16 February 2024

Australian Energy Market Operator (AEMO)
Via email: ISP@aemo.com.au

Dear AEMO ISP Team,

Marinus Link submission on AEMO's draft Integrated System Plan 2024

Marinus Link Pty Ltd (MLPL) welcomes the opportunity to provide a response to the Australian Energy Market Operator's (AEMO) 2024 Draft Integrated System Plan (ISP). We strongly support AEMO's forecasting and planning activities in the development of the Draft ISP and commend the collaborative approach, underpinned by AEMO's extensive stakeholder engagement. The draft ISP is an extensive set of forecasts and report, backed by a sophisticated array of analysis in the appendices.

MLPL is the proponent of Marinus Link, a proposed high voltage direct current (HVDC) 1500-megawatt (MW) capacity undersea and underground electricity and telecommunications interconnector to further link Tasmania and Victoria as part of Australia's future electricity grid. MLPL is a subsidiary business of Tasmanian Networks Pty Ltd (TasNetworks). TasNetworks is wholly owned by the State of Tasmania and is the Tasmanian jurisdictional planner and the builder, owner and operator of Tasmania's transmission and distribution electricity networks. The ownership of MLPL is expected to transition to the Commonwealth, Victorian and Tasmanian governments in early 2024.

Marinus Link remains critical to unlocking Tasmania's energy opportunities to support Australia's energy transition by providing greater access to Tasmania's existing flexible and dispatchable capacity and deep storage, which is capable of cost-effectively integrating increasing shares of variable renewable energy (VRE) in Victoria, and further across the NEM. In addition, Marinus Link will be capable of supporting optimal system security outcomes in the NEM, using grid-forming inverter and Voltage Source Converter technologies. These technologies can allow for Marinus Link to provide critical and increasingly vital system services to maintain grid stability, and the ability to operate in periods of very low system strength.

The 2024 Draft ISP forecasts a rapid retirement of coal-fired generators in all scenarios and substantial demand growth driven by the electrification of transport, heating and industrial processes, and as new industries such as hydrogen emerge. This rapid transformation means that any delays to critical transmission and firming projects represents a substantial risk to energy consumers.

We were pleased to note that the 2024 Draft ISP still considers Marinus Link as a single actionable project with no regulatory staging requirements despite rising investment costs for all planned transmission projects. Further, AEMO forecasts that an actionable Marinus Link (both stages) will create substantial net market benefits.

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The Draft ISP identified that consumers are expected to avoid $17 billion in additional costs if actionable and future transmission projects, including Marinus Link, are delivered. MLPL considers that the Draft ISP tends to undervalue the benefits of transmission and deep storage and that AEMO's assessment of the net benefits of actionable projects is conservative due to the approach taken on several key inputs and assumptions, which are discussed in more detail in Attachment A. These additional observations relate to:

- Marinus Link second cable timing in the Optimal Development Path (ODP);
- Distributed storage uptake and coordination;
- Perfect foresight and operational implications;
- Concessional finance;
- Updated technology cost and distributed resource costs;
- Hydrogen load growth and flexibility.

If you wish to discuss any aspect of this submission, please contact Jonathan Myrtle at Jonathan.Myrtle@Marinuslink.com.au.

Yours sincerely,

Prajit Parameswar
Chief Commercial officer

Attachment A
Specific comments on modelling scenarios, inputs, assumptions and results

1. Central scenario selection

Marinus Link supports the rapid decarbonisation of the NEM. However, given observed market outcomes and changed market outlook since the 2022 ISP (for example, relatively slow actual growth in new grid-scale renewable capacity, slow transmission build out, and flat actual operational demand) and the Delphi Panel's similar weighting of Progressive Change (42% support) and Step Change (43% support), it is prudent to consider both these scenarios as 'central' (or not have a central scenario at all). Given this, our preference is for the Final 2024 ISP report to include a similar amount of material on the Progressive Change and Step Change scenarios.

2. Second cable timing

MLPL is pleased to see that the two highest ranked candidate development paths (CDP11 and CDP14) both include Marinus Link (both cables) as an actionable project. We note, however, the delayed timing of the second cable in the ODP (CDP11) relative to the 2022 ISP.

MLPL's view is that transmission benefits (including Marinus Link) in the Draft ISP (particularly the Step Change scenario) are adversely affected by several modelling assumptions selected by AEMO, including but not limited to distributed storage uptake, perfect foresight of storage operation, concessional finance, and hydrogen load growth and flexibility. While each assumption may or may not be credible, it is important that AEMO considers the risks of particular assumptions not coming to fruition, their likelihood of occurrence (not just whether they are plausible), and whether these risks can be managed by planning for earlier and larger deployment of transmission.

Further commentary on these modelling inputs and assumptions is provided in the sections below.

3. Distributed storage

The 2024 Draft ISP exogenously assumes significant uptake and coordination of distributed battery storage in two out of three of the central scenarios. Notably, the Step Change Scenario assumes:

- By the end of the forecast period, 76% of all residential solar systems are coupled with a battery. This equates to batteries at 6.8 million households (or 41% of all households).
- By the end of the forecast period, dispatchable distributed batteries represent nearly 50% of all dispatchable capacity in the NEM.

- A very high proportion of distributed batteries are assumed to be coordinated (dispatchable).

In the Draft 2024 ISP, AEMO obtained distributed battery forecasts (and consumer energy resource [CER] forecasts more broadly) from CSIRO and Green Energy Markets (GEM). The Step Change and Green Energy Export scenarios use an average of the two consultant's forecasts, while Progressive Change uses CSIRO's forecast.

Based on our analysis of the consultant's modelling reports, there appears to be significant differences in the consultant's distributed battery forecasts across all three scenarios. For example, GEM forecasts in the Step Change scenario that distributed battery capacity will reach ~114 GWh (degraded) by 2053-54, more than three times higher than CSIRO's forecast of ~31 GWh (degraded) by 2053-54.

We have identified several aspects in the forecasting methodology employed by GEM which renders the forecast uptake of coordinated distributed storage highly optimistic:

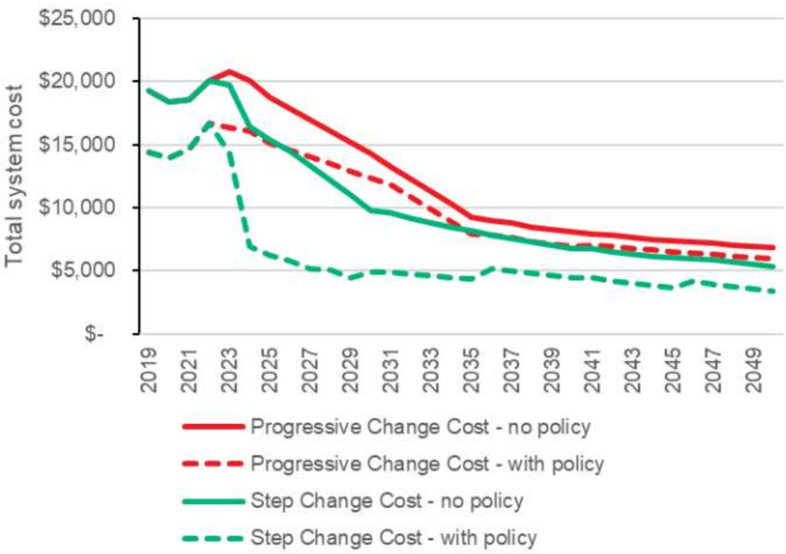
- **Government policy support.** In the Step Change and Green Energy Export scenarios, GEM assumes a "National rebate equal to 50% of capex introduced in 2024 and then steadily declines over time"[1]. This assumption halves the payback period, and is a key driver of the divergence in distributed battery uptake between these two and the Progressive Change scenario.
  - Figure 1 shows the major impact that this assumption, coupled with forecast capex reductions, has on distributed battery costs. In this forecast, combined solar and battery system costs reduce from ~$16,000 in 2023 to ~$6,000 in 2025. Given the most recent information on battery costs and policies since this forecast was conducted, these cost reductions no longer remain plausible in the short to medium term.
  - It is important to note that the inclusion of such a rebate is inconsistent with the policy inclusion criteria of the ISP, as outlined in clause 5.22.3 of the National Electricity Rules (NER) and was not adopted by CSIRO in their modelling.
  - We consider that moderating or removing this assumption of policy support for batteries would be a more robust approach, particularly in the absence of a clear indication that the Australian Government (at either state or federal level) will be introducing such a policy initiative.
- **Alternative technologies not considered.** One of the key value-adds of distributed storage is its ability to store excess rooftop PV energy that would otherwise be curtailed (particularly given the forecast increase in size in rooftop PV systems). GEMs current modelling methodology does not consider the

[1] Green Energy Markets, Draft Projections of distributed solar PV and battery uptake for AEMO (2022), p.44. https://aemo.com.au/-/media/files/stakeholder_consultation/consultations/nem-consultations/2022/2023-inputs-assumptions-and-scenarios-consultation/supporting-materials-for-2023/gem-2022-solar-pv-and-battery-projection-report.pdf?la=en

impact of other technologies that would absorb excess rooftop PV, including electric vehicle (EV) charging and other demand response (for example, electrification of heating).

- **Payback period used exclusively.** GEM notes that residential batteries are yet to reach levels of financial attractiveness that would support mass-market uptake, making it difficult to establish a minimum baseline for uptake. Their model currently assumes that battery uptake only takes place once the paybacks on a battery plus a solar system reach close to parity on a solar system alone.
  - We consider this a relatively optimistic assumption as it does not take into account the higher upfront cost of batteries. For equal payback periods, we consider battery uptake to have a lower (rather than a similar) rate of system uptake relative to solar systems alone, with the higher upfront cost being a barrier to many consumers.

Figure 1 Green Energy Market's combined solar & battery system cost with and without policy support Step Change compared to Progressive Change (6.6kW solar + 10kWh battery system, 2022)



Based on the above observations, **MLPL recommends that AEMO revisits its assumptions, methodology and forecasts for distributed battery storage in the upcoming and future ISPs**.

4. Perfect foresight

MLPL welcomes AEMO's exploration of alternative approaches to modelling perfect foresight in Appendix A4: System Operability and finding from the modelling highlighting the risk to reliability from imperfect management of stored energy. AEMO notes:

The implications of imperfect weather, load and renewable energy forecasting, and of imperfect foresight in planning and investment models, is likely to increase the value of transmission (increasing diversity of flow paths) and storage depth (and/or other forms of dispatchable generation to increase reserves).

Despite the above, AEMO's current modelling approach does not account for this perfect foresight limitation in identifying the ODP for generation and transmission. To date, the different options explored by AEMO are all focussed on the ST phase (dispatch) of the modelling, rather than in the investment phase (LT). We suggest that there is now a clear body of evidence that shorter-duration storage does not contribute as strongly to system reliability outcomes as currently modelled and that this has implications in both the LT and ST phase of the modelling.

Further to our comments above, our analysis suggests that one of the metrics used by AEMO to measure the historical performance of batteries – average price spread captured by batteries (p.32, Fig 23) – may not be the best measure of actual battery performance versus optimal (or modelled) battery performance. We suggest a better metric for comparing differences between actual market outcomes and modelled outcomes would be spot revenue capture in actual outcomes versus perfectly optimised outcomes.

We recommend:

- AEMO to consider the reliability implications of imperfect foresight and identify modelling techniques that could be applied in the LT (investment phase) to better account for imperfect foresight and avoid resulting reliability shortfalls.
- Of the 3 methodologies explored in the ST phase Appendix A4, de-rating storage capacity (Option 1) appears to be the method that best captures the perfect foresight limitation and should be applied more broadly in the ISP modelling to better capture real world behaviour and association costs and limitations.

Given the materiality of storage deployed in AEMO's model, we suggest AEMO continues to improve its modelling approaches and consult extensively with stakeholders on this important topic.

5. **Concessional finance**

The AEMC has recently published a draft determination in relation to concessional finance, which will enable the benefits of concessional finance to be passed onto consumers in accordance with the terms of the concessional finance agreement between the TNSP and the Government Funding Body.

In its draft determination, the AEMC explains that concessional finance may be used to support a project option (by changing its ranking or timing) where the concessional finance reduces the cost of the project option by providing a benefit to consumers in the form of lower network tariffs. The AEMC recommends that the AER updates its Cost Benefit Analysis and Regulatory Investment Test Application Guidelines to explain the treatment of concessional finance in the economic assessment process.[2]

We note that Marinus Link expects to obtain concessional finance that will reduce the network charges associated with the project. While the AER is unlikely to update its guidelines in advance of AEMO finalising its 2024 ISP, it would be useful if AEMO indicated the impact of concessional finance on the optimal timing of Marinus Link. By providing this information in its 2024 ISP, stakeholders will have a better understanding of how the benefits of concessional finance will advance the optimal timing of Marinus Link.

6. New technology cost and distributed resource assumptions

We note the release of the updated data inputs published by AEMO in its *December 2023 Draft 2024 Forecasting Assumptions* update for technology costs, distributed PV, distributed battery storage, participation in virtual power plants (VPPs), and electric vehicles. We also observe that AEMO is not currently proposing to apply these updated assumptions in the forthcoming 2024 ISP.

By the time the 2024 ISP is finalised and published in June 2024, many of the previous assumptions developed in its 2023 Inputs, Assumptions and Scenarios Report will be 18 to 24 months out of date. The updated inputs include the latest market developments and improvements in modelling methodologies. For example:

- The latest distributed battery outlook accounts for recent slower than anticipated battery sales and a forecast reduction in the number of PV installations.
- Several enhancements have been made to the electric vehicle outlook, incorporating new insights, including:
  - Higher forecast EV uptake, reflecting recent strong sales, above all 2023 IASR scenarios and consideration and likelihood of a potential fuel efficiency standard.
  - Lower forecasts utilisation of EVs, resulting in a relatively unchanged overall energy use (despite higher uptake mentioned above).
  - New charging profiles, including better recognising the importance of public charging, as well as lower assumed uptake of coordinated charging.
- Notable increases observed in the current capital cost of several technologies, including combined-cycle gas turbines, gas with carbon capture and storage (CCS) and onshore wind, with a decrease in large-scale PV costs.

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[2] AEMC, Draft Rule Determination, Sharing concessional finance benefits with consumers 2024, paragraph 22, page iv, 14 December 2023.

These assumptions are likely to materially affect results, including timing and selection of the ODP. While some updates may be difficult to incorporate in time for the final ISP, **we recommend AEMO to consider adoption of updated assumptions that can be implemented in a timely manner for the Final 2024 ISP**.

7. New load growth and flexibility

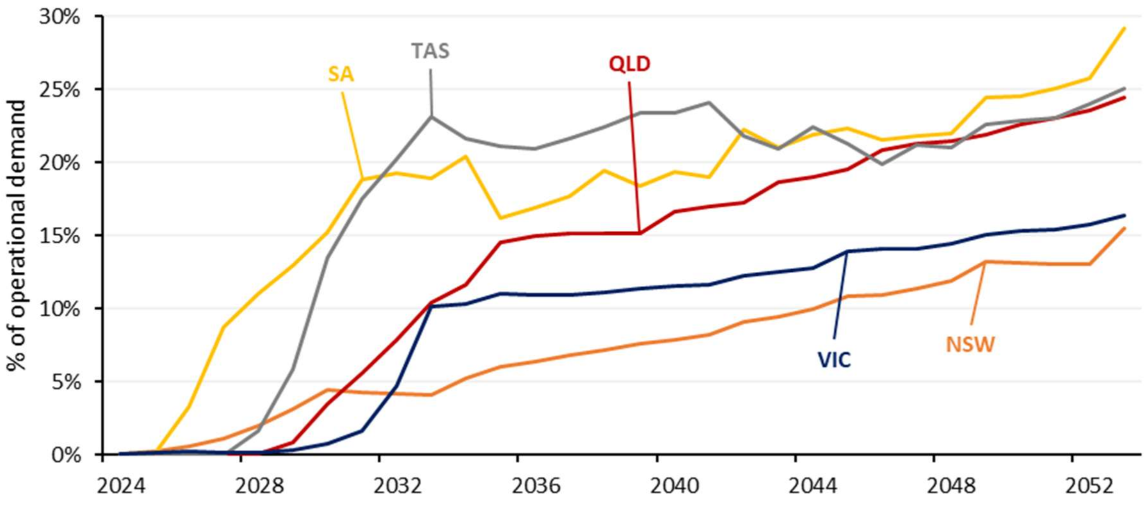
New hydrogen load is an important assumption in the ISP, with hydrogen load making up 18% of NEM operational demand by 2050 in the Step Change scenario, 10% in the Progressive Change scenario, and 73% in the Green Energy Export scenario.

The hydrogen load growth assumption in the Draft 2024 ISP was developed by CSIRO and ClimateWorks in late 2022 and is largely a function of hydrogen cost projections as an alternative gaseous fuel, and the carbon budgets applied in the different scenarios. AEMO has acknowledged a high degree of uncertainty regarding hydrogen load growth in its 2023 Inputs, Assumptions and Scenarios Report:

> *Although every state has outlined hydrogen strategies the cost, timing and magnitude of an eventual hydrogen economy with Australia is highly uncertain*.

The current hydrogen growth assumption sees relatively more rapid development in Tasmania and South Australia relative to total operational demand in those regions. This is illustrated in Figure 2, which shows hydrogen load as a proportion of operational demand in those regions increasing to around 20% by 2030, much more rapidly than other NEM regions (for the Step Change scenario).

Figure 2 Hydrogen load as a proportion of operational demand by region (Draft 2024 ISP – Step Change scenario)



From our review of available documentation, it is unclear how the regional breakdown of hydrogen load growth was developed. Many factors are likely to influence the regional spread of hydrogen load growth, including:

- Availability of low-cost and clean supply.
- Availability of intra-regional transmission to accommodate large demand growth.
- Availability of supporting infrastructure.
- The supply-demand balance of a given region (including capacity not restricted to energy balance). For example, NEM regions with an abundance of existing generation and capacity, and that are already net exporters of electricity to other regions, are more likely to be able to accommodate rapid load growth (including hydrogen load).

MLPL considers that the location of new load in the NEM is a material factor in determining the timing and selection of the ODP. **We recommend that AEMO continues to collaborate with governments and subject matter experts to ensure that the hydrogen load assumption incorporates the best and latest available information and that regions can accommodate the assumed hydrogen growth in the next 10-15 years**.

Hydrogen flexibility

The ISP Methodology[3] notes that monthly production targets are assumed for hydrogen:

> *Hydrogen operation is flexible to minimise total costs while meeting monthly production targets, subject to an inflexible baseload component. More electrolyser capacity can increase operational flexibility and lower operating costs, but comes at a higher capital cost.*

However, the Draft ISP does not mention how the more granular operation affects modelling outcomes, nor does it share the capacity or utilisation of the electrolysers needed to supply the assumed hydrogen load. Without the additional information, it is assumed that monthly targets and a high degree of hydrogen load flexibility is maintained.

The monthly target effectively assumes a hydrogen storage duration of up to a week (on the basis that the electrolyser utilisation factor is approximately 75%). Marinus Link's understanding is that hydrogen facilities are considering very little hydrogen storage (only a few hours) given the very high costs. This assumed additional hydrogen storage will severely underestimate the modelled need for long-duration storage, gas peaking plant and interconnection, as it enables significant and prolonged demand response from hydrogen loads during scarcity periods (extended periods of very high demand and/or very low wind and solar output).

[3] AEMO, ISP Methodology June 2023, page 54.https://aemo.com.au/-/media/files/stakeholder_consultation/consultations/nem-consultations/2023/isp-methodology-2023/isp-methodology_june-2023.pdf?la=en

MLPL recommends that AEMO explore the impact of the hydrogen load flexibility assumption, including modelling runs where much lower flexibility is assumed. These results should inform selection and timing of transmission in the ODP and be communicated in the Final 2024 ISP.

8. Gas supply and price risks

The Draft 2024 ISP forecasts a small, but important role for gas-power generation (GPG), providing energy supply during renewable energy droughts and high demand periods after the retirement of coal-fired generation. In the Step Change scenario, the NEM is forecast to need 16.2 GW of gas-powered generation. In the draft report, AEMO has also noted the changing role of GPG into the future, particularly in meeting winter peaks, which is forecast to test the limitations of the gas supply network,

AEMO's 2023 Gas Statement of Opportunities (GSOO) also highlighted challenges to domestic gas supply in southern Australia, which is declining faster than projected demand. While AEMO's forecasts suggest adequate gas supply to meet demand before 2027, shortfalls are forecast from 2027 without new supply being committed to the market (even though gas demand is falling). The GSOO report also noted uncertainty regarding the development of LNG import terminals.

Given the above, we consider it prudent for AEMO's ISP to consider the long-term risks to adequate gas supply to gas-powered generators, and whether cost premiums should be included to ensure these generators have a reliable access to gas supply (that is, in a future of lower overall gas consumption and dwindling supply, there is a risk in dramatic escalation in gas costs to ensure reliable supply).

9. Battery costs

All three central scenarios in the Draft 2024 ISP see large deployment of batteries (both distributed and grid-scale), which are forecast to make up 58% of dispatchable capacity by 2050 in the Step Change scenario, and 33% of dispatchable capacity in the Progressive Change scenario. This is largely a function of the critical services they are forecast to provide (including frequency control, capacity provision etc) and anticipated large reductions in battery costs. AEMO uses CSIRO technology costs for batteries (and more generally) which anticipate a very steep cost reduction to 2030, falling from $2,348/kW in 2023-24 to $1,253/kW by 2030-31 (4 hour battery, representing an almost halving in battery costs over 8 years).

There is currently a large degree of uncertainty about the battery cost reduction trajectory, with the United States National Renewable Energy Lab recently forecasting capital cost reductions in the range of 23% to 64% by 2050[4], with CSIRO forecasting long term cost reductions at the high end of this range. Given this uncertainty,

[4] National Renewable Energy Laboratory, Cost Projections for Utility-Scale Battery Storage: 2023 Update. https://www.nrel.gov/docs/fy23osti/85332.pdf

we consider it plausible that we will not see as rapid a reduction on battery-storage costs as currently anticipated. MLPL encourages AEMO to undertake sensitivity analysis of battery cost assumptions, to better understand implications for the least-cost build out of the NEM, should these anticipated cost reductions not materialise as currently assumed.