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Australian Energy Market Operator — Draft 2022 Integrated System Plan — December 2021

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 4,500MW of generation capacity.

The draft 2022 Integrated System Plan (ISP) reflects a significant improvement on prior year plans and we applaud the efforts of all AEMO staff and contributors. The level of sophistication and transparency in analysis has been lifted at the same time as broadening the scope of modelling to reflect sectoral adjacencies, and extension of the modelling horizon to capture critical jurisdictional decarbonisation objectives.

Overall we consider AEMO has undertaken a robust analysis and provided valuable insights on many trends and uncertainties that align with our own view of the energy transition over the longer term. The attached submission outlines potential areas of improvement and guidance on areas that AEMO has flagged it will investigate for the final ISP later this year. Other matters relate to additional transparency of data and findings where this will assist the wider policy discussion, rather than necessarily affect AEMO's findings. Our main reflections are:

- the scenarios show **accelerated exits of coal plant** ahead of existing announcements in order to meet decarbonisation targets, and AEMO's modelling solves by having replacement capacity delivered with perfect foresight to maintain a secure and reliable power system at least cost. This has important implications for the current debate around market reform, namely the need to deal with uncertain retirement dates and the collective challenge we face in ensuring new capacity, with the right capabilities, is online before these retirements occur. Deep dives into the economic drivers for these closures and for new investment for the final ISP can help inform this policy debate. Similarly, more transparency on how AEMO's modelling ensures **reliability outcomes** are met under its projections would be valuable.

- AEMO's multisector modelling reflects a complex undertaking and will evolve. Ideally for the final ISP we suggest AEMO comment on **gas and electricity distribution network impacts and behind the meter** investments in terms of the relativity of cost and feasibility across different scenarios, as well as informing the broader policy debate around least cost decarbonisation pathways.

- Similarly, further testing of the **commercial and policy settings associated with gas generation** and upstream infrastructure appears necessary if it is going to continue to provide a critical backup and firming role out to 2050 as foreshadowed in AEMO's scenarios. Similar **insights into the operation of REZs** would also be valuable, particularly the likely revenue shortfalls associated with economic curtailment, and generally how storage plays a role.

- AEMO should give more consideration to decision rules around various candidate development paths. The net benefits of different groups of transmission projects are basically indistinguishable given the uncertainty involved in their calculation. While the package of investments appears to deliver a fair return on investment e.g. net benefits are 2.5 times the transmission cost, **some individual investments are more marginal than others** with implications for the metrics behind decision rules and future materiality assessments.

- AEMO's proposal to include **resilience testing of its modelling** for extreme weather events in the Final ISP is critical. The historical dataset and reference years included may not capture credible future operational conditions that may need to be reflected in planning decisions. Similarly, the role of perfect foresight assumptions underpinning AEMO's methods should be explored in this assessment.

- The Final ISP should also highlight the **quantification of total system costs** rather than focus so heavily on the notion of net benefits. This would include an explanation of why system costs appear to have significantly increased relative to the 2020 ISP. It is important customers are aware of this concept to better inform a discussion of their willingness to pay for the transition, and moreover where certain costs are excluded.

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

AEMO can release further data and insights to inform the policy debate

The ISP's scenarios identify that large amounts of new capacity, of many different technology types, would need to be installed by 2050 to meet long term decarbonisation targets. The most important question arising is how all this investment will take place given current market and policy settings.

Much of AEMO's modelling is based on numerous constraints that abstract from private investment decisions, particularly the entry and exit of plant, with perfect foresight, to stay within carbon constraints as well as system security parameters. The net effect of these assumptions is likely to be that actual (i.e. suboptimal) levels of investment to meet net zero commitments will need to be higher, with lower utilisation and implications for returns to asset owners. Conversely, the investment identified in the ISP will not take place without an associated step change in policy settings.

AEMO refers to current reforms on foot and additional interventions that are needed to enable this transition, including:

- AEMC and the ESB proposals around technical system requirements and 'Post 2025' market reforms
- AEMO's Engineering Framework work streams, covering the operational, technical and engineering requirements, as well as the extensive industry collaboration and effort, needed to prepare for the futures envisioned in the ISP
- specific incentives to counter high levels of renewables curtailment associated with 'efficient' REZ overbuilding
- the need to gain social licence for active DER management to support system wide reliability and security, but also in communities where grid scale generation and transmission projects will be commissioned, particularly in REZs.

To inform these discussions AEMO can release further data and analysis along the following themes:

- **Market settings for resource adequacy** — stakeholder consultations on market reforms, including the need for a capacity mechanism, touch on the roles of technologies with different output durations, degrees of flexibility and plant economics. Each of these technologies responds different to current market settings, with implications for market re-design. AEMO could release information on modelled spot price outcomes, including worked examples, where this drives economic retirement and entry decisions, and highlighting the relative differences across the scenarios.

- **Projected reliability performance of the system** — further to resource adequacy incentives, AEMO should be clearer on how different elements of its modelling ensure the Reliability Standard is met. AEMO's methodology explains that capacity reserve levels are a proxy for the Reliability Standard and these levels are varied via interactions between its capacity expansion and time series models. The Final ISP should provide more insight into what these reserve levels are, how they compare to historical levels, and what drives their investment. We also support further work to explore system impacts of extreme events and suggest more analysis around the adequacy of historical data sets, 'tail risk' and other case studies on reliability issues be published to inform parallel processes being conducted by the Reliability Panel and the ESB.

- **Congestion management and transmission access** — we note AEMO will publish MLF sensitivities with the final ISP for REZs and support the level of transparency it has provided on economic and transmission curtailment. There may be benefit in presenting technology type breakdowns of curtailment as well as case studies of how high levels of curtailment present challenges for plant economics. This analysis could also illustrate how AEMO models storage (either at a state level or potentially inside REZs), for example whether storage behaves to optimise REZ hosting capacity or other transmission constraints, or to optimise dispatch patterns across regions. AEMO's detailed views of how transmission investment reduces interregional congestion and price separation would also be very valuable.

- **Specifics on the role of storage** — in addition to REZ and congestion interactions, AEMO should address in more detail how assumptions of perfect foresight for storage operation affect development pathways in its capacity modelling, particularly in the face of any hydrological and wind droughts in its historical datasets. Further explanation of how storage responds to price signals associated with arbitrage would also be beneficial in understanding the drivers of investment relative to other sources of revenue not captured in AEMO's modelling. It is evident that, at present, energy arbitrage is only a small component of the overall revenue of storage.

- **Interactions with distributed solar** — as mentioned further below the assumptions around DER operation have important implications. As it relates to curtailment of wind and solar, we question whether AEMO's modelling gives adequate treatment to the potential need to curtail behind the meter solar output to manage system wide issues. This includes questions around whether and how coal plant would instead be backed off to deal with minimum demands as well as to accommodate high grid scale renewable output. Overall it would seem that, even with the building of interconnectors and sharing of energy across NEM regions, there will be periods of significant surplus.

Modelling integration with electricity distribution networks

We support AEMO's efforts in integrating economy-wide carbon constraints and impacts on adjacent sectors into its modelling of NEM development pathways. This is an area that will evolve with each ISP and the temptation will be to incorporate more dynamic feedback loops between sectors, particularly for gas infrastructure given AEMO's GSOO and other projections.

However, it is not clear what assumptions AEMO has applied regarding the changes in the costs of distribution networks arising under different development paths and scenarios. We are not suggesting AEMO model elements of the distribution network as we understand this would be excessively complex. We also appreciate that AEMO's capturing of subregional transmission elements is already a significant undertaking.

We note that distribution assets are included in the rules definition of 'ISP development opportunity' under clause 5.10.2. There does not appear to be a corresponding obligation in the rules or guideline requirements to explicitly consider or identify distribution level opportunities, costs or benefits. Our expectation is that distribution impacts are likely to be similar across the various CDPs and may have little bearing on the timing and composition of Actionable transmission projects. AEMO may wish to validate this.

AEMO will present customer bill impacts in its final ISP in identifying distributional impacts. Retail price changes already form part of its forecasts of demand and DER uptake. AEMO appears to be contemplating bill impacts in terms of wholesale price changes inferred from time sequential modelling, as well as from transmission costs.[1] We question whether AEMO can realistically disregard potential bill impacts for distribution assets associated with changed load profiles, rising maximum demand and accommodating two-way power flows. The projected levels of DER integration will also have bill impacts in terms of purchasing and integrating smart appliances, with specific cost structures where they provide 'dispatchable' capacity. While at the customer level, costs associated with DER technologies are expected to decrease[2], new costs may arise where they are used to provide system services e.g. curtailment, load shifting and foregone revenues.

These cost and technical considerations may warrant identification as 'development opportunities', in addition to social licence issues that AEMO has already and appropriately flagged.[3] For example, AEMO could undertake or commission some limited analysis of augmentation expenditure associated with changing consumption profiles, mainly EVs and electrification of gas loads, in order to provide some high-level cost indication of different scenarios or sensitivities. AEMO could also draw on a range of existing analyses, mostly published by or on behalf of gas network owners, and further information to be released by credible independent bodies such as Infrastructure Victoria.[4] As it relates to distributional impacts, this will be relevant in exploring bill impacts for jurisdictions with significant gas load. Otherwise this analysis would be important for testing any assumptions that depend on retail price feedback loops.

Modelling interactions with gas networks

The relative total system cost impacts of different decarbonisation pathways involving renewable gas has been the subject of ongoing discussion in AEMO's FRG and in other fora.

AEMO has an important role in guiding how its analysis should, and should not, be used in the policy debate, such that its results are not misconstrued by stakeholders with different interests. Its scenarios are not intended to highlight the merits of different pathways. For example, one cannot simply compare the total system costs of different scenarios to determine which one is 'cheaper', or that a scenario with faster emissions reductions should be pursued for environmental reasons.

At the same time, AEMO's scenarios should reflect plausible futures with a range of parameters that test the prudence of Actionable projects. Arguably if a scenario design involves prohibitive cost e.g. in terms of distribution networks or in-home appliance change over, it should be given less weighting. Exploring the full range of cost impacts of scenario design is also important for calibrating various input assumptions.

For example, electrification of gas loads will erode the revenue base of gas transmission and distribution networks. Associated regulatory decisions around accelerated depreciation, tariff restructuring and even possibly asset write downs of gas assets[5] will affect differentials between gas and electricity bills and affect customers' decisions to

[1] AEMO, *ISP Methodology*, August 2021, p. 93.
[2] AEMO, *Draft 2022 Integrated System Plan*, December 2021, p. 36.
[3] ibid., pp. 15, 92.
[4] https://www.infrastructurevictoria.com.au/project/infrastructure-victoria-advice-on-gas-infrastructure/
[5] https://www.aer.gov.au/system/files/AER%20Information%20Paper%20-%20Regulating%20gas%20pipelines%20under%20uncertainty%20-%2015%20November%202021.pdf pp. 36-7

switch fuels. These interactions are complex, with likely differences across customer segments, however are something AEMO should attempt to explore or at least acknowledge in communicating findings to policy-makers.

On a related matter, FRG discussions have given rise to the suggestion of a further scenario that tests the prospects of decarbonisation via large levels of biomethane and hydrogen production. As per our submission of 4 February to the 2023 IASR consultation, this actually raises questions around the gas blending tolerances assumed in the ISP's Hydrogen Superpower scenario, including how these are increased over time, with likely high costs of pipeline and appliance switching. Multisector modelling by Climateworks and CSIRO excludes costs associated with supplying blended gas through transmission and distribution networks, and they note this is an important consideration in terms of economic feasibility.[6] Rather than embarking on a new scenario, these issues should be explored in potential revisions to the current Superpower scenario, or as another sensitivity (e.g. 'weak electrification').

Modelling implications for gas generation

Regarding general NEM implications, we agree that gas will continue to play an important role in backing up and providing flexible generation with very high levels of VRE output and aging coal plant. There are important questions, however, in how this role would be sustained in reality. Again this goes to AEMO's role in highlighting modelling limitations and appropriately framing policy implications, in addition to potentially amending modelling parameters from a commercial feasibility standpoint.

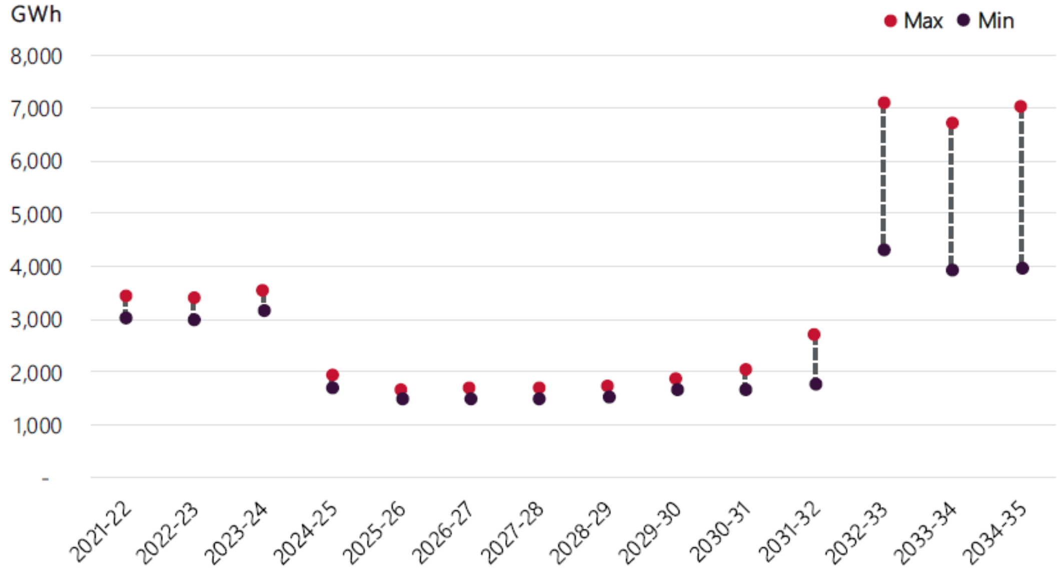
For example, the Step Change scenario shows 6.9GW of new peaking gas installed by 2050, which presents several challenges:

- There is likely to be a high carbon risk associated with this investment. This risk will increase over modelling horizon as policy settings and community expectations escalate. This could be reflected in higher hurdle rates which might prompt heavier reliance on DER or grid-scale storage to provide backup.
- Our expectation is that AEMO's modelling requires this plant to be built to satisfy reliability constraints rather than for economic reasons. Similar to drivers around coal plant exit, more transparency on gas generation economics may inform separate discussions on market design and policy incentives.
- The analysis presented in section A4.2.8 is useful and could be supplemented with charts showing ranges of output, similar to Figure 19 and 20 reproduced below from the 2020 Final ISP, which might inform:
    - whether there is enough capacity in the current gas system to support the implied levels of daily usage. For example, current Victorian maximum gas demand is approximately 1.2PJ/day. This compares to 2 PJ/day in the Step Change scenario, which is admittedly NEM-wide, however warrants further testing in terms of feasibility
    - upstream production impacts arising from increased gas generation output, and also storage to account for intermittency, somewhat offset by lower gas usage for space and some industrial heating.

[6] CSIRO and Climateworks Australia, *Multi-sector energy modelling*, July 2021, pp. 46, 51.

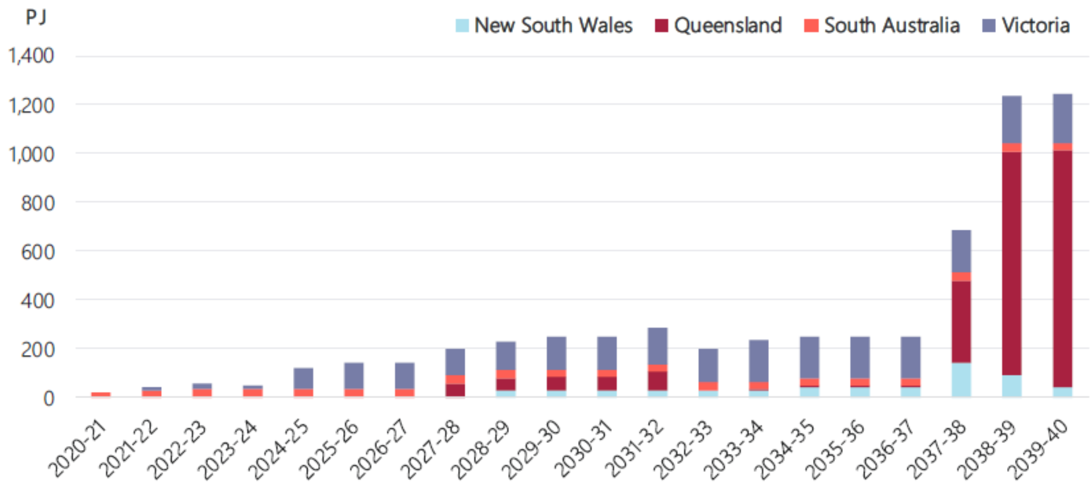
- Shifts towards electrification of gas load and increasing intermittency will have cost recovery implications for gas transport infrastructure, including from a forward commodity and capacity contracting perspective. The likely higher emphasis on fixed cost recovery and away from variable charging may ultimately affect price bids by gas generators and hence wholesale price outcomes.

Figure 19 Projected GPG generation across a range of reference years



Source: AEMO, 2020 Final ISP.

Figure 20 New gas supplies required each year, under Central scenario



Source: AEMO, 2020 Final ISP.

Revenue adequacy and owner decisions around coal generation

Most of the media reporting around the draft 2022 ISP related to accelerated coal exits as this is an area of heightened uncertainty and interest. AEMO should be clear in communicating to stakeholders the reasons why its projected retirement schedules are more aggressive than the current announcements of plant owners, particularly given the implication we may not be compliant with notice of closure requirements. These reasons are, of course, that the modelling reflects policy constraints that do not yet exist, and that plant decisions are based on economics and other real-world factors, rather than simply satisfying this assumed modelling constraint.

The policy implications of AEMO's analysis are potentially quite important. For example, AEMO's time sequential modelling may provide insights into how best to design policies that accelerate current retirement trajectories to align with those consistent with net zero pathways. Policy settings that focus on bringing in new investment that crowds out and eventually forces economic coal closures (basically an extension of the status quo) may or may not be preferable, or as effective, as alternatives that work in reverse — for example an emissions constraint or other mechanism that forces coal closures and thereby creates the business case for more low emissions generation and other replacement investment.

The analysis presented in section A4.2.7 is a useful starting point to explore the challenging economics of coal plant operation in terms of ramping and unit decommitments. This appears to be limited to the Progressive Change scenario and up to 2030, as carbon budgets are the main driver of plant exit in later years (and other scenarios).

Revenue adequacy modelling for the Progressive Change scenario, however, may not provide particularly useful insights given the pace of retirements is similar to current announcements (and slower than the Slow Change scenario until the mid-2030s).

With respect to decommitments, AEMO found that allowing for unit decommitment was unlikely to have materially altered the modelled retirements in the Progressive Change scenario. It is not clear that this is a useful finding as most of the retirements in this scenario take place after 2030, which AEMO state are driven by the model's carbon constraints, rather than economics. That is, AEMO should clarify the extent to which these timing decisions are sensitive to economic factors in the first place.

Any further analysis of revenue sufficiency as a basis for exit or decommitment decisions should explore how any perfect foresight assumptions play a role, namely knowing which higher cost units would decommit first, and of the related forecast prices that drive such a decision. Added to this, AEMO's modelling does not accommodate revenue streams from contract and FCAS markets, and potentially new ESS markets, noting all of these are difficult to reliably capture.

We encourage AEMO to publish spot prices arising in its time sequential modelling, to provide some insights into average prices but also the frequency and duration of high and low price events. This is important in understanding the extent to which the changing technology mix affects price volatility and therefore any challenges in making necessary investments relative to current market conditions. Our understanding is that one of the drawbacks of optimisation modelling with perfect foresight is that it may produce unrealistically low levels of price volatility. There are methods to deal with this, which we would welcome discussing with AEMO.

As AEMO notes, projected ramping requirements will also increase running costs, affect plant outages and eventually retirement decisions.[7] It is not clear that ramping data for the Progressive Change scenario, particularly in earlier years as presented in Figure 20 of Appendix 4, provides useful insights into coal plant economics or operations in high VRE situations. AEMO should release information on the assumed daily operational profiles of individual plant such that owners are able to validate them and their dependent findings. Noting that closure decisions appear to be driven by carbon constraints rather than economics, it may be that infeasible technical or operational requirements drive even earlier retirements than in AEMO's modelling.

Project decision rules, delivery risk and timings

AEMO's headline claim regarding the value of transmission projects is that they will deliver a return of 2.5 times the cost, that is, net weighted benefits of $29 billion for actionable investment of around $12.5 billion in today's value.[8]

Table 11 lists the net market benefits of different candidate paths. Our view is that the differences in values are well within the range of uncertainty or forecast error. This suggests that the combinations of these transmission investments and various timing options are basically indistinguishable in terms of what value they will deliver.

Table 11 Performance of candidate development paths across scenarios (in $b) – ranked in order of weighted net market benefits

CDP	Description	Slow Change	Progressive Change	Step Change	Hydrogen Superpower	Weighted Net Market Benefits	Rank
	Scenario weighting	**4%**	**29%**	**50%**	**17%**		
10	CDP5, with VNI West staged	3.52	16.35	25.59	70.01	29.58	1
12	CDP10, with HumeLink staged	3.35	16.20	25.59	70.20	29.56	2
2	Step Change least-cost	3.25	16.26	25.59	70.01	29.54	3
5	CDP1, adding Marinus Link	3.71	16.51	25.51	69.60	29.52	4
6	CDP1, adding VNI West	3.62	16.47	25.59	69.37	29.51	5
1	Progressive Change least-cost	4.17	16.72	25.50	68.95	29.49	6
7	CDP1, without New England	3.94	16.67	25.49	68.45	29.37	7
4	Slow Change least-cost	4.34	16.50	25.41	68.73	29.35	8
11	CDP8, with VNI West staged	3.13	15.66	25.39	70.20	29.30	9
8	CDP2, adding HumeLink	2.87	15.56	25.39	70.20	29.26	10
3	Hydrogen Superpower least-cost	2.51	15.47	25.34	70.53	29.25	11
9	No actionable projects	4.05	16.36	25.28	68.33	29.16	12
13	CDP12, removing Marinus Link	2.19	13.54	20.96	64.50	25.46	13

Source: AEMO, 2022 Draft ISP.

There is likely to be far higher certainty on the cost of transmission projects in terms of net benefit contributions than on other elements making up total system costs. While transmission cost estimates are subject to large forecast errors on a project-by-project basis, they only constitute around 7 per cent of total system costs, and will be overshadowed by the expected variance of the 93 per cent remaining.

[7] AEMO, *Appendix 4 System Operability*, December 2021, pp. 20-21.
[8] AEMO, *Draft 2022 Integrated System Plan*, December 2021, p. 11.

For these reasons we ask AEMO, in preparing its final ISP, to consider including a more systematic analysis of cost-benefit ratios and beyond the figure of 2.5 quoted in the draft ISP's executive summary. Ultimately this would be useful when considering the value of individual projects and decision rules relating to expected 'break even' project costs.

To some extent AEMO has already considered this in its 'TOOT' assessments in section A6.5.2. On a cost-benefit ratio basis, Humelink, at 0.4[9], appears to be the most marginal. We support the intent of AEMO's decision rules for Humelink in relation to 'material' increases in costs and changes in dispatchable capacity, and acknowledge that completion of early works (now confirmed by AEMO[10]) is a low regret means to provide for accelerated delivery if required. Regarding further substantive completion of the project, we recommend AEMO:

- be clearer regarding the thresholds around changes in NSW dispatchable capacity (as the AER has identified in its transparency review), as well as 'new commitments' leading to these changes
- provide further guidance on the 'materiality' of project cost increases, for example the threshold at which the project is no longer expected to provide net benefits. This materiality should be framed in the in the context of updating analysis for changing market conditions such that variability in benefits, and not just project costs, are appropriately considered
- consider whether it would be simpler to trigger an updated assessment of the prudence of the project following competition of early works, for example as a separate project for assessment in future ISPs.

These recommendations equally apply to the same language used in the VNI West decision rules.

The regret costs of delaying Marinus Link by 2 years are marginal (i.e. CDP 1 versus CDP 5) and we note AEMO's consideration of how scenario weightings affect optimal timings on a least-worst weighted regret basis.[11] We also note TasNetworks has indicated to AEMO that the project could be delayed by two years due to covid-related supply issues. It is not clear how this analysis or deliverability issues affect the RIT-T that TasNetworks has already completed, nor the implications of it seeking any confirmation via the feedback loop. For example, AEMO has explored the effect of supply chain issues by moving commissioning dates beyond 2030, however it also highlights potential costs of delaying the project now and restarting at a later date, which now seems to be the consequence of supply chain issues irrespective of whether it is identified as Actionable project.

When viewed together, the draft ISP's proposed transmission build profile is aggressive, with several projects being accelerated relative to the 2020 ISP. Deliverability in these timeframes is questionable given many projects are yet to commence seeking requisite regulatory approvals. It seems prudent to explore whether supply chain issues affecting Marinus Link are applicable to other projects identified. We note that resolving the 'who pays' issue for Marinus Link has been identified as a delivery risk[12] whereas this formed part of AEMO's decision rule in the 2020 ISP. Policy-makers have been deliberating on this issue for considerable time now with no visible signs of progressing.

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[9] Reflecting a contribution of $1.3 billion of net benefits in the Step Change Scenario, relative to a project cost of $3.3 billion.
[10] [isp-feedback-loop-notice-humelink-early-works.pdf (aemo.com.au)]
[11] AEMO, *Appendix 6. Cost benefit analysis*, December 2021, pp. 51-2.
[12] AEMO, *Draft 2022 Integrated System Plan*, December 2021, p. 88.

Assumptions around distributed energy resources, including dispatchable load

The heavy reliance on DER envisaged under the ISP's scenarios, particularly to the extent it contributes to 'dispatchable' capacity, warrants close attention and additional transparency relative to what has been published so far:

- In our view the proportion of distributed battery installations used in VPPs appears low, at around 50 per cent. There are strong commercial drivers for VPP arrangements and AEMO could validate this by surveying the commercial and customer contracting arrangements for batteries being sold in the market now.

- Assumptions for the capacity duration of distributed VPP batteries seem aggressive and AEMO should consider whether some of this duration or capacity would be reserved for network or own customer use. This might justify including an additional third category of batteries where capacity is split for VPP and other purposes.

- Generally we would appreciate more detail on how dispatchable loads have been modelled, including load shapes, and the impact of WDR reforms. AEMO's projections around WDR would also be useful to inform the ongoing discussion around the benefits of this reform, noting the small number of units registered on its commencement.

- As noted above there are likely to be important price feedback loops or critical assumptions around pricing that affect trend growth rates and the shape of demand, via behavioural and other responses, particularly during the middle of the day. In the same way as information on spot price outcomes would be useful in understanding the economics of grid scale investments, information on "market-driven price signals" should be published to validate AEMO's assumptions around EV charging[13] and the full range of DER behaviours.

- Figure 2 of Appendix 4 shows large growth in midday demand in the 2040s. The corresponding profiles for the Progressive Change scenario suggest a more pronounced effect in the evening from electric vehicles than we would have expected. If AEMO has not done so already there may be useful information to be obtained from Ausgrid's recent EV trials.

Testing the resilience of development paths to tail risks and imperfect foresight

We welcome AEMO conducting resilience testing of its outputs for the final ISP, particularly extreme wind or solar droughts given the recent impact of unprecedented wind droughts in the UK recently.

AEMO should move beyond what it characterises as "extreme event case studies"[14] and carefully consider the extent to which its weather reference years do not capture conditions that warrant business as usual planning solutions. The analysis presented in section A4.2.4 of its draft ISP suggest that AEMO is comfortable that it has tested its development pathways for a range of reliability risks, including renewables droughts, and the weather patterns over 2010-11 to 2019-20 capture the range of likely conditions out to 2050. We understand from comments at AEMO's recent forum that this may not be

[13] AEMO, *Appendix 4. System operability*, December 2021, p. 7.
[14] AEMO, *Draft 2022 Integrated System Plan*, December 2021, p. 98.

the case and it is looking to expand its weather dataset, including reviewing the number of reference years and potentially incorporating synthetic data. AEMO includes a synthetic low hydro inflow year in its set of reference years. A similar approach should be applied for wind and solar to ensure the impact of renewables droughts are genuinely included in the core ISP modelling, as opposed to it being used for post-modelling resilience testing.

AEMO's case studies in section A4.2.4 can also be expanded. The snapshots of different events highlight the critical role of energy storage in providing energy duration (to deal with renewable droughts) and shifting of load (in the case of summer peak days). This in turn raises questions around the role of perfect foresight in some elements of AEMO's time-sequential modelling (i.e. the medium term schedule) which it uses to validate and refine development paths arising from its less granular capacity outlook model. The risk of relying on models with a degree of perfect foresight will be much larger as the market transitions, and we would like AEMO to test this. We understand the need for perfect foresight to underpin least cost market modelling, however real-life outcomes will be driven by commercial factors and other uncertainties. AEMO is exploring ways to reduce the level of perfection in foresight[15] which we support and suggest taking a scenario approach, for example where long-term storages are only 50 per cent charged ahead of an unexpected wind drought event. We also suggest an additional case study involving coal fuel shortages, which have happened in the past.

Further to comments above about the concurrent ESB and Reliability Panel reviews, AEMO should publish more information of the type contained in Figure 9 in appendix 4, and in doing so should:

- reiterate that reliability events are increasingly going to be less about managing the system during high temperature events, which many stakeholders and policy-makers are preoccupied about. Furthermore, it is worth emhpasising these events will depend on supply-side conditions rather than maximum demand.

- highlight that these projected reliability outcomes are largely the result of technologies being 'forced' into the system by modelling constraints rather than investments that would arise under current market conditions. These include VRE plant that would be commissioned in spite of very high levels of 'economic' curtailment, peaking gas generation and other plant optimally timed to replace coal retirements.

[15] AEMO, *ISP Methodology*, August 2021, p. 53.

Figure 9 Forecast expected unserved energy in *Step Change* Scenario (left) and seasonal share of NEM-wide reliability events (right)

Source: AEMO, 2022 Draft ISP, Appendix 4.

Further areas where more data or explanations are warranted

To build understanding and confidence in the study, there are several outputs that we would like to see:

- The substantial increase in total system costs compared with the 2020 ISP needs to be called out more directly. For example, the Step Change scenario has an NPV over the 30-year outlook of $147 billion, with a counterfactual of $172 billion. Total system costs for the 2020 ISP were roughly in the order of $80 to $90 billion for development path cases and up to $130 billion in some counterfactuals. The higher values in the 2022 Draft ISP seem to reflect more than changes in scenario designs and modelling horizons, and warrants some explanation. The Draft ISP almost exclusively discusses the value of development pathways in terms of billions of dollars of net benefits which, when understood, is not intuitive from a customer perspective. Ultimately the massive transformation of the sector ahead of us will involve considerable cost and it will be important to carefully articulate this in gauging willingness to pay, as well as explaining bill impacts. The presentation of 'total' system costs would need to give some idea of elements that are excluded such as distribution network and behind the meter technologies.

- More transparency on AEMO's approach to determining firmness for renewables generation. This was previously identified as a set of assumptions and we understand this now depends on the rate of technology uptake, however it would be valuable to understand this in more detail, and ideally before the final ISP is released. We expect these calculations will have interactions with the testing of outputs for extreme weather events and other tail risks.

- The potential role of load locating inside REZs should be considered. This would form part of a packaged analysis of the feasibility of REZ design and operation that captures elements already raised above (i.e. commercial drivers for VRE in the face of significant curtailment, diversity of output inside the REZ to accommodate significant apparent overbuild, and generally how storage investment and operation is incentivised).

- AEMO should explore how its results are affected in the absence of capturing FCAS. We recognise FCAS revenue streams may not be feasible to model, or potentially not influence development paths[16], however capturing physical impacts could be more tractable. For example AEMO comments that batteries may need to operate within a narrower range[17], however we expect the modelling allows for unconstrained operation.

- AEMO's assumption of having no large synchronous units online from 2025-26 in most NEM regions appears heroic and we note this is dependent on the successful execution of initiatives arising out of the Engineering Framework. We request AEMO to consider whether its development paths would be materially affected if there were a requirement to keep synchronous units online.

- We would also like additional transparency of how many long-duration forced outages for existing coal and OCGT generators are reflected in AEMO's modelling results.

[16] AEMO, *ISP Methodology*, August 2021, p. 63.
[17] AEMO, *Appendix 4. System Operability*, December 2021, p. 11.