Submission to the Draft 2026 Integrated System Plan (ISP)
Centre for Smart Power and Energy Research (CSPER), Deakin University

To: Australian Energy Market Operator (AEMO) Integrated System Plan (ISP) Team
Date: 27/01/2026

Dear AEMO ISP Team,

On behalf of the Centre for Smart Power and Energy Research (CSPER) at Deakin University, we are pleased to provide this submission in response to AEMO's consultation on the Draft 2026 Integrated System Plan (ISP).

AEMO's ISP plays a critical role in guiding the transition of NEM toward a secure, reliable, and affordable net-zero system. We acknowledge the scale, rigour, and complexity of the work underpinning the Draft 2026 ISP, including the development of the Optimal Development Path (ODP), the integration of updated Inputs, Assumptions and Scenarios, and the continued strengthening of stakeholder engagement processes.

This submission focuses on decision robustness under increasingly inverter- and storage-dominated system conditions. Our intent is not to challenge the overall direction of the Draft ISP, but to contribute constructively by identifying where optimistic or implicit assumptions could materially influence planning outcomes, particularly under stressed operating conditions. Moreover, the comments are framed to support transparency, interpretability, and resilience of ISP conclusions across the relevant appendices.

Specifically, the submission:

- highlights a small number of decision-critical assumptions that have disproportionate influence on operability, deliverability, and cost-benefit outcomes;
- emphasises the need to distinguish between installed capacity and reliably deliverable system capability as penetration of inverter-based resources increases;
- examines the sensitivity of planning outcomes to storage performance, degradation, and lifecycle behaviour;
- considers transmission delivery realism, Renewable Energy Zone operability readiness, and system security assumptions; and
- proposes targeted clarifications and stress-testing, aligned with international system-operator practice, without expanding modelling scope or revisiting established policy settings.

The submission has been prepared by CSPER academics with expertise spanning power system operation, inverter-dominated grids, energy storage, network planning, demand-side integration, and energy market analysis.

We hope this submission provides a constructive technical contribution to AEMO's ongoing engagement process and supports confidence in the robustness of the final 2026 ISP. Finally, we appreciate the opportunity to provide feedback and would welcome further engagement or clarification discussions as appropriate.

Yours sincerely,
Associate Professor Saman A. Gorji, PhD, SMIEEE, FHEA
Director, Centre for Smart Power and Energy Research (CSPER), School of Engineering, Deakin University
Victoria, Australia
Email: saman.asgharigorji@deakin.edu.au
Phone: +61 3 5227 2383

On behalf of CSPER members:

Dr Alireza Ganjovi
Dr Ameen Gargoom
Associate Professor Md Enamul Haque
Dr Mohammad Taufiqul Arif
Associate Professor Samson Yu
Associate Professor Shama Islam
Dr Sheikh Tanzim Meraj
Dr Van Tanh Huynh
Professor Hieu Trinh

Submission to the Draft 2026 Integrated System Plan (ISP)

Improving Decision Robustness Under High Penetration of Inverter-Based Resources and Storage

Response to AEMO Draft 2026 Integrated System Plan-Consultation on ISP Appendices (A1-A9)

Authors

Dr Alireza Ganjovi
Professor Saman A. Gorji
Dr Ameen Gargoom
Associate Professor Md Enamul Haque
Dr Mohammad Taufiqul Arif
Associate Professor Samson Yu
Associate Professor Shama Islam
Dr Sheikh Tanzim Meraj
Dr Van Tanh Huynh
Professor Hieu Trinh

Affiliation

Centre for Smart Power and Energy Research (CSPER)
Deakin University

Submission context

This submission provides technical commentary on the Draft 2026 ISP, with a focus on decision robustness under increasingly inverter- and storage-dominated power system conditions. The comments are intended to strengthen transparency, interpretability, and robustness of planning outcomes across ISP appendices, without challenging the overall direction of the ISP.

Table of Contents

Executive Synthesis:
Decision Robustness Under Optimistic Assumptions

1. Purpose

This executive synthesis summarises the core issues raised in this submission and highlights where optimistic assumptions could materially affect planning outcomes in the Draft 2026 Integrated System Plan (ISP). It is intended to help readers quickly identify:

- the most material cross-cutting planning risks if assumptions prove optimistic, and
- which ISP appendices are most critical to decision robustness, before engaging with the detailed appendix-by-appendix commentary that follows.

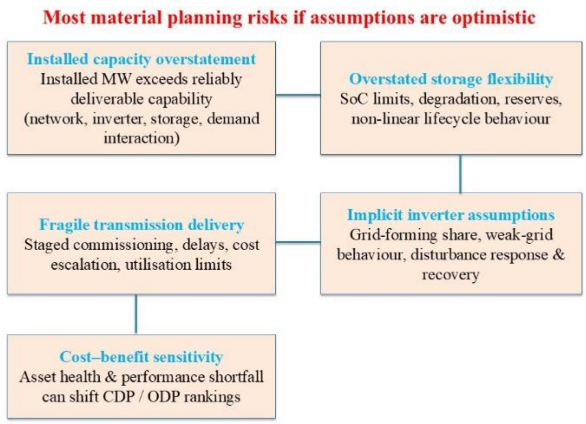
The intent is not to challenge the direction of the ISP, but to strengthen transparency, interpretability, and robustness as the NEM transitions to a highly inverter- and storage-dominated system.

2. Most material planning risks if assumptions are optimistic

Across the issues examined in this submission, five system-level risks emerge as most material to ISP decision robustness:

i. Installed capacity increasingly overstates reliably deliverable system capability, particularly where network constraints, inverter behaviour, storage availability, and demand-side participation interact.
ii. Storage flexibility and adequacy may be overstated under stressed conditions, given State-of-Charge limits, degradation, reserve requirements, and non-linear lifecycle behaviour.
iii. Operability and system security outcomes depend on implicit inverter assumptions, especially regarding grid-forming capability, weak-grid behaviour, disturbance response, and recovery.
iv. Transmission delivery, timing, and utilisability are more fragile than modelled, with staged commissioning, cost escalation, and operability constraints potentially reducing effective system value.
v. Cost-benefit rankings are sensitive to asset health and performance shortfall, particularly in storage-heavy pathways where small deviations in degradation or availability can materially alter net market benefits.

These risks are interdependent and tend to bind during the same stressed conditions that drive reliability, operability, and investment confidence.



3. Decision-critical priorities for robustness

All ISP appendices contribute to transparency and completeness. However, the analysis in this submission indicates that decision robustness is not equally sensitive to all assumptions. If planning effort, sensitivity testing, or explanatory focus must be prioritised, the following areas emerge as the most decision-critical, because small deviations from central assumptions can have disproportionate impacts on reliability, operability, and cost-benefit outcomes. It must be noted that, Appendix A1 is included to strengthen decision robustness by improving traceability between stakeholder input and the assumptions driving operability, deliverability, and cost-benefit outcomes in Appendices A2, A4, A5, and A6.

A. Primary decision-critical priorities

i. **Appendix A4-System Operability**: Operability assumptions determine whether projected capacity and investment pathways can function under stressed conditions. Realistic treatment of inverter behaviour, storage State-of-Charge constraints, and essential system services is foundational. Over-optimism in these assumptions directly affects reliability margins and system security conclusions.
ii. **Appendix A2-Generation and Storage Deliverability**: Development opportunities underpin all downstream planning conclusions. Clear distinction between installed capacity and reliably deliverable capability is critical to interpreting build trajectories, retirement timing, and system adequacy, particularly in storage- and inverter-dominated pathways.

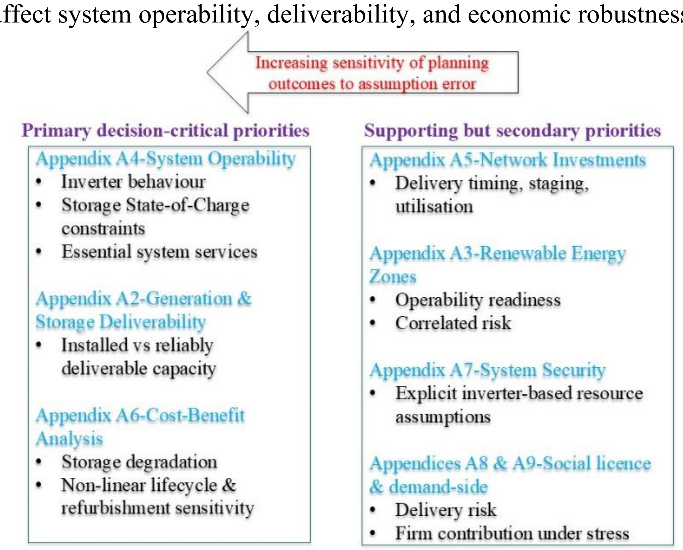
iii. **Appendix A6-Cost-Benefit Analysis (storage lifecycle sensitivity)**: Cost-benefit outcomes increasingly hinge on storage performance, degradation, refurbishment timing, and non-linear lifecycle behaviour. Targeted sensitivities in this area are essential to confirm that Candidate Development Path rankings and the Optimal Development Path remain robust under realistic asset-health uncertainty.

B. Supporting but secondary priorities

Other appendices remain important, particularly where they influence risk concentration, delivery feasibility, and regional outcomes:

- Appendix A5-Network Investments, where delivery timing, staging, and utilisation materially affect system outcomes.
- Appendix A3-Renewable Energy Zones, where operability readiness and correlated risk influence practical system value.
- Appendix A7-System Security, which depends on bounded and explicit assumptions about inverter-based resource performance.
- Appendices A8 and A9, which shape delivery risk and demand-side contribution under stress.

The appendix-by-appendix commentary that follows is structured to reflect this prioritisation, with greatest emphasis placed on assumptions that most directly affect system operability, deliverability, and economic robustness.



4. Executive summary of consultation issues by appendix

Consultation theme	Full issue framing	Short response
Stakeholder engagement (A1)	Does Appendix A1 ensure stakeholder engagement is decision-relevant and traceable to planning and modelling outcomes?	Engagement breadth is strong, but credibility would be materially improved by making feedback explicitly decision-relevant. Clear "you said / we did" traceability would strengthen transparency, legitimacy, and confidence in how engagement informs ISP assumptions.
Generation & storage opportunities (A2)	At high VRE and storage penetration, do installed capacity projections reliably represent system capability?	No. Installed MW increasingly overstates firm contribution. The ISP would be strengthened by clearly distinguishing installed, dispatchable, and reliably deliverable capability, particularly where storage, CER, and network constraints interact.
Renewable Energy Zones (A3)	Does REZ ranking and sequencing adequately reflect operability and deliverability risks beyond resource quality?	The REZ framework is supported, but rankings should explicitly account for system strength, operability readiness, and deliverability constraints. Resource quality alone is insufficient at high inverter penetration.
System operability (A4)	Are operability conclusions robust to realistic storage and inverter behaviour under stress?	There is a risk of over-optimism. Greater hardware realism is needed, particularly around storage SoC limits and inverter control behaviour, to ensure operability outcomes remain credible during stressed conditions.
Network investments (A5)	Does Appendix A5 adequately treat transmission as a delivery-critical and time-constrained system risk?	Transmission should be treated as a dominant delivery and critical-path risk, not a frictionless enabler. Clearer staging, partial-delivery, and timing-risk transparency would strengthen confidence in the ODP.
Cost-benefit analysis (A6)	Are CBA outcomes robust under realistic uncertainty in storage lifecycle performance and costs?	CBA robustness increasingly hinges on storage degradation, refurbishment, and non-linear lifecycle costs. Targeted sensitivities are needed to confirm that rankings remain stable under realistic asset-health uncertainty.
System security (A7)	Are assumptions regarding inverter-based resource contributions to system strength and inertia sufficiently explicit and bounded?	The direction of Appendix A7 is supported, but security outcomes would be strengthened by explicit, bounded assumptions for IBR and grid-forming contributions, including stress-testing under degraded or delayed delivery.
Social licence (A8)	Is social licence treated as a material delivery risk with system-level consequences?	Social licence should be treated as a quantifiable delivery-risk driver affecting timing, cost, and scope, rather than a qualitative overlay. Bounded delivery sensitivities would improve planning robustness.
Demand-side factors (A9)	Does the ISP clearly distinguish between installed, available, and firm demand-side contribution?	No. The ISP should explicitly distinguish installed, available, and firm demand-side capacity, accounting for diagnostics, degradation, aggregation limits, and behavioural constraints, particularly under stress.

Appendix A1-Stakeholder Engagement

1. Purpose and scope

Appendix A1 provides a comprehensive and transparent account of the engagement activities undertaken to inform the Draft 2026 ISP, including extensive consultation with consumers, industry, jurisdictions, and expert panels. The breadth of engagement is substantial, encompassing multiple formal consultation stages, reference groups, webinars, and written submissions, and reflects good practice in procedural transparency consistent with recognised stakeholder engagement frameworks.

However, while Appendix A1 clearly documents the scale and diversity of engagement, it is less explicit about how engagement outcomes are translated into specific planning assumptions, modelling choices, and investment decisions. On the other hand, the international experience indicates that, for large-scale system plans, credibility increasingly depends not only on participation volume, but on clear traceability between stakeholder input and decision outcomes. Table 1 summarises the key implicit assumptions in Appendix A1 regarding engagement influence, the associated risks where that influence is not explicit, and the targeted refinements requested to strengthen transparency, representativeness, and decision traceability.

Table 1: Summary of key assumptions in Appendix A1, associated risks, and requested refinements

ID	A1 topic	A1 assumption / framing	Identified risk	Requested clarification	Primary impact
R1	Engagement volume	Participation implies influence	Feedback not traceable	Decision-traceability mapping	Trust & legitimacy
R2	Representativeness	Broad access=balanced input	Silent stakeholders under-weighted	Representativeness reflection	Equity & credibility
R3	Consultation pace	Formal opportunity=effective input	Cognitive overload limits impact	Engagement load disclosure	Quality of input
R4	Feedback handling	Themes summarised qualitatively	Contested inputs unresolved	"You said / we did" framing	Decision confidence

2. Engagement breadth does not guarantee representativeness (R2)

Appendix A1 reports engagement with more than 1,400 stakeholders and 241 submissions across ISP-related processes, indicating a substantial level of participation. However, the international infrastructure planning literature consistently cautions that participation volume alone does not guarantee representativeness. Engagement processes that rely heavily on technical submissions, written feedback, or time-limited consultation windows can systematically underrepresent affected or less-resourced groups, even when headline participation numbers are high.

OECD infrastructure governance guidance emphasises the importance of explicitly identifying who is not participating in consultation processes, and assessing whether engagement outcomes are disproportionately shaped by well-resourced incumbents unless corrective measures are applied [1]. Similar findings are reflected in IAP2 international practice guidance [2] and World Bank infrastructure planning frameworks [3], particularly for large-scale energy transition programs where regional, First Nations, and cost-exposed consumers are most directly affected.

Observation: Appendix A1 would be strengthened by explicitly describing how representativeness risks are identified, monitored, and mitigated within the engagement process, particularly for regional communities, First Nations stakeholders, and consumers most exposed to network development and cost impacts.

3. From engagement to influence: the missing link (R1, R4)

Appendix A1 summarises key themes raised by stakeholders and appropriately references consultation summary reports. However, it stops short of clearly mapping stakeholder feedback to specific changes in planning assumptions, modelling choices, or ISP outcomes. Table 2 illustrates this gap by distinguishing between different types of engagement inputs and the degree to which they typically influence planning decisions, ranging from indicative participation (such as attendance volume) to decision-shaping inputs (such as quantified modelling inputs and explicit assumption changes). Making this distinction explicit would help clarify how engagement informs planning outcomes and where decision influence is exercised. This distinction is illustrated in Table 2.

Table 2: Engagement inputs versus planning influence

Engagement output	Indicative	Potentially influential	Decision-shaping
Attendance volume	✓		
Thematic submissions		✓	
Quantified modelling inputs			✓
Assumption changes			✓

This framing is intended to clarify how engagement informs planning decisions, not to evaluate the quality or legitimacy of individual stakeholder contributions. On the other hand, the international system planners increasingly distinguish between different purposes of engagement, including:

- engagement for information,
- engagement for consultation, and
- engagement with demonstrable decision influence.

Transmission system operators such as ENTSO-E and the UK National Grid ESO now routinely publish "you said / we did" matrices that explicitly link stakeholder input to planning decisions, including transparent explanations where feedback was not adopted and why [4-8]. This practice has been shown to improve trust, reduce consultation fatigue, and clarify whether engagement is substantive rather than procedural.

Observation: Without clearer feedback-to-decision traceability, stakeholders may find it difficult to assess how their input influenced key outcomes such as the Optimal Development Path, particularly where contested assumptions persist across successive ISP cycles.

4. Pace and cognitive load as engagement constraints (R3)

Appendix A1 acknowledges that the pace and sequencing of the ISP process can challenge stakeholder participation. Morevoer, the international evidence indicates that high consultation density and technical complexity can act as de facto barriers to effective engagement, even where formal consultation opportunities exist. Studies by the UK Infrastructure and Projects Authority and the OECD emphasise that meaningful engagement requires not only access, but sufficient time, interpretability, and cognitive bandwidth, particularly when multiple interdependent technical reports are released in parallel [1, 8-11].

Observation: While AEMO has taken constructive steps to improve accessibility, including the ISP Toolkit, Appendix A1 could more explicitly recognise the risk that consultation fatigue and cumulative complexity may limit the depth of stakeholder influence. Furthermore, this risk is particularly relevant for non-technical participants and stakeholders engaging across multiple ISP appendices simultaneously.

Recommendation A: Decision-traceable engagement reporting

To strengthen the credibility and effectiveness of stakeholder engagement, future ISP documentation could include:

- a concise decision-traceability table linking major stakeholder themes to:
  - changes adopted,
  - changes deferred, or
  - changes rejected (with rationale);
- a brief reflection on any material representativeness gaps in engagement and the strategies used to mitigate them; and
- a clear differentiation between engagement used to inform modelling assumptions and inputs, and engagement used those used to validate, test, or stress-check modelling outputs.

These refinements would align the ISP with international best practice in large-scale energy system planning and reinforce confidence that engagement meaningfully informs planning outcomes, not just process compliance. This would directly address the engagement-to-decision gaps illustrated in Table 2.

5. References

1. Organisation for Economic Co-operation and Development. (2025). *Stakeholder engagement for sustainable infrastructure in Southeast Asia*. (OECD Business and Finance Policy Papers, No. 94). OECD Publishing.
2. Uzorka, A., Olaniyan, A. O., & Fakuade, O. V. (2023). *Engaging communities in renewable energy projects for sustainable development*. *Journal of Applied Sciences, Information and Computing*, 4(2), 57–67. https://doi.org/10.59568/JASIC-2023-4-2-06
3. World Bank Group. (2023, November 28). *World Bank unveils comprehensive framework to accelerate solar-plus-storage adoption in developing countries*. Press release. https://www.worldbank.org/en/news/press-release/2023/11/27/world-bank-unveils-comprehensive-framework-to-accelerate-solar-plus-storage-adoption-in-developing-countries#:~:text=WASHINGTON%2C%20Nov.,solar%2Dplus%2Dstorage%20capacity.
4. National Energy System Operator. (2024, February). *You said, we did*. National Energy System Operator.
5. National Energy System Operator. (2024, December). *Long Term Roadmap*. National Energy System Operator.
6. National Grid Electricity System Operator. (2022, August). *ESO RIIO-2 stakeholder engagement*. National Grid Electricity System Operator.
7. European Network of Transmission System Operators for Electricity. (2023, May). *TYNDP 2022 stakeholders engagement report*. ENTSO-E.
8. European Network of Transmission System Operators for Electricity & Gas. (2024). *Stakeholder engagement in TYNDP scenarios 2024*. ENTSO-E & ENTSOG.
9. Government Project Delivery. (2025, April 2). *Chapter 26: Stakeholder engagement* in *The Teal Book* (Part E: Planning and control).
10. Organisation for Economic Co-operation and Development. (2017). *OECD due diligence guidance for meaningful stakeholder engagement in the extractive sector* (OECD Publishing).
11. Infrastructure and Projects Authority. (n.d.). *Infrastructure and Projects Authority*. GOV.UK.

Appendix A2-Generation and Storage Development Opportunities

1. Purpose and scope

This submission provides comments and recommendations on Appendix A2-Generation and Storage Development Opportunities in the Draft 2026 Integrated System Plan (ISP). Its intent is to strengthen the interpretation of development opportunities by making key technical assumptions explicit, particularly the distinction between installed capacity, dispatchable capability, and reliably deliverable system contribution as the NEM transitions to a storage- and inverter-dominated generation mix. We acknowledge that Appendix A2 appropriately focuses on identifying least-cost development opportunities across scenarios rather than prescribing investment outcomes. The purpose of this submission is not to challenge the projected scale or direction of generation and storage development, but to highlight where implicit assumptions about deliverability, timing, and performance materially influence how these opportunities should be interpreted and stress-tested. Moreover, table 1 summarises the key assumptions examined in Appendix A2, the associated risks, and the specific clarifications or sensitivities requested, and provides a structured guide to the detailed comments that follow.

Table 1. Summary of key assumptions in Appendix A2, associated risks, and requested clarifications

ID	Topic	Assumption / framing	Identified risk	Requested clarification or test	Primary impact
R1	Installed capacity	MW treated as opportunity proxy	Overstates firm contribution	Distinguish installed vs deliverable	Planning realism
R2	Storage role	Depth ≈ adequacy	Misreads storage capability	Role-specific interpretation	Reliability
R3	Delivery timing	Build volume focus	Lifecycle gaps hidden	Lifecycle-aware sensitivity	Cost & adequacy
R4	CER contribution	Aggregate contribution	Performance uncertainty	Explicit linkage to A9 limits	Deliverability

2. Why development opportunity realism matters now?

Appendix A2 describes a system trajectory characterised by rapid growth in utility-scale Variable Renewable Energy (VRE), increasing deployment of medium- and deep-duration storage, and expanding coordinated Consumer Energy Resources (CER), with the flexible gas generation retained to support reliability and operability. Under the Step Change scenario alone, the Draft 2026 ISP projects utility-scale VRE increasing from approximately 23 GW today to around 58 GW by 2029-30 and to about 120 GW by 2049-50. Over the same period, total storage capacity is projected to reach roughly 32 GW/460 GWh by 2029-30 and to continue expanding thereafter, while the coordinated CER storage grows to tens of gigawatts by mid-century.

At these levels of penetration, the value of generation and storage development opportunities is no longer determined by installed capacity alone. Instead, it increasingly depends on:

i. the pace at which projects can be delivered and integrated into the system,
ii. the extent to which installed capacity translates into dispatchable and operable capability under real system constraints, and
iii. the interaction between generation, storage, network limits, and essential system services. Furthermore, the international system operators consistently emphasise that, in high-IBR systems, development outlooks must be interpreted through a deliverability and system-services lens rather than an installed-capacity lens alone, as reflected in ENTSO-E and NERC planning frameworks [1-6].

3. Summary of key recommendations

We recommend that AEMO take the following steps to strengthen the clarity and interpretability of generation and storage development opportunities in Appendix A2:

i. Clearly distinguish between installed capacity and reliably deliverable system capability when describing development opportunities, consistent with international system-planning practice.
ii. Clarify the assumed role of storage across different time horizons, explicitly distinguishing between intra-day energy shifting, multi-day firming, and contributions to seasonal adequacy, in line with established guidance on storage classification and use.
iii. Test sensitivity to delivery timing and performance shortfall, rather than focusing solely on build volumes, particularly for storage-heavy development pathways.
iv. Strengthen cross-linking between Appendices A2, A4, A6, and A9 so that generation, storage, and CER development opportunities are interpreted consistently with operability, cost-benefit, and demand-side assumptions.

4. Detailed comments and proposed refinements for Appendix A2

This section provides detailed comments and proposed refinements to Appendix A2, focusing on how generation and storage development opportunities should be interpreted in a power system that is increasingly dominated by inverter-based resources. While Appendix A2 presents installed capacity trajectories clearly and transparently, international experience shows that installed megawatts alone do not fully describe system capability, resilience, or value at high penetrations of variable renewables and storage. The comments below therefore focus on making key assumptions explicit, clarifying the operational roles and limitations of different resource types, and strengthening consistency with operability, lifecycle, and system-services considerations addressed elsewhere in the ISP. The intent is not to alter modelling outcomes, but to improve interpretability, credibility, and alignment with contemporary system-planning practice.

4.1 Installed capacity growth does not equal firm system capability (R2)

Appendix A2 presents installed capacity trajectories across scenarios in a clear and transparent manner. However, at high penetrations of inverter-based generation and storage, installed capacity alone becomes an incomplete proxy for system contribution. In practice, the extent to which installed megawatts translate into firm and usable system capability is constrained by several factors that are not visible in capacity totals.

International experience shows that reliably deliverable capability is bounded by network congestion and connection constraints, inverter control and protection behaviour, storage availability and State-of-Charge constraints, and interactions with system strength and voltage control. ENTSO-E explicitly distinguishes between installed capacity and "firm capacity contribution" in high-renewables systems, noting that the gap between the two widens as storage and inverter penetration increases [7]. Where this distinction is not made explicit, there is a risk that development opportunities are interpreted as providing greater firm system contribution than can realistically be delivered under system constraints.

To make this distinction explicit and testable, Table 2 illustrates how installed capacity, nominal dispatchable capability, and reliably deliverable contribution differ across major resource classes.

Table 2: Capability framing (installed vs deliverable)

Metric	Installed capacity	Nominal dispatchable	Reliably deliverable
Utility VRE	MW	MW	MW under congestion
Storage	MW / GWh	MW	MW under SoC + ESS limits
CER	GW	GW	GW under participation

This framing is intended to clarify the interpretation of development opportunities, not to redefine operational or market capacity metrics.

Recommendation A: Capability framing

Where Appendix A2 discusses generation and storage development opportunities, explicitly clarify whether the reported figures represent:

- installed capacity,
- nominal dispatchable capacity, or
- reliably deliverable capacity under prevailing system constraints.

This clarification would materially improve how stakeholders interpret development opportunities, without requiring changes to the underlying modelling framework.

4.2 Storage depth and role should be explicitly tied to system needs (R2)

Appendix A2 appropriately distinguishes between shallow, medium, and deep storage technologies. However, the interpretation of reported storage development opportunities would benefit from a clearer linkage between storage depth and the specific system needs being addressed. Storage technologies have fundamentally different operational roles and limitations depending on duration, cycling regime, and availability, as reflected in international standards such as IEC 62933 [8, 9].

At the system level, shallow storage primarily supports intra-day balancing and ramping, while medium- and deep-duration storage contribute to peak firming, multi-day adequacy, and resilience during prolonged low-VRE periods. Without explicitly stating the intended system role, there is a risk that storage deployment volumes are misinterpreted as interchangeable across these functions.

Recommendation B: Role-specific interpretation

When presenting storage development opportunities, explicitly indicate the primary system function being addressed, such as:

- intra-day energy shifting,
- peak firming,
- resilience during prolonged low-renewable events, or
- provision of essential system services.

This clarification would improve consistency between the development outlooks in Appendix A2 and the operability and adequacy conclusions presented in Appendix A4, without requiring changes to the underlying modelling assumptions.

4.3 Delivery timing and replacement cycles materially affect development opportunity value (R3)

Appendix A2 includes a Constrained Delivery sensitivity, which appropriately recognises build-rate limitations. However, delivery timing interacts strongly with storage replacement and refurbishment cycles, particularly as early-built assets age and experience degradation. At high storage penetrations, system capability depends not only on initial build-out, but on sustained reinvestment to maintain effective capacity over time. In addition, the international system operators increasingly highlight that storage fleets require ongoing replacement and refurbishment to preserve system capability, rather than a one-off build phase, as reflected in

NERC long-term reliability assessments [10]. If these lifecycle effects are not explicitly tested, there is a risk that development opportunities appear more robust over the outlook period than is achievable in practice.

Recommendation C: Lifecycle-aware sensitivity

Complement existing delivery sensitivities with a case that tests:

- delayed replacement of ageing storage assets, or
- faster-than-assumed degradation that reduces effective capacity.

This would strengthen confidence that identified development opportunities remain credible and robust across the full ISP horizon.

4.4 Generation, storage, and CER opportunities should be interpreted consistently across appendices (R4)

Appendix A2 appropriately references other ISP appendices that address operability, cost-benefit analysis, and demand-side factors. However, in practice, these appendices are often read in isolation. International best practice increasingly integrates development outlooks with operability constraints, lifecycle behaviour, and asset-health considerations, rather than treating them as separate analytical streams. Moreover, where this integration is implicit rather than explicit, there is a risk that stakeholders over-interpret development opportunities without fully accounting for the assumptions and limitations examined elsewhere in the ISP.

Recommendation D: Cross-appendix signposting

Add explicit signposts indicating where:

- storage and CER development opportunities in Appendix A2 rely on operability assumptions tested in Appendix A4,
- economic value depends on degradation and replacement assumptions examined in Appendix A6, and
- coordinated CER contributions depend on diagnostic, observability, and participation limits discussed in Appendix A9.

This does not increase modelling burden, but materially improves transparency and interpretability for stakeholders.

5. Practical enhancements AEMO can implement incrementally

To keep the proposed changes, proportionate and practical, we recommend that AEMO consider the following incremental enhancements:

i. including brief capability qualifiers alongside installed-capacity figures to distinguish between installed and reliably deliverable contributions;
ii. strengthening the linkage between storage depth and the specific system roles being addressed;
iii. adding one targeted, lifecycle-aware sensitivity to test the robustness of storage-heavy pathways; and
iv. improving cross-referencing between appendices so that development opportunities are interpreted consistently across operability, cost–benefit, and demand-side analyses.

These refinements are low overhead to implement but provide high explanatory value for stakeholders.

6. Closing statement

Appendix A2 provides a clear and informative picture of generation and storage development opportunities under the Draft 2026 ISP. As the NEM transitions toward a system increasingly dominated by inverter-based resources and storage, the way these opportunities are interpreted depends not only on installed capacity, but also on deliverability under system constraints, lifecycle behaviour, and integration with networks and essential system services. Making these assumptions more explicit would strengthen the credibility and practical usefulness of Appendix A2, and support consistent interpretation with international system-planning practice reflected in IEC standards, IEEE literature, and assessments by NERC and ENTSO-E [11-15].

7. References

1. North American Electric Reliability Corporation. (2024). *Inverter-based resource strategy*.
2. European Network of Transmission System Operators for Electricity. (2025, November 4). *ENTSO-E publishes Phase II technical report on grid-forming requirements*. ENTSO-E.
3. North American Electric Reliability Corporation. (2015). *Essential Reliability Services Task Force measures framework report*.
4. North American Electric Reliability Corporation. (2024, December; corrected July 11, 2025). *2024 Long-Term Reliability Assessment*.
5. European Network of Transmission System Operators for Electricity. (2024, July 10). *RDI roadmap 2024–2034: Innovation missions to build the power system for a carbon-neutral Europe*. ENTSO-E.
6. European Network of Transmission System Operators for Electricity. (2025, November). *Report on flexibility from renewable energy sources*. ENTSO-E.
7. European Network of Transmission System Operators for Electricity. (n.d.). System development. ENTSO-E.
8. International Electrotechnical Commission. (2025). *Electrical energy storage (EES) systems – Part 3-1: Planning and performance assessment of electrical energy storage systems – General specification* (IEC 62933-3-1:2025, 1st ed.). IEC. https://webstore.iec.ch/en/publication/75427#:~:text=Your%20IEC%20benefits:-,Products,be%20found%20throughout%20this%20document.
9. International Electrotechnical Commission. (2024). *IEC 62933-1:2024-Electrical energy storage (EES) systems-Part 1: Vocabulary*. IEC.
10. North American Electric Reliability Corporation. (n.d.). Assessments. NERC.
11. IEEE Power & Energy Society. (2024, March). *Grid-forming inverter-based resource research landscape: Understanding the key assets for renewable-rich power systems.*
12. European Network of Transmission System Operators for Electricity. (2025, November 4). ENTSO-E publishes Phase II technical report on grid-forming requirements. ENTSO-E.

13. North American Electric Reliability Corporation. (2025). *Evolving planning criteria for a sustainable power grid*.
14. National Renewable Energy Laboratory. (2025, July 29). *Distributed energy resource integration*.
15. European Network of Transmission System Operators for Electricity. (2024, May 3). *First interim report in technical requirements*. ENTSO-E.

Appendix A3-Renewable Energy Zones (REZs)

1. Purpose and scope

This submission provides comments on Appendix A3-Renewable Energy Zones (REZs) in the Draft 2026 Integrated System Plan (ISP). Its purpose is to strengthen the robustness of REZ selection, ranking, and sequencing by making explicit how operability, deliverability, and risk-concentration factors influence REZ performance beyond resource quality and cost metrics alone. Appendix A3 provides a clear and structured overview of candidate REZs, development outlooks, and scorecards. However, as the NEM transitions to very high penetration of inverter-based resources, REZ outcomes increasingly depend on non-resource factors such as system strength, fault levels, climate stress, coordination complexity, and correlated failure modes, all of which materially affect whether a REZ delivers its forecast system value in practice. Table 1 summarises the key assumptions implicit in Appendix A3, the associated risks if those assumptions do not hold, and the targeted refinements requested to improve transparency and robustness. The intent of this submission is not to challenge the REZ framework itself, but to ensure that REZ planning and interpretation remain aligned with power-system physics and operational reality, consistent with international system-operator experience [1-3].

Table 1: Summary of key assumptions in Appendix A3, associated risks, and requested refinements

ID	Topic	Assumption / framing	Identified risk	Requested clarification or test	Primary impact
R1	REZ ranking	Resource quality dominates	Weak-grid REZs over-ranked	Deliverability readiness flag	Operability risk
R2	REZ concentration	Scale=efficiency	Correlated failure modes	Concentration sensitivity	System resilience
R3	Climate metrics	Descriptive indicators	Stress impacts understated	Climate-operability linkage	Reliability
R4	Transmission	Wires resolve constraints	Non-wire limits ignored	Beyond-wires assumptions	System security

2. Why REZ realism matters now (context from Appendix A3)

Appendix A3 projects nearly 120 GW of utility-scale variable renewable energy by 2049-50 under the Step Change scenario, with a large share concentrated within a limited number of Renewable Energy Zones (REZs). Moreover, the modelling indicates increasing reliance on both co-located and remote battery energy storage to manage curtailment, congestion, and energy shifting. While the REZ scorecards appropriately consider factors such as resource quality, demand correlation, climate hazards, and curtailment, the interpretation of these results implicitly assumes that network augmentation and coordination will reliably convert REZ capacity into system value. In addition, the international experience suggests that this conversion is not automatic at very high penetrations of inverter-based resources. In practice, large and highly concentrated REZ developments can amplify system-level risks, including system-strength and fault-level weaknesses, correlated inverter behaviour during disturbances, heightened exposure to extreme weather and climate stress, and social-licence and delivery challenges. As a result, system operators in North America and Europe increasingly treat REZ-scale developments as operability-critical zones rather than simply energy production clusters [4-6].

3. Summary of key recommendations

We recommend that AEMO consider the following refinements to strengthen the interpretation and robustness of REZ planning in Appendix A3:

i. Explicitly integrate operability and system-strength readiness directly into REZ ranking and sequencing, rather than treating these considerations only in downstream appendices such as A4 and A7.
ii. Recognise and test REZ concentration risk by including sensitivity cases in which large and highly concentrated REZs underperform central assumptions due to weak-grid conditions, climate-driven constraints, or correlated disturbances.
iii. Strengthen interpretation of REZ scorecards by clearly distinguishing between metrics that are indicative under normal conditions and which are likely to become binding under stressed system conditions.
iv. Align REZ development logic with the international transmission-planning practice [1-3], where deliverability, resilience, and operability are treated as co-equal with resource quality in development and sequencing decisions.

4. Detailed comments and proposed refinements for Appendix A3

This section provides detailed comments and proposed refinements to Appendix A3, focusing on how Renewable Energy Zone (REZ) opportunities are assessed and interpreted in a power system increasingly dominated by inverter-based resources. While Appendix A3 appropriately highlights renewable resource quality, diversity, and scale benefits, the international experience shows that these attributes alone are insufficient to determine whether a REZ can deliver reliable and resilient system value. Therefore, the comments below will focus on making implicit assumptions explicit, strengthening the linkage between REZ development and deliverability, system strength, correlated risk, and climate-driven operability constraints, and improving consistency with contemporary international system-planning practice. However, the intent is not to challenge the REZ framework itself, but to improve transparency and help stakeholders to understand the conditions under which REZ opportunities translate into dependable system outcomes.

4.1 Resource quality alone does not define REZ deliverability (R1)

Appendix A3 correctly emphasises renewable resource quality, diversity, and demand correlation as core attributes for identifying and ranking REZs. However, international experience demonstrates that high-quality resource areas can still underperform system expectations if grid conditions are weak or insufficiently conditioned. At high penetrations of inverter-based generation, deliverability increasingly depends on system-strength conditions, fault levels, and coordinated control behaviour, rather than resource quality alone. Hence, to support consistent interpretation of REZ rankings, Table 2 illustrates which REZ attributes are typically indicative under normal conditions and which are likely to become binding under stressed system conditions.

Table 2: REZ deliverability and stress binding indicators

REZ attribute	Indicative	Potentially binding	Binding under stress
Resource quality	✓		
Transmission access		✓	✓
System strength		✓	✓
Climate stress		✓	✓

This framing is intended to support interpretation of REZ performance and prioritisation under stressed conditions, not to prescribe REZ eligibility, scoring thresholds, or investment decisions. It is worth mentioning that the system operators in Europe and North America note that clustering large volumes of inverter-based generation without commensurate system-strength measures increases exposure to voltage instability, fault ride-through failures, and widespread inverter tripping during disturbances [3, 5]. Where these factors are not explicitly accounted for, REZ rankings may overstate the practical system value of zones that are resource-rich but weakly conditioned.

Recommendation A: Deliverability readiness flag

Augment the REZ scorecards with a simple deliverability readiness flag indicating whether a REZ:

- is already adequately system-strength conditioned,
- requires additional synchronous condensers or equivalent measures, or
- relies on future assumptions regarding grid-forming capability or advanced inverter behaviour.

This would improve the interpretation of REZ rankings without altering the underlying scoring framework.

4.2 REZ concentration increases correlated risk, not only efficiency (R2)

Appendix A3 appropriately highlights the economies of scale and coordination benefits associated with REZ development. However, concentrating large volumes of generation within a small number of zones also creates correlated risk. When substantial capacity shares common inverter controls, protection settings, weather exposure, and transmission corridors, failures are no longer isolated and can propagate rapidly across a region. Notably, the international disturbance analyses show that clustered inverter fleets can exhibit simultaneous control interactions during stressed conditions, even when individual assets comply with technical standards [6, 7]. Without explicit treatment of this effect, REZ concentration may be interpreted primarily as an efficiency gain, while its implications for system resilience remain understated.

Recommendation B: REZ concentration sensitivity

Include a sensitivity case in which one or more major REZs deliver reduced effective capacity during stressed conditions due to correlated inverter behaviour, network limitations, or climate-driven impacts. Report the resulting effects on:

- transmission utilisation,
- reliance on alternative REZs or non-REZ resources, and
- overall system costs and operability margins.

4.3 Climate hazard metrics require an operability interpretation (R3)

Appendix A3 commendably includes climate hazard indicators, such as temperature and bushfire risk, within REZ scorecards. However, these metrics are currently treated as descriptive indicators rather than as drivers of operability outcomes. Moreover, the international system operators increasingly link climate hazards directly to asset derating, reduced storage availability during heatwaves, and elevated outage and maintenance risk, particularly during periods of coincident system stress. However, without an explicit interpretation of how climate hazards affect deliverability, there is a risk that REZs exposed to higher climate stress appear equivalent to less-exposed zones under normalised scoring.

Recommendation C: Climate-operability linkage

Explicitly describe how REZ climate hazard scores influence:

- expected thermal deratings of generation and storage assets,
- outage rates and maintenance-driven unavailability, and
- performance during coincident system stress periods.

This would improve transparency without requiring additional modelling detail.

4.4 Transmission augmentation is necessary but not sufficient (R4)

Appendix A3 appropriately identifies transmission investment as a critical enabler of REZ development. However, international planning frameworks increasingly recognise that transmission augmentation alone does not resolve operability constraints in inverter-dominated zones. System-strength services, control coordination, and protection alignment are now treated as first-order planning inputs alongside new lines. Furthermore, where these elements are assumed implicitly, there is a risk that REZ deliverability is overstated, particularly under stressed or faulted conditions.

Recommendation D: Beyond-wires framing

Where REZ development relies on transmission augmentation, explicitly state whether:

- additional system-strength assets are assumed,
- grid-forming capability is required to maintain stable operation, and
- protection coordination has been considered at the REZ scale.

This clarification would strengthen alignment between REZ planning, operability assessments, and system-security considerations elsewhere in the ISP.

5. Practical enhancements AEMO can include (low overhead)

To strengthen Appendix A3 without requiring major modelling rework, AEMO could consider a small set of targeted enhancements:

i. adding a simple REZ deliverability readiness indicator as an additional column in the REZ scorecards;
ii. including one or two sensitivity cases that test the impact of REZ concentration risk under stressed system conditions;
iii. providing a short narrative explaining how climate hazards translate into operability impacts for generation and storage assets within REZs; and
iv. improving cross-referencing between Appendix A3, which identifies where capacity is developed, and Appendices A4 and A7, which assess whether that capacity can operate securely.

These refinements are low overhead to implement but would materially improve transparency, interpretability, and consistency across the ISP.

6. Closing statement

Appendix A3 provides a strong foundation for coordinated renewable development in the NEM. However, at the penetrations projected in the Draft 2026 ISP, REZ performance is no longer determined solely by resource quality and transmission cost. It is increasingly shaped by system strength, inverter behaviour, climate stress, and correlated risk at scale. Explicitly recognising these factors within Appendix A3 would materially strengthen the credibility of REZ prioritisation and help reduce the risk that operability constraints emerge only after major investment commitments have been made.

7. References

1. European Network of Transmission System Operators for Electricity. (2025). High penetration of power electronic-interfaced power sources and the potential contribution of grid forming converters (PDF). ENTSO-E.
2. North American Electric Reliability Corporation. (n.d.). Reliability guidelines. NERC.
3. North American Electric Reliability Corporation. (2023). Inverter-based resource performance issues: Public report.
4. North American Power & Energy Society. (n.d.). Technical publications. IEEE Power & Energy Society.
5. Jankowski, M., Gunduz, D., & Mikolajczyk, K. (2022). *AirNet: Neural network transmission over the air* (Article No. 9834372). IEEE.
6. North American Electric Reliability Corporation. (2024, corrected July 2025). 2024 Long-Term Reliability Assessment.
7. Institute of Electrical and Electronics Engineers. (2022). *IEEE Standard for interconnection and interoperability of inverter-based resources (IBRs) interconnecting with associated transmission electric power systems (IEEE Std 2800-2022)*. IEEE.

Appendix A4-System Operability

1. Purpose and scope

This submission sets out comments and recommendations on Appendix A4-System Operability in the Draft 2026 Integrated System Plan (ISP). Its aim is to help to strengthen the operability conclusions by making the key modelling assumptions clearer and by suggesting a small number of targeted sensitivity tests that better reflect how an increasingly inverter-dominated power system is likely to behave in practice. We recognise that ISP modelling necessarily relies on assumptions about the future behaviours and market interactions, and that actual outcomes may differ from forecasts. Therefore, the intent here is not to remove uncertainty, but to improve transparency and robustness where optimistic or implicit assumptions could otherwise mask material operability risks. Moreover, table 1 provides a concise summary of the key A4 assumptions considered, the risks they introduce, and the specific clarifications or tests requested, and serves as a guide to the detailed discussion that follows.

Table 1: Key Appendix A4 modelling assumptions, resulting operability risks, and recommended clarifications and sensitivity tests

ID	Topic	Assumption / approach	Identified risk	Requested clarification or test	Primary impact
R1	Storage firming	Full usable State-of-Charge (SoC) (0-100%) assumed	Overstates deliverable energy in stress	Quantise SoC floors/ceilings and test	Reliability, unserved energy
R2	Long dark still	Energy balance focus	ESS constraints bind first	Report ESS-binding hours by type	Operability transparency
R3	Inverter behaviour	Implicit control modes	Weak-grid instability masked	Declare GFM/GFL shares explicitly	System security
R4	Curtailment	Aggregate outcomes only	Local constraints hidden	Report binding constraint class	Network planning

2. Why A4 operability needs "hardware realism"?

The Draft 2026 ISP charts show a rapid shift toward an electricity system that is increasingly dominated by inverters and storage. Under the Step Change scenario, this transition is reflected in a substantial growth in both storage and distributed energy resources. At an order-of-magnitude level, utility-scale storage increases from around 11 GW in 2026-27 to approximately 27 GW by 2030-31, reaching about 32 GW by 2049-50. Over the same period, rooftop solar capacity grows from roughly 29 GW to 38 GW by 2030-31, and to around 87 GW by 2049-50. Moreover, the coordinated Consumer Energy Resource (CER) storage expands markedly, from about 0.6 GW in 2026-27 to 2.0 GW by 2030-31, and to approximately 23 GW by 2049-50.

Against this backdrop, the Inputs & Assumptions workbook defines storage operating parameters that materially influence how operability outcomes are interpreted in Appendix A4. For example, utility-scale battery templates allow operation between a minimum State-of-Charge (SoC) of 0% and a maximum of 100% across several duration classes (1-hour, 2-hour, 4-hour, and 8-hour systems). The aggregated and Virtual Power Plant (VPP) storage adopts a reduced maximum SoC (for example, 85%), but still assumes a minimum SoC of 0%. While these assumptions are reasonable for high-level planning, they risk overstating the amount of storage flexibility that can be delivered during stressed operating conditions.

In practice, operators maintain reserves, network constraints limit dispatch, and inverter control and protection behaviour restrict what storage and inverter-connected resources can deliver during the critical hours that Appendix A4 is intended to address. Therefore, at the levels of inverter and storage penetration projected in the Draft 2026 ISP, system operability is increasingly shaped by

i. inverter control modes and performance limits,
ii. real-world storage constraints under stress, and
iii. system strength and fault-level interactions, rather than by energy balance alone.

This shift in operability drivers is well documented internationally by system operators and standards bodies, including NERC [1], IEEE [2], and ENTSO-E [3].

3. Summary of key recommendations

We recommend that AEMO take the following steps to strengthen the transparency and robustness of the Appendix A4 operability assessment:

i. Make inverter control assumptions explicit and testable, including the assumed shares of grid-forming and grid-following inverters, their performance envelopes, behaviour under weak-grid conditions, and response to disturbances, in line with the intent of IEEE Std 2800-2022 [2].
ii. Stress-test storage performance under non-ideal operating conditions, rather than assuming near-perfect flexibility and full usable SpC during critical hours, consistent with observed Battery Energy Storage System (BESS) behaviour documented by NERC [1].
iii. Clearly distinguish between energy adequacy and the adequacy of essential system services, and report where operability constraints bind first (for example, frequency, voltage, system strength, or congestion), consistent with international system-operator practice.
iv. Introduce a small, targeted set of operability-focused sensitivity cases for long, dark, still periods and weak-grid operation, in order to quantify operability risk margins rather than relying solely on central modelling assumptions.

4. Detailed comments and proposed refinements for Appendix A4

In an increasingly inverter-dominated NEM, operability is no longer primarily a matter of balancing energy supply and demand. Instead, it depends on how inverters and storage resources behave in practice during disturbances, under weak-grid conditions, and through extended periods of low renewable output, and on whether the assumed flexibility and essential system services can actually be delivered when and where they are required. Therefore, the subsections that follow focus on the practical operability drivers that most strongly influence Appendix A4 outcomes, and outline a small number of transparent assumption disclosures and stress tests aligned with international system-operator practice and relevant standards.

4.1 Inverter control assumptions: grid-forming versus grid-following must be explicit (R3)

As inverter-based resources continue to displace synchronous generation, the distinction between grid-following and grid-forming inverter behaviour becomes critical to system operability. These two control modes are not operationally interchangeable, particularly during disturbances, under weak-grid conditions, and at times when synchronous online capacity is low or curtailment is high. In such conditions, system stability depends not just on the amount of inverter-connected capacity, but on how those inverters establish or follow system voltage and frequency. Furthermore, these inverter control and curtailment effects interact with system security considerations outlined in Appendix A7.

On the other hand, the international standards and operator guidance consistently highlight this distinction. IEEE Std 2800-2022 sets out different performance expectations for transmission-connected inverter-based resources, while NERC identifies loss of a stable synchronising reference and adverse control interactions as credible system-level risks in high-IBR systems [2, 4]. Where Appendix A4 relies on inverter performance to support operability outcomes, therefore, these control assumptions need to be made explicit.

Recommendation A: Disclosure of inverter control assumptions

Include a concise inverter operability assumption table, disaggregated by technology class and time horizon, that clearly states:

- the assumed share of grid-forming capability,
- the assumed control features (such as frequency droop or fast frequency response, voltage droop, ride-through, and recovery behaviour), and
- the assumed behaviour under weak-grid or low fault-level conditions, including how these behaviours are represented in the modelling framework.

Recommendation B: Validation and performance framing

Clearly define the dynamic performance metrics used to assess operability in Appendix A4, such as voltage recovery, frequency nadir, Rate of Change of Frequency (RoCoF), and post-fault recovery. These metrics should be aligned with the plausible inverter and protection settings, rather than idealised or best-case behaviour.

4.2 Storage is essential, but not perfectly flexible under stress (R1)

The scale of storage deployment projected in the Draft 2026 ISP makes storage central to operability outcomes. However, real-world storage performance is constrained by well-understood technical and operational limits that become most visible during stressed system conditions. These limits include inverter current caps and control saturation during voltage disturbances, trade-offs between active power delivery and voltage support, protection responses such as momentary cessation or tripping, and operational constraints related to SoC management, reserve holding, and deratings during prolonged events.

In addition, the international standards and disturbance experience reinforce the importance of these constraints. IEEE Std 1547-2018 explicitly limits the inverter current contribution and prioritisation during disturbances [5], while NERC disturbance reports document instances of BESS underperforming relative to nominal capability during grid events [6]. Moreover, IEC 62933 recognises the operational derating and availability constraints for energy storage systems [7]. These realities mean that assuming near-perfect storage flexibility risks overstating deliverable operability support.

Recommendation C: Storage response envelope definition

In Appendix A4, or in a supporting annex, define a storage operability "response envelope" that explicitly documents:

- active and reactive power limits and prioritisation assumptions,
- response and recovery behaviour following disturbances,
- credible derating or outage assumptions, and
- an operability-focused treatment of SoC reserves (for example, minimum SoC floors during stressed periods).

Recommendation D: State-of-Charge realism sensitivity

Include at least one sensitivity case in which storage cannot access the full 0-100% SoC range during critical periods, reflecting reserve policies, operational constraints, or degraded availability, and report the resulting impacts on operability metrics.

Additionally, the SoC assumptions play a material role in determining how much storage flexibility is available during stressed system conditions. While the Draft 2026 ISP appropriately uses simplified SoC ranges for high-level planning, these assumptions can materially influence operability outcomes during prolonged or compound stress events. Table 2 presents indicative SoC bounds suitable for operability-focused sensitivity testing, intended to test the robustness of Appendix A4 conclusions to more realistic storage constraints under stress. Moreover, these operability constraints have direct valuation implications, consistent with the sensitivity outcomes discussed in Appendix A6.

Table 2: Proposed SoC quantisation for operability testing

Storage class	AEMO assumed min SoC	Proposed test min SoC	Rationale
Utility BESS	0%	10-20%	Reserve holding, inverter limits
Aggregated CER	0%	15-25%	Behavioural + network constraints
VPP	0%	20-30%	Availability uncertainty

It must be noted that, these values are not operational prescriptions, but stress-test bounds intended to expose the sensitivity of Appendix A4 conclusions to SoC assumptions.

4.3 Curtailment and demand flexibility require an operability lens (R4)

Curtailment is an expected and necessary feature of high-VRE systems. However, curtailment decisions influence which inverter-connected resources remain online and providing grid support, and can unintentionally exacerbate local voltage or system-strength issues if not considered explicitly from an operability perspective. Similarly, demand flexibility can provide valuable support, but its effectiveness under stress depends on customer participation, aggregation logic, and communications reliability. Moreover, the local curtailment effects interact with network congestion and dispatch outcomes discussed in Appendix A5. However, where curtailment or demand flexibility is relied upon in Appendix A4 narratives, the implications for essential system services need to be clearly assessed rather than inferred.

Recommendation E: Essential services adequacy reporting

Where curtailment or demand flexibility contributes to operability outcomes, explicitly assess whether essential system services remain adequate at the relevant locations, including:

- voltage support,
- frequency response,
- system strength and fault levels, and
- disturbance ride-through and recovery capability.

4.4 Long, dark, still events: quantify operability margins through targeted stress tests (R2)

Appendix A4 appropriately identifies prolonged low-VRE periods as a key operability challenge. These conditions are precisely when assumptions about storage availability, SoC constraints, network limits, and system services are most likely to bind. International system operators typically treat such events as compound stress scenarios, in which multiple constraints act simultaneously rather than in isolation, as reflected in NERC seasonal reliability assessments [8]. Furthermore, to support robust interpretation of operability outcomes, these compound risks should be explicitly tested rather than inferred from central assumptions.

Recommendation F: Operability stress-test set

For key regions or critical NEM sub-regions, include a small, targeted set of stress tests that combine:
prolonged low VRE availability,

- credible interconnector constraints or outages,
- reduced storage availability and/or binding SoC constraints, and
- demand flexibility performance below central assumptions.

Moreover, results should clearly report which operability constraint binds first, and identify what additional system services, network support, or operational measures would be required to maintain secure operation.

5. Practical deliverables AEMO can include (low overhead, high value)

To ensure these improvements remain practical and proportionate, we recommend that AEMO publish the following as part of Appendix A4 or its supporting materials:

i. an Inverter-Based Resource (IBR) operability assumption table, limited to approximately one page;
ii. a concise storage operability envelope, also of approximately one page;
iii. a small, clearly defined set of sensitivity cases (around three to six) designed to bound key operability uncertainties; and
iv. separate reporting of energy adequacy outcomes and essential system services adequacy outcomes.

Therefore, this framing keeps the requests concrete, scoped, and difficult to dismiss as excessive.

6. Closing statement

We recognise AEMO's acknowledgement that operability assessment within the ISP is necessarily driven by modelling assumptions. The Draft 2026 ISP datasets point to a system trajectory in which operability outcomes will increasingly depend on inverter control behaviour, protection responses, performance under weak-grid conditions, and realistic storage constraints. Making these assumptions explicit, and complementing them with a limited number of targeted stress tests, would materially strengthen the credibility and practical usefulness of Appendix A4 for system planning, project delivery, and operational readiness.

7. References

1. North American Electric Reliability Corporation. (2023, June). *Quick reference guide: Inverter-based resource activities*.
2. Institute of Electrical and Electronics Engineers. (2022). *IEEE standard for interconnection and interoperability of inverter-based resources (IBRs) interconnecting with associated transmission electric power systems (IEEE Std 2800-2022)*. IEEE.
3. European Network of Transmission System Operators for Electricity. (n.d.). *System operations reports*. ENTSO-E.
4. North American Electric Reliability Corporation. (n.d.). *Reliability Guidelines*. NERC.
5. Institute of Electrical and Electronics Engineers. (2018). *IEEE Standard for interconnection and interoperability of distributed energy resources with associated electric power systems interfaces (IEEE Std 1547-2018)*. IEEE.
6. North American Electric Reliability Corporation. (2025, June). *2025 State of Reliability: Assessment overview of 2024*.
7. Jalthar, R. (2025, August 25). *IEC 62933: Global standard for grid energy storage systems*. SunLith Energy.
8. North American Electric Reliability Corporation. (n.d.). *Assessments*. NERC.

Appendix A5-Network Investments

1. Purpose and scope

This submission provides comments and recommendations on Appendix A5-Network Investments in the Draft 2026 Integrated System Plan (ISP). Its intent is to strengthen confidence in the timing, scale, and sequencing of transmission investments by making key assumptions explicit, particularly the relationship between network build, operability limits, asset health, and delivery realism, rather than treating transmission as a frictionless enabler of generation and storage outcomes. Appendix A5 sets out a comprehensive and integrated transmission roadmap aligned with the Optimal Development Path (ODP). The purpose of this submission is not to re-argue project selection or jurisdictional frameworks, but to highlight where implicit assumptions about operability, delivery timing, cost escalation, and REZ utilisation materially influence how network investments should be interpreted and stress-tested. In addition, table 1 summarises the key assumptions examined in Appendix A5, the associated risks if those assumptions do not hold, and the targeted clarifications or sensitivity tests requested, and provides a structured guide to the detailed comments that follow.

Table 1: Summary of key assumptions in Appendix A5, associated risks, and requested refinements

ID	Topic	Assumption / framing	Identified risk	Requested clarification or test	Primary impact
R1	Transmission role	Energy-only enabler	Operability limits hidden	Operability-linked justification	System security
R2	Delivery timing	Full availability on COD	Over-reliance on optimistic dates	Delay / partial delivery sensitivity	Reliability
R3	Cost escalation	Linear cost growth	Ranking instability	Non-linear cost sensitivity	Investment confidence
R4	REZ enablement	Connection = utilization	Curtailment risk understated	Utilisable vs connected capacity	System value

2. Why network realism matters now?

Appendix A5 indicates that, under the Step Change scenario, approximately 6,000 km of new transmission is required by 2050, with more than 5,000 km needed within the next decade. Moreover, AEMO acknowledges materially higher transmission costs than assumed in previous ISPs, in some cases approaching 100% real increases, alongside growing project complexity driven by scope changes, social-licence challenges, supply-chain pressure, and workforce constraints. At the same time, the transmission network is increasingly relied upon to unlock Renewable Energy Zones (REZs) and maintain reliability as synchronous generation retires.

At this scale, network investment outcomes are no longer governed solely by economic optimisation under ideal delivery assumptions. Instead, they are increasingly shaped by

i. deliverability risk and staging constraints,
ii. operability limits under inverter-dominated operating conditions, and
iii. non-linear cost escalation and schedule slippage.

Additionally, the international system planners now treat these factors as first-order considerations in long-term transmission planning, rather than as secondary implementation details.

3. Summary of key recommendations

We recommend that AEMO consider the following targeted refinements to strengthen the robustness and interpretability of network investment decisions in Appendix A5:

i. Explicitly link network investment justification to operability constraints, including system strength, fault levels, and dynamic performance requirements, rather than framing transmission primarily as an energy transfer enabler, consistent with international transmission-planning practice (e.g. ENTSO-E and NERC) [1].
ii. Stress-test the Optimal Development Path (ODP) against scenarios in which major transmission projects are delayed or only partially delivered, rather than assuming full availability at the modelled in-service date [2].
iii. Make assumptions regarding system strength, fault-level adequacy, and dynamic support requirements explicit in transmission investment justification, particularly for projects intended to enable Renewable Energy Zones (REZs) [3].
iv. Test the robustness of cost–benefit outcomes under non-linear transmission cost escalation, rather than relying solely on centralised or linear cost assumptions [4].

4. Detailed comments and proposed refinements for Appendix A5

This section provides detailed comments and proposed refinements to Appendix A5, focusing on how transmission investments are interpreted in a power system increasingly dominated by inverter-based resources. While Appendix A5 clearly identifies transmission as essential infrastructure for enabling renewable generation, storage, and Renewable Energy Zone (REZ) development, international experience shows that transmission can no longer be treated as a neutral, energy-only enabler. Instead, the system value of transmission investments increasingly depends on operability roles, delivery realism, non-linear cost escalation, and network performance under stressed conditions. The comments below therefore focus on making these assumptions explicit and improving alignment with contemporary international transmission-planning practice, without re-opening project selection or jurisdictional frameworks.

4.1 Transmission is no longer a neutral enabler in an inverter-dominated system (R1)

Appendix A5 appropriately frames transmission as critical infrastructure connecting renewable generation, storage, and load. However, as synchronous generation retires and inverter-based resources dominate, transmission assets increasingly perform active system functions beyond energy transfer. In practice, these functions include managing fault levels and short-circuit strength, supporting voltage control and dynamic stability, and enabling inverter-based resources to remain connected and stable during disturbances. Table 2 summarises these transmission functions and indicates which are typically indicative under normal conditions and which become potentially binding or binding under stressed system conditions, highlighting why transmission can no longer be interpreted solely as an energy-transfer enabler in an inverter-dominated system.

Table 2: Transmission functions beyond energy transfer

Transmission function	Indicative	Potentially binding	Binding under stress
Energy transfer	✓		
System strength		✓	✓
Voltage stability		✓	✓
Dynamic support		✓	✓

This framing is intended to clarify interpretation of network investment roles under stressed conditions, not to redefine regulatory or operational obligations.

Notably, the international experience shows that transmission planning which assumes primarily “energy-only” functionality increasingly understates these roles. Moreover, ENTSO-E explicitly links transmission expansion to system stability and inertia management in high-IBR systems, while NERC identifies transmission-dependent system strength as a limiting factor in renewable integration [5–7]. Where these operability roles are not made explicit, there is a risk that network investments are justified on incomplete functional grounds.

Recommendation A: Operability-linked justification

For major REZ-enabling and interconnector projects in Appendix A5, explicitly state:

- whether the project is required primarily for energy transfer, system strength, dynamic stability, or a combination of these functions; and
- how those roles are expected to evolve as inverter penetration increases.

This would align transmission investment justification with the operability risks and system needs identified in Appendix A4.

4.2 Timing and staging assumptions require explicit downside testing (R2)

Appendix A5 identifies multiple actionable and anticipated projects with defined in-service dates and assumed availability. In practice, however, large transmission projects internationally rarely deliver full capability as a step change. Instead, they commonly experience staged commissioning, delayed energisation of full transfer capacity, and extended periods of constrained operation during testing, protection tuning, and system integration. Recognising this, NERC and European transmission system operators increasingly incorporate delay and partial-delivery sensitivities into long-term planning to avoid over-reliance on optimistic commissioning assumptions [2, 8]. Without such testing, development pathways can appear more robust than is achievable in practice.

Recommendation B: Delivery realism sensitivity

Introduce a sensitivity case in which one or more major transmission projects:

- enter service later than assumed, or
- deliver reduced initial transfer capability,
- and assess the resulting impacts on generation curtailment, reliability outcomes, and system costs.

4.3 Cost escalation is non-linear and interacts with sequencing (R3)

Appendix A5 appropriately acknowledges significant increases in transmission costs driven by supply-chain pressure, labour constraints, and growing project complexity. International evidence indicates that these effects are not linear. Concurrent project delivery amplifies labour and materials scarcity, late-stage scope changes disproportionately increase costs, and social-licence delays often cascade across multiple projects within a portfolio.

As a result, ENTSO-E and NERC planning guidance increasingly treat cost escalation and delivery congestion as systemic risks rather than project-specific anomalies [4, 8]. Where cost escalation is assumed to scale linearly, there is a risk that network sequencing and ranking appear more stable than they are under realistic delivery conditions.

Recommendation C: Non-linear cost sensitivity

Test the Optimal Development Path under a scenario in which transmission costs escalate faster than assumed for overlapping or concurrent projects, and report whether the relative ranking, timing, or sequencing of network investments remains robust.

4.4 REZ connection value depends on network performance, not just existence (R4)

Appendix A5 correctly identifies REZ expansion as a central driver of transmission investment. However, international experience shows that the value of REZ-related transmission depends not only on connection capacity, but on network performance under stressed conditions. Key factors include voltage and system strength at connection points, availability of dynamic support and coordinated protection, and the ability of the broader network to absorb coincident output from multiple generators. It is worth mentioning that, where these factors are not explicitly considered, nominal REZ capacity can translate into high curtailment rather than reliably utilisable supply.

Recommendation D: REZ performance framing

For REZ-related network investments, explicitly distinguish between:

- connected capacity, and
- reliably utilisable capacity under stressed system conditions.

This clarification aligns with international practice and avoids overstating the effective system contribution of network-enabled renewables.

5. Practical enhancements AEMO can implement incrementally

To keep changes, proportionate and implementable, we recommend that AEMO consider a small set of targeted refinements:

i. including a short table that links major transmission projects to the specific operability constraints they are intended to address;
ii. applying one or two delivery-delay sensitivity cases to the ODP to test robustness to realistic commissioning outcomes;
iii. explicitly acknowledging staged commissioning behaviour and reduced initial capability in the interpretation of in-service dates; and
iv. improving signposting of where network investments substitute for, or complement, non-network solutions in meeting system needs.

These refinements are low overhead to implement and would materially improve transparency, interpretability, and confidence in the network investment pathway.

6. Closing statement

Appendix A5 provides a comprehensive and necessary roadmap for network investment in the NEM transition. As transmission becomes increasingly central to operability, system strength, and reliability in an inverter-dominated system, the credibility of the ISP depends not only on identifying the right projects, but on testing how those projects perform under realistic delivery, cost, and operating constraints. The recommendations in this submission are intended to strengthen that credibility by aligning network investment assumptions with international system-operator experience, without expanding scope or revisiting policy settings.

7. Reference

1. European Network of Transmission System Operators for Electricity. (2013, November 14). *ENTSO-E guideline for cost benefit analysis of grid development projects*.
2. North American Electric Reliability Corporation. (2021). *TPL-001-5.1-Transmission system planning performance requirements*.
3. North American Electric Reliability Corporation. (2018, September). *BPS-connected inverter-based resource performance guideline*.
4. European Network of Transmission System Operators for Electricity. (2024, April 9). *ENTSO-E publishes the final guideline for cost benefit analysis of grid development projects*. ENTSO-E.
5. Ahmed, F., Al Kez, D., McLoone, S., Best, R. J., Cameron, C., & Foley, A. (2023). Dynamic grid stability in low carbon power systems with minimum inertia. *Renewable Energy, 210*, 486-506.
6. North American Electric Reliability Corporation. (2025). *Grid-forming microgrid functional specification white paper*.
7. European Network of Transmission System Operators for Electricity. (2025, January 10). *Project Inertia-Phase II: Recovering power system resilience in case of system splits for a future-ready decarbonised system: Supporting technical report*.
8. North American Electric Reliability Corporation. (2024, corrected July 2025). *2024 Long-Term Reliability Assessment*.

Appendix A6-Cost-Benefit Analysis

1. Purpose and scope

This submission provides comments and recommendations on Appendix A6-Cost-Benefit Analysis in the Draft 2026 Integrated System Plan (ISP). Its purpose is to strengthen the robustness and interpretability of cost-benefit outcomes by making explicit how sensitive Net Present Value (NPV) results are to assumptions about storage performance, degradation, availability, and asset health over time. AEMO's cost-benefit framework is well established, transparent, and aligned with regulatory guidance, and uncertainty is already explored through scenario and sensitivity analysis. Hence, the intent of this submission is not to challenge the structure of the CBA, but to identify a small number of technically grounded sensitivities where real-world behaviour of inverter-based and storage assets could materially influence rankings and value outcomes. Table 1 summarises the key assumptions embedded in Appendix A6, the risks that arise if those assumptions do not hold, and the targeted refinements requested to improve robustness, consistent with international system-operator practice such as NERC and ENTSO-E planning approaches [1-4].

Table 1: Summary of key assumptions in Appendix A6, associated risks, and requested refinements

ID	Topic	Assumption / framing	Identified risk	Requested clarification or test	Primary impact
R1	Storage degradation	Average lifetime costs	NPV overstated	Explicit degradation sensitivity	Ranking robustness
R2	Asset health	Smooth cost trajectories	Step-change costs hidden	Non-linear lifecycle sensitivity	Cost credibility
R3	Diagnostics	Performance uncertainty fixed	Avoidable costs ignored	Diagnostic-enabled sensitivity	System value
R4	Performance shortfall	Coordination focus only	Technical underperformance missed	Capacity shortfall sensitivity	Reliability & cost

2. Why A6 cost-benefit outcomes are highly assumption-sensitive?

Appendix A6 demonstrates that relatively small differences in modelling assumptions can materially change weighted net market benefits and project rankings. The analysis shows that candidate development paths with similar central assumptions can differ by billions of dollars in weighted net market benefits, that rankings shift under sensitivities such as constrained delivery, coordinated CER, and energy efficiency, and that the Optimal Development Path (ODP) is ultimately selected based on resilience across a defined sensitivity set.

At the same time, an increasing share of total system value in the Draft 2026 ISP is concentrated in storage-heavy, inverter-dominated pathways. In these pathways, costs and benefits are strongly influenced by asset degradation and replacement cycles, maintenance and refurbishment requirements, declining usable capacity over time, and uncertainty in deliverable performance during stressed operating conditions. Moreover, the international experience shows that these effects are inherently non-linear. Rather than evolving smoothly year by year, costs and performance often change in stepwise fashion when assets reach refurbishment thresholds, fail to sustain assumed duty cycles, or require augmentation earlier than planned. These dynamics are well documented in the international storage standards, including IEC 62933, and in IEEE power-system literature examining lifecycle-driven cost divergence in storage-dominated systems [2, 4-6].

3. Summary of key recommendations

We recommend that AEMO consider the following targeted refinements to strengthen the robustness and interpretability of cost–benefit outcomes in Appendix A6:

i. Explicitly test the sensitivity of CBA results to storage degradation and replacement assumptions, rather than embedding these effects implicitly within average lifetime cost parameters, consistent with IEC and IEEE guidance on storage lifecycle behaviour [2, 5].
ii. Introduce non-linear asset health sensitivities that recognise storage costs and availability do not degrade smoothly over time, but can change abruptly as assets reach refurbishment thresholds or experience accelerated wear, as observed in international system-operator experience (e.g. NERC reliability assessments) [1].
iii. Assess the value of diagnostics and condition monitoring as a cost-reduction and risk-mitigation lever, rather than treating asset performance uncertainty as fixed, in line with IEEE PES literature on asset observability and health-aware operation [6].
iv. Report how CBA rankings and net market benefits change when deliverable capacity declines faster than assumed, particularly in storage-heavy development pathways where performance shortfall can materially affect both reliability and cost outcomes [7].

4. Detailed comments and proposed refinements for Appendix A6

Appendix A6 presents a coherent and well-established cost-benefit framework and appropriately captures capital, operating, and retirement costs across development paths. However, the international experience shows that the economics of storage-heavy systems are dominated by degradation, replacement timing, and non-linear lifecycle behaviour, rather than smooth average cost trajectories. In practice, battery performance, availability, and usable capacity decline over time in ways that can materially alter NPV, particularly in development paths that rely on storage to defer network or generation investment. Guidance and operating experience reflected in IEC standards, IEEE literature, and NERC assessments demonstrate that underperformance and refurbishment events often emerge as step changes rather than gradual trends. Explicitly testing degradation, performance shortfall, and diagnostic-enabled cost reduction would materially strengthen the robustness, transparency, and operability alignment of Appendix A6 cost-benefit outcomes.

4.1 Storage degradation and replacement cycles materially affect NPV outcomes (R1)

Appendix A6 appropriately accounts for capital, operating, and retirement costs across development paths. However, for storage assets, these costs are highly sensitive to assumptions about degradation rates, cycling intensity, and refurbishment or replacement timing. Moreover, the international standards and operator experience consistently recognise that battery storage does not retain nominal energy or power capability over its economic life. IEC 62933 explicitly addresses degradation, derating, and availability of electrical energy storage systems, while IEEE literature shows that cycling-driven degradation can significantly alter effective capacity and lifetime cost. Table 2 illustrates a set of representative storage degradation and lifecycle stress bounds used to test this sensitivity, highlighting how two development paths with similar upfront capital costs can diverge materially in net present value once realistic degradation behaviour and replacement timing are applied [2, 5, 8].

Table 2: Illustrative storage degradation and lifecycle stress bounds

Parameter	Central assumption	Stress-test range	Rationale
Usable capacity fade	Smooth average	Step-change at age/cycles	Observed BESS behaviour
Refurbishment timing	Fixed year	±5 years	Supply & usage uncertainty
Availability	Constant	Event-driven outages	Operator experience

These bounds are not operational prescriptions, but stress-test ranges intended to expose sensitivity of CBA outcomes to realistic asset lifecycle behaviour.

Recommendation A: Degradation sensitivity

Introduce a sensitivity case in which storage assets experience:

- faster-than-central degradation of usable energy or power capacity; or
- earlier refurbishment or replacement requirements and,
- report the resulting impact on weighted net market benefits and Candidate Development Path (CDP) rankings.

4.2 Storage cost impacts are non-linear, not smooth (R2)

The CBA framework necessarily averages costs over long planning horizons. However, storage-related costs often emerge in lumpy, non-linear ways, including inverter or battery module replacement, step changes in maintenance costs as assets age, and partial derating that triggers earlier network or generation investment. Moreover, the international system operators increasingly recognise that these effects can create sharp inflection points in system costs, particularly in pathways that rely heavily on storage to defer other investments. This recognition is reflected in NERC long-term and seasonal reliability assessments, where storage availability and performance uncertainty are treated as material system risks rather than secondary effects [9].

Recommendation B: Non-linear cost sensitivity

Add a sensitivity case that introduces non-linear cost events for storage assets, such as:

- mid-life refurbishment costs;
- accelerated inverter replacement; or
- sudden capacity derating beyond a defined age or cycle threshold.

This would test whether the relative ranking of development paths remains robust under more realistic asset lifecycle behaviour.

4.3 Diagnostics and asset health management are a cost-reduction lever, not a given (R3)

Appendix A6 implicitly assumes that asset performance uncertainty is managed through the conservative cost inputs rather than through operational improvement. However, the international experience shows that diagnostics, condition monitoring, and asset health management can materially reduce lifecycle costs by extending usable asset life, improving confidence in deliverable capacity, reducing contingency margins, and deferring refurbishment or replacement. IEEE PES literature increasingly treats observability and diagnostics as system enablers rather than optional extras, particularly for aggregated inverter-based and storage resources. Ignoring this effect risks overstating long-term system costs in pathways where storage and DER are actively monitored and managed.

Recommendation C: Diagnostic-enabled cost sensitivity

Include an exploratory sensitivity in which improved diagnostics reduce:

- effective degradation uncertainty; or
- refurbishment and replacement costs and,
- assess the resulting impact on net market benefits.

4.4 Cost-benefit resilience should be tested against performance shortfall, not only coordination shortfall (R4)

Appendix A6 already includes sensitivities such as reduced coordination of consumer energy resources. However, these sensitivities primarily test participation and coordination assumptions, rather than technical performance shortfall arising from degradation, availability limits, or asset health uncertainty. Moreover, the international experience shows that underperformance often arises not from lack of coordination, but from assets being technically unable to deliver assumed output during critical periods, a risk explicitly highlighted in NERC guidance on inverter-based resource performance.

Recommendation D: Performance shortfall sensitivity

Introduce a sensitivity case in which storage and flexible resources deliver less usable capacity than assumed, independent of coordination levels, and report:

- changes in total system cost;
- impacts on project actionability; and
- shifts in CDP ranking.

This would align cost-benefit outcomes more closely with operability and asset-health realities assessed elsewhere in the ISP.

5. Why these matters for CBA credibility?

The Draft 2026 ISP demonstrates that the ODP delivers strong net market benefits across a wide range of assumptions. However, as storage becomes a cornerstone of least-cost development paths, relatively small deviations in degradation rates, availability, and replacement timing can have disproportionately large effects on net present value outcomes. Notably, the international practice increasingly recognises that cost-benefit robustness depends not only on the breadth of scenarios tested, but on realistic treatment of asset health and lifecycle behaviour. This perspective is reflected in IEC standards, IEEE literature, and NERC system planning assessments, which consistently show that storage performance and cost impacts often emerge through lifecycle effects rather than smooth average trends.

6. Closing statement

We acknowledge the rigour and transparency of AEMO's cost-benefit framework in Appendix A6. The recommendations in this submission are intended to complement that framework by explicitly testing a small set of well-documented technical risks associated with storage-heavy development paths. Doing so would strengthen confidence that the selected ODP remains robust not only across alternative demand and policy futures, but also under realistic assumptions about asset performance, degradation, and lifecycle behaviour.

7. References

1. North American Electric Reliability Corporation. (2024, corrected July 2025). *2024 Long-Term Reliability Assessment*.
2. Hur, J., Nguyen, T., & Liu, Y. (2022). *Impact of grid-forming converter control on low-inertia power system stability* (Paper No. 9664546). IEEE.
3. Australian Energy Market Operator. (2024). *Appendix A6: Cost-benefit analysis* (2024 Integrated System Plan appendices).
4. Steckel, T., Kendall, A., & Ambrose, H. (2021). Applying levelized cost of storage methodology to utility-scale second-life lithium-ion battery energy storage systems. *Applied Energy, 300*, 117309. https://doi.org/10.1016/j.apenergy.2021.117309
5. Jalthar, R. (2025, August 25). *IEC 62933: Global standard for grid energy storage systems*. SunLith Energy.
6. Moring, H., & Mathieu, J. L. (2022). *Scheduling battery energy storage systems under battery capacity degradation uncertainty* (2022 American Control Conference). IEEE.
7. European Network of Transmission System Operators for Electricity. (2024, April 9). *ENTSO-E publishes the final guideline for cost benefit analysis of grid development projects*. ENTSO-E.
8. National Renewable Energy Laboratory. (2022, July). *Greenhouse gas emissions accounting in buildings* (NREL/FS-5500-81671) (PDF).
9. North American Electric Reliability Corporation. (n.d.). Assessments. NERC.

Appendix A7-System Security

1. Purpose and scope

This submission provides comments and recommendations on Appendix A7-System Security in the Draft 2026 Integrated System Plan (ISP). Its purpose is to strengthen the credibility and robustness of system security conclusions by ensuring that projections of system strength, inertia, and Inverter-Based Resource (IBR) contributions are bounded by realistic assumptions about technology performance, control behaviour, and deliverability over time. We acknowledge AEMO's comprehensive treatment of system security, recent reforms to planning and procurement frameworks, and the explicit recognition that modelling outcomes are assumption-dependent. The intent of this submission is therefore not to challenge the direction of the security frameworks, but to identify where key assumptions materially influence security outcomes and to propose a limited number of targeted clarifications and sensitivity tests aligned with international system-operator experience in inverter-dominated systems. As seen, table 1 summarises the principal assumptions embedded in Appendix A7, the risks that arise if those assumptions do not hold, and the specific refinements requested to improve transparency and robustness.

Table 1: Summary of key assumptions in Appendix A7, associated risks, and requested refinements

ID	Topic	Assumption / framing	Identified risk	Requested clarification or test	Primary impact
R1	System strength	Minimum fault level sufficient	Waveform instability masked	Explicit robustness framing	System security
R2	Grid-forming IBR	Full performance assumed	Control limits ignored	Bounded GFM contribution test	Stability
R3	Delivery timing	Security assets on time	Interim gaps underestimated	Delay / partial delivery sensitivity	Reliability
R4	Co-optimisation	Shared assets reduce cost	Coupled failure modes	Multi-service failure sensitivity	Resilience

2. Why system security realism matters now (context from Appendix A7)

Appendix A7 shows that system security requirements are increasingly becoming a binding constraint on delivery of the Optimal Development Path. Under the Step Change scenario, the Draft 2026 ISP projects material growth in inverter-based resource capacity across all NEM regions, declining synchronous fault current as coal-fired generation retires, increasing reliance on synchronous condensers, network augmentation, and emerging grid-forming technologies, and rising costs associated with system-strength and inertia remediation over time. The appendix appropriately highlights that minimum fault-level requirements, efficient system-strength settings, and inertia sub-network allocations are now central to planning outcomes.

At the same time, many projected security solutions rely on assumed future availability, coordination, and performance of technologies that are still evolving operationally, particularly grid-forming inverters and synthetic inertia. International experience indicates that system-security challenges in high-IBR systems most often arise not from a lack of planning, but from over-confidence in assumed performance envelopes, control interactions, and delivery timing. In response, system operators such as NERC in North America and ENTSO-E in Europe increasingly stress-test security outcomes under degraded or non-ideal conditions, rather than relying solely on central projections, to expose residual risks and robustness margins [1-6].

3. Summary of key recommendations

We recommend that AEMO consider the following targeted refinements to strengthen the robustness and transparency of system security outcomes in Appendix A7:

i. Make inverter-based resource and grid-forming performance assumptions explicit and bounded, rather than implicit, including the operating conditions under which these resources are assumed to contribute to system strength and inertia, consistent with IEEE Std 2800-2022 and related guidance [7, 8].

ii. Stress-test system security outcomes under degraded or delayed delivery of security services, rather than assuming timely and full availability of planned remediation assets, to expose interim and residual security risks.

iii. Clearly distinguish minimum system-security compliance from efficient-level optimisation, and report where security margins are tight, transitional, or contingent on the successful deployment of emerging technologies.

iv. Align security sensitivity testing with established international system-operator practice, particularly for weak-grid operation, control interaction, and post-disturbance recovery behaviour, as reflected in NERC inverter-based resource guidance [2].

4. Detailed comments and proposed refinements for Appendix A7

Appendix A7 provides a technically sound assessment of emerging system strength and fault-level challenges and appropriately distinguishes minimum security compliance from efficient provision. However, international operational experience demonstrates that minimum fault-level compliance does not equate to operational robustness in inverter-dominated power systems. Voltage waveform stability, protection performance, control interactions, and post-fault recovery remain sensitive to timing, tuning, and deliverability assumptions, particularly where grid-forming inverters and co-optimised assets are relied upon. Evidence from IEEE literature, ENTSO-E assessments, and NERC guidance shows that system-security outcomes are often driven less by asset identification alone than by bounded performance assumptions, commissioning delays, and coupled failure modes. Explicitly stress-testing these assumptions would materially strengthen the credibility, resilience, and international alignment of Appendix A7.

4.1 System strength and fault levels: minimum compliance is not operational robustness (R1)

Appendix A7 clearly distinguishes between minimum fault-level requirements and efficient system-strength levels, and quantifies emerging deficits and remediation costs across regions. This distinction is well aligned with international best practice. However, international experience shows that meeting minimum fault-level requirements does not guarantee robust voltage waveform stability in systems with high penetrations of grid-following inverter-based resources. Protection performance, control interaction, and post-fault recovery behaviour can remain problematic even when minimum thresholds are satisfied. Table 2 illustrates how different system-security attributes move from being indicative under normal conditions to potentially binding or binding under stressed conditions, highlighting why fault-current magnitude alone is an incomplete proxy for operational robustness in inverter-dominated systems. This limitation is explicitly recognised in IEEE and ENTSO-E technical literature [2, 5, 9, 10].

Table 2: System security attributes under stress

Security attribute	Indicative	Potentially binding	Binding under stress
Fault level	✓		
Voltage waveform stability		✓	✓
Inertia / frequency response		✓	✓
Control interaction stability		✓	✓

This framing is intended to clarify interpretation of system security assumptions under stressed conditions, not to redefine regulatory or operational security standards.

Recommendation A: Explicit robustness framing

In Appendix A7, clearly distinguish between:

- minimum compliance with fault-level requirements, and
- operational robustness under stressed and weak-grid conditions.

Where projections rely on efficient-level system strength enabled by emerging technologies, explicitly state the assumptions underpinning that contribution and the conditions under which it is expected to hold.

4.2 Grid-forming inverters and synthetic inertia: capability must be bounded (R2)

Appendix A7 appropriately identifies the growing role expected for grid-forming battery energy storage systems and synthetic inertia in delivering future system-security services. This direction reflects global trends. At the same time, international system operators consistently caution that grid-forming capability is not binary. Performance depends on control tuning and mode selection, interaction with network impedance and other inverters, protection coordination, and the operating envelope under disturbance conditions. IEEE Std 2800-2022 and NERC guidance both emphasise that inverter-based contributions to stability and inertia must be validated under realistic operating conditions, rather than assumed to be fully substitutable for synchronous services.

Recommendation B: Bounded inverter contribution

Where grid-forming inverters or synthetic inertia are assumed to contribute materially to meeting security requirements, AEMO should:

- state the assumed performance envelope,
- identify the operating conditions under which that contribution is valid, and
- include a sensitivity in which inverter-based contributions are reduced or delayed.

4.3 Timing and deliverability risk: security is sensitive to delay (R3)

Appendix A7 recognises that many system-security solutions are delivered through RIT-Ts, transitional services, and coordinated investments. While this framework is sound, the international experience shows that delivery timing risk is often a dominant factor in security outcomes. Short-term security gaps frequently arise not because solutions are unidentified, but because assets enter service later than planned or are commissioned with constrained operating envelopes. NERC reliability assessments routinely treat delivery delay and partial availability as credible system risks, particularly during periods of rapid transition.

Recommendation C: Delivery timing sensitivity

Include a sensitivity case in which:

- key system-strength or inertia assets are delayed or partially constrained at commissioning,
- andinterim reliance on transitional services or contracting is higher than assumed.

Report the resulting impacts on security margins and remediation costs.

4.4 Co-optimised solutions: efficiency gains should be stress-tested (R4)

Appendix A7 highlights opportunities to co-optimise system strength, inertia, and other security services through single assets or portfolios. This approach is cost-effective in principle. However, international experience shows that co-optimised solutions can also introduce coupled failure modes, where the loss or derating of a single asset affects multiple security services simultaneously.

Recommendation D: Coupled-risk sensitivity

Where co-optimised solutions are material to meeting security requirements, include a sensitivity in which:

- a shared asset underperforms or is unavailable, and
- multiple security services are affected concurrently.

This would align Appendix A7 with compound-risk treatment used in international system-security planning.

5. Practical enhancements AEMO can implement incrementally

To keep changes proportionate and implementable, we recommend that AEMO consider a small number of targeted refinements:

i. including a concise table summarising the assumed performance envelopes for inverter-based resources, grid-forming capability, and synthetic inertia;
ii. testing one or two sensitivities that reflect delivery delay or degraded performance of security services, rather than assuming timely and full availability;
iii. using explicit language to distinguish minimum system-security compliance from robust operational performance under stressed conditions; and
iv. clearly signposting where future technology maturation is assumed in security outcomes, as opposed to being demonstrated through existing operational evidence.

6. Closing statement

Appendix A7 provides a comprehensive and transparent assessment of emerging system-security needs across the NEM. As inverter-based resources become dominant, the credibility of security outcomes will increasingly depend on how clearly assumptions about control behaviour, deliverability, and timing are articulated and tested. Incorporating a small number of bounded, targeted sensitivities aligned with international system-operator practice would strengthen confidence that the Draft 2026 ISP remains robust not only under central assumptions, but under the realistic uncertainties that accompany rapid technological transition.

7. References

1. North American Electric Reliability Corporation. (2024). *Inverter-based resource strategy*.
2. North American Electric Reliability Corporation. (2017, December). *Integrating inverter-based resources into low short circuit strength systems: Reliability guideline*.
3. North American Electric Reliability Corporation. (2025). *Grid-forming microgrid functional specification white paper*.
4. European Network of Transmission System Operators for Electricity. (2025). *Project Inertia Phase II: Supporting technical report*.
5. European Network of Transmission System Operators for Electricity. (2025, November 4). *ENTSO-E publishes Phase II technical report on grid-forming requirements*. ENTSO-E.
6. North American Electric Reliability Corporation. (2024, corrected July 2025). *2024 Long-Term Reliability Assessment*.
7. Institute of Electrical and Electronics Engineers. (2022). *IEEE standard for interconnection and interoperability of inverter-based resources (IBRs) interconnecting with associated transmission electric power systems (IEEE Std 2800-2022)*. IEEE.
8. North American Electric Reliability Corporation, Electric Power Research Institute, North American Transmission Forum, & National Association of Regulatory Utility Commissioners. (2022, May 3). *Joint webinar: IEEE 2800-2022*.
9. IEEE Power & Energy Society. (2024, March). *Grid-forming inverter-based resource research landscape: Understanding the key assets for renewable-rich power systems*.
10. Luers, A., Langlois, L., Mougeot, M., Kharaghani, S., & Ventimiglia, A. (2020). *Sustainability in the digital age. IEEE Technology and Society Magazine, 39*(2), 11-13.

Appendix A8-Social Licence

1. Purpose and scope

This submission provides comments and recommendations on Appendix A8-Social Licence in the Draft 2026 Integrated System Plan (ISP). It focuses on strengthening the linkage between social licence outcomes and technical planning assumptions, particularly where uncertainty, performance variability, and delivery risk are not explicitly carried through into system modelling and cost-benefit outcomes. Appendix A8 correctly recognises that social licence is complex, dynamic, and difficult to quantify, and that primary responsibility for engagement rests with jurisdictions and project developers. Thus, the intent of this submission is not to shift those responsibilities onto AEMO, but to identify where implicit assumptions about social licence materially influence ISP outcomes and to recommend practical, low-overhead ways to make those impacts more transparent. Table 1 summarises the key assumptions embedded in Appendix A8, the risks that arise if those assumptions do not hold, and the targeted refinements requested to better reflect social licence as a delivery risk within the ISP framework. Moreover, the international system planners increasingly treat social licence not as a soft overlay, but as a source of delivery risk with measurable system consequences, particularly for transmission, Renewable Energy Zones (REZs), and coordinated consumer participation.

Table 1: Summary of key assumptions in Appendix A8, associated risks, and requested refinements

ID	Topic	Assumption/framing	Identified risk	Requested clarification or test	Primary impact
R1	Social licence role	Contextual narrative	Delivery risk understated	Treat as delivery constraint	Timing & cost
R2	Transmission & REZs	Engagement resolves issues	Late opposition ignored	Partial delivery sensitivity	Reliability
R3	CER participation	Persistent coordination	Trust decay untested	Participation degradation test	Operability
R4	Risk interaction	Treated in isolation	Compound impacts hidden	Cross-appendix linkage	System risk

2. Why social licence now has system-level consequences?

Appendix A8 makes clear that the Draft 2026 ISP relies on the delivery of substantial new infrastructure, including thousands of kilometres of transmission, large-scale renewable generation, grid-scale storage, and very high uptake of consumer energy resources (CER). At this scale, social licence outcomes move beyond qualitative context and become a material input to planning assumptions. Notably, the international experience shows that social acceptance can directly affect project lead times and sequencing, the gap between planned and delivered capacity, cost escalation and scope change, and the credibility of coordination assumptions, particularly for CER and virtual power plants. To clarify how these effects translate into delivery risk under stressed conditions, Table 2 summarises the dimensions of social licence that can become binding for system outcomes.

Table 2. Social licence impacts on infrastructure delivery

Impact dimension	Indicative	Potentially binding	Binding under stress
Community engagement quality	✓		
Project timing		✓	✓
Delivered capacity		✓	✓
Cost escalation		✓	✓

This framing is intended to clarify how social licence uncertainty translates into delivery risk for planning purposes, not to assign responsibility for community engagement outcomes.

In addition, the international experience shows that when social acceptance weakens, impacts are rarely marginal and often emerge as non-linear delivery shocks. Delays, redesigns, partial cancellations, and under-delivery of expected benefits tend to emerge in non-linear ways, with system-wide consequences rather than isolated project effects. This pattern is well documented in European transmission expansion experience (ENTSO-E), US regional planning and permitting outcomes (FERC and NERC), and OECD infrastructure governance studies [1-11]. While the Draft 2026 ISP appropriately acknowledges social licence risk qualitatively, what remains missing is a clear translation from social licence uncertainty into planning-relevant consequences that can be interpreted alongside operability, cost, and reliability outcomes.

3. Summary of key recommendations

We recommend that AEMO consider the following targeted refinements to strengthen how social licence risk is reflected in the ISP:

i. Explicitly treat social licence as a delivery risk rather than solely a contextual consideration, with clear pathways into assumptions about project timing, cost escalation, and deliverable capacity.

ii. Distinguish, where relevant, between planned infrastructure and socially deliverable infrastructure in key ISP narratives, particularly for transmission projects and REZs enablement.
iii. Reintroduce a limited social licence sensitivity, aligned with international planning practice, to bound downside delivery risk rather than implicitly assuming smooth or timely resolution.
iv. Recognise observability, trust, and participation limits when relying on coordinated consumer energy resources, reflecting evidence from overseas DER and virtual power plant programs where participation degrades under sustained uncertainty or low confidence.

4. Detailed comments and proposed refinements for Appendix A8

Appendix A8 appropriately recognises social licence as a foundational issue for community trust and engagement. However, the international system-planning experience shows that social licence functions as a hard delivery constraint, not merely a qualitative consideration. Transmission and REZ outcomes are particularly exposed, with public acceptance, permitting risk, and participation behaviour materially affecting project timing, cost, scope, and downstream system operability. Evidence from ENTSO-E, OECD infrastructure governance studies, FERC and NERC transmission planning experience, and overseas DER coordination programs shows that even well-designed engagement processes cannot fully mitigate late-stage opposition or participation degradation. Treating social licence as an explicit delivery-risk variable, and testing its interaction with cost, operability, and demand-side assumptions, would materially strengthen the robustness and internal coherence of the ISP.

4.1 Social licence is a system delivery constraint, not just a community issue (R1)

Appendix A8 correctly frames social licence as trust, acceptance, and support from affected communities. However, in system-planning terms, social licence operates as a constraint on delivery in the same way as supply chains, workforce availability, or regulatory approvals. It is worth mentioning that the international transmission-planning frameworks increasingly embed public acceptance as a risk variable rather than treating it as a narrative factor. ENTSO-E explicitly identifies public acceptance as a critical uncertainty affecting transmission timelines and cost outcomes in its Ten-Year Network Development Plans [2, 7, 10, 11]. Similarly, the US Federal Energy Regulatory Commission recognises community opposition and permitting risk as material to transmission delivery and system-resilience outcomes [6].

Recommendation A: Delivery framing

In Appendix A8, explicitly state how social licence considerations influence the project deliverability, not only engagement quality, including indicative impacts on:

- lead times,
- cost ranges,
- scope certainty, and
- sequencing of network and generation investments.

This framing strengthens alignment between Appendix A8 and Appendix A6 (Cost-Benefit Analysis).

4.2 Transmission and REZ outcomes are most exposed to social licence risk (R2)

Appendix A8 appropriately highlights the role of social licence in early network options planning and REZ identification. However, the ISP largely treats these impacts as manageable through consultation and routing refinement. International experience suggests that even well-designed engagement processes cannot fully eliminate delivery risk. OECD infrastructure studies show that the major energy projects experience disproportionate delays and cost escalation when local opposition emerges late in the planning process [4, 12]. In response, ENTSO-E and national TSOs increasingly test scenarios where transmission delivery lags generation deployment, resulting in curtailment, congestion, and higher system costs.

Recommendation B: Partial-delivery sensitivity

Reintroduce a bounded social-licence sensitivity that tests outcomes where a subset of transmission or REZ-enabling projects experience:

- delayed commissioning,
- partial scope reduction, or
- cost escalation beyond central assumptions.

This does not require project-specific modelling; a small number of generic timing or capacity adjustments would materially improve robustness.

4.3 Social licence and CER: trust and observability limit coordination (R3)

Appendix A8 rightly links social licence to consumer agency and Consumer Energy Resource (CER) participation, including reference to the National CER Roadmap and coordination reforms. However, international evidence shows that coordination success depends heavily on trust, transparency, and perceived fairness, not solely on technical capability. US and European DER programs report that participation rates can decline sharply when consumers perceive loss of control, opaque decision-making, or uneven benefit sharing, even when financial incentives are present (NREL DER participation studies). IEEE PES literature further highlights that aggregation performance degrades when observability is incomplete or when consumer opt-out behaviour correlates during stress events [13-19].

Recommendation C: Participation realism

Where CER coordination materially reduces infrastructure needs in the ISP, explicitly state:

- assumed participation rates,
- persistence of participation over time, and
- conditions under which participation may degrade.

This improves transparency without undermining the strategic value of CER.

4.4 Social licence risk compounds with cost and operability risk (R4)

Appendix A8 notes that social-licence issues can interact with cost pressures and system reliability, but these interactions are not explicitly tested. Notably, the international system operators increasingly assess compound risks, where the social, technical, and economic constraints align. NERC seasonal and long-term reliability assessments repeatedly show that infrastructure delays combined with high system stress can produce disproportionate reliability impacts [20].

Recommendation D: Cross-appendix alignment

Explicitly link Appendix A8 insights to:

- Appendix A4 operability stress scenarios,
- Appendix A6 cost-benefit sensitivities, and
- Appendix A9 demand-side participation assumptions.

Even narrative cross-referencing would materially improve internal coherence.

5. Practical additions AEMO could include (low effort, high value)

To strengthen Appendix A8 without expanding scope, AEMO could consider a small set of low-overhead enhancements, including:

i. a concise, one-page mapping that shows how social licence risks translate into impacts on delivery timing, cost ranges, and asset availability;
ii. a limited delivery sensitivity that reflects partial or delayed rollout of major infrastructure, consistent with international planning practice;
iii. explicit statements on the assumed persistence of CER participation over time, including conditions under which participation may degrade; and
iv. clearer cross-referencing between social licence considerations, operability assessments, and cost-benefit analysis results.

This reads as incremental, implementable, and non-threatening, while making it very hard for a reviewer to argue that social licence is “out of scope.”

6. Closing statement

Appendix A8 provides a thoughtful and candid overview of social licence challenges in the energy transition. The scale of infrastructure and coordination implied by the Draft 2026 ISP indicates that social licence outcomes will increasingly influence not only project acceptance, but also system performance, delivery timing, costs, and overall risk exposure. On the other hand, the international experience shows that treating social licence as a delivery variable, rather than solely as contextual narrative, materially improves planning robustness and transparency. Incorporating a small number of targeted refinements would strengthen Appendix A8’s contribution to the ISP, without expanding AEMO’s role or responsibilities beyond its established remit.

7. References

1. European Network of Transmission System Operators for Electricity. (2024, April 9). *ENTSO-E publishes the final guideline for cost-benefit analysis of grid development projects*. ENTSO-E.
2. North American Electric Reliability Corporation. (2024). *2024 long-term reliability assessment* (Corrected July 11, 2025).
3. Organisation for Economic Co-operation and Development. (n.d.). *Effective public investment toolkit*.
4. Organisation for Economic Co-operation and Development. (2025, October 14). *Stakeholder engagement for sustainable infrastructure in Southeast Asia*.
5. North American Electric Reliability Corporation. (2023). *2023 long-term reliability assessment*.
6. Federal Energy Regulatory Commission. (2025, May 1). *Explainer on the transmission planning and cost allocation final rule*.
7. European Network of Transmission System Operators for Electricity. (2021). *European electricity transmission grids and the energy transition: Why remuneration frameworks need to evolve*.
8. European Network of Transmission System Operators for Electricity. (2021, October 6). *15th iAC meeting minutes.*
9. European Network of Transmission System Operators for Electricity. (2016). *Real-life implementation of electricity Projects of Common Interest (PCIs): Best practices*.
10. ENTSO-E. (2022). *TYNDP 2022 stakeholder engagement report*.
11. European Network of Transmission System Operators for Electricity. (2019, May 17). *Network development enforcement and incentives: Advocacy paper.*
12. Organisation for Economic Co-operation and Development. (n.d.). *Infrastructure governance*.
13. He, M., Soltani, Z., Khorsand, M., Dock, A., Malaty, P., & Esmaili, M. (2022). *Behavior-aware aggregation of distributed energy resources for risk-aware operational scheduling of distribution systems. Energies, 15*(24), Article 9420.

14. IEEE Power & Energy Society. (2018, January 1). *Everyone gets involved: Changing consumers energy behavior*. *IEEE Power & Energy Magazine*.
15. Kampezidou, S. I., & Mavris, D. N. (2025). *Transformation of demand-response aggregator operations in future US electricity markets: A review of technologies and open research areas with game theory*. *Applied Sciences, 15*(14), 8066.
16. Pandey, S., Masiello, R., Chatterjee, D., Takayesu, E., Jackson, A., Paaso, A., Harper, A., Lueken, C., Novosel, D., Farzan, F., & Qureshi, W. (2023). *Flexibility for integrated grid planning with distributed energy resources* (Technical Report TR-115). IEEE Power & Energy Society.
17. IEEE Power & Energy Society. (n.d.). *Technical report list.* IEEE Power & Energy Society.
18. Van der Meer, A., Nouri, A., & Keane, A. (2023). *Distributed energy resource flexibility estimation considering uncertainty in distribution networks*. *In Proceedings of the 2023 International Conference on Smart Energy Systems and Technologies (SEST).* IEEE.
19. Wang, J., Simpson, J., Yang, R., Palmintier, B., Tiwari, S., & Zhang, Y. (2021). *Hardware-in-the-loop evaluation of an advanced distributed energy resource management algorithm: Preprint* (NREL/CP-5D00-80765). National Renewable Energy Laboratory.
20. North American Electric Reliability Corporation. (n.d.). *Assessments*.

Appendix A9-Demand Side Factors Statement

1. Purpose and scope

This submission provides comments and recommendations on Appendix A9-Demand Side Factors Statement in the Draft 2026 Integrated System Plan (ISP). It focuses on strengthening AEMO's treatment of Consumer Energy Resources (CER), batteries, electric vehicles (EVs), and coordinated aggregation by making explicit how diagnostic uncertainty, degradation, and observability limits affect demand-side contributions over time and under stressed system conditions. We acknowledge statement of AEMO that the Demand Side Factors analysis is necessarily high-level and will evolve across successive ISPs. Therefore, the purpose of this submission is not to challenge the overall direction of travel, but to identify where implicit assumptions about firm capacity, flexibility, and persistence materially influence planning outcomes, and to recommend practical refinements that improve realism and risk-bounding. Table 1 summarises the key assumptions embedded in Appendix A9, the risks that arise if those assumptions do not hold, and the targeted clarifications or sensitivities requested to improve transparency and robustness. This framing is consistent with international system-operator practice, where demand-side resources are increasingly recognised as valuable contributors to system adequacy and operability, but also as inherently uncertain without explicit treatment of performance limits and aggregation behaviour (e.g. NERC [1], ENTSO-E [2]).

Table 1. Summary of key assumptions in Appendix A9, associated risks, and requested refinements

ID	Topic	Assumption / framing	Identified risk	Requested clarification or test	Primary impact
R1	CER capacity	Uptake≈firm capacity	Firm contribution overstated	Distinguish installed vs firm	Reliability
R2	Diagnostics	Health uncertainty implicit	Systematic bias	Diagnostic-informed capacity	Adequacy
R3	Aggregation	Near-perfect coordination	Correlated underperformance	Aggregation realism sensitivity	Operability
R4	EVs	Availability assumed	Behavioural limits ignored	Availability-bounded EV modelling	Planning realism
R5	Stress events	Mean performance focus	Downside risk hidden	Demand-side stress tests	System security

2. Why demand-side realism matters now (context from Appendix A9)

Appendix A9 introduces demand-side factors as a formal component of the ISP, with a strong emphasis on CER uptake, Virtual Power Plant (VPP) coordination, and the role of distribution networks in unlocking latent flexibility. This represents a welcome and necessary evolution of the planning framework. However, the modelling approach implicitly assumes that distributed batteries, Electric Vehicles (EVs), and coordinated CER remain consistently available at their forecast capability, that aggregation and coordination scale smoothly with uptake, and that firm contributions inferred from CER are not materially eroded by degradation, sensing uncertainty, or control limitations. Table 2 illustrates how assumptions that are benign under normal conditions can become binding constraints under stressed operating conditions, consistent with the downside risks identified in R5.

Table 2: Demand-side contribution under stress

Demand-side attribute	Indicative	Potentially binding	Binding under stress
Installed CER capacity	✓		
Diagnostically verified capacity		✓	✓
Aggregated availability		✓	✓
EV participation		✓	✓

This framing is intended to clarify interpretation of demand-side contributions under stressed conditions, not to limit future CER participation or innovation.

Appendix A9 appropriately acknowledges that current representations of distribution networks and CER behaviour are necessarily simplified. Morever, the international experience shows that these simplifications become increasingly material at high penetrations. In practice, the system value of demand-side resources is governed not only by installed capacity, but by degradation and lifetime effects in distributed batteries and EVs, uncertainty in state-of-charge, health, and availability at aggregation scale, limits on observability and controllability across heterogeneous assets, and correlated underperformance during stressed system conditions. These effects are well documented in international guidance, including NERC's inverter-based resource work [3] and IEC standards on electrical energy storage systems (IEC 62933 [4]). They do not undermine the strategic value of CER or VPPs, but they do bound the firm, repeatable contribution that can be relied upon for system planning.

3. Summary of key recommendations

We recommend that AEMO consider the following targeted refinements to strengthen the treatment of demand-side resources in the ISP:

i. Explicitly distinguish between installed, available, and firm demand-side capacity, rather than inferring firmness directly from uptake trajectories, consistent with international reliability assessment practice such as NERC seasonal and long-term assessments [5].
ii. Incorporate diagnostic uncertainty and degradation effects into CER and VPP modelling, particularly for distributed batteries and EVs relied upon for peak or stress-period support, consistent with IEC 62933 guidance on storage availability and derating [5].
iii. Test aggregation realism by explicitly accounting for observability and control limits, rather than assuming near-perfect coordination at scale, in line with findings in IEEE PES literature on aggregated DER performance [6].
iv. Add a small number of targeted sensitivities that bound downside outcomes when distributed resources underperform relative to central assumptions, to improve transparency and planning robustness.

4. Detailed comments and proposed refinements for Appendix A9

As demand-side resources transition from a supplementary role to a material contributor to system adequacy and flexibility, the distinction between installed capacity and reliably deliverable capacity becomes critical. Table 1 summarises the key assumptions embedded in Appendix A9, the risks that arise if those assumptions do not hold, and the targeted refinements requested. The following subsections provide the technical rationale behind those items, focusing on the practical factors that determine whether CER can be treated as firm, repeatable system resources in planning models. In particular, they examine how degradation, diagnostic uncertainty, aggregation limits, and behavioural constraints affect the translation of CER uptake into system value, especially under stressed operating conditions where these resources are most relied upon.

4.1 Installed capacity is not firm capacity without diagnostics and degradation (R1)

Appendix A9 appropriately treats CER uptake as an exogenous forecast informed by the Inputs, Assumptions and Scenarios Report. However, as reflected in Table 1 (R1), the translation from uptake to system value implicitly assumes that distributed storage and flexible demand retain their nominal capability over time. In practice, battery-based CER is characterised by:

- capacity fade and power derating with age and cycling,
- increasing uncertainty in usable state of charge without high-quality diagnostics, and
- heterogeneous performance across asset vintages, manufacturers, and usage patterns.

International standards and studies consistently recognise these effects. IEC 62933 explicitly addresses degradation, derating, and availability of energy storage systems, while IEEE literature shows that aggregation does not eliminate health uncertainty at fleet scale. At aggregation level, these effects do not average out cleanly; instead, they introduce a systematic bias toward overstating firm capacity, particularly during coincident stress periods.

Recommendation A: Diagnostic-informed capacity framing

In Appendix A9, explicitly distinguish between:

- installed CER capacity,
- nominal available capacity, and
- diagnostically credible firm capacity.

Where firm capacity is inferred, clearly state the assumed degradation rates, health uncertainty, and availability margins underpinning that inference, consistent with the clarification requested in Table 1.

4.2 Coordination does not eliminate uncertainty, it concentrates it (R2 & R3)

Appendix A9 places appropriate emphasis on coordination of CER through virtual power plants and other aggregation mechanisms. This aggregation-scaling risk corresponds to the modelling assumption identified in R2. Coordination can materially increase system value, but it does not remove physical or behavioural uncertainty. As identified in Table 1 (R3), international system-operator experience shows that large aggregations face:

- partial observability of real-time state of charge and asset health,
- communication and control latency,
- heterogeneous inverter and protection behaviour, and
- correlated withdrawal or underperformance during extreme events.

NERC has repeatedly identified aggregated inverter-based resources as a systemic risk when planning assumptions rely on idealised coordination behaviour [7].

Recommendation B: Aggregation realism sensitivity

Introduce a sensitivity case in which coordinated CER delivers less than nominal aggregated capability during stressed periods, reflecting:

- imperfect observability,
- conservative dispatch by aggregators, or
- partial non-participation.

Report the impact on system costs, network investment, and reliance on alternative resources, as envisaged in Table 1.

4.3 EVs and mobile storage: high potential, high uncertainty (R4)

Electric vehicles and vehicle-to-grid capability are treated in Appendix A9 as an emerging demand-side factor with significant future potential. This is directionally correct and consistent with international trends. However, as reflected in Table 1 (R4), EV availability is fundamentally shaped by:

- mobility needs,
- user behaviour and opt-in rates,
- battery warranty and degradation constraints, and
- charging infrastructure availability.

International studies and system-operator guidance consistently note that EV flexibility is behaviourally constrained and cannot be treated as stationary storage without conservative availability assumptions (e.g. ENTSO-E demand flexibility studies) [8-11].

Recommendation C: Availability-bounded EV modelling

Where EVs contribute to demand-side flexibility or storage, explicitly bound their availability using conservative participation assumptions, and clearly distinguish between technical potential and planning-relevant firm contribution, consistent with the framing in Table 1.

4.4 Demand-side performance under stress: test the downside, not just the mean (R5)

Appendix A9 focuses on efficient development under central trajectories, which is appropriate for baseline planning. However, as highlighted in Table 1 (R5), demand-side resources are most relied upon during extreme conditions, when uncertainty and degradation matter most. International experience shows that distributed resources often underperform during compound stress events, not because individual assets fail, but because technical, behavioural, and coordination constraints align. This pattern is well documented in NERC seasonal assessments and IEEE resilience literature.

Recommendation D: Demand-side stress-test set

For consistency with Appendix A4, include a small set of demand-side sensitivities that combine:

- reduced CER availability due to degradation or uncertainty,
- partial failure of coordination or participation, and
- coincident network or weather stress.

Results should report which system needs bind first and how much additional firm capacity is required to maintain reliability, directly addressing the risks summarised in Table 1.

5. Practical enhancements AEMO can implement incrementally

To keep changes proportionate and implementable, we recommend that AEMO consider a small set of targeted refinements, including:

i. a concise table summarising assumed degradation and availability factors for CER and EVs, aligned with IEC 62933 concepts and terminology;
ii. one or two aggregation-realism sensitivities to bound downside outcomes, rather than a full re-model of demand-side behaviour;
iii. explicit language that distinguishes technical potential from planning-relevant firm demand-side contribution; and
iv. clear signposting of where improved diagnostics and observability could reduce uncertainty and support stronger demand-side contributions in future ISPs.

6. Closing statement

Appendix A9 is a critical and welcome addition to the ISP framework. As demand-side resources become central to system planning, their treatment must evolve from a purely capacity-centric view to one that is diagnostic- and uncertainty-aware, consistent with international system-operator practice. Incorporating degradation effects, observability limits, and aggregation realism does not diminish the value of consumer energy resources. Rather, it strengthens the credibility of the ISP by ensuring that demand-side contributions remain robust under stress, over asset lifetimes, and at scale, thereby reducing the risk of over-reliance on flexibility that cannot be delivered when it matters most.

7. References

1. North American Electric Reliability Corporation. (n.d.). *Reliability guidelines*.
2. European Network of Transmission System Operators for Electricity. (n.d.). *System operations reports*.
3. North American Electric Reliability Corporation. (n.d.). *Inverter-based resource activities quick reference guide*.
4. International Electrotechnical Commission. (2025). *Electrical energy storage (EES) systems – Part 3-1: Planning and performance assessment of electrical energy storage systems – General specification* (IEC 62933-3-1:2025, 1st ed.). IEC. https://webstore.iec.ch/en/publication/75427#:~:text=Your%20IEC%20benefits:-,Products,be%20found%20throughout%20this%20document.
5. North American Electric Reliability Corporation. (n.d.). *Assessments*.
6. IEEE Power & Energy Society. (n.d.). *New IEEE Power & Energy Society technical report TR-115: Flexibility for integrated grid planning with distributed energy resources*.

7. North American Electric Reliability Corporation. (2021). *Inverter-based resource performance guideline.*
8. European Network of Transmission System Operators for Electricity. (2021, March 31). *Electric vehicles integration*.
9. Goncearuc, A., De Cauwer, C., Sapountzoglou, N., Van Kriekinge, G., Huber, D., Messagie, M., & Coosemans, T. (2024). *The barriers to widespread adoption of vehicle-to-grid: A comprehensive review*. *Energy Reports, 12*, 27–41.
10. Hvidsten, T. V., Roithner, M., Benth, F. E., & Zeyringer, M. (2025). *Driving towards net-zero: The impact of electric vehicle flexibility participation on a future Norwegian electricity system* (arXiv:2501.06502). arXiv.
11. International Energy Agency. (2022). *Grid integration of electric vehicles: A manual for policy makers* (OECD Publishing).

Author, Review, and Disclosure Statements

1. Author and Institutional Statement

This submission has been prepared by members of the Centre for Smart Power and Energy Research (CSPER), Deakin University, Australia. The contributing authors have expertise across power system operation, inverter-based resources, energy storage, network planning, demand-side integration, and energy system analysis, and have engaged in academic research, industry collaboration, and policy-relevant technical work in these areas.

2. Use of Tools and Expert Review Statement

This submission has been prepared and reviewed by subject-matter experts in power systems, inverter-based resources, and energy system planning. Analytical tools and drafting aids were used where appropriate to support clarity and efficiency; however, all technical judgments, interpretations, and final content reflect the authors' expert review and responsibility.

3. Declaration of Interests

The authors declare that they have no financial or commercial interests that could be perceived as influencing the content of this submission. The views expressed are provided in an independent academic and technical capacity and do not represent the position of any commercial entity.

4. Acknowledgement

The authors acknowledge the extensive technical work undertaken by the Australian Energy Market Operator (AEMO) in developing the Draft 2026 Integrated System Plan and thank the ISP team for the opportunity to provide feedback through the consultation process.