16 February 2024

EnergyAustralia Pty Ltd
ABN 99 086 014 968

Level 19
Two Melbourne Quarter
697 Collins Street
Docklands Victoria 3008

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

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

Ms Merryn York
Executive General Manager System Design
Australian Energy Market Operator
GPO Box 2008
MELBOURNE VIC 3001

Submitted electronically: ISP@aemo.com.au

Australian Energy Market Operator — Draft 2024 Integrated System Plan — 15 December 2023

EnergyAustralia is one of Australia's largest energy companies with around 2.4 million electricity and gas accounts across eastern Australia. We also own, operate and contract a diversified energy generation portfolio across Australia, including coal, gas, battery storage, demand response, wind and solar assets, with control of over 5,000MW of generation capacity.

We appreciate the opportunity to provide feedback on AEMO's draft 2024 Integrated System Plan (ISP). The ISP is a significant exercise. We applaud AEMO's commitment to genuine stakeholder engagement and the significant effort it has spent on consultation in preparing this draft ISP.

This edition of the ISP is being developed at a time when there is heightened focus on the community, environmental and landholder impacts of new investments required to deliver the transition. AEMO has appropriately devoted considerable effort to exploring various factors under the heading of social licence, which affect large renewable and transmission projects but also behind the meter technologies. It also examines broader supply-side constraints and the potential for delayed investment. The ISP's modelling provides a view of the least cost development pathway for the National Electricity Market (NEM), including in the presence of various delivery constraints. It is therefore a critical public policy tool as it can identify specific barriers or enablers for the transition, and the importance of each in delivering net benefits for customers.

Energy consumers are also facing significant cost of living pressures. It is expected that the transition to a renewables-dominated energy system will provide bill relief over the medium to long term. Again the ISP can be an important resource for policy-makers by showing how net market benefits arising from AEMO's optimal development path could translate into actual price outcomes for customers.

Noting the different ways AEMO's analysis can be used, we have the following suggestions as it prepares its final ISP:

- expand on the **consequences of not achieving 2030 targets** for renewables and emission reduction, which are critical policy milestones. The Draft ISP's **Constrained Supply Chains sensitivity** already relaxes these policy constraints. It should be refined and elevated in AEMO's communications as a type of 'business as usual' forecast, with the cost of not achieving policy targets, in terms of higher emissions and foregone market benefits, measured relative to both the Step Change and Progressive Change scenarios.

- AEMO should publish more granular information about and attempt to **quantify the 'risks to the delivery of the optional development path'** listed in section 8 of the main report. Many of these risks arise in the near term. Actions to address them could be prioritised according to their consequence.

- the **need for and emissions impacts of gas-powered generation** (GPG) should also be explored in a **sensitivity in which GPG is not deployed**. This would reflect the outworkings of current policy settings which do not support this technology. The **need for medium duration and deep storage should be similarly tested**. Again this would illustrate what we consider to be a critical policy gap and the need to overcome challenges for pumped hydro storage projects in particular.

- AEMO's further work that explores the extent of **orchestrated consumer energy resources (CER)** should include some **high-level costing or case study of distribution network impacts** if this is possible.

- AEMO should refine its **sensitivity for cost uncertainties for transmission** and identify break-even points where particular projects become uneconomic. It should also model a **broader 'high cost' technology sensitivity** which includes upper bound costs for generation and storage, not just transmission.

- AEMO's quantification of **distributional impacts of the ISP should provide some indication of end use prices**, for example average wholesale spot prices and network costs. Analysis of spot prices is also important in testing the commercial and policy implications for critical technologies that need to be deployed.

- The final ISP should also draw out **commercial implications for variable renewable resources and hydrogen loads**, as well as provide clarity on other key modelling assumptions.

These suggestions are briefly expanded in the attached.

If you would like to discuss this submission, please contact me on 03 9060 0612 or Lawrence.irlam@energyaustralia.com.au.

Regards

Lawrence Irlam
Regulatory Affairs Lead

Modelling the consequences of not achieving policy and climate targets

The ISP must set out the efficient development of the power system that achieves the power system needs defined under clause 5.22.3 of the National Electricity Rules (NER). Subclause 5.22.3(b) requires AEMO to consider emissions reduction targets set out in the relevant targets statement, however these targets are not power system needs. AEMO's approach for the ISP has nevertheless been to take these various targets as modelling constraints across all of its scenarios, with some variations on how they are met.

In some ways this has reduced the informative value of the ISP by constraining the design of AEMO's scenarios. For example the Slow Change Scenario has now been removed, which may have provided a useful lower bound 'bookend' of potential development pathways.

We support AEMO's efforts in addressing deliverability barriers. This 2024 ISP contains valuable information derived from AEMO's Social Licence sensitivity that can help gain public 'buy-in' for the transition, namely by valuing the additional system cost if social licence is not gained. This same approach should be adopted to illustrate the consequence of not achieving government targets for technology investment and emission reduction. AEMO has already done this to some extent in its Constrained Supply Chain sensitivity, which should be expanded for use by stakeholders engaged in policy debate.

This sensitivity suggests that adding 2 years of lead time for transmission and limiting construction of wind and solar generation to 4GW per year to 2030 would <u>increase</u> weighted net market benefits by around $2 billion relative to AEMO's core scenarios.[1] This is counterintuitive. AEMO's explanation suggests that these modelling assumptions favour development pathways that bring-forward investment in order to avoid delays and manage build constraints. Again it seems counterintuitive that a constrained supply chain situation would allow for any such accelerated investment.

AEMO should consider more refined assumptions and publish detailed analysis of this sensitivity. For example, rather than adding lead time to transmission investments and still allowing the model to optimise via earlier commissioning, it should exogenously apply delays, of (say) 2 years to commissioning dates. AEMO currently appears to accept the earliest in-service dates identified by each proponent in isolation, and without consideration of the likely infrastructure bottlenecks this creates. Most of the current actionable projects would be constructed in the late 2020s. AEMO could therefore consider some 'smoothing' constraint which pro-longs construction lead times in addition to modifying commissioning dates. Such project sequencing was suggested by AEMO in the 2022 ISP as an area for potential stakeholder collaboration,[2] however it is not apparent that this work has taken place. Such sequencing is likely to be cheaper from a total system perspective, considering how increased construction and other demand would drive up costs in the short term.

We recommend AEMO maintain a 4GW build limit beyond 2030 to reflect a 'business-as-usual' trajectory based on historical industry efforts. Otherwise a deeper analysis of workforce and logistical enablers (discussed further below) could inform more tailored build limits over the modelling horizon. However the overall point of this sensitivity should be to, by comparison with AEMO's core scenarios, quantify the benefits of higher climate ambition and hence justify policy and community support above what we see

[1] AEMO, *Draft 2024 Integrated System Plan*, December 2023, appendix 6, p. 80.
[2] AEMO, *2022 Integrated System Plan*, June 2022, p. 99.

currently. The valuation of benefits should also include emissions impacts. The distributional impacts of not meeting government policy targets should be expressed on a jurisdictional basis, as they are unlikely to be evenly spread. As discussed further below, they should also be expressed in terms of end use price impacts for consumers.

Energy ministers are still considering the value of emissions reduction under the recent NEL amendments. AEMO states it may adopt this value for the final ISP if it is published in time and by an appropriate market institution or government body. In expectation of this value not being published in time, we recommend AEMO adopt an indicative value using the NSW Treasury Cost Benefit Analysis guidelines.[3] This is being applied by government agencies now (including as a placeholder in recent modelling for the AEMC[4]) and is sufficiently reputable and independent. Using a placeholder value in sensitivity analysis now could inform the need to make an ISP update under NER clause 5.22.15(b) once an 'official' value is published. AEMO's Constrained Supply Chain sensitivity exceeds the implied 2030 carbon budget in the Step Change scenario by 155 million tonnes of CO_2 equivalent.[5] At an assumed carbon price of $100 a tonne, this suggests a potential additional cost in the order of $15 billion. If so recognised, this would likely dominate the calculation of net market benefits. As it relates to the importance of meeting government policy targets, such a high value reflects the real detriment of carbon emissions to the community, in addition to unacceptable outcomes politically, particularly given Australia's various international commitments.

More granular examination and prioritisation of supply constraints

Similar to the above point, we recommend AEMO give further thought to how the ISP is used to motivate action towards specific policy or other deliverability gaps. The draft ISP already identifies various risks to delivering the transition however it is worth trying to quantify their individual impacts. Such analysis could be used to prioritise action that steers the sector towards development pathways with higher net benefits. Priority actions could also be tracked in terms of progress, similarly to that in AEMO's Engineering Roadmap. AEMO could also consider what information can be drawn from its analysis and whether this aligns with recommendations arising from the recent Community Engagement Review[6] or infrastructure planning reports.[7]

AEMO has already usefully quantified some of the implications for the significant upscale of investment required in its scenarios, including kilometres of transmission lines and workforce needs. The analysis produced for the 2022 ISP by the Institute of Sustainable Futures provides workforce breakdowns to Renewable Energy Zone (REZ) level and by occupation type.[8] There is scope for AEMO to partner with academia and workforce agencies to produce cross-sectional projections that can then be used to identify skills gaps and associated employment opportunities. These workforce data could be combined with materials cost estimates and other input-output data to create broader estimates of increased economic activity, and hence benefits for host regions.

Similarly, AEMO's regional and sub-regional modelling could be used to conduct a bottom-up assessment of equipment and logistical requirements. Others have already calculated the number of wind turbines and solar panels that need to be installed on

[3] 20230302-technical-note-to-tpg23-08_carbon-value-to-use-for-cost-benefit-analysis.pdf (nsw.gov.au)
[4] ERC0352 - IES size of the prize benefits modelling-20241502 (aemc.gov.au)
[5] AEMO, *Draft 2024 Integrated System Plan*, December 2023, appendix 6, p. 80.
[6] Community Engagement Review - DCCEEW – see pp. 23, 40-41.
[7] State of Australia's Regions Report | Department of Infrastructure, Transport, Regional Development, Communications and the Arts
[8] See for example Focus_on_NSW_Rev1 (2).pdf (uts.edu.au)

average each month to meet 2030 renewables targets.[9] As with labour requirements, AEMO could liaise with relevant planning and commercial stakeholders to help produce granular data on the number of key pieces of equipment (transformers, wind turbine blades, towers etc) with potential transport routes and critical supporting facilities well in advance, such as that contemplated at Port of Hastings in Victoria. Providing information on transport routes may be a necessary complement to consultation on transmission route selection. Insights could also be gained on the likely timeframes to develop local industrial production capacity, including in the context of global activity.

Exploring the role of gas generation via a 'take one out' technology sensitivity

The draft 2024 ISP emphasises the reliance on gas-powered generation (GPG) to underpin reliability, similar to previous editions. We encourage AEMO to present additional analysis of the implications of how GPG is deployed in its scenarios in order to validate whether it is feasible, from a commercial and emissions perspective. If GPG does form part of a least cost technology mix while also keeping within carbon budgets, this has important policy implications.

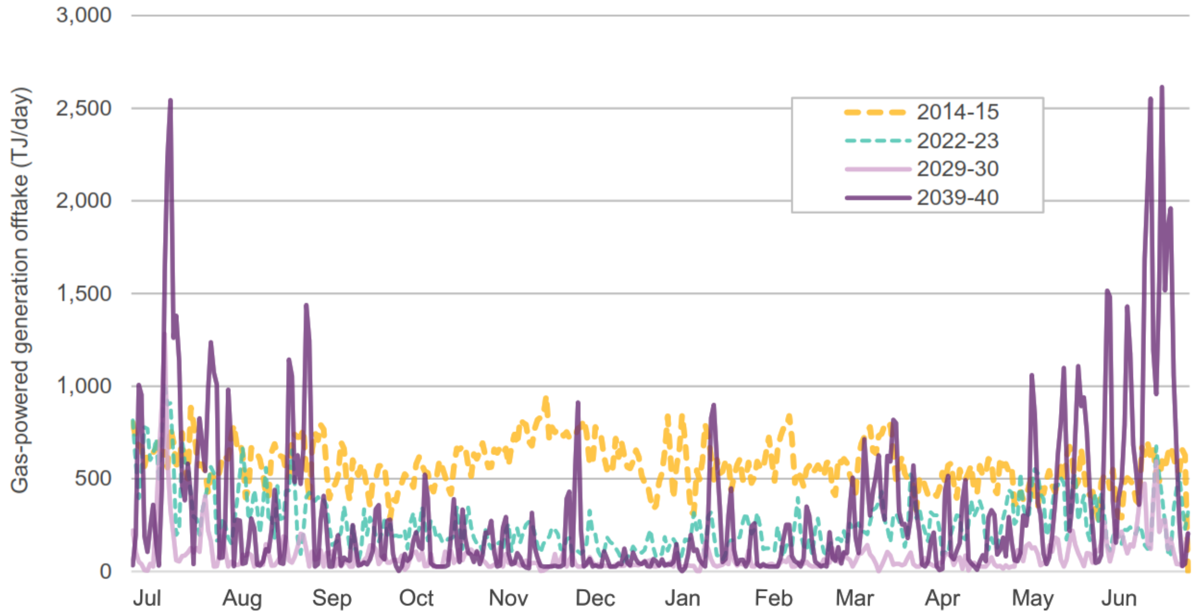
The Commonwealth's Capacity Investment Scheme will aim for up to 32GW of generation and storage capacity being commissioned by 2030. GPG is not eligible for support under this Scheme, even though (in part) it is intended to maintain reliability by incentivising flexible technologies. This appears to be because of an in-principle position against supporting any fossil fuel generation. Instead, governments appear to be contemplating subsidies[10] to extend the life of coal-fired generators to address reliability concerns in the short to medium term.

To further inform these policy settings, we recommend AEMO run a sensitivity that excludes new investment in GPG. The resulting reduction in emissions relative to AEMO's core scenarios should be measured and explicitly valued as a benefit. Our expectation is that excluding GPG would, however, result in a higher reliance on medium duration and deep storage to underpin reliability. This would be at potentially higher cost, and also raise relevant questions about policy settings and government direct investment in storage as discussed below.

AEMO should also publish plant-level analysis for an example GPG project. Our expectation is that AEMO's modelling requires GPG to be built to satisfy reliability constraints rather than for economic reasons. AEMO's projections see GPG running with very low capacity factors, with the need to recover fixed costs during fewer but increasingly significant high-priced events. AEMO's analysis (see example figure 22 below) suggests that total energy sold by GPG would progressively decline into the 2030s, but then materially increase with more running hours during winter periods thereafter. A time series of dispatch weighted price curves for peaking GPG would be useful, including how this compares to plant that currently operate in the NEM. Engie's recent announcement suggests these types of assets are already unprofitable under current market and policy settings.[11]

[9] The staggering numbers behind Australia's 82 per cent renewables target | RenewEconomy
[10] Orderly Exit Management Framework Consultation Paper – December 2023 | energy.gov.au
[11] Engie to shutter two South Australian generators as losses mount (afr.com)

Figure 22 **Gas-powered generation offtake, NEM** (TJ/day 2014-15 and 2039-40, *Step Change*)



We strongly support AEMO's integration of data from its Gas Statement of Opportunities to assess the effect of daily delivery constraints. This indicates that under extreme conditions, up to 2,200MW or 15% of installed GPG may be curtailed.[12] This finding suggests that AEMO's optimal development path is not feasible. AEMO should clarify whether its analysis of curtailment feeds back into its scenario projections, given the general statement that it expects reliability would be maintained via a combination of alternative back-up fuels and demand response.[13]

Aside from system level effects, further data showing operational and price outcomes for an example GPG would be useful to inform the following:

- The presence of market dynamics that could see GPG generating for more hours than suggested in AEMO's modelling, for example the extent to which prices are above fuel costs. This would inform the risk of carbon budgets being breached if GPG does gain policy support and becomes investable.
- The significant decline in utilisation of gas infrastructure implied from the above daily usage, as well as from electrification of customer load, would see significant changes in how transport costs are recovered from users, to an extent that may require AEMO to change its approach to modelling fuel costs.
- High intermittency of demand would also have impacts on pricing outcomes in gas markets and under supply contracts, with higher risk premia and shape costs needing to be passed on in GPG bidding in the NEM.

[12] AEMO, *Draft 2024 Integrated System Plan*, December 2023, appendix 4, p. 41.
[13] Ibid.

Valuing medium and deep storage via a 'take one out' technology sensitivity

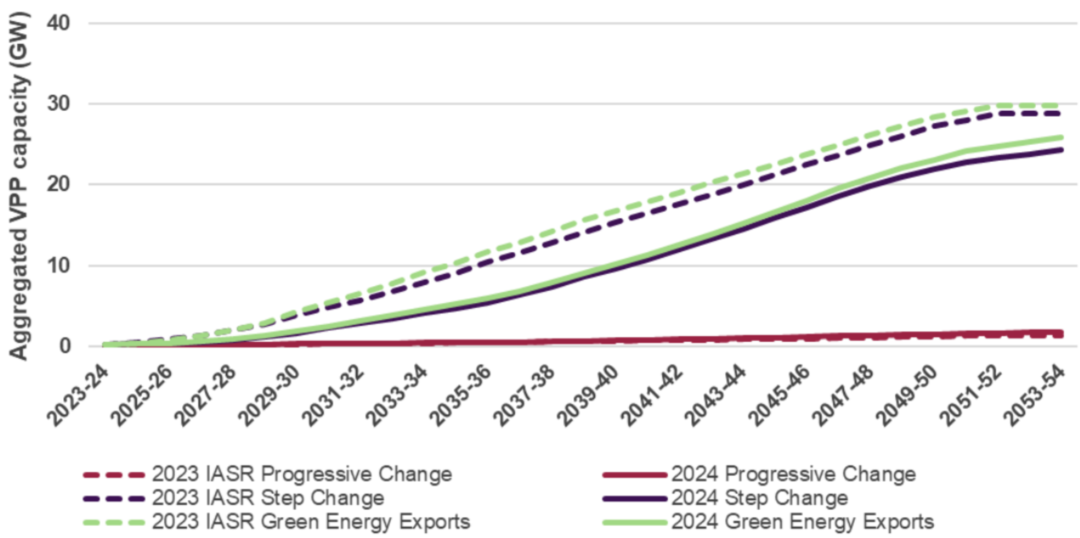
There seems to be several barriers from a technology and policy perspective to delivering necessary investment in pumped hydro energy storage (PHES) and other long duration technologies. PHES is being driven by few but very large government-sponsored projects. The experience of Snowy 2.0 and the recent GenCost update illustrate that the costs for PHES are highly uncertain and project-specific, which poses challenges in establishing appropriate policy settings. Governments are internalising risk and cost variations associated with their own projects, with questions on how privately-funded projects would enter the market, as suggested in the ISP, and solve system needs for medium duration and deep storage. That is, aside from Snowy 2.0 and Borumba, the Step Change scenario suggests the addition of 4 to 5GW of medium and deep storage by the late 2030s. Governments seeking to act quickly to satisfy current policy targets for dispatchable capacity seem to favour batteries given their shorter lead times. AEMO's analysis of perfect foresight assumptions suggests that the ability of shorter duration batteries to meet system needs is also being overstated in the ISP and in similar modelling exercises which inform government decisions.

To the extent PHES and other forms of medium and deep storage form part of the least cost development pathway, this should be drawn out by AEMO. Similar to our suggestion for GPG, AEMO could illustrate the extent to which these technologies are necessary by excluding them as a modelling sensitivity, then measuring the change in net market benefits, as well as reliability and other important system characteristics.

Uncertainty regarding the role and network impacts of CER

AEMO has identified the critical role of coordinated CER in meeting system needs, providing up to 65% of total storage capacity in the NEM by 2050 in the Step Change Scenario. The corresponding amount for the Progressive Change scenario is, however, far less at 16% by 2050. Figure 10 below from AEMO's latest draft update to inputs and assumptions shows materially lower trajectories for Virtual Power Plants (VPP), by approximately 5GW over most of the forecast horizon in the Step Change and Green Energy Exports scenarios.[14]

Figure 10 Aggregation trajectories for VPP forecasts



[14] AEMO, *Draft 2024 Forecasting Assumptions Update*, December 2023, p. 21.

AEMO notes it will consider a specific sensitivity to understand the impact of passive rather than orchestrated CER for the final ISP.[15] With this sensitivity, or in informing its bounds, AEMO should review its assumptions and the critical role of its modelled VPP operations in three key areas:

- the mechanisms and required investment of modernising distribution networks for VPPs to operate efficiently
- the planned integration efforts and the development of new commodities that support VPPs profitability
- the necessary policy and consumer engagement initiatives to drive the uptake of VPPs and coordinated CER, especially considering current low consumer interest.

We note that exploration of distribution network impacts is currently beyond the scope of the ISP but may be included in future editions. For the interim, we encourage AEMO to present a case study of an example set of distribution network elements, overlayed with higher amounts of CER, which would illustrate the extent to which import and export profiles can be coordinated within local constraints. The extent of any constraints and the cost of alleviating these via network augmentation to serve needs in the wider market could be extrapolated and compared to the net system benefits AEMO has already attributed to CER.

Appendix 4 of the ISP in testing the operability of the system appears to be primarily concerned with the ability of different technologies to accommodate increasing variance in load and VRE generation output. The final ISP should contain analysis on the contribution of CER in managing extreme maximum and minimum demand events. Given their substantial installed capacity by 2050, we believe it is crucial to incorporate this aspect for a comprehensive approach to ensure the resilience and reliability of the power system during peak periods.

While Project Edge has provided valuable insights, we recommend the implementation of additional pilots to better understand the role and opportunities of VPPs and CER more generally. EnergyAustralia is willing to collaborate with AEMO in devising new pilots that explore the ability to upscale CER and deliver system benefits as identified in the ISP.

Detailed cost sensitivities for transmission, as well as generation and storage

AEMO's sensitivity analyses test the robustness of its highest ranked candidate development paths. Further insights should be gained by exploring more detailed changes in net market benefits and across scenarios. AEMO's presentation of results tends to show benefit changes for the Step Change scenario and on a scenario weighted basis. Results for the Progressive Change scenario should also be presented given its assigned likelihood.

Net market benefits as a proportion of total system costs are relatively small, namely $17 billion relative to $200 billion of total costs in the Step Change scenario, and $7 billion and $162 billion in Progressive Change. In this context we recommend AEMO identify 'tipping points' where key sensitivities or combinations thereof produce situations of zero or negative net market benefits. While AEMO's calculations are more

[15] AEMO, *Draft 2024 Integrated System Plan*, December 2023, p. 81.

complex and involve counterfactual assessments, the values quoted above suggest a 4 to 8% increase in total system costs would reduce net benefits to zero.

Generally the analysis and implications of higher transmission costs need to be considered in more detail. AEMO does not present dollar values of net benefit changes for its Cost Uncertainty sensitivity. Instead it lists the rankings of different candidate pathways, which materially change with 30% higher transmission costs.[16] Rankings also change in terms of least-worst regrets. Elsewhere AEMO reports that this sensitivity reduces weighted net market benefits of around $5 billion, which is significant.[17] The extent of observed cost increases after Regulatory Investment Test assessments has been in the order of 50% for Project Energy Connect and Humelink. While proponents and AEMO have taken recent steps to improve cost estimation, a general cost increase of 30% still seems on the low side. The listing of actionable projects indicates that several are still subject to cost estimates within the range of ±50%.[18] AEMO should consider adopting a 50% value for this sensitivity, with perhaps some consideration of lower values for projects that are more progressed. The coincidence of timing for many actionable projects in the late 2020s suggests a risk of drawing on scarce labour and other resources with likely cost pressures, which may have not been contemplated by proponents who have prepared cost estimates for their projects in isolation.

Break even points for particular actionable projects should be identified, that is, the value at which project costs result in no or negative net market benefits. AEMO's 'take-one-out-at-a-time' analysis suggests that VNI West and Project Marinus are relatively marginal in terms of their net benefit contributions in the Step Change scenario ($704 million[19] and $342 million[20] respectively of the total $17 billion). As part of the aforementioned sensitivity, cost increases in the order of 30% for these projects would likely to alter the business cases of these two projects. Identifying cost increases or other conditions that result in projects no longer delivering net positive benefits could help inform stakeholders of potential 'reopening triggers'[21] — a concept that was introduced in part as a response to cost increases for Project Energy Connect.

AEMO should clarify the extent to which its analysis provides for the selection of potentially cheaper options involving upgrades to existing transmission network infrastructure, in the event candidate options for actionable projects are subject to material cost increases.

We note that proponents of various actionable projects appear to be receiving concessional finance under the Commonwealth Government's Rewiring the Nation policy.[22] AEMO states that VNI West can be delivered earlier than 2029 with "additional support" which we understand to mean by 2028 under its Rewiring the Nation agreement.[23] However the impact of concessional financing is not reflected in AEMO's analysis for any transmission projects. The impact of any external funding contributions should be explicitly addressed in the final ISP, and in accordance with the AER's Cost Benefit Analysis guidelines.[24]

---

[16] AEMO, *Draft 2024 Integrated System Plan*, December 2023, Appendix 6, p. 85.
[17] ibid p. 10.
[18] AEMO, *Draft 2024 Integrated System Plan*, December 2023, p. 57.
[19] AEMO, *Draft 2024 Integrated System Plan*, December 2023, Appendix 6, p. 45.
[20] ibid p. 48.
[21] See for example an increase in the cost of a preferred option, Appendix B.1 - https://www.aer.gov.au/system/files/2023-10/AER%20-%20RIT-T%20guidelines%20-%20final%20amendments%20%28clean%29%20-%206%20October%202023_0.pdf
[22] Landmark Rewiring The Nation deal to fast-track Clean Energy jobs and security In NSW | Prime Minister of Australia (pm.gov.au); Rewiring the Nation - DCCEEW
[23] Rewiring The Nation To Supercharge Victorian Renewables | Prime Minister of Australia (pm.gov.au)
[24] See 'binding element' number 24, page 103, [Document title] (aer.gov.au)

In addition to transmission, AEMO should also consider modelling upper bound estimates for generation and storage costs as part of a more fulsome 'high costs' sensitivity. AEMO's Social Licence sensitivity already applies cost increases to different technology types. A wider sensitivity on costs would capture other important factors that contribute to cost pressures, while also accommodating the range in more recent cost estimates from CSIRO and others.[25]

We note AEMO's comments in relation to undergrounding of transmission lines and its ongoing collaboration with community and other stakeholders on this topic.[26] It may be worthwhile modelling a sensitivity with significant proportions of transmission lines undergrounded. While there appears to be compelling prima facie evidence that this is not feasible from a cost perspective, such a sensitivity could quantify the bill impacts of the associated increases in regulated transmission costs, or of the costs associated with more and more expensive generation and storage investments. Spatial analysis could indicate where additional generation siting would affect more landowners and communities than a situation with the proposed set of (overhead) actionable projects. AEMO should consider releasing more details of its counterfactual 'no transmission' development path if it resembles these types of outcomes, which may also be similar to those of a 'Reduced Social Licence' sensitivity.[27]

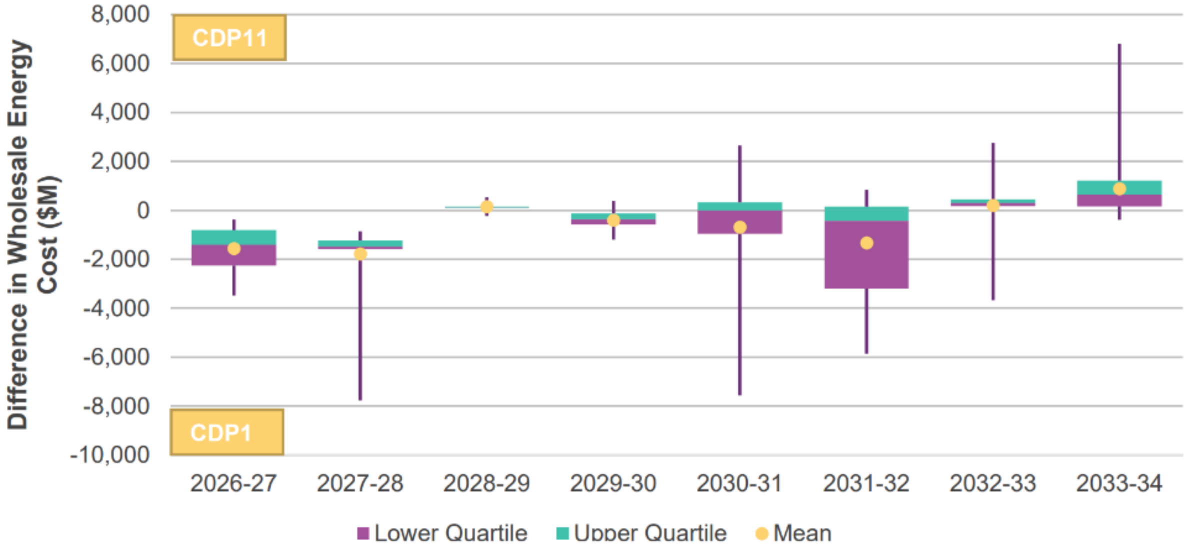
Modelling of wholesale price and customer bill impacts

AEMO states it will present information on distributional impacts of the optimal development path for the final 2024 ISP. Given how this was presented in the final 2022 ISP, we strongly encourage AEMO to express wholesale and transmission cost impacts on matters that are most relevant to the current policy environment, and in ways that are meaningful to end-use customers. Presenting data on wholesale prices and bills in exploring distributional effects are both suggested in the AER's Cost Benefit Analysis guidelines.[28]

AEMO's approach for the 2022 ISP was to focus on costs and benefits flowing from candidate paths and individual projects, and risk asymmetry where project timing is variable. Values were presented at the total system level. Figure 23 below is a typical chart from the final 2022 ISP. Assessing project impacts at the system level are important, however there would be greater value in illustrating how investments affect energy flow paths and thus price outcomes via sharing and better utilisation of energy resources. This could be added to AEMO's 'take-one-out' analysis in illustrating how project benefits materialise via changes in wholesale prices relative to the counterfactual.

[25] AEMO | 2024 Forecasting Assumptions Update Consultation
[26] AEMO, *Draft 2024 Integrated System Plan*, December 2023, Appendix 8, p. 14.
[27] ibid., p. 12.
[28] [Document title] (aer.gov.au) pp. 41-2.

Figure 23 Distribution of differences in wholesale energy costs under *Step Change*



We also encourage AEMO to present results for different NEM regions, rather than on a NEM-wide basis only. Many actionable projects will increase inter-regional energy flows with different jurisdictional impacts, including reduction in price separation between regions. This will be important to illustrate when trying to elicit support for these projects. This analysis could also inform how concessional finance is allocated to particular projects, with the aim of mitigating bill impacts.[29] That is, policy-makers appear to be concerned with offsetting the cost of transmission projects, even though they might already be offset by changes in wholesale market prices.

Key policy questions relate to the scale and pace of renewable investment and emissions reduction, and in addressing stakeholder concerns about land use competition. As noted above this will be important to explore in terms of the higher net market benefits relative to 'business as usual' counterfactuals that do not achieve policy targets. AEMO should also present this information in ways that energy customers can recognise i.e. cents per kWh or $ per MWh, rather than esoteric benefits in the order of billions of dollars. More relatable metrics will ultimately ensure meaningful stakeholder engagement and hopefully 'buy in' regarding the transition.

We appreciate the political sensitivities and potential pitfalls in quoting bill impacts and price outcomes arising from counterfactuals. Publishing bill impacts may attract heightened attention from stakeholders and give rise to misinterpretation or deliberate misuse. However the attention given to such data reflects their value in the public debate. Pieces of information arising from the ISP, including system costs and kilometres of transmission line, can already be taken out of context and misconstrued in the public debate, and this will always be beyond AEMO's control.

The AEMC intends to publish residential price trends including the impacts of potential policies and various market scenarios over a 10-year period.[30] AEMO can use the AEMC's existing approach to translating wholesale and network costs into representative bills for customers. Our expectation is that the AEMC's modelling would draw from ISP scenarios and datasets. AEMO has also identified the need to estimate annual electricity bills in order to explore consumer risk preferences.[31] Overall it therefore seems more

[29] Sharing concessional finance benefits with consumers | AEMC
[30] Update on residential electricity prices report | AEMC
[31] AEMO, *Draft 2024 Integrated System Plan*, December 2023, appendix 6, p. 86.

expeditious for AEMO to present price projections with the ISP, noting this is contemplated in any case under its obligations to conduct distributional analysis.

As noted above, publishing indicative wholesale market prices from AEMO's modelling would be critical in understanding the commercial feasibility of projections for GPG (and other critical technologies). Where there are commercial gaps, this directly informs the debate on supporting policy settings.

Our expectation is that a VRE-dominated grid would involve significant periods of very low or even negative prices, in line with broader commentary from advocates that zero marginal cost renewables are the cheapest forms of technology. Wholesale markets will be punctuated by other, potentially extreme, price outcomes where storage or other dispatchable technologies are the marginal price-setting plant. This level of price risk would have important implications for contracting and hedging costs that are ultimately passed onto consumers. It may be feasible for AEMO to publish case studies or price duration curves over time that illustrate these dynamics.

On a related topic, a future grid will involve declining levels of dispatchable resources and potentially less sources of forward contracting than today. This is combined with government provided out-of-market incentives that bring on new dispatchable plant, which potentially dull incentives to contracts. AEMO may wish to provide supplementary analysis which looks at levels of market concentration or numbers of dispatchable units relative to aggregate retail loads in each region, to identify whether contract markets may have liquidity problems.

Other issues AEMO should explore or clarify in the final ISP

AEMO should generally assess and draw highlights from different scenarios in reflection of their relative weighting. That is, the Progressive Change has been deemed (in practical terms) as likely as the Step Change scenario. Noting other reasons for changes from the 2022 ISP, it seems somewhat counterintuitive that the Slow Change scenario was removed yet Progressive Change was increased in weighting. In the context of cost of living, social licence and deliverability concerns, scenarios outlining a slower pace of change may be increasingly likely, at least for the short term. This arguably gives further justification for analysing the Progressive Change scenario in greater detail than AEMO has done in its draft.

We strongly support AEMO's ongoing exploration of the effects of perfect foresight on short duration storage. Its analysis suggests the ISP's development pathways may not be resilient to imperfect battery operation. The final ISP should present the amounts of unserved energy found in this analysis in a form that is comparable to the NEM's Reliability Standard. Further analysis using actual, observed battery behaviours (once data are available) will be helpful in validating different approaches to relaxing perfect foresight assumptions, and informing whether they should be integrated into AEMO's core modelling.

We also support AEMO's ongoing efforts to develop better datasets around the likelihood and consequences of renewables droughts. Publishing additional metrics such as reserve margins during these events is also informative.

We note the material impact of assumed smelter closures between the Step and Progressive Change scenarios. AEMO should comment on recent events including AGL's nine year agreement to supply the Portland smelter, and policy announcements[32] around green steel and aluminium that may see these facilities continue operation in the Progressive Change scenario as well. Otherwise we encourage AEMO to explain the reasons for the large differences in industrial load between the Step and Progressive Change scenarios.

Similar to the 2022 ISP, this draft ISP foreshadows material amounts of VRE curtailment as part of the least cost technology mix. As we have suggested for GPG, we encourage AEMO to present wholesale price or other information illustrating how VRE generators would sustain commercial operations in these scenarios. On face value, curtailed or spilled energy of around 20% appears material although the revenue impacts of this cannot be inferred without knowing prices at times of dispatch. Presenting this analysis may help policy-makers understand the extent of potential compensation that developers may seek under support arrangements like the Capacity Investment Scheme and the NSW Electricity Infrastructure Investment Roadmap, and the disadvantages faced by developers outside of these schemes.

We understand that cost and operational parameters for VRE generation to some extent reflect declining cost curves due to learning rate effects. We encourage AEMO to consider the extent to which projects progressively exploit more attractive sites in terms of renewable resources, marginal loss factors, congestion, and land use competition or other stakeholder issues. All of these would tend to see project economics deteriorate over the forecast horizon. AEMO should clarify the extent to which any cost penalties are applied where VRE capacity exceeds REZ specific build limits, which can capture some of these locational effects.

AEMO's separation of unused VRE output due to economic spill versus transmission constraints is also useful in informing the debate around congestion risk and access arrangements. We encourage AEMO to present an example of how curtailment within each REZ is calculated, including the presence of any localised load or storage, and differences between hosting capacity and transmission limits. For example, there is no transmission curtailment reported for N5 South West NSW in the Step Change scenario even though its installed solar capacity exceeds its network capacity.[33] Similarly, S1 South East SA has installed wind capacity well in excess of its transmission limit but without any network-driven curtailment.[34]

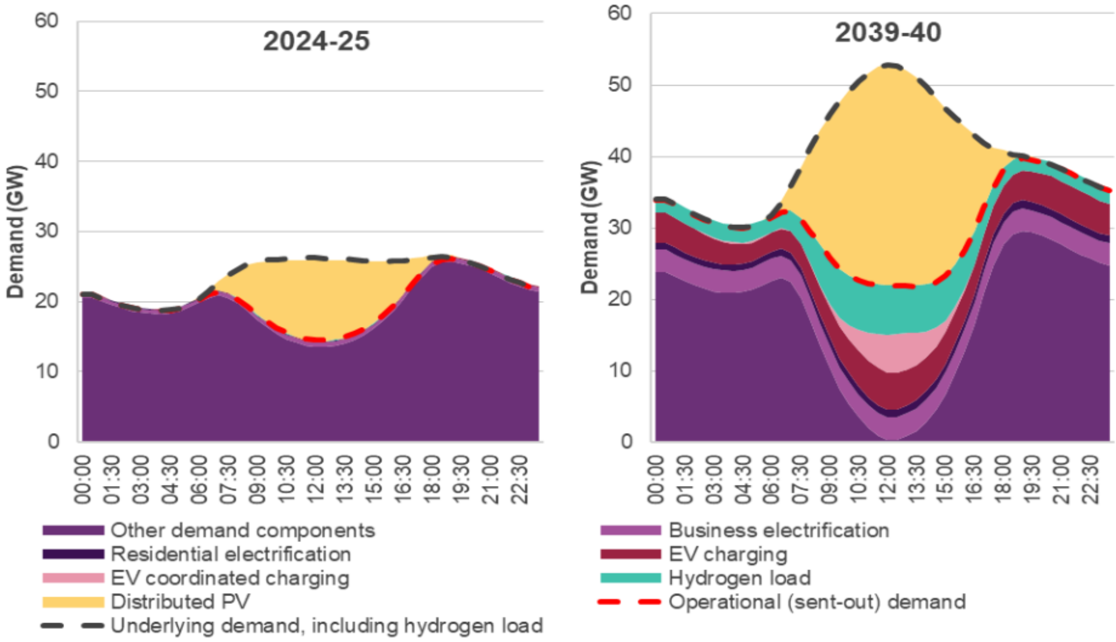
More broadly on transmission limits, AEMO should clarify if and how it accommodates actual network-based limitations on interconnectors e.g. QNI and VNI operational limits. It should explain how interconnectors are utilised and constrained, and how augmentations enable better and more efficient inter-regional trade, particularly in future situations involving significant daytime solar output (including from behind the meter). As noted above in the context of quantifying the benefits of individual actionable projects, AEMO should illustrate how increased network capacity helps on a day-to-day basis or in particular situations.

Further on the commercial prospects of individual technologies, we encourage AEMO to examine the feasibility or drivers of the assumed flexibility of hydrogen loads. The analysis presented in Appendix 4 of the draft ISP (see example figure 1 below) suggests that these loads (alongside orchestrated CER) will essentially eliminate 'duck curve' type challenges in system operation. This seems optimistic. It may be prudent to consider the project economics of electrolysers, namely their capital intensity and how the need to

[32] Joint media release: $200 million to help future-proof regional steel manufacturing | Ministers (dcceew.gov.au)
[33] AEMO, *Draft 2024 Integrated System Plan*, December 2023, appendix 3, p. 28.
[34] ibid., p. 60.

recover fixed costs interacts with diurnal spot price variations. Less flexibility in these loads would presumably reduce the ability of the system to absorb high amounts of rooftop solar PV. It may be worth exploring this as a modelling sensitivity.

Figure 1 Average annual demand profile for the NEM, 2024-25 and 2039-40, *Step Change* (GW)



Also in the context of load profiles, we note and appreciate AEMO publishing trace data for the draft ISP. The final 2022 ISP was accompanied by trace data that were disaggregated for individual load elements e.g. electric vehicle charging and discharging, VPPs as well as electrification impacts. We encourage AEMO to publish this information again, including now for its draft ISP datasets.