholesale electricity market at the spot price.[8] A non-market generator is one that sells all the electricity it produces directly to a local retailer or customer at the generator's connection point.[9] The classification of market or non-market generators is generally related to settlement of the wholesale market rather than the obligations of the generator to participate in the central dispatch process.

The classification that relates to the obligations of a generator to participate in central dispatch is that of non-scheduled, semi-scheduled and scheduled. Generally, a generator is:[10]

- a scheduled generator where it has a generating unit with a nameplate capacity rating of 30 MW or more and has the technical capability to participate in the central dispatch process[11]
- a semi-scheduled generator where it has a generating unit with a nameplate capacity rating of 30 MW or more but has intermittent output such as a wind or solar farm[12]
- a non-scheduled generator where it has a generating unit with a nameplate capacity rating less than 30 MW or does not have the technical capability to participate in the central dispatch process.[13]

---

6 NER Clause 2.2.1(a) and (c)

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

8 NER, clause 2.2.4

9 NER, clause 2.2.5

10 For the purposes of classification, where a group of generators are connected at a common connection point the units are aggregated to determine the appropriate classification.

11 NER, clause 2.2.2

12 NER, clause 2.2.7(a)

13 NER, clause 2.2.3

Examples of each type of generator classification are shown below in Figure 1.1.

Figure 1.1 Generator classification in the NEM

		Typical Capability	Examples
Exempt		Less than 5 MW	1 MW backup diesel generator in a high-rise building
		Less than 30 MW, and annual export less than 30 GWh	20 MW biomass-fuelled generator with limited fuel supplies
Non-scheduled	Non-market	Less than 30 MW, all purchased locally	10 MW, all purchased by a *Customer* at the same connection point
	Market	Between 5 MW and 30 MW, not purchased locally	10 MW generator supplying pool
Semi-scheduled	Non-market	Intermittent output, greater than 30 MW, all purchased locally	150 MW wind farm, all purchased under contract to a *Local Retailer*
	Market	Intermittent output, greater than 30 MW, not purchased locally	150 MW wind farm supplying pool
Scheduled	Non-market	Greater than 30 MW, all purchased locally	40 MW hydro station, all purchased under contract to a *Local Retailer*
	Market	Greater than 30 MW, not purchased locally	2000 MW power station supplying pool

Source: AEMO, NEM Generation Registration Guide, 2016, p.25[14]

Under the NER, AEMO may also exercise certain discretion in respect of registration of generators. For example, a non-scheduled generator may be required to comply with some or all of the obligations of a scheduled or semi-scheduled generator if AEMO, in its opinion, determines it is necessary for power system security.

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 wholesale electricity market. 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. These retail tariffs would take into account not only the wholesale electricity costs but also costs incurred by the retailer in managing the spot market risk, the costs of its business, retail profit margin as well as costs passed-through related to network and environmental policy

14 https://www.aemo.com.au/-/media/Files/Electricity/NEM/Participant_Information/Application-forms-and-supporting-documentation/NEM_GENERATOR_REGISTRATION_GUIDE.pdf

costs. That said, it may be 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.

In addition to customers who contract with a retailer to purchase electricity, there are also customers who purchase electricity directly from the wholesale electricity 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 scheduled, it will be required to participate in AEMO's central dispatch process.

A load also generally operates as "normally-on" or "normally-off"[15] . 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 all or part of its load 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.

The central dispatch process

In the NEM, the settlement price is based on the average of six five-minute dispatch interval prices over the 30-minute trading interval.[16] Market participants that participate in AEMO's central dispatch process include scheduled and semi-scheduled generators, scheduled load and scheduled network service providers. Each participant is required to submit initial price/quantity bids for each of the 30-minute trading intervals to AEMO by 12:30 pm the day before the trading day.[17]

The bids specify the quantities at which each participant is willing to supply or consume electricity at nominated prices. For scheduled 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 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 the 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 has 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.

---

15 Normally on and normally off are terms defined in Chapter 10, Glossary of the NER

16 The AEMC is currently considering a rule change request to introduce a five-minute trading interval. See AEMC website at :http://www.aemc.gov.au/Rule-Changes/Five-Minute-Settlement

17 Generators submit offers and load submit bids to AEMO. Both generators and loads are able to change their initial offers by rebidding. For the sake of simplicity, throughout this paper both offers and bids are simply referred to as bids.

AEMO uses 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 and supply of all participants who are not scheduled. Once the bid stack has been created and demand forecasted, 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 five regions has its own regional spot price that is determined based on the supply and demand conditions in that region.

1.1.2 Demand forecasting in the NEM

In balancing supply and demand in the NEM, given 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 process relating to:
  - the process by which the quantity and price of electricity generation or scheduled load is dispatched
  - the requirements for FCAS[18]
  - reserve capacity mechanisms such as procuring services through the Reliability and Emergency Reserve Trader (RERT)[19] 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.

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

19 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 reserves under reserve contracts (known as RERT)

Pre-dispatch schedule

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 is required to be published by AEMO under the NER.[20]

The pre-dispatch schedule examines the scheduled and semi-scheduled generation, scheduled load and projected demand for all trading intervals (30-minute period) covering the period from the current trading interval up to and including the last trading interval for which participants have provided bids. This schedule includes a number of studies with a range of different forecast demands. In addition to the other requirements in the NER related to the pre-dispatch schedule, AEMO is also required to publish the aggregated MW allowance (if any) made for generation from non-scheduled generation in relation to, among other things, the most probable peak power system load and aggregate generating plant availability.

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 capacity 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 then reduces the demand forecast by the quantity of the scheduled load.

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 or generator which is price-responsive to a high or low price event. As a result, the pre-dispatch schedule does not necessarily reflect the true intentions of market participants. This may result in a difference between the pre-dispatch supply and demand conditions and the actual supply and demand conditions. However, because a range of different demand forecasts are used, market participants can take their own view on likely outcomes.

AEMO updates and publishes the pre-dispatch schedule to provide market participants with up-to-date information. The primary purposes of the pre-dispatch schedule are to[21]:

- provide wholesale market participants with sufficient information for them to make informed and timely business decisions relating to the operation of the scheduled generation and load

20 See NER section 3.8.20.

21 AEMO, Pre-dispatch process description, July 2010, p.6

- provide AEMO with sufficient information to assist them in maintaining the power system in a reliable and secure operating state in accordance with the NER.

Demand forecasts

In both dispatch and pre-dispatch processes, AEMO forecasts the amount of demand that is likely to occur in the market for each of the trading intervals. The demand forecast includes both unscheduled load and non-scheduled generation. Non-scheduled generation acts as a reduction in the demand forecast as it reduces the supply that must be met by scheduled generation.

In pre-dispatch, the demand forecast is for each half-hourly trading interval, and is based on historical profiles of average actual demand and is adjusted by AEMO to suit forecast conditions. The major factors considered by AEMO's pre-dispatch demand forecast include temperature, weather season, week day/weekend, and unusual conditions, for example, public holidays.[22] In dispatch, the forecast demand at the end of each dispatch interval is based on the actual measured demand at the start of the dispatch interval plus a forecast demand change over the 5-minute interval.[23] Neither demand forecast explicitly takes into account price responsiveness of non-scheduled generators or loads.

Forecasts of semi-scheduled generators

A semi-scheduled generator must submit bids to AEMO which may contain up to 10 price bands and must specify for each of the trading intervals an incremental MW amount of each price band and the ramp up and down rates. In practice, this generally results in a semi-scheduled generator being able to sell all of the electricity it produces into the wholesale market except in the case where AEMO constrains a semi-scheduled generator for system security reasons.

Given the intermittent nature of semi-scheduled generation, AEMO is required to prepare forecasts of all the available capacity of semi-scheduled generators. AEMO prepares the unconstrained intermittent generation forecast (UIGF). The UIGF is used in dispatch, 5-minute pre-dispatch, the pre-dispatch scheduled and the projected assessment of system adequacy to estimate the quantity of electricity that will be produced by semi-scheduled generators in each dispatch interval.[24]

---

22 For details about AEMO's pre-dispatch forecasting methodology, see Power System Operating Procedures - Load Forecasting at: http://www.aemo.com.au/Electricity/Policies-and-Procedures/System-Operating-Procedures.

23 For details about AEMO's dispatch forecasting methodology see Five Minute Electricity Demand Forecasting Neural Network Model Documentation at: http://www.aemo.com.au/Electricity/Policies-and-Procedurres/Forecasting.

24 The UIGF includes forecasts for semi-scheduled and non-scheduled wind farms and solar generators. It is only the semi-scheduled component of this forecast that is used in dispatch.

AEMO has developed different models for wind and solar generation:

- **Australian wind energy forecasting system:** produces wind generation forecasts for all semi-scheduled and non-scheduled wind generators in the NEM
- **Australian solar energy forecasting system:** provides forecasts for large solar power stations and small-scale PV systems covering forecasting timeframes from five minutes to two years.

The UIGF (which is comprised of the Australian wind energy forecast and the Australian solar energy forecast) is used in central dispatch to determine whether an upper-limit needs to be placed on the semi-scheduled generating unit's calculated dispatch level.

1.1.3 Current rule requirements for scheduled loads

Currently, upon request by a 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.[25]

If a market load is classified as a scheduled load, the market customer in respect of that load must submit bids in accordance with Chapter 3 of the NER[26] and must comply with AEMO's dispatch instructions.[27]

A market customer must, in respect of its scheduled load, 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) in the trading day:
  - an incremental MW amount for each price band specified in the dispatch bid
  - an up ramp rate and a down ramp rate
- prices associated with each band which must increase monotonically with an increase in available MWs.[28]

25 NER, clause 2.3.4(e)

26 NER, clause 2.3.4 (f)

27 NER, clause 2.3.4(g)

28 NER, rule 3.8.7

A market customer must, in respect of its scheduled loads, 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.

1.1.4 Recent and current rule change requests and review

The Commission has recently or is currently considering several rule change requests or reviews related to the Snowy/ENGIE rule change requests.

AEMC related work

- **Five minute settlement:** Sun Metals Corporation Pty Ltd submitted a rule change request to reduce the time interval for settlement in the wholesale electricity market from 30 minutes to five minutes. The rule change proponent is of the view that the difference in the dispatch and settlement intervals leads to inefficiencies in the operation and generation mix of the market. It submits that this provides incentives for generators to withdraw capacity to influence price outcomes and impedes some categories of participants from entering the market.[29] The proposed solution in this rule change request represents a material shift in the operation of the wholesale electricity market; however, the outcome of the Snowy/ENGIE rule change request, although related is not tied to the outcome of the five minute settlement rule change request, and vice versa

- **System security market frameworks review:** the AEMC is reviewing aspects of system security as new technologies drive a transformation of the NEM. The review's purpose is to consider, develop and implement changes to the market rules to allow the continued uptake of new, non-synchronous technologies while maintaining the security of the system. The two key issues being considered in the review, and associated rule change requests, include the management of frequency and of system strength in a power system with reduced levels of synchronous generation. The Commission published a directions paper on this review on 23 March 2017.[30]

29 See AEMC website: http://www.aemc.gov.au/Rule-Changes/Five-Minute-Settlement

30 See AEMC website: http://www.aemc.gov.au/getattachment/5a04b185-23f8-4690-9ad3-2a59b6010772 /Directions-paper.aspx

- **Distribution market model:** The AEMC initiated a project to explore how the operation and regulation of electricity distribution networks may need to change in the future to accommodate an increased uptake of distributed energy resources. As part of this project the Commission is exploring:
  - the technical, forecasting and security opportunities and challenges presented by distributed energy resources
  - what, if any, new roles, price signals and market platforms are required to optimise the development, deployment and use of distributed energy resources
  - how the role of a distribution network service provider may need to adapt to facilitate a transition to a more decentralised market for electricity services
  - whether the existing electricity regulation framework impedes or encourages innovation and adaptation by distribution network service providers to support the efficient uptake and use of distributed energy resources
  - whether changes to the existing distribution regulatory arrangements, or the design of a new market, are necessary to address any impediments to business model evolution.[31]
- **Reporting on drivers of change that impact transmission frameworks:** The AEMC is required, pursuant to a request from the COAG Energy Council to undertake a biennial reporting regime on a set of drivers that could impact on future transmission and generation investment in the NEM. The drivers include government policy, technological developments and new business models and the variance in demand forecasts.[32]

AEMO related work

In addition to the work being undertaken by the AEMC, AEMO is undertaking several pieces of work related to the issues raised in the rule change requests:

- **Future Power System Security program:** AEMO has established a program of work to assess and address the technical impacts that are likely to emerge as the NEM generation mix continues to change and consumers become increasingly active in how their demand is met. The Future Power System Security program seeks to identify opportunities and challenges to power system security and stability that could arise in the long-term and promote solutions as soon as

31 See AEMC website: http://www.aemc.gov.au/Markets-Reviews-Advice/Distribution-Market-Model

32 See AEMC website: http://www.aemc.gov.au/Markets-Reviews-Advice/Reporting-on-drivers-of-change-that-impact-transmi

practicable where appropriate.[33] One area that is being examined by AEMO as part of this work program is related to the visibility of distributed energy resources which relates, among other things, to generation that is 5MW and less.[34]

- **Demand side participation guidelines:** AEMO has prepared and are now implementing the demand side participation guidelines. These guidelines indicate the information that registered participants must provide to AEMO to assist AEMO in its development of electricity load forecasts. The objective of these guidelines is to provide AEMO with additional information to further develop and improve its current load forecasting.[35]

Independent review into the future security of the National Electricity Market

On 7 October 2016, COAG Energy Ministers agreed to an independent review of the NEM, led by Chief Scientist, Dr Alan Finkel, to take stock of its current security and reliability and to provide advice to governments on a coordinated, national reform blueprint. The national reform blueprint outlines national policy, legislative, governance and rule change requests to maintain the security, reliability, affordability and sustainability of the NEM. The final report for this review was provided to COAG on 9 June 2017 and the recommendations contained within are now being considered by COAG.

33 See https://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Security-and-reliability

34 https://www.aemo.com.au/-/media/Files/Electricity/NEM/Security_and_Reliability/Reports/AEMO-FPSS-program----Visibility-of-DER.pdf

35 https://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Planning-and-forecasting/Demand-Side-Participation-Information-Guidelines

2 The rule change requests

This chapter provides detail on the Snowy and ENGIE rule change requests including the rationale for the rule change requests, the proposed changes to the rules and the expected costs and benefits as set out by the rule change proponents.

2.1 Snowy rule change request

2.1.1 Overview of the proposed rule

Snowy's rule change request includes a proposed rule (that provides for amendments to clause 2.3.4 of the NER) which would:

- require a market customer to classify its market load as a scheduled load if it is 30 MW or greater and that market load varies, or may vary, its demand in response to changes in the spot price of electricity[36]
- 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 demand in response to changes in 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[37]
- 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
- require a market customer to submit dispatch bids in respect of scheduled loads in accordance with Chapter 3 of the NER.[38]

2.1.2 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 as part of central dispatch and associated processes.

36 It should be noted that a market load may either be spot market exposed or may have a retail contract where they are not exposed directly to the spot price. Generally those loads that are exposed directly to the spot market (rather than having a retail contract) may be price-responsive in the sense contemplated in the rule change request.

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

38 Snowy rule change request, Appendix A.

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 scheduled and semi-scheduled generators only, provide this information to AEMO when submitting bids. 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 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 possible change in demand [39]

- **inaccurate reserve forecasting by AEMO:** unscheduled 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 unscheduled loads may reduce demand and hence, AEMO has to forecast its reserve requirements without any information regarding how unscheduled load will behave [40]

- **impedes AEMO's ability to manage the central dispatch process:** unscheduled loads impact on the central dispatch process as they reduce the effectiveness of AEMO's transmission constraint equations which set the operational boundaries for secure and reliable system operations[41]

- **incorrect pricing of financial contracts[42]:** unscheduled 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 relation to long-term financial contracts, prices do not accurately reflect underlying supply and demand conditions and therefore, may impact new entrant timing decisions.[43]

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.

---

39 Snowy rule change request, pp. 7 & 8

40 Snowy rule change request, pp. 8 & 9

41 Snowy rule change request, p. 9

42 A contract is generally entered into between market participants to manage their exposure to the spot market. These contracts are settled by reference to the spot price in the region where the parties generate or consume electricity. Contracts are either bi-lateral contracts negotiated between the parties or exchange traded. Common forms of contracts include swaps, cap contracts and baseload futures.

43 Snowy rule change request, pp. 9 & 10.

2.1.3 Snowy's National Electricity Objective assessment

Snowy argues that the rule change request will contribute to the achievement of the NEO as a result of:

- **more efficient operations:** more predictable prices will improve spot market operations[44]
- **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:
  - loading on interconnectors
  - the expected loading for each scheduled generating unit
  - to fulfil its general system security and reliability obligations[45]
- **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.[46]

2.1.4 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
- AER: the proposed rule would remove administrative 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:

44 Snowy rule change request, pp. 12 & 13

45 Snowy rule change request, p. 14

46 Snowy rule change request, p.15

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

Snowy indicates that it is inherently difficult to quantify the impact of unscheduled 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 contribute to the NEO suggests there would be significant net benefits from the proposed rule resulting from an improved and efficient price discovery process.[47]

2.2 ENGIE rule change request

ENGIE in its rule change request describes, in general terms, three options for addressing the issues raised in the request.

2.2.1 Rationale for the rule change request

ENGIE considers that the ongoing success of the wholesale electricity market relies upon the ability of market participants to reasonably anticipate and respond to dynamic changes in the market. ENGIE considers that for this to be achieved all participants capable of impacting market outcomes need to be equally obliged to inform the market of their intentions.[48]

ENGIE considers that due to significant growth in the amount of non-scheduled generation in the market in recent years (and forecast further growth) non-scheduled generation is having a significant impact on market outcomes. Furthermore, because non-scheduled generators are not required to inform the market of their intentions, other generators' ability to respond to changes in their generation is limited. This in turn leads to inefficiencies in market outcomes since the most cost effective response can be impaired due to inadequate information.[49]

In addition to inefficient market outcomes, ENGIE considers that information asymmetries limit AEMO's ability to monitor and maintain the security of the power system, as key pieces of information are unavailable. ENGIE considers that where information is incomplete, AEMO needs to take a more conservative approach to managing the security of the power system and this contributes to inefficient asset utilisation and market outcomes.[50]

47 Snowy rule change request, p. 15

48 ENGIE, rule change request, p.2

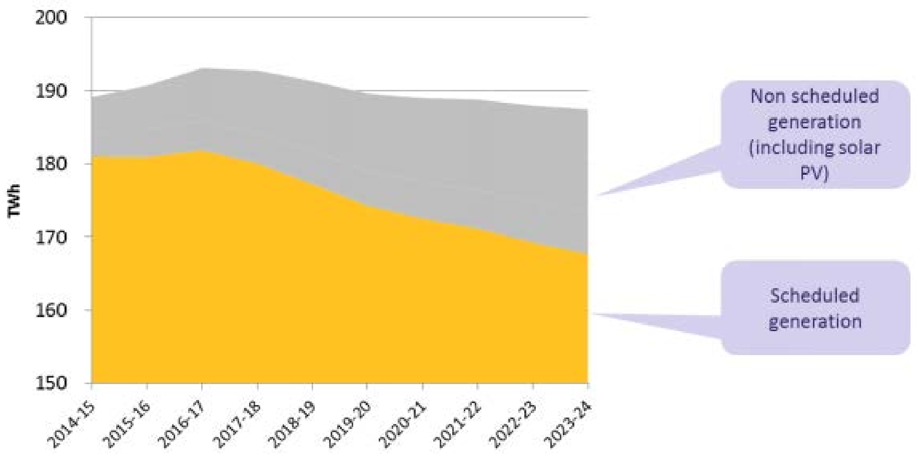
49 ENGIE, rule change request, p.2

50 ENGIE, rule change request, p. 2

ENGIE therefore considers changes to the NER are necessary to oblige non-intermittent non-scheduled generators to inform the market of their intentions.[51]

ENGIE submitted the following figure as evidence of the overall increase to date, and forecast continued increase in non-scheduled generation. ENGIE notes that while small wind farms and solar photovoltaic (PV) installations have contributed to this growth, the growth is not limited to such intermittent generation.[52]

Figure 2.1 Forecast generation from non-scheduled sources



Source: ENGIE, rule change request, p.3. Sourced from the AEMO national Electricity Forecast Report 2014

2.2.2 Proposed changes

ENGIE has proposed three options to address the issues identified in its rule change request, and considers that one or a combination of the three options could be implemented to address the issues. Each of the proposed options is summarised below.

Option one - threshold reduction

ENGIE considers that the ideal solution to the issues identified is to reduce the threshold at which controllable generators are required to be scheduled from 30 MW to 5 MW.[53] By requiring generators above 5 MW to be scheduled, and therefore bid into the central dispatch process and follow dispatch instructions, ENGIE considers that the information asymmetries that currently exist would be reduced.[54]

---

51 ENGIE, rule change request, p.2

52 ENGIE, rule change request, p.3

53 ENGIE proposes that wind generators would not be subject to the proposed threshold reduction. However, ENGIE has not proposed any changes to the threshold for intermittent generators to be classified as semi-scheduled generators and due to technical constraints these generators may not be capable of being scheduled. Therefore, the Commission's explanation of the rule change request assumes the proposed rule change would not apply to other forms of intermittent generation.

54 ENGIE, rule change request, p. 5

ENGIE proposes that the 5 MW threshold apply to all new non-intermittent generators registered after the final rule is made.[55] Existing non-intermittent non-scheduled generators registered with AEMO that are capable of being scheduled would be required to become scheduled generators by a nominated time.[56] ENGIE does not propose any changes to the requirements for intermittent generation.[57]

Option two - soft-scheduled

The second option in the rule change request is to introduce a new participant category - a soft-scheduled generator. Soft-scheduled generators would be required to provide AEMO with information of their expected generation profiles but would not be required to meet the full bidding requirements or follow dispatch instructions.[58]

Under the proposed model of a soft-scheduled generator, each soft-scheduled generator would indicate to AEMO whether it is price responsive or non-price responsive. This classification would depend on whether the generator changes its generation output in response to changes in the electricity spot price. ENGIE proposes that:[59]

- price responsive soft-scheduled generators would provide information on generation price-quantity response bands (up to ten bands) for the upcoming pre-dispatch period, and be allowed to update their band data up to one hour before actual dispatch
- non-price responsive soft-scheduled generators would provide their expected generation profiles for each 30-minute interval in the upcoming pre-dispatch period, and may update this information up to one hour before actual dispatch.

ENGIE proposes that AEMO take into account price responsive soft-scheduled generators' generation profiles in the same way as scheduled generators' profiles in the pre-dispatch and dispatch process.[60] Non-price responsive generators' generation profiles would be incorporated into the pre-dispatch and dispatch demand forecasts.[61]

ENGIE does not propose that soft-scheduled generators be required to follow dispatch instructions. However, ENGIE considers it is important to have a reasonable compliance obligation in place to require that soft-scheduled generators take measures to run their generation consistent with the information provided to AEMO. Therefore, the rule change request proposes that soft-scheduled generators be required to provide

55 ENGIE, rule change request, p. 5

56 ENGIE does not set out how it would be determined that a generator is capable of being scheduled or set out a time by which these currently registered non-scheduled generators would have to become scheduled.

57 ENGIE, rule change request, p. 11

58 ENGIE, rule change request, p. 6

59 ENGIE, rule change request, p.7

60 Under this proposal, soft-scheduled generators would not be subject to network constraints.

61 ENGIE, rule change request, p.7

a report each month to the AER and AEMO comparing their forecast and actual generation. ENGIE also proposes that new rules be introduced to set tolerance limits on non-conformance with their generation profiles.[62]

Option three - AEMO proxy bids

As a third option, ENGIE proposes that AEMO develops a new process to incorporate price responsiveness of non-scheduled generators into the demand forecast. This would involve AEMO, through existing real-time measures of demand at all connection points, correlated with five-minute regional prices, preparing proxy price and quantity bids to represent the expected aggregate price response of non-scheduled generators.

ENGIE considers that a benefit of the proxy bid solution is that it could apply to all non-scheduled generators, including those less than 5 MW, and also to all unscheduled loads.[63]

Expected costs, benefits and impacts of the proposed rule

ENGIE's high level cost estimates of each of its proposed options in respect of non-scheduled generators and AEMO are set out in Table 2.1.

62 ENGIE, rule change request, p.8

63 ENGIE, rule change request, p.5

Table 2.1 ENGIE's estimated costs

	Option 1	Option 2		Option 3
Cost for each non-scheduled generator		price responsive	non-price responsive	
Communications platform establishment	$10,000 (one-time)	$5,000 (one-time)	$5,000 (one-time)	N/A
Internal resources to establish policies and procedures	$3,000 (one-time)	$1,500 (one-time)	$750 (one-time)	N/A
Prepare and submit bids. Respond to dispatch instructions under option one	$7,500 to $37,500 per annum (on-going)	$7,500 per annum (on-going)	$3,700 per annum (on-going)	N/A
Total cost for each non-scheduled generator	**$13,000 (one-time)** **$7,500 to $37,500 per annum (on-going)**	**$6,500 (one-time)** **$7,500 per annum (on-going)**	**$5,750 (one-time)** **$3,700 per annum (on-going)**	N/A
Cost to AEMO	small increase	$40,000 (one-time)		$160,000 (one time) $80,000 per annum (on-going)

Source: ENGIE rule change request, p. 11

ENGIE notes that like many initiatives to improve market efficiency and effectiveness, the benefits that are expected to arise from the proposed change to the NER are difficult to quantify accurately. ENGIE considers that the key benefits will include:[64]

- AEMO will be able to include the expected dispatch changes from price responsive non-scheduled generators in the NEM dispatch engine, thus reducing the likelihood of inefficient dispatch of scheduled generating units

- the accuracy of the pre-dispatch forecasts will be improved by the inclusion of information regarding non-scheduled generator intentions. This will contribute to increase confidence in the accuracy of the pre-dispatch forecast by scheduled generators which will lead to:

  — **improved dispatch efficiency:** as scheduled generators will have more time to prepare and make changes in generation. For example, when a price spike is forecast 24 hours in advance and is believable some peaking gas generators might make arrangements for gas supply and transport, based on the pre-dispatch forecast schedule

— **improved investment certainty:** generators will have increased confidence that difficult to predict price shocks, based on a lack of information transparency, will not arise. Such risks can cause participants to run at a loss which may harm the long-term financial viability and deter investment. Where investment is sub-optimal it can interfere with least cost delivery of electricity to consumers. For instance, longer-term impacts on the efficient plant mix will increase the costs of electricity to consumers

— **improved contract pricing:** improved information will promote accurately priced contracts, for example, caps. Alternatively, contract prices may be inflated to manage the unexpected and difficult to predict impacts of non-scheduled generation. Better information reduces this source of inefficiency and risk. Inefficiently priced contracts harm retail markets and impact retail competition.

ENGIE considers that whilst difficult to quantify, the likely magnitude of these benefits is greater than the costs described above by a considerable margin.[65]

2.3 The rule making process to date

On 5 November 2015, the AEMC published a notice that it commenced the rule making process for the Snowy rule change request, as well as a consultation paper on the issues raised by the rule change request. [66]The Commission received 13 submissions on the rule change request as part of the first round of consultation. Where appropriate, issues raised by stakeholders in their submission are addressed throughout this draft rule determination. A summary of issues that have not been explicitly addressed in this draft rule determination, and the Commission's response to them, is provided in Appendix A.

On 21 April 2016, the AEMC published a notice that it commenced the rule making process for the ENGIE rule change request, as well as a consultation paper on the issues raised by the rule change request. In addition, the Commission published notice that it consolidated the Snowy rule change request with the ENGIE rule change request.[67] The Commission received 14 submissions on this rule change request as part of the first round of consultation. Similarly to with submissions received on the Snowy rule change request, issues raised by stakeholders in their submission, where appropriate, are addressed throughout this draft rule determination. A summary of issues that have not been explicitly addressed in this draft rule determination, and the Commission's response to them, is provided in Appendix B.

---

64 ENGIE, rule change request, p. 13

65 ENGIE, rule change request, p.14

66 This notice was published under section 95 of the National Electricity Law (NEL)

67 This notice was published under section 93(1)(a) of the NEL.

2.4 Consultation on draft rule determination

The Commission invites submissions on this draft rule determination by **1 August 2017**. Following consideration of submissions, the Commission intends to publish its final determination on 12 September 2017.

Any person or body may request that the Commission hold a hearing in relation to the draft rule determination. Any request for a hearing must be made in writing and must be received by the Commission no later than 27 June 2017.

Submissions and requests for a hearing should quote the project number "ERC0203". They may be lodged online at www.aemc.gov.au or by mail to:

Australian Energy Market Commission
PO Box A2449
Sydney South NSW 1235

3 Draft rule determination

The Commission's draft rule determination is not to make a draft rule. This chapter outlines the:

- rule making test for changes to the NER
- assessment framework for considering the rule change requests
- current market conditions relevant to the Commission's consideration of the rule change requests
- summary of the Commission's reasons for not making a draft rule.

3.1 Rule making test

Under the NEL, the Commission may only make a rule if it is satisfied that the rule will, or is likely to, contribute to the achievement of the NEO.

The NEO is:[68]

> "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 NEO captures the three dimensions of efficiency: productive (efficient operation), allocative (efficient use of) and dynamic efficiency (efficient investment). Productive efficiency means goods and services should be provided at the lowest possible cost to consumers. Allocative efficiency means that the prices of goods and services should reflect the cost of providing them, and that only those products and services that a consumer desires should be provided. Lastly, dynamic efficiency means arrangements should promote investment and innovation in the production of goods and services so that allocative and productive efficiency can be sustained over time, taking into account changes in technologies and the needs and preferences of consumers.

The most relevant aspects of the NEO for the rule change requests 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 in relation to the safety and reliability of the national electricity system.

68 As set out under section 7 of the NEL

3.1.1 Additional rule making tests - Northern Territory

From 1 July 2016, the NER, as amended from time to time, apply in the Northern Territory, subject to derogations set out in the Regulations made under the Northern Territory legislation adopting the NEL.[69] Under those Regulations, only certain parts of the NER have been adopted in the Northern Territory.[70] As the proposed rules relates to parts of the NER that currently do not apply in the Northern Territory, the Commission has not assessed the proposed rule against the additional elements required by Northern Territory legislation.[71]

Further information on the legal requirements for making this draft rule determination is set out in Appendix C.

3.2 Assessment framework

To determine whether the proposed rules, if made, are likely to promote the NEO, the following factors were 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 rules to better inform wholesale electricity spot prices by including both demand and more supply information, thereby increasing the accuracy of AEMO's pre-dispatch forecast and the price discovery process. This may lead to better investment and operational decisions by market participants and other electricity market stakeholders

- **price of financial derivatives:** impact on the pricing of financial derivatives in the market as a result of increased information available to all parties. The increased information would in respect of the intentions of scheduled loads and may result in decreased expected price volatility and reduced reliance on forecast inputs into the pricing of derivatives

- **improvements in market operation:** the potential of the rule change requests 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 the behaviour of load and non-scheduled generators at various spot prices being known in advance

- **planning:** the potential of the proposed rules 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

---

69 National Electricity (Northern Territory) (National Uniform Legislation) (Modifications) Regulations

70 For the version of the NER that applies in the Northern Territory, refer to: http://www.aemc.gov.au/Energy-Rules/National-electricity-rules/National-Electricity-Rules-(Northern-Territory).

71 *National Electricity (Northern Territory) (National Uniform Legislation) Act 2015.*

- **impact on market participants:** the impact of the rule change on:
  - the incentives and disincentives on market participants to participate in AEMO's central dispatch process under the NER
  - the degree to which the proposed rules creates an obligation on parties to participate in the central dispatch process
  - how the obligation impacts market participants' incentives to respond to price signals and participate in the spot market
  - 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 rules, including the allocation of costs and benefits among the various participants are examined where possible.

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

The proposed rules are 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 classified as a scheduled load and participate in the central dispatch process
- generators with a nameplate capacity rating of 5 MW or greater up to, but not including 30 MW or greater, can be classified as non-scheduled and are not required to participate in the central dispatch process.

3.3 Context within which the rule change requests are being assessed

The rule change requests have been evaluated against the assessment framework set out above and whether the proposed rules will, or are likely to, contribute to the achievement of the NEO. However, it is important to understand the broader context within which the rule change requests are being assessed.

The technological developments that are driving changes in generation and demand are significant and appear to be continuing into the foreseeable future.

The outlook for generation capacity in the NEM is:

- a reduction in large non-intermittent generators
- an increase in smaller generating units (between 5MW and 30 MW)
- a higher proportion of intermittent generation than historically has been the case

- an increasing availability of storage technologies
- increased levels of distributed energy resources which are generally at the smaller end of the generation capacity, that is, at less than 5MW
- a higher proportion of generation and storage capacity being owned and controlled by consumers rather than traditional energy suppliers.

Given this, the outlook is for a lower proportion of total generation capacity in the NEM being scheduled (under the existing rules) and connected to the transmission network, rather than the distribution network, in comparison to previous years.

A substantial quantity of new generation capacity is forecast to be less than 5MW in nameplate capacity.[72]The growth of this type of generation is already observable.

From January 2011 to July 2016 rooftop solar PV capacity grew from 560 MW to 5,380 MW[73], which represents capacity growth equivalent to approximately three large coal-fired generators (such as the recently retired Hazelwood coal-fired generator). This capacity is all exempt from registration and so is not required to be scheduled through the central dispatch process. The impacts this generation may or may not have on the issues in both requests was not raised by either rule change proponent, so was not the subject of the Commission’s detailed analysis.

Similarly on the demand side, the outlook is for a limited number of new large loads[74] and greater price responsiveness from large loads, building management systems and consumers as more sophisticated meters and IT systems enable consumers to be increasingly active in their consumption decisions.

These developments are relevant to the rule change requests because it addresses the appropriate boundary between smaller market participants with limited obligations and the larger participants around whom the current market mechanisms are designed. While the rule change requests have been put forward by participants operating in the market as scheduled generators, similar issues are being addressed in work-streams examining the operation and regulation of distribution networks in light of increasing levels of distributed energy resources; namely, the AEMC's distribution market model project and its technology work program, among others, and in AEMO's work on the visibility of distributed energy resources. [75] Both of these reviews generally consider generation less than 5 MW.

72 Refer to: AEMO, National Electricity Forecasting Report, June 2016, http://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/~/-/media/080A47DA86C04BE0AF93812A548F722E.ashx

73 Australian photo-voltaic institute, http://pv-map.apvi.org.au/analyses. The estimate as at April 2017 is capacity is greater than 5.92 GW

74 There are 36 loads with average demand greater than 30 MW today. While there may be a change in the nature of large loads over time (for example, more data centres rather than manufacturing processes), the expectation is that the number of large loads will not increase significantly.

75 See AEMC website: http://www.aemc.gov.au/Major-Pages/AEMC-work-overview

The rule change requests raise complex and inter-related issues. As noted there are a number of rule change requests and reviews (by the AEMC, AEMO and others) underway that potentially impact on the design and operation of the central dispatch process. The Commission is mindful to ensure that there is consistency and coordination between the outcomes of the processes underway, and that absent such coordination there is the prospect of inefficient outcomes or costs being imposed on market participants, and ultimately on consumers through higher prices, inefficient asset utilisation or investment.

3.4 Summary of decision

In relation to the rule change requests, the Commission does not consider the proposed rules will, or are likely to contribute to the achievement of the NEO at this time.

The Commission has decided not to make a draft rule. The Commission is of the view that the materiality of the issue raised by the rule change requests is insufficient to warrant making the proposed changes. The Commission's analysis indicates:

- the proposed changes would only apply to a limited number of generators and loads, and would have limited impact on forecasting accuracy
- AEMO's demand forecasts are generally accurate at dispatch, and its price forecasts provide signals to the market to enable participants to plan and adjust their generation or consumption
- the proposed changes would place considerable costs and obligations on parties that are not justified by the limited benefits that may accrue
- AEMO has a range of powers to address forecasting issues and maintain system security, including security issues arising from market participation.

The central issue in both rule change requests relates to the consequences and inefficiencies that arise from inaccurate demand and price forecasting[76]:

- Snowy considers there is reduced confidence in market pricing, inaccurate forecasting of reserves, inefficient generation and an inefficient contracts market
- ENGIE considers asymmetric information obligations distort the pre-dispatch and dispatch processes, AEMO needs to be overly conservative in relation to system security, there is uneconomic generation and there is reduced liquidity in the contracts market.

76 It should be noted that the assessment of inaccurate demand and price forecasting relates to the short-term operational forecasts of AEMO (ie those which forecast demand and price for the next trading day) and not the longer-term forecasts used primarily for planning (ie short-term PASA, long-term PASA)

Non-scheduled generation and load in the NEM

In November 2016, there were 96 registered non-scheduled generators with nameplate generation capacity of 5MW or greater in the NEM representing total capacity of 2,872 MW. Only a third of these generators are potentially suitable for scheduling. That is:

- intermittent renewable generators such as wind and solar PV would be categorised as semi-scheduled generators and are not covered by the rule change request
- generators that produce electricity as a by-product of an industrial or commercial process rather than in response to electricity market conditions may not be suitable for scheduling

Netting off these categories from total non-scheduled generation leaves 33 generators representing 771 MW of capacity that are potentially able to be scheduled. This represents less than two per cent of the total registered generation capacity in the NEM. This breakdown is summarised in the following table.

Table 3.1 Breakdown of registered non-scheduled generation, November 2016

	Number	Share of total	MW	Share of total
Total non-scheduled	96		2,872	
Of which: intermittent renewable	23	24%	1,268	44%
Of which: industrial process	40	42%	828	29%
Remaining - potential for scheduling	33	33%	771	27%
NEM total			49,091	
Remaining as % of NEM total			1.6%	

Note: registered non-scheduled generators with a capacity of 5 MW or greater

In relation to large loads, there are 36 unscheduled loads with maximum demand above 30 MW in the NEM. Together they account for approximately 18 per cent of average total load in the NEM. At a regional level, these loads represent varying proportions of average regional demand:

- in Tasmania, four loads represent 41 per cent
- in Queensland, 12 loads represent 26 per cent

- 20 loads in New South Wales, Victoria and South Australia represent between 12 and 15 per cent.

Of relevance to the rule change request is whether these loads are "price responsive"; that is, whether they vary their consumption in response to high or low spot market prices. Not all 36 large loads would be price-responsive in this sense and therefore subject to Snowy's proposed rule.

The Commission engaged Ernst and Young to undertake a quantitative analysis to determine if loads (and non-scheduled) generators are spot price-responsive and if there is a link between spot price-responsive behaviour and forecasting accuracy. The conclusions of the study were limited by the unavailability of five minute metering data for the loads (and generators) studied, but included:

- in the majority of dispatch intervals with large forecast inaccuracy there is no observable relationship with spot price responsive behaviour

- for some loads (and generators) changes in consumption and generation aligned with forecast inaccuracy and were linked to spot price responsiveness

- other loads varied their consumption significantly in accordance with industrial and commercial requirements rather than in response to electricity market pricing.

Demand forecasting accuracy

A detailed analysis undertaken by the AEMC of AEMO's pre-dispatch and dispatch demand forecasts over the last seven years shows:

- AEMO's demand forecasting is generally accurate near and at dispatch, and less accurate earlier in the pre-dispatch process. The five minute pre-dispatch and dispatch demand forecasts are reasonably accurate, with forecast errors generally in the range of one per cent and 1.5 per cent in South Australia.

- the forecast accuracy has been relatively consistent from 2010 to 2017, except in South Australia where there is a discernible trend to less accuracy. Notably South Australia has the highest proportion of intermittent generation in the NEM, in addition to the highest proportion of non-scheduled generation, both of which may be contributing factors to forecast inaccuracy

- dispatch intervals for which demand forecasting was least accurate occurred in a limited number of instances but those intervals are materially less accurate than the demand forecasts across the majority of dispatch intervals examined

- the demand forecasts become more accurate as dispatch nears. This is expected as the forecasts provide information to market participants that allow them to plan and adjust their generation and consumption decisions.

From this analysis it is apparent that the usefulness of the demand forecasts to a market participant varies according to how quickly they can respond to changing market conditions and the time they need to make, or adjust, generation and consumption decisions. Further, as the demand forecast has historically been fairly accurate, the level of generation that dispatched has generally been at an efficient level to meet actual demand.

Price forecasting accuracy

A detailed analysis undertaken by the AEMC of AEMO's pre-dispatch price forecasts over the last seven years shows:

- the price forecasts are less accurate than the demand forecasts, with error rates between 4.5 per cent and 7.5 per cent in the five-minute pre-dispatch forecasts and significantly lower accuracy in the 30-minute pre-dispatch forecasts
- there has been an observable reduction in price forecast accuracy since 2014-15 across all regions of the NEM
- there is a discernible pattern in the pre-dispatch price forecasts, with different accuracy when the forecast price is in different price bands. It is observable that when prices are forecast to be below $300/MWh the actual spot price is generally below $300/MWh
- this contrasts with the result for higher forecast prices where price forecasts tend to be less accurate. It is important to note in these cases that the results are skewed to a false positive, which are instances where a high price is forecast but does not occur. This is an indication that the market is responding to high price forecasts; a reduction in load or an increase in generation in response to a high price forecast may lower the actual wholesale price. This market response to forecast high prices so as to lower the actual spot price is an expected outcome, and one that should be observable in an efficiently operating market
- forecast accuracy improves closer to dispatch, again indicating that market participants are responding to market signals, that is, using information made available to them to plan and adjust their generation and consumption decisions.

The pre-dispatch process requires scheduled participants (in practice this is essentially generators, given the absence of scheduled load) to provide AEMO with bids specifying the prices at which they are willing to offer generation capacity. Generators can then rebid their offers in response to shifting market conditions, such as changes in demand, plant availability, or network constraints. Rebids can be undertaken at any time following the submission of the initial bids up until the relevant five-minute dispatch interval. The only timing constraint is a practical limitation of the time required for rebids to be incorporated in the NEM dispatch process and reflected in the dispatch merit order. This process provides a mechanism for the wholesale price of electricity to more accurately reflect the balance of supply and demand at the time of dispatch.

While the ability of participants to make rebids until just before the time of dispatch means that the latest market conditions can be reflected in dispatch outcomes, it also reduces the certainty and predictability that participants have regarding expected price outcomes. This is particularly important for market participants that require a period of time to respond due to operational and technical limitations, such as peaking generators or large industrial loads wishing to curtail their consumption. The earlier in time that price forecasts are made, the greater the interim period in which rebids can occur, and therefore the more likely it is that the actual price outcomes will be different. Therefore, there is a trade-off that exists between the accuracy of pre-dispatch forecasts and the flexibility of the market to respond to changing market conditions.

The relationship of forecast error to non-scheduled generation and load

Further analysis was undertaken to understand the extent to which loads and non-scheduled generation were causing the forecast error, in particular the pricing error given the relatively accurate levels of historical demand forecast accuracy.

In addition to the Ernst and Young analysis previously noted, the $5,000 reports prepared by the AER were examined. These indicated the primary cause of high price events were the actions of scheduled generators in bidding and rebidding their prices and generation quantities. Demand forecast error was also cited in some of these reports, but usually as a contributing factor to a high price event, and generally this was not attributed to the actions of non-scheduled generation or load.

The Commission also engaged the University of Wollongong to review AEMO's demand forecasting model. The study concluded the model is outdated and not able to account for volatility, price spikes and price response.

In aggregate the evidence linking the actions of non-scheduled generation or load to forecast error was inconclusive. The Commission found:

- the actions of non-scheduled generators and unscheduled loads were clearly not the only or necessarily the primary cause of forecast error and not all non-scheduled generators or load contribute to forecast inaccuracy, in particular price error

- in relation to the causes of forecasting inaccuracy, the analysis indicated contributions from a number of sources, including: the actions of scheduled generators, in particular in relation to price forecasting; and, general forecasting issues related to the capabilities of AEMO's demand forecasting model and the accuracy of forecasts for intermittent generation and unregistered generation (ie that below the 5 MW registration threshold)

- as a point of reference, there is approximately 2.8 GW of intermittent semi-scheduled generation in the NEM, and approaching 6 GW of unregistered unscheduled generation below the 5 MW registration threshold. AEMO must forecast the generation that would be provided by these units. The proposed changes would not change this

- given the limited number and size of participants captured by the rule change proposals and the variety of factors contributing to forecast error, it is not clear that there would be a material improvement in forecast accuracy if these participants were scheduled.

Costs and net benefit assessment

There was limited information provided by stakeholders on the costs of scheduling and the estimates varied significantly. However, the Commission considers that for loads, whose primary business is not related to electricity, and for smaller generators, the costs and requirements of scheduling would represent a significant impost.

Requiring non-scheduled generators to be scheduled would impose costs, change investment incentives, and change business models for these participants, but it would not necessarily improve demand and price forecasts materially. To the extent that benefits are uncertain and the costs may be inefficient and flow through to consumer pricing, the proposed changes will not, or are not likely to, contribute to the achievement of the NEO.

In relation to loads, while large price responsive loads can affect demand and price forecast accuracy, the Commission does not consider there is sufficient evidence to support the case for scheduling these loads at this time. The question of scheduling or not is different to questions around the information and visibility of these loads to the system operator.

The NEM is designed to enable, but not to require, loads to be scheduled.[77] To date, most loads have elected not to be scheduled, which indicates they do not see a business advantage in doing so. If the opt-in nature of the market design was changed to require large price responsive loads to be scheduled, loads would have to incur the costs of establishing and operating communication and telemetry systems for bidding into the market and receiving dispatch instructions. These costs will vary depending on how active the load is in the market, but can be material.

Compliance costs may also be significant. In addition to ensuring bids conformed to requirements, and to the extent that industrial or commercial requirements meant dispatch instructions could not be followed, then additional costs would be incurred in AEMO or Australian Energy Regulator (AER) compliance processes. The Commission recognises that many businesses are already under financial pressure from high energy costs, and does not consider it reasonable to add additional costs when the benefits that may accrue from scheduling are uncertain.

On this basis, a decision to require loads to become scheduled will not, or is not likely, to contribute to the achievement of the NEO, given the costs and impacts on loads are more certain and therefore, in the Commission's view outweigh the possible benefits that may accrue from scheduling.

77 It should be noted that there are circumstances in which loads may be required to be scheduled under the NER (for example, clause 3.8.2(e).

Other issues raised by the rule change proponents

Although the primary focus of the rule change requests was related to market transparency and the accuracy of the forecasting and dispatch processes, the rule change proponents raised issues that arise as a consequence of forecasting inaccuracy. While noting that the materiality of the primary claim is not supported by the analysis undertaken, the Commission also considered the consequent issues raised including issues related to system security and the contracts market.

System Security

In relation to system security the rule change proposals stated AEMO could achieve better reserves forecasting, that it could manage transmission constraint equations better, and that lower costs for frequency control ancillary services (FCAS) could be achieved, if large loads and non-scheduled generators were scheduled.

In its submission AEMO comments that:

> "In theory, any increase in the scope of generation covered by the central dispatch process would improve market efficiency and power system security, provided the additional generation has the ability to respond to dispatch instructions. The proposal would not alter existing exemptions from central dispatch for practical or technical reasons, so the main consideration is whether the remaining generation affected by the proposal will be material.[78]"

Given the Commission's analysis indicates that the majority of non-scheduled generation is either intermittent or the by-product of an industrial process, and the number of large loads that are price responsive is limited, the benefits that may accrue from scheduling these participants would also be limited.

The Commission recognises that the changes in generation and consumption technologies result in new system security challenges. These challenges may require changes to market participation requirements or processes and the information and data available to the system operator. Implementing a broad mechanism affecting all generating units of a particular size may not be the appropriate answer in the absence of knowing what the specific system security issues are.

The Commission does not consider the rule change requests as the most appropriate method for addressing such issues.

Further, the Commission notes AEMO has powers to deal with system security issues that arise from the participants that could be affected by the Snowy and ENGIE rule change proposals, in particular:

78 AEMO also commented that contingency FCAS would not be affected by the proposed rule, and regulation FCAS was unlikely to be affected. See AEMO submission to consultation paper, p 4

- it can impose any terms conditions it considers reasonably necessary on participants at the time of registration, under cl. 2.2.3(c) of the National Electricity Rules (NER). This would enable it to apply specific requirements on certain types of participants, or on certain technologies (with particular attributes), if it considered this necessary for system security reasons
- it has power under cl. 3.8.2(e) of the NER to require participants to participate in central dispatch to the extent necessary to ensure system security.

The Commission also notes emerging system security issues are being dealt with more broadly. The AEMC is undertaking the *System Security Market Frameworks Review* to assess the regulatory frameworks that affect system security in the NEM. Further, in its *Distribution Market Model Project* the Commission is exploring how the operation and regulation of distribution network may need to change in the future to accommodate increased distributed energy resources, like rooftop solar PV. AEMO is considering power system security challenges emerging in the market through its *Future Power Systems Security Program*, including a specific program on the visibility of distributed energy resources. The AEMC and AEMO have been working closely to consider, develop and implement changes to the market framework to facilitate the ongoing market transformation while maintaining the security of the system, and will continue to do so, including in relation to any additional specific security issues arising as a consequence of forecasting inaccuracy.

The contracts market

The rule change proponents claimed inaccurate price forecasting may impact on the efficiency of the contracts market. In the Commission's view, market participants value contracts on the basis of their particular circumstances, their expectations of the market, and their appetite for risk. Within this broad context the price forecasts are just one of a range of inputs that must be considered in contracting, and not necessarily the most significant factor.[79]

Recommendations

The Commission recognises the technological change that is occurring is likely to result in increased amounts of small generation and more responsive loads. In order to maintain a transparent market with accurate information for participants, the requirements to participate in central dispatch may also need to change. Any such change should take account of a broad range of factors and market design options, and be informed by the outcomes of the reviews and rule change requests that are relevant to the central dispatch process and are currently underway.

---

79 AEMO publishes a range of forecasts. The five minute pre-dispatch demand and price forecast is available one hour before dispatch, covers the five minute dispatch interval, and is refreshed every five minutes. The 30 minute pre-dispatch demand and price forecast is available up to 40 hours before dispatch, covers the 30 minute trading interval, and is refreshed every 30 minutes. These forecasts are the focus of the rule change requests. AEMO also publishes a series of Projected Assessment of System Adequacy forecasts, for the short (six days), medium (two years) and long (10 years) terms

At this time, and in relation to the specific issues raised and classes of participants the proposed rule would apply to – price responsive load and non-scheduled non-intermittent generation – the Commission is of the view that the analysis indicates there is not a material issue. Therefore the costs imposed on participants would outweigh the marginal, if any, benefit that would arise under the proposed rules.

The Commission notes that AEMO's demand forecasting accuracy results indicate it has to date managed to adapt its forecasting methods to account for the increased quantity and proportion of non-scheduled generation in the market, and the actions of loads. AEMO has regularly refined its forecasting methodology, is pursuing more information through its new demand side participation guidelines, and has power to require market participants to participate in the central dispatch process if it considers such participation is reasonably necessary for adequate system operation and the maintenance of power system security.

The Commission considers a more preferable course of action is for AEMO to continue to maintain and improve forecast accuracy by means of its existing powers. To the extent AEMO considers its powers are inadequate to manage system security issues or to continue to forecast with reasonable accuracy, the Commission will work closely with AEMO to examine the issues and develop appropriate mechanisms to ensure it has the necessary tools to operate the market.

Accordingly, the Commission recommends that AEMO:

- takes account of the findings of the demand forecast analysis, in particular those dispatch intervals where historically demand forecasting has been most inaccurate, and adopts a precautionary approach in relation to system reserve requirements where there is a congruence of factors that contribute to such results
- continues to improve its forecasting models and methodologies, including: addressing the deficiencies of the neural network model; assessing whether it can include existing information from the unconstrained intermittent generation forecast (UIGF) [80] and the large non-scheduled generation forecast into its demand forecasts; and, incorporating additional information from implementation of the Demand Side Participation Information Guidelines[81] into its forecasts
- actively consider whether it has requirements that are beyond its existing information gathering and system security powers and, to the extent it considers it does, to work closely with the AEMC if considering to propose a rule change request or review in respect of these specific requirements.

80 See NER 3.7B

81 See NER 3.7D

4 Materiality of the issues raised

As noted above, central to both rule change requests is the suggestion there are inaccurate pre-dispatch forecasts, which cause inefficiencies in dispatch, reduce AEMO’s ability to monitor and maintain the security of the power system, and reduce the efficiency of the contracts market.

Analysis was undertaken on the evidence for and materiality of the issues raised by the rule change proponents. The analysis was necessary to understand the extent of any benefits that could accrue from altering scheduling requirements in light of the costs of doing so.

There were multiple elements of this analysis.

- The quantity of non-scheduled generation and load in the NEM was examined, to understand whether the quantities were significant enough to cause or contribute to forecasting inaccuracy.

- The accuracy of AEMO's pre-dispatch demand and price forecasting was assessed, to understand whether there is forecasting error and if so the scale of the error.

- The evidence from a number of studies was examined to determine the causes of forecast error, and in particular whether there are causal links between forecast errors and the actions of non-scheduled generation or load.

- AEMO's forecasting methods, improvements it is undertaking, and its powers in relation to information gathering and system security were considered, as these are relevant to whether there are alternative means to maintaining and improving pre-dispatch forecasting accuracy other than those proposed by the rule change proponents.

Further elements of the analysis assessed:

- the costs a participant would incur if it were required to become scheduled. This is important to be able to consider the benefits that may accrue from requiring additional participants to become scheduled

- the ownership and type of non-scheduled generator to inform how onerous a requirement to be scheduled might be and the practical issues associated with scheduling different types of generators.

4.1 Non-scheduled generation and load in the NEM

By changing their generation or consumption profile throughout a trading day non-scheduled generation and non-scheduled load may, if their scale in the market is material, affect the accuracy of AEMO’s demand and price forecasting. If this occurs then the demand and supply conditions upon which pre-dispatch forecasts are based, and dispatch determined, may also be inaccurate. Changes to generation or consumption profiles may impact on forecasting accuracy, regardless of whether the changes are for operational or price reasons.

The extent to which non-scheduled generation and non-scheduled load can actually cause or contribute to forecasting inaccuracy and, in turn, dispatch inaccuracy will depend on how accurately AEMO forecasts their generation or consumption in the absence of these participants being scheduled.

A detailed description of the analysis and findings on the quantity of non-scheduled generation and load is in Section 1 of Appendix D. A summary of the results is presented in this chapter.

4.1.1 Non-scheduled load above 30 MW

Under the NER, loads have the option to, but are not required to, be scheduled[82] . Most loads do not choose to be scheduled, which suggests that loads do not consider there is a net business benefit in being scheduled and participating in the central dispatch process.

The analysis of non-scheduled loads shows:

- there are 36 loads in the NEM with maximum demand above 30 MW. This represents over 18 per cent of the average aggregate load in the NEM. However, not all of these loads are necessarily price responsive and therefore the proposed rule would only apply to a portion of these 36 loads
- the quantity and proportion of large loads varies by region. In Tasmania, four loads account for 41 per cent of the average regional demand. Queensland has the next highest proportion of large loads, where 12 loads account for 26.5 per cent of average regional demand. In NSW, Victoria and South Australia the proportion of large loads is between approximately 12 per cent and 15 per cent. Notably South Australia has the lowest proportion at 11.8 per cent.

The significance of these non-scheduled large loads is that individually their behaviour can have a system impact similar to a scheduled generator and to the extent that AEMO is not able to accurately forecast their consumption, they may contribute to forecast inaccuracy.

4.1.2 Non-scheduled generation

The rule change proponents expressed an expectation that the quantity of non-scheduled generation would increase in the future[83], as large

82 Note clause 3.8.2 (e) does enable AEMO to require a load to become scheduled in certain circumstances.

83 This expectation was expressed by both Snowy and ENGIE in their rule change requests, and at the AEMC workshop on 24 March 2017. Snowy's rule change request (p 10) stated an expectation for

transmission-connected generators are replaced by smaller more distributed energy resources.[84] This increase will include both registered generation above 5 MW and exempt generation below 5 MW. The exempt generation below 5 MW in most cases is not captured by any of the proposals contained in the rule change request.

The Commission tested this expectation by examining the quantity of registered non-scheduled generation in the NEM, including changes in the quantity over time and by jurisdiction. The key findings of the analysis were:

- there is approximately 2.9 GW of registered non-scheduled generation capacity in the NEM from generation units with a nameplate capacity of 5 MW or greater. Of this, approximately 1.6 GW is non-intermittent (and the subject of the rule change request) and 1.3 GW is intermittent. This can be compared with approximately 2.8 GW of semi-scheduled generation, and approaching 6 GW of unregistered embedded generation

- since 2008 the quantity of non-scheduled generation with a nameplate capacity of 5 MW or greater has increased by approximately one GW and from 4.3 per cent to 6.4 per cent of total registered generation capacity in the NEM. While there has been an increase, it has not been dramatic or rapid

- at a regional level, South Australia and Tasmania have the highest proportions of non-scheduled generation at between eight and nine per cent of regional generation capacity.

The significance of these non-scheduled generators is that they can have an impact similar to scheduled generators and to the extent that AEMO is not able to accurately forecast their consumption, they may contribute to forecast inaccuracy.

4.2 Demand forecast accuracy

There are a number of elements in the AEMC's analysis of AEMO's pre-dispatch demand forecast accuracy. The analysis undertaken and the key findings are

"more demand response, more distributed generation and more non-scheduled generation" in addition to highlighting AEMO's forecasts for increasing demand side participant. See http://www.aemc.gov.au/getattachment/0b9688b8-dc3c-49b1-8bf8-df587ca8ed53/Rule-change-request.aspx. ENGIE, in its rule change request, stated "the total amount of non-scheduled generation in the NEM has increased significantly in recent years, and is forecast by AEMO to continue to grow." (p.2) See http://www.aemc.gov.au/getattachment/4219ffd9-f0f1-4690-84a8-555282d44374/Rule-change-request.aspx

84 It should be noted that it is expected that a significant increase in smaller generation is a reference to generation connected to the distribution network, and generally less than 5MW. The impacts of this level of non–market generation has not been the subject of analysis as part of these rule change requests, given AEMO automatically exempts non-market generating systems below 5 MW from registration, because compliance with the connection process in schedule 5.2 of the NER historically was considered negligible, the registration would be a significant cost, impacting on the viability of such generating units.

summarised below. A more detailed description of the methodology and results is available in Section 2, Appendix D.

- AEMO's pre-dispatch forecasts are reasonably accurate compared to dispatch, and consistent with the accuracy rates of dispatch itself (ie the start of the dispatch interval forecast is reasonably consistent with the actual demand that occurred in the interval). In general the forecasts are accurate to within one per cent in all NEM jurisdictions excluding South Australia and within 1.5 per cent in South Australia.

- The accuracy of the forecasts improves as dispatch nears. The five minute pre-dispatch forecasts are more accurate than the thirty-minute pre-dispatch forecasts. This is an expected result as the thirty minute pre-dispatch forecasts are designed to provide information to the market to enable participants to plan and adjust their generation and consumption. This means the usefulness of the forecasts to market participants will vary according to the time they require to react to market signals. For example, any participant that needs to make unit commitment decisions four hours ahead of dispatch must rely on forecasts that are materially less accurate than those available five minutes before dispatch.

- The accuracy of the forecasts has remained relatively consistent over the period from 2010 to 2017, except in South Australia where there is a discernible trend to less accuracy. This may be related to the high level of intermittent generation in that state.

- The least accurate forecasts were also examined. These occur in 0.1 per cent of dispatch intervals, which represents approximately 100 instances per year. The demand forecasts in these few dispatch intervals are materially less accurate than the majority of forecasts, with average error rates increasing to between two and three per cent for New South Wales, Victoria and Queensland, and approximately five to six per cent in South Australia.

4.3 Price forecast accuracy

The other key part of AEMO's pre-dispatch forecasting relates to price. An analysis similar to that undertaken for demand forecast accuracy was undertaken for price forecasts. The results of the analysis are summarised below with a more detailed description of the analysis and results in Section 2 of Appendix D.

- Pre-dispatch price forecast accuracy is noticeably less accurate than pre-dispatch demand forecasting accuracy. Where the error rate in five minute pre-dispatch demand forecasts was between one and 1.5 per cent in the forecast five minutes before dispatch, the error in price forecasting was between 4.4 and 7.3 per cent in the same period. Consistent with the demand analysis, price forecast accuracy in South Australia is lower than other regions.

- The five minute pre-dispatch price forecasts are noticeably more accurate than the thirty minute forecasts, reflecting at least in part that the price signalling process is providing information to which market participants are responding.

- There is a discernible pattern in the pre-dispatch price forecasts, with different accuracy when the forecast price is in different price bands. It is observable that when prices are forecast to be below $300/MWh[85] the actual spot price is generally below $300/MWh.

- This contrasts with the result for higher forecast prices where price forecasts tend to be less accurate. It is important to note in these cases that the results are skewed to a false positive, which are instances where a high price is forecast but does not occur. This is an indication that the market is responding to high price forecasts; a reduction in load or an increase in generation in response to a high price forecast may lower the actual wholesale price. This market response to forecast high prices so as to lower the actual spot price is an expected outcome, and one that should be observable in an efficiently operating market.

- There has been a material reduction in price forecast accuracy since 2014-15.

4.4 Additional analysis on forecast error, high price events and non-scheduled participants

The preceding analysis examined the quantity of non-scheduled generation and load in the NEM and the accuracy of AEMO’s pre-dispatch demand and price forecasting. From this it can be seen that non-scheduled generation and load quantities are not immaterial, and may impact on forecasting accuracy where AEMO is unable to accurately predict their behaviour. Although there is a possibility that non-scheduled generation and load may have an impact on forecasts, the preceding analysis does not address whether there is a causal relationship between the two.

The relevant issue then becomes whether a causal relationship can be established between forecast errors and non-scheduled generation and load. In order to assess this, a number of analyses were undertaken including:

- examining the relationship between the incidence of high price events and the scale of demand forecast error

- examining the AER's reports on price events greater than $5,000 to understand the reasons for the high prices, and in particular to understand whether non-scheduled generation or loads were causal factors

85 This price is used as it is a common strike price for financial cap contracts which are used by retailer's to limit their exposure to high price events. A cap contract trades a fixed volume of energy for a fixed price when the spot price exceeds a specified price - the strike price. In the case of a cap contract with a $300/MW strike price, the seller of a cap is required to pay to the buyer the difference between the spot price and $300/MWh.

- a quantitative study to assess whether forecast error was caused by the price responsive behaviour of non-scheduled participants.[86]

While a correlation between demand forecast error and high price events can be observed, a critical issue is whether a causal relationship can be proven with the behaviour of non-scheduled participants.

4.4.1 Analysis of AER $5000 reports

The AER is required to publish a report whenever the electricity spot price exceeds $5,000/MWh.[87] The report identifies the key factors that caused the high price events. In the period from February 2011 to 10 February 2017 there were 27 such reports.[88] These were examined to understand whether non-scheduled generation or load was a significant factor in causing high prices.

In most cases the reports identify a number of contributing factors. Common factors identified were high demand and limitations on supply. The demand level was usually attributable to weather in a region, whereas the reasons for limited supply were more varied and included factors such as generator or interconnector outages, transmission constraints and withdrawal of supply.

The most common factor contributing to high price events noted in the reports are the bidding behaviour of scheduled generators, where they submit large price steps between supply levels. In instances where supply is limited, this approach to pricing can result in the marginal generator being dispatched at a high price band. For example on 9 February 2017 in New South Wales, there was no capacity priced between $500/MWh and $12,500/MWh.

The reports also note the following contributing factors:

- a common cause of high price events was scheduled generators rebidding their offered capacity from low to high price bands

- the withdrawal of supply was a further reason cited in five of the reports, noting the bidding in good faith rule change came into effect on 1 July 2016[89]

---

86 The Commission engaged Ernst & Young to undertake this analysis. Their report can be found on the AEMC's website on the project page for the rule change requests

87 The report is required under clause 3.13.7(d) of the NER. The report: describes the significant factors contributing to the high spot price including withdrawal of generation capacity and network availability; assesses whether rebidding contributed to the high spot price; identifies the marginal scheduled generating units; and identifies all units with offers for the trading interval equal to or greater than $5,000/MWh and compares these dispatch offers to relevant dispatch offers in previous trading intervals.

88 This figure excludes $5,000 reports related to high FCAS prices.

89 Since the introduction of the bidding in good faith rule change from 1 July 2016, generators are prohibited from making false or misleading bids, are required to make known any variations as soon as practical, and to preserve a contemporaneous record of the circumstances surrounding late bids. See AEMC website at :http://www.aemc.gov.au/Rule-Changes/Bidding-in-Good-Faith

- there were instances of generators rebidding their ramp rates, which had the effect of prolonging network constraints and periods of high prices.

The reports do not provide strong support for the proposition that non-scheduled generation or load is consistently contributing to demand forecast inaccuracy, and in turn, pricing inaccuracy at least in regard to high price events. The reports do provide clear examples of how the bidding behaviour of scheduled generators can contribute to high price events.

4.4.2 Relationship between non-scheduled participants and dispatch demand inaccuracy

The AEMC engaged Ernst & Young (EY) to do a quantitative analysis of the impact of non-scheduled generation and load on dispatch demand inaccuracy. A particular focus of the analysis was to determine the extent to which dispatch demand forecast inaccuracies are the result of price responsive behaviour.[90] A copy of the EY report is published alongside this draft rule determination.

The study was based on data for 82 non-scheduled generators and loads. The intention was to examine five minute data for each participant as that would allow any change in generation or consumption during the dispatch interval to be assessed, and this would provide a strong indication of whether the participant was being price responsive. Five minute data was only available for nine non-scheduled generators. For the other facilities, which comprised 22 loads, 32 non-scheduled generators and 19 loads registered as non-scheduled generators,[91] the study used 30 minute data. As 30 minute data blends the magnitude and timing of changes to demand and generation across six dispatch intervals, the conclusions that could be drawn from the analysis were more limited than if five minute data had been available.

The key findings from EY's report were:

- in the majority of dispatch intervals with large dispatch demand inaccuracy there is no observable relationship with price responsive behaviour or contribution from any of the facilities analysed. This may be due to the limitations of data availability, or that other variability in residential and commercial demand is significant

90 The study aimed at identifying the level of forecast error at each facility examined and comparing this with the regional error. As the specific forecast for each facility within AEMO's demand forecasting process was not available, EY used a linear regression technique to determine the 'typical operation' of a facility. The study essentially focussed on the tails in the distribution of forecasting results, in that it only focussed on dispatch intervals with large demand error.

91 These are mostly small auxiliary loads, with many of the facilities being pumped hydro.

- for some facilities, changes in consumption and generation are aligned to regional dispatch demand inaccuracy, and a significant proportion of the changes are linked to price responsive behaviour:
  - the contribution to dispatch demand inaccuracy from very large loads such as aluminium and zinc smelters is highly correlated with dispatch intervals with large dispatch demand inaccuracy[92]
  - the contribution from highly variable facilities such as steel and paper mills is less conclusive
- it is not clear that scheduling facilities that contribute to dispatch demand inaccuracy, but are highly variable in their operation at all times (eg steel and paper mills), would improve dispatch demand accuracy. In contrast, scheduling facilities such as aluminium and zinc smelters may improve dispatch accuracy, although EY notes that in the majority of dispatch intervals with material regional error smelters do "not have a material error indicating there are frequently other causes of material regional error in Queensland."[93]
- the evidence of price responsive behaviour is weaker for facilities that are linked to some other operation, eg co-generation facilities, bio-gas, coal mine gas. It is likely that generation from these facilities is more dependent on the operation of their core industrial process than on the wholesale electricity price.

4.4.3 Relationship between non-scheduled participants and dispatch demand inaccuracy

The preceding analysis has shown that the quantities of non-scheduled generation and load in the NEM may, to the extent that AEMO cannot forecast generation and consumption profiles accurately, impact on pre-dispatch forecast and dispatch accuracy.

AEMO's pre-dispatch demand forecasting accuracy improves as dispatch approaches, indicating that it is working as a market signalling process. The five minute demand forecasts made just before dispatch, and dispatch, are generally accurate.

Pre-dispatch price forecasting is less accurate than pre-dispatch demand forecasting and dispatch. There are instances where a contribution to price forecast errors can be attributed to non-scheduled generation and load, but in most cases there is no such contribution and it is other factors contributing to pricing inaccuracy; including, the actions of scheduled generators and general forecast errors. In order to understand these other forecast errors the Commission undertook further analysis.

---

92 EY noted that smelters are not very variable in their consumption but when they do change their consumption by a material amount the contribution to regional error is likely to be large.

93 EY, Non-scheduled generation and load in central dispatch rule change request, 5 September 2016, p.53.

4.5 AEMO forecasting

4.5.1 The neural network model

The EY study noted that AEMO's neural network model did not account for substantial changes between dispatch intervals. To better understand this, the AEMC engaged the University of Wollongong to advise on the adequacy of AEMO's neural network model to provide accurate pre-dispatch forecasting and dispatch. This report is published together with this draft rule determination.[94] The key findings of this report were:

- AEMO's model is a first generation neural network model and major components of it are now nearly 20 years old.[95] It cannot deal with a range of circumstances including volatility, price spikes and price response
- a more modern neural network model would likely improve demand forecast accuracy, relatively quickly and at relatively low cost [96]
- it is possible to incorporate smart meter and climate data in more modern models
- the report also noted there is a trend towards predicting the demand of individual loads.

The report concluded the benefit from the rule change requests would be very limited if AEMO continues to use the current neural network model. This conclusion is consistent with the EY findings, which stated that in the majority of cases where there were large dispatch demand inaccuracies, there was no observable relationship with price responsive behaviour or contribution from any of the generation and load facilities analysed. Whereas EY concluded this may be due to the limitations of data availability or significant variation in residential or commercial demand, it is possible that AEMO's current demand forecasting model also contributes.

4.5.2 AEMO forecasting improvements and opportunities

The analyses of EY and the University of Wollongong both indicate that some component of forecasting inaccuracy may be attributable to the limitations of AEMO's neural network model.

In this context it is worth recognising the improvements AEMO has taken to improve its forecasts, and others that may potentially assist forecast accuracy. These are summarised below, and set out in more detail in Section 3 of Appendix D.

---

94 University of Wollongong, Evaluation of Neural Network Models for Australian Energy Market Operators Five Minute Electricity Demand Forecasting, 13 December 2016.

95 The neural network model was originally developed and tuned in 1999. The original tuning is still in use in New South Wales, Victoria and South Australia, although new model components (MetrixND) were developed and tuned for Tasmania (2005) and Queensland (2007).

96 There was no specific assessment provided as to the cost of developing a new neural network model.

- AEMO makes regular improvements to its forecasting methodology[97]. Various of these are described in The Forecasting Methodology Information Paper[98] which sets out a range of improvements made to the longer term forecasts, including: incorporating new data and new component models, updating policy and technology assumptions, surveying large users, and updating assumptions about energy efficiency.

- AEMO is currently implementing its Demand Side Participation Information Guidelines.[99] This will increase a range of information available to AEMO, including information relating to demand response and available load reduction.

- There appear to be opportunities to incorporate information that is already available into the forecasting process. In particular, (I) the information on non-scheduled generation that is in the “demand plus non-scheduled generation”, which is part of the MMS database,[100] and (ii) the information on non-scheduled generation in the unconstrained intermittent generation forecast[101] , could be incorporated into the demand forecasting process.

- AEMO also has information gathering powers and powers to ensure system security that may also be used to maintain or improve forecasting accuracy.

4.6 Other data and analysis

The costs a market participant would face if required to be scheduled is relevant to the rule change requests, as is an understanding of the types of generators in the non-scheduled category given the practical ability to comply with dispatch instructions will vary depending on generator type.

97 See Box D.1 for a discussion of recent improvements to AEMO’s forecasting methodology

98 See AEMO, Forecasting Methodology Information Paper, 2016, https://www.aemo.com.au/-/media/Files/Electricity/NEM/Planning_and_Forecasting/NEFR/2016/Forecasting-Methodology-Information-Paper---2016-NEFR---Final.pdf

99 The Demand Side Participation Guidelines enable AEMO to obtain information on demand side participation from registered participants in the NEM to develop and improve its load forecasting. See Box D.2 for a discussion on these AEMO guidelines. see: https://www.aemo.com.au/Electricity /National-Electricity-Market-NEM/Planning-and-forecasting/Demand-Side-Participation-Information-Guidelines

100 The non-scheduled generators are listed in the DISPATCH_UNIT_SCADA table of AEMO's MMS database. These are units included in the DEMAND_PLUS_NONSCHEDGEN field of the DISPATCHREGIONSUM table. Note, a number of scheduled generators are also listed in the table (eg Angaston). The generation capacity cited only refers to the non-scheduled generators. In relation to the non-scheduled generation in the UIGF, while this is forecast, it does feed into the demand estimation used in dispatch.

101 This is explained further in Appendix D.

4.6.1 Costs of scheduling participants

Given the rule change requests suggest scheduling additional market participants, it is important to understand the potential cost components and amounts related to scheduling.

The information provided by stakeholders was limited and varied significantly. These costs are described in more detail in section 4 of Appendix D.

ENGIE suggested the costs of scheduling would be in the order of $13,000 in establishment costs, and ongoing annual costs of between $7,500 and $37,500 depending on how active the participant was in the market. SA Water estimated the establishment costs at $95,000 and annual costs of $260,000. Feedback from the AEMC's industry workshop suggested the annual costs could be up to $10 million per annum for a participant that is actively trading during business hours. It was noted that companies can contract the trading activities to a third-party and this would reduce their costs, depending on their levels of bidding and rebidding activity. However, these parties would still incur costs related to compliance and legal, which may be significant.

Although the cost estimations put forward vary considerably the Commission considers the combination of set-up costs, operations costs and legal and compliance costs would be material, in particular for smaller generators and loads.

4.6.2 Registered non-scheduled generation - ownership and generation type

There is a range of different generator types in the registered non-scheduled generator category, which has implications for their practical ability to comply with dispatch instructions. The ownership of these generators may also influence the costs that would be incurred if they were required to be scheduled. Both of these issues are summarised here and examined in more detail in section 4 of Appendix D.

In November 2016, there were 96 registered non-scheduled generators with nameplate generation capacity of 5MW or greater in the NEM representing total capacity of 2,872MW. However, only a third of these generators are potentially suitable for scheduling, because:

- intermittent renewable generators such as wind and solar PV would be categorised as semi-scheduled and are not covered by the rule change request.
- generators that produce electricity as a by produce of an industrial or commercial process rather than in response to electricity market conditions may not be suitable for scheduling.

Netting off these categories from total non-scheduled generation leaves 33 generators representing 771 MW of capacity that are potentially able to be scheduled. This represents less than two per cent of the total registered generation capacity in the NEM. This breakdown is summaries in the following table.

Table 4.1 Breakdown of registered non-scheduled generation, November 2016

	Number	Share of total	MW	Share of total
Total non-scheduled	96		2,872	
Of which: intermittent renewable	23	24%	1,268	44%
Of which: industrial process	40	42%	828	29%
Remaining - potential for scheduling	33	33%	771	27%
NEM total			49,091	
Remaining as % of NEM total			1.6%	

Note: registered non-scheduled generators with a capacity of 5 MW of greater

In relation to the ownership of non-scheduled generators:

- 61 per cent of non-scheduled generation capacity was identified as being owned by persons who also own a scheduled generator. These generators may incur lower incremental costs if they were required to be scheduled.
- nine per cent of non-scheduled generation capacity is generators that are not owned by a person who also owns a scheduled generator, are not intermittent generation, and are not generating as a by-product of an industrial or commercial process. This category may face the largest compliance burden if required to be scheduled (on the assumptions that: there would be incremental costs for participants already operating scheduled generators, intermittent generators could only become semi-scheduled, and it may not be practical to schedule generators using industrial or commercial by-products for generation.

4.7 AEMO discretion to require participation in central dispatch

At this time, the Commission has found that there is not a material issue related to non-scheduled load and generation and their impact on pre-dispatch forecasting inaccuracy. However, the Commission takes note that some stakeholders have indicated that non-scheduled load and generation may result in system security issues resulting from these forecasting inaccuracies. Although no particular system security issues were raised, the Commission is of the view that AEMO has mechanisms available to it to address specific instances of system security concerns.

4.7.1 Power to require a registered participant to participate in central dispatch - clause 3.8.2(e)

If AEMO considers it reasonably necessary for "adequate system operation" and the maintenance of "power system security" it may require registered market participants who may otherwise be exempt from participating in the central dispatch process to do so to the extent and in the capacity specified by AEMO.[102]

This power provides AEMO with a reasonably flexible way of dealing with issues that may compromise system operation and security. This flexibility arises as this provided can be applied in relation to an individual participant, and the obligations on the participant can be graduated as needed. For example, AEMO could require additional information or broader obligations equivalent to scheduling.

4.7.2 Registration terms and conditions - clause 2.2.3(c)

AEMO has the ability to impose terms and conditions at the time of registration of a non-scheduled generator:

> “(c) If, in relation to an application under paragraph (b), in AEMO's opinion it is necessary for any reason (including power system security) for the relevant Generator to comply with some of the obligation of a Scheduled Generator or Semi-Scheduled Generator for that generating unit, AEMO may approve the classification on such terms and conditions as AEMO considers reasonably necessary.”

This clause enables AEMO to make it clear to any new participant that they may be required to provide additional information or otherwise participate in central dispatch if their activities materially and negatively affect power system security. The benefit of this approach is that there is flexibility to address system security issues on a one-off basis where costs are only imposed in those, potentially limited, circumstances where power system security is affected rather than imposing obligations on a whole class of participants where there is insufficient evidence at this time to establish there are material issues.

Further, this clause is not limited to power system security alone and can also be used if AEMO is of the view that a specific non-scheduled generating unit is materially and negatively impacting AEMO's ability to forecast demand and price. For example, a specific obligation requiring information related to price responsiveness could be applied if such information is considered necessary for future forecasting accuracy. This allows new market participants to understand there is a risk they may have to participate in central dispatch at some point in the future. The nature of any requirements imposed would have to balance the need for information or other action against the risk that such conditions may create uncertainty for participants about future costs and may deter investment.

102 See NER, clause 3.8.2(e)

4.8 Conclusions

Based on the preceding analysis, the Commission has come to the following conclusions.

- The quantities of non-scheduled load and generation in the NEM are not insignificant and therefore, there behaviour has the potential to impact on pre-dispatch demand and pricing forecasting. However, based on the analysis undertaken by the Commission, AEMO appears to be able to accurately forecast their consumption and generation profiles and therefore, the non-scheduled load and generation do not appear to be having a material impact on pre-dispatch forecast accuracy.

- AEMO's demand forecasting is generally accurate near and at the time of dispatch, and less accurate earlier in the pre-dispatch process. This means the usefulness of the pre-dispatch forecasts to market participants depends on when they need to make commitment decisions for their consumption or generation. A participant that needs to commit four hours before dispatch has significantly less accurate information available to it than a participant that can respond in five minutes.

- Pre-dispatch price forecasting is less accurate than pre-dispatch demand forecasting. It does improve as dispatch nears, indicating that the pre-dispatch process does provide signals the market participants respond to.

- There are many causes of pricing inaccuracy. While specific instances of forecast error can be attributed to a specific non-scheduled generator or load, in general there are a range of reasons for price forecast inaccuracy in any particular dispatch interval. The actions of scheduled generators are a commonly identifiable factor in causing high price events, and general forecasting errors related to modelling limitations, forecasting intermittent generation including unregistered embedded generation, and general consumption forecasting may also be more significant contributing factors. The implication is that even if non-scheduled generation and large loads were required to be scheduled the benefit would only occur in some dispatch intervals, and would only address a proportion of the forecast error. This indicates that scheduling loads and non-scheduled generators would deliver uncertain benefits at this time.

- In relation to non-scheduled generators, the uncertain benefit from scheduling would be limited further given the type of generators in the registered non-scheduled category. Over 40 per cent of these generators are wind generation, and therefore could only be semi-scheduled rather than scheduled if obligated to be scheduled. An additional 25 per cent generate electricity as a by-product of an industrial or commercial process. As they generally generate in accordance with industrial and commercial requirements rather than in response to electricity market conditions, it may not be pragmatic to schedule all of the generators in this category, that is, scheduling obligations may result in these generators avoiding the electricity market altogether. These factors would further reduce the effectiveness of a requirement for such generators to be scheduled.

- The costing information provided by stakeholders indicates the costs of scheduling will vary depending on how active a market participant currently is in trading. Although this indicates a level of uncertainty in relation to costs, in light of the information available to it, the Commission considers the overall imposition may be material. Costs would be incurred in relation to: establishing communication and telemetry systems; operating, including bidding into the market and receiving dispatch instruction; and, in ensuring legal and compliance requirements were met. These costs may be material for the impacted businesses.

- In relation to large loads, these businesses are already under financial pressure from historically high energy prices. There are also practical constraints as to the proportion of these loads that may be scheduled without risk to their core business. The Commission does not consider there would be a net benefit in requiring these businesses to be scheduled at this time.

- In relation to non-scheduled generators, the costs of scheduling may be material to the scale of their operations and negatively impact their business models. There is also a risk that imposing additional costs of small generators may deter new investment and market entry. At this time, the Commission is not convinced there is a net benefit in requiring small generators to be scheduled.

- The Commission considers AEMO has various powers to seek information and manage system security that may be used to maintain and improve its forecasting accuracy – specifically AEMO has the power under clause 3.8.2(e) of the NER to require market participants to participate in the central dispatch process if it considers such participation is reasonably necessary for adequate system operation and the maintenance of power system security. It also has existing information that may contribute to increased accuracy. Given the Commission has been unable to identify net benefits from requiring loads greater then 30MW and market generation greater then 5MW from being scheduled at this time, the Commission recommends that AEMO continues to develop and improve its forecasting processes. To the extent to which AEMO considers its powers are inadequate to manage system security issue arising from non-scheduled generation greater then 5MW, the Commission will work closely with AEMO to develop appropriate mechanisms to ensure it has the necessary tools.

The Commission is of the view that at this time, the evidence and analysis does not support a finding that the behaviour of non-scheduled generation and load are materially leading to the issues identified by the rule change proponents relating to inefficient market outcomes. Therefore, any costs incurred by market participants to become scheduled or to comply with additional requirements would be inefficient and result in increased retail or wholesale costs and therefore is not in the long-term interests of consumers.

This finding applies to all of the options put forward by the rule change proponents, and to the additional options considered by the AEMC.

The assessment of the individual proposals and options against the assessment framework explained in Chapter 3, that follow in the subsequent chapters, are all based on this underlying determination related to the materiality of the issues.

5 Assessment of Snowy's proposal

Snowy's proposed rule, which is described in section 2.1, is to schedule loads greater than 30 MW that are or intend to be price responsive. Snowy considers the different obligations on scheduled and non-scheduled market participants create inefficiencies, including:

- inefficient price discovery and reduced confidence in pre-dispatch prices
- inaccurate reserve forecasting by AEMO
- a reduced ability for AEMO to manage central dispatch, because of reduced effectiveness of constraint equations
- incorrect pricing of financial contracts.

In Snowy's view requiring price responsive loads to participate in central dispatch would address these issues and will, or is likely to, contribute to the achievement of the NEO.

5.1 Price discovery and reduced confidence in pre-dispatch prices

Snowy's view is that the ability of large loads to change their consumption in response to market prices without an obligation to inform the market of their intentions reduces the efficiency of the price discovery process. This could be addressed by requiring large price responsive loads to be classified as scheduled and participate in central dispatch.

5.1.1 Stakeholder views

Stakeholder comments on this option varied.

The Major Energy Users Inc. and Sun Metals argued that requiring energy users to adapt their operations to the electricity market, where electricity is just one input into their commercial operation, is not in the long term interests of end users (and therefore consumers as end users are also consumers).[103]

In relation to whether requiring large loads to participate in central dispatch would improve forecast accuracy:

- Rio Tinto Alcan Yarwun commented that the lack of market loads as scheduled loads is not an issue, and that a more effective improvement to pre-dispatch pricing would be to constrain supplier re-bidding and capacity withdrawal.[104]

---

103 See Major Energy Users Inc submission to the consultation paper, p 5 and Sun Metals submission to the consultation paper p1,

104 See Rio Tinto Alcan Yarwun submission to the consultation paper, pp. 4, 8,

- AGL stated "While the demand side response of market customers to the pool price may make the pre-dispatch price more accurate, its effect may be limited considering there are many other variables that make the spot price different from the pre-dispatch price. Therefore, it is unlikely that requiring market customers to bid into central dispatch will result in a greater ability to forecast the spot price."[105]

- The Energy Efficiency Council stated that the lack of scheduled loads in central dispatch is not a material issue, and that increasing demand side participation is desirable to empower consumers and improve the efficiency of the NEM.[106]

- Stanwell expressed a counter view, stating that the rule will increase the transparency of the market, increase confidence in pre-dispatch outcomes, and improve efficiency and network stability.[107]

5.1.2 Commission's assessment

In the Commission's view the evidence and analysis undertaken indicates that the issues raised in the rule change requests are not sufficiently material at this time to require large price responsive loads to participate in central dispatch.

There are many factors that contribute to pre-dispatch pricing inaccuracy, and it is not clear that any contribution from large loads to forecast error is particularly significant or a consistent source of error. This position recognises that there is evidence indicating specific large loads do have an effect on price forecasting accuracy at particular times. It also recognises that other factors such as the actions of scheduled generators and general forecasting error may be more material factors in a larger number of intervals.

Further, the fact that pre-dispatch pricing is different to dispatch pricing is not unexpected. The pre-dispatch forecasts are designed to provide information to market participants to enable them to plan and adjust their generation and consumption decisions. To the extent that there is change between pre-dispatch forecasts and dispatch, it is at least in part an indication that this process of responding to new information is working.

5.2 Costs on market participants to participate in central dispatch

As part of the assessment of the rule change requests, it is necessary to examine the potential costs that would be incurred by market participants' as a result of any proposed change to the NER against the benefits. In this case, given the Commission's findings in chapter 4 relating to the materiality of the issue, any costs that may be imposed on participants would need to be balanced against the unclear benefits that

105 See AGL submission to the consultation paper, p.1,

106 See Energy Efficiency Council to the consultation paper, p.1,

107 See Stanwell submission to the consultation paper, p.1,

may result from requiring loads and non-scheduled generators to participate in central dispatch.

5.2.1 Stakeholder views

A number of stakeholders commented on the costs associated with the proposed rule change:

- Rio Tinto Alcan Yarwun referred to the significant burden of being required to bid and respond to dispatch instructions, and that this served only to inhibit the ability of a consumer to respond to a high price signal.[108]
- Ergon Energy suggested significant costs would be incurred and these would apply to industries already under economic pressure.[109]
- AGL suggested the costs would likely outweigh the benefits, and the requirements would include market knowledge and expertise in trading, significant system and IT costs for monitoring and participating in the market, as well as ongoing legal and compliance costs.[110]
- EnergyAustralia stated that the benefits of scheduling do not warrant the rule changes.[111]
- The Energy Efficiency Council stated “Snowy’s proposed rule change is an extremely expensive way to address a non-issue.”[112]
- QGC commented that the benefits are unlikely to outweigh the costs and the imposition on loads would be unnecessarily burdensome relative to the materiality of the issue. It also commented that solutions need to be proportional to the problem, and that no clear case for change was evident.[113]
- Stanwell commented that the rule would place significant financial burdens on the customer or their retailer, and it needed to be established that the burden would be offset by significant benefits.[114]

---

108 Rio Tinto Alcan Yarwun submission to consultation paper, p.4,

109 Ergon Energy submission to the consultation paper, p.1,

110 AGL submission to the consultation paper, pp.1-2,

111 EnergyAustralia submission to the consultation paper, p.1,

112 Energy Efficiency Council submission to the consultation paper, p.4,

113 QGC submission to the consultation paper, p.1,

114 Stanwell submission to the consultation paper, p.1. Stanwell also noted that if the benefits case could not be made, the AEMC should consider whether the obligations on scheduled generators are efficient.

5.2.2 Commission's assessment

The Commission considers the costs of establishing and operating communication and telemetry systems and for legal and compliance requirements, would add to the financial pressure many large businesses are already under from historically high energy prices. These costs would be incurred by scheduled loads in relation to all dispatch intervals of a trading day, whereas the benefits that may accrue in terms of an improvement in forecast accuracy would only occur in some locations at some times.

On this basis the Commission considers a requirement on loads to participate in central dispatch would not materially improve market efficiency, impose increased costs on consumers and therefore will not, or is not likely, to contribute to the achievement of the NEO.

5.3 Contract market efficiency

Snowy claims that scheduling large price responsive loads would enable more efficient pricing of financial products in the contract markets.

Snowy considers there are both short term and long term impacts on the pricing of financial contracts. In the short-term, if the spot price is lower than the pre-dispatch price due to price responsiveness, the day ahead outage cover may be incorrectly priced. In the longer term if prices do not reflect underlying supply and demand it may influence new entrant decisions.

5.3.1 Stakeholder's views – contract market efficiency

In terms of the comments relating to the contracts market, three stakeholders did not consider the influence of loads significant:

- AGL commented that requiring customers to bid into central dispatch may not provide a more accurate forecast or a more accurate spot price, and therefore will not result in more certainty in the derivatives market.[115]
- The Major Energy Users Inc considered there would be minimal if any impact on derivative products.[116]
- Pacific Aluminium stated that market participants rely on historical data on actual prices rather than on pre-dispatch pricing to price hedges. "The bigger issue is the late re-bidding by generators inflating the actual spot price and hence hedge prices."[117]

Other than the views put forward by Snowy and ENGIE, there were no additional stakeholder comments supporting the issue as identified in the rule change requests.

---

115 See AGL submission to the consultation paper, p.1,

116 See Major Energy Users Inc. submission to the consultation paper, p.21,

5.3.2 Commission's assessment – contract market efficiency

The contracts market provides market participants with a means of managing risk. The variability of demand and supply conditions results in fluctuations in the spot price such that prices range from the Market Price Cap (MPC) of $ 14,000/MWh to the Market Floor Price of - $1,000/MWh.

To manage their exposure to the spot market, participants typically seek to enter contracts to effectively convert uncertain future spot market prices into more certain wholesale prices to better match upstream or downstream obligations that are relatively stable across time. By helping to smooth their future effective wholesale revenues or payments, contracts lower participants' risk profiles and enable them to obtain equity and debt financing.

Generators face upstream obligations in the form of fixed and variable costs. The magnitude of these costs vary considerably by plant technology, fuel type and location, but rarely vary on a half-hourly basis and are therefore more stable than the spot price.

Retailers typically enter into contracts to supply electricity to customers at prices that are fixed or vary in a pre-determined manner over a specified period of time. These often provide fixed pricing over a period of several years.

These factors mean market participants will value contracts on the basis of their particular circumstances, their expectations of the market, and their appetite for risk. Within this context the spot price is one of a range of inputs that must be considered, but is not necessarily the most significant factor.

In terms of new entrants, their investment and entry decisions are more likely to be based on forecasts of future demand and system adequacy rather than being limited to the spot price or contract prices.

The Commission does not consider Snowy's rule would result in materially more accurate or efficient price signals to the market, and notes that AEMO's demand forecasting is reasonably accurate and does reflect the balance of supply and demand in the market at dispatch. On these grounds, the Commission does not consider the proposed rule would, or be likely to, contribute to the achievement of the NEO.

5.4 System security

Snowy makes two claims related to system security. The first is that AEMO has a reduced ability to manage central dispatch because non-scheduled loads reduce the effectiveness of AEMO's constraint equations.

To maintain the power system security AEMO continually manages network constraints. In locations where constraints regularly bind, and where there is a material amount of unscheduled load (or non-scheduled generation) there may be instances

117 See Pacific Aluminium submission to the consultation paper p.3,

where AEMO constrains a scheduled generator unnecessarily, and higher priced dispatch occurs. For example, AEMO may constrain a scheduled generator due to a transmission constraint. Therefore, if the demand forecast is such that, if not for the transmission constraint, the constrained generator would have been dispatched but instead a higher priced generator is dispatched as the marginal generator, a higher than efficient spot price for that dispatch interval would result.

Snowy's second claim related to system security is that large price sensitive loads reduce AEMO's ability to plan and procure other market services required to ensure the safe and reliable operation of the electricity system over the medium and long-term.

5.4.1 Commission’s assessment

The Commission notes that AEMO publishes information on network constraints so that information is available to all market participants. As such participants can take this information into account, along with their market knowledge and experience, and reflect their position in their bids and rebidding activity. Additionally it is demand rather than price forecasts that are most relevant to managing network constraints, and as demonstrated, AEMO's demand forecasts are reasonably accurate at dispatch.

The Commission notes that AEMO’s contingency planning considers larger impacts than those related to individual loads and generators, and that AEMO’s submission to ENGIE’s rule change requests (as part of the consolidated rule change) did not raise specific concerns related to system security but did comment that contingency FCAS would not be affected by the proposed rules, and regulation FCAS was unlikely to be affected.[118]

5.5 Additional issues raised by stakeholders

5.5.1 Loads practical ability to comply with dispatch instructions

A number of stakeholders indicated that scheduling requirements may be in conflict with industrial requirements and processes, including pre-existing contractual arrangements. Pacific Aluminium stated “Electricity market rules should not dictate how industrial producers operate their production processes as this ’tail wagging the dog’ approach can only lead to economic inefficiency.”[119] Similarly, EnerNOC commented that many large loads cannot be controlled without risk to the industrial requirements.[120]

118 AEMO submission to the consultation paper, p.4,

119 Pacific Aluminium submission to the consultation paper p.2,

120 EnerNOC submission to the consultation paper, p.2,

5.5.2 Commission’s assessment

The Commission understands that compulsory scheduling may not be practical for all loads, as their demand may be variable for operational reasons rather than or in addition to price responsiveness. In addition, even where the load is price responsive, only a portion of its total demand may be variable and any demand response may only be able to occur in specific increments or on specific occasions. As such, and on the basis that loads' industrial requirements should not be affected by electricity market requirements, it would only be practical to schedule a proportion of particular loads. This would reduce the claimed benefits of the loads being scheduled.

5.5.3 Price elasticity and demand response

Another important consideration is how the proposed rule may alter the incentives of market participants. A comment from EnerNOC suggested there would be a reduction in demand responsive behaviour if loads were required to be scheduled, and that this may result in inelastic demand and in turn higher spot prices, and higher prices for retail consumers.[121] The Commission considers this would be a poor outcome, and notes that the ability of market participants to respond to changing circumstances is an important feature of an efficient market.

5.6 Conclusion

Based on the evidence on the materiality of the issues in the rule change request, together with the analysis undertaken, the Commission is of the view that Snowy’s rule will not, or is not likely to, contribute to the achievement of the NEO. The potential limited benefits do not outweigh the identified costs that would be incurred by large loads. Further, the potential for reducing price responsive behaviour of large loads is not, in the Commission's view, in the long-term interests of consumers.

121 EnerNOC submission to the consultation paper, p.1,

6 Assessment of ENGIE's proposed rule

ENGIE put forward three related proposals as part of its rule change requests that it suggested could be implemented individually or in combination. The proposals aim to address a deficiency that allows non-scheduled generation to interact with the market without obligations to inform the market of its intentions. There are a number of market impacts that ENGIE attributes to the lack of information on non-scheduled generation:

- distortions to the pre-dispatch and dispatch processes caused by price responsive non-scheduled generators
- inefficient dispatch can result in uneconomic generation. Part of this claim is that scheduled generators are being sent targets that are "calculated without any account of the impact of non-scheduled generation."[122] This raises the total cost of generation and prices
- AEMO is required to take a more conservative approach to managing system security than it would with better information
- there may be a reduction in liquidity if peaking generators are not able to offer cap contracts because of uncertainty over dispatch pricing.

ENGIE states its proposed rules are intended to improve information transparency. It considers its suggestions are proportionate to the scale of the issues raised, and it has been "mindful not to impose complex or overly onerous obligations on owners of smaller generators, especially those that are not seeking to be active in the market."[123]

6.1 ENGIE proposal - reduce the threshold for scheduling non-intermittent generators to 5 MW

The first option put forward in ENGIE's rule change request is to reduce the threshold for scheduling non-intermittent generators from 30 MW to 5 MW. This would apply to all new non-intermittent generators registered after the making of the rule, and then to existing generators that are capable of being scheduled by a nominated time. ENGIE's proposed rule would not apply to existing non-scheduled intermittent generators, and it assumes any new intermittent generators would be classified as semi-scheduled as per the current provisions in the NER.

ENGIE states that the amount of non-scheduled generation at the commencement of the NEM in 1998 was inconsequential and its exclusion from the scheduling process did not impact the market. It considers there has been strong growth in non-scheduled

122 ENGIE rule change request, p. 4

123 ENGIE rule change request, p.1

generation since then and is "now having a detrimental impact which is likely to increase going forward."[124]

ENGIE considers scheduling non-intermittent generators that are 5 MW or larger would address the inaccurate and inefficient pre-dispatch and dispatch outcomes.

6.1.1 Stakeholder views – market information

In terms of stakeholder comments on the proposed rule:

- Stanwell commented that the proposal did not capture wind farms regardless of their nameplate capacity and that this inconsistency should be addressed.[125]
- ERM Power stated that implementing the rule change would provide a more accurate picture of the level of supply available to the market, allowing a more efficient dispatch process.[126]
- AGL commented that any efforts to improve the accuracy of the pre-dispatch forecast would be better focussed on improving AEMO's short term demand forecast, which would contribute more to forecast inaccuracies than the behaviour of non-scheduled generation.[127]
- Westpac commented that scheduling small generators would not "make a material improvement to pre-dispatch that is distinguishable from the noise currently in demand forecasts."[128]

6.1.2 Commission's assessment – market information

The Commission agrees with ENGIE that the quantity of non-scheduled generation at the commencement of the NEM was small and did not have a material impact on the pre-dispatch and dispatch processes. It also notes the growth in the quantity of non-scheduled generation has been relatively gradual over the last decade, and acknowledges the outlook is for an increase in smaller, more distributed, intermittent generation and that this may increase the quantity and proportion of non-scheduled generation in the market, even though a significant portion of new generation is expected to be distributed generation which is generally below 5 MW and therefore would not be captured under this proposed rule.

The Commission does not consider a requirement for non-intermittent generators above 5 MW to be scheduled would materially improve the information available to the market nor the accuracy of pre-dispatch forecasts and dispatch.

124 ENGIE rule change request, p.1

125 Stanwell submission to the consultation paper, p.3,

126 ERM Power submission to the consultation paper, p.1,

127 AGL submission to the consultation paper, p.2,

128 Westpac submission to the consultation paper, p.1,

- 44 per cent of non-scheduled generation is wind generation or solar PV, which is intermittent generation and so would not be covered by the proposed rule.
- 29 per cent of non-scheduled generation is associated with industrial or commercial processes and may not practically be able to comply with dispatch instructions. Any benefits from scheduling generators in this category will vary and depend on the generator's characteristics.
- The remaining non-scheduled generation represents less than two per cent of NEM generation capacity, and only impacts on pre-dispatch and dispatch accuracy to the extent that AEMO is not able to forecast it accurately. Non-scheduled generators are similar to loads, in that they vary significantly in their size, variability, predictability and price responsiveness. At an individual generator level there may be no improvement in forecasting accuracy resulting from it being scheduled. As described in chapter four, AEMO’s demand forecasts are generally accurate and there are many more significant factors contributing to pricing forecast error, and some of these factors contribute to efficient market outcomes. For example, although price responsiveness may contribute to price forecast error, it can also result in more efficient market outcomes.

The Commission considers the benefits of the proposed rule would be limited and uncertain. Against this assessment of the benefits, the Commission needs to consider the costs that would be incurred by non-scheduled generators if they were required to be scheduled and balance the benefits and costs, in the long-term interests of consumers.

6.1.3 Stakeholder views – costs on market participants

Stakeholder views on the costs of scheduling varied significantly:

- AGL expressed the view that the costs are significant given that participation in central dispatch is a complex and dynamic task requiring people with considerable market knowledge and expertise in trading and the wholesale spot market.[129] This is in addition to the system and IT costs of monitoring and participating in the market. Similar comments were received from the Major Energy Users Inc, SA Water and Westpac.[130]
- Origin took a precautionary stance, suggesting the proposal had merit but that the benefits must outweigh the regulatory costs to smaller participants resulting from the new requirements.[131]
- ERM Power stated that approximately 75 per cent of the non-scheduled non-intermittent generation was operated by market participants that operate

129 AGL submission to the consultation paper, p.2,

130 Major Energy Users Inc to the consultation paper, p.12, SA Water submission to the consultation paper, p.1, x Westpac submission to the consultation paper, p.1,

131 Origin submission to the consultation paper p.1,

other scheduled generation units, and the cost of scheduling to them would be incremental.[132]

- Stanwell considered the likely benefits of the proposal would far exceed the costs.[133]

6.1.4 Commission's assessment – costs on market participants

The Commission considers the likely costs of establishing communication and operating systems and processes, and ensuring legal and compliance requirements are satisfied, would be material to small generators. These costs would be definite and must be weighed against benefits that are unclear and periodic. Such costs could materially affect the business models of small generators already operating in the market, and may also deter future entry and investment.

6.1.5 Appropriate threshold for participation in central dispatch

An important aspect of the proposed rule relates to the appropriate threshold for scheduling. While ENGIE's proposal suggests the existing 5 MW threshold as the level at which non-intermittent generators must be required to become scheduled, there were a number of other views. Snowy suggests 15 MW[134], Arrow Energy indicates an unspecified level higher than 5 MW[135], Stanwell suggests there may be merit in setting the threshold at 1 MW[136], and AEMO recommends specific consultation on the threshold should occur before it is changed as there is no clear basis for using 5 MW as the threshold for central dispatch.[137] Irrespective of the level chosen the Commission recognises that some participants may design their market entry around the specific threshold chosen.[138]

6.1.6 Commission's assessment – appropriate threshold for participation in central dispatch

The Commission considers setting the threshold for classification as a scheduled generator and therefore the requirement to participate in central dispatch as a significant decision. As described in section 3.3, the industry is evolving and there is an

132 ERM Power submission to the consultation paper, p.2,

133 Stanwell submission to the consultation paper

134 Arrow Energy submission to the consultation paper, pp.1-2,

135 Ibid, pp.1-2,

136 Stanwell submission to the consultation paper, p.10,

137 AEMO submission to the consultation paper, p.4,

138 Tesla Corporation own 4 diesel generators in Western Australia each with a nameplate capacity of 9.9 MW. As this is lower than the 10 MW threshold for registration in Western Australia, Tesla is not required to register. Tesla is a full participant in the market, certified to provide Reserve Capacity and participate in the Short Term Energy Market and Balancing Market. It can be expected that other participants will seek to achieve a similar outcome; participating to the extent wanted commercially, and avoiding any additional obligations.

expectation that a greater proportion of generation will be smaller and more distributed than currently is the case. The Commission:

- considers it would be inappropriate to apply the full requirements of scheduling to such small generators at this time, as the costs and compliance requirements may unreasonably disrupt businesses and deter investment
- recognises that the emergence of distributed generation poses challenges to AEMO in relation to the visibility and predictability of generation, and its ability to control participants to ensure system security.

It is for these reasons that the Commission is undertaking its Distribution Market Model Review, and AEMO is conducting its Distributed Energy Resources project. While it is not clear what the outcome of these processes may be, the Commission considers there may be approaches for dealing with AEMO's visibility, predictability and control requirements that can be applied to small generators without imposing unreasonable economic or administrative burdens. This would better inform the issue of where to draw the boundary between smaller market participants with a lower ability to bear substantial compliance obligations and costs, and the larger participants who operate as scheduled participants in central dispatch.

Given the lack of evidence to support a finding of a net benefit from requiring non-scheduled generators to participate in central dispatch, and the work being undertaken by the Commission and AEMO in relation to smaller-scale generation (less than 5 MW), the Commission is of the view that the threshold for classification as a scheduled generator should not be amended at this time. This however, does not preclude this issue from being examined in the future to determine if, given market conditions at the time, the threshold level should be adjusted.

6.1.7 System security

ENGIE states that the lack of visibility of non-scheduled generation causes AEMO to take a more conservative position in managing system security.

In its submission AEMO comments that:

> “In theory, any increase in the scope of generation covered by the central dispatch process would improve market efficiency and power system security, provided the additional generation has the ability to respond to dispatch instructions. The proposal would not alter existing exemptions from central dispatch for practical or technical reasons, so the main consideration is whether the remaining generation affected by the proposal will be material.[139]”

139 AEMO also commented that contingency FCAS would not be affected by the proposed rule, and regulation FCAS was unlikely to be affected

Given the Commission's analysis indicates that the majority of non-scheduled generation is either intermittent or the by-product of an industrial process, and the number of large loads that are price responsive is limited, the benefits that may accrue from scheduling these participants would also be limited.

The Commission recognises that the changes in generation and consumption technologies may result in new system security challenges. These challenges may require changes to market participation requirements or processes and the information and data available to the system operator. Implementing a broad mechanism affecting all generating units of a particular size may not be the appropriate answer in the absence of knowing what the specific system security issues are.

The Commission does not consider the rule change requests as the most appropriate method for addressing such issues.

Further, the Commission notes AEMO has powers to deal with system security issues that arise from the participants that could be affected by the Snowy and ENGIE rule change proposals, in particular:

- it can impose any terms conditions it considers reasonably necessary on participants at the time of registration, under cl. 2.2.3(c) of the National Electricity Rules (NER). This would enable it to apply specific requirements on certain types of participants, or on certain technologies (with particular attributes), if it considered this necessary for system security reasons

- it has power under cl. 3.8.2(e) of the NER to require participants to participate in central dispatch to the extent necessary to ensure system security.

The Commission also notes emerging system security issues are being dealt with more broadly. The AEMC is undertaking the *System Security Market Frameworks Review* to assess the regulatory frameworks that affect system security in the NEM. Further, in its *Distribution Market Model Project* the Commission is exploring how the operation and regulation of distribution network may need to change in the future to accommodate increased distributed energy resources, like rooftop solar PV. AEMO is considering power system security challenges emerging in the market through its *Future Power Systems Security Program*, including a specific program on the visibility of distributed energy resources. The AEMC and AEMO have been working closely to consider, develop and implement changes to the market framework to facilitate the ongoing market transformation while maintaining the security of the system, and will continue to do so, including in relation to any additional specific security issues arising as a consequence of forecasting inaccuracy.

6.1.8 Impacts on the contracts market

In another similarity with Snowy's submission, ENGIE states the uncertainty around future pricing creates risks for peaking generators and this may mean they do not offer cap contracts into the market, thereby reducing market liquidity. The risk for such generators is that in committing to run for a period, on the expectation of a high spot price informed by a high forecast pre-dispatch price, non-scheduled generation may enter the market and as a result, the generator dispatched that sets the price is not the same as forecast and the actual price is lower than forecast and the peaking generator is not dispatched at all. The peaking generator may then operate inefficiently for its minimum run time. There are a number of issues related to this:

- Pre-dispatch forecasts are designed as signals to the market and responses to these signals are part of an efficient market process, especially in relation to price forecasts.
- There are many influences on price, in addition to non-scheduled generation, and unless these are also controlled the rule change proposal would not materially alter the situation.
- One possible solution that may give peaking generators certainty would be some form of gate closure that locked in a spot price beyond the peaking generator's commitment time. However, this would undermine market efficiency by preventing a more responsive interaction between supply and demand. It would also create consumption inefficiencies of potentially greater magnitude and beyond the control of loads. For example, if a price was established four hours ahead of dispatch and a load then had to reduce consumption for commercial reasons, the dispatch price may be inefficiently high. While the peaking generator would achieve certainty, the inefficient price would represent a cost to every load and consumer in the market, and would likely lead to higher prices for consumers.

6.1.9 Conclusion – reducing the threshold for non-intermittent generation to 5 MW

Based on the evidence and the materiality of the issues in the rule change request, and the analysis undertaken, the Commission is of the view that the proposed rule will not, or is not likely to, contribute to the achievement of the NEO. The potential limited benefits do not outweigh the costs that would be incurred by non-scheduled generators. In part this is driven by the fact that the majority of non-scheduled generators are either intermittent wind generators or generating as a by-product of industrial processes, so the practical ability to comply with dispatch instructions is limited. Further, there is a risk that adding costs to small non-scheduled generators will not only disrupt the business models of existing generators but may also deter new and innovative investment in the sector. In the Commission’s view this would not be in the long-term interests of consumers.

6.2 ENGIE proposal - soft scheduling

ENGIE's second option is to create "soft-scheduled" generators as a new class of participant. These generators would inform AEMO of their intended generation but would not have to participate in bidding or to follow dispatch instructions.

ENGIE considers the potential benefits of this option are that it improves the information available in the pre-dispatch and dispatch processes because the information is from market participants rather than as forecast by AEMO. It considers that more accurate information will result in more informed decisions by market participants and more efficient dispatch.

ENGIE's rule change request discusses the need for participants to comply with the information they provide to AEMO, and it notes that currently there is no such compliance mechanism.

6.2.1 Stakeholder views – soft-scheduling classification

Stakeholders were not generally in favour of this option and indicated:

- There is not an appropriate existing compliance mechanism. This was pointed out by stakeholders, including Snowy and ERM Power[140]
- the proposal would create an opportunity for gaming. Participants could inform AEMO of one generation level in order to influence the market price, and then change that level during dispatch. Stanwell and ERM Power commented that it would be inconsistent and inefficient if the dispatch price were able to be set by participants who did not receive dispatch instructions[141]
- AEMO did not support this option, stating that it would introduce complexity and confusion into the registration process.

6.2.2 Commission's assessment – soft-scheduling classification

The Commission considers there is merit in examining the extent to which information and other mechanisms can improve market efficiency, as alternatives to scheduling. However it does not agree that this option would be an effective mechanism.

In the absence of an effective compliance process the risk of manipulative conduct or participants simply choosing not to comply with the information provided is high.

If a compliance process was created and participants were required to conform to the information provided, then the proposed rule strongly resembles scheduling. Generators would have to nominate and conform to its output, even though it would not be a participant in the price setting process, nor subject to constraints, under the proposal. Nonetheless it would have to incur most of the costs associated with scheduling. As noted, the Commission does not consider there is a net benefit justifying the scheduling of non-scheduled generators at this time and therefore where a compliance program is included under this proposal, the same justifications exist for

140 Snowy submission to the consultation paper, p.2, , and ERM Power submission to the consultation paper, p.2,

141 Stanwell submission to the consultation paper, p.10,, ERM Power submission to the consultation paper, p.3.

why, at this time, the Commission is of the view that the proposal rule will not, or is not likely to, contribute to the achievement of the NEO.

The AER would also have to develop and implement a separate conformance process for "soft-scheduled" generators. This process would create additional costs and administrative burden for the AER, AEMO and market participants.

Based on the analysis described, the Commission does not support the proposal to create a "soft-scheduled" category of generator.

6.3 ENGIE's proposal - proxy bidding

ENGIE's third option was for AEMO to develop a new process to incorporate the price responsiveness of non-scheduled generators in the form of price/volume bids into the dispatch demand forecast. The potential benefit of this option is that it would apply to all non-scheduled generating units, including those below 5 MW, and potentially to all non-scheduled loads.

ENGIE's intention, evident in all of its proposals, is to increase the level of market information and thereby to improve market efficiency. Noting this, there are significant concerns with this option.

6.3.1 Stakeholder views – proxy bidding

A primary consideration in the Commission's assessment of this option is that AEMO does not consider it has the capability to implement the option.

The majority of stakeholders oppose this option and have concerns that it would compromise AEMO's status as an independent market operator. In effect, if AEMO bids its forecasts into the market, it would become a market participant in addition to the market operator.

The Major Energy Users Inc, Snowy, ERM Power and Origin all expressed concerns about AEMO bidding into the market, and opposed this proposal.

6.3.2 Commission’s assessment – proxy bidding

The Commission is concerned that the option may require AEMO to undertake a role that is inconsistent with its existing statutory functions, and that the option would compromise its status as an independent market operator. The Commission notes AEMO’s view that it does not have the capability to implement the option, and considers there would be significant complexity and cost, and no guarantee of accuracy, associated with attempting to develop the suggested proxy bids. On this basis the Commission is of the view that the proposed rule would not be in the long-term benefits of consumers and will not, or is not likely to, contribute to the achievement of the NEO.

7 Assessment of other options considered by the Commission

7.1 Additional options considered by the Commission

Despite the fact that at this time there is not sufficient evidence to suggest that a material issue exists in relation to the issues raised by the rule change requests, the Commission:

- agrees that a transparent market with accurate forecasts and competitively responsive participants is desirable
- acknowledges the changes occurring as the market transitions to new generation and consumption technologies.

Given this, an additional set of options was considered.

7.2 All market participants must be scheduled or operate through a scheduled entity

The most significant option considered was a fundamental market redesign in which all participants that bought or sold electricity in the NEM would have to be scheduled, or to operate through a scheduled entity. This option was assessed on the basis of it being a logical end-point to the concept of increasing the number of market participants that are scheduled, but the Commission acknowledges it is a significant departure from the current obligations in relation to participating in central dispatch.

The option is premised on a view that as changes to generation and consumption technologies occur there will be a reduction in the quantity of scheduled market participants. This will mean fewer market participants will be required to indicate their supply and demand intentions through participation in the central dispatch process, the price setting process will be based on a reducing proportion of generation volume, and the forecasting burden on AEMO will increase.

To address these issues this option would redraw the balance of responsibilities between AEMO and industry participants, so that participants take a more active role in contributing to the process of balancing supply and demand, and creating an efficient market. For generators and consumers there would be a simple choice: in order to buy or sell energy in the NEM they must either be scheduled or operate through a scheduled participant. The scheduled participant could be a generator, a load, a market network service provider, a retailer or an aggregator. The participation requirement would apply universally irrespective of the size of the generator or load, and would include distributed energy and all consumers. The option could be considered as an extension of the model that already exists for small generators that want to sell their output to the NEM but do not want to incur the expense of registering as a market participant or becoming a scheduled participant; these generators are able to operate through the market small generation aggregator framework.

The option also highlights an issue of market organisation. In a market where there are many more generators and active consumers, of different sizes and capabilities, there is a question of whether it is more efficient for AEMO to deal with a limited number of participants operating in a hierarchical structure than it is to engage with all participants in a totally flat structure. Most corporate structures suggest a hierarchical model is more efficient.

This option is simple in its premise and in that there is clear choice for every generator or load as to how they operate in the market. However the implementation of such an option would be costly, complex and disruptive. The option represents a fundamental change to the current market design, and for businesses would affect: participant requirements; investment incentives; operational costs; and business models. For consumers, a transition to this model may be disruptive and confusing depending on the offers they received from retailers or other aggregators.

7.2.1 Commission's assessment – scheduling all market participants

The evidence on demand and price forecasting accuracy does not support the basic premise of the option that the forecasting task is beyond AEMO's capabilities.

The option encompasses the issues being considered in detail in the AEMC's and AEMO's work on distributed energy resources and market structures. The outcomes of these reviews should be considered ahead of any detailed work on options for market redesign.

In the event that such a fundamental market redesign was considered necessary, it would most appropriately be considered in a review, and would include a broader set of alternative market models for consideration.

7.3 Selective identification and participation requirements

AEMO has the power under clause 3.8.2(e) of the NER to require market participants to participate in the central dispatch process if it considers such participation is reasonably necessary for adequate system operation and the maintenance of power system security. Such power can be exercised in respect of generators or loads, and can require participation to the extent and in the capacity specified by AEMO. This option considers broadening the scope of this clause to enable AEMO to require participation in the central dispatch process if a market participant operates in such a way as to cause forecasting inaccuracy. Importantly as the clause states "to the extent reasonably necessary" it enables AEMO to determine the level of participation in dispatch that is reasonably necessary for adequate system operation and forecasting accuracy; from information provision to dispatch compliance.

New Zealand operates a system with similarities to this option, although it only applies to industrial loads. In 2012 New Zealand introduced a demand side bidding and forecasting (DSBF) process in order to improve the accuracy of forecast loads and prices, and achieve better coordination between demand and supply. With DSBF, a grid exit point (GXP) is determined as either "conforming" or "non-conforming". A conforming GXP is one from which the load can be accurately forecast by the system operator.[142] Consumers at these points do not need to forecast their load, unless they want to respond to price in which case they provide a "difference" bid. Purchasers at non-conforming nodes must input bids indicating their load quantity and willingness to reduce load in response to price. These are called "nominated" bids. Participants at non-conforming GXP's have responsibilities equivalent to scheduled participants in the NEM.

In order to determine if a GXP is conforming or non-conforming, there are specific criteria that must be taken into account for system security reasons and separately for forecasting accuracy, and specific processes to be followed. In relation to forecasting accuracy the key criterion is whether the system operator considers the consumer, rather than the system operator, will be better able to predict demand at the GXP. If so it can set out its reasons in writing to the Electricity Authority which then considers those reasons and the view of the consumer and makes a determination as to whether the GXP is non-conforming.

7.3.1 Commission’s assessment - selective identification and participation requirements

The benefit of this option is that if clause 3.8.2(e) was broadened it would enable AEMO to selectively identify participants that are causing forecasting inaccuracy and determine an appropriate level of obligations to impose on the participant to ensure system security and forecasting accuracy. The benefits of this approach are that:

- it could apply to non-scheduled generators as well as loads
- compliance requirements can be graduated from simple information requirements through to more onerous obligations such as participation in central dispatch
- compliance costs are only imposed on those participants whose market participation causes forecast inaccuracy

This option does not depend on the specific scheduling threshold, as obligations can be imposed on non-scheduled participants (including potentially to large non-scheduled wind farms). It was considered as a more flexible option than those put forward by the proponents, in that it would not necessarily apply to a whole class of market participant and the compliance requirement could be set at a level lower than that required for scheduled participants.

142 Appendix E sets out the criteria used to determine if a GXP is conforming or non-conforming

Although this option provides some flexibility to AEMO to address only those market participants that are causing the forecast inaccuracy, there are significant impediments to the implementation of this approach.

The adaptive nature of the proposal may be criticised for creating regulatory uncertainty. Sun Metals provides a useful example in this regard. The EY analysis identified Sun Metals as regularly being price responsive and that its responsiveness was a contributing factor in instances of regional forecast error. On this basis if the option were implemented Sun Metals may be identified and required to participate more fully in the central dispatch process. However the EY analysis also highlighted that there were many instances where forecast error occurred and there was no attributable link to the actions of Sun Metals. This highlights that whereas the costs to the load of participation are definite, the benefit to forecasting accuracy that is gained is uncertain and will not occur consistently.

A similar issue arises in relation to loads that are not price responsive but whose consumption is variable. They may be identified as the cause of forecast error but have limited ability to conform to requirements without risk to their commercial operation. A further issue may be faced by the marginal participant. They may be identified as causing forecast inaccuracy, but their actions are only identifiable as the topmost action in layers of supply and demand interaction. In this way they may face compliance costs even though their contribution to error is marginal within a broader context of market activity.

These examples highlight the need for clarity in the definitions used to identify participants, and also issues related to the process. For example, there would need to be clarity around the level and frequency of behaviour that would cause a participant to be identified as contributing to forecast error. An equivalent process enabling a participant to cease being required to comply would also be required for participants that stopped contributing to forecast inaccuracy.

There is a risk to new investment if the terms and conditions of participation in the market are unclear and may change over time. A participant may be caught by this rule if broader market changes, rather than any specific individual action, cause their operation to be identified as contributing to forecast inaccuracy.

In terms of process, an authority to make determinations as to whether a participant's behaviour contributes to forecast inaccuracy would need to be established. Australia does not have an equivalent body to the New Zealand Market Authority, and none of the existing market authorities in the NEM are naturally suited to this assessment task.

The process may become administratively complex if a large number of market participants are captured by the mechanism, and are subject to varying levels of obligation.

While noting that these issues would need to be addressed in detail if the option were to be implemented, at this time, the Commission does not consider the option will, or is likely to, contribute to the achievement of the NEO:

- the evidentiary analysis indicates demand forecasts are reasonably accurate close to dispatch, and the causes of price forecast error are varied and not primarily or consistently related to the actions of large loads or non-scheduled generators
- market participants captured by the clause would incur costs to comply with AEMO's requirements. The scale of these costs is unclear, but the Commission considers these could be material if they approach the estimated costs associated with being scheduled
- the proposal may require a new authority to be established to undertake the assessment function of causation. Alternatively the powers of an existing market body may need to be amended to undertake the function. These are additional costs and administrative process and burden that must be considered and balanced against the unclear benefits of the proposal.

7.4 Create an incentive for generators to become scheduled

This option examined whether the issues raised by the rule change proponents could be addressed indirectly by creating an incentive for non-scheduled generators to become scheduled.

The market design of the NEM provides for generator access to transmission capacity to be determined via the competitive bid stack process. As non-scheduled generation does not participate in the bid stack and is not constrained off when there is a transmission network constraint and therefore it effectively receives priority access to the transmission network. This priority physical access also provides financial benefits, in that non-scheduled generators are paid for all of its output.

When the NEM was established there were immaterial quantities of non-scheduled generation. However with the quantity increasing, with particular effect in specific locations where constraints regularly apply, an option was examined to change the way AEMO manages network constraints so as to constrain off non-scheduled generators ahead of scheduled or semi-scheduled generators. This change should create an incentive on non-scheduled generators to become scheduled or semi-scheduled. If they do not respond to the incentive they will risk a loss of generation revenues commensurate with the constraints in their location.

There were two options considered to alter the way the incentive would be managed:

- physically constrain non-scheduled generators before scheduled generators
- change the financial settlements process so that scheduled generators are made whole for being constrained off due to non-scheduled generation up to the amount received by the non-scheduled generator.

7.4.1 Option 1 – physical constraints

In order to implement the option using physical constraints, AEMO would need to be able to communicate with non-scheduled generators. There are a number of practical issues that prevent this option being viable:

- many non-scheduled generators may not have the required communication or telemetry equipment required for automated communication with AEMO
- some generators may only be able to be on or off, rather than scaled to a specific level, and AEMO would need to understand and manage this
- this option would depend heavily on monitoring and compliance, putting additional obligations on both AEMO and AER
- given this mechanism would work through compliance which is ex-post, there could be a risk to the physical system if a non-scheduled generator did not comply in real-time.

If measures were required to overcome these issues, the obligations would effectively be equivalent to scheduling. As discussed in relation to the ENGIE rule change request, the Commission does not consider there is evidence justifying the scheduling of non-scheduled generation above 5 MW at this time.

7.4.2 Option 2 – financial settlements process

The alternative method considered was to change the financial settlements process to create an incentive for non-scheduled generators to become scheduled.

Under this option scheduled generators would generate in accordance with dispatch instructions. In the event they were constrained off due to non-scheduled generation in that location, then the scheduled generator would be "made whole" for the non-scheduled quantity. Being "made whole" means the generator would be paid for the generation it committed to ahead of transmission constraints being applied due to non-scheduled generation. In this way the scheduled generator would avoid the risk of inefficient generation associated with the constrained volume (ie it would be paid for the constrained volume) as that risk would transfer to the non-scheduled generator (ie it would not be paid for the constrained amount). To be clear, this means non-scheduled generators may not be paid at all for their generation.

The practical complexity of this option would need to be worked through in significant detail before it could be applied, including whether the option would impact on the bidding incentives of scheduled generators. At this time however the Commission does not consider that the option will, or is likely to, contribute to the achievement of the NEO, given:

- there is no direct net benefit from this option. Scheduled generators that incur the costs of inefficient generation today would be compensated under the model, but that compensation would come from non-scheduled generators. In effect the option would transfer revenue from non-scheduled to scheduled generation in areas where constraints apply

- the only benefit that may apply is an indirect one in that if more generators become scheduled there may be an increase in forecast accuracy. Given the Commission has concluded that the direct case for requiring non-scheduled generation to be scheduled is not likely to contribute to the achievement of the NEO, it is consistent to come to the same conclusion in relation to this indirect method
- AEMO would need to change its settlement process and incur associated costs and increased administrative burden
- the option is described as an incentive but in effect is a requirement. If a non-scheduled participant does not become scheduled it would create a risk to its generation revenues. Although this risk would vary by region depending on the scale and regularity of the constraints and the quantity of non-scheduled generation, it could materially affect the business models of many non-scheduled generators. As noted in the evidentiary analysis and in the discussion of the ENGIE proposal, approximately 25 per cent of the non-scheduled generation is a by-product of industrial or other processes. The nature of their operations may not be suited to scheduling, and if there was no financial benefit associated with generation, they may cease generation. This would likely have negative environmental and employment impacts.

7.5 Reduce the threshold for all new generating units

Another option assessed was whether there should be a reduction in the threshold for scheduling all new generators. This option is a variation on the ENGIE proposal to reduce the threshold for scheduling non-intermittent generators from 30 MW to 5 MW, in addition to re-classifying existing generators by a nominated time. The two variations in the options are:

- all generators, including intermittent generators, above a given threshold would be required to be scheduled or semi-scheduled
- the proposal would only apply to new generators, and would not require the re-classification of existing generators.

The identified benefit of the option is that, to the extent to which non-scheduled generation do contribute to forecast inaccuracy, this option would stop the problem getting worse. However the option does not deal with existing market participants such as large loads and non-scheduled generators whose market behaviour is the premise of the proponents' rule change requests. There is also a risk that adding costs and compliance requirements to small generators will deter investment and may hinder or foreclose on the development of new and innovative business models centred on new generation technologies.

This option would apply the same threshold to intermittent and non-intermittent generators. To that extent it avoids the inconsistent obligations that the ENGIE option creates. However because it does not re-classify existing generators to the new threshold it means different thresholds would apply to generators depending on when they entered the market. This could be viewed as inconsistent and inequitable.

This proposal does not clarify what an appropriate threshold level for scheduling is. In the event 5 MW was considered appropriate now, given the changes in generation technology and scale, it is not clear that this threshold would have longevity before potentially needing further adjustment.

7.5.1 Commission's assessment – reduce the threshold for all new generating units

In the Commission's view, there is no clear benefit associated with this option that exceeds the risks associated with the proposed rule deterring market entry and investment in new, small generation technology. On this basis the Commission does not consider this option will, or is likely to, contribute to the achievement of the NEO.

7.6 Formalise the requirement in the NER for AEMO to produce a 5-minute pre-dispatch forecast

An option considered in the assessment process was to formalise in the NER the requirement for AEMO to produce the five-minute pre-dispatch forecast. AEMO currently produces this forecast, even though it is not required under the NER. Based on the Commission's analysis it is apparent that the demand forecasts are reasonably accurate, and are relied on by stakeholders.

The option was considered for two reasons:

- The option recognised the growing importance of the five-minute pre-dispatch forecast in comparison to the 30-minute forecast. This is irrespective of the Commission's decision on the 5 minute settlement rule change request and is related to the fact of technological changes enabling participants to make more responsive generation and consumption decisions.
- There was consideration of whether formalising the requirement for the five-minute pre-dispatch forecasts would ensure AEMO could prioritise their production, potentially including making improvements to the neural network model and incorporating information such as the UIGF to improve forecast accuracy.

7.6.1 Commission's assessment – formalising in the NER the requirement for the 5-minute pre-dispatch forecast

This option is an indirect option for addressing the issues raised by the rule change requests, and there is no reason to assume any change in forecasting accuracy following formalisation of the requirement for the forecast to be produced. Any improvements to AEMO's forecasting processes and accuracy can occur equally without this option. On this basis, the Commission does not consider this option will, or is likely to, contribute to the achievement of the NEO.

7.7 Conclusion

The issues raised in these rule change requests are complex and inter-related to a broader range of issues that are being examined in other rule change and review processes.

The rule change proponents put forward views on the market inefficiencies that are caused by large price responsive loads and non-intermittent non-scheduled generators. They also requested specific rule changes to address those inefficiencies.

Having examined:

- the context within which the rule change requests are proposed
- the evidence relating to forecasting accuracy, system security, and the contracts market
- the substance of the specific rule change requests
- the views of stakeholders on the issues and rule change requests
- an alternative set of options for addressing the issues raised

the Commission does not consider there are grounds to agree to the changes proposed in the rule change requests. In particular, and in relation to the issue of forecasting accuracy which is the most substantive issue raised, the evidence does not indicate that scheduling the requested participants would materially improve forecast accuracy. This is because there are other more influential factors impacting on forecasting accuracy that would not be improved by the proposed rule changes; in particular, the actions of scheduled generators and general issues of forecasting accuracy related to, for example, modelling capability and intermittent generation.

Given the uncertain benefits that might result from the proposed rule changes, but the certainty of costs to the market participants who would be subject to increased obligations and requirements, the Commission is of the view that at this time there is not a net benefit associated with the proposed rules. There is also no apparent benefit to consumers, and indeed there is a risk that higher costs, associated both with being scheduled and the legal and compliance costs of increased requirements, may flow through as higher prices to consumers.

Similar conclusions were reached in relation to the alternative options that the AEMC considered. The options are partial in coverage, administratively complex and on balance the evidence and analysis, at this time, does not support the finding that the issues raised in the rule change requests are sufficiently material to justify the imposition of costs on market participants, the AER and AEMO.

It is on this basis that the Commission has decided not to make a draft rule at this time.

Abbreviations

EMC or Commission	Australian Energy Market Commission
AEMO	Australian Energy Market Operator
AER	Australian Energy Regulator
COAG Energy Council	Council of Australian Governments' Energy Council
DSBF	Demand Side Bidding and Forecasting
EY	Ernst & Young
FCAS	Frequency Control Ancillary Services
GXP	Grid Exit Point
MCE	Ministerial Council on Energy
MPC	Market Price Cap
NEL	National Electricity Law
NEM	National Electricity Market
NER	National Electricity Rules
NEO	National Electricity Objective
PV	Photovoltaic
RERT	Reliability and Emergency Reserve Trader
Snowy	Snowy Hydro Limited
UIGF	Unconstrained Intermittent Generation Forecast

A Summary of issues raised in Snowy consultation paper

This appendix sets out the issues raised in the first round of consultation on the Snowy rule change request and the AEMC's response to each issue.

Stakeholder	Issue	AEMC Response
Purpose of the National Electricity Market		
EnerNoc (p.1) Major Energy Users (pp.4-6) Pacific Aluminium (p.2) Rio Tinto (p.1) Sun Metals (pp.1-2)	The purpose of the electricity market is to enable consumers to consume electricity. Unlike generation, loads are not in the electricity business - rather it is just one input into their business.	The Commission understands consumers' primary focus is on their industrial and commercial activities, and that electricity is an input into those processes. This understanding is reflected throughout the assessment of the rule change requests.
Defining price responsiveness for the purpose of the proposed rule		
Snowy (p.6)	Snowy suggests using historical behaviour to determine if a load is responsive to the electricity spot price. AEMO may have a valuable role to play in identifying relevant price responsive market loads through available historic market data associated with transmission connection and bulk supply point forecasts.	The Commission did not explore, in a detailed way, the most appropriate way to determine if a load is price responsive. Given the Commission does not consider there are sufficient grounds to require large price responsive loads to be scheduled at this time, there is no need to define such a mechanism.
Other options		
AGL (p.2)	There may be merit in investigating whether there are better ways of capturing information about the	The Commission does not support the scheduling of large price responsive loads as this time, and considers there are alternative ways

Stakeholder	Issue	AEMC Response
EnergyAustralia (p.1)	larger loads that places less regulatory burden on these smaller participants, but improves transparency.	to maintain or improve forecasting accuracy: AEMO has a range of powers that it may use; and, alternative solutions may come from the AEMC and AEMO work currently underway on the distribution market and distributed energy resources.
Energy Efficiency Council (p.4)	There are much cheaper options for improving predictions on the level of DSP, such as gather information on the likely level of demand side participation that large customers might provide during period of high prices.	As above.
ENGIE (p.4)	It might be possible to achieve some improvements in information transparency without requiring market loads to become scheduled. AEMO could publish information that it obtains through its capacity to perform real time demand measurements.	As above.
Snowy (pp. 2 & 8)	Further information would be ineffective in ensuring loads would abide by their stated intention at times when the wholesale spot price is either high or volatile. If the AEMC went down this path, load should be subject to good-faith provisions.	The Commission discussed the challenges of ensuring participants complied with their stated intentions in ENGIE's option two. The bidding in good faith provisions may be one method of achieving this objective, at this time, the Commission does not intend to impose any additional requirements on loads.
Sun Metals (p.3)	If demand customers are to take a more active role in the market, then customers should be at least given the opportunity to know what the price is in advance of consuming it. To facilitate this, AEMO could make the following changes to the dispatch model: • prior to dispatch AEMO notifies the demand participants what the price will be in the next 5 minute pricing period prior to dispatch	The Commission considers demand response has played, and should continue to play, a valuable role in contributing to market efficiency. Having said that, the specific issues raised are more related to the five minute rule change process.

Stakeholder	Issue	AEMC Response
	• allow demand participants to either accept or reject the actual known price and notify what the consumption level will be • the dispatch model re-calculate the dispatch generation required given the customers' notifications • the price to demand participants customers to be settled on 5 minute rather than 30 minute settlement pricing • pay the demand participant as an ancillary service to compensate them for the interruption to their process.	
Other issues raised		
EnergyAustralia (p.1)	A revision to the ancillary services causer pay methodology could be made to ensure demand response and other unscheduled generation more directly face the costs of sudden supply/demand charges.	The Commission does not consider there is sufficient evidence to justify the imposition of additional requirements on loads and non-scheduled generators at this time. The proposed change may dampen the responsiveness of participants to market conditions, with consequent impacts on efficiency and potentially higher prices for consumers.
Pacific Aluminium (p.3)	Unscheduled demand response only provides an up-side to ensuring adequate supplies of electricity as it is essentially additional reserves which can relieve tight supply conditions and is currently acting as additional redundancy.	The Commission considers demand response has played, and should continue to play, a valuable role in contributing to market efficiency. To the extent that demand response contributes to lowering the spot price, there are benefits to consumers.
EnerNoc (p.3)	A demand response mechanism provides better real-time visibility than unscheduled generation.	The Commission considers demand response has played, and should continue to play, a valuable role in contributing to market efficiency.

Stakeholder	Issue	AEMC Response
	Further, the 5/30 issue is more severe on demand response and therefore would need to be solved before demand response could contribute to the issue of not knowing the response of loads to high price events.	The Commission has decided to keep this rule change and the five minute settlement rule change separate.
ENGIE (p.2)	ENGIE believes that the majority of market loads response to prices is at pre-determined and stable thresholds that might only vary occasionally. If this is correct, the new requirements will not have a significant on-going impact on the effected participants.	The stakeholder responses from large loads and energy user groups did not agree with this position. Comments indicated that consumption varied according to industrial and commercial requirements, and that these variations are not predictable and stable over time. The Commission accepts that many loads and non-scheduled generators have varying operational requirements, primarily driven by their industrial or commercial operations.

B Summary of issues raised in ENGIE consultation paper

This appendix sets out the issues raised in the first round of consultation on this rule change request and the AEMC's response to each issue.

Stakeholder	Issue	AEMC Response
Retrospectivity		
Stanwell (p.3)	Stanwell welcomes the explicit recognition that the Commission is cognisant of the effect of making changes to the rules that apply retrospectively - but clarification is required. Grandfathering of the exemption to become scheduled should be set high to minimise market distortions.	Given the Commission does not consider there is sufficient evidence to support a requirement for non-intermittent non-scheduled generation above 5 MW to be scheduled at this time, the issue of retrospectivity does not need to be addressed. In all rule change processes the Commission balances the requirements to adjust or change market arrangements against the impacts such changes may have on the interests of stakeholders and the incentives for new investment and market entrants.
Australian Energy Council (p.2)	Subject to cost considerations, the Australian Energy Council supports retrospectively requiring non-scheduled generators to become scheduled.	As above.
SA Water (p.2)	The registration of existing generation should be grandfathered so that any changes to registration categories or thresholds would not apply.	As above.
Forecast and dispatch process		
ENGIE (p.4)	Non-scheduled generation above 5 MW is more likely to be dispatched in accordance with a regular pattern driven either by response to the spot price or in accordance with an operating schedule to suit the owner/operator needs. A key factor contributing to this dispatch pattern is that non-scheduled generation above 5 MW is primarily comprised of synchronous controllable generation.	Analysis of the non-scheduled generation in the NEM indicated that over 43 per cent was wind generation, and 25 per cent was a by-product of an industrial process. The by-product generation is driven more by industrial or commercial requirements than electricity market conditions. The wind generators are intermittent and not synchronous.

Other issues raised by stakeholders		
Origin (p.2)	Another option may be to develop a simplified version of AEMO's online portal Market Management System for non-scheduled generators between 5 - 30 MW.	The rule change requests were premised on the need to have more accurate pre-dispatch forecasts and dispatch. While the Commission does not consider the proposed rules would, or are likely to, contribute to the NEO, it does support AEMO continuing to maintain and improve the accuracy of its forecasts. Developing the online Market Management System may be one such option.
AEMO (p.1)	AEMO is concerned with the number of related or overlapping proposals relating to central dispatch, integration of renewable energy, and energy settlement that are being addressed through independent consultations. AEMO recommends a broad review of relevant aspects of the wholesale electricity market including whether changes should apply retrospectively.	AEMO's comments are consistent with the views of the Commission. As described in the draft determination, this rule change has been undertaken cognisant of the other rule change and review processes underway that may have an impact on central dispatch. The Commission has decided not to make a rule change at this time. The option for a review at a later date if circumstances change remains open.
AGL (p.2)	A more appropriate option may be for non-scheduled generators who are already connected to SCADA to make this information available to the market. This would provide the market with better transparency of the generation of non-scheduled generators, without placing a significant regulatory burden on them.	The rule change requests were premised on the need to have more accurate pre-dispatch forecasts and dispatch. While the Commission does not consider the proposed rules would, or are likely to, contribute to the NEO, it does support AEMO continuing to maintain and improve the accuracy of its forecasts and to make as much information as possible available to market participants. Enabling SCADA data from non-scheduled generators to be available to the market may be one such option.

C Legal requirements under the NEL

This appendix sets out the relevant legal requirements under the NEL for the AEMC to make this draft rule determination.

C.1 Draft rule determination

In accordance with s.99 of the NEL, the Commission has made this draft rule determination in relation to the rules proposed by Snowy and ENGIE.

The Commission has determined it should not make a draft rule.

The Commission's reasons for making this draft rule determination are summarised in section 3.4

C.2 Power to make a rule

The Commission is satisfied that the subject matter of the rule change request falls within the subject matter about which the Commission may make rules.

It falls within s.34 of the NEL as it relates to:

- the operation of the national electricity market[143]
- the activities of persons (including Registered participants) participating in the national electricity market or involved in the operation of the national electricity system.[144]

C.3 Commission's considerations

In assessing the rule change requests the Commission considered:

- the Commission's powers under the NEL to make the proposed rules
- Snowy's rule change request
- ENGIE's rule change request
- submissions received during the first round consultation
- consultant reports prepared by Ernst & Young and University of Wollongong
- the Commission's analysis as to the ways in which the proposed rules will or are likely to, contribute to the NEO.

143 NEL, section 34(1)(a)(i)

144 NEL, section 34(1)(a)(iii)

D Analysis of the materiality of the issues raised

As indicated in chapter 4, the Commission undertook analysis on the evidence for and materiality of the issues raised by the rule change proponents. There were multiple elements of this analysis.

- The quantity of non-scheduled generation and load in the NEM was examined, to understand whether the quantities were significant enough to cause or contribute to forecasting inaccuracy.
- The accuracy of AEMO's demand and price forecasting was assessed, to understand whether there is forecasting error and if so the scale of the error.
- The evidence from a number of studies was examined to determine the causes of forecast error, and in particular whether there are causal links between forecast errors and the actions of non-scheduled generation or load.
- AEMO's forecasting methods, improvements it is undertaking, and its powers in relation to information gathering and system security were assessed, as these are relevant to whether there are alternative means to maintaining and improving forecasting accuracy other than those proposed by the rule change proponents.

Further elements of analysis assessed:

- the costs a participant would incur if required to become scheduled. This is an important reference against which to consider the benefits that may accrue from requiring additional participants to become scheduled.
- the ownership and type of non-scheduled generator to inform how onerous a requirement to be scheduled might be and the practical issues associated with scheduling different types of generators.

D.1 Non-scheduled generation and load in the NEM

By changing their generation or consumption profile through a trading day non-scheduled generation and unscheduled load may, if their scale in the market is material, affect the accuracy of AEMO’s demand and price forecasting. If this occurs then the demand and supply conditions upon which pre-dispatch forecasts are based, and dispatch determined, may also be inaccurate. Changes to generation or consumption profiles may impact on forecasting accuracy, regardless of whether the changes are for operational or price reasons.

The extent to which non-scheduled generation and unscheduled load can actually cause or contribute to forecasting inaccuracy and, in turn, dispatch inaccuracy will depend on how accurately AEMO forecasts their generation or consumption in the absence of these participants being scheduled.

This section examines the quantity of non-scheduled generation and load in the NEM and in particular regions, over time, in order to understand the capacity of non-scheduled generation and load to cause or contribute to forecast inaccuracy.

D.1.1 Unscheduled load

The NEM allows but does not require loads to be scheduled. There are currently only four scheduled loads. These are all pumped hydro facilities that are "normally-off", meaning they do not operate unless the spot price is lower than a nominated level.[145] The fact that most loads do not choose to be scheduled indicates that loads do not consider there to be sufficient net benefits to become scheduled and participate in the central dispatch process.

Figure D.1 shows there are currently 36 loads with maximum demand greater than 30 MW in the NEM, representing over 18 per cent of average aggregate load.[146]

Figure D.1 Load in the NEM, October 2015

		Number of loads	Aggregate load (MW)	% of total NEM load
Scheduled		4	720	2.8%
Non-scheduled	> 30 MW	36	4,726	18.4%
	Other	N/A	20,204	78.8%
Total			25,650	100.0%

Figure D.2 shows that large unscheduled load with average demand greater than 30 MW represent between 12-41 per cent of the average regional demand in the various states that make up the NEM.

145 Pumped hydro facilities pump water from low to higher storage reservoirs when electricity prices are low, and release the water to generate electricity during periods of high demand or high prices.

146 Data from AEMO October 2015.

Figure D.2 Unscheduled large loads as a proportion of average regional demand

	Average regional demand	No. of loads	Aggregate load size (MW)	Aggregate load size (%)
NSW	9600	12	1451	15.1%
VIC	6650	5	859	12.9%
SA	1700	3	200	11.8%
QLD	6500	12	1724	26.5%
TAS	1200	4	492	41.0%

Tasmania and Queensland have the highest proportion of large unscheduled loads at 41 per cent and 26.5 per cent of average regional demand respectively. South Australia, Victoria and New South Wales have lower but still significant proportions, representing between 12 and 15 per cent of average aggregate demand.

The significance of these non-scheduled large loads is that individually they can have a system impact similar to a scheduled generator and to the extent that AEMO is not able to accurately forecast their consumption, they may contribute to forecast inaccuracy.

D.1.2 Non-scheduled generation

The rule change proponents expressed an expectation that the quantity of non-scheduled generation would increase in future[147], as large transmission-connected generators are replaced by smaller more distributed energy resources.[148] This increase will include both registered generation above 5 MW and exempt generation below 5 MW. The Commission tested this expectation by examining the quantity of registered non-scheduled generation in the NEM, including changes in its quantity over time and by jurisdiction.

147 This expectation was expressed by both Snowy and ENGIE in their rule change requests, and at the AEMC workshop on 24 March 2017. Snowy's rule change request (p 10) stated an expectation for "more demand response, more distributed generation and more non-scheduled generation" in addition to highlighting AEMO's forecasts for increasing demand side participant. See http://www.aemc.gov.au/getattachment/0b9688b8-dc3c-49b1-8bf8-df587ca8ed53/Rule-change-request.aspx. ENGIE, in its rule change request, stated "the total amount of non-scheduled generation in the NEM has increased significantly in recent years, and is forecast by AEMO to continue to grow." (p 2) See http://www.aemc.gov.au/getattachment/4219ffd9-f0f1-4690-84a8-555282d44374/Rule-change-request.aspx

148 It should be noted that it is expected that a significant increase in smaller generation will arise in the distribution network. This embedded generation would not, in most cases, be captured by any of the proposed rules considered in these rule change requests.

The quantity of non-scheduled generation in the NEM

Figure D.3 shows the quantity of registered non-scheduled generation in the NEM broken down between non-intermittent and intermittent generation.

Figure D.3 Registered generation in the NEM (MW), November 2016

	Non-intermittent			Intermittent		
	Scheduled	Semi-scheduled	Non-scheduled	Scheduled	Semi-scheduled	Non-scheduled
Above 30MW	43,222	-	918	-	2,793	1,124
15MW - 30MW	79	-	362	-	-	99
10MW - 15MW	-	-	160	-	-	34
5MW - 10MW	-	-	164	-	-	11
Below 5MW	-	-	120	-	-	5
Total	43,301	-	1,724	-	2,793	1,273

From Figure D.3, the following observations can be made:

- in the NEM there is 2,872 MW of registered non-scheduled generation capacity from generation units with a nameplate capacity of 5 MW or greater. This represents approximately six per cent of total registered generation capacity, which exceeds the total quantity of semi-scheduled generation in the NEM[149]. Of this registered non-scheduled generating capacity:
  - 1,604 MW is non-intermittent generation, representing 3.3 per cent of total NEM registered nameplate generation capacity
  - 1,268 MW is intermittent generation, representing 2.6 per cent of total NEM registered nameplate generation capacity.[150]
- against the average aggregate load in the NEM of approximately 25,650 MW, this combined capacity may represent a much higher proportion of actual generation participating any point in time depending on the region, conditions for renewable energy generation and the spot price.[151]

149 There is also over 5.9 GW of unregistered exempt generation in the NEM, as at xxx, source

150 Data from AEMO NEM registration list November 2016

151 Given nameplate generation capacity is close to twice the average aggregate load in the NEM, the nameplate capacity may represent close to double the actual generation percentage at a given time, if it were all available and generating concurrently. The actual generation percentage achieved will depend on many factors including the weather (for renewable units), industrial processes (for co-generation and bio-waste units), network constraints, the region (which have different mixes of generating units), generator availability (accounting for maintenance and outages), and market prices (which may affect the decision of various generators to operate).

The growth in non-scheduled generation over time

The change in the quantity of non-scheduled generation over time was examined to provide perspective on the pace of change and the challenge AEMO may face in incorporating non-scheduled generation into its forecasting processes. ENGIE's submission argues that an increase in the quantity of non-scheduled generation increases the forecasting challenge and the likelihood of increased forecasting error.[152]

Figure D.4 Proportion of non-scheduled generation in the NEM

Proportion of non-scheduled generation in the NEM			
	Non-scheduled generation (MW)	Scheduled and semi-scheduled generation (MW)	Non-scheduled generation % of Total generation (%)
2008	1,923	42,369	4.3%
2009	2,227	44,725	4.7%
2010	2,645	46,162	5.4%
2011	2,645	46,204	5.4%
2012	3,080	46,559	6.2%
2013	3,124	46,909	6.2%
2014	3,044	47,244	6.1%
2015	3,280	48,089	6.4%
2016	2,980	45,729	6.1%
2017	3,005	44,255	6.4%

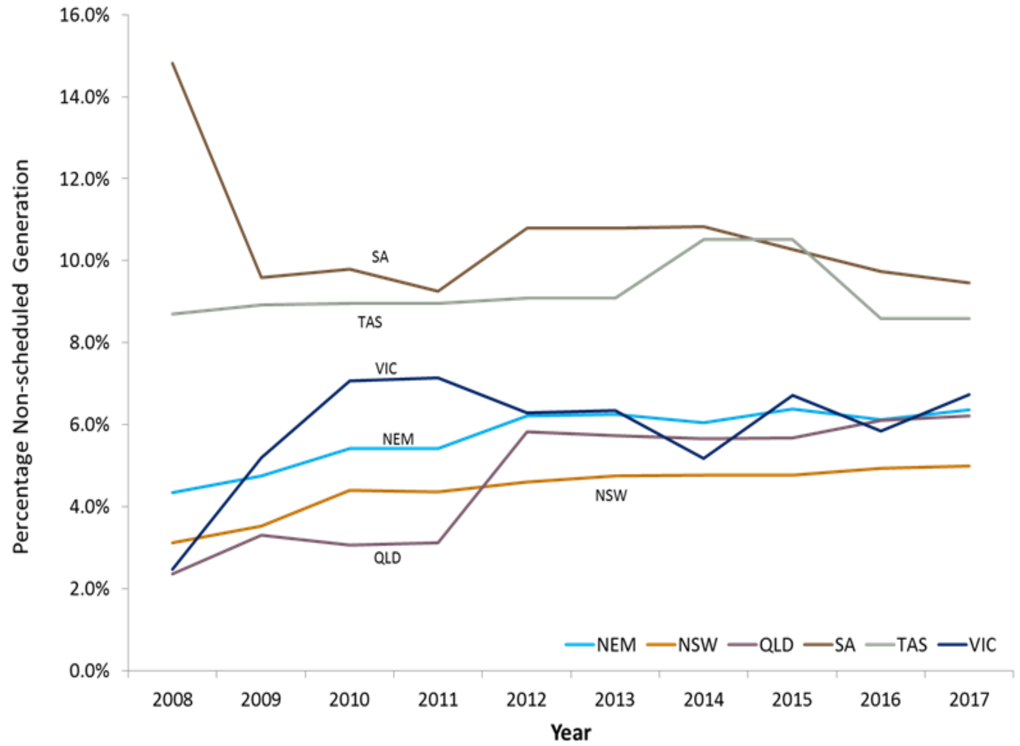
Figure D.4 shows that since 2008 there has been an increase in the quantity and proportion of registered non-scheduled generation in the NEM[153], although the increase has not been notably large or rapid.

Figure D.5 shows registered non-scheduled generation as a proportion of total nameplate generation by jurisdiction. At a regional level, there is a more varied story in relation to the proportion of registered non-scheduled generation to registered generation.

152 See: http://www.aemc.gov.au/getattachment/4219ffd9-f0f1-4690-84a8-555282d44374/Rule-change-request.aspx

153 There are minor differences between Figure 4.3 and 4.4 due to the specific dates of data used in each table. The differences are not material to the analysis.

Figure D.5 **Total registered non-scheduled generation as a proportion of total registered generation by jurisdiction**



Notable observations from Figure D.5 include:

- the proportion of registered non-scheduled generation in Tasmania and South Australia has remained relatively flat since 2009, although it represents a higher overall proportion of registered generation than in other jurisdictions and with some volatility between years[154]
- New South Wales, Victoria and Queensland account for approximately 85 per cent of total registered nameplate generation capacity in the NEM, so it is not surprising that the general increase in the proportion of non-scheduled generation in the NEM has matched the growth in the registered non-scheduled generation in the three largest states, noting there has been varying volatility over the period.

The significance of these non-scheduled generators is that collectively they can have a system impact similar to scheduled generators and to the extent that AEMO is not able to accurately forecast their consumption, they may contribute to forecast inaccuracy.

154 The large decrease in South Australia from 2008 to 2009 was driven by the introduction of the semi-scheduled generator category which required a number of non-scheduled generators to become semi-scheduled.

D.2 Demand forecast accuracy

The AEMC has undertaken analysis of AEMO's pre-dispatch demand forecast accuracy, including:

- an assessment of whether the thirty minute pre-dispatch forecast (P30) and the five minute pre-dispatch forecast (P5) are consistent with actual dispatch
- an assessment of the accuracy of forecast demand at dispatch against the actual demand that occurred by the end of the dispatch interval
- an assessment of the distribution of forecasting errors to understand if there is any systemic bias in the demand forecasting process
- an examination of the accuracy of demand forecasts over time, to understand whether forecast errors are increasing
- an examination of the forecast accuracy results at the tails of the distribution curve, to understand the variance from general demand forecasting results.

This analysis is to determine whether there is forecasting error and, if so, the scale of that error.

D.2.1 Demand forecasting results

Average forecasting results

The figure below summarises the accuracy of the thirty minute pre-dispatch forecasts (P30) and the five minute pre-dispatch forecasts (P5) compared to dispatch.

In the P30 part of the analysis the percentage error is calculated at one, four and ten hours. For the P5 analysis, there are two results shown. The T-12 time shows results one hour before dispatch, and T-1 shows results five minutes before dispatch.

The time period of the P5 analysis was 1 July 2009 to 31 March 2017, and the period for the P30 forecasts was 1 July 2013 to 31 March 2017. This means there were 888,752 dispatch interval forecasts examined, comprising 815,040 P5 forecasts and 65,712 P30 forecasts.

The table shows the results between the 10th and 90th percentiles, meaning it covers the 80 per cent of results that are closest to the median. Put another way, there are ten per cent of results higher and ten per cent of results lower than those shown in the results table. The table represents results for 704,602 dispatch interval forecasts.

Data is from AEMO’s Market Management Systems (MMS) database.

Figure D.6 Average demand forecast accuracy

	P5				P30					
	T – 1 (10th , 90th) percentiles		T – 12 (10th , 90th) percentiles		1 hour (10th , 90th) percentiles		4 hours (10th , 90th) percentiles		10 hours (10th , 90th) percentiles	
NSW	-0.8%	0.8%	-1.7%	1.9%	-1.5%	1.8%	-2.1%	3.0%	-2.5%	3.6%
QLD	-1.1%	1.1%	-1.7%	1.8%	-1.5%	1.8%	-2.1%	2.6%	-2.7%	3.0%
SA	-1.5%	1.5%	-3.7%	4.1%	-4.6%	4.3%	-6.5%	6.0%	-7.1%	6.8%
TAS	-1.1%	1.1%	-2.9%	3.0%	-3.1%	4.8%	-4.3%	5.9%	-5.2%	6.4%
VIC	-0.9%	0.9%	-2.0%	2.2%	-2.5%	2.7%	-3.6%	4.0%	-4.2%	4.3%

Figure D.6 reflects that AEMO's demand forecasts improve in accuracy as dispatch nears. It can be seen that there is a material improvement in accuracy from the P30 forecasts at ten hours to the forecast at one hour in all jurisdictions. This is to be expected as the P30 forecasts are designed as a method of providing information to the market to enable participants to plan and adjust their generation and consumption.

Similarly, there is a notable improvement from the P5 forecast at T-12 (one hour before dispatch) to the forecast at T-1, which is the last forecast before dispatch (ie 5 minutes before dispatch). Again this is to be expected as participants incorporate information regarding the supply and demand conditions for the dispatch interval and adjust their generation and consumption based on this information.

The final P5 forecast (T-1) is consistently close to the dispatch forecast (see section highlighted in blue in Figure D.7). In most regions, the P5 forecast of demand at T-1 is within approximately one per cent of the dispatch forecast. South Australia has slightly lower accuracy with an error rate of 1.5 per cent. While it is notable that South Australia has the highest proportion of non-scheduled generation in the NEM, it is important to recognise that the vast majority of this generation is intermittent. Indeed, 389 MW out of 399 MW of registered non-scheduled generation in South Australia is intermittent wind generation. There is also a further 1,208 MW of semi-scheduled wind generation in the state. Together the semi-scheduled and registered non-scheduled generation represent 34.7 per cent of regional nameplate capacity. In terms of actual generation, wind produces approximately 40 per cent of regional generation, but at given periods provides 100 per cent.[155] The forecast error rates may be caused more by the difficulties of forecasting intermittency than non-scheduled generation. Notably, as

155 See http://reneweconomy.com.au/south-australia-graphs-60608/

wind generators are intermittent generators, they are outside the scope of the rule change requests.

Given the forecast timeframes and the accuracy achieved at different times before dispatch, the usefulness of the forecasts to participants will vary according to the time they require to react to market signals. For example, any participant that needs to make unit commitment decisions four hours ahead of dispatch must rely on forecasts that are materially less accurate than those closer to dispatch. That said, the forecasts prepared by AEMO would be just one input used by participants in determining their behaviour in the dispatch interval. Other factors will include:

- generators own expectations of market outcomes based on their assessment of market conditions and their own behaviour
- loads consumption decisions would be based in large part on other commercial factors such as production scheduled and technical limitations.

Distribution of forecasting results

The figure below shows the distribution curve of results for the five minute pre-dispatch forecasts at 5 minutes before dispatch (T-1) and one hour before dispatch (T-12).

The chart shows results for the time period 1 April 2016 to 31 March 2017. Data is from AEMO's Market Management Systems (MMS) database.

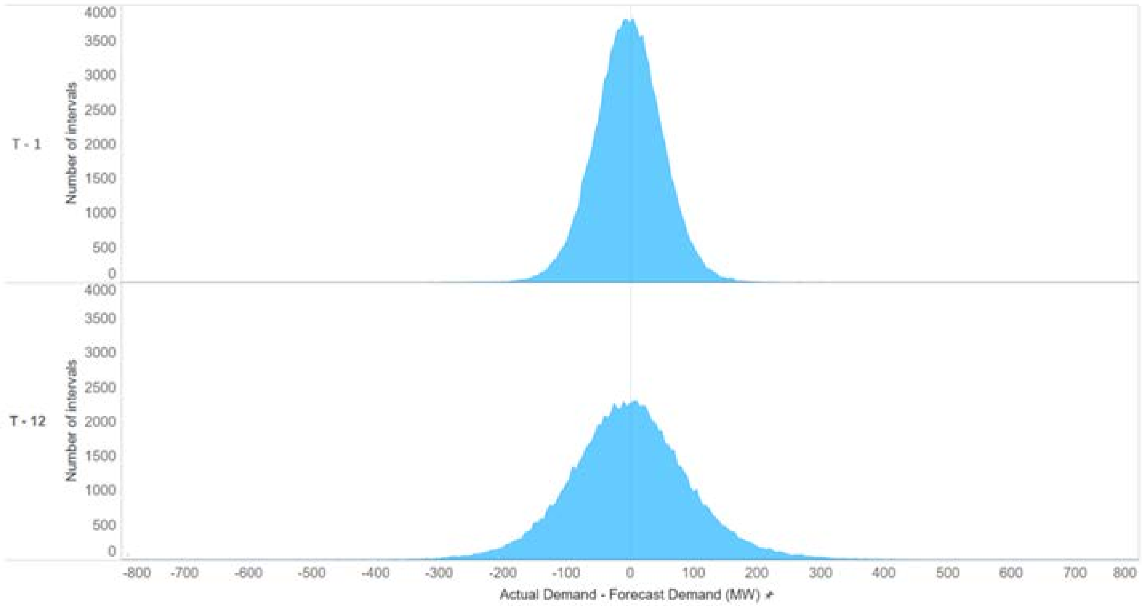
The vertical axis of the distribution curve shows the number of instances that a result occurred in the analysis period. The horizontal axis shows how close the forecast demand results were to the actual demand that occurred, with results at zero being accurate.

In comparing the results for the T-12 and T-1 periods, it can be seen that T-1:

- has an increased number of intervals near zero
- has a narrower distribution curve indicating more consistently accurate results.

It is also notable that the demand forecast errors are normally distributed, indicating there is no systemic bias in the demand forecasting process.

Figure D.7 Distribution of forecast error (T-1, T-12): 1 April 2016 to 31 March 2017



Assessing dispatch accuracy

The next stage of the analysis examined dispatch accuracy.

At the start of every five minute dispatch interval, and based on AEMO's estimation of demand, AEMO issues dispatch instructions to scheduled generators specifying the quantity of generation they must provide to the market by the end of the dispatch interval. The dispatch instructions take account of generator bids, network constraints, and system security requirements. A price for electricity is also determined for that dispatch interval.[156]

This part of the analysis focussed on whether the estimation of demand in dispatch actually matched the demand that occurred at the end of the dispatch interval. The methodology used for this analysis in contained in appendix E.

The data and time period of the analysis are the same as for figure D.6.

156 Note the actual spot price is the average price that is achieved across the six dispatch intervals that comprise a trading interval.

Figure D.8 Demand forecast error: comparing dispatch to actual demand

	Dispatch vs end of DI		P5 vs Dispatch				P30 v Dispatch					
	(10th , 90th) percentiles		T – 1 (10th , 90th) percentiles		T – 12 (10th , 90th) percentiles		1 hour (10th , 90th) percentiles		4 hours (10th , 90th) percentiles		10 hours (10th , 90th) percentiles	
NSW	**-0.80%**	**0.74%**	-0.8%	0.8%	-1.7%	1.9%	-1.5%	1.8%	-2.1%	3.0%	-2.5%	3.6%
QLD	**-1.07%**	**0.99%**	-1.1%	1.1%	-1.7%	1.8%	-1.5%	1.8%	-2.1%	2.6%	-2.7%	3.0%
SA	**-1.41%**	**1.52%**	-1.5%	1.5%	-3.7%	4.1%	-4.6%	4.3%	-6.5%	6.0%	-7.1%	6.8%
VIC	**-1.05%**	**0.81%**	-0.9%	0.9%	-2.0%	2.2%	-2.5%	2.7%	-3.6%	4.0%	-4.2%	4.3%

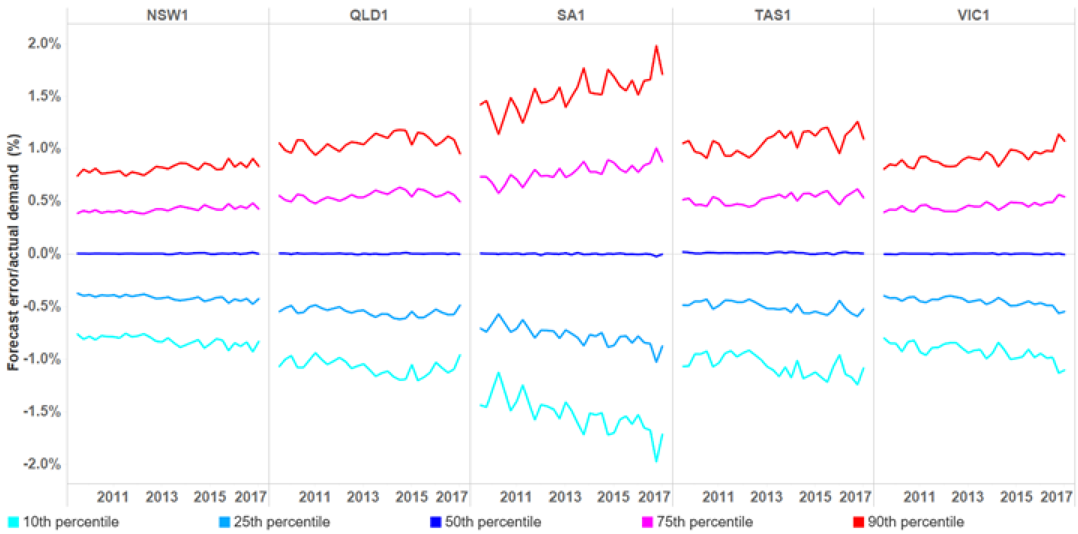
Figure D.8 shows the accuracy of the dispatch compared to the end of the dispatch period (results highlighted in green in Figure D.8) reasonably accurate and consistent with the results between the last five minute pre-dispatch forecast and dispatch (shown in blue in Figure D.8).

D.2.2 Demand forecast accuracy over time

An additional finding was that demand forecast accuracy has been relatively consistent over the time period examined, as shown in Figure D.9.

The chart shows the accuracy of the five minute pre-dispatch forecast before dispatch. The results are for the average quarterly results for each region of the NEM for the period form Q3 2009 and Q1 2017. Data is from AEMO's MMS database.

Figure D.9 Demand accuracy over time by region



In most regions there is not a material difference in the accuracy of results since 2010, except in South Australia which has a discernible trend to greater inaccuracy over the period. The high level of intermittent generation in South Australia may be a larger contributing factor to the regional forecast error than the quantity of non-scheduled generation (noting also that 97.5 per cent of non-scheduled generation in South Australia is intermittent wind generation).

D.2.3 Demand forecasting results - accuracy at the tails of the distribution curve

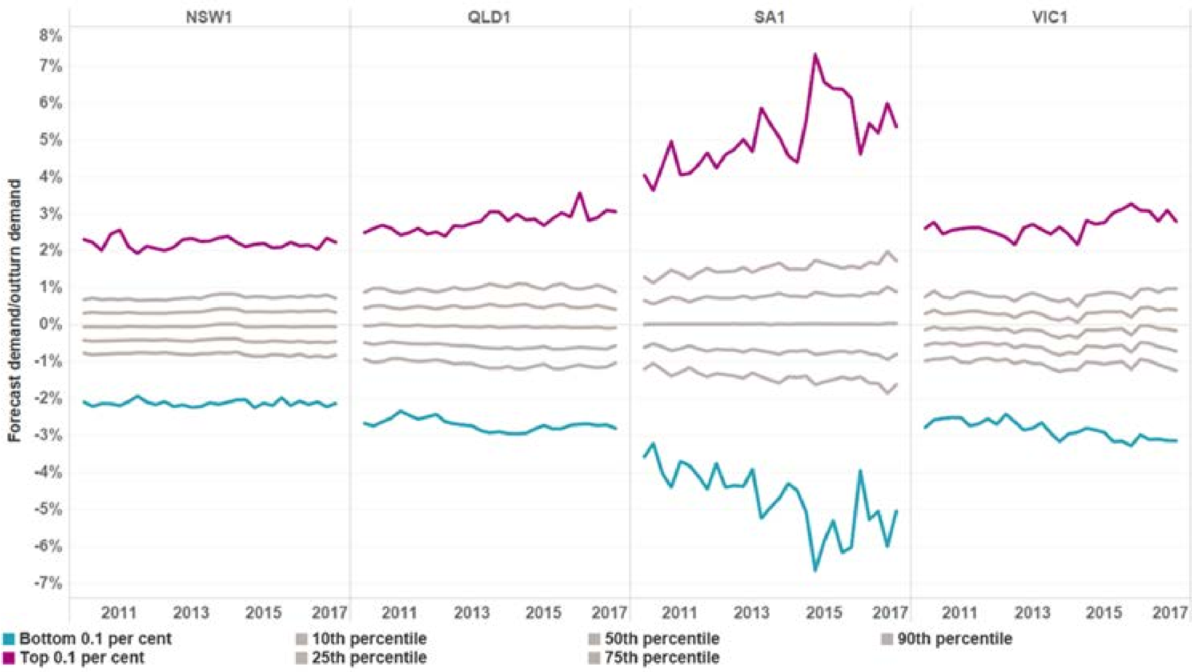
The preceding analysis has described the most usually observable results (ie those 80 per cent of results that are closest to the median). While the results for this data set has shown pre-dispatch forecasts close to dispatch are reasonably accurate, it is also important to understand the scale of forecast error that occurs in the least accurate instances. For this purpose we examined the top and bottom 0.1 per cent of forecast errors by quarter for New South Wales, Victoria, South Australia and Queensland. These results represent approximately 100 dispatch intervals per annum[157], and are those results at the tail ends of the distribution curve.

Figure D.10 shows there is a noticeable reduction in demand forecast accuracy when these tail results are considered, with the largest error and volatility occurring in South Australia. For New South Wales, Queensland and Victoria, the forecast error increased from approximately one per cent in the 80 per cent analysis to between two and three per cent, while in South Australia the forecast error increased from approximately 1.5

157 The 0.1 per cent of dispatch intervals equates to an average of 26.28 observations per quarter above and below the median for each jurisdiction.

per cent to approximately five to six per cent (noting it was approximately seven per cent in 2015).[158]

Figure D.10 Least accurate demand forecasts



D.2.4 Conclusion: demand forecast accuracy

The above analysis of AEMO's demand forecast accuracy shows:

- the pre-dispatch forecasts are reasonably accurate compared to dispatch, and consistent with the accuracy rates of dispatch itself (ie the start of the dispatch interval forecast is reasonably consistent with the actual demand that occurred in the interval). In general the forecasts are accurate to within one per cent, and within 1.5 per cent in South Australia
- the accuracy of the forecasts improve as dispatch nears, with the last pre-dispatch forecast (ie five minutes before dispatch) being significantly more accurate than the thirty-minute pre-dispatch forecast ten hours ahead of dispatch
- the forecasts have a normal distribution, indicating there is no systemic bias in the forecasting process
- the accuracy of the forecasts has remained relatively consistent over the period from 2010 to 2017, except in South Australia where there is a discernible trend to less accuracy

158 The higher level of inaccuracy in South Australia in the period 2014-2016 may in part be attributed to the operation of three generators owned by Snowy. This is discussed in section D.4.2.

- the least accurate results at the tails of the distribution curve of results are associated with high price events but are materially less accurate than the majority of forecasts
- given the varying accuracy of the demand forecasts depending on how close the forecast is to dispatch, the usefulness of the forecasts to participants depends on how quickly participants can response to changing market conditions and the time which they need to make generation and consumption decisions.

D.3 Price forecast accuracy

An analysis similar to that undertaken for demand forecast accuracy was undertaken to assess pre-dispatch price forecast accuracy.

- Price forecasting accuracy was assessed for the five minute pre-dispatch forecast (P5) and the 30-minute pre-dispatch forecast (P30).
- The accuracy of the forecasts in different price bands was also considered, to understand whether there was discernible pattern to forecast error results.
- Price forecasting accuracy over time was also assessed, to determine whether forecast accuracy was constant, improving or deteriorating.

D.3.1 Price forecast accuracy by region

Figure D.11 shows the forecasting accuracy for the thirty minute pre-dispatch price forecast.

The percentages shown are the forecast error rates.[159]

The analysis period was from 1 January 2010 to 31 March 2017, and comprised 127,008 30-minute pre-dispatch forecasts.

Consistent with the demand forecasting analysis, the pricing analysis covers results between the 10th and 90th percentiles, meaning it covers the 80 per cent of results that are closest to the median.

Data is from AEMO's MMS database.

159 Forecast error rates are calculated as (Forecast price – Actual price) / Actual price.

Figure D.11 Accuracy of the 30-minute pre-dispatch price forecasts

	Whole observation period						1 Jan. 2016 – 31 March 2017					
	1 hour (10th , 90th) percentiles		4 hours (10th , 90th) percentiles		12 hours (10th , 90th) percentiles		1 hour (10th , 90th) percentiles		4 hours (10th , 90th) percentiles		12 hours (10th , 90th) percentiles	
NSW	-9.2%	12.3%	-11.2%	16.7%	-11.8%	22.0%	-24.2%	26.5%	-32.5%	33.1%	-40.5%	40.3%
QLD	-11.3%	15.0%	-14.2%	20.7%	-16.3%	26.5%	-32.2%	29.3%	-46.6%	34.9%	-67.9%	40.2%
SA	-19.0%	17.0%	-25.9%	22.8%	-30.5%	29.6%	-54.9%	37.7%	-77.7%	46.5%	-108.7%	53.6%
TAS	-48.1%	13.5%	-57.4%	17.0%	-72.8%	19.7%	-251.6%	28.1%	-296.3%	36.2%	-323.8%	41.9%
VIC	-13.7%	16.7%	-18.0%	23.7%	-19.0%	31.1%	-36.1%	33.8%	-44.5%	44.1%	-51.4%	53.8%

The analysis in Figure D.11 indicates that:

- while there are regional differences in the levels of accuracy achieved it is apparent that there is significant pricing error in the price forecasts even one hour before dispatch.
- in the whole observation period, there is consistent improvement in the accuracy of the forecasts closer to dispatch compared to those made earlier. Notably however price forecasting accuracy is considerably lower than demand forecasting accuracy, and the regional variations are more distinct than those observable for demand forecast accuracy.
- the results in the whole observation period are influenced by the results in the period from the start of 2016 to 31 March 2017. Results for this period are shown on the right hand side of Figure D.12. Pricing results in this period have been materially less accurate and more volatile than previously. The reasons for this deterioration in forecast accuracy are not clear. However there has been no material change in the quantity of non-scheduled generation in that time, suggesting other factors have caused the deterioration in price forecasting accuracy.

The Commission also examined the accuracy of the five minute pre-dispatch price forecasts. Figure D.12 shows the results for the 80 per cent of results closest to the median.

The analysis period was from 1 January 2010 to 31 March 2017 and comprised 762,048 five minute pre-dispatch forecasts.

The forecasts analysed were those one hour before dispatch (shown as the T-12 on the table) and five minutes before dispatch (shown as T-1).

Data is from AEMO's MMS database.

Figure D.12 Accuracy of the 5-minute pre-dispatch price forecasts

	Whole observation period				1 Jan. 2016 – 31 March 2017			
	T – 1 (10^{th}, 90^{th}) percentiles		T – 12 (10^{th}, 90^{th}) percentiles		T – 1 (10^{th}, 90^{th}) percentiles		T – 12 (10^{th}, 90^{th}) percentiles	
NSW	-4.5%	5.5%	-10.1%	10.8%	-11.7%	15.5%	-32.9%	24.4%
QLD	-6.2%	6.9%	-13.2%	13.5%	-13.9%	17.1%	-39.0%	26.4%
SA	-7.3%	7.3%	-17.7%	16.0%	-20.6%	21.3%	-54.6%	36.1%
TAS	-4.5%	4.4%	-16.9%	12.2%	-11.6%	10.7%	-44.6%	27.9%
VIC	-5.9%	6.2%	-14.0%	14.3%	-18.6%	17.3%	-41.3%	30.7%

From Figure D.12, it is observable that:

- the five minute pre-dispatch forecasts are significantly more accurate than the thirty minute forecasts. This is consistent with the findings in relation to demand forecasting accuracy
- the pricing forecasts are less accurate than the equivalent demand forecasts. Pricing error rates range from 4.4 per cent to 7.3 per cent in the last period before dispatch and compare to rates of approximately one per cent to 1.5 per cent in the demand analysis
- pricing accuracy improves closer to dispatch, with the last forecast prior to dispatch being significantly more accurate than the forecast one hour before. As noted in the demand analysis, this is an expected result given the forecasts closer to dispatch incorporate more current information than those earlier in the pre-dispatch cycle. It is also apparent that the usefulness of the pre-dispatch prices to participants will vary depending on when they need to make a commitment to generate or consume and what other information the participant has access to when making those decisions
- consistent with the 30 minute analysis, the results over the whole observation period are impacted by the materially less accurate results that have occurred from the start of 2016 to 31 March 2017.

The accuracy of the five minute pre-dispatch price forecasts in given price bands is examined in Figure D.13, to assess whether there are discernible trends in forecast accuracy at different price bands.

The time periods examined were the forecasts five minutes before dispatch (shown as T-1 in Figure D.13) and one hour before dispatch (shown as T-12).

The results are for price forecasts in Queensland from 1 September 2015 to 8 March 2017, with data from AEMO's MMS database. Although Figure D.13 shows the results in Queensland, other jurisdictions have similar results.

The first price band, up to $300, was chosen as it is a common price point for market cap contracts. These contracts provide customers with surety that they will not pay a higher price for the contracted quantity of generation.

Figure D.13 Relative frequency of P5 forecast versus actual prices - T-1 and T-12, QLD

Actual Price Outcome ($/MWh)

Forecast Price ($/MWh)	T-1					T - 12				
	<300	300 to 1000	1000 to 3000	3000 to 6000	6000 to MPC	<300	300 to 1000	1000 to 3000	3000 to 6000	6000 to MPC
<300	100%	0%	0%	0%	0%	100%	0%	0%	0%	0%
300 to 1000	48%	46%	4%		3%	78%	18%	1%	0%	2%
1000 to 3000	67%	14%	7%	2%	10%	81%	14%	2%		3%
3000 to 6000	100%					69%		8%	23%	
6000 to MPC	49%	6%	1%	1%	43%	65%	7%	2%		26%

The results from the price forecasts in Queensland indicate:

- forecast prices of less than $300/MWh were very accurate and occurred in almost all instances where forecast
- in the $1,000 - $3,000 forecast price range the actual price is rarely in that price band (ie only seven per cent at T-1)
- in the range from $6,000 to the market price cap the high forecast price occurred in 43 per cent of cases.

Overall, for the forecasts above $300, the forecast price was achieved in less than 50 per cent of cases. For example, in the $1,000 to $3,000 range, in seven per cent of cases the actual price was in the forecast range, but in 67 per cent of cases the actual price was less than $300, and in 10 per cent of cases the actual price exceeded $6,000.

In most instances the actual spot price was lower than forecast, indicating market participants responded to the signal provided by the high-price forecast. To some extent this is expected and reflects the efficient operation of the market - namely, market participants adjusting their generation or consumption decisions to suit their commercial interests. This market response applies to market participants whether scheduled or non-scheduled.

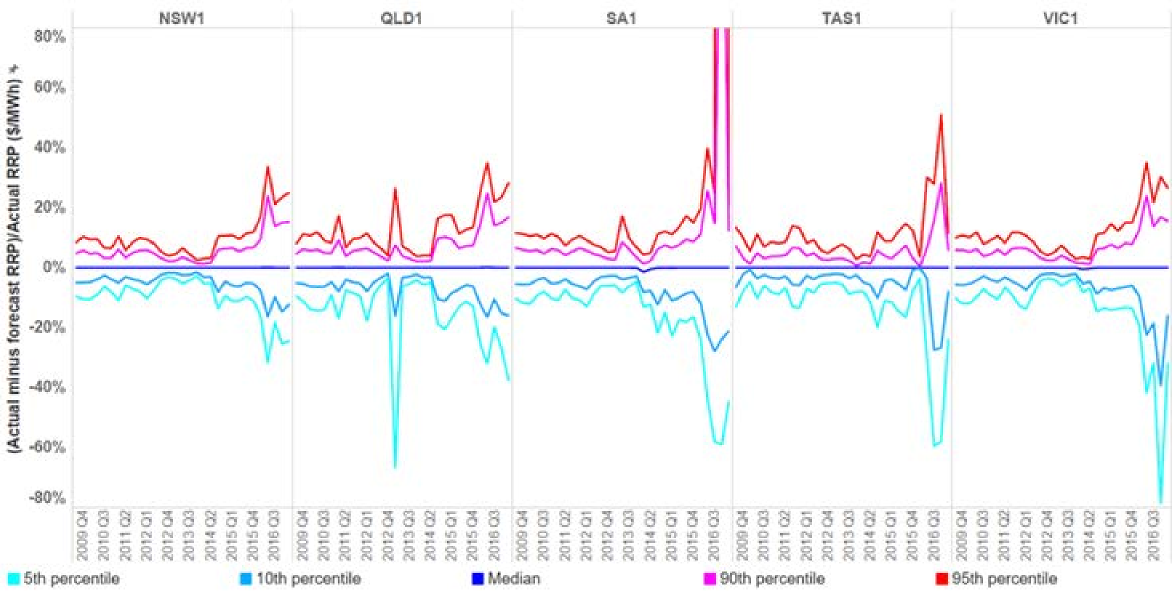
D.3.2 Price forecast accuracy over time

The Commission looked at the five minute pre-dispatch forecast accuracy for the last forecast before dispatch, to understand whether there was any trend in relation to the accuracy of the forecast results over time.

The analysis period from was from Q1 2010 to Q1 2017 for all regions, with data sourced from AEMO's MMS database.

The results of this analysis are shown in Figure D.14 below. To enable regional comparisons the results are normalised to the level of price in each regional reference node.[160]

Figure D.14 Five minute pre-dispatch price results by region



While it can be seen that there is significant variability in the results over time, the pre-dispatch price accuracy has reduced in all regions since 2014-15.

The observations in this analysis are consistent with those made by the AER in its weekly report on instances when there is significant variation between the pre-dispatch

160 This method enables percentage results to be comparable across regions.

forecast and the actual spot price.[161] Whereas this analysis is based on five minute pre-dispatch data, the AER reports of the accuracy of the thirty minute pre-dispatch forecasts four hours and 12 hours from dispatch. It uses these timeframes as being indicative of the timeframes within which different technology types may be able to commit (intermediate plant within four hours and slow start plant within 12 hours.[162]

AER data indicates there is increasing variation between pre-dispatch price forecasts and dispatch prices. In 2016 there was a weekly average of 273 such incidents, compared with an average of 133 discrepancies in 2015 and 71 in 2014[163].

The AER also identify the reasons for such price variations (see figure D.15 below). The categories used in its analysis are: availability (ie a change in the total quantity or price offered for generation); demand forecast inaccuracy; changes to network capability; or, as a combination of factors (when there is not one dominant reason).

The AER data shows availability and demand forecast inaccuracy are the prime reasons for price variations. Notably it is not clear whether demand forecast inaccuracy is due to price responsiveness from non-scheduled participants or as a result of other issues. Variation in the pre-dispatch and dispatch prices is expected to some extent whereas the increasing instances of variation between the pre-dispatch and actual prices is a more notable factor.[164]

Figure D.15 AER analysis of reasons for difference between pre-dispatch and dispatch price forecasts

	2014	2015	2016
Availability	50%	48%	41%
Combination	10%	7%	13%
Demand	40%	45%	46%
Network	0%	0%	0%

D.3.3 Conclusion: price forecast accuracy

The Commission's analysis of AEMO's pre-dispatch price forecasting accuracy shows:

- pre-dispatch price forecast accuracy is noticeably less accurate than pre-dispatch demand forecasting accuracy. This is the case for both the five minute and 30 minute pre-dispatch forecasts. Where the error rate in demand forecast accuracy

161 The AER weekly reports can be accessed at https://www.aer.gov.au/taxonomy/term/324

162 These assumptions are outlined in each weekly report from the AER. As an example, refer to https://www.aer.gov.au/wholesale-markets/market-performance/electricity-report-7-13-may-2017

163 Advice received from the AER on 10 January 2017 and 19 January 2017.

164 The AER comments in each weekly report "It is not unusual for there to be significant variations as demand forecasts vary and participants react to changing market conditions.

was between one and 1.5 per cent in the forecast five minutes before dispatch, the error in price forecasting accuracy is between 4.4 and 7.3 per cent in the same period. Consistent with the demand analysis, price forecast accuracy in South Australia is lower than other regions

- the five minute pre-dispatch price forecasts are noticeably more accurate than the thirty minute forecasts, reflecting at least in part that the price signalling process is providing information to which market participants are responding
- there is a discernible pattern in the pre-dispatch price forecasts, with different accuracy when the forecast price is in different price bands. It is observable that forecast prices below $300/MWh (which is a common market contract price for caps which limit a consumer's exposure to high price events) almost always occur. This contrasts with higher forecast prices where there are lower accuracy rates and the results are skewed to false positives, which are instances where a high price is forecast but does not occur. This is an indication that the market is responding to high price forecasts; a reduction in load and an increase in generation in response to a high price forecast will drive the actual price lower
- there has been a material reduction in price forecast accuracy since 2014-15.

D.4 Additional analysis on forecast error, high price events and non-scheduled participants

The preceding analysis shows:

- there is sufficient quantity of non-scheduled generation and load in the NEM to potentially contribute to demand and price forecast inaccuracy
- demand forecasts are relatively accurate, particularly pre-dispatch forecasts close to dispatch and dispatch itself
- price forecasts have significantly lower levels of accuracy than demand forecasts.

The relevant issue is whether a causal relationship can be established between forecast errors and non-scheduled participants. In order to assess this, a number of analyses were undertaken including examining:

- the relationship between the incidence of high price events and the scale of demand forecast error
- the AER's reports on price events greater than $5,000 to understand the reasons for the high prices, and in particular to understand whether non-scheduled generation or loads were causal factors

- a quantitative study to assess whether forecast error was caused by the price response behaviour of non-scheduled participants.[165]

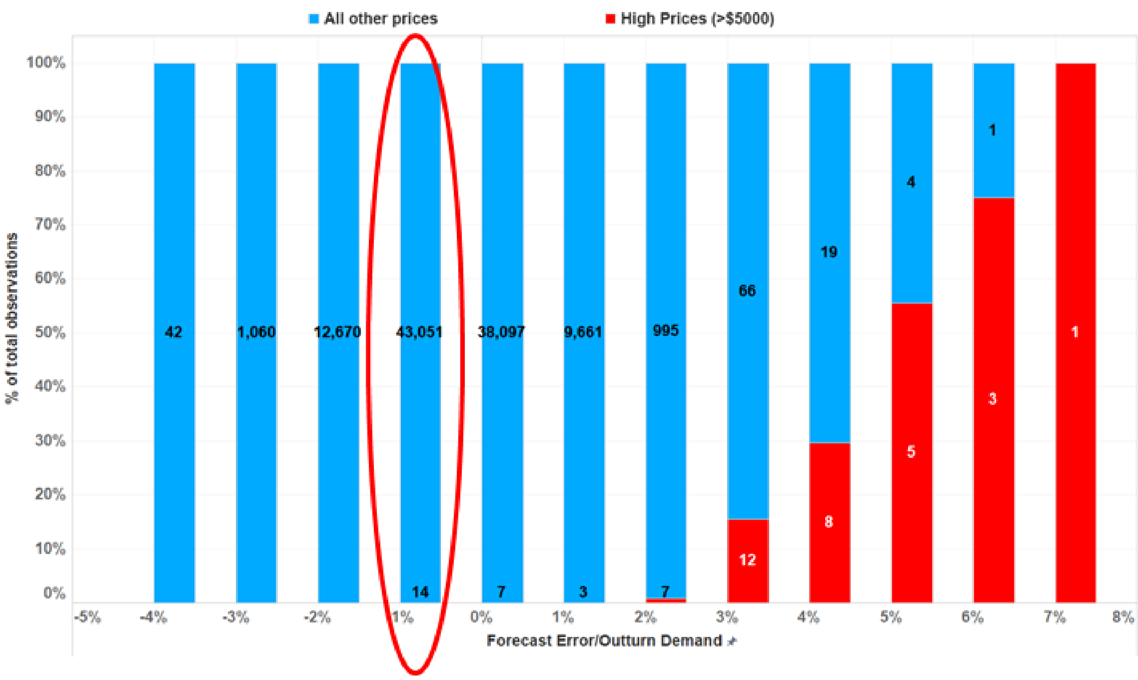
D.4.1 Assessing the relationship between demand forecast errors and high price outcomes

Figure D.16 below shows the coincidence of high price events and the scale of demand error.

For this analysis, high price events are those above $5,000, which is the same price point used by the AER to report on high price events.

The data is for Queensland in 2016, sourced from AEMO's MMS database.

Figure D.16 Assessing demand forecast errors and pricing outcomes in QLD 2016



To understand the chart, start at the left column. It shows 42 dispatch intervals where the demand forecast error was between minus three and minus four per cent, and there were no high price events. At the right of the chart, there was one dispatch interval where the demand forecast error was between six and seven per cent, and there was a high price event. Some of the columns between these end points show two numbers, with the top number being the number of dispatch intervals without a high price event, and the bottom number being those intervals with a high price. In the example circled in red, when the demand forecast error was at minus 1 per cent there were 43,051 intervals without a high price event and 14 intervals with high prices.

165 The Commission engaged Ernst & Young to undertake this analysis. Their report can be found on the AEMC's website on the project page for the rule change requests: http://www.aemc.gov.au/Rule-Changes/Non-scheduled-generation-in-central-dispatch

A key observation is that there is a correlation between the incidence of high price events and the scale of demand forecast error. The occurrence of a high price event (pricing above $5,000 for this analysis) is more frequent when demand forecast error is larger. For example, the data indicates that: when demand forecast error was at minus one per cent, high price events occurred in 14 of 43,051 dispatch intervals (0.03 per cent); whereas when demand forecast error was between six and seven per cent, high price events occurred in three of four dispatch intervals (75 per cent).

It is also notable that high price events are relatively rare. In the data analysed, for Queensland in 2016, there were 60 instances of pricing over $5,000/MWh in over 105,000 dispatch intervals. When considered in the context of the demand forecast analysis where the least accurate results represented 0.1 per cent of the dispatch intervals (ie 105 intervals per year), it indicates that high price events occur in just over half of those intervals (60 instances from 105 intervals is 57 per cent).

A similar correlation between the scale of demand forecast error and high price events was also observable in Queensland in Q1 2017, and in South Australia between 2013 and 2015 prior to a number of large non-scheduled generators becoming scheduled in that region.

While a correlation between the scale of demand forecast error and high price events can be observed, a critical issue is whether there is a causal relationship with the behaviour of non-scheduled participants.

D.4.2 The impact of non-scheduled generation on demand forecast accuracy and price

Figure D.17 below shows a correlation between changes in large non-scheduled generation and the incidences of high price events in South Australia between 2010 and 2017. The region was chosen specifically given the AER's $5,000 reports[166] had identified non-scheduled generators in that region and during that period as contributing to high price events.[167]

Data is from AEMO's MMS database.

166 These are described in section D.4.3.

167 The Ernst & Young study described later in this paper, in section 4.4.4, also identified Angaston and Lonsdale as contributing materially to regional demand inaccuracy.

Figure D.17 Identifying non-scheduled generation impacts on South Australia

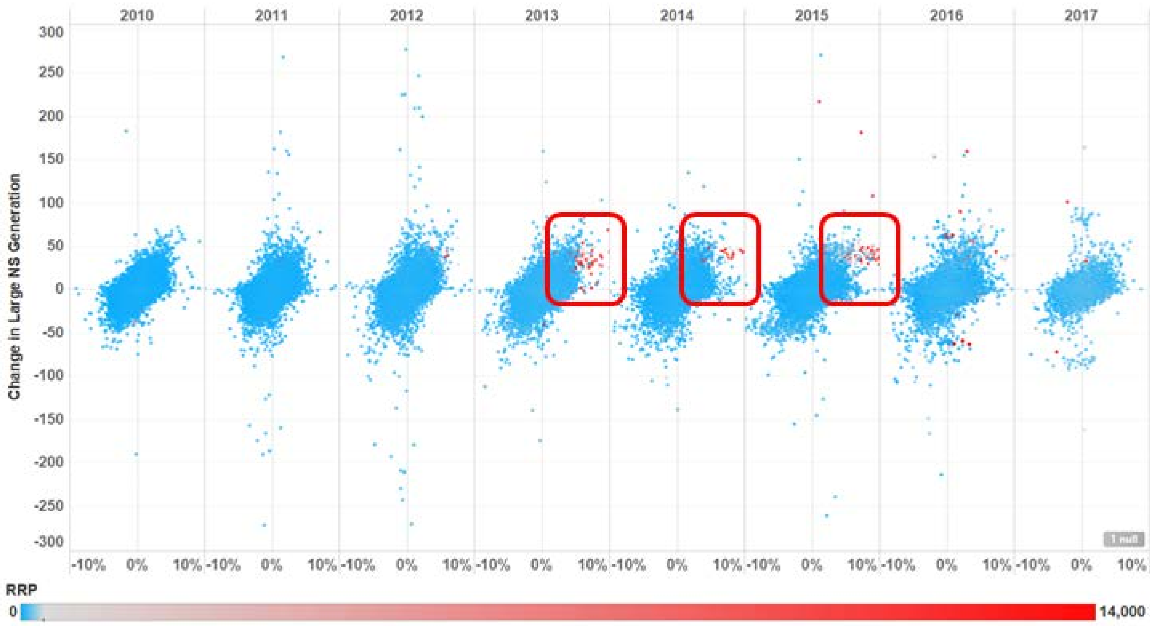


Figure D.17 shows a pattern of high price events (red dots) coinciding with changes in the quantity of generation supplied.

Snowy operated three non-scheduled diesel generators as a portfolio in South Australia during the period 2013-2015. In combination the generators (Port Stanvas 58 MW, Angaston 50 MW, Lonsdale 21 MW) had generation capacity equivalent to approximately eight per cent of average regional demand (which is 1,700 MW). The chart shows there is correlation between the changes in non-scheduled generation and the incidence of high price events. In these cases, some contribution to causation has also been found by the AER in its analysis of pricing events over $5,000/MWh, and by Ernst & Young in a quantitative study it undertook for the Commission.[168]

While the example does show that non-scheduled generation can contribute to demand forecast error and high prices, it does not show it is the only or primary cause of such errors, and in particular that individually observable results can be applied more generally or to other regions. For example a broader conclusion could not be reached for generators that do not have the same relative size and the ability to act together. Further, the analysis does not show whether or to the extent to which the actions of large loads, forecast errors around aggregate demand and intermittent generation, or the actions of scheduled generators also contribute to demand forecast errors and high price events.

D.4.3 Analysis of AER $5000 reports

The preceding analysis showed a correlation between high price events and the scale of demand forecast error, and a specific correlation between changes in the quantity of

168 Refer sections D.4.3 and D.4.4.

non-scheduled generation and high price outcomes in South Australia. In order to understand whether non-scheduled generation or load was a significant causal factor in causing high prices or demand forecast error, the AEMC examined the AER's $5,000 reports.

The AER is required to publish a report whenever the electricity spot price exceeds $5,000/MWh.[169] The report identifies the key factors that caused the high price events. In the period from February 2011 to 10 February 2017 there were 27 such reports.[170]

Figure D.18 Summary of reasons provided by the AER for $5,000 spot price events

Primary cause	Additional categorisation	Instances
Bidding behaviour	price bands	15
High Demand		11
Bidding behaviour	capacity bid from low to high prices	9
Demand error	under-estimate	8
Generation availability	outage, supply, other	8
Other	LOR Notice, load shedding, Direction to generate	8
Constraints	interconnector	6
Generation availability	supply withdrawal	5
Interconnector	outage	5
Bidding behaviour	rebidding ramp rates	4
Demand error	over-estimate	2
Network	congestion or constraint	2

The AER reports indicated there were instances where an under-estimate of demand was cited as a contributing factor to the high price events, however there were no instances where demand error was identified as the sole causal factor. In most cases the reports identify a number of contributing factors to the high price events.

Common factors identified were high demand and limitations on supply. The demand level was usually attributable to weather in a region, whereas the reasons for limited supply were more varied and included factors such as generator or interconnector outages, transmission constraints and withdrawal of supply.

The most common factor contributing to high price events noted in the reports is the bidding behaviour of scheduled generators, where they submit large price steps between supply levels. In instances where supply is limited, this approach to pricing can result in the marginal generator being dispatched at a high price band. For

169 The report is required under clause 3.13.7(d) of the NER. The report: describes the significant factors contributing to the high spot price including withdrawal of generation capacity and network availability; assesses whether rebidding contributed to the high spot price; identifies the marginal scheduled generating units; and identifies all units with offers for the trading interval equal to or greater than $5,000/MWh and compares these dispatch offers to relevant dispatch offers in previous trading intervals.

170 This figure excludes $5,000 reports related to high FCAS prices.

example on 9 February 2017 in New South Wales, there was no capacity priced between $500/MWh and $12,500/MWh.

The reports also note the following contributing factors:

- a common cause of high price events was scheduled generators rebidding their offered capacity from low to high price bands
- • the withdrawal of supply was a further reason cited in five of the reports, noting the bidding in good faith rule change came into effect on 1 July 2016[171]
- • there were instances of generators rebidding their ramp rates, which had the effect of prolonging network constraints and periods of high prices.

It is important to recognise that these findings are not unexpected. Given AEMO's demand forecasts are reasonably accurate and that it is essentially only scheduled generators that participate in the price setting process,[172] it is actually the bidding and rebidding activity of scheduled generators that determines the forecast and dispatch prices. Indeed this is part of the market design.

Generator's initial offers are based on their market intentions and expectations of market conditions. From this base, rebidding provides the necessary flexibility to achieve an economically efficient dispatch arrangement of generation in the short-term. Rebidding facilitates an iterative process of price discovery as generators adjust their position to reflect changes in the market, including the actions of other generators. Importantly, it is not the change in the market itself that triggers generators to adjust their position but rather the change in their expectations. In practice, a generator's offers will reflect its subjective expectations of any number of events occurring or not occurring. While participants will generally have a good idea about the implications of the occurrence or non-occurrence of a given event on their relative position and costs, they are likely to know less about the implications for other market participants and how they will react. As such, there is a process of learning that is typically undertaken following the occurrence or non-occurrence of a market event. The process may be quite short and predictable if participants are responding to a familiar event but could be substantially more protracted or volatile if the implications of the event are more complex.

The AER reports do not provide strong support for the proposition that non-scheduled generation or load is consistently contributing to demand forecast inaccuracy, and in turn, pricing inaccuracy. The reports do provide clear examples of how the bidding behaviour of scheduled generators can contribute to high price events.

171 Since the introduction of the bidding in good faith rule change from 1 July 2016, generators are prohibited from making false or misleading bids, are required to make known any variations as soon as practical, and to preserve a contemporaneous record of the circumstances surrounding late bids. See AEMC website at :http://www.aemc.gov.au/Rule-Changes/Bidding-in-Good-Faith

172 Noting that there are only four scheduled loads in the NEM, and these are "normally off".

D.4.4 Relationship between non-scheduled participants and dispatch demand inaccuracy

The AEMC engaged Ernst & Young (EY) to do a quantitative analysis of the impact of non-scheduled generation and load on dispatch demand inaccuracy. A copy of the EY report is published alongside this draft rule determination. A particular focus of the analysis was to determine the extent to which dispatch demand forecast inaccuracies are the result of price responsive behaviour.[173]

The study was based on data for 82 non-scheduled generators and loads. The intention was to examine five minute data for each participant as that would allow any change in generation or consumption during the dispatch interval to be assessed, and this would provide a strong indication of whether the participant was being price responsive. Five minute data was only available for nine non-scheduled generators. For the other facilities, which comprised 22 loads, 32 non-scheduled generators and 19 loads registered as non-scheduled generators[174], the study used 30 minute data. As 30 minute data blends the magnitude and timing of occurrences across six dispatch intervals, the conclusions that could be drawn from the analysis were more limited than if five minute data had been available.

The key findings from EY's report were:

- in the majority of dispatch intervals with large dispatch demand inaccuracy there is no observable relationship with price responsive behaviour or contribution from any of the facilities analysed. This may be due to the limitations of data availability, or that other variability in residential and commercial demand is significant

- for some facilities, changes in consumption and generation are aligned to regional dispatch demand inaccuracy, and a significant proportion of the changes are linked to price responsive behaviour:

  — the contribution to dispatch demand inaccuracy from very large loads such as aluminium and zinc smelters are highly correlated with dispatch intervals with large dispatch demand inaccuracy.[175]

  — the contribution from high variable facilities such as steel and paper mills is less conclusive

173 The study aimed at identifying the level of forecast error at each facility examined and comparing this with the regional error. As the specific forecast for each facility within AEMO's demand forecasting process was not available, EY used a linear regression technique to determine the 'typical operation' of a facility. The study essentially focussed on the tails in the distribution of forecasting results, in that it only focussed on dispatch intervals with large demand error.

174 These are mostly small auxiliary loads, with many of the facilities being pumped hydro.

175 EY noted that smelters are not very variable in their consumption but when they do change their consumption by a material amount the contribution to regional error is likely to be large

- it is not clear that scheduling facilities that contribute to dispatch demand inaccuracy but are highly variable in their operation at all times (eg steel and paper mills) would improve dispatch demand accuracy. In contrast, scheduling facilities such as aluminium and zinc smelters may improve dispatch accuracy, although EY notes that in the majority of dispatch intervals with material regional error "Townsville Zinc does not have a material error indicating there are frequently other causes of material regional error in Queensland."[176]
- the evidence of price responsive behaviour is weaker for facilities that are linked to some other operation, eg co-generation facilities, bio-gas, coal mine gas. It is likely that generation from these facilities is more dependent on the operation of their core industrial process than on the wholesale electricity price.

D.5 AEMO forecasting

D.5.1 The neural network model

EY's study noted that AEMO's neural network model did not account for substantial changes between dispatch intervals. To better understand this, the AEMC engaged the University of Wollongong to advise on the adequacy of AEMO's neural network model to provide accurate pre-dispatch forecasting and dispatch. This report is published together with this draft rule determination.[177] The key findings of this report were:

- AEMO's model is a first generation neural network model and major components of it are now nearly 20 years old.[178] It cannot deal with a range of circumstances including volatility, price spikes and price response
- a more modern neural network model would likely improve demand forecast accuracy, relatively quickly and at relatively low cost[179]
- it is possible to incorporate smart meter and climate data in more modern models
- the report also noted there is a trend towards predicting the demand of individual loads.

The report concluded the benefit from the rule change requests would be very limited if AEMO continues to use the current neural network model.

---

176 EY, Non-scheduled generation and load in central dispatch rule change request, 5 September 2016, p 53

177 University of Wollongong, Evaluation of Neural Network Models for Australian Energy Market Operators Five Minute Electricity Demand Forecasting, 13 December 2016.

178 The neural network model was originally developed and tuned in 1999. The original tuning is still in use in New South Wales, Victoria and South Australia, although new model components (MetrixND) were developed and tuned for Tasmania (2005) and Queensland (2007).

179 There was no specific assessment provided as to the cost of developing a new neural network model.

This is consistent with the EY findings, which stated that in the majority of cases where there were large dispatch demand inaccuracies, there was no observable relationship with price responsive behaviour or contribution from any of the generation and load facilities analysed. Whereas EY concluded this may be due to the limitations of data availability or significant variation in residential or commercial demand, it is also possible that AEMO's current demand forecasting model may also contribute.

D.5.2 AEMO forecasting improvements and opportunities

The analyses of EY and the University of Wollongong both indicate that some component of forecasting inaccuracy may be attributable to the limitations of AEMO's neural network model.

The AEMC notes that the potential for non-scheduled participants to impact forecast accuracy is limited by the extent to which their actions are not able to be forecast accurately by AEMO. In this context it is worth recognising the recent actions AEMO has taken to improve its forecasts, and others that may potentially assist its forecast accuracy.

AEMO's Forecasting Methodology Information Paper, sets out the improvements AEMO has made to its forecasting processes in the previous year. These are summarised in Box D.1.

Box D.1 Recent improvements to AEMO's forecasting methodology

AEMO provides a 20 year forecast of electricity consumption for each region of the NEM. The forecast combines sectoral forecasts for residential customers and business, with business being split into liquefied natural gas (LNG), coal mining, manufacturing and other business.

At a high level, the business forecasting process combines and calibrates the individual forecasts of the component business sectors and then adjusts for a series of factors including: drivers of the longer term economic outlook (eg population growth, household disposable income, gross state product); surveys and interviews with the largest industrial loads; solar PV and battery uptake and use, and energy efficiency.

Similarly for the residential forecasts, historical consumption per connection is the starting point augmented by connections growth, and heating and cooling load forecasts. The model is then further adjusted to account for energy efficiency, appliance growth, solar PV use, and gas to electricity switching.

Specific methodology change in 2016 included:

- **new forecasting methods:** in recognition that the bulk transmission data that has been the primary traditional source of data for forecasting is: (1) highly aggregated, (ii) historic, and (iii) is not indicative of broader structural changes, AEMO has augmented this with more detailed 'bottom-up' models. These include (i) consumer energy meter data, and (ii) supplementary data from other agencies, such as national account data from the Australian Bureau of Statistics

- **policy assumptions:** the forecasts assume Australia will reduce its emissions by 28 per cent from 2005 levels by 2030, via increased energy efficiency, pricing and coal-fired generator retirements. On pricing, it is assumed that abatement costs will add 2.5 per cent per annum to prices for the 10 years after 2020

- **technology assumptions:** rooftop PV projections now account for panel degradation over time. Forecasts for the uptake and use of battery storage are included. Electric vehicle uptake forecasts are not included

- **surveys and interviews with the largest energy users:** surveys and interviews with the largest energy users inform adjustments to the separately determined business sector forecasts

- **consumer behaviour:** AEMO is using appliance level, forecasting, consumer trend analysis and meter data to refine its energy efficiency projections. It is also assuming a rebound effect where consumers use more energy enabled by the lower cost of energy efficient appliances. Solar PV and batter users' consumption is also assumed to increase resulting from their lower energy costs. Price elasticity of demand adjustments are now only made in response to permanent price increases. Estimates have been revised downwards to avoid overlap with energy efficiency assumptions

- **maximum and minimum demand forecasts:** are not included for all regions (in 2015 only a minimum forecast for South Australia was included). These forecasts are for the next 5 year, 10 year and 20 years, have a summer and winter forecast by region, and include analysis on the probability of exceedance (ie the number of times an event will occur outside the forecast bounds) are not included for all regions (in 2015 only a minimum forecast for South Australia was included). These forecasts are for the next 5 year, 10 year and 20 years, have a summer and winter forecast by region, and include analysis on the probability of exceedance (ie the number of times an event will occur outside the forecast bounds)

- **LNG:** forecasts for electricity use by Queensland LNG facilities have been revised down in line with actual data available now that the facilities are in production.

While there are a range of improvements listed and applied to AEMO's longer term forecasts, it is not clear whether or the extent to which these feed into its shorter term forecasts and the TotalDemand[180] field in AEMO's dispatch engine.

180 This is the quantity of demand that is estimated at the start of the dispatch interval, and on which scheduled generators are dispatched.

A further development that is currently being implemented relates to the demand side participation information guidelines.[181] The guidelines are summarised in the box below.

Box D.2 AEMO's demand side participation information guidelines

In March 2015, the AEMC made a rule that enables AEMO to obtain information on demand side participation from registered participants in the NEM.[182] The objective of the rule is to give AEMO better quality information to develop and improve its load forecasting. In April 2017 AEMO published the guidelines which require registered participants to submit demand side participation data annually from April 2018, including:

- For all connections, information about whether the National Metering Identifier (NMI)[183] is on a time-of-use tariff, whether it has controlled load, whether it has energy storage, whether it is exposed to the spot price, whether it is on a "network event" tariff, whether the customer is on an alert list (for example a warning about when prices are expected to be high as an incentive to reduce demand), and lists of any future demand side participation deployment programs for those NMIs where potential demand side participation response exceeds 1 MW.
- For large connections, or programs where the total possible demand side participation is over 1 MW, information including the NMI, the meter configuration, name, address, demand side participation program, available load reduction, demand side participation type (eg energy storage, load reduction), what price (trigger/tariff) the response is driven by, who controls the response, what the control algorithm is, the type of energy storage, if any (capacity, purpose, installation date, whether export is permitted, inverter make and model), information about historical response, how the demand side participation is monitored, seasonal variation, temperature restrictions and when the demand side participation program ends.

The guideline is currently restricted to information that is obtainable by current processes and systems. However, AEMO expects the provided data may increase in the future.[184]AEMO is required to publish information at least annually about how the information it receives informs its load forecast.[185]

181 See: https://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Planning-and-forecasting/Demand-Side-Participation-Information-Guidelines

182 http://www.aemc.gov.au/Rule-Changes/Improving-Demand-Side-Participation-information-pr

183 The National Metering Identifier (NMI) is a unique 10 or 11 digit number used to identify every electricity network connection point in Australia

184 See http://www.aemc.gov.au/Rule-Changes/Improving-Demand-Side-Participation-information-pr page 5

Beyond these actual and in-progress improvements there appear to be other opportunities for AEMO to improve its forecasts. These relate to incorporating some information that is already available into the forecasting process.

AEMO publishes a forecast of demand plus non-scheduled generation (DPNSG). The non-scheduled generation that is included in this forecast includes large wind farms and a series of other large generators including gas turbines, diesel, sugar mills and other bio-waste generators. The non-scheduled generators included in the DPNSG represent in excess of 1,500 MW of nameplate generation capacity which is over half of the total registered non-scheduled generation with a nameplate capacity of 5 MW or greater in the NEM.[186]

Figure D.19 Comparing Total Demand to Total Demand plus non-scheduled generation

	Total Demand				Total Demand + NS Generation			
	T – 1 (10th , 90th) percentiles		T – 12 (10th , 90th) percentiles		T – 1 (10th , 90th) percentiles		T – 12 (10th , 90th) percentiles	
NSW	-0.8%	0.8%	-1.7%	1.9%	-0.8%	0.8%	-1.7%	1.9%
QLD	-1.1%	1.1%	-1.7%	1.8%	-1.1%	1.0%	-1.7%	1.8%
SA	**-1.5%**	**1.5%**	**-3.7%**	**4.1%**	**-1.3%**	**1.3%**	**-3.0%**	**3.3%**
VIC	-0.9%	0.9%	-2.0%	2.2%	-0.9%	0.9%	-2.0%	2.0%

The DPNSG forecasts were compared against dispatch (which is referred to as the Total Demand forecast)[187] to assess the extent to which including more information from non-scheduled participants would improve demand forecast accuracy. The results in the above figure show that the DPNSG forecast is generally similar to the total demand forecast except for South Australia where a modest improvement is observable.

185 See http://www.aemc.gov.au/Rule-Changes/Improving-Demand-Side-Participation-information-pr page 6

186 The non-scheduled generators are listed in the DISPATCH_UNIT_SCADA table of AEMO's MMS database. These are units included in the DEMAND_PLUS_NONSCHEDGEN field of the DISPATCHREGIONSUM table. Note, a number of scheduled generators are also listed in the table (eg Angaston). The generation capacity cited only refers to the non-scheduled generators.

187 Total Demand is the demand value used in NEM dispatch. Scheduled generators are dispatched to meet this value. It is the forecast of demand made just before the start of each dispatch interval.

D.5.3 AEMO's additional information and operation powers

AEMO also has powers which may enable it to improve its forecasting processes without a rule being made. Specific powers relate to:

- information gathering
- an ability to require participation in central dispatch for system security reason
- an ability to impose terms and conditions on registration of a market participant.

Information gathering and use

In addition to the demand side participation information guidelines already described, AEMO produces the Projected Assessment of System Adequacy (PASA)[188] which is a forecasting study divided into short, medium and long term timeframes.

PASA is defined in clause 3.7.1(b) of the NER as a program of information collection, analysis and disclosure of medium and short term power system security and reliability of supply prospects so that registered participants are properly informed to enable them to make decisions about supply, demand and outages of transmission networks in respect of periods up to 2 years in advance.

- Long Term PASA (LT PASA) is undertaken on an annual basis, informing the Electricity Statement of Opportunities (ESOO) and it considers the 10-year planning horizon for generation, demand side programs and network capacity
- Medium Term PASA (MT PASA) details system adequacy and generation requirements on a weekly basis for a 3-year horizon, and is published monthly
- Short Term PASA (ST PASA) details system adequacy and generation requirements on a 6-hourly basis for a 3-week horizon, and this is published weekly.

Clause 3.7.1(c) requires AEMO to do the following on a weekly basis:

- collect and analyse information (for the proceeding 2-year period) from all scheduled generators, market customers, transmission network service providers and market network service providers about their intentions for:
  - generation, transmission and market network service maintenance scheduling
  - intended plant availabilities
  - energy constraints

188 See links to PASA details at https://wwwaemo.com.au/Datasource/Archives/Archive1897 and https://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Data/Market-Management-System-MMS/Projected-Assessment-of-System-Adequacy

— other plant conditions which could materially impact on power system security and reliability of supply

— significant changes to load forecasts previously notified to AEMO

- prepare the unconstrained intermittent generation forecasts for the proceeding 2-year period
- publish information that will inform the market regarding forecasts of supply and demand.

AEMO is required to prepare and publish a range of information, for each day covered by the MT PASA and for each trading interval of the ST PASA, comprising:

- forecast load information for each region
- forecast network constraints known to AEMO
- an unconstrained intermittent generation forecast for each semi-scheduled generating unit for each day (MT PASA) and each trading interval (ST PASA)
- forecast of the 10 per cent probability of exceedance peak load and most probable peak load
- aggregated MW allowance (if any) to be made by AEMO for generation from non-scheduled generating systems in each of the forecasts of the 10 per cent probability of exceedance daily peak load and most probable daily peak load
- aggregate generating unit availability for each region
- aggregate capacity for each regions.

There appears to be two opportunities related to AEMO's PASA functions which may improve its forecasting processes. The first is that the PASA provisions enable AEMO to request market participants provide information that is required in order to fulfil its PASA functions. To the extent that AEMO considers there are material gaps in its knowledge base, the PASA provisions may enable those gaps to be addressed.[189]

The second opportunity relates to the information AEMO has in its unconstrained intermittent generation forecast (UIGF). The UIGF incorporates semi-scheduled and non-scheduled intermittent generation and is built up using detailed wind and solar models incorporating industry inputs.[190]

189 AEMO's requests in this regard would be limited to the categories of "inputs" that scheduled generators or market participants must provide under clause 3.7.2(d) for MT PASA and clause 3.7.3(e) for ST PASA.

190 The wind forecasting model is the Australian Wind Forecasting System model, and the solar model is the Australian Solar Energy Forecasting System.

AEMO uses the semi-scheduled component of the UIGF, but does not use the non-scheduled component in its dispatch forecast of demand. This is one reason why there can be differences between pre-dispatch forecasts and dispatch; the different forecasts have different components.

Figure D.20 UIGF use in AEMO forecasting

UIGF use in AEMO forecasts		
	Semi-scheduled UIGF	Non-scheduled UIGF
Dispatch	Yes	No
5 min. pre-dispatch	Yes	Yes
30 min. pre-dispatch	Yes	Yes

Given the level of information in the UIGF exceeds that available in the neural network model in relation to intermittent generators, there may be an option for AEMO to include the non-scheduled component of the UIGF in the demand forecast as negative demand. This would have the effect of reducing reliance on the neural network model, to an extent, and some proportional improvement in forecasting accuracy may be achievable.

D.6 Other data and analysis

D.6.1 Costs of scheduling participants

Given the rule change requests suggest scheduling additional market participants, it is important to understand the potential cost components and amounts related to scheduling. The limited information that was provided by stakeholders is described below.

ENGIE put forward a view of costs in its rule change request. In relation to its option for scheduling generators above 5 MW it estimated the following:

- establishment costs:
  - communication platform to send bids and receive dispatch instructions, $10,000
  - internal resource to establish policy and procedures (40 hours), $3,000
- costs:
  - preparing, submitting and responding to dispatch (2-10 hours per week), $150 to $750 per week, $7,500 to $37,500 per annum.

It also estimated that the costs of non-scheduled generators already active in the market would be lower, and that the costs to AEMO would be minimal (unspecified).

ENGIE's estimate for its "soft-scheduled" options was as follows:

- establishment costs:
  - communication platform to provide intentions to AEMO: $5,000
  - internal resource to establish policy and procedures (20 hours), $1,5000
- ongoing costs:
  - preparing and submitting information to AEMO (2 hours per week), $150 per week, $7,500 per annum.

It also estimated that the costs to AEMO would be $40,000.

SA Water offered alternative cost estimates.[191] SA Water operates small non-scheduled waste treatment generators. Its operation is variable, responsive to industrial processes rather than electricity market condition. Its cost estimates were:

- establishment costs:
  - hardware and communications, $20,000
  - control software configuration and integration, $10,000
  - project management $5,000
  - preparation of internal procedures and processes, $10,000
  - development of bidding systems, $50,000
  - total one off costs - $95,000.
- ongoing costs:
  - internal compliance monitoring, $20,000
  - maintenance of systems/processes, $20,000
  - monitoring of obligations under the NER, $20,000
  - bidding/rebidding activities, $200,000
  - Total ongoing costs, $260,000 per annum.

191 SA Water, submission on ENGIE consultation paper, p 2 See: http://www.aemc.gov.au/getattachment/3d956c7c-b4af-49d4-9dfe-dd8382ae5f25/SA-Water-received-23-May-2016.aspx

There was also a view of costs put forward at the AEMC's industry workshop in March 2017 that the costs could be up to $10 million per annum for a participant that is actively trading during business hours. It was also noted that companies can contract for the trading activities and this would reduce their costs, depending on their levels of bidding and rebidding activity. However, these parties would still incur costs related to compliance and legal, which would not be insignificant.

Although the cost estimations put forward vary considerably the Commission acknowledges that there are three distinct categories of cost that are relevant to the rule change requests:

- set-up costs include: the establishment of communication systems for the provision of bidding information and the receipt of dispatch instructions; the establishment of policies and procedures for operations and compliance; the development of bidding strategies; and telemetry systems for provision of metering data
- operations costs include: trading desk functions (bid preparations and submission), noting this will vary depending on whether the trader is active or passive and conducts these functions in-firm or by outsourcing; response capabilities to ensure an ability to follow dispatch instructions, noting that costs will vary depending on the generator's level of automation
- legal and compliance costs include: ensuring adherence to bidding requirements including volume, price and ramp rates, and bidding in good faith requirements, ensuring an ability to satisfy AER compliance requirements.

D.6.2 Registered non-scheduled generation - ownership and generation type

There is a range of different generator types in the registered non-scheduled generator category, which has implications for their practical ability to comply with dispatch instructions. The ownership of these generators may also influence the costs that would be incurred if they were required to be scheduled. Both of these issues are examined in this section.

In November 2016, there were 96 registered non-scheduled generators with nameplate generation capacity of 5MW or greater in the NEM representing total capacity of 2,872MW. However, only a third of these generators are potentially suitable for scheduling, because:

- intermittent renewable generators such as wind and solar PV would be categorised as semi-scheduled generators and are not covered by the rule change request
- generators that produce electricity as a by-product of an industrial or commercial process rather than in response to electricity market conditions may not be suitable for scheduling.

Netting off these categories from total non-scheduled generation leaves 33 generators representing 771MW of capacity that are potentially able to be scheduled. This represents less than two per cent of the total registered generation capacity in the NEM. The breakdown is summarised in the following table.

Table D.1 Breakdown of registered non-scheduled generation, November 2016

	Number	Share of total	MW	Share of total
Total non-scheduled	96		2,872	
Of which: intermittent renewable	23	24%	1,268	44%
Of which: industrial process	40	42%	828	29%
Remaining - potential for scheduling	33	33%	771	27%
NEM total			49,091	
Remaining as % of NEM total			1.6%	

In relation to the ownership of non-scheduled generators:

Figure D.21 below summarises the registered non-scheduled generators in the NEM. Data on the non-scheduled generators is from AEMO's registration and exemption list, as at November 2016.[192] Analysis of the ownership was conducted by the AEMC.

- 61 per cent of non-scheduled generation capacity was identified as being owned by persons who also own a scheduled generator. There was a view[193] that participants that already own or control a scheduled generator would face minimal incremental costs to include non-scheduled generators that they own or control into their portfolio
- nine per cent of non-scheduled generators are not owned by a person who also owns scheduled generator, are not intermittent, and are not a by-product of an industrial or commercial process. It is this category that may face the largest compliance burden if required to be scheduled (on the assumptions that: there would only be incremental costs for participants already operating scheduled generators, intermittent generators could only become semi-scheduled, and it may not be practical to schedule generators using industrial or commercial by-products for generation.)

192 https://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Participant-information/Current-participants/Current-registration-and-exemption-lists

193 See ERM Power submission to the consultation paper, p2,

Figure D.21 Non-scheduled generators in the NEM

	No. of generators	Capacity of generators	% of capacity	
Generators equal to or greater than 5MW	96	2872		
Generators equal to or greater than 5MW owned by scheduled generators	47	1748	61%	
Acciona	1	192	7%	Intermittent
Infigen Energy	1	141	5%	Intermittent
Woolnorth Wind Farm Holding	1	140	5%	Intermittent
Lake Bonny Wind Power	1	81	3%	Intermittent
Meridian	1	70	2%	Intermittent
Ratch Australia	3	68	2%	Intermittent
EnergyAustralia	1	66	2%	Intermittent
ENGIE	1	46	2%	Intermittent
Pacific Hydro	5	255	9%	Other
Hydro Electric Corporation	6	106	4%	Other
Green State Power	4	49	2%	Other
Stanwell	3	27	1%	Other
Snowy Hydro	1	14	0%	Other
Delta Electricity	1	5	0%	Other
AGL	12	194	7%	Other
Rio Tinto	1	180	6%	Other
Origin	2	54	2%	Other, intermittent
Arrow	1	30	1%	Other
CS Energy	1	30	1%	Other
Remaining generators equal to or greater than !	49	1124	39%	
EDL	15	342	12%	By-product
Pioneer Sugar Mills P/L	8	203	7%	By-product
Cape Byron Power	2	68	2%	By-product
Mackay Sugar Ltd	1	48	2%	By-product
MSF Sugar	4	43	1%	By-product
LMS	3	24	1%	By-product
South Australian Water Corporation	1	10	0%	By-product
Veolia Environmental Services Aust P/L	1	6	0%	By-product
Infrastructure Capital Group	1	91	3%	Intermittent
Innovation Capital, Lend Lease, local community	1	20	1%	Intermittent
CGN Wind Energy Limited	1	20	1%	Intermittent
Future Energy Pty Ltd	1	6	0%	Intermittent
Essential Energy	3	89	3%	Other
Water NSW	2	70	2%	Other
ExxonMobil	1	32	1%	Other
First Pacific Capital Underwriters	1	30	1%	Other
Joint Santos - Essential Energy	2	16	1%	Other, by-product
Crown Resorts	1	6	0%	Other

E Estimating demand forecast error in pre-dispatch forecasts and dispatch

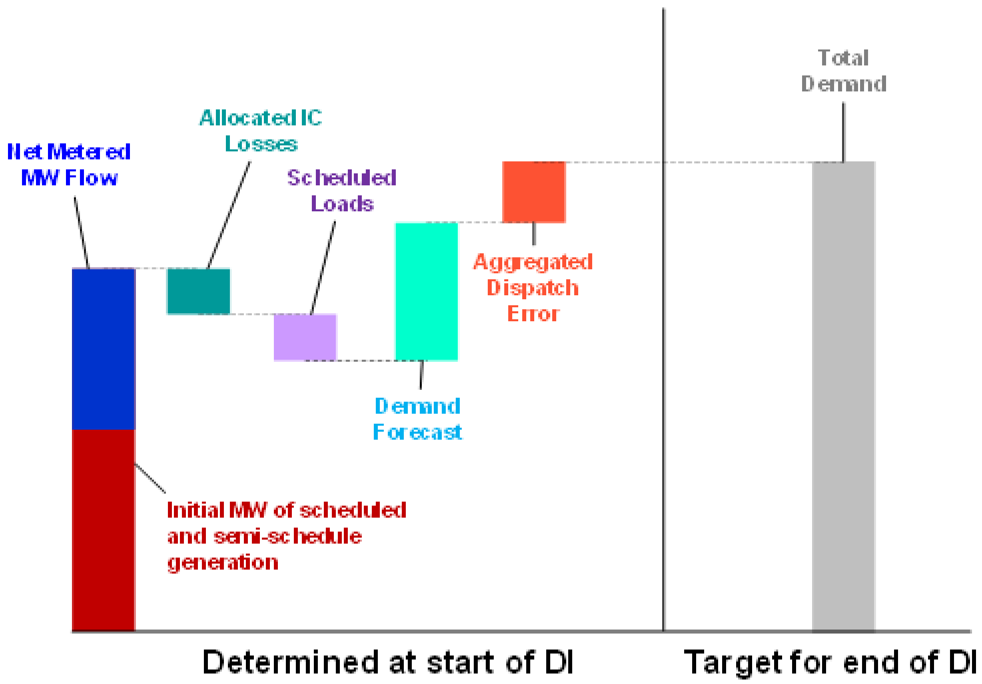
AEMO's P5 and P30 pre-dispatch demand forecasts are forecasts of the level of demand at the end of the dispatch interval. Dispatch is similar in that it estimates demand that will occur at the end of the dispatch interval. The following description outlines how forecast error was calculated.

At the start of the dispatch interval the dispatch calculation estimated total demand for the end of the interval. Total demand is made up of:

- initial MW of scheduled and semi-scheduled generation, plus
- net metered MW flow of interconnectors (which can be positive or negative), less
- allocated interconnector losses, less
- scheduled loads, plus
- the incremental change in the demand forecast (which can be positive or negative), plus
- the aggregated dispatch error (which is the real time difference between estimated and actual generation).

This is represented by Figure E.1 below.

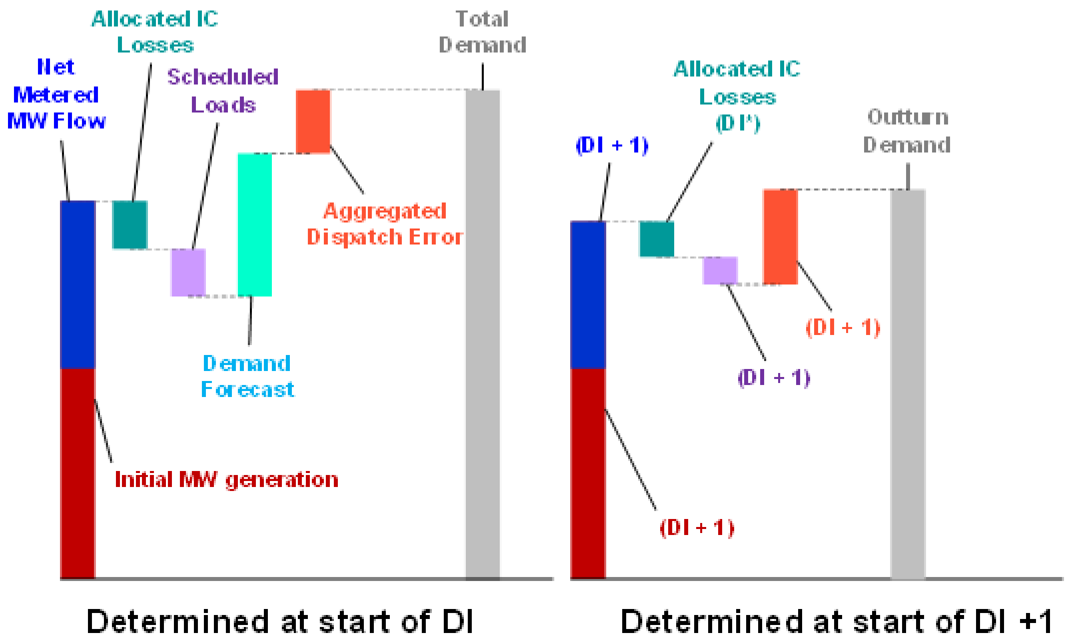
Figure E.1 Determination of total demand



To then assess actual demand at the end of the dispatch interval (termed outrun demand for the purposes of this analysis) we then compare the actual metered data for the forecast components from dispatch to just prior to the start of the next dispatch interval. The difference is the forecast error.

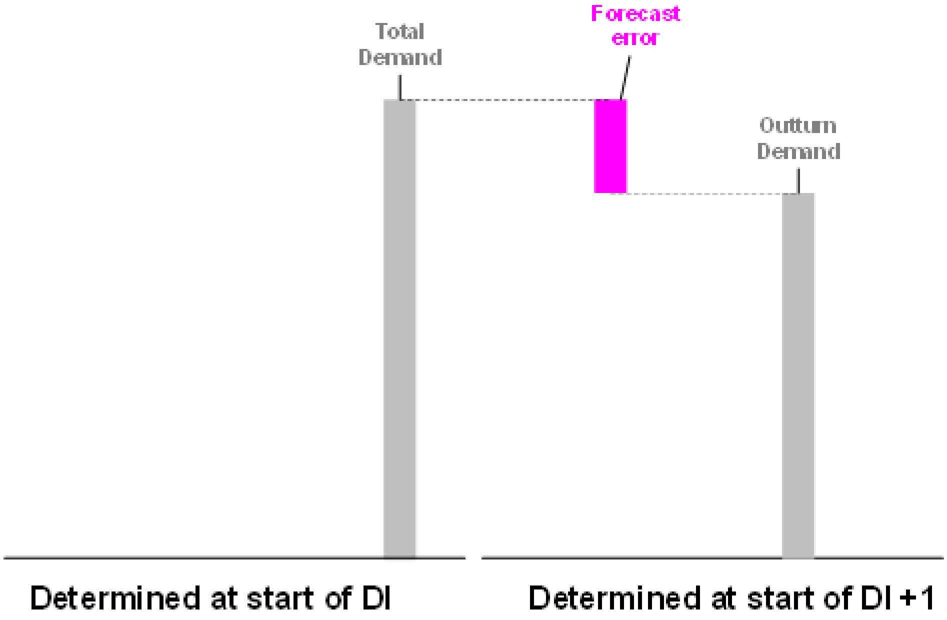
The figure below shows how the outrun demand is calculated.

Figure E.2 Determination of outrun demand



The next figure shows forecast error as the difference between total demand at dispatch and outrun demand just prior to the commencement of the next dispatch interval.

Figure E.3 Determination of forecast error



If the demand forecast for the next interval is added to the outrun demand data, it provides the total demand for the next dispatch interval.

It is important to note that there may be some contribution to demand error given the method of calculating allocated interconnector losses. This is because an average interconnector loss factor is calculated once per annum for each region. To the extent to which the actual interconnector loss factors in each dispatch interval vary from this historic average, there will be a contribution to forecast error.

F New Zealand criteria for non-conforming grid export point (GXP)

The following is an excerpt from the criteria used in New Zealand.

Criterion 1: System security

The Authority may determine that a GXP is a non-conforming GXP if:

1. the system operator has advised in writing and with reasons that it is unable to forecast the demand at the GXP at all times to a level of accuracy that will ensure system security; and

2. taking the system operator's advice into account, the Authority is satisfied that the GXP should be non-conforming to ensure system security.

Criterion 2: Forecasting accuracy at industrial GXP

The Authority may determine that a GXP is a non-conforming GXP if:

1. the demand at the GXP is primarily an industrial load. The Authority will determine if the demand at the GXP is primarily industrial in the following way:

   (a) if industry load accounts for more than 50 per cent of the load at the GXP over the previous 12 months, then the Authority will consider that the demand at the GXP is primarily an industrial load

   (b) if industry load accounts for 50 per cent or less of the load at the GXP over the previous 12 months, then the Authority will consider all relevant factors to determine if the demand at the GXP is primarily an industrial load

2. the system operator has advised, and provided supporting reasons, that in its opinion the purchaser, rather than the system operator, will be better able to predict the demand at the GXP, and

3. taking into account the system operator's advice and any relevant views of purchasers at the GXP, the Authority is satisfied that the GXP should be considered as non-conforming.