16 February 2023

Mr Daniel Westerman
Chief Executive Officer & Managing Director
Australian Energy Market Operator

Submitted via email at forecasting.planning@aemo.com.au.

Dear Mr Westerman,

Consultation on the 2023 Draft Inputs, Assumptions and Scenarios Report

Fortescue Metals Group (**Fortescue**), including its green energy company, Fortescue Future Industries (**FFI**), welcomes the progression of the Inputs Assumptions and Scenarios Report (IASR) in support of increased efforts to address emissions and limit climate change. Fortescue notes that scenarios previously considered to be a notable "step change" in action are now considered usual progression for the National Electricity Market (NEM) and a continuation of current trends. Equally, it is noted that continued vigilance is required to avoid sliding backwards and to avoid the trap of adopting too many assumptions that simplify or underestimate the challenges ahead.

The draft report shows that the Green Energy Export scenario is the only scenario that aligns with the identified state-based investments, totalling almost $1 billion. In addition, the Federal Government has budgeted $1.2b to support the hydrogen industry. Assuming industry matches (at least) this investment (likely materially more), this scenario could represent thousands of Megawatts (MW) of electrolyser capacity. Only the Green Energy Export scenario would be consistent with this level of investment.

The 2023 IASR claimed that the 2022 ISP Step Change scenario was consistent with the government expectation of 82% renewable energy by 2030 – yet looking at the details of primary energy sources, in 2029-30 the Step Change scenario projects 53.5 terawatt hours (TWh) of fossil fuel-derived energy compared with 185.5 TWh of renewable energy. To achieve the 82% would require around 10 TWh less fossil fuels and 10 TWh more renewable energy. For context, this gap is roughly equivalent to Tasmania's annual electricity consumption. However, despite the notable gap and a strong appetite in the market for renewable energy, the 2023 IASR forecasts slower emissions reductions until 2030. Fortescue there surmises that the only 2023 IASR scenario that is likely to meet the expectation of 82% renewables is the Green Energy Export scenario.

Furthermore, the only World Energy Outlook scenario which *ensures* an outcome well below 2 degrees Celsius is the Net Zero Emissions by 2050 (NZE) scenario, also consistent with the Australian Energy Market Operator's (AEMO) Green Energy Export scenario. All other scenarios, including the "Step Change" scenarios, risk temperature rises above 2 degrees C, not meeting the government's international commitments. Our view is, while the other scenarios are important to understand, any plan should adopt the transition to the only scenario that meets Australia's emissions reduction policy commitments, particularly in light of recent proposals to update the National Electricity Objective (NEO).

Fortescue therefore supports focusing most strongly on the Green Energy Export scenario, using the other scenarios to understand what commitments and outcomes would be missed if a different future were to occur. Further, no clear reasoning is provided regarding the lack of hydrogen export in the Step Change scenarios. It is unclear how these volumes were established, but the hydrogen production is unlikely to be consistent with the earmarked funding from state and federal governments.

Fundamentally, the IASR is intimately tied to the methodology behind the various Integrated System Plan (ISP) reports, which in turn relies heavily on the intent of the reports in the first place. Fortescue questions if the reports are intended to be:

- plans for the future,
- a source for information and context, or,
- a decision-making tool.

Fortescue's view is that the reports assumptions must be linked to problems that need to be solved. For example, identifying a constraint and assuming it will be resolved may be a realistic assumption and therefore a better forecast – but without identifying the problem, the action may never be taken and therefore the assumption of action is flawed.

AEMO's remit does not give the investment to execute a plan, nor the accountability to make decisions on the strategic development of the NEM. Therefore, the reports are best focussed on the provision of rich information and context. This also means that producing a "likely" forecast is less useful than communicating risks, sensitivities and the need for action. Ideally AEMO's publications would recognise the path that we are on, but also identify actions which may be needed to achieve different outcomes, across multiple future scenarios and sensitivities.

- Example 1: All scenarios rely heavily on negative emissions but if these cannot be successfully or cost-effectively adopted at the necessary scale, the only viable option is to accelerate the reduction of emissions to avoid back-ending emissions reductions. It is not prudent planning to wait for 10 years to see if a technological breakthrough may occur. This risk should not be considered acceptable, and large assumptions about options for negative emissions downplay this risk and mute the signal that the rate of change needs to be accelerated.
- Example 2: The energy efficiency forecast is extreme. All scenarios assume massive improvements in energy efficiency such that it is forecast to displace electricity consumption equivalent to the current consumption of NSW. In the Green Energy Export scenario, the assumed energy efficiency improvement is forecast to displace electricity consumption equivalent to the current consumption of NSW and QLD combined. Prior energy efficiency forecasts ranged from 20-50 TWh – still highly ambitious, but these have been increased substantially with little supporting evidence. If this forecast comes true, the challenge will be notably easier, but if enormous savings in energy efficiency are not realised, this could leave system planning at risk.

- Example 3: Even the assumption of least-cost outcomes with large amounts of energy spill has no mechanism to incentivise that kind of investment. Should the modelling assume that is addressed or instead consider the rules as they are and therefore consider investment signals as they are? Similarly, there is currently no carbon price, therefore there is no incentive for carbon farming or direct air capture and sequestration of CO_2. Should investable technologies be preferenced over non-investable ones? What is the consequence and cost of such outcomes?
- Example 4: Massive over-investment in PV and residential batteries which then give control to a VPP aggregator is an assumption, but it undermines the robustness of the plan. It would be better to consider no residential investment and build a system that is resilient to that, then look at how under-utilised key infrastructure would be if the residential investment were to occur. With massive residential solar uptake, it is likely that utility-scale solar would be severely impacted, but what about the other investments? It may be that the other investments still provide a more secure path to the future with little additional cost. It would then provide a "free" option to scale up utility-scale investment in solar PV if the residential market slows.
- Example 5: The hosting capacity of distribution networks for continued residential solar PV installations is assumed to be lifted – but without seeing the issue, and also the alternatives, it is hard to know what actions should be taken.
- Example 6: Forced outage rates and long-duration outages are highly material to the ability of the system to manage interruption. The observed outages are becoming more frequent, particularly for the fossil fuel generators and the probability of one gas or coal unit being out of action on a sustained basis is around 30% on any given day. These assumptions are highly material and should be tested under increased or decreased outages – and such outages need to be simulated without prior knowledge to ensure the system is robust.
- Example 7: Electric vehicles will likely charge at times that are convenient for the user, not for the grid. There may be simple to use technologies that obscure that from the user, ensuring that the consumer is not inconvenienced, and the grid is not disadvantaged. This is a reasonable scenario assumption, but it is far from a given. Each scenario should also be tested against all users consuming against a profile that is similar to the current EV charging profile.
- Example 8: Large BEV trucks have a front axle load that does not comply with Australian road regulations – should this be assumed away or should alternative technologies that might comply with the road rules be preferenced? Large trucks are a major source of emissions in Australia and if BEV trucks were not an option, the system planning would likely need to be changed.
- Example 9: The 'non-REZ' locations are needed to understand an alternative future without investment – i.e. a counterfactual to network expansion. However, the wind and solar resources identified in these "non-REZ" areas are almost as good as the REZ opportunities and appear to be modelled as a plentiful resource without the need to build transmission or worry about social license. If such opportunities existed today, they would be being developed. It is more likely that the counterfactual is a failure to deliver on the constraints of the system.

Any one of these examples could notably change the future of the power system, and yet each is treated as a fixed assumption in the various scenarios. Exploring such uncertainties would help understand the potential futures and create actions which are more robust to future developments.

A forecast where the issues are resolved through assumed outcomes in the forecast may be 'cleaner' or 'neater', but ultimately less useful.

Developing a plan

Cost to consumers

A fundamental aspect to the NEO is achieving an efficient system that is in the long-term benefit of the consumers. It is pleasing to see that the long-term retail price indices still recognise that a stronger shift to renewable energy (as presented in the Green Energy Export scenario) would produce the lowest retail prices in the longer-term. In the nearer-term, while it is convenient to assume that low investment will produce a low system cost, that benefit doesn't necessarily pass to consumers. A better measure would explore the cost of scarcity rent and also the opportunities presented by demand response at varying prices.

Equally, the cost of consumer investments also needs to be communicated – if the system cost is kept down by assumptions regarding residential investment in PV and VPP, the cost of these assets should also be considered. It is not necessarily in the interest of the consumer to pay increased capital costs that are not captured in the modelling, to avoid system costs that are captured in the modelling. Understanding the total cost to the economy and to consumers, particularly consumer profiles, will better inform good planning and policy making.

Reliability of the system

Black swan events or 'high-impact, low probability' events tend to drive price and reliability outcomes in the operation of the system. These events are such that individual events may be unlikely, but when considered in aggregate, major events occur frequently. Understanding the impact of unexpected events such as major asset failures, global energy crises, pandemics, bushfires and other such outcomes should be considered in the planning, testing the system design against potential challenges. The system must be robust. Testing how well the designed system would cope with various disturbances could be done in a relatively simple post-processing step without additional optimisation. This makes the scope much more deliverable and also tests the proposed design, noting the risks and costs of certain outcomes.

Sustainability

As noted previously, only the Green Energy Export scenario meets the international commitments to addressing climate change as well as being the only scenario that meets the governments' stated target of 82% renewable energy by 2030. Using 'non-REZ' developments to simulate a counterfactual is probably less useful than explicitly noting what is not achieved under various different futures. Sustainability is not a given, it will need planning and actions to achieve the energy transition.

Our responses to the individual questions raised in the draft IASR are addressed as an appendix to this letter.

Thank you for the opportunity to comment on the draft IASR. If you would like to discuss any of the issues raised in this submission or to arrange a briefing, please contact tom.parkinson@fmgl.com.au or myself on the below details.

Yours sincerely

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FORTESCUE FUTURE INDUSTRIES

Responses to specific consultation questions

AEMO is seeking stakeholder feedback on the scenarios, including the scenario names that will be used in the 2024 ISP. AEMO considers this amended scenario collection provides logical extension to the 2021 IASR collection, used in the 2022 ISP and other planning assessments, and provides greater transparency for stakeholders through this Draft 2023 IASR.

Scenario breadth

While FFI is pleased to see a shift towards greater action on emissions reduction, it is unfortunate that the scenario space was narrowed. The 2022 Hydrogen Superpower scenario was viewed as most likely or most useful by a material portion of respondents in the Delphi Panel for the 2022 ISP. While Step Change was viewed as most likely, Hydrogen Superpower received strong support and was certainly not considered implausible. On that basis, it was disappointing to see a reduced rather than expanded vision for hydrogen in the scenarios – especially given the progress in the green hydrogen industry over the past 12 months. Moreover, the changes in the power system over the last 12 months show the importance of broad scenario planning.

Two "Step Changes"

The use of two scenarios to explore variants on the 2022 ISP Step Change scenario does provide greater focus around a scenario that has been identified as the most likely. However, is there really sufficient difference? Orchestrated Step Change is not sufficiently more orchestrated than other scenarios to really define its own scenario space. This is likely because all scenarios assume a high degree of consumer energy resources (CER) and orchestration.

For example, what is driving the investment decisions? Is it internally consistent that the CER uptake (particularly rooftop PV and batteries) is higher in a future with substantial growth of industrial renewable energy (Green energy export)? If there is more centralised action and cheaper sources of power, why do residential consumers continue to see that as a good investment opportunity? To support the use of these two similar scenarios, increased differentiation would likely be useful in informing decisions making.

Inconsistencies

The IASR is clearly a huge amount of work, but due to the large range of stakeholders, consultants and uncertainties, there is always a risk that there will be inconsistencies between assumptions and/or scenarios.

Examples of inconsistencies include:

- The large industrial load (LIL) forecast for Diverse Step Change vs other scenarios.
- The degree of carbon forestry in the various scenarios.
- The development of direct air capture in scenarios other than the Green Energy Export scenario (where there will actually be a driver for it to be developed).
- The difference between how fast the coal price recovers vs how fast new build capital costs recover.

Sensitivities

The proposed sensitivities are all well thought out and would be useful. However, it would also be useful to consider a sensitivity where there is notable tariff restructure such that owners of rooftop

PV still need to pay their fair share of connection fees (or disconnect from the grid and face the full cost of storage)?

Uncertainties

The identified uncertainties seem very well founded, although it may be useful to consider them broken down even further to better understand the scenarios and sensitivities:

- Economy
  - a slower economy may result in reduced load growth (or even contraction) also result in higher costs (or vice versa). It is unlikely that there will be a sustained surplus over time so any short-term surplus is probably negligible.
  - A faster economy may see increased growth and investment, including lower costs.
- Electrification
  - Electrification is not necessarily tied to economics. A sufficiently difficult economy may lead to increased electrification if there are still carbon emissions reduction targets. It may or may not be paired with an underlying growth in demand.
- Orchestration of CER
  - It is possible that CER continues to grow without orchestration. In fact, recent ethnographic research indicates that CER growth without orchestration may be the most likely future. Consumers won't want to give up freedoms and the case for giving up freedoms is challenging economically. Enforced orchestration may also act as a dampener on investment.
- Growth of CER
  - While not a given, it is expected that CER will continue to play a major role going forward and will likely continue to grow. However, currently the tariff structures mean that a 17% efficient solar array is outcompeting a 25% efficient solar array, not on the basis of capital efficiency or operational efficiency, but instead on the basis of cost avoidance (i.e. transmission and distribution). This is surely not sustainable. Without major orchestration we are already seeing issues from CER performance. It may be that a more practical solution than enforcing orchestration (control) or CER is to change the economics to be more inclusive of all costs.

Does the draft 2023 IASR scenario collection adequately enable AEMO to sufficiently test the risks of over-and under-investment in the power system in the Integrated System Plan?

As noted above, the 2023 IASR scenarios are not as broad as 2021 and many of the assumptions act to ease the energy transition – although the evidence for such changes is often unclear – particularly given the scale of change (for example efficiency gains). There are many assumptions which currently do not appear to be tested sufficiently and this presents a notable risk that is not adequately assessed.

Also, it is notable that only the Green Energy Export scenario meets the international commitments, the 82% renewable energy by 2030 expectation and the currently earmarked spend on hydrogen development. Surely it would be beneficial to consider more scenarios that meet these requirements. With the change to the National Electricity Objective, it will be important to plan for the desired outcome. Understanding the relative cost of a more robust and cleaner plan should be communicated, but the plan should still deliver on all commitments.

The descriptions of the scenarios may be broadly useful, but the details are a concern. Action on emissions reduction is deferred in every scenario compared with the 2021 IASR. There is also little breadth of scenario space leading up to 2030. Is there really so little uncertainty?

Do the scenario names provide improved clarity regarding their drivers and potential use?

FFI welcome the addition of the temperatures in the scenario names, it provides more transparency regarding the implications of each scenario. If Australia is serious about supporting global action to limit climate change to 1.5 degrees C rise in temperature, it is highly likely that more ambitious actions will be needed – including finding export options to share our renewable energy resources with the world. Explicitly acknowledging the climate drivers for each scenario is welcomed.

It should also be noted that the Step Change scenario is no longer truly considered a "step change". In fact, the emissions projection in Figure 4 shows that even the two Step Change scenario show a short-term rise in emissions from the NEM – which is a notable deviation from the current trend of emissions reductions year on year. Maybe changing this name to recognise the more gradual or cautious nature of the scenario would be more accurate given its change over time.

Similarly, "Progressive Change" is the least progressive scenario. The scenario name is misleading. Gradual Change or Moderated Change would be more representative of the narrative.

Do you consider any of the proposed sensitivities is not sufficiently relevant to be investigated in the 2024 ISP?

All sensitivities have merit. The smoothed infrastructure investment should also be weighed against the cost and consequences (and potential benefits) of that approach. Does it require earlier investment to achieve the smoothing? If so, the plan will be more robust to changes. However, if the smoothing is achieved by delayed investment, it may be that emissions targets are not met and there may be sustained scarcity rent on energy and/or capacity. Moreover, smoothed investment may change the capital efficiency which will be a major influence on the practicality of taking such an approach. It is critical that this sensitivity is paired with a practical way to achieve this outcome rather than just being academic analysis.

Do you consider any additional sensitivities ought to be explored in the 2024 ISP?

Testing impact of uncertain outcomes

The most important test (that is not currently performed) is the resilience of the planned system to uncertain outcomes. For example, nobody forecast the energy crisis that occurred in 2022. The total wholesale market cost in 2022 was ($37.1B[1]), almost perfectly 3 times the long-term average market price ($12.4B), and that is not just inflation or structural change, the average market cost across 2020 and 2021 was also $12.4B. This was an unexpected increase in market costs of $24.7B[2], which can be contrasted against the total benefit of the optimal development path identified in the 2022 ISP of $27.7B as well as the total network cost of $12.7B. The increase in wholesale power costs would have paid for any of the system developments considered in the 2022 ISP –

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[1] Sourced from OpenNEM.

[2] Even a highly robust market with redundancy in both energy and capacity would still have seen some increase in these unexpected market conditions. However, it also shows just how material these uncertainties may be. A market less reliant on international fossil fuel pricing with more redundancy would not have seen the same price outcomes.

including the Hydrogen Superpower scenario. Saving on system investment by optimising against uncertain forecasts is a false economy.

Without changing the build out, which development path is most robust if:

- The gas/coal prices are notably higher or lower?
- The peak demand and/or annual consumption forecasts are notably higher or lower?
- There is an unexpected retirement of a large generator?
- There is a major drought (beyond what is forecast) or conversely there are major rains?
- The capital costs of new build are notably higher or lower?
- Transmission plans are delayed by several years?
    - Note: they could also arguably be accelerated, but I am not sure if this will have much impact
- Unexpected rejection or adoption of CER orchestration?
- Unexpected increase or decrease in the uptake of CER, particularly PV and batteries?
- Electric vehicle charging profiles remain consistent with current charging patterns (i.e. aligned with peaks)?
    - Arguably they are already assumed to be fairly optimal without much reason to believe that will be the case.

Each of these uncertainties are tested by the ISP, but they are tested by a model which has perfect foresight of the upcoming requirement and adapts the system to cope with the change. Some of the uncertainties will not be resolved until it is too late to adjust the plan. Therefore, it is critical to understand how much influence each of these uncertainties has on the total cost to consumers and the emissions from the NEM. It may be that some of these uncertainties could be remediated with reasonably fast capital investment, but not all. For example, an unexpected retirement of a large coal station (for example due to safety concerns) may take five or more years to put together a suitable energy generation response – possibly longer if additional transmission is required. This could translate into a significant cost to consumers.

From a practicality perspective, this looks like a large increase in scope, but many of these sensitivities could be run purely using the short-term dispatch model since the intent is to test the cost of choosing a development path that is finely tuned to a specific future. There should be no need to run the longer, more-expensive, capacity expansion models. It is assumed that comparatively small increases in investment would ensure that the system is substantially more robust to uncertainty. Moreover, this would also highlight the importance of certainty in policy (where relevant).

Do you have any further views on the individual policies and their proposed application?

There are a range of policies which were recognised in the IASR, yet assumed to be covered by the scenario spread or not relevant to investment decisions. As with earlier discussions, the Green Energy Export scenario seems to address many of the policies, but it is critical to be clear that the other scenarios do not meet the policies or the commitments outlined. This raises the risk that there is only one scenario which is consistent with many policies.

Hydrogen investments

There are a large number of state-based hydrogen investments:

SA: Hydrogen Jobs	$593m
QLD: Central Queensland Hydrogen Project	$15m
QLD: Kogan Renewable Hydrogen Project	$28.9m
QLD: Hydrogen-Ready Gas Peaking Power Station at Kogan Creek	TBA
VIC: Transport	$12m
VIC: H2 and offshore wind ($7m, assume 50:50 split)	$3.5m
NSW: Transport (assume parity with VIC)	$12m
NSW: Other hydrogen initiatives	$150m
NSW: Tallawarra B	TBA
TAS: Bell Bay	$70m
	$884.4m +

Assuming government funding is at least matched by industry (and not even considering any federal incentives) this would be around $1.8B of investment. The federal government has budgeted for $1.2b to support the hydrogen industry, raising the investment to $3b – more if this is also expected to be matched by industry. Using the IASR electrolyser price of $1m/MW in 2030. This funding could result in thousands of MW of hydrogen plant, consuming electricity at a volume comparable to the aluminium sector. This would exceed the projected hydrogen development in all scenarios bar Green Energy Export. Therefore, if these policies are considered, the only viable scenario would be Green Energy Export. FFI would propose that some level of substantial hydrogen uptake is expected across all scenarios.

A plan for 82% renewable energy production by 2030

As noted above, the previous ISP did not model 82% renewable energy by 2030 in the Step Change scenario. It was closer to 78% - meaning that the non-renewable energy accounted for around 20% more energy than planned. Moreover, it relies heavily on an assumption that distributed PV will almost double leading up to 2030. With penetration rates in some suburbs already reaching 70%, expecting such outputs might be interpreted more as a hope and less as a plan. The plan should have options to deliver on this policy should the CER PV not eventuate.

Similarly, what plans can be evidenced to show a pathway towards a 43% reduction in emissions from other sectors? If the policy is to be taken seriously, the electricity industry should be prepared to show how it could achieve that outcome without making assumptions about other sectors.

State-based emissions targets

The state-based emissions targets are key policy items and we have already seen decisions taken, at least partially, on the basis of emissions targets. If the states are making decisions influenced by these targets, then they should be modelled. If Green Energy Export is the only scenario which adequately meets all the targets, then it should be clearly communicated that the plans developed in the other scenarios do not meet these requirements. Table 6 was useful as a comparison for Victoria, but it didn't include other states. It also showed that even Green Energy Export didn't actually meet all the targets – the last few % can be challenging and this is where new technologies, fuels and options need to be considered. Properly identifying that these targets will not be met provides important context to decisions being made today. It may be that it is worth enforcing the application of those targets in at least Green Energy Export.

Various firming tenders and support policies

Whether large subsidies (or legislated targets) to encourage storage are the most efficient option for balancing the power system is yet to be established. Large amounts of flexible demand incentivised to respond may be a more cost-effective solution for the market – reducing costs to consumers. Exploring the effectiveness of extended demand response (in the order of 20% utilisation) vs the effectiveness of storage investment (whether utility or residential) would be a useful piece of analysis to help inform decision makers.

Appetite for decarbonisation

While it is agreed that the RET is unlikely to drive substantial additional investment across the life of new wind or solar developments, it is important to recognise that even if the RET has already been met, the LGC price is currently high and this is due to customer appetite for voluntary emissions reduction / green products. Capturing this appetite for decarbonisation is an important driver in investment and purchasing decisions and such investment drivers should be considered in the IASR and ISP.

Do you consider any additional policies missing that you consider important to include in some or all the scenarios? If so, please provide details.

Commitments and agreement to international targets such as trying to achieve a temperature rise of no more than 1.5 degree C should be considered a key driver of policy and decisions. While it is not certain that all future scenarios would meet such commitments, it is important to recognise that only one of the scenarios is consistent with this international commitment.

One thing that would be really useful would be a tornado chart of influence. i.e. Look at the largest assumptions of change and test the impact that it has on the modelling outcomes. This could be done by comparing the breadth of assumptions across all scenarios as well as the current state[3]. This would give a reasonable measure of uncertainty. Then by applying the different outcomes for the most uncertain assumptions to a central scenario and seeing the change that would drive if the impact/change/variance was the average, twice as large or half as large. For example, consumer energy resources are projected to change substantially and hydrogen uptake is also a notable difference between scenarios. It would be good to understand the influences that those assumptions are having on the modelled outcomes.

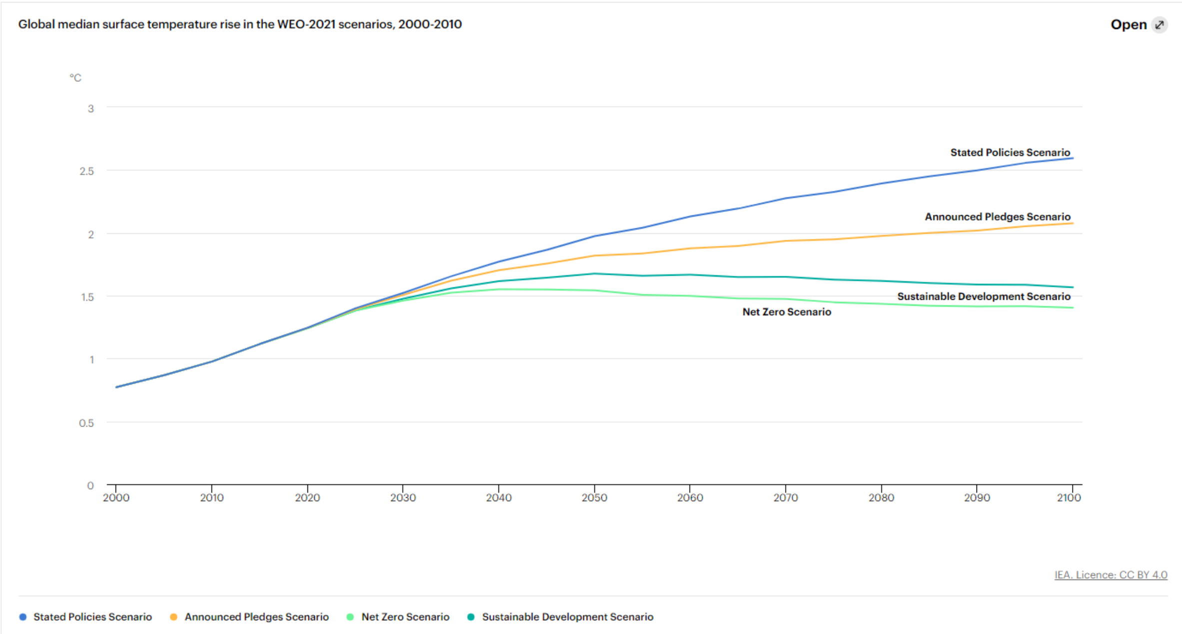
Do you consider the use of the listed weather stations appropriate to forecast consumption and maximum/minimum demand?

No comment.

[3] There is a risk that all scenarios may over or underestimate a change, so grounding the deviations against current state, not just the existing scenarios, provides useful context on the size and impact of the assumption.

Do you consider the proposed scenario alignment to the IEA scenarios appropriate? AND
Do you consider the global temperature pathways proposed to be assigned to each scenario appropriate?

In terms of the narrative, the alignment of IASR scenarios to IEA scenarios is considered appropriate, but the ambition/implementation of some of the IASR scenarios is insufficient to maintain that consistency. Green Energy Export might align with Net Zero Emissions by 2050 (NZE), but the two Step Change scenarios are targetting an outcome that is consistent with a 50% chance of staying below 1.8 degrees C, therefore also accepting a 50% chance of being above 1.8 degrees C. The Sustainable Development Scenario (SDS) targets 50% chance of below 1.65 degrees C. – which is half-way between Green Energy Export and Step Change. The Announced Pledges Scenario (APS) in 2021 was notably unable to meet the 2-degree threshold at all, let alone be “well under it”. It is noted that the IEA dropped the SDS after international commitments pushed the APS closer to that outcome. However, the IASR still refers to the SDS and therefore the 2021 version of the APS, which is inconsistent with the even the name *1.8°C* Diverse Step Change.



Even considering the 2022 World Energy Outlook (where the SDS scenario was dropped) the announced pledges had progressed sufficiently to be similar to the previous SDS – projected to have a 50% chance of being below 1.7 degrees C. This is below the ambition set for either Step Change Scenario.

Do you consider the proposed carbon budgets appropriate?

Carbon budgets

The carbon budgets are weaker than they should be to align with the IEA scenarios. This is covered by the previous question.

Negative emissions

A broader concern is the use of carbon sequestration. Direct air capture is currently an uneconomic technology not yet in operation at scale and yet it is heavily relied upon for the meeting of most carbon budgets. Similarly, the use of land-based carbon sequestration relies on substantial land use and capture at this rate is yet to be proven either. Major reductions in carbon emissions – particularly meeting tight carbon budgets – is challenging and using unproven negative emissions can run the risk of downplaying the size of the challenge. If negative emissions cannot be successfully or cost-effectively adopted at the necessary scale, the only viable option is to accelerate the reduction of emissions to avoid back-ending emissions reductions. It is not prudent planning to wait for 10 years to see if a technological breakthrough may occur. This risk should not be considered acceptable, and large assumptions about options for negative emissions downplay this risk and mute the signal that the rate of change needs to be accelerated. In the least, there should be a sensitivity which tests the cost of the change, or the rate of the change that would be necessary if it was found that the technological breakthrough did not occur and contrast it with earlier action.

Table 12 shows the emissions budgets (note: there may be a typo in the various column headers?). Taking the last two columns at face value – Green Energy Export must shift to negative emissions from 2030 to meet the carbon budget. The two Step Change scenarios must also shift to deep negative emissions, but do so later, making it appear that the period from 2030 is effectively net zero. Without the assumed carbon sequestration breakthroughs (or land use) these scenarios may fail to meet their carbon budgets.

Finally, if there is a scenario where direct air capture has a chance of development, it is more likely to be Green Energy Export since the R&D investment required to realise the opportunity would be backed by commercial opportunities to capture emissions free CO2 for use in synthetic fuels such as green methane, sustainable aviation fuel and synthetic diesel. The direct air capture maybe a source of negative emissions, but also instead a source of zero emissions fuel-substitutes. This could potentially underpin the development of the technology for pure carbon budget purposes – assuming that there would be a way to pay for these services.

Do you consider the approach to applying electrification to the load shape of residential and business consumers as reasonable?

The proposed approach seems like a largely logical approach, with one key caveat. Some of the business load is likely to be heating facilities – which would mean that there WOULD be some level of seasonality in the business electrification. The approach of using the same shape as the residential gas demand seems justified, it would seem reasonable to do the same for the business load. How the four-hourly gas demand is converted into 5-minute electricity demand is not yet clear. It is assumed that the new electrification would mostly match the profile of the existing electricity, with the volume in each four-hour block being provided by the gas consumption data.

Do you consider the methods and assumptions described in this section regarding transport electrification are reasonable and provide appropriately for each scenario?

Currently, Australian road legislation has a limit on the front axle load, and without a notable breakthrough in technology, this will severely limit the size and/or range of battery-electric trucks in Australia[4]. It is possible that the legislation may change, but typically AEMO does not assume legal changes will be made in the IASR. This could mean that any BEV uptake for articulated, rigid or

[4] This is an article based on a discussion with an executive from Volvo highlighting the challenge of front axle load limits. https://www.trucksales.com.au/editorial/details/volvo-heavy-duty-electric-trucks-next-year-138137/

possibly even large light commercial vehicles may need to use alternative power trains. Analysing the BEV uptake data, this could change consumption in 2030 by around 6 TWh in the Green Energy Export scenario – but more critically, it also means that these vehicles would need an alternative fuel source, which may push them back to fossil fuels, which would in turn require greater emissions reductions elsewhere. By 2050, this impact could be as much as 41 TWh. The assumptions used for vehicle uptake are likely to be missing this key limitation at the moment. It is one of the key factors in heavy vehicles pushing towards fuel-types that have a better weight-to-energy ratio than batteries.

Do you consider the change in vehicle charging load profiles (compared in Figure 10) are appropriate than the 2021 IASR profiles given they are developed from trial data, particularly for the reduced peak demand from 'convenience' charging?

The idea that trucks or buses (which are heavily in use during daylight hours for both business and passenger purposes) use day-time charging misses the key purpose for their existence. The article from Volvo referenced in the previous question shows that the current trials all charge at night. They charge when it is convenient to their business. The practicality of fast charging is unclear for such large vehicles. The demand would almost exclusively be during the night-time hours. Similarly, the idea that light commercial vehicles may find it convenient to charge between 10am and 4pm is unlikely to be backed up by evidence. These vehicles are typically high-use vehicles delivering goods during business hours, meaning that the majority of the charging will need to occur outside business hours, supplemented by fast charging when needed.

Even the residential vehicles are showing a bias towards day-time charging. It is agreed and understood that some vehicles will be charged during the day using a daytime charging profile – but if the user has a tendency to charge for convenience, it will not peak during the day. Moreover, even the "night" profile has a notable midday peak. These assumptions which bias demand towards consuming the solar spill from the overbuilt CER PV underplay the challenges in the changes to the system.

Should other factors regarding electrification be considered that may impact the consumer electricity load shape?

The idea that consumers will elect to use a less convenient form of energy misses the reason that people own vehicles in the first place: if the desire was to minimise cost, they would take public transport. The ownership and use of vehicles shows that this energy conservation is unlikely to be a major driver. Ethnographic research undertaken by Monash (supported by Energy Consumers Australia (ECA), AusNet and AusGrid and presented at the ECA Foresighting Forum) shows that consumers want control. Even if there were to be automation, the evidence shows that people want to maintain the option to override the systems. They don't want to engage with the power system – but they DO want to engage with their devices and appliances on their own terms. Tariffs will have some effect, but it is not likely to be large. In the very least, the impact of minimal load shape adjustment should be tested to see what might be required if consumers choose to operate to their convenience rather than cost profile.

No question asked - Fuel switching commentary

It is noted that biomethane is only used in very small quantities in Orchestrated Step Change, yet it is unclear why biomethane would increase substantially in Green Energy Export? Hydrogen is plentiful, it is assumed to be more cost effective in this scenario, and even at the Orchestrated Step Change prices, hydrogen outcompeted biomethane substantially. A high bioenergy future is explored in the Diverse Step Change scenario, it is not needed to be replicated in the Green Energy Export scenario as well.

It is interesting that the domestic hydrogen consumption is higher in Progressive Change than it is in either Step Change scenario. It is assumed that this is due to the fixed assumption across all scenarios that there is 10% by volume hydrogen blending by 2030 – and reduced electrification in Progressive Change? Decreased hydrogen utilisation in the Step Change scenarios seems inconsistent with the narrative.

The assumption that NEM states will export their current share of Liquified Natural Gas (LNG) – assumes that all hydrogen exports will be from QLD. However, there is substantial development in all states with a view towards hydrogen exports. Limiting this to Queensland is unlikely to be accurate. Moreover, hydrogen projects are not just targeting the gas market. Hydrogen is also being used to displace oil-based fuels and potentially coal. Limiting the export market to the existing LNG market is not likely to be an accurate forecast and will likely skew the model outcomes in the NEM. Finally, assuming no hydrogen exports in the Progressive Change scenario does not seem consistent with the assumption that there is a 10% blend in the domestic pipelines. It is considered likely that such requirements would likely either result in an export market or be based on trying to incentivise an export market.

Finally, no reasoning is given regarding the lack of hydrogen export in the Step Change scenarios. It is unclear how these were established, but the hydrogen production is unlikely to be consistent with the earmarked funding from state and federal governments.

Are the assumptions which are proposed to apply affecting CER (including PVNSG) investments providing a reasonable spread of futures to evaluate the transmission-scale investments needed for the energy transition?

The distributed PV forecasts appear to be driven by current uptake trends without considering likely thresholds. The PV installations are approximately twice the maximum demand, meaning that on a sunny day, approximately half of the generation must either be going to storage or being spilled. Already we are seeing the value of solar in the market being below its levelised cost of energy. Doubling of distributed PV by 2030 is assumed in most scenarios and would likely result in major curtailments and/or negative pricing for around 4-8 hours most days. This does not seem like a realistic forecast for 2030 and does not make sense as an investment proposition for a residential property, nor is it efficient use of Australia’s limited investment dollars.

This outcome would require each residence with a PV installation to install panels substantially larger than their own consumption – relying on grid exports and/or co-located batteries to pay for the PV over-install. Moreover, the hosting capacity of the distribution network is increasingly being identified as a constraint. The cost of upgrading the hosting capacity of the distribution system should be considered as part of the overall planning process.

The distributed battery forecasts have been reduced based on evidence that previous forecasts were too ambitious. However, they are still notably over-forecast. The power to energy ratio is based on consumer need, yet the batteries are also substantially over-installed, undermining the power to energy ratio. Assuming a peak load of 40 GW for the entire NEM, there is enough capacity in the distributed storage to provide the peak demand for the entire NEM from distributed sources alone. Considering that that residential demand only accounts for around 25% of the consumption and PV is forecast to be installed on only 50% of dwellings, the battery installation may be more appropriately capped at somewhere from 5-10 GW (depending on how peaky the residential demand profile is). Much like for distributed PV, these assumptions are not looking at the drivers for the uptake. Currently the business case for a residence to install batteries beyond their needs is not sufficient – proven by the slower than forecast uptake. Similarly, there is no business case to install batteries simply to better manage PV production if the PV is also over-installed. Even Progressive Change appears to be a bullish forecast once these thresholds regarding the grid-impacts and investment drivers and considered.

The consequence of these assumptions is that the modelling is likely to underestimate the degree of generation development required and also the transmission development required to access the more-efficient generation sources. Instead, these assumptions rely on over-built distributed PV and storage at the cost of consumers.

Should other considerations affecting the operation and orchestration of consumer resources be considered, particularly regarding the variation between the 1.8°C Diverse Step Change and 1.8°C Orchestrated Step Change scenarios? Will these assumptions effectively distinguish the investment needs of transmission-scale infrastructure with greater or lesser consumer resources?

There is very little evidence of VPP uptake currently, noting that battery uptake is slower than previously forecast. While VPPs may be good for the grid, this is not sufficient to make an investment decision for investing household capital in a battery.

If the investment is being made, it needs to be balanced against alternative options rather than assumed into the model. A VPP may increase the value of a battery, but will it increase the value beyond the capital efficiency of a more centralised development? Will VPPs be able to outcompete utility-scale batteries? This is far from clear, and yet there is an assumption that most of the batteries that are purchased will be enrolled in VPP schemes – essentially assuming that consumers are investing in batteries as a money-making investment rather than as a cost-offsetting investment. This is a very influential assumption with little evidence to back it up. Even Diverse Step Change still has well over 50% of all battery capacity enrolled in a VPP scheme – and it is meant to be testing a non-orchestrated future.

By contrast, ethnographic research undertaken by Monash currently indicates that the opposite is likely with very little appetite for orchestration and loss of control. Orchestrated Step Change can be used to explore the impact of this critical uncertainty, but all other scenarios should assume very low levels of participation (<10%) unless additional evidence can be provided.

AEMO has adopted the average of each consultant's projections regarding battery and VPP orchestration levels from GEM and CSIRO for the 1.8°C Diverse Step Change scenario, which results in a higher uptake forecast than an alternative if adopting the lower forecast from CSIRO in isolation. Do stakeholders have any comments on the adoption of this level?

As noted above, both consultant's forecasts seem to omit the likely grid interactions and the drivers for consumer uptake. Therefore, the mix of CSIRO vs GEM is less relevant than baselining the results against certain limiting factors.

No question asked 3.3.11 – Large industrial loads

It is unclear why the Diverse Step Change LIL forecast is so much higher? Electrification is stronger in Orchestrated Step Change while industrial growth is the same. The LNG demand is forecast lower than last year, so while Diverse Step Change has more LNG exports, it can't be attributed to that since it should be putting downwards pressure on LIL consumption. This appears to also be counter to the increased industrial activity in Green Energy Export. This forecast seems to be in conflict with the other scenarios and narratives. It needs to be reconsidered or in the very least explained carefully. A 20% increase in LIL load from Orchestrated Step Change to Diverse Step Change is highly material and not expected.

No question asked 3.3.12 – Energy efficiency forecasts

It is far from certain that energy efficiency will increase at the rates projected. The reason given for a substantial lift in Green Energy Export is that more efficiency is "needed" – but that is not a strong foundation for a forecast. Moreover, alternative emissions reduction options are available, such as increased fuel switching to green hydrogen. The emissions objectives don't appear to have changed from Hydrogen Superpower to Green Energy export, and yet the energy efficiency assumption has increased substantially. This is likely to underestimate the work and investment needed to achieve this future. Moreover, it could be argued that energy efficiency is more important in the scenarios where the grid is dirtier than cleaner as it will make a larger emissions reduction, now part of the NEO.

Do you consider it reasonable to target the 8.5% by 2053 in the high growth case in the table above, or should that potentially be brought forward?

Note: The question relates to the demand side participation section (DSP). While it is noted that there was literature-based analysis, the provided summary was not clear on what was, or was not, included in the 8.5% demand side participation in the published works. For example, does this include EV charging? If so, the IASR is double-dipping by having variable charging profiles as well as considering DSP. Similarly, does it include any price elasticity? Does it include electrolyser flexibility? Does it include batteries, VPPs or other CER? Does it consider efficiency? All of these elements are explicitly accounted for in the IASR but may or may not be accounted for in the international literature. Considering the existing system rules and regulations, is it reasonable to assume increased DSP at all? Maybe a more useful analysis would be to look at the current DSP responses to given prices. The future power system may be more volatile, resulting in more instances of high prices, resulting in more DSP – this would be a logical and defensible approach. It may be that Australia's power market continues to be more volatile than larger international markets – meaning that the DSP could be higher. However, it could be that the other actions may act to reduce volatility, resulting in a lower level of DSP. This could be converted into an endogenous variable which would be closer to price elasticity. It should be noted that electrolyser flexibility is likely to be a strong demand side option, particularly if the commercial signals are refined to help minimise market price.

The NSW scheme is a mechanism to encourage peak demand response, but will it be sufficient to create a signal larger than the upper limit identified by the international studies? This seems questionable. Maybe this is a pathway to achieving the higher number – although even then the number still needs to be tested against the other assumptions in the IASR. The Australian Stock Exchange (ASX) forward markets certainly don't foresee a smothering of peak prices in NSW over the next few years. It would be reasonable to test this forecast with some variability across scenarios.

Finally, the Tasmanian reasoning is fair – but Tasmania can be exposed to high spot prices when there is no price separation from the pool price in Victoria. When Marinus Link is completed, it is much more likely that Tasmania's pool price will more closely follow Victoria's – sharing the Tasmanian capacity with the other regions, but also sharing the energy from the other regions more freely with Tasmania. Using a more direct measure of current peak price response would be a more useful approach and could be used equally for all regions – including whether or not the load profiles in each region have more or less peak price sensitivity.

Do you have specific feedback and data on the assumed technical and cost parameters for existing generators?

It should be noted that generators have a conflict of interest in providing accurate information regarding their operating costs and forced outage rates. For example, an individual generator can improve its position on the cost stack by claiming more efficient heat rates, lower VOM and higher FOM. This in turn reduces the forecast need for new generation and transmission investment, resulting in higher capacity factor for that generator. This is in the interest of companies for asset valuation and also suppresses the signal for competition.

It is considered unlikely that the generators would be intentionally misleading due to the transparency of the process, but when there is self-interest, analysis can be unintentionally skewed. A relatively simple process to independently assess these numbers would be useful and alleviate such concerns.

Other parameters also appear to be inconsistently treated between similar generators. Comparing the following parameters shows quite different approaches to the information provided.

- Seasonal ratings
- Minimum stable levels

As well as testing these parameters, it would be good to understand how these are interpreted. Are these limits sustainable for extended periods? Do they affect the maintenance cycle? Are they technically or economically based? For example, a minimum level that may be technically achievable, but may not be economically sustainable. Therefore, if the capacity expansion model is reducing capacity factors much below current levels, it is questionable whether the plant would continue to operate. This should be considered as part of a feedback cycle.

It is also worth noting that a model with perfect foresight will select plant to start on time by choosing the plant to commence start up perfectly to be prepared for operation when needed. In reality, such outcomes are not known and longer-start up units struggle with this more than the more dynamic units. It is worth trying to capture this since it is a material operational issue that will likely be underestimated due to the use of a linear optimisation.

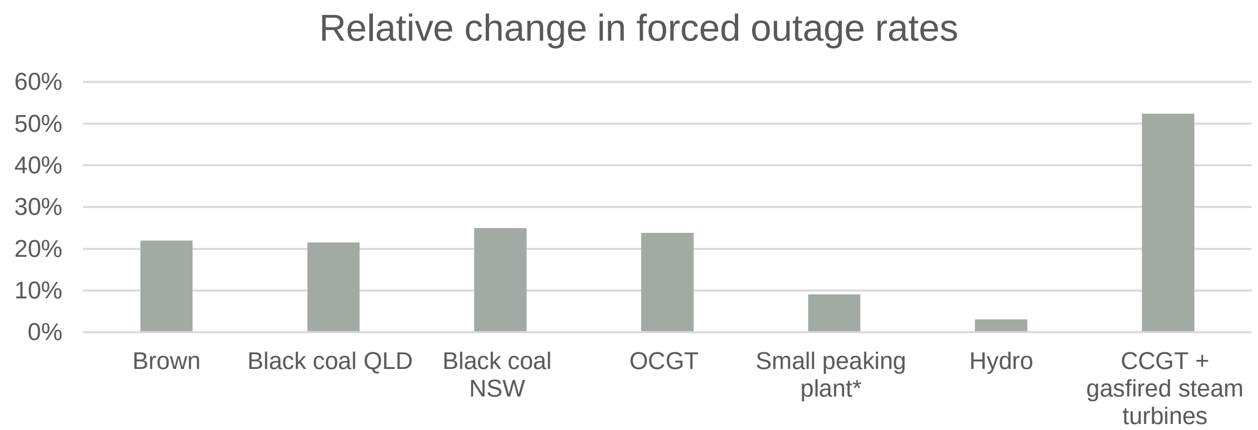
If you are an operator of an existing generator, do you have any specific technical or cost data that you are prepared to be used in AEMO's modelling? It would be preferable if this was data that was able to be published, but confidential data would also be considered.

N/A

No question asked 3.4.3 - Forced Outage Rates

With 47 operational coal units and a further 25 gas units, a long duration outage in any particular year is fairly likely. With 72 units with an average long-duration forced outage rate of somewhere from 0.54% up to 0.84% and a mean time to repair ranging from 7 to 9 months, results in around a 30% chance that something will be unavailable on any given day and around a 10% chance that there will be two such outages. The power system must be robust to extended outages *without notice*. This means that the system needs to have sufficient capability to cover that lost energy without relying on preparatory actions. Moreover, once the possibility of large outages on renewable energy transformers, transmission lines or other causes may also occur, it highlights a need to build a large amount of redundancy into the grid and the supply options to achieve a reliable system.

The forced outage assumptions (derived by analysis) are showing an increase over time. If this can increase so substantially over a few years it either begs the question on the stability of the data set used or indicates that maybe the units are becoming increasingly unreliable. If the latter is the case, the forced outage rate should be projected to increase over time. AEMO notes that they do not see this as material to the forecast, and yet in a single IASR cycle the forced outages rates have increased by around 20% (and over 50% for CCGT). Moreover, the forced outages again should be simulated without warning to the system. The system must have the capability to manage these outages without foresight and additional targeted investment or energy stockpiling.



Finally, the 'lumpiness' of the outages must be maintained as the size of an outage (or group of outages) is exponentially material in the management of the power system. This is why Figure 28 is concerning since the forecast shows a smoothing out of the impact of long duration outages. The historical data shows the real impact is much 'lumpier'. A good year and a bad year are much more difficult to manage than two middling years. It is hoped that the modelling is capturing this behaviour more accurately than depicted in this figure.

Do you have any views on the approach described above to address generator retirements?

It is not clear how the cost of retirement is used. Care is needed when using such assumptions. Once a generator is commissioned, the decommissioning cost is effectively a sunk cost. It can be delayed or managed in a variety of ways – not all of which include remaining fully operational and some can be beneficial to the growth of future industry. The key to handling the cost of generator retirement is that it shouldn't be considered as a cost-based inhibitor to ceasing operations. This only serves to exaggerate the incumbency benefit and slows the market transition.

Is AEMO's proposed list of candidate technologies reasonable? If not, what changes should be made?

The choice to use heat capture for biomass is an efficient use of an opportunity – but without understanding the demand this may have limited usefulness. European nations have extensive district heating which is beneficial for their energy system, but Australia typically does not have the same requirements and so has not invested in the same infrastructure. Assuming that there will be a demand for the heat risks selecting a technology based on an unfounded assumption. There is already substantial waste heat from industrial processes in Australia which is not captured. Specifically selecting biomass to benefit from that opportunity is not technology neutral. If it is to be included, waste heat demand (and supply opportunities) all need to be considered. Otherwise, it is purely an operational cost reduction for biomass and not for other plant.

Do you have specific feedback or data on the assumed current and projected costs for new generation and storage technologies?

It is good that the modelling considers the influence of the current costs – but it is questionable how long these high prices will continue. If the costs are driven by a rarity of input materials (e.g. lithium carbonate was noted to be in short supply) then this may have a longer-term impact and may even be a reason to consider a much more structural change in capital cost. However, if the change is purely due to temporary factors, such as logistics, is it not more reasonable to assume that they will be resolved before 2028 and the previous trajectory will be reached?

It is also worth noting that for some reason solar, and to a lesser extent gas, have been exempt from the rising price pressure. This seems unusual and does not align with the information that we have seen in the market.

Finally, in terms of consistency, it is noted that the coal price forecasts project the current cost peaks to resolve much faster than the technology cost peaks, even though the drivers for both cost increases are strongly related.

Do you have a view on the described approach to adjust wind build costs?

The approach seems reasonable unless CSIRO have any reason to believe that the wind efficiency improvements would be able to be added retrospectively to existing turbines. FFI does not believe that this is the case, and therefore consider the approach reasonable.

Do you agree with continuing to use the same regional cost factors as the previous ISP? If not, please provide suggestions for improvements or alternative data sources.

The regional cost factors are quite old now and it would be good to test their validity. The fact that Victoria is cheap in all regions seems unlikely when compared with other states. The scalars applied to equipment costs in the more expensive regions are extremely high – and yet there is little penalty in Victoria. Unless there is good evidence to differentiate the cost effectiveness of transport and employment in Victoria compared with other states, it is recommended that all states adopt the lower cost profiles from Victoria. The maps already account for differing accessibility by the size of the radius around the key ports. The size of the low cost and medium cost areas in QLD are much greater than in Tasmania.

Are there any other considerations that should be factored into these regional cost factors?

The employment costs are more likely to favour the states with lower socioeconomic data (such as Tasmania and South Australia). However, as noted above, having all states adopt the Victorian scalars is probably most reasonable.

Do you agree with these proposed technical parameters, as well as fixed and variable operating and maintenance costs of new entrant technologies? If not, please provide suggestions for improvements.

No comment.

Do you have a view on the cost assumptions for pumped hydro?

No comment

Do you consider the adjustments to pumped hydro limits reasonable?

No comment

Do you consider the proposed approach to model battery storage technologies appropriate?

No comment

Do you consider the proposed change to solar thermal technologies appropriate?

No comment

Do you have any feedback on the assumed coal and gas price trajectories?

If the gas prices are sustained at the levels forecast through until 2027, has this been considered in terms of the demand and potential fuel switching? Such prices would provide a good incentive to consider other options and it is unlikely that the demand would return once it switched away to electricity or an alternative energy molecule (such as hydrogen or biofuel).

It is also worth noting that the coal price trajectories are projected to recover to more normal levels by 2025, yet the cost of new build generation was projected to be affected through until 2028 and gas is projected to be affected until 2027. This seems like an inconsistency between various assumptions. It seems the faster recovery forecast by coal prices is the more likely outcome.

Do you have a view on the proposed discount rates that will be applied in the 2024 ISP?

It seems extreme that the views on discount rates could move so much in such a short period of time. The investments are generally very long-term investments and discount rates should be close to the long-term mean. The current challenges in the market should not overly influence the discount rate, nor short any short-term views on cheap capital. These influences may affect very near-term investments but should not be material over the life of the ISP.

Do you consider that the discount rate is appropriate for private sector investment, consistent with the guidance in the CBA Guidelines?

No comment.

Do you have a view on the VCR to be applied in the 2024 ISP?

Agree with this approach. If some of this additional value was available to voluntary demand response, it may be that the reliability could be substantially increased or at least delivered in most cost-effective ways. If considering the value of customer reliability (VCR) is necessary for proper planning, it should also be represented in how the market works.

The theoretical design of a counter-factual where no transmission is built is an influential part of the ISP cost-benefit analysis framework. Do you have any suggestions to enhance the approach to modelling a future without any transmission projects?

The non-REZ wind capacity factors are extremely high. For both NSW and VIC the "non-REZ" resource is actually higher than the REZ opportunities – this is clearly very different to the explanation that these resources will be lower.

It also appears that the capacities may not limited in the same way as the other REZs. If there was that kind of opportunity, there would be no need for new transmission development and no constraints on current connection processes. Moreover, while solar resource variation is not that great getting the land and approval is still a notable challenge and unlimited non-REZ opportunities seems to ignore these challenges. To maintain credibility, FFI would suggest that for the counterfactual, development costs are substantially raised for non-REZ developments and they would also be strictly limited. This may mean that some scenarios are not achievable, but that in itself is a useful insight.

Do you have specific feedback on the proposed REZ resource limits?

No direct feedback. It is assumed that the jurisdictions and jurisdictional planners will have appropriate insight into specific REZs. More broadly, it is worth thinking about whether different scenarios will have different appetite/acceptance and also whether a single large installation may be considered more/less acceptable than a series of smaller ones?

Is the capacity density for offshore wind farms of 5 MW/km2 appropriate for the calculation of offshore REZ offshore wind build limits?

No comment at this stage, but it would be good to communicate if this was found to be a binding limitation in the final reports.

Is the maximum depth of 60 meters for fixed offshore wind turbine structures reasonable?

No comment at this stage, but it would be good to communicate if this was found to be a binding limitation in the final reports.

Is it reasonable to assume 90% of the area of the offshore REZ can be developed?

No comment.

Is the maximum land use assumption of 5% for the REZ hard limits appropriate?

No comment.

Do you have specific feedback on the quantification of social licence in the development of REZs?

FFI suggest that different scenarios may have different appetites for social acceptance.

How should AEMO incorporate social licence in the assessment of transmission, generation, and/or storage projects?

The proposed projects will be more likely to gain social license in the near term and so it would be good to preference development of proposed projects first. It is hard to really understand how social license will develop. It would be good to understand social license in the individual REZ. That may allow for different land coverage in different REZ. That would likely require some detailed analysis. That effort would benefit from AEMO, jurisdiction and jurisdictional planner input.

Do stakeholders have any other suggestions for representation of REZ transmission limit constraints and the secondary REZ transmission limits?

No comment

Do stakeholders have any other suggestions for representation of inter-related constraints across multiple REZs and/or REZs and flow paths?

No comment.

Do you have any feedback on the proposed values of the REZ transmission modifiers as a result of interconnectors or sub-regional augmentations, and the REZs they apply to?

The only comment here would be to consider the benefits of investing in larger capacity to be resilient to additional developments in later years. The augmentations may be better managed by a larger more scale-efficient investment that future-proofs against other renewable energy development needs. This is particularly important in light of the likely challenges in “non-REZ” development.

Does the proposed sub-regional model reasonably represent the network? Are there any additional subregions which should be considered (and why)?

No comment.

Do you have any specific feedback on the existing and proposed flow path transfer capabilities?

No comment.

Do you have any feedback on the uplift factors applied to flow paths as a result of committed and anticipated projects?

No comment

Is there any specific feedback on the treatment of costs and options developed via preparatory activities for inclusion in the ISP?

No comment.

How should AEMO escalate the cost for preparatory activities received in response to the 2020 ISP for use in the 2024 ISP?

No comment.

Is there any information on non-network technologies or proponents regarding opportunities for competitive non-network investment?

Generation investment, storage and demand response are all critical elements to planning the future grid. While the ISP does a good job modelling the generation and utility storage opportunity, the demand response is typically challenging to model. Accordingly, demand profiles are considered (such as for EVs) and assumed uptake for CER storage and energy efficiency. These assumptions are all HIGHLY influential on the outcomes of AEMO's modelling, particularly the ISP. However, the separation of network vs non-network solutions should only be considered for addressing particular constraints and challenges meeting peak demand in specific locations. These details may be more influential beneath the sub-regional level of modelling.

At the sub-regional level of modelling, there is large-scale transmission which is likely needed to manage efficient energy transfers, but challenges in meeting capacity constraints as well as sustained need for energy during low variable renewable energy production are also increasingly occurring. FFI believe that in a strong hydrogen future, demand response can play a critical role. There are options to operate hydrogen production plant flexibly for the benefit of both the operator and the system. Accordingly, if new loads can incentivise new generation, but then avoid consuming at times when prices are high and supply is low, this can notably improve the system reliability and if properly incentivised could do so while reducing the cost to consumers.

Given that non-network investments generally involve commercial arrangements with plant with multiple revenue streams, how should AEMO estimate their cost transparently?

Generation investments typically get a majority of their revenue from revenue streams that are captured within the ISP. However, the ISP does not usually capture the cost implications of a system under substantial stress due to extended long-duration outages or black swan events. These events drive the investment of the "pure capacity" supply or demand response options. These investments may capture a value from trading cap contracts – but even then that is on the basis of risk avoidance and price management which should all be captured within the ISP modelling. Batteries receiving additional revenue streams for transmission avoidance should be captured within the ISP as well, although it is recognised that distribution avoidance would need to be captured separately. It is suggested that the jurisdictional planners could support this information request. Finally, demand response should also be able to be captured within the ISP model, similarly to the cap contracts, although possibly at different strike prices or through operational engagement in the spot market. However, to accurately reflect this the individual loads would need to understand a cost of reducing production as well as an opportunity cost – much like for flexible supply. A small amount of demand response at a higher price may be more valuable than a smaller increase in price spread across a large volume of supply.

As with all major investments, that may also be additional support from various stakeholders (including governments) who may value other aspects such as employment and energy security beyond the levels considered in the modelling. This would apply to transmission as well and should be captured for all projects, not just the non-network ones.

Is there any specific feedback on the proposed intra-regional loss equations and loss factor equations?

No comment.

Is there any feedback on the proposed updated inter-regional loss equations, loss factor equations and proportioning factors following committed and anticipated network upgrades?

No comment.

Do you have any specific feedback on the proposed hydrogen export ports?

The capital costs of electrolysers seem high. More broadly in terms of the ports, the selection of the ports to model appears reasonable.