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Australian Energy Market Operator
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Submitted via forecasting.planning@aemo.com.au

RE: Australian Energy Market Operator (AEMO) – Consultation Paper on Key Forecasting Inputs in 2020

ERM Power Limited (ERM Power) welcomes the opportunity to respond to AEMO's consultation on AEMO's key inputs and assumptions for use in its 2020 Forecasting publications for the National Electricity Market (NEM).

About ERM Power

ERM Power (ERM) is a subsidiary of Shell Energy Australia Pty Ltd (Shell Energy). ERM is one of Australia's leading commercial and industrial electricity retailers, providing large businesses with end to end energy management, from electricity retailing to integrated solutions that improve energy productivity. Market-leading customer satisfaction has fuelled ERM Power's growth, and today the Company is the second largest electricity provider to commercial businesses and industrials in Australia by load[1]. ERM also operates 662 megawatts of low emission, gas-fired peaking power stations in Western Australia and Queensland, supporting the industry's transition to renewables.

www.ermpower.com.au
https://www.shell.com.au/business-customers/shell-energy-australia.html

General

The NEM is undergoing rapid changes to patterns of supply, projected demand and consumption. The current rate of change is placing pressure on the electricity system to quickly adapt to new generation technologies and adjusted demand profiles. The need for transition planning is clear. The scenarios, inputs, assumptions and methodologies used by AEMO to forecast and plan for the NEM are critical for determining the planning pathways for market and network development.

The design of the electricity system is intended to deliver electricity to consumers at the least cost, as established in the National Electricity Objective (NEO). The forecasting modelling undertaken to direct the future design of the NEM must account for changing market dynamics, while ensuring the scenarios modelled are the optimal pathways for minimising consumer costs. In the context of the market transition, the selection of forecasting inputs, assumptions and methodologies has arguably never been more important. The modelling outcomes have significant impacts on future investment in the NEM and as such, the forecasting process must be transparent, comprehensive and rigorous.

It is clear that the NEM requires targeted and appropriate investment to deliver for the future needs of the system and consumers. The intention to implement the ISP as the primary means of planning the future energy system highlights the importance of ensuring the inputs and assumptions used in the ISP process deliver outcomes in the best interest of consumers. As AEMO has identified, planning and forecasting publications are an input currently

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

being used as a basis for investment decision-making. However, historical AEMO planning documents have demonstrated a conservative bias, where forecasted futures often significantly deviate from the real outcomes. As such, ERM Power believe that while it is important to ensure that forecasting outputs provide a reasonable signal for planned investments, published forecasts should not solely be used as a basis for accelerated investment decisions or market intervention.

ERM Power believes the primary function of the ISP and ESOO should be to transparently communicate a range of plausible scenarios which can be achieved within the timeframe allocated. In selecting plausible scenarios, and accompanying sensitivities, AEMO should direct greater emphasis towards providing comprehensive description and discussion on the scenarios provided to allow more informed review and commentary by external parties. The role of pricing outcomes and signals for transmission investment should be addressed in the modelling.

In relation to the 2020 key forecasting inputs, we believe that:

- An integrated consultation approach within the forecasting development process is essential to safeguarding against overly conservative demand forecasting approaches
- Amendments to the residential and business consumption forecasts can be made through improved approaches to economic forecasts and sensitivity analysis
- The direction of Australia's emissions reduction policies impact the accuracy of modelled outcomes
- Additional technological considerations will improve the projected demand profiles of increased DER in the NEM
- Current demand forecasts are limited through recency bias
- Clarity is required regarding AEMO's approach to half-hourly demand trace scaling
- Evidence-based generation supply modelling inputs should be encouraged
- The level of DSP in the modelling should be reconsidered within the context of on-going regulatory reform

We provide further detail below.

Consultation process

Investments are exposed to increased risk and consumers are exposed to increased price outcomes if the forecasting inputs, methodology and assumptions are overly conservative, particularly in the context of the ESOO reliability forecast and ISP transmission augmentation. From a comparison of actual to forecast outcomes for energy consumption, some regions continue to show a skewed bias towards increased forecast consumption, where actual energy outcomes decline, see Table below. The Victorian region has experienced annual declines in energy consumption from July 2008, with consumption approximately 11,000 GWh lower in 2018/19 than in 2007/08.

	July to January			Change	Actual	AEMO	AEMO
	2018/19	2019/20	Change	Average	Change	2019 ESOO	Forecasting
	GWh	GWh	GWh	1/2 hr MW Load	%	Forecast	Error
Qld	32,619	32,412	-208	-47	-0.6%	0.2%	-0.8%
NSW	41,973	40,958	-1,015	-230	-2.4%	-2.0%	-0.4%
Vic	26,204	26,044	-160	-36	-0.6%	2.0%	-2.6%
SA	7,287	7,145	-142	-32	-1.9%	1.7%	-3.6%
Tas	6,433	6,230	-203	-46	-3.2%	-2.0%	-1.2%
NEM	114,515	112,788	-1,727	-391	-1.5%	-0.1%	-1.4%

The data demonstrates that forecast demand does not consistently represent actual consumption. Hastened action to construct long-lived network assets based on conservative estimates of forecast demand may result in unnecessarily high and long-lived costs to consumers. As such, ERM Power believe that AEMO's conservative approach to forecasting demand should be reconsidered.

Effective and involved stakeholder engagement can safeguard forecasts which are not overly conservative. To achieve this, stakeholders should be engaged as much as practicable. For instance, the modelling and analysis required to produce the ISP is a detailed and multi-staged process. ERM Power believe that AEMO should detail all outcomes and supporting data from the initial draft modelling process that was used to prepare the initial draft ISP publication, and provide sufficient time for external review of the published information prior to the commencement of works for finalisation of the ISP. Providing stakeholders with the opportunity for input and feedback into the development processes of forecasting documents will likely improve forecasting accuracy and reduce some of the risk that conservative forecasts are seeking to mitigate.

We support AEMO's approach to engaging independent consultants for aspects of review and analysis, particularly in areas such as projecting energy efficiency opportunities, DER uptake trajectories and emerging policies. Independent analysis encourages the transparency and rigor required for comprehensive analysis.

Residential and business energy consumption forecasts

There are a number of forecasting inputs and assumptions which determine forecast modelling accuracy. We believe there are some improvements which can be made to the assumptions of inputs related to consumption, the price elasticity of demand, energy efficiency and economic forecasts.

The identification of demand drivers is strongly dependent on the classification of consumption classes. We support AEMO's approach to separate residential and business distribution connection consumption from the aggregate electricity meter data, as distinguishing different demand drivers is essential for forecasting accuracy. Similarly, ERM Power supports the segmentation of non-residential consumers of electricity in the NEM into large industrial load (LIL) and small to medium enterprise (SME) categories. As a retailer servicing commercial and industrial (C&I) and SME customers exclusively, we understand that these customers have drastically different drivers of demand. Considering the complexity of identifying consumption patterns for LILs, we agree with AEMO's approach that surveys of LILs are an effective way of determining LILs consumption in addition to establishing consumption thresholds. However, we believe that this would benefit from an audit process which compares actual consumption to forecast consumption to determine if any forecasting skew exists.

Forecasting demand is dependent on its assumed price elasticity. With regards to the assumed price elasticity of demand in the Forecasting 2020 Inputs paper, we are concerned with the lack of sensitivity analysis around this assumption. This is particularly evidence in relation to the step change scenario that would apply for a change in electricity pricing tariffs to a Time of Use tariff structure. We believe it is also unclear whether it is valid to assume that the price elasticity of demand would be higher under the slow change scenario and lower under the step change scenario, where the sensitivity of demand is based on a price outcome rather than a scenario selection. ERM Power believe that price elasticity of demand should remain constant, irrespective of scenario modelled.

Under scenario modelling, we believe sensitivity analyses should be applied. Given that the aluminium industry has publicly stated that ongoing operation of the smelters is not viable due to forecast firmed wholesale energy costs, which we believe would align with the step change scenario, ERM Power believes that a demand destruction sensitivity should be modelled as part of the step change scenario.

The interaction between policy drivers and energy efficiency measures across the market means that energy efficiency is a complex variable to forecast. Projecting energy efficiency measures based on assumptions about policy and behavioural responses can involve some subjectivity. In the Forecasting 2020 Inputs paper, AEMO has assumed that adjusted energy efficiency forecasts should be amended to reflect the potential increase in consumption that may result from lower electricity bills. It is unclear from the Paper if the statement "lower electricity bills" refers to lower wholesale costs only or total delivered energy costs, also considering the somewhat subjective nature of this assumption, ERM Power would like to have this assumption supported by more detailed empirical evidence. Similarly, the basis for AEMO's perceived risk of overestimated savings from potential double-counting and non-realisation of expected savings from policy measures is also unclear.

Assumptions on economic futures and consumption behaviours are required to be made and are complex to undertake. As such, ERM Power would appreciate additional detail regarding AEMO's assumptions on economic forecasts applicable to SMEs.

We are also seeking advice from AEMO on whether there are large segments with growth potential for energy usage, but not directly affected by economic forces, that are being considered to adjust the economic forecasts, other than desal facilities. ERM Power are interested to understand AEMO's projections for other economic segments, considering the current climate of increased regulation and market intervention.

Climate change impacts on annual consumption

Climate change scenarios and emissions reduction trajectories will drive technology and market investments in the near to medium-term future. In relation to projecting climate change impacts, ERM Power supports AEMO's decision not to base emission reduction scenarios on assumed trajectories of coal-fired generation retirements. We agree that emissions scenarios are a preferred approach to modelling the impacts of climate change on the market. However, it is not clear how AEMO's Representative Concentration Pathways incorporates Australia's commitment to meet the Paris Agreement target of 26% reductions, or how this policy commitment may impact the modelled outcomes.

We are concerned that the climate scenarios modelled do not include sensitivity analysis. We believe that there is inherent bias implied by selecting a fixed 0.5 degree Celsius temperature increase by 2040, in absence of a sensitivity analysis. We believe that sensitivity analysis should be undertaken to provide a lower and upper bound around the 0.5 degree Celsius temperature input.

Distributed Energy Resources (DER)

The uptake of DER has significant potential to alter the typical consumer demand profile across the NEM. We agree with AEMO's assertion that in particular, BTM residential and commercial battery systems have the potential to significantly change the future demand profile in the NEM, and consequently maximum and minimum demand. We believe there are some additional factors to consider in relation to DER as discussed in the Forecasting 2020 Inputs paper.

ERM Power agrees that aggregated batteries operating as part of a VPP have greater potential for full utilisation of their peak capacity at peak demand times. We believe AEMO is correct to consider that given the controllability of this aggregated battery class, VPPs should be modelled as a source of supply within the market simulation software.

However, ERM Power disagrees with AEMO view of charging and discharging profile for unaggregated batteries as shown in Figure 2. AEMO's data indicates that batteries will charge overnight and discharge during the morning period, simultaneous with solar PV output. However, we believe that the charging profiles of batteries will not follow this profile.

Batteries are equipped with sophisticated monitoring and control systems, configurable to maximise storage from daytime solar PV production and to discharge at times of low solar PV output. These control system act to maximise the storage from solar PV output, monitor household consumption and supplement reduced PV output during the afternoon and evening period. We believe that although batteries may not act to provide full discharge capability during the afternoon and evening peak demand periods, compared to externally controlled aggregated batteries, they will act to minimise grid consumption.

ERM Power suggests that the forecast uptake of DER would be improved through the consideration of the following technical factors: The ability of the current distribution network to facilitate increasing roll out of DER; estimates of additional costs to facilitate the increased roll out of DER; the impact of potential changes to network tariff structures on the future roll out of DER; ongoing maintenance and disposal costs; potential saturation levels for DER; potential impacts of DER on power system resilience of increased DER. We also suggest that AEMO provide information on the consideration that has been given to regulatory reform currently in the pipeline in relation to DER.

Maximum and minimum demand forecasts

ERM Power believes for some regions AEMO's maximum demand forecasts continue to contain a conservative bias. Based on recent extreme weather events, AEMO have currently overestimated demand in the ESOO. ERM Power believes that AEMO and stakeholders should engage to analyse and consider how the observed outcomes from the extreme weather events will be included in the 2020 Forecasting Input assumption.

We believe recency bias can be observed in the current ESOO. For instance, high demand outcomes have recently been observed. It is our view that when these high demand outcomes are observed within the modelled forecasting range, but above the 10% POE level, it is automatically assessed by AEMO as the new 10% POE threshold for model tuning. We believe this is not a valid approach, as a more extreme weather outcome on another day of the same day type within the same seasonal period may result in a lower daily maximum demand outcome.

We also recommend that further consideration be given to cooling load on maximum demand. Although the demand forecasting model adjusts for saturation of energy efficiency on cooling load during extreme temperature outcomes, it is unclear if the model allows for maximum energy consumption from air-conditioning units as an input. This should be considered, as air-conditioning units will operate to a maximum capability at a design temperature point. At this operational maximum, no further increase in energy consumption occurs and an increase in ambient temperature will not increase grid demand. In our view, it is not clear that this design temperature point has been assessed and incorporated in the modelling.

We recommend that these observations and approaches be considered in the process to define forecasting inputs for 2020.

Half-hourly demand trace scaling

ERM Power believes additional clarity is required regarding the selection of reference year demand traces. It would be beneficial for AEMO to provide further clarity and justification for the methodology used for the demand trace scaling, and the application of scaling of benign reference years. Details provided in Table 16 appear to not align with details previously disclosed to the Forecasting Reference Group (FRG).

In particular, we would appreciate further detail on AEMO's approach to matching traces with targets. It is unclear in the Forecasting 2020 Inputs paper on whether this refers to a target of forecast yearly energy consumption or an alternative target.

If the former, ERM Power questions the appropriateness of applying scaling to 5 day blocks, rather than a larger number of days. We recommend AEMO provide further details and seek further input regarding the methodology for scaling of half-hourly demand traces from the FRG. We submit that initial scaling to achieve the yearly energy consumption target, followed by adjustment of the top X number of demand days, as set out in Table 16, followed by a final scaling to achieve the yearly energy consumption target would achieve a robust scaling methodology that the methodology currently employed.

Generation supply modelling inputs

We support the provision of the opportunity to propose evidence-based revisions to the parameters that are used in the ESOO modelling. We support AEMO's approach to defining modelling supply inputs based on generation technology costs and generation fuel costs. This is preferred to proposing discrete inputs to force retirement of existing generation capacity at designated points in time. We however believe that the range of selected technology costs need to be specifically expanded to those included in the current GenCost model. We understand that the list of potential technology inputs to the GenCost model are truncated due to limitations of the model when calculating the levelised cost of electricity. We are concerned that this truncated input selection may lead to inaccurate "lowest cost optimisation" in the ISP modelling.

It is our view that outage parameters should not be based on only the previous four years of outage data. We would support the application of ten year rolling average outcomes on an individual period basis on the last 4 separate years. We are also concerned by AEMO's statements that if generator forced outage rates were to improve in future years then the selected years would be expanded to continue to include poorly performing years in the modeling inputs, this increases the perception of selective input assumption bias and an attempt to "cherry pick" input assumptions to achieve a desired outcome. In the event that AEMO believes recency bias is warranted, then this recency bias must be consistently applied even in periods where low forced outage rates are recorded.

We note that the model applies a significant technology learning discount to the costs of solar PV in the future. Given the relative maturity of the technology and the high penetration of extensive mass production capability we believe further details are warranted to justify such a significant technology learning discount in the future. With regards to battery storage costs, although grid scale battery storage costs may continue to fall in the future, it is unclear if the same reductions will apply to home storage batteries at the same rate and magnitude. Using installed costs for the Tesla Powerwall 2 as a guide, this has remained relatively static or has increase slightly.

"In 2017 the Tesla Powerwall 2 launched with the cheapest price point at ~$8000 for 13kWh in the residential battery market. Since then, challenges in production quantities, have led to increases in their retail price $9,600 plus installation costs. In Australia, across our network of over 150 solar installers we expect this installed cost of a Tesla Powerwall 2 to cost between $11,000 and $13,000 excluding Solar PV."[2]

Further, we make the following recommendations regarding supply input assumptions:

- Batteries of at least 4 hours storage capability are required to meet summer peak demand periods, both as standalone storage projects and as combined storage facilities with both wind and solar farm projects.
- Solar and wind farms supported by either open cycle gas turbines or alternatively reciprocating engine gensets should also be considered.
- Open cycle gas turbines should be modelled reflecting capital costs for both smaller aero-derivative and larger frame size OCGT alternatives.
- Pumped hydro storage and standalone hydro generation should be modelled on the basis of new generation installed on existing storage reservoirs and also on the basis of requiring the construction of storage reservoirs.
- With regards to both grid scale and home battery storage costs, clarity should be provided. It is unclear if the costs indicated allow for routine replacement at regular intervals of the storage component of a BESS.

Demand-side participation

The input level of DSP is a complex variable. We support the use of future DSP based on a percentage of forecast maximum demand. However, Table 18 requires clarity regarding whether the percentage is applied to the 10% or 50% POE forecast of maximum demand. We query the application of the percentage of forecast maximum demand to future years, due to the potential implementation of the Wholesale Demand Response mechanism. We believe that a sensitivity case of a high DSP participation rate should be considered.

[2] Solar Choice - https://www.solarchoice.net.au/blog/tesla-powerwall-a-complete-2019-buyers-guide/

Please contact Ron Logan (rlogan@ermpower.com.au, 0427 002 956) or Emma White (ewhite@ermpower.com.au, 03 9214 9347) if you would like to discuss this submission further.

Yours sincerely,

[signed]

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