22 August 2017

Michael Bradley
Project Leader
Australian Energy Market Commission
Submitted via website
AEMC reference - ERC0203

Dear Michael,

Thank you for the opportunity to provide comment on the Australian Energy Market Commission's (AEMC's) Draft Determination on Non-scheduled Generation and Load in Central Dispatch (draft determination). We note the AEMC has determined not to make a draft rule based on the conclusion that the rule would make limited improvements to forecasts.

Stanwell does not support the draft determination which is an anachronism. It cannot be read alongside any contemporaneous consideration of the National Electricity Market (NEM) to produce a consistent narrative, and must be reconsidered.

The value of participants being visible, responsive and providing reliable information is well established:

1. In the 2012 Power of Choice report, the AEMC recommended the establishment of a scheduled demand response mechanism[i].
2. In 2016 the AEMC rejected a rule change[1] resulting from the 2012 report noting the key difference that the rule change did not require demand response to be scheduled[ii].
3. In 2015 the AEMC made changes to the rebidding rules noting the importance of transparency of price formulation and the efficacy of price signals[iii].
4. In 2016 the AEMC rejected a rule change request to shift from strict obligation to comply with dispatch instructions to an obligation based on reasonable endeavours noting the importance of dispatch for ensuring the most efficient mix of generation[iv].
5. The AEMC is currently considering, and has indicated an inclination to implement, a change from 30 minute to 5 minute settlement noting the importance of the right price signals in order to incentivise an efficient level of generation and consumption[v].
6. The AEMC, AEMO and jurisdictional bodies are currently considering a range of measures relating to technical requirements and information disclosure in order to enable the ongoing operation of the NEM[2].

The future NEM is likely to have increased participation by distributed generators, non scheduled generators, aggregators and price responsive loads. As a result, AEMO will have decreased visibility and control over the electricity market unless measures are put in place to provide AEMO with these resources. This has implications for both dispatch efficiency, system security and ultimately costs for consumers.

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[1] The AEMC rejected the proposed Demand Response Mechanism but adopted the proposed Ancillary Services Unbundling Rule change.

[2] For example in 2017 AEMO recommended to ESCOSA that all new entrant generators greater than 5MW have AGC control, automatic response to changes in system frequency and capability to limit rate of change of active power within a dispatch interval.

AEMO is very clear about the relationship between data and market efficiency, system security and forecasts[vi]. Similarly Finkel recognises the system security implications of Distrubuted Energy Resources (DER)[3] and even appears to envisage scheduling of DER[4].

More preferable rule change options

While the contemporaneous events and processes do not require the specific rule change proposals to be adopted they clearly support some form of update to the Rules to enhance transparency and allow the market to function efficiently. To this end, Stanwell expect the AEMC may progress a *More Preferential Rule Change* which may address the bulk of the observed inefficiency in a cost effective manner, similar to their approach to other rule change processes. Stanwell does not expect that this rule change proposal will eliminate all errors in AEMO forecasts. It will however reduce the information asymmetry present in volatile situations which are highly sensitive to such forecasting errors.

New Zealand model

Stanwell understands that the AEMC is reluctant to impose costs on loads, especially where loads have little or no correlation with forecast error. However, some loads have a significant correlation with forecast errors. In this case, it is likely that the New Zealand model discussed by the AEMC could work for the Australian market. This would avoid the need to schedule most large loads, but would allow for scheduling of the loads that have the most impact on forecast error. Stanwell notes that for these loads, who already participate actively in the wholesale market, the cost to be scheduled is likely to be incremental. Stanwell supports investigation into this model and whether it would work of the Australian market.

Impose the scheduling obligation on new participants

The AEMC could determine improved transparency arrangements for new entrants without adding burden to existing participants. This would have the effect of capturing the forecast growth in non-scheduled generators and price-responsive loads and would go some way to assisting AEMO with its central dispatch process. Stanwell suggests the AEMC also consider this as an alternative approach.

Appendix A provides some commentary on the EY and AEMC calculations. Appendix B contains extracts from the references noted above.

Thank you for consideration of Stanwell's response to the draft determination. If you would like to discuss any aspect of this submission, please contact Jennifer Tarr on 07 3228 4546.

Regards

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Manager Regulatory Strategy
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[3] *Independent Review into the Future Security of the National Electricity Market - Blueprint for the Future*, June 2017 page 62

[4] *Independent Review into the Future Security of the National Electricity Market - Blueprint for the Future*, June 2017 page 63

Appendix A - commentary on EY and AEMC calculations

EY analysis

In the current consultation the AEMC commissioned Ernst and Young (EY) *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*[5]. Inexplicably EY were provided primarily with 30 minute resolution data[6] despite the analysis clearly requiring 5 minute resolution data. If AEMO have 5 minute data for these sites it is unclear why it would not be provided. Conversely if AEMO does not have 5 minute data for these sites it would appear to lend greater urgency to attempts to improve the transparency of such operations.

The lack of 5 minute resolution data hampered the investigation unnecessarily; however EY still found that "*For some facility types, changes in facility consumption/generation are aligned with regional dispatch demand error. This indicates that some facility types are contributing to large errors in the forecast of demand at the regional level.*"[7] And "*There is a correlation between wholesale market prices and dispatch demand inaccuracy. In particular, high wholesale prices in Queensland and South Australia result in an increased likelihood of large overestimates in dispatch demand.*"[8] With more granular data this finding would be expected to be more pronounced.

Stanwell has records of 1 minute and 5 minute data at key facilities and has observed numerous instances of price responsive behaviour. These near-instantaneous changes in load approach 100MW at a single connection point causing flow on effects to FCAS markets and compliance with dispatch instructions for scheduled generators. Stanwell thanks the AEMC for the opportunity to discuss, in person, this data and its implications.

AEMC analysis

The AEMC concluded that "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"[9]. Stanwell makes the comparison to a large scheduled peaking generator such as Mt Stuart. Despite generating at up to 400MW, Mt Stuart's "average" generation compared to demand is around one tenth of the size of the demand forecast error as shown in the table below.

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[5] Draft determination, page iv

[6] Draft determination, page 41 "*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, the study used 30 minute data.*"

[7] Ernst & Young, *Non-scheduled generation and load in central dispatch rule change request, Final report to Australian Energy Market Commission*, 5 September 2016, Executive Summary

[8] Ibid

[9] Draft Determination page 38

Year	Qld demand average (MW)	Mt Stuart Generation average (MW)	Proportion
2010	5,973	2	0.0%
2011	5,834	4	0.1%
2012	5,827	3	0.0%
2013	5,704	5	0.1%
2014	5,746	3	0.0%
2015	6,035	3	0.0%
2016	6,272	7	0.1%
2017	6,359	14	0.2%

Despite the minor “average” impact on dispatch outcomes it is still considered important that a facility such as Mt Stuart specifies its intent to the market and it is obliged to follow dispatch instructions. That is, a generator with negligible “average” impact on dispatch outcomes is important enough to warrant scheduling. Stanwell considers that the same conditions exist for a number of the non scheduled participants subject to this rule change request – while the “average” impact of their circa 100MW participation on dispatch outcomes is minimal they are important enough, in certain circumstances, to warrant scheduling.

Regardless of whether forecasts are “generally accurate”, if controllable price sensitive generators and loads were scheduled the forecast would be more accurate. No improvement in the neural network model could outperform specific provision of intent by a participant.

Appendix B - Extracts from references

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[i] AEMC 2012, *Power of choice review - giving consumers options in the way they use electricity, Final Report*, 30 November 2012, Sydney. Page 112-113
"…we have developed a set of recommendations to enhance participation by consumers in the wholesale electricity and ancillary services markets. We have also recommended ways to promote accurate demand forecasts of the increasing levels of DSP in the NEM… An efficiently operating electricity market should incorporate both dynamic supply and demand resources "

[ii] AEMC 2016, *(Demand Response Mechanism and Ancillary Services Unbundling), Final Rule Determination*, 24 November 2016, Sydney page 8
"Demand response under the proposed DRM is not scheduled and hence its price effects are no different from the demand response occurring currently in the market. This is a variation from the original DRM specifications proposed by the Commission as part of its PoC recommendations, where it was envisaged that demand response would be scheduled by AEMO through central dispatch rather than by a demand response aggregator outside of it."

[iii] AEMC 2015, *Bidding in Good Faith, Final Rule Determination*, 10 December 2015 , Sydney page 6
"*the price setting process should be sufficiently transparent and robust such that market participants have confidence that these signals are generally reflective of underlying supply and demand conditions in the NEM.*
The Commission has considered the following matters in assessing whether making a change to the existing arrangements will, or is likely to, promote the NEO:
- *the impact on the efficacy of wholesale price signals, such that efficient investment decisions can be made with confidence; and*
- *the provision of reliable and timely information to market participants, including pre-dispatch forecasts, such that efficient operational responses can be made in the short term which are in line with underlying supply and demand conditions."*

[iv] AEMC 2016*, Compliance with dispatch instructions, Final Rule Determination,* 5 May 2016, Sydney. Page 3
" Given that the central dispatch process, and the dispatch instructions it produces, maximises the value of spot market trading, it is critical that market participants follow these instructions. Where this does not happen, some capacity of generators which forms part of the optimal mix of generation for that five minute dispatch interval could potentially be displaced by capacity of generators who may not be part of this optimal mix. In these circumstances, the value of spot market trading would likely be reduced and total system costs would likely increase, with any higher wholesale electricity prices in the long-term ultimately flowing through to customers. In addition, there are likely to be consequences for individual generators who may be moved away from their original dispatch instructions through the action of frequency control ancillary services (FCAS). It could also reduce AEMO's ability to manage power system security."

[v] AEMC, *Five Minute Settlement, directions paper*, 11 April 2017, Sydney page i
"Given the change underway, it is increasingly important that the NEM market design provides the right price signals, as this will affect the incentives for the efficient use of generation assets, the efficient consumption of electricity, and efficient investment in generation and demand-side technologies."

[vi] AEMO *Future Power System Security Program - Visibility of Distributed Energy Resources*, January 2017 Page 3

When referring to Distributed Energy Resources (DER):

"*Broadly, AEMO requires… Real time, or at least five-minute, DER [Distributed Energy Resources] output data, aggregated at the connection point level for operational forecasts.*

These information gaps affect all AEMO's operational processes, from real-time dispatch to longer-term planning. Broadly, the range of impacts will be:

- *To mitigate potential system security risks, AEMO would need to apply more conservative limits on the technical envelope than the limits that would be applied if there were more certainty around load behaviour. This would result in more stringent constraints in the dispatch process, creating market inefficiencies that would end up having economic consequences for both consumers and participants. It will also make it more challenging to plan short-term outages and network augmentation needs.*
- *The inability to accurately forecast the increased variability in load will create greater requirements for FCAS [Frequency Control Ancillary Services]…..*
- *…Inaccuracies in medium- and long-term planning processes will distort the signals sent to the market on future power system needs, creating the risk of either under- or over-investment in infrastructure.*"