GE VERNOVA

Submitted to:

AEMO

Project title:

Draft 2026 Integrated System Plan –

GE Vernova Response Submission

Submitted by:`

GE Vernova – Australian Country Council

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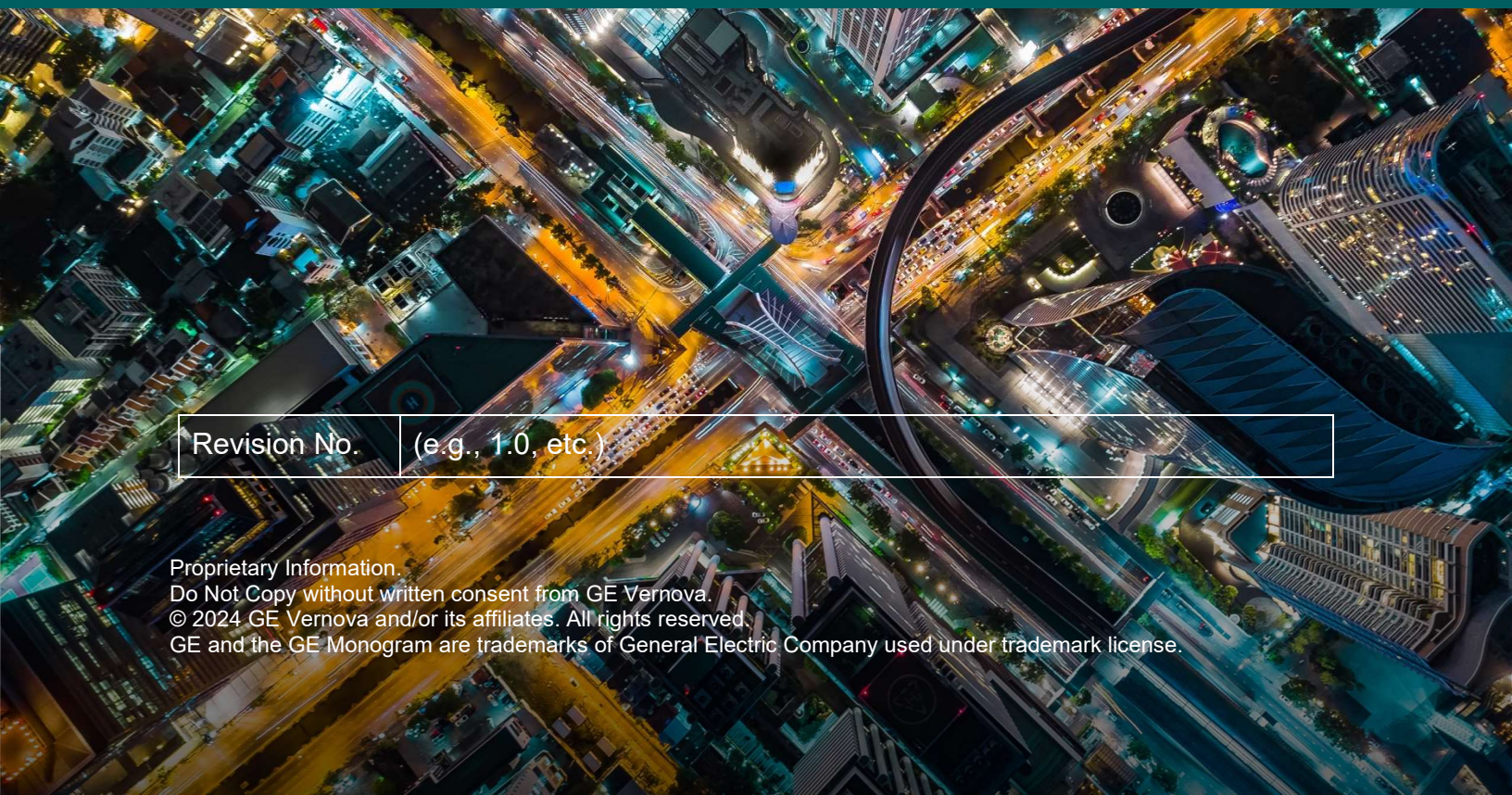

Revision No.	(e.g., 1.0, etc.)

Australian Energy Market Operator (AEMO):

Integrated System Plan Consulatation team

GE Vernova appreciates the opportunity to comment on the draft 206 Integrated Systems Plan (ISP) and we are pleased to contribute to this important consultation process. This submission is intended to constructively support AEMO in strengthening the credibility, robustness, and deliverability of the Optimal Development Path (ODB). While the Draft ISP presents a coherent technically optimal pathway to a highly decarbonised power system, our feedback highlights several areas where key assumptions may warrant deeper scrutiny. In particular, we focus on the alignment between the proposed investment mix and the market mechanisms required to deliver it; the treatment of locational networks system; service risks under very high renewable penetration; and the adequacy of sensitivity testing to demonstrate resilience under adverse conditions. Our comments are aimed at ensuring that the final ISP reflects not only a least-cost system in modelling terms, but one that is financeable, operable, and resilient in practice, given existing market structures and foreseeable cross-sector dependencies.

1. Consultation Question 1:

AEMO has proposed an ODP that represents a mix of investments that help deliver a reliable, secure, and least-cost power system while also meeting government policy targets.

Do stakeholders agree with AEMO's optimal development path selection in the Draft 2026 ISP? If yes, what gives you that confidence? If not, what should be further considered, and why?

Response:

The Draft ISP appears to implicitly assume that investment coordination problems will be resolved through market behaviour, despite clear evidence that existing energy-only market signals are insufficient for long-lived, capital-intensive dispatchable assets under very high renewable penetration.

The ISP also seems to assume that development across each state is monolithic and may not consider the current nodal impacts of grid development at this scale. Greater transparency on nodal or sub-regional outcomes is recommended. Publishing locational dispatch, congestion, marginal loss factor trajectories, and voltage stability outcomes at a finer spatial resolution would allow stakeholders to assess whether the ODP unintentionally concentrates investment near reference nodes and or exacerbates regional inequities. Without this visibility, investors face asymmetric risk that is not reflected in the ISP's least-cost conclusions.

Taking Queensland for example, where the reference node sits just outside of Brisbane in the southeastern corner of the state. Many generation investments are going to favour nodes closest to the reference node, and this in regions where competition for land resources is already high. This significantly disadvantages development opportunities in the mid and northern portions of the state due to the corrective imposition of Marginal Loss Factors (MLF). Furthermore, new investments won't know their MLF until after their investment is connected to the electric grid and could change if future investments negatively impact their MLF. Greater transparency on nodal or sub-regional outcomes would be of benefit.

It seems to be assumed that natural gas plants (Flexible gas) will be built based on future energy market revenues (e.g. merchant generation relying on spot energy revenues). More than likely, given the high level of renewables, the spot market prices will be insufficient to support the replacement of the existing natural gas fleet and build new flexible gas without a form of capacity market incentives for dispatchable generation.

Positively from a CER perspective, ODP has considered for the first time investments in Distribution Networks which can enhance the hosting capacity for New CERs (via Network Augmentation) and existing CERs (via Voltage Optimisation).

However, there are no further details (in Appendix A9) provided in terms of how best CER coordination can help address network capacity constraints. There are some areas that can be further considered, as listed below:

1. Orchestration of CERs (based on type of CER and what services it can provide).
2. Grouped Orchestration of CERs on same feeder/location (to provide hybrid services).
3. Coordination of CERs based on "controller type" whether CERs are controlled by DNSP or Retailer/ Aggregators (to serve different objectives).
4. Flexible connections and how does it impact long term DNSP/Dx network investments by providing non-network solutions/options.

2. Consultation Question 2:

In the Draft 2026 ISP, AEMO has proposed some changes to actionable transmission projects including:
– 11 actionable projects to remain for delivery over the next decade,
– three projects to move to 'committed or anticipated' status,
– one project to move to 'future' status to align with the timing of other projects that influence its benefits (Central Queensland to Southern Queensland Expansion aligned with Borumba Pumped Hydro), and
– two projects under review due to uncertainty in input assumptions and the influence of recent policies (Northern Transmission Project and QNI Connect).

Do you agree with the proposed timing and treatment of actionable projects in this draft?

Response:

There may be an unintended consequence of dropping the regulated rate of return on transmission projects from 7% to 3%, in that the transmission network service providers (TNSP) will look higher paying prospects for their capital or at least less enthusiastically commit to building this vital infrastructure? Particularly in a forecast where unleashing most of the benefits in dependent on the timely build of transmission lines.

Is there an argument to interconnect the Northern Territory and Western Australia, within this decade or possibly the next? Darwin in the North Territory would be the easiest candidate, given the proposed line out to Mt. Isa, and number of proposed RE investments in the Northern Territory, and Kimberly region that are looking to supply the ASEAN regional interconnect. While the transmission investment would be significant (most likely via HVDC), there are some additional benefits. First, solar and wind profiles across multiple time zones would diversify the resource fleet, reducing the need for some of the storage. For example, additional solar power in the morning on the east coast could provide generation to central and western Australia before their sunrise. Equally, solar power in the west could provide power to the east after their sunset. Second, as you extend the transmission network, you expand further opportunities for new wind and solar. Lastly, you create a geographically larger pool of resources to diversify risk of weather patterns. Therefore, do you look beyond the current NEM topology?

AEMO should consider whether the ISP implicitly assumes delivery certainty that may no longer exists under the revised regulatory framework, and whether alternative risk-sharing or incentive mechanisms are required to preserve delivery confidence. Sensitivity testing that explicitly models delayed or partial transmission delivery under reduced investment appetite would materially strengthen the credibility of the ODP.

3. Consultation Question 3:

For the Draft 2026 ISP, the tested sensitivities were on constrained delivery of the ODP, variations on the gas development projection, and the pace of coal closures. The effect of demand-side factors was also tested by assessing the impact of reduced energy efficiency measures, and no further CER coordination.
What other sensitivities should be considered to further test the robustness of the candidate development paths, and why? What other sensitivities are relevant to testing robustness of investment decisions, why?

Response:

In addition to the sensitivities already considered, the ISP would benefit from explicit testing of high-electrification scenarios across residential, commercial, and industrial heat loads, particularly in

southern states where seasonal demand alignment with current and proposed renewable outputs could materially improve system efficiency. These scenarios would also stress gas network resilience and reveal cross-sector dependencies that are currently underexplored.

The robustness of the proposed and or final system build could also be demonstrated through full chronological dispatch simulations once the candidate development path is identified and subsequently finalised. Factors should include stochastic stress testing across forecast horizons including extreme weather years, extended renewable droughts, and correlated outages of storage and dispatchable assets. Publishing unserved energy metrics, reserve shortfalls, and system service violations under these stress tests would materially increase stakeholder confidence that the ODP is not only optimal in expectation, but resilient under adverse conditions.

The assumed availability of gas-powered generation (GPG) for black start warrants explicit validation. This should include an assessment of gas network critical load designation, compressor station backup arrangements, and fuel security under prolonged outages, to validate if the natural gas network can sustain operation during a blackout. Note that during the Texas winter blackout in February 2021, many of the natural gas pipeline compressors were not identified as critical electric needs and were subsequently disconnected from the grid by rolling black / brownouts. This further disrupted natural gas generation from receiving natural gas supplies and both deepened and prolonged the black out. Unless the compressors serving the natural gas pipelines in Australia are grid protected, GPG may only provide black start with alternatives such as oil. While the draft ISP mentions alternative fuel supplies for GPG, it is silent on a proposed funding mechanism.

4. Consultation Question 4:

For the first time, AEMO has assessed opportunities for investment in distribution networks across the NEM, that are consistent with the efficient development of the power system, to support operation of consumer energy resources. This recognises the key role of distribution networks in supporting the integration of consumer energy resources.

See Appendix A9 for more information. Does the ODP appropriately identify and leverage distribution investment opportunities?

Response:

While the recognition of distribution network investment is welcomed, the ISP holds back on how to operate and coordinate transmission and distribution, to see how consumer energy resources will be achieved in practice. In particular, electric vehicles represent a rapidly scalable and highly flexible storage resource that appears to be a clear opportunity to weigh the system value of coordinated EV charging and discharging.

Consideration could be placed on explicit dynamic pricing, managed charging, or aggregator-led participation of EVs in energy and system service markets and quantify the extent to which these

measures reduce curtailment, defer network augmentation, and displace utility-scale storage. Without this, the ISP risks overstating future storage and network requirements by underutilising consumer-side flexibility.

In addition to the $420M of investments - connecting grid-scale generation and storage to existing networks and making network refinements to utilise latent CER capacity, there are opportunities to further explore and evaluate, such as:

1. Leveraging or investing in technologies to orchestrate behind the meter (CER)

2. Orchestrating CERs specifically network benefits (such as non-network solutions, flexible planning, etc.)

3. ODP may consider additional investment opportunities like adding “Flexibility” to all hot water systems across the NEM/WEM, which theoretically would provide instant access to Giga-watt level flexibility and helps to address network constraints while extending benefits/services for market operations (via Aggregators)

4. ODP can also consider other levers such as extending the “useful life” of network assets such as Distribution Transformers by optimising “thermal constraints” in addition to voltage constraints.

5. DSF (Demand Side Factors), device level OR CER level considerations can be helpful to understand the impact on network investments.

6. VPP and V2G are considered in ODP but there can be additional areas as hot water systems, thermal batteries, stacking of batteries for distinct types of NSS (network support services). These considerations can further extend the benefits of Distribution Network Investments for the ODP or amplify additional candidate ODPs.

5. Consultation Question 5:

For the first time in the Draft 2026 ISP, AEMO has incorporated combinations of gas investments that may be developed by the gas industry. These gas development projections influence the availability of gas to support the power system in the future, and (potentially) the mix of investments required in the ODP.
Do the gas development projections reflect an appropriate level of investment to support the gas sector, including gas-powered generation in the NEM?

Response:

The ISP forecasts Gas Power Generation (GPG) to transition from a mid-merit to a peaking role, given the future level of renewable investments, which makes sense. Furthermore, the ISP projects the primary period of generation will shift from summer to winter for GPG, when there are more days with fewer renewable generation, commonly referred to by dunkelflaute (German for "dark doldrums") which describes a weather event, common in winter, characterised by a lack of both wind and

sunlight, severely limiting renewable energy generation from solar and wind power and creating challenges for grid stability and energy supply. In turn natural gas supply in winter may be constrained due to limited natural gas pipelines serving utility heating loads in winter. Recognising the likelihood, the ISP recommends that gas generation also develop alternative fuel capabilities as backup to natural gas (primarily oil-fired generation), however a funding mechanism to facilitate this development is not considered.

The ISP's treatment of gas-powered generation highlights a broader discrepancy between the system services required and the market revenues available to support them. As GPG transitions to a low-utilisation but high-criticality, its value increasingly lies in reliability, flexibility, and resilience rather than energy production. These attributes are not adequately remunerated under current NEM arrangements. Therefore, further development is required to explicitly assess alternative funding mechanisms for dispatchable capacity, including reliability contracts, strategic reserves, or system service payments, and test how these mechanisms alter the feasibility and timing of gas and alternative firming investments. International experience demonstrates that without such mechanisms, reliance on merchant peaking assets leads to underinvestment and heightened reliability risk during extreme conditions. Ultimately, consideration for a funding mechanism for dispatchable generation that does not rely on the spot market revenues (which will be minimal with 80%+ renewable generation) and will compensate GPG for this level of investment. ISO New England in the U.S. had similar issues in the winter periods where non-firm gas generation had no natural gas supplies and were unavailable to dispatch. They recognised the issue and paid natural gas generation to build and maintain back up oil facilities.

6. Consultation Question 6:

The Addendum to the 2025 Inputs Assumptions and Scenarios Report (IASR) provides further explanation in response to the AER's Transparency Review. This includes further explanation of forecast components including policies affecting consumer demand, data centres, hydrogen production, biomethane and community batteries.

Do stakeholders have feedback on the Addendum to the 2025 IASR?

Response:

The Addendum provides particularly useful clarification to the AER's Transparency Review; however, stakeholders would benefit from greater traceability between input assumptions and ISP outcomes. The availability of such quantitative, would influence investment decisions and improve confidence in the modelling results. Furthermore, enhanced transparency by publishing scenario-specific sensitivities that isolate the impact of each major assumption change, allowing stakeholders to understand which inputs are most influential and where uncertainty materially affects the ODP.

In conclusion, GE Vernova support the intent and objectives set out in the Draft 2026 Integrated Systems Plan and recognise the critical role this plays in guiding Australia's energy transition. We appreciate the opportunity to be consulted and would welcome the opportunity to provide further consultation and engagement with AEMO, as the ISP is refined and progressed towards finalisation. We remain keen to contribute further insights, analysis or clarification where helpful, and look forward to ongoing collaboration to support the development of a power network that is reliable, secure, affordable, and resilient through the energy transition.

Sincerely

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