Mr Ben Davis
Australian Energy Market Commission
Level 6, 201 Elizabeth Street
Sydney NSW 2000
Lodged via www.aemc.gov.au

Friday, 20 May 2016

Dear Mr Davis,

RE: Non-scheduled generation and load in central dispatch (ERC0203)

ENGIE appreciates the opportunity to comment on the Australian Energy Market Commission (AEMC) consultation paper regarding the rule change proposal for non-scheduled generation in the central dispatch process.

ENGIE is a global energy operator in the businesses of electricity, natural gas and energy services. ENGIE is the number one independent power producer in the world with 115.3 GW of installed power-production capacity, 19 GW of which is renewable. ENGIE employs 1,800 people in Australia and supplies 12 per cent of Australia's National Electricity Market, and has an installed generating capacity of more than 3,550 MW. ENGIE also owns Simply Energy which provides electricity and gas to more than 550,000 retail customer accounts across Victoria, South Australia, New South Wales and Queensland.

Question 1: Potential inefficiencies in the dispatch process

ENGIE is of the view that allowing non-scheduled generation to change its output without informing the dispatch process introduces significant inefficiencies into the National Electricity Market (NEM). These inefficiencies manifest in a number of different ways, as outlined below.

The 5-minute dispatch price which is a key parameter that drives NEM participant behaviour can be incorrectly too high or too low, due to non-transparent changes in output of non-scheduled generators.

For example, suppose that the dispatch process publishes a 'high' 5-minute price of say $300 in a particular dispatch interval, and sends dispatch targets to a scheduled peaking generator to commence its start up. The scheduled peaking generator then commences its start-up sequence according to its fast start inflexibility profile (FSIP), which typically requires 10 to 20 minutes to reach full output.

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Before the end of the 5-minute period non-scheduled generators that are price sensitive can respond to the published $300 dispatch price, and increase their output. This will be observed by the NEM dispatch process as a sudden decrease in demand.

The sudden and unexpected decrease in demand will need to be accommodated by frequency control ancillary service (FCAS), to maintain the power system frequency within the operating range. At the start of the subsequent 5-minute dispatch interval the NEM dispatch process will measure the decrease in demand (due to the non-scheduled generator increase), and publish a new 5-minute price, which will most likely be lower than the previous dispatch interval, due to the apparent decrease in demand. For example, the 5-minute price could fall to say $100.

Meanwhile, the scheduled peaking generator that received its start instruction in the previous $300 dispatch interval, is now well into its start sequence, which cannot be stopped without significant operational and maintenance costs. The scheduled peaking generator participant notices that the latest dispatch interval price of $100 is below its offer price, but it has little choice but to allow the scheduled peaking generator to continue through its start-up sequence.

Once the scheduled peaking generator actually synchronises, it will then need to assess whether it continues to operate despite the spot price now being below its offer price, or to shut down. In either case, the scheduled peaking generator suffers a financial loss. The longer-term implication of this type of event is that the peaking generator operator will be more cautious about starting its peaking generator in future similar circumstances.

It is difficult for ENGIE to quantify the inefficiencies in both the energy and FCAS markets outlined above, but it is clear that scenarios similar to these are not uncommon in the NEM. Evidence of the frequency and extent of the inefficiencies introduced by non-scheduled generation can be obtained by examination of the Australian Energy Regulator (AER) reports into high price events in the NEM. For example, the AER State of the Energy Market 2015 report includes the following statement:

> *"South Australia's non-scheduled generators control capacity equal to around 11 per cent of the region's scheduled capacity. When the demand–supply balance is tight, these generators can rapidly reduce output, causing the dispatch price to spike. The generators then boost output for the remainder of the trading interval to capture those higher prices. Because non-scheduled generation falls outside the market dispatch process, this behaviour is not transparent, making it difficult for other participants to react to their commercial advantage."*

and this:

> *"On [10 June 2015], Snowy Hydro reacted to an already tight market (with dispatch prices of around $500 per MWh at 11.45 am), by reducing output at its Angaston plant at 12.10 pm. The sudden reduction in output increased South Australia's five minute dispatch price to the cap. Angaston kept generating for enough time to capture significant revenue in the half hour trading interval (which settled above $2000 per MWh). Snowy Hydro repeated this behaviour throughout the afternoon."*[1]

[1] AER State of the Energy Market 2015, at www.aer.gov.au/wholesale-markets/market-performance

Other pricing events reported by the AER due to the impact of non-scheduled generation in the NEM include:

Date	Region	Summary	Report
22 May 2010	Tas	Increase in non-scheduled gen of 40 MW in 5 min when spot price was $9995/MWh	Prices above $5000/MWh - 22 May 2010 (TAS)
1 Nov 2015	SA	uncontrolled dispatch of non-scheduled generators contribute to SA frequency deviations when islanded	FCAS prices above $5000/MW - 1 November 2015 (SA)
15 Jan 2014	SA	Significant non-scheduled generation at time of very high demand complicated assessment of low reserve conditions	15 January 2014 South Australia and Victoria
19 Dec 2013	SA	Significant non-scheduled generation displaced wholesale market demand	19 December 2013 South Australia
7 and 8 Aug 2010	Tas	Non-scheduled generators reduce output during peak price periods.	7 and 8 August 2010 Tasmania

Question 2: Impacts on market participants from inefficiencies in the dispatch process

ENGIE believes that the participants which are most impacted by the inefficiencies in the dispatch process are likely to be those that seek to respond dynamically to the 5-minute price, including peaking generators. All market participants are impacted to the extent that unexpected changes to, and uncertainty in the 5-minute dispatch price creates wealth transfers (winners and losers), and introduces uncertainty, leading to inefficient operational and investment decisions.

ENGIE is not aware that there are any particular times in the day that the non-scheduled generators are more likely to respond and therefore create inefficiencies in the NEM. Based on ENGIE's experience, it would seem that there are some non-scheduled generators that are largely responding to the wholesale energy price in a certain region, or alternatively, seem to be following a reasonably fixed operating schedule.

As far as the non-scheduled generators with nameplate ratings below 5 MW are concerned, it is clear that household solar PV has begun to have a significant impact and would be the main contributor in this. It would clearly neither be appropriate nor feasible for household level generation to be required to be scheduled in the NEM.

Although the impact of generators below 5 MW is becoming significant at times, this is not a matter that ENGIE was seeking to resolve in this particular rule change proposal. If the impact of less than 5 MW generators is an issue that the AEMC are inclined to take further, ENGIE believes that this should be subject to a separate rule change process.

Question 3: Potential inefficiencies in pre-dispatch

ENGIE's rule change proposal includes a discussion of the importance of the pre-dispatch forecasts to both the efficiency of the NEM and the ability of AEMO to maintain a secure and reliable power system in an effective manner. ENGIE will not repeat those statements in this submission, but does emphasise the key point that so long as the current blind spot associated with non-scheduled generation continues, there will be a continuation of the dispatch inefficiencies and power system management impediments.

The AEMC Consultation Paper seeks to understand the extent to which inaccuracies in pre-dispatch are caused by non-scheduled generators above or below 5 MW. ENGIE believes that both of these categories are contributing to the inaccuracies, although the characteristics of the inaccuracies due to these two categories vary.

ENGIE believes that the above 5 MW category of non-scheduled generation is more likely to be dispatched in accordance with a regular pattern driven either by response to wholesale price, or in accordance with an operating schedule to suit the owner/operators local needs. ENGIE suggests that a key factor contributing to this dispatch pattern is that non-scheduled generation above 5 MW is primarily comprised of synchronous controllable generators.

The category of non-scheduled generation that is below 5 MW is increasingly made up of household solar PV which responds to time of day and local weather conditions. Although this category is not generally price responsive, it does impose significant disturbances onto the NEM dispatch process, which if left unaccounted for, will lead to dispatch inefficiencies and potential system security problems.

Question 4: Option one

As outlined in the rule change proposal, ENGIE is supportive of revising the threshold for generators to be scheduled from the current 30 MW to 5 MW on the basis that it would lead to improved dispatch efficiency and power system security outcomes.

ENGIE is concerned that any proposal for a flexible approach to setting the threshold will result in inconsistent and potentially non-transparent outcomes for different generators. ENGIE suggests that if there is a legitimate argument for reducing the threshold to 5 MW (as ENGIE believes there is), then this should be applied consistently.

Question 5: Option two

Option two proposes a new 'soft-scheduled' mechanism which is intended to be less onerous and less costly on the generator than option one, although it would not provide the same level of market transparency as the preferred option one.

A question arises in considering the soft-scheduled approach as to whether a soft-scheduled generator that is the marginal generator, should be allowed to set the wholesale spot price in the NEM. Whilst it is true that soft-scheduled generators cannot be constrained (since they are not required to adhere to a dispatch target from AEMO), ENGIE is of the view that soft-scheduled generators should be able to set the spot price.

In considering whether marginal soft-scheduled generators should be allowed to set the spot price, it is important to consider the consequences from the perspective of a price responsive soft-scheduled generator. Such a generator has offered its generation capacity to the NEM dispatch process by indicating the volume of generation it will provide if and when the spot prices reaches its offer price.

If the soft-scheduled generator finds that its offer has become marginal in the dispatch process, then AEMO are therefore assuming that some or all of its offered capacity is being dispatched. Under the soft-scheduled proposal, the only mechanism to signal to the soft-scheduled generator that it should dispatch its generation is the current spot price. It will therefore be important that the soft-scheduled generators offer price be allowed to set the spot price to ensure that the soft-scheduled generator receives the signal to dispatch its generation via the spot price.

Question 5: Option three

Options three is based on AEMO entering proxy bids which have been determined on the basis of historical records of demand changes and their correlation with spot price as measured at the connection point level.

The question of whether proxy bids should be allowed to set spot price is similar to the equivalent question relating to soft-scheduled generators. AEMO would determine their proxy bids based on their measurements of demand changes correlated with price changes at a connection point. When an AEMO proxy bid becomes marginal in the NEM dispatch process, it will be important that the correct price signal be sent out to all of the entities that make up the demand and distributed generators that sit behind the proxy bid, so that the expected demand response will be observed.

The AEMC consultation paper correctly notes that having AEMO, the independent market operator, responsible for calculating and entering proxy bids into the NEM dispatch process raises questions regarding market transparency and safeguards. ENGIE agrees that if such a step were to be taken up, consideration should be given to the level of transparency surrounding AEMO’s procedures, the need for independent audit and reporting. ENGIE believes that provided the AEMO processes are transparent and robust, then it could be acceptable.

ENGIE trusts that the comments provided in this response are of assistance to the AEMC in its deliberations. Should you wish to discuss any aspects of this submission, please do not hesitate to contact me on, telephone, 03 9617 8331.

Yours sincerely,

Chris Deague
Wholesale Regulations Manager