19 May 2016

Veronika Nemes
Director
Australian Energy Market Commission
PO Box A2449
Sydney South NSW 1235

Dear Ms Nemes

## RE: Non-Scheduled Generation and Load in Central Dispatch Consultation Paper (Reference: ERC0203)

ERM Power Limited (ERM Power) welcomes the opportunity to respond to the Australian Energy Market Commission's (the Commission) Consultation Paper on non-scheduled generation and load in central dispatch. We note that the Commission has combined the ENGIE initiated rule change request *Non-scheduled generation in central* dispatch with the Snowy Hydro-initiated rule change request *Demand side obligation to bid into central dispatch* to form the current combined rule change request.

## About ERM Power Limited

ERM Power is an Australian energy company that operates electricity generation and electricity sales businesses. Trading as ERM Business Energy and founded in 1980, we have grown to become the fourth largest electricity retailer in Australia, with operations in every state and the Australian Capital Territory. We are also licensed to sell electricity in several markets in the United States. We have equity interests in 497 megawatts of low emission, gas-fired peaking power stations in Western Australia and Queensland, both of which we operate.

## General comments

ERM Power supports ENGIE's proposed Option 1 which reduces the threshold at which controllable generators are required to be scheduled from 30 MW to 5 MW. This approach would present a more accurate picture of the level of supply available to the market, allowing for a more efficient dispatch process where the market can be supplied using the lowest costs portfolio of generation. It also allows the Australian Energy Market Operator (AEMO) the ability to more accurately control flows across congested network elements which has benefits for system security as well as dispatch efficiency.

The continued uncontrolled dispatch of non-scheduled generation has the potential to result in additional costs to consumers due to:

- Additional dispatch of Frequency Control Ancillary Service (FCAS) regulation services, the cost of which is primarily borne by scheduled generators and demand; and
- Fast start generators rebidding to avoid uneconomic dispatch, due to the view that non-scheduled generation will enter the market and collapse price outcomes, which could then result in the high price outcome extending into future dispatch intervals.

ERM Power considers that adopting Option 1 would reduce the need for a more complex multi-tier system (Option 2) where more generators are scheduled but many remain unscheduled and are not required to comply with dispatch instructions. ERM Power opposes implementing Option 2 as a backstop approach if non-scheduled generation more than 5 MW in capacity is unable to become scheduled.

We believe that there are benefits in AEMO adopting a modified version of Option 3 from the Consultation Paper, as set out below, in order to provide greater levels of information to market participants. By providing the market with a clearer picture of the levels of generation from smaller non-registered generation (less than 5 MW), participants would be able to bid more efficiently based on an expectation of the supply available from all sources.

We provide more detailed commentary on each option below.

## Option 1

The purpose of scheduling generation in the National Electricity Market (NEM) is to ensure that generation is dispatched efficiently with the lowest-cost portfolio of generation dispatched to ensure supply matches demand in real time (subject to network constraints). The better the level of information about participants' availability and intention to provide generation output, the clearer the signals are to bring more supply online when needed or to remove generation when it is not needed. AEMO's forecasts of demand assist generators in this regard to determine how much supply may be needed at any given time.

Unfortunately, the market is distorted by the current situation where significant amounts of non-scheduled generation can opaquely dispatch into the market without receiving a dispatch instruction and without providing reasonable forecasts of intent to dispatch. Without the true levels of supply and demand accurately conveyed, an asymmetry is created where the market is unable to respond as efficiently as it otherwise may.

Network system security is achieved in real time dispatch by AEMO by the use of constraint equations in the National Electricity Market Dispatch Engine (NEMDE). Where loading on parts of the network may be influenced by the unforecast and uncontrolled dispatch of non-scheduled generation, AEMO applies higher safety margins in these constraint equations. This results in lower network capacity than would otherwise be available for use. This reduces the dynamic efficiency of generation dispatch and results in higher overall costs to consumers.

Currently there is around 1,400 MW of non-scheduled, non-intermittent generation exceeding 5 MW in output registered with AEMO. This is a substantial capacity of generation that may commence or reduce generation output totally independently of dispatch instructions from AEMO.

Approximately 75 per cent of these non-scheduled generation units are operated by market participants with other generating units active in the market.[1] This suggests that the additional costs of preparing and submitting quantity price bids for these generators to AEMO would be an incremental change to normal business practice for these participants. As such, ERM Power contends that the costs of scheduling generation above 5MW of capacity are likely to be relatively minor for the bulk of non-scheduled generators.

[1] ERM analysis based on AEMO's NEM Registration and exemption list

The remaining 25 per cent is controlled by seven participants who currently do not have any scheduled generation and would either be required to acquire this capability internally or by external contracting with another market participant with existing capability. The costs for the provision of this are likely to be immaterial compared to the system security and dispatch efficiency benefits achieved.

As highlighted in ENGIE's rule change request, fast-start generation is particularly disadvantaged by the current situation. At present, a high price in the wholesale market generally results in a fast-start generator, which usually requires at least 5 minutes to synchronise from rest, receiving a start request from AEMO for dispatch to at least minimum load in the following dispatch interval. However, non-scheduled generators can and often do start to generate power within the current dispatch interval without receiving a dispatch instruction. This results in reductions in the AEMO measured demand and spot price for the subsequent dispatch interval. Consequently, by the time a fast-start generator has synchronised, the unforecast entry of non-scheduled generation into the market has caused the spot price to fall. A fast-start generator is then likely to run uneconomically for its minimum run time.

This uncontrolled dispatch of non-scheduled has the potential to result in additional costs to consumers due to:

- Additional dispatch of Frequency Control Ancillary Service (FCAS) regulation services due to the larger difference between forecast and actual levels of generation and demand. The cost of procuring additional FCAS is primarily borne by scheduled generators and demand; and
- Fast start generators rebidding to avoid uneconomic dispatch, due to the view that non-scheduled generation will enter the market and collapse price outcomes, which could then result in the high price outcome extending into future dispatch intervals.

### Option 2

ENGIE proposes a fall-back option whereby generators connected prior to the rule change request, or that are unable to become scheduled, would become "soft-scheduled generators". Soft-scheduled generators would be further differentiated into two sub-categories as either price-responsive or non-price responsive. Soft-scheduled generators would not have to comply with the full bidding requirements or follow dispatch instructions.

In ERM Power's view, this approach would do little to resolve the inefficiencies currently caused by non-scheduled generators, particularly with regards to not being required to comply with dispatch instructions. Soft-scheduled generators would still be able to increase generation levels, potentially restricting generation from lower-cost sources, particularly in the event of transmission network congestion. Fast-start generators would continue to face the same dispatch inefficiencies as they currently do, as discussed above in our response to Option 1. As discussed above, the market would still face additional costs as a result of more FCAS regulation services being needed and the potential for system security to be compromised due to the uncontrolled output of non-scheduled generation.

Additionally, it would be inconsistent for bids by soft-scheduled generators to be able to set the dispatch price when they are not required to follow dispatch instructions and are not subject to transmission constraints. This runs counter to the operation of a reliable and efficient market.

ERM Power therefore opposes the implementation of Option 2. Requiring generation above 5 MW in capacity to become scheduled would provide the greatest benefits to the market. Creating additional categories of generators such as the proposed soft-scheduled generators with its two sub-categories (price responsive and non-price responsive) would add additional cost and complexity and is unlikely to resolve the potential system security impacts or dispatch inefficiencies currently caused by non-scheduled generation.

We do acknowledge that there is a retrospective cost impact for existing non-scheduled generators who would have to become scheduled. However, the overall costs and benefits to the market need to be considered. Allowing time for effected generators to become scheduled rather than imposing an immediate requirement would help to mitigate this to some extent. Phasing the requirements in over time could also allow for the new technologies or service providers to enter the market and help lower costs.

## Option 3

ENGIE's proposed third option involves AEMO developing a new process to incorporate the price responsiveness of non-scheduled generators into the demand forecast by preparing proxy price and quantity bids to represent the expected aggregate price response of non-scheduled generators. The rule change request suggests that the proxy bid process could apply to all non-scheduled generators, including those less than 5MW.

In response to greater volumes of intermittent renewable generation entering the market in order to meet the Renewable Energy Target, there may be a need for more fast-start backup and reserve plant to enter the market in order to help manage the variability of intermittent generation and ensure reliable supply to consumers. Some of this plant, particularly battery storage facilities, may be below the 5 MW threshold required for registration. As more of these technologies enter the market there will be a need for transparent information about the potential levels of supply from these units in the NEM.

As such, ERM Power contends that AEMO should play an important role in providing this information to the market. Increasing the information available allows for more efficient bids which translate to a more reliable and efficient market with lower overall costs. However, ERM Power is opposed to Option 3 as described in the Consultation Paper which would result in AEMO not only forecasting the expected level of generation from all non-scheduled generation but also bidding into the market through a proxy bid process. Allowing AEMO to bid into the market on behalf of an aggregated set of small generation facilities would run counter to its position as an independent market operator.

ERM Power considers that a better approach would be for AEMO to provide an expected aggregated generation profile for non-scheduled generators smaller than 5MW. This would allow the market to respond to this signal alongside AEMO's other pre-dispatch and dispatch forecasts and would therefore provide a clearer picture to market participants of the expected response of small, non-scheduled (and in many cases non-registered) generation. AEMO's existing Australian Wind Energy Forecasting System and Australian Solar Energy Forecasting System operate in a similar manner.

## Additional comments

While no change is discussed in the Consultation Paper, ERM Power considers that this rule change process should not affect the current exemption process for generation. There are a number of entities that maintain generation facilities but use these solely for backup power generation or occasionally demand response. ERM Power recommends that the current exemption process for generation be retained as is.

ERM Power encourages the Commission to adopt the rule change proponent's preferred option to reduce the threshold at which controllable generators are required to be scheduled from 30MW to 5MW. Further benefits to the market could also be achieved by adopting a revised version of Option 3, where AEMO would publish an expected generation profile from non-scheduled generation.

Please contact me if you would like to discuss this submission further.

Yours sincerely,

[signed]

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