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LIGHT THE WAY

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Draft 2026 Integrated System Plan — December 2025

EnergyAustralia is one of Australia's largest energy companies with around 2.2 million electricity and gas accounts across eastern Australia. We also own, operate and contract a diversified energy generation portfolio across Australia, including coal, gas, battery storage, demand response, wind and solar assets, with control of over 5,000MW of generation capacity.

EnergyAustralia appreciates the opportunity to provide feedback on the draft 2026 Integrated System Plan (ISP). We recognise the expanded role of the ISP, the statutory requirements, and the planning framework underpinning it. We support AEMO's commitment to broad engagement and the sustained effort to incorporate feedback and improve the outcomes of the ISP.

The inclusion of a broader range of sensitivities to enhance understanding of the "probability envelope" is a commendable step forward. Further, AEMO continues to highlight the increasing importance of social licence, workforce and supply-side constraints as key risks underpinning the feasibility of the scenarios modelled – we agree entirely with this position. Likely delays with potential investment decisions and delivery across all aspects of the transition – generation (solar, wind, gas), storage (batteries and PHES) and transmission network including coordinated renewable energy zone developments – fundamentally undermine the ability of the modelling to inform well-grounded discussion. Examples include ongoing problems and associated assumptions with delivery of Western Victorian Renewables and VNI West, Snowy 2 and Humelink, alongside changes to the QLD Energy Roadmap and PHES prospects.

As the primary public policy instrument for the transition, the ISP must identify specific barriers and enablers to ensure the Optimal Development Path (ODP) translates into actual benefits for consumers, now and into the future.

We seek to provide feedback that would close the gap between modelled optimum and delivery-constrained operational reality, particularly in the context of higher capital

costs, constrained global supply chains and volatile financing conditions. Given the scale of infrastructure required over the next 10–20 years, delivery realism is central to credibility.

Our suggestions are:

- Elevate the Constrained Delivery sensitivity as a more prominent reference case, reflecting observable delivery conditions rather than treating it solely as a downside sensitivity.
- Expand the analysis of winter adequacy, given the structural shift in reliability risk toward winter conditions.
- Quantify near-term delivery risks in a more granular manner, linking risks to system consequences.
- Present clearer analysis of congestion and curtailment (economic and network) by technology and geography, including outside REZs, and indicate implications for project-level viability.
- Provide greater transparency on transmission cost, timing and sequencing across development paths, including comparison with prior ISPs and explicit discussion of delay risk.
- Where possible translate total system costs into relative end-use price impacts per scenario across regions (wholesale, network and any scheme costs)

Inputs, constraints and economic interpretation

The ISP should represent what is most likely to be delivered, not only the least-cost output assuming deterministic delivery dates for major projects (for example, Western Victorian Renewables in 2028/29, VNI West in 2031/32, Sydney Ring North in 2029/30).

AEMO is correct that system planning now centres on managing a complex, multi-sector transformation. The inclusion of regional and hourly demand traces capturing electrified industry, EVs, data centres and distribution-level developments is a welcome expansion.

In our view, the Constrained Delivery sensitivity is an essential bridge to a more realistic outcome for transmission planning. Structural risks, including approvals, social licence, long-lead equipment, workforce availability, connection processes and rising capex, justify elevating this sensitivity as a likely near-term reference case. Since it lowers build rates, rises costs across generation, storage and transmission, and shows a 2030 renewables share of 75% instead of 82% it helps governments and investors calibrate expectations for timing and cost over the next decade. We also note that since the 2026 ISP work began, the 2035 electricity emissions target have been set to 62-70% below 2005 levels.

Further insight would be gained by applying Constrained Delivery conditions across all scenarios, including Slower Growth, and publishing net market benefit outcomes accordingly. given the inputs into that scenario and the observed pace of the transition.

Further, we also recommend:

- More granular analysis of how tightening or relaxing binding constraints (policy targets, emissions trajectories, minimum security settings) alters trade-offs between transmission, storage depth and gas reliance.

- Clear explanation of how scenario weights interact with delivery constraints, including whether least-worst regret rankings shift when build limits and cost uplifts bind. This helps strengthen confidence that the ODP remains robust to delivery challenges.

- A summary table comparing ODP/CDP rankings under Step Change and Constrained Delivery conditions.

Given material changes since the 2024 ISP, a side-by-side summary mapping 2024 to 2026 changes in key drivers (GenCost updates, policy programs) will make the direction of the ISP clearer. It would help to reconcile the headline net-benefit increase to $24bn NVP with observed cost escalations and the lower WACC, preventing confusion about whether the "pull-back" in transmission (from 7,600km to 6,000km) is techno-economic or a deliverability response.

Winter adequacy operations

Reliability risk is increasingly concentrated in winter, and the ISP should reflect that structural shift.

Electrification is projected to materially increase winter demand, while renewable output is more variable and often lower. We recommend that AEMO present regional hourly demand profiles for major emerging loads, particularly larger loads such as data centres, alongside coincidence metrics relative to low-wind and low-solar periods. This would help clarify where non-network solutions, demand flexibility, or onsite firming could credibly defer transmission or reduce deep storage requirements, rather than treating all incremental load as system-wide peak demand.

With substantial coal retirement by 2035 under Step Change, winter renewable lulls increase operational complexity. USE results should be paired with monthly reserve margins and Loss-of-Load Probability (LOLP) to make seasonal adequacy more transparent. The draft report already notes that future weather conditions may be more extreme than historical experience and the transition is a multi-faceted problem. We suggest AEMO provide further information and analysis on compounding transitional risks such as VRE under-delivery, workforce/equipment delays, gas infrastructure lag to inform the winter adequacy narrative.

The 14GW flexible gas by 2050 and 7% utilisation is operationally meaningful only if expressed as run-length/start distributions (for example, 50^{th}/95^{th} percentile durations) across winter lulls ensembles. Analysis by Endgame Economics[1] shows just how important it is to move from analysing median outcomes to a distribution-based approach that accounts for extreme events. The variability of renewable energy output can lead to gas consumption swings of up to 120 PJ depending on the weather year.

We recommend gas midstream developments (regasification terminals, pipeline flows and seasonal storage) be explicitly aligned with electricity firming needs. If infrastructure lags, the draft report notes diesel fallback (onsite 14-hour storage) for a significant share of GPG in 2039–2050. That has cost and emissions implications which should be

[1] Stress-testing the NEM - Endgame

reflected in the market-benefit and emissions-limb accounting. This will position gas credibly as a firming resource during extended lulls rather than mid-merit.

ODP delivery risks

Timing risk is manageable when it is transparently quantified and understood by stakeholders.

We recommend that AEMO introduce a concise risk-by-consequence framework identifying, for each augmentation window:

- primary delay channels (approvals, engagement, equipment, workforce, procurement); and
- system impacts of slippage (curtailment, congestion, winter margin erosion, USE/LOLP outcomes).

This would complement the Draft's high-level discussion with a short, decision-useful layer and responds to the AER's transparency review call for clearer mapping from assumptions to ODP outcomes.

Considering the complexity of jurisdictions in implementing the REZs and the statement that most generation will be produced inside the REZ, we encourage AEMO to present an example of how curtailment within each REZ is calculated by explicitly identifying the treatment of storage and local load and illustrating how non-network solutions alter spill outcomes.

We acknowledge that the human element of delivering the ISP remains a challenge for modelling as well as for implementation. We consider that many of the delays are related to lack of workforce and the draft 2026 ISP proposes lower workforce compared to the 2024 ISP. At the same time, it also assumes a significant increase in workforce from 2025 to 2026. We consider there needs to be more empirical evidence around the assumption for workforce to strengthen credibility.

The CER component also remains difficult to model. Evidence shows that the rapid surge in distribution storage (more than 160,000 home batteries installed since the beginning of the Cheaper Home Battery Program totalling more than 3.6 GWh) out-performs the expected near-term update of CER. The central scenario under-represents CER contribution and likely it does so for the accelerating VPP participation and maturing V2G readiness. The final ISP could recalibrate the CER uptake, including coordinated and uncoordinated storage, to reflect market changes.

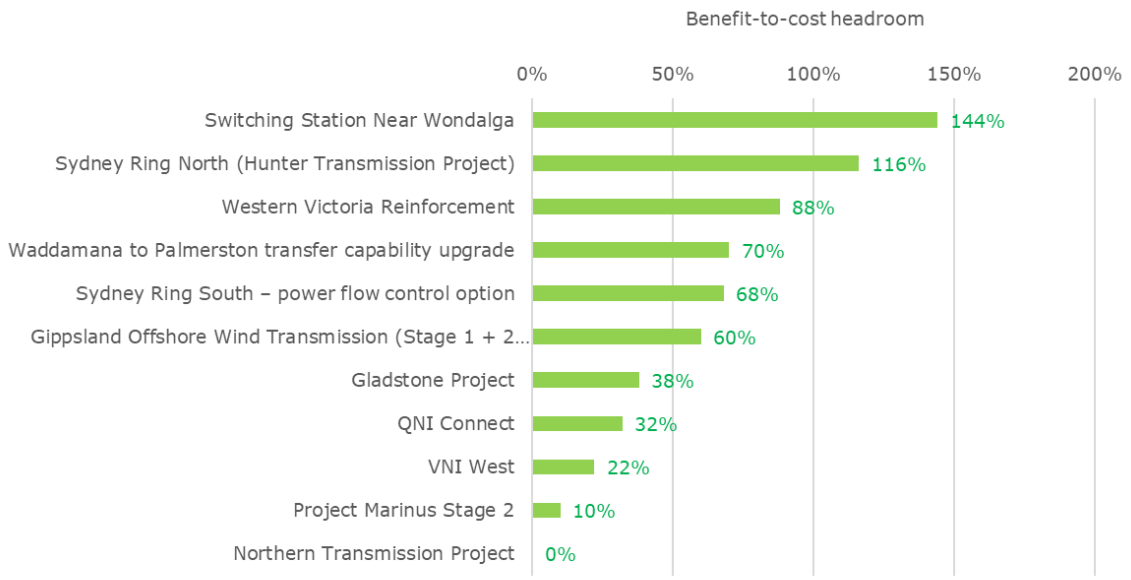
Transmission investment and project robustness

The Draft re-stages some projects and marks Sydney Ring South (500 kV) as future project (2037/38) showing near-optimality by 2033 under CDP6. We support maintaining optionality and continuing to present alternative pathways to strengthen transfer capacity into Sydney, particularly when assessed against winter operating conditions and system security needs.

Projects with narrow net-benefit headroom require transparent justification. Where Take-One-Out analysis shows limited tolerance to cost escalation, AEMO should clearly articulate the rationale for inclusion and conditions under which benefits are expected to materialise (Figure below). For example, VNI West costs $7,627mil with $1,700mil net benefits, implying only a 22% cost increase headroom – this seems precarious. For

Sydney Ring North, there is a considerable positive ratio of 116% headroom, therefore we support the timely delivery with coordination of system strength remediation in NSW. Sydney Ring South – 500kV is also required to be accelerated if south of Sydney transfer constraints tighten. Northern Transmission Project has a $0 net benefit; however, it is tied to REZ deliverability and firm connection commitments when re-evaluated.

In this context, AEMO could present commentary of how any considered projects are buffered against cost changes.



The CIS is an input with material effect on project economics and siting and has an impact on project WACC. We consider that AEMO could further explain how CIS underwriting changes WACC assumptions within the cost benefit analysis and explain if the CIS implicitly alters project-level risk perceptions relative to the system discount rate. We also consider AEMO can reasonably considered a scenario where not all CIS awarded projects are delivered.

Sydney Ring South – 500kV

As a case study, the Draft findings highlight Sydney Ring South – 500kV as a Future project that warrants much closer discussion. The ODP outlines the installation of power flow control devices as actionable in 2030/31 and building new 500kV lines in 2037/38.

In the cost benefit analysis Appendix, the Draft notes that advancing the 500kV option four years earlier to its earliest in-service date in 2033/34 and removing the power flow controller option (Alternative DP2) results in only marginally lower net market benefit in the step change scenario alone (-$80m or -0.3%). We believe this sort of difference is outside the tolerance of accuracy of the ISP framework and therefore support a more detailed evaluation of the timing options in the final ISP 2026 and Transgrid's RIT-T across all scenarios.

We note the following matters:

- Transgrid has already assessed that the power flow controller option is not credible and proposed that it be deleted from the options in the ISP in its submission to the 2025 Electricity Network Options Report. We believe that

the Final ISP 2026 should only include credible options and, subject to any updates from Transgrid, this option should be excluded, or at least the benefits in terms of increased transfer limits be more transparently described.

- Internal EA analysis suggests that, while improved, constraints through the southern cut-set 330kV lines would continue to be substantial even with the power flow controller option and only reduce to minimal levels after the 500kV option. The level of congestion we observe growing out to 2037/38, even supported with the power flow controller option, means that system reliability is more vulnerable to abnormal events, such as extreme weather patterns, forced network and plant outages, and less amenable to fundamental changes across scenarios, such as earlier closures, possibly higher demand forecasts. An option in the ODP that significantly reduces potential constraints (i.e., the 500kV option delivered at an earlier date as per DP2) may materially improve resilience of the grid and provide both significant and efficient network transfer upgrades.

- Based on observed market outcomes, constraints on the CNSW-SNW South flow path have typically resulted in counter-price flows towards Victoria. These events are usually sustained, which result in southerly flows being clamped and renewables in south NSW then being curtailed. Since the power flow controller option would still have high level of congestion, we expect that there would also be significant counter-price flows until the 500kV option is built. If the ISP model does not clamp counter-price flows to manage importing region consumers costs, it would not be capturing any additional costs from generation re-dispatch and negative residue payments in Victoria. Having less constraints, the 500kV option would not be subject to the same level of uncertainty on additional costs.

Considering these matters, we encourage AEMO as it finalises its Draft to provide a much greater insight into the operation of the power system and observed congestion in the market during the period following Eraring closure and Snowy 2, HumeLink, VNI West and Hunter Transmission (Sydney Ring North) completion, the critical period before Sydney Ring South 500kV is modelled. While we acknowledge that this future project is expensive, we believe the future state without it may present a particularly challenging outlook with acute pressure on wholesale prices, the need for demand side management and a heightened supply reliability risk that is not well understood.

Modelling credibility and stress testing

AEMO's market models have incorporated a better approach to counter "perfect foresight" by including energy reserves and deliberate modelling errors for grid-scale batteries. We recommend expanding similar approaches to long duration energy storage, particularly as it relates to the operation of Snowy 2.0 and long duration LTESAS projects. In our view, there are refill-time limitations that emerge from wind-draught conditions ahead of time. Providing clarity on whether these imperfect foresight approaches are integrated into the ODP or are a resilience test, would provide stakeholders with a better understanding of the findings.

We encourage AEMO to also stress test the system in relation to the impact of reduced rooftop solar capacity due to likely severe weather conditions (such as storms). This represents an appropriate evaluation of the system in the near-term in relation to expected supply/demand disruptions or shocks due to extreme weather events. This can also include an analysis of these impacts on a 5-minute window.

On the demand side, credibility rests on treating CER as an operational resource bounded by tariffs, interoperability, and distribution operating envelopes. The narrative could further introduce representative distribution archetypes (urban, regional) to explore how practical voltage management lifts hosting capacity and under what technical conditions a modest spend can credibly unlock additional CER export

Constrained deliverability

Transmission deliverability under the ODP (approvals, social licence, procurement and long-lead equipment) is at least as influential as technology cost trajectories. The Final ISP would be strengthened by including confidence intervals around in-service dates.

The Constrained Delivery sensitivity is aligned with current conditions and should be further developed to show whether project rankings and sequencing materially change under binding delivery constraints. Stability of rankings would demonstrate robustness, while material shifts would highlight where flexibility or optionality is required.

A further improvement would be for the sensitivity to include one representative adaptation pathway explaining why wind build increases by 7 GW by the mid-2030s despite higher costs, what happens to utility solar, why rooftop solar and passive and coordinated CER storage remain unchanged, and how emissions outcomes shift.

Ultimately, consumers are the beneficiaries of the transition. While price impacts are politically sensitive, the ISP would benefit from a clearer narrative on relative price trajectories and indicative bill impacts across scenarios.

Customers are increasingly sensitive to energy affordability. Transparent discussion of cost pathways, even at a directional level, would strengthen understanding of the trade-offs inherent in the development path.

If you would like to discuss this submission, please contact me via email at Ana.Spataru@energyaustralia.com.au.

Regards

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