7 February 2020

EnergyAustralia
LIGHT THE WAY

EnergyAustralia Pty Ltd
ABN 99 086 014 968

Level 33
385 Bourke Street
Melbourne Victoria 3000

Phone +61 3 8628 1000
Facsimile +61 3 8628 1050

enq@energyaustralia.com.au
energyaustralia.com.au

Nicola Falcon
GM Forecasting
Australian Energy Market Operator
GPO Box 2008
MELBOURNE VIC 3001

Submitted electronically: forecasting.planning@aemo.com.au

Dear Ms Falcon

Australian Energy Market Operator - Consultation Paper on key Forecasting inputs in 2020 – December 2019

EnergyAustralia is one of Australia's largest energy companies with around 2.6 million electricity and gas accounts across eastern Australia. We also own, operate and contract an energy generation portfolio across Australia, including coal, gas, battery storage, demand response, wind and solar assets, with control of over 4,500MW of generation capacity.

We appreciate the opportunity to provide feedback on AEMO's 2020 forecasting inputs consultation paper. We also appreciate AEMO's desire to not re-open matters affecting the 2020 Integrated System Plan (ISP), particularly following its consultation on forecasting inputs over 2019. We nevertheless encourage AEMO to consider the materiality of the issues we raise below in refining its analysis for the final 2020 ISP.

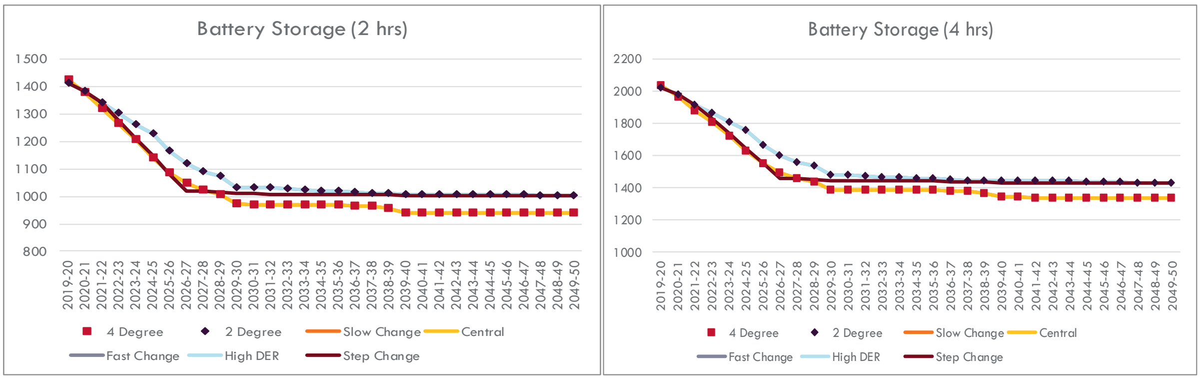
Under the proposed ISP rules framework, we question whether AEMO's 2020 Forecasting Inputs Report will constitute the 'Inputs, Assumptions and Scenarios Report' or contain 'ISP parameters' that must be adopted or varied (with explanation) by RIT-T proponents.[1] We appreciate the draft rules and transitional provisions relating to the 2020 ISP are still being finalised, and our comments below reflect the potential for AEMO's 2019 report and its December 2019 inputs and assumptions book (version 1.3) to be superseded and potentially binding on RIT-T proponents.

A further complication, and source of confusion, may arise where AEMO publishes divergent assumptions for its 2020 ISP (expected in June) and its 2020 Electricity Statement of Opportunities (ESOO) shortly afterwards. AEMO should clarify which assumptions it does not intend to update for the ISP but does for the ESOO, and we otherwise encourage these to be aligned.

[1] See draft rule 5.15A.3(7)(iv). ESB Integrated System Plan Rule Changes, consultation version 19 November 2019.

Battery usage and cost assumptions

Forecasting technology cost reduction curves is an inexact science, especially when global volumes will be a key driver of learning curve reductions. We would strongly suggest that a more divergent range of capex costs for batteries are developed for future use (including under RIT-Ts). The examples below from AEMO's assumptions workbook and CSIRO's most recent GenCost analysis illustrate this lack of diversity.



Source: AEMO 2019 Input and Assumptions workbook version 1.3.

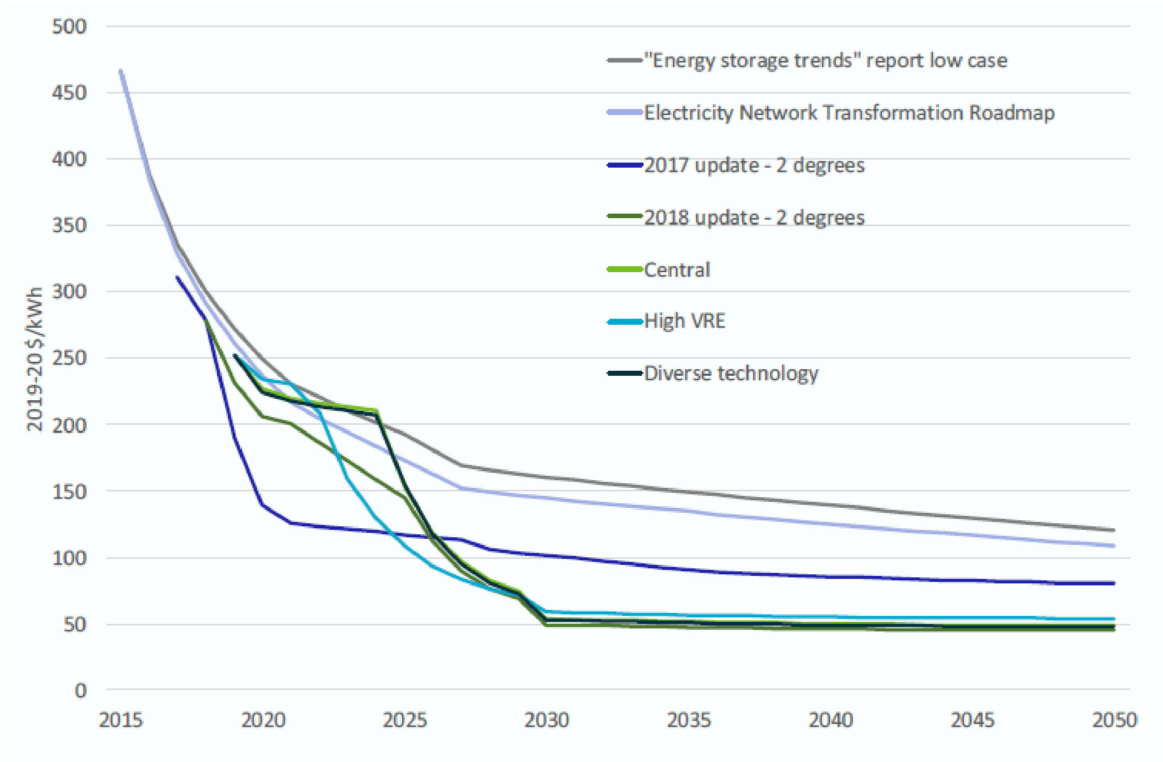


Figure 3-13 Projected capital costs for batteries by scenario compared to previous studies

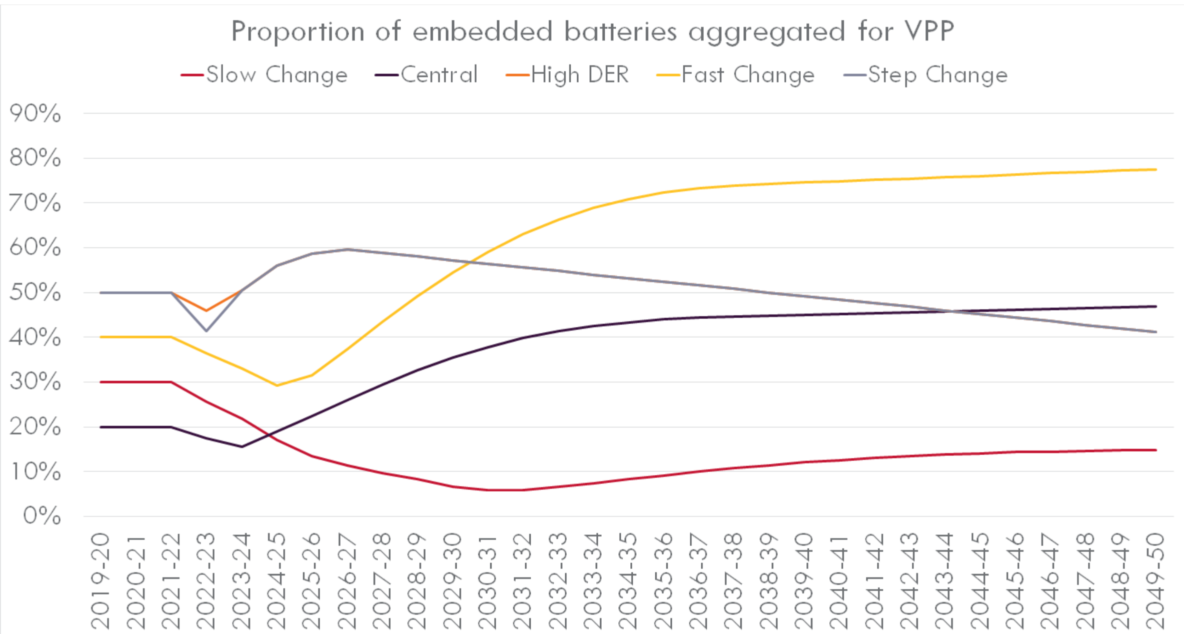
Source: CSIRO, GenCost 2019-20: preliminary results for stakeholder review, December 2019.

In addition to underlying technology cost assumptions, AEMO should also consider the implications of assumed economic and technical lives of 10 and 15 years respectively for batteries. Over this time horizon plant owners are likely to invest in replacement battery cells to extend asset life and continue realising value from the longer lived switchyard and balance of plant equipment. This may warrant ongoing refurbishment assumptions or recognition of terminal value for the balance of plant (which can be up to 50 to 60 per cent of initial capex costs). We note that utility scale batteries are gaining market traction and there is a clear disconnect between the Draft ISP projections with limited utility batteries and the actual uptake of utility batteries. We feel annualization of new entrant costs based on a relatively short economic life may also partly explain this disconnect, as well as revenue streams (arbitrage, capacity, market and ancillary services etc) missing from the ISP modelling.

On the basis of the 2018 CSIRO and GHD estimates, AEMO's Fast and Step Change scenarios have higher battery capex assumptions than other scenarios. This appears directionally inconsistent with technology-led scenarios, where technology innovation and cost reductions are typically considered key drivers of technology disruption. We would also question why costs plateau so strongly from 2030 onwards.

AEMO's sample discharge profiles for non-aggregated embedded energy storage show batteries discharge overnight to cover residential usage. Forecasting scenarios that presume a high degree of distributed energy uptake are likely to involve complex battery usage profiles, including optimisation around network tariff structures. We request AEMO to provide greater detail on these discharge profiles and the underlying assumptions they are based upon.

We would also appreciate more information on how AEMO arrived at the embedded battery VPP aggregation trajectories for each scenario (see figure below).



Source: EA analysis from AEMO Input and Assumptions workbook.

Pumped hydro cost assumptions

Entura's capital cost estimates for pumped hydro energy storage (PHES) are primarily based on high-level engineering estimates, without being tested with actual EPC pricing or the actual cost of completed Australian projects. Although we agree that PHES is a mature technology globally, Australia does not have a recent track record for these kind of developments which increases the risk of estimating capex prices.

There is therefore a high degree of inherent uncertainty regarding desk-top estimates such as Entura's. EnergyAustralia has experienced large divergence between engineering estimates and actual EPC pricing on a range of generation and non-generation projects and has recent experience with EPC contracts for PHES. EPC contracts are not risk-free, and there are many recent examples of large projects with cost and time overruns even through there were fully wrapped EPC contracts in place. We therefore recommend AEMO consider modelling a sensitivity on PHES capex of at least 40% per cent above Entura's cost estimates to account for this uncertainty.

Rooftop PV costs and deployment

We believe that AEMO/ CSIRO's cost estimates overstate the cost of rooftop PV to the consumer and therefore deployment rates may be understated. CSIRO's June 2019 Small Scale Embedded Technologies Report, which we understand also forms part of AEMO's ISP projections, is based on cost estimates in the 2018 GenCost report[2] and should ideally reflect more recent cost reductions that are now apparent in CSIRO's draft 2019 GenCost report.

CSIRO's cost estimates explicitly exclude state-based rooftop solar deployment schemes which have impacted local update considerably. However, *Table 3-3: Extended scenario definitions* of CSIRO's technologies report refers to state-based subsidies included in the LGC price for each scenario. We request AEMO to clarify whether state-based rooftop solar subsidies are included in the cost forecasts and uptake projections, as these are material to the rates of small-scale technology adoption and the ISP scenarios.

The recent increase in the installation rates of rooftop PV rates exceeds the trajectories being used in the draft ISP. We encourage AEMO to publish its forward trajectories with several years of historic actual observations for context, which will help to highlight any obvious disconnects. Our view is that the combination of higher, outdated capex costs and the exclusion of relevant subsidies are key factors contributing to unrealistically conservative forward trajectories.

Open cycle gas turbine (OCGT) assumptions

CSIRO's 2019 draft GenCost report assumes a smaller unit size of OCGT which is driving an increase in the capital cost assumption for new entrant OCGTs. Larger gas generation units have been excluded because of perceived deployment challenges and falling minimum demand. AEMO should reconsider these assumptions as existing development permits and even some newly developed plans are considering larger units given their cost advantages compared to the new entrant capital cost assumed by CSIRO. We also expect that the scale of forecast coal generator retirements will create opportunities for

[2] CSIRO, *Projections for small scale embedded energy technologies – report for AEMO*, June 2019, p. 22.

larger flexible gas generation (which can avoid time of low demands), particularly in situations where PHES is not a feasible substitute.

We therefore recommend AEMO consider both the larger and smaller unit sizes and allow its least cost modelling to determine which units or combinations thereof are optimal for capacity planning. Assumptions for the larger units can be drawn from AEMO's prior work, which is broadly consistent with the current budgetary estimates for these machines.

We also request AEMO test the sensitivity of its 25 year economic life assumption for OCGTs by increasing it to closer to its technical life of 50 years.

Firm capacity and thermal de-rates

Recent summers including the current 2019-20 summer have seen extreme maximum temperatures and significant thermal de-rates on inverter connected equipment, both utility and behind the meter. We recommend AEMO review the firmness assumptions for inverter connected equipment, as well as the performance of underlying wind resources during these previously unprecedented temperatures.

Maximum Demand Forecasts

AEMO describes the introduction of a climate adjustment informed by global climate models through a linearised indexation of reference years across the capacity outlook and time sequential models. It is not clear whether this impact of climate change has influenced the energy and demand inputs to the modelling, or whether this is only applied to hydro inflow, as per the Hydro Climate factor. We encourage AEMO to provide further insights into these assumptions, for example, whether they are included as a sensitivity or incorporated into each scenario by default, and whether they impact on PHES storages.

We also request AEMO to provide commentary on whether its maximum demand forecasting methodologies contemplate the extraordinary extreme temperatures that have become apparent in the last two summers and are expected to become more prevalent as we go forward.

Use of Reference Years and stochastic results

We welcome the use of multiple reference years to capture a wider range of outlook conditions, however it is not clear which reference years have been selected for each forecast year, nor how the application of 10% PoE and 50% PoE peak demands have been applied or weighted, or how random forced outages of generators have influenced or vary the results.

Regional demand traces

It is challenging to reconcile the OPSO and OPSO_PVLITE demand traces as the loss factors used in deriving these traces are not included in the ISP dataset. We would like AEMO to publish the relevant loss factors to enable participants to better reconcile these demand traces.

Renewable energy traces

There is considerable variation in the annual outputs of the rooftop PV regional traces for the different reference years. Whilst this reflects the underlying weather patterns of the relevant reference years, we would like AEMO to outline how the annual PV energy projections in the 2019 Input and Assumptions workbook are applied to create the PV traces for the various reference years.

Inter-regional loss factor equations

It is not apparent what inter-regional loss factor equations have been applied over the outlook, in particular for the 'with transmission investment' cases, where the build of significant new transmission lines and connections to REZs is likely to materially change the marginal loss relationships between regions. This also applies for new EnergyConnect SA-NSW interconnector, which introduces loop flows in the market design.

Costs of transmission projects

AEMO's assumptions about the annualisation of transmission costs are not fully transparent. For example, we request clarification of:

- what economic life is assumed
- whether the assumed 1% O&M costs per year as a function of capex is reasonable and how this compares to the O&M for the existing RAB
- why the mid-point of the range of capital costs is used for capacity planning and why the range is so wide for a given project
- whether the sensitivity to discount rates affects annualised costs or is simply the discount rate used to determine the PV of the future cash flows
- whether interconnector transmission projects have regional cost factors applied in the same way as other technology costs.

Demand side participation

We request AEMO to clarify if any duration or frequency limits are assumed for the voluntary demand side participation volumes included in its inputs.

Gas price forecasts

CORE's gas price assumptions are below what we would regard as realistic forecasts in the short term. For example, its 2019 prices are below the average prices actually settled in the Declared Wholesale Gas Market and its 2020 forecast is below the ACCC's assessment of contract prices provided to all buyers.[3] Its Sydney-Brisbane price differential is also too low.

We expect this is attributable in part to CORE's overemphasis on the role of legacy contracts in setting forward price expectations. CORE's methods could be improved by

[3] ACCC, *Gas inquiry 2017-2020 Interim Report*, July 2019

incorporating available market data for short term price expectations as well as marginal and opportunity costs, rather than being entirely reliant on contract price formulae.

We also expect that demand for gas (and domestic prices) would be lower under AEMO's Step Change scenario due to fuel switching, energy efficiency etc. We note that the Brent oil price is the highest in this scenario, as are gas prices, which appears counter-intuitive.

CORE's transmission tariff assumptions also ignore that the declining utilisation of gas-fired generation in AEMO's modelled scenarios will drive up the average transmission tariff in some cases, compounded in those scenarios where overall demand for gas declines. That is, the fixed costs of transmission are recovered over a smaller volume, making it more expensive in per GJ terms.

If you would like to discuss this submission, please contact me on 03 8628 1655 or Lawrence.irlam@energyaustralia.com.au.

Regards

Lawrence Irlam
Industry Regulation Lead