13 February 2018

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Dear Ms Derby

## RE: Reliability Frameworks Review

ERM Power Limited (ERM Power) welcomes the opportunity to respond to the Australian Energy Market Commission's (AEMC) Reliability Frameworks Review Interim Report.

## About ERM Power

ERM Power is an Australian energy company operating electricity sales, generation and energy solutions businesses. The Company has grown to become the second largest electricity provider to commercial businesses and industrials in Australia by load[1], with operations in every state and the Australian Capital Territory. A growing range of energy solutions products and services are being delivered, including lighting and energy efficiency software and data analytics, to the Company's existing and new customer base. ERM Power also sells electricity in several markets in the United States. The Company operates 497 megawatts of low emission, gas-fired peaking power stations in Western Australia and Queensland. www.ermpower.com.au

## General comments

ERM Power appreciates the depth of analysis the AEMC has undertaken to produce the interim report. The interim report is an important complement to recent work in the National Electricity Market (NEM) such as the Finkel Review Final Report and the National Energy Guarantee (NEG). Given the state of flux that the NEM is in, the Reliability Frameworks Review serves as a useful tool to discuss the myriad options for the NEM to consider as part of its evolution.

The following submission outlines ERM Power comments on the AEMC's analysis so far.

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[1] Based on ERM Power analysis of latest published financial information.

## Forecasting

The AEMC in the Executive Summary notes the explicit decision that has been made with regards to the market framework to deliver reliability in the NEM.

> *"The design of the framework to deliver reliability in the NEM has been a deliberate one. Market-based solutions provide incentives to be innovative, benefiting consumers. This is because competitive pressures drive more cost-effective and efficient investment, operational and consumption decisions. Centrally-planned or mandated solutions can provide higher levels of certainty of having a reliable supply of energy but, compared to a well-functioning market, are unlikely to deliver an efficient level of reliability at efficient cost. Unlike market participants, central planners do not have the same financial incentives to make efficient decisions and do not have to bear the risk of poor decisions, and so their incentives are often to over-invest".*[2]

However, in assessing the ability of the NEM to deliver reliable supply of electricity to consumers in the short, medium and longer term it is currently a central planner's view of the current and future NEM that provides the paramount view in this regard. Therefore, it is critical that the central planner's view be as accurate as possible, as an inaccurate view has the real potential to result in increased cost to consumers.

As stated in a number of AEMC reports, the NEM is changing with the retirement of generally reliable and dispatchable coal fired and potentially gas fired generation. Even though demand growth has been relatively stagnant in the period post 2008, the result of this generation retirement is that the supply vs demand balance in the NEM is tightening, particularly dispatchable supply. For this reason the accuracy of the Australian Energy Market Operator's (AEMO) short, medium and long term forecasts of maximum demand consumption are of far more critical importance than has historically been the case.

Long-, medium- and short-term forecasting all play important roles in the operation of the NEM. The AEMO's long-term forecasting through the Electricity Statement of Opportunities (ESOO) provides a signal to the market of the need for investment in electricity generation in the longer term time horizon. At the other end of the time-scale, short-term, pre-dispatch signals provide signals to the market of possible supply-demand outcomes including signalling for plant to come online, for users to reduce load in response to high prices, or for AEMO to intervene in the market at additional costs to consumers. At each time scale there is a signal given to the market about how supply and demand conditions may influence the forward price curve as well as the potential for reliable supply to consumers. As such, forecasts are an important tool for all in the energy market.

Whilst the National Electricity Rules (the Rules) - Clause 3.13.3 sets out requirements with regards to the accuracy of AEMO's demand forecasts as issued in the Statement of Opportunities there are no obligations which apply to forecasts in the Short Term or Medium Term Projected Assessment of System Adequacy ST and MT PASA reports issued by AEMO. We believe that it is critical that the Rules contain specific reporting obligations on AEMO with regards to all its load forecasts in the short-, medium- and long-term timeframes. These reporting obligations should include reference to historical and actual temperature outcomes and require that forecasts and real time data be provided to

[2] AEMC - Page i Executive Summary Interim Report – Reliability Frameworks Review

participants in a matching format to allow independent verification of outcomes. Unfortunately, this is currently not the case.

In the lead up to the summer of 2017-18, AEMO published MT PASA forecasts which indicated the potential for supply to fall short of demand if high temperature weather conditions were to occur. Whilst the NEM has seen temperature outcomes outside the Christmas into the New Year holiday period in the 90th and 95th percentile of historical temperature outcomes, across most regions, maximum demand outcomes have in general struggled to exceed the 50% Probability of Exceedance forecasts as contained in the MT PASA. These MT PASA forecasts were used to justify the contracting of Reliability and Emergency Reserve Trader reserve for the 2017-18 summer, the costs of which will be borne by consumers. Provided in Appendix 1 is data prepared by ERM Power comparing the November 2017 to January 2018 MT PASA forecasts against actual outcomes alongside Bureau of Meteorology monthly historical and actual temperature outcomes for the same period.

ERM Power acknowledges that AEMO's knowledge of the market cannot be expected to be perfect. As the AEMC notes in the interim report, AEMO has limited visibility of how demand will respond to prices and how non-scheduled generators will perform in terms of generation. This introduces some inherent error into the forecasts, which will lead to inefficient prices and inefficiencies in how the market responds or AEMO intervenes in the market. Unfortunately, the AEMC rejected a rule change designed to better inform the market about the actions of price responsive non-scheduled generation and load. ENGIE and Snowy Hydro's *Non-scheduled generation and load in central dispatch* rule change proposed that non-scheduled generation and price-responsive load over 5 MW be required to bid into central dispatch. This rule change would have acted to improve AEMO's understanding in these areas of demand response. ERM Power generally supported this rule change.

The AEMC's rationale for not making the rule change pointed to clauses within the existing National Energy Rules that allow AEMO 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. In ERM Power's view, this is an almost impossibly high threshold for AEMO to apply.

Consequently, ERM Power believes that the AEMC missed an opportunity to improve AEMO's pre-dispatch forecasting ability in rejecting the *Non-scheduled generation and load in central dispatch* rule change. As such, the AEMC should find ways to provide AEMO with the tools it requires in order to improve AEMO's visibility of the response of such non-scheduled generators or price responsive load. This will enable AEMO to develop better short-term forecasts which include the impact of price-responsive load and non-scheduled generation.

Going forward, consumer and investor confidence can be supported through a rule setting environment that provides more accurate forecasts and transparent reporting of forecast vs actual outcomes in all forecasting timeframes.

## Contracting

The AEMC's analysis appears to suggest that there are few concerns in the contracting market with regards to liquidity given that ASX data shows that a greater volume of trading occurs than consumption. The AEMC acknowledges that this analysis is somewhat incomplete given that the volume of over-the-counter contracts is unknown. ERM Power understands how the AEMC may have reached this conclusion, but we strongly caution against reaching any firm conclusions whether contract market liquidity is sufficient.

A liquid contract market helps to underpin a competitive retail market for both residential and commercial and industrial (C&I) consumers. Some large users are also active in contract markets separate from retailers.

ERM Power has concerns about the future of contract market liquidity given the trends in ownership and generation technologies. Policies such as the National Electricity Guarantee (NEG) and five minute settlement have the potential to have a disruptive impact on how the contract market operates. As such, it is difficult to presume, as the AEMC does, that the current state of the contract market is a sound proxy for the future of the market.

We have concerns over the depth (that there is a sufficient volume of contracts available) and breadth (that there is a number of different providers of contracts) of contract market liquidity over the coming years. There is also a question about whether the prices of contracts are at a level that supports retail competition, particularly among smaller retailers which do not have a generation portfolio. Regardless of the volumes available, if contracts are not available at prices that allow smaller retailers to compete against the larger vertically-integrated 'gentailers' then, retail competition will suffer, which will likely lead to poorer outcomes for consumers.

## Demand response

ERM Power agrees with the AEMC's conclusion that there are no regulatory barriers to wholesale demand response in the NEM. We have a large portfolio of demand response in the NEM and as such we have a strong understanding of the challenges and opportunities in contracting for demand response. Demand response is a complex investment for both the party (or parties) providing the response and the party requesting the service. There may well be more demand response available in the market, but unlocking it requires finding value for the user providing the response as well as the retailer or other third-party who is dispatching, requesting or controlling the action.

One of the key challenges is the difficulty in securing firm volumes and firm timing of any response. Businesses may need to fulfil orders or be unable to respond to multiple events within the same day to prevent excessive wear and tear on machinery or a significant loss of productive output. There are many and varied considerations that go into providing demand response.

ERM Power also considers that there is a risk in the current approach of using methods such as the Reliability and Emergency Reserve Trader (RERT) and the joint ARENA-AEMO demand response trial to attempt to bring more demand response into the market. Chiefly, our concern is around paying well above-market rates to demand response providers. There is a risk that this sets a new expectation for what demand response is worth and therefore the potential for existing providers offering their service to the RERT or the ARENA-AEMO trial rather than using existing service providers. This would lead to no more wholesale demand response in the market, just a transfer between participants at a higher cost to consumers. Overall, this would be a poor outcome for the market.

It is also important to remember that demand response currently does not necessarily participate in the price setting calculation. As such, it will not result in lower price events in the instances where it is enacted once the high price has already eventuated. Were AEMO given better indications of the expected response of demand to high price events, many high price events may be lower than they currently are. Spot market prices would be more efficient if price responsive load were required to signal these intentions to AEMO as part of the bidding process in a similar way to generation, and at the same thresholds (e.g. 30MW based on the current rules).

Yet, as discussed previously, the AEMC rejected this very option in the *Non-scheduled generation and load in central dispatch* rule change. In our view, making this rule change would have improved market efficiency with few risks and at a low cost. We do not believe that all loads need to provide bids for consumption on a dispatch interval basis. Nor do we believe that a compliance regime as strict as those for generator bidding would be necessary. Simply put, we consider that the AEMC could have made a rule that required price responsive load to signal how it intends to respond at different price bands. This would allow AEMO to factor in expected demand response into the NEMDE.

## Strategic Reserves

The AEMC argues that the reliability standard should be the driver of responses such as strategic reserves, which are designed to counter potential shortfalls in energy. ERM Power understands the rationale for the existence of an emergency reliability safety net such as the RERT, however, we continue to believe the RERT creates the potential for a distortionary impact in the normal operation of the market as set out in the Demand Response section of this submission. Discussions of whether other options are needed require a greater level of analysis, and at this stage we remain unconvinced that additional measures are required. The AEMC's interim report contains a solid discussion of the issues at play.

In assessing the ongoing suitability of the RERT, we believe it is important that the AEMC notes that the existing RERT provisions as set out in the Rules do not prevent AEMO from calling for tenders or forming a RERT panel of entities that may be called upon to make reserve offers, and enter into, a contract for reserves at any time in the lead up to a forecast low reserve period. The existing RERT provisions allow for better assessment of potential and actual market responses and in our view, correctly impose on AEMO a discipline that additional costs are only imposed on consumers when greater certainty exists that these additional costs are warranted. In this regard we support the existing timeframes for RERT contracting – 10 weeks prior to the low reserve condition for medium-notice and 7 weeks for short-notice – as currently contained in the Rules.

ERM Power also contends that a greater level of transparency is needed on the operations of the existing RERT. In particular, reports should be issued to the market following the activation of the RERT in a timely manner to outline the reasons behind activating the service and the impact this had on the market. Similarly, the costs (or estimated costs) of activation should also be revealed sooner, preferably in AEMO's RERT exercise report, than current arrangements are (following the end of the relevant financial year). This would help to provide market participants with a better indicator of the impact of RERT activation costs on their market fees.

We believe the AEMC should also be mindful that contracting and exercise of the RERT by AEMO to maintain high reserve levels could be counterproductive for the negotiation and dispatch of economically efficient DRM going forward. This may also have a negative impact on investment decisions for the introduction of new dispatchable generation and storage.

## Day ahead markets

Whilst earlier in this submission we expressed some concerns regarding the existing contracts market, a mandatory day ahead market would represent a fundamental change to the operations of the NEM. Consideration of such a change should only be made following exhaustive consultation with the industry to determine if there would indeed be long-lasting benefits to consumers. At this stage, ERM Power is unconvinced that there is a case for a mandatory day-ahead market. As noted by the AEMC, many electricity markets currently operating a day-ahead market have vastly different structures to the NEM. It is likely that a series of changes to the NEM would be needed in order for a day ahead market to be workable and effective. Additionally, it is far from clear than any of the potential market changes that may be required to justify a mandatory day-ahead market would meet the National Electricity Objective.

The AEMC also found that a voluntary day-ahead market could be established right now, but that for various possible reasons, one has not formed. While not opposed to a voluntary day-ahead market, ERM Power is not of belief that such a market would currently be widely supported within the NEM.

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

Yours sincerely,

[signed]

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# APPENDIX 1: AEMO MT PASA FORECASTS VS ACTUAL OUTCOMES, NOVEMBER 2017 TO JANUARY 2018

## November 2017

| November Monthly Temperature Outcomes | | | | | | | November Monthly Peak Demand Outcomes | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | Historical Outcomes | | | | 2017 | Days > | AEMO Forecasts | | | Actual | Historical | Maximum |
| | 90th Percentile | 95th Percentile | Maximum | Year | Maximum | 90th | | 50% POE | 10% POE | Peak | Maximum | Ocurred |
| Brisbane | 31.1 | 35.0 | 38.9 | 2014 | 29.7 | NIL | Qld | 8,723 | 9,279 | 7,686 | 8,593 | 2009 |
| Bankstown | 32.1 | 37.5 | 43.1 | 1982 | 32.0 | NIL | NSW | 13,147 | 13,992 | 10,058 | 13,267 | 2009 |
| Canberra | 29.4 | 34.5 | 38.9 | 2009 | 31.0 | 3 | | | | | | |
| Melbourne | 29.6 | 34.6 | 39.6 | 1982 | 35.9 | 12 | Vic | 8,796 | 9,666 | 8,661 | 9,326 | 2012 |
| Adelaide | 34.1 | 38.6 | 43.0 | 2009 | 39.1 | 12 | SA | 2,486 | 2,742 | 2,460 | 2,997 | 2009 |
| Hobart | 24.3 | 34.5 | 38.9 | 1937 | 31.5 | 9 | Tas | 1,339 | 1,430 | 1,368 | 1,485 | 2008 |
| Note | Vic demand includes addition of RERT dispatch on 30/11/17 | | | | | | | | | | | |

## December 2017

| December Monthly Temperature Outcomes | | | | | | | December Monthly Peak Demand Outcomes | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | Historical Outcomes | | | | 2017 | Days > | AEMO Forecasts | | | Actual | Historical | Maximum |
| | 90th Percentile | 95th Percentile | Maximum | Year | Maximum | 90th | | 50% POE | 10% POE | Peak | Maximum | Ocurred |
| Brisbane | 32.7 | 36.2 | 40.0 | 2001 | 33.1 | 1 | Qld | 8,651 | 9,585 | 8,520 | 8,804 | 2009 |
| Bankstown | 34.0 | 38.8 | 43.6 | 1994 | 41.7 | 4 | NSW | 12,870 | 13,699 | 12,986 | 13,435 | 2009 |
| Canberra | 32.3 | 35.8 | 39.2 | 1994 | 34.3 | 5 | | | | | | |
| Melbourne | 32.7 | 37.2 | 43.8 | 2005 | 38.3 | 3 | Vic | 8,604 | 9,457 | 8,411 | 9,008 | 2013 |
| Adelaide | 35.8 | 39.6 | 43.4 | 2013 | 38.8 | 2 | SA | 2,702 | 2,978 | 2,309 | 2,870 | 2015 |
| Hobart | 26.0 | 32.5 | 39.2 | 1998 | 31.1 | 3 | Tas | 1,244 | 1,277 | 1,221 | 1,459 | 2008 |
| Note | Max temperature and demand recorded up until 22nd for comparion outside the holiday period | | | | | | | | | | | |

## January 2018

| January Monthly Temperature Outcomes | | | | | | | January Monthly Peak Demand Outcomes | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | Historical Outcomes | | | | 2018 | Days > | AEMO Forecasts | | | Actual | Historical | Maximum |
| | 90th Percentile | 95th Percentile | Maximum | Year | Maximum | 90th | | 50% POE | 10% POE | Peak | Maximum | Ocurred |
| Brisbane | 33.1 | 36.6 | 40.0 | 2000 | 34.7 | 1 | Qld | 9,204 | 9,790 | 9,020 | 9,357 | 2017 |
| Bankstown | 34.4 | 40.2 | 46.1 | 2013 | 38.5 | 4 | NSW | 13,546 | 14,423 | 12,495 | 13,948 | 2017 |
| Canberra | 34.6 | 37.3 | 41.1 | 1970 | 39.2 | 5 | | | | | | |
| Melbourne | 35.6 | 40.1 | 44.6 | 2003 | 42.4 | 3 | Vic | 9,407 | 10,303 | 9,138 | 10,496 | 2009 |
| Adelaide | 38.0 | 41.9 | 45.7 | 2009 | 44.1 | 7 | SA | 2,852 | 3,106 | 2,880 | 3,385 | 2011 |
| Hobart | 28.7 | 34.5 | 40.3 | 2013 | 36.7 | 3 | Tas | 1,176 | 1,275 | 1,264 | 1,347 | 2009 |
| Notes | Max temperature and demand recorded from 15th for comparion outside the holiday period | | | | | | | | | | | |
| | Vic demand includes addition of RERT dispatch on 19/1/18 | | | | | | | | | | | |
| | Brisbane recorded a maximum temperature of 37.5 on 14/1/18 | | | | | | | | | | | |
| | Bankstown recorded a maximum temperature of 45.2 on 7/1/18 | | | | | | | | | | | |
| | Canberra recorded a maximum temperature of 40.6 on 7/1/18 | | | | | | | | | | | |

Demand forecasts in the MT PASA are currently provided on a scheduled/semi-scheduled, this is the only area of forecast provided by AEMO that allows comparison with actual real time data.

90th Percentile – only 10 days in one hundred would be expected to exceed this temperature
95th Percentile – only 5 days in one hundred would be expected to exceed this temperature
90% POE – In 9 years out of 10, peak demand would be expected to exceed this demand value
50% POE – In 5 years out of 10, peak demand would be expected to exceed this demand value
10% POE - In one year out of 10, peak demand would be expected to exceed this demand value