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Submission to Draft 2026 ISP Consultation

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Recent research from the ANU Centre for Energy Systems determined that ***balancing solar and wind generation with large-scale, long-duration pumped hydro energy storage and batteries eliminates the need for gas-powered generators without incurring a cost penalty***. Analysis was based on the publicly available *2024 ISP Model* for PLEXOS. This research is currently available as a pre-print[1] and is in the process of undergoing peer review, with publication expected later this year. We refer readers to the pre-print for technical details that are not covered in this submission. An ***integrated method of transmission line planning*** was also recently developed and is discussed in detail in a peer-reviewed paper published in *Applied Energy.*[2] The key points of our submission to the *Draft 2026 ISP* consultation include:

- Gas-powered generators currently enable secure and reliable electricity supply for the National Electricity Market (NEM) as solar and wind penetration increases. However, supply chain constraints, fuel price volatility, the absence of any commercial carbon capture and storage (CCS), and the substantial fugitive methane emissions mean that gas-powered generators pose a risk to the “price” and “emissions” components of the National Electricity Objective.
- The use of the “sampled chronology” setting in the Single-Stage Long-Term model prohibits tracking of energy storage state-of-charge over long durations (e.g., weekly or seasonal storage). This means that long-duration storage is entirely filtered out from the development paths from the very first capacity outlook modelling activity.
- The cost and maximum storage duration assumptions for new build pumped hydro are only suitable for small-scale, short-duration systems.
- Compared to the *2024 ISP*, the *Draft 2026 ISP* inadvertently doubles the cost of Tasmanian pumped hydro, rather than halving the cost of mainland pumped hydro, through its adjustment of the relative locational cost factors.
- High real discount rates/WACC and short assumed lifetimes in the *Draft 2026 ISP* nearly triples the annualised capital cost of large-scale pumped hydro.
- Only a narrow range of development paths are considered, which limits the options available for the cost benefit analysis and excludes near-optimal 100% renewable configurations of the NEM.
- A *Long-Duration Energy Storage Options Report* would bypass many issues related to modelling large-scale pumped hydro in the capacity outlook models, effectively treating long-duration energy storage in a similar manner to transmission augmentation in the cost benefit analysis.
- Systematic screening for new high-voltage alternating current (HVAC) and high-voltage direct current (HVDC) transmission lines reveals additional opportunities to enhance reliability and lower total system costs.

The Optimal Development Path in the *Draft 2026 ISP* indicates that the NEM will still require 14 GW of gas-powered generators in 2050. It also suggests a rather tiny increase of 16 GWh of new build deep storage, despite Australia’s pumped hydro development pipeline already including 80 GWh of deep storage. There is a focus on incremental transmission line upgrades, rather than systematically identifying a broad range of opportunities to unlock new solar and wind resources and improve system reliability. A 100% renewable development path based upon solar and wind supported by short-duration batteries, large-scale long-duration pumped hydro, and transmission would still be capable of fulfilling the “price”, “reliability”, and “security” components of the National Electricity Objective, while also reducing risk associated with achieving Australia’s greenhouse gas emission reduction targets.

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[1] https://arxiv.org/abs/2512.20286

[2] https://doi.org/10.1016/j.apenergy.2025.126908

ID	Theme	Recommendation
1.1	Modelling	The sampled chronology in the Single-Stage Long-Term (SSLT) model fails to capture the value of long-duration energy storage and is heavily biased towards gas-powered generators instead. The SSLT should be replaced with a better process that is not affected by this issue.
1.2	Modelling	An initial modelling to generate alternatives (MGA) process should be undertaken that explores a much broader range of near-optimal development paths, including 100% renewable energy pathways. The MGA process could be either an alternative to the SSLT or a prior step.
2.1	Inputs and assumptions	The locational cost factors are relative values and should not be updated independently of the underlying pumped hydro cost model. Mainland pumped hydro costs in the *2026 ISP* should be roughly half the cost used in the *2024 ISP*, while Tasmanian pumped hydro costs may be roughly the same (all other cost assumptions being equal).
2.2	Inputs and assumptions	The cost model for pumped hydro is not representative of high-quality, large-scale, long-duration off-river systems and should be updated. A bottom-up cost model should be applied to the best quality pumped hydro options near the NEM transmission network (including transmission augmentation options) to recalculate the $/kW CAPEX for each storage duration.
2.3	Inputs and assumptions	New build long-duration pumped hydro energy storage (~160 hours duration) should be added to the capacity outlook modelling. There is effectively unlimited availability of these sites on the east coast of the mainland near existing transmission.
2.4	Inputs and assumptions	A small number of large-scale, long-duration pumped hydro systems perform a unique role in energy security and are expected to act as a natural monopoly. Large-scale, long-duration pumped hydro should have a long economic lifetime (~75 years) and a real WACC similar to other natural monopolies, such as transmission. The 40-year economic lifetime and 8.5% real WACC used for the Step Change scenario in the *Draft 2026 ISP* is not suitable for large-scale long-duration pumped hydro systems (equivalent to the scale of Snowy 2.0). Furthermore, corporate government entities such as Snowy Hydro, Queensland Hydro, and Hydro Tasmania have access to much cheaper capital.
3.1	Scenarios	A sensitivity scenario should be developed for the *2026 ISP* which considers 100% renewable electricity development paths (i.e., no new gas-powered generators) using good large-scale pumped hydro assumptions and chronology settings that capture long-duration storage behaviour. This could eventually replace the Accelerated Transition core scenario and may provide better options for achieving Australia's greenhouse gas emission reduction targets, as required by the National Electricity Objective.
4.1	Cost benefit analysis	In the medium term, a *Long-Duration Energy Storage Options Report* should be developed, comparable to the *Gas Infrastructure Options Report* and *Electricity Network Options Report*. Detailed large-scale pumped hydro site selection with site-specific cost modelling would allow AEMO to adjust candidate development paths during the cost benefit analysis, bypassing issues modelling pumped hydro in the capacity outlook models (effectively treating long-duration storage in a similar manner to transmission augmentation).
5.1	Transmission	The existing transmission network will soon be saturated. We suggest that AEMO strengthen the ISP transmission expansion options by systematically screening new HVAC corridors that connect new generation to load centres effectively, rather than relying mainly on incremental augmentation options presented by individual TNSPs. We also suggest including long-distance HVDC links as future ISP project options, with promising connection regions near Mount Isa and Victoria Daly for the NEM.

Background

Australia is currently undergoing the fastest energy change in history. The Australian Government has established greenhouse gas emissions reduction targets of 43% by 2030[3], 62–70% by 2035[3], and net zero by 2050. Early decarbonisation is being led by the energy sector, with an additional target of 82% renewable electricity generation by 2030. Achieving these targets is now a core component of Australia's National Electricity Objective.

The National Electricity Objective

> *to promote efficient investment in, and efficient operation and use of, electricity services for the long term interests of consumers of electricity with respect to:*
>
> *a. price, quality, safety, reliability and security of supply of electricity; and*
>
> *b. the reliability, safety and security of the national electricity system; and*
>
> *c. the achievement of targets set by a participating jurisdiction—*
>
> > *i. for reducing Australia's greenhouse gas emissions; or*
> >
> > *ii. that are likely to contribute to reducing Australia's greenhouse gas emissions.*

During windless, cloudy periods and contingency events, gas-powered generators currently serve an important role in delivering secure and reliable electricity to Australians, as required by the National Electricity Objective. However, production backlogs of up to seven to eight years are currently forecast for new gas turbines. The high demand has more than doubled the cost of gas turbines in some markets. Gas fuel price is driven by unpredictable geopolitical and economic events, with existing Australian gas contracts exposed to these international prices. Currently, there are no commercial gas-powered generators operating anywhere in the world with carbon capture and storage (CCS), meaning that there is no way to eliminate combustion emissions. Furthermore, there was an estimated 81 Mt of oil and gas methane emissions in 2024 related to upstream processes, transport, storage, refining, and abandoned wells. These methane emissions have a global warming potential that is 83 times larger than carbon dioxide over a 20-year horizon.

While gas can provide secure and reliable electricity supply, it now poses a risk to the "price" and "emissions" components of the National Electricity Objective. Failing to address the fugitive methane emissions and combustion emissions associated with gas-powered generators also poses a risk to Australia's obligations under international law. A recent Advisory Opinion from the International Court of Justice states that[4]:

> *Failure of a State to take appropriate action to protect the climate system from GHG emissions — including through fossil fuel production, fossil fuel consumption, the granting of fossil fuel exploration licences or the provision of fossil fuel subsidies — may constitute an internationally wrongful act which is attributable to that State.*

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[3] Below 2005 levels.

[4] https://www.icj-cij.org/case/187

These obligations are imparted by Australia's treaties, as well as conventional and customary international law. Developing and actioning plans to eliminate fossil fuels from the electricity system would demonstrate the due diligence required to uphold Australia's obligation to prevent significant harm to the environment.

There is a prevailing narrative that gas-powered generators are an essential part of balancing variable solar and wind generation beyond 2050. This narrative purports that alternatives are too expensive to deliver the firming required for a secure and reliable power system. However, mature technology already exists that can replace gas-powered generators at similar cost – large-scale, long-duration pumped hydro energy storage. A small number of these large-scale, long-duration systems (roughly equivalent in scale to Snowy 2.0) across the NEM could provide all of the deep storage required to manage windless, cloudy winter weeks, while short-duration batteries supply peak demand, all at a total system cost that is similar to the gas-dependent pathways.[5]

The Optimal Development Path in the *Draft 2026 ISP* currently indicates that 14 GW of gas-powered generators will be required in 2050, but only 16 GWh of new build deep storage (>12 hours duration) will be required. This volume of additional deep storage is 25 times smaller than the storage provided by Snowy 2.0 and Borumba alone. It is 5 times smaller than the remaining 80 GWh of deep storage already in Australia's development pipeline for pumped hydro.[6] It is clear that deep storage in the form of large-scale, long-duration pumped hydro is not properly captured in the ISP at this stage.

Transmission is another key method for balancing variable renewable generation. HVAC and HVDC transmission play different but complementary roles in an electricity system with high shares of renewables. HVAC is usually best suited for connecting large volumes of new solar and wind in remote and rural areas to the existing grid backbone and load centres. HVDC transmission prioritises long-distance, point-to-point links to balance supply-demand mismatch during stressful periods. The attractiveness of each candidate route can be evaluated against renewable resource distribution, environmental and social constraints, and how well the resulting renewable supply profile matches demand (to reduce balancing requirements). New techniques can systematically screen for new HVAC and HVDC transmission lines for consideration within the ISP that unlock large new solar and wind capacities and improve grid reliability during stressful periods.[7]

There is an opportunity for Australia to confidently deliver on the National Electricity Objective and demonstrate the due diligence required to uphold its international obligations with respect to climate change. By properly incorporating large-scale, long-duration pumped hydro into the ISP and expanding the scope of HVAC and HVDC future project options, AEMO can support Australia in taking hold of that opportunity.

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[5] https://arxiv.org/pdf/2512.20286

[6] Based on sites with a storage duration greater than 12 hours in Table 3, excluding Pioneer-Burdekin: https://www.aemo.com.au/-/media/files/stakeholder_consultation/consultations/nem-consultations/2024/2025-iasr-scenarios/final-docs/ghd-2025-pumped-hydro-energy-storage-cost-parameter-review.pdf?rev=23aa606f804b44c9a60efb1cd078468b&sc_lang=en

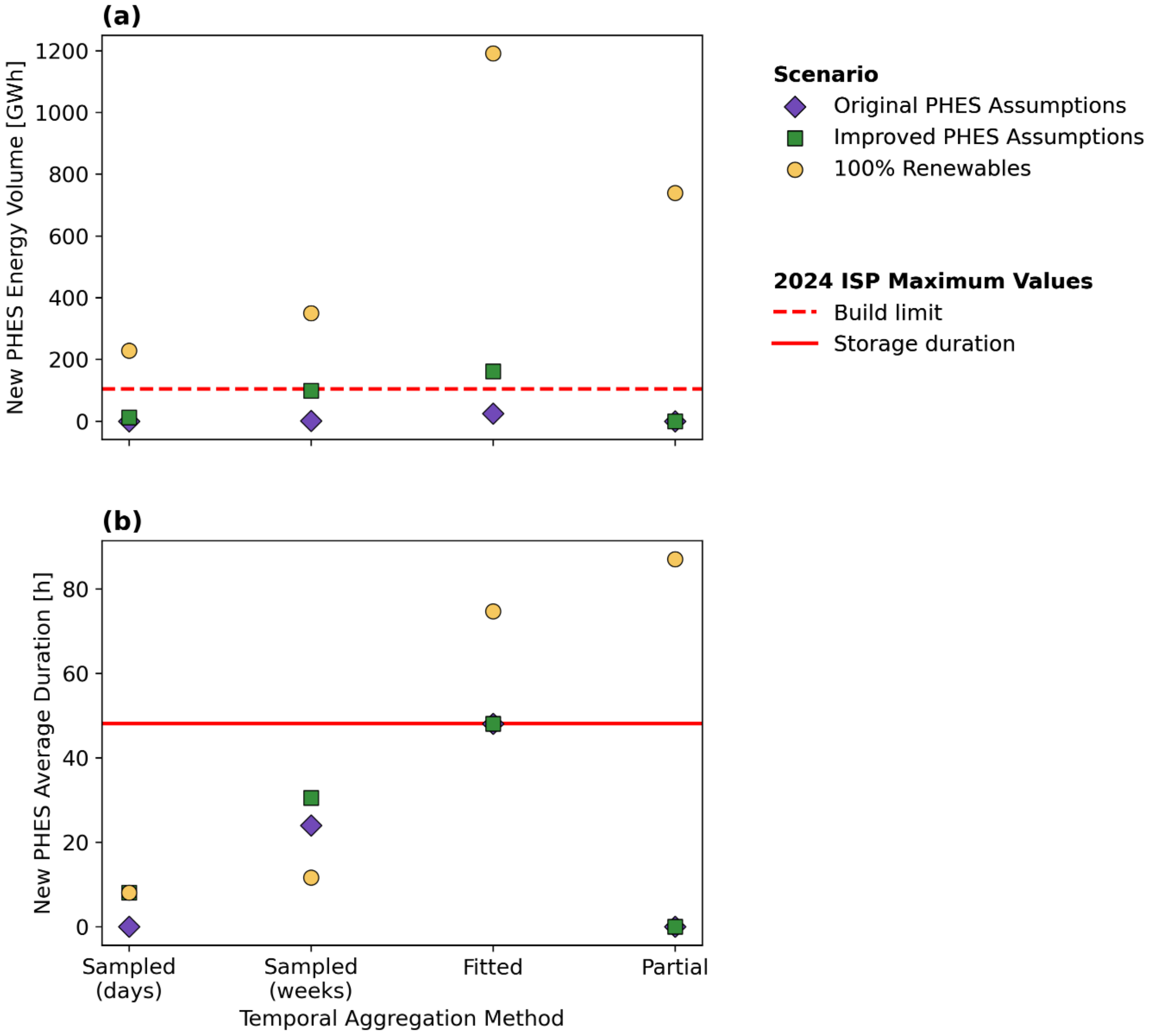
[7] https://doi.org/10.1016/j.apenergy.2025.126908

Recommendation 1.1

The sampled chronology in the Single-Stage Long-Term (SSLT) model fails to capture the value of long-duration energy storage and is heavily biased towards gas-powered generators instead. The SSLT should be replaced with a better process that is not affected by this issue.

The SSLT model provides the starting point for developing and refining candidate development paths for the ISP. The SSLT uses the "sampled chronology" LT Plan setting in PLEXOS to reduce model complexity, allowing the high-resolution (30 min intervals) capacity outlook optimisation between now and 2050 to be performed in a single optimisation step. Our research indicates that this setting prevents the model from investing in long-duration energy storage, leaving no alternative but to invest in gas-powered generators for managing infrequent solar and wind lulls. We found this issue was not present when using a "fitted chronology" in the Detailed Long-Term (DLT) model.

Figure 1. Influence of LT Plan chronology settings on investment decisions in modified 2024 ISP Model: (a) new build pumped hydro energy capacity, and (b) average duration of new build pumped hydro



We compared different LT Plan chronology settings for a modified version of the *2024 ISP Model* in PLEXOS.[8] Results are plotted in Figure 1 for a sampled chronology with 2 representative days per month (Sampled (days)), sampled chronology with 4 representative weeks per year (Sampled (weeks)), partial chronology with 8 blocks per day (Partial), and fitted chronology with 8 blocks per day (Fitted). Each chronology setting was used when optimising a scenario with the original *2024 ISP* pumped hydro assumptions (Original PHES Assumptions); improved assumptions related to pumped hydro cost, duration, and build limits (Improved PHES Assumptions); and a 100% renewable electricity NEM with improved pumped hydro assumptions (100% Renewables). Further details are available in the pre-print.

Notably, it was found that:

- For the 100% Renewables scenario, the sampled chronology (days) invested in 230 GWh of pumped hydro, while the fitted chronology invested in 1200 GWh of pumped hydro (420% more). This is equivalent to at least tens of billions of dollars in investment dictated entirely by the LT Plan chronology setting. The mere fact that a different chronology setting produces such a large swing demonstrates a serious limitation in the SSLT.
- The sampled chronology is heavily biased towards investing in shorter duration pumped hydro (8- or 24-hour duration), while the fitted chronology invests in long-duration pumped hydro (48- or 160-hour durations). This issue may be the reason why AEMO has previously found no additional value when including pumped hydro options with a storage duration longer than 48 hours.
- The fitted chronology finds a “near-optimal” solution to the 100% Renewables scenario (i.e., close to the cost of the least-cost solution), while the solution using the sampled chronology setting (2 days per month) appears substantially more expensive than the least-cost solution. **Using the sampled chronology setting would give the false impression that a 100% renewable electricity NEM is not cost competitive with a gas-dependent system**.

When using the sampled chronology setting, PLEXOS constrains storage state-of-charge to be equal at the start and end of the representative period. This is mathematically necessary for maintaining state-of-charge chronology between representative periods, but prevents cycling for periods that are longer than the representative period. For example, the sampled chronology setting based upon representative days per month prevents storage systems from cycling for periods longer than 1 day. The LT Plan cannot find value in investing in long-duration energy storage since it cannot cycle the system over a long period of time (e.g., weekly or seasonally). This behaviour is depicted in Figure 2.

The state-of-charge profile for the fitted chronology in Figure 2d closely resembles the full-series optimisation (i.e., no time-series aggregation) in Figure 2a. When comparing the investment and dispatch decisions made using each chronology setting, the fitted chronology produces a solution that most closely resembles the full-series optimisation. The sampled chronology produces solutions that are very different from the full-series optimisation (refer to the L1-distance discussion in the pre-print for details).

Our analysis suggests that the **fitted chronology setting in the DLT is suitable for modelling 100% renewable energy systems since it captures long-duration energy storage behaviour and produces solutions that closely resemble the full-series optimisation**.

However, the **SSLT is not fit-for-purpose** when modelling long-duration energy storage or 100% renewable energy systems **due to its usage of the sampled chronology LT Plan setting**. In the absence of long-duration energy storage, the SSLT has no option but to invest in gas-powered generation to manage infrequent solar

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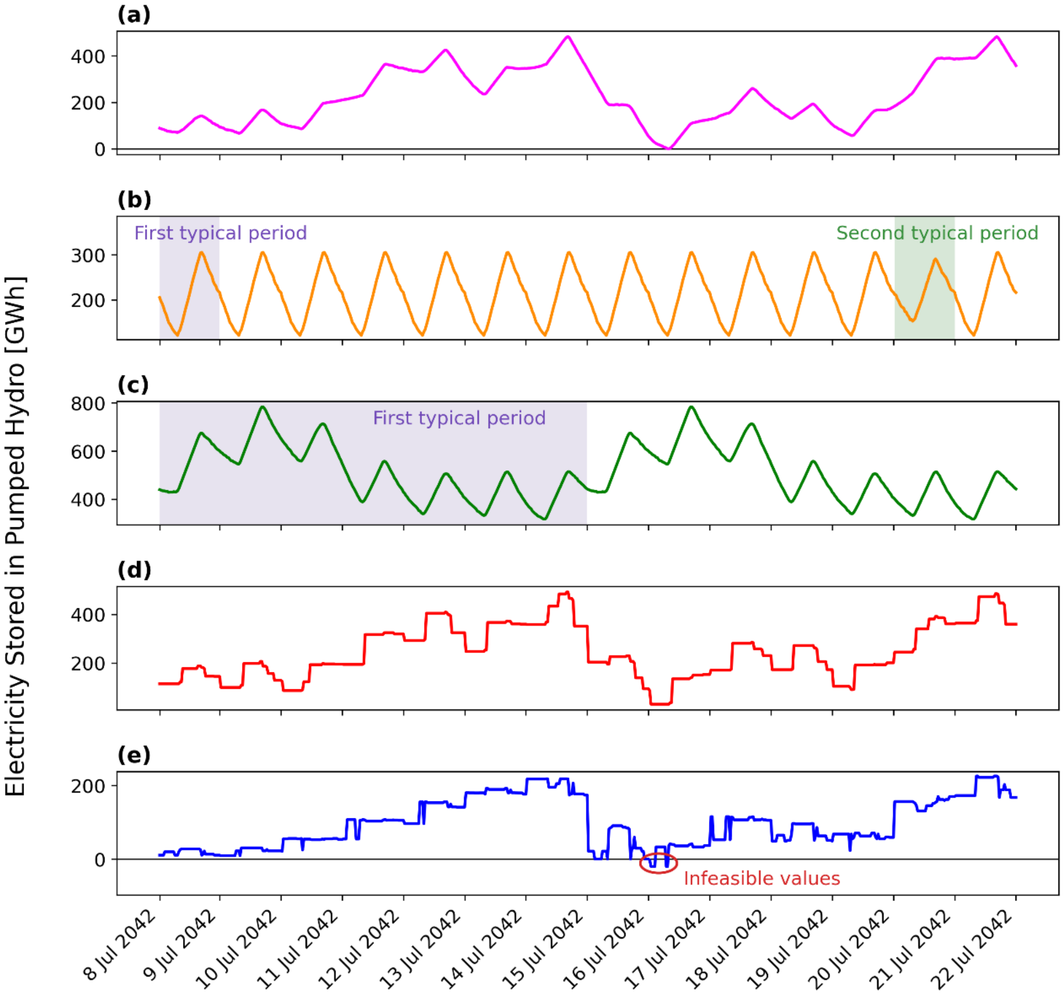
[8] Note that this version of the model relates to the analysis in our pre-print, and differs slightly from the version used in our previous submission: https://www.aemo.com.au/-/media/files/stakeholder_consultation/consultations/nem-consultations/2024/2026-isp-methodology/submissions/anu-100-renewable-energy-group.pdf?rev=9a4df18d52144a9389b051fa65be2002&sc_lang=en

and wind lulls. The bias towards gas and away from long-duration storage in the SSLT would propagate through the entire iterative modelling process, including the DLT and time-sequential model.

Figure 2. Net state-of-charge for pumped hydro in 100% Renewables scenario over two-week period for: (a) full-series optimisation (no chronology simplification), (b) Sampled (days), (c) Sampled (weeks), (d) Fitted, and (e) Partial



Additionally, the fact that the SSLT and DLT may both build gas-powered generators is a coincidence as each model dispatches gas for different purposes. The SSLT (sampled chronology) uses gas for short-term balancing (e.g., intra-day) because the sampled chronology method captures short-term variation in solar/wind generation, while the DLT dispatches gas for long-term balancing (e.g., seasonally) since the fitted chronology method captures long-term variation in solar and wind generation. The same gas capacity can provide balancing over both short and long timeframes in the model, since there is no detailed tracking of the gas storage and supply (unlike storage state-of-charge). For storage systems, the SSLT would dispatch storage for short-duration balancing purposes, so will invest in short-duration storage (e.g., batteries and small-scale pumped hydro). When that solution is passed to the DLT, the short-duration storage is incapable of providing the deep seasonal balancing captured by the fitted chronology.

Recommendation 1.2

An initial modelling to generate alternatives (MGA) process should be undertaken that explores a much broader range of near-optimal development paths, including 100% renewable energy pathways. The MGA process could be either an alternative to the SSLT or a prior step.

Lombardi et al. (2025) provides a good framework for how energy planners can explore the near-optimal space for capacity expansion models.[9] The MGA process should avoid using the "sampled chronology" setting and could use a coarser model of the NEM than the subsequent DLT and time sequential model optimisations to reduce computational complexity. The goal of the MGA process would be to generate a highly diverse range of near-optimal development paths to ensure AEMO has access to as much information as possible regarding potential energy transition options. As new information is received over time, AEMO can direct its efforts towards refining the most useful of these development paths, while retaining a high-level view of the broad range of alternative options that remain available. The near-optimal solution space would be expected to contain both 100% renewable energy and gas-dependent development paths for the NEM.

When defining the near-optimal range of costs, AEMO should keep in mind the very large parametric uncertainty associated with forecasting fuel costs, technology costs, weather data, discount rates, WACCs, and industrial loads out to 2050, along with structural uncertainty associated with the construction of the model. That is, a 5–10% cost tolerance from the global optimum would likely be too small given the very large uncertainty in the model. AEMO would need to establish a reasonable range of costs in accordance with this high uncertainty – effectively establishing a contingency cost for the system.

Recommendation 2.1

The locational cost factors are relative values and should not be updated independently of the underlying pumped hydro cost model. Mainland pumped hydro costs in the *2026 ISP* should be roughly half the cost used in the *2024 ISP*, while Tasmanian pumped hydro costs may be roughly the same (all other cost assumptions being equal).

The AEMO-supported review of pumped hydro assumptions by GHD[10] helped to align the build limits and locational cost factors for the *2025 IASR* more closely with up-to-date data. The "practical maximum build capacity" for the NEM determined by GHD was 7460 GWh (21 times more than Snowy 2.0) of additional pumped hydro, which is more than sufficient for a broad range of 100% renewable energy candidate development paths. Regardless, it is worth noting that the actual build limit may be larger than this – the practical maximum build limit assumed that only 25% of the technical potential would be viable for construction, though this is a highly uncertain estimate. Furthermore, new transmission lines are likely to unlock additional pumped hydro potential in each NEM region.

The update to locational cost factors now reflects mainland Australia having pumped hydro options of similar cost and quality to Tasmania. However, locational cost factors are a relative value. Updating these factors independently of the underlying cost model has counterintuitively ***doubled*** the cost of Tasmanian pumped hydro, rather than ***halving*** the cost of mainland pumped hydro, relative to the *2024 ISP*. Mainland pumped hydro systems in the latest version of the Global Pumped Hydro Energy Storage Atlases[11] ("the Atlases") are

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[9] https://doi.org/10.1016/j.joule.2025.102144

[10] https://www.aemo.com.au/-/media/files/stakeholder_consultation/consultations/nem-consultations/2024/2025-iasr-scenarios/final-docs/ghd-2025-pumped-hydro-energy-storage-cost-parameter-review.pdf?rev=23aa606f804b44c9a60efb1cd078468b&sc_lang=en

[11] https://re100.eng.anu.edu.au/pumped_hydro_atlas/

understood to be of better quality and lower cost than those originally considered in the 2018 Entura report[12]. The GHD review was based upon the latest version of the Atlases, while the 2018 Entura report was based on a very early iteration of the Atlases with far fewer sites using much smaller reservoirs. Mainland pumped hydro systems should be expected to be cheaper after this update, rather than Tasmanian sites being more expensive.

Recommendation 2.2

The cost model for pumped hydro is not representative of high-quality, large-scale, long-duration off-river systems and should be updated. A bottom-up cost model should be applied to the best quality pumped hydro options near the NEM transmission network (including transmission augmentation options) to recalculate the $/kW CAPEX for each storage duration.

Separate from the anomaly associated with the update to locational cost factors, the existing pumped hydro cost model remains unsuitable for large-scale, long-duration systems. Although Snowy 2.0 costs are currently undergoing a review and are expected to increase, it is still likely to be substantially cheaper per unit of energy volume than any new build sites considered by the *Draft 2026 ISP*. Assuming a rough final cost of A$15 billion[13], Snowy 2.0 has a capital cost of A$43/kWh compared to the A$163/kWh for 48-hour pumped hydro (the longest duration in the *Draft 2026 ISP*) in *GenCost 2024-25*[14] with locational cost factors ranging between 0.9407 to 1.1567[15]. Building deep energy storage in the *Draft 2026 ISP* is four times more expensive than Snowy 2.0, whereas there are many mainland sites near transmission that match Snowy 2.0 for cost.

Part of this issue appears to relate to the underlying cost model, which ought to be reviewed to develop appropriate costs for the ***best quality large-scale long-duration*** pumped hydro systems near the NEM (similar in scope to Snowy 2.0), rather than small-scale high-power systems. Developers will prefer to develop the highest quality, lowest cost options available, so an average cost representing all possible sites in a subregion is not suitable. A bottom-up cost model (similar to the National Laboratory of the Rockies pumped hydro cost model developed for the United States of America[16]) could be applied to a selection of the best quality pumped hydro options near the NEM (based on the latest version of the Atlases).

We filtered the Atlases for all class A, AA, and AAA pumped hydro systems near the existing NEM transmission network which are outside protected areas and large urban centres.[17] The parametric cost model used by the ANU to generate cost classes for the Atlases was applied to each of the sites, with an added 50% overhead.[18] Power capacity costs ($/kW) and energy volume costs ($/kWh) for each site were estimated, assuming they could be an 8-, 24-, 48-, or 160-hour duration system. These cost estimates are summarised in Figure 3. The intention of this figure is not to provide an exact estimate of the cost for each project, but to demonstrate the relative difference in costs between different storage durations and cost classes. Furthermore, none of the pumped hydro sites in this list have been subject to geological, hydrological, environmental, heritage, community impact and other studies. As with all major engineering

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[12] https://www.aemo.com.au/-/media/Files/Electricity/NEM/Planning_and_Forecasting/Inputs-Assumptions-Methodologies/2019/Report-Pumped-Hydro-Cost-Modelling.pdf

[13] Project is 70% completed, previous budget of A$12 billion.

[14] https://www.csiro.au/-/media/Energy/GenCost/GenCost2024-25ConsultDraft_20241205.pdf

[15] https://www.aemo.com.au/energy-systems/major-publications/integrated-system-plan-isp/2026-integrated-system-plan-isp/2025-26-inputs-assumptions-and-scenarios

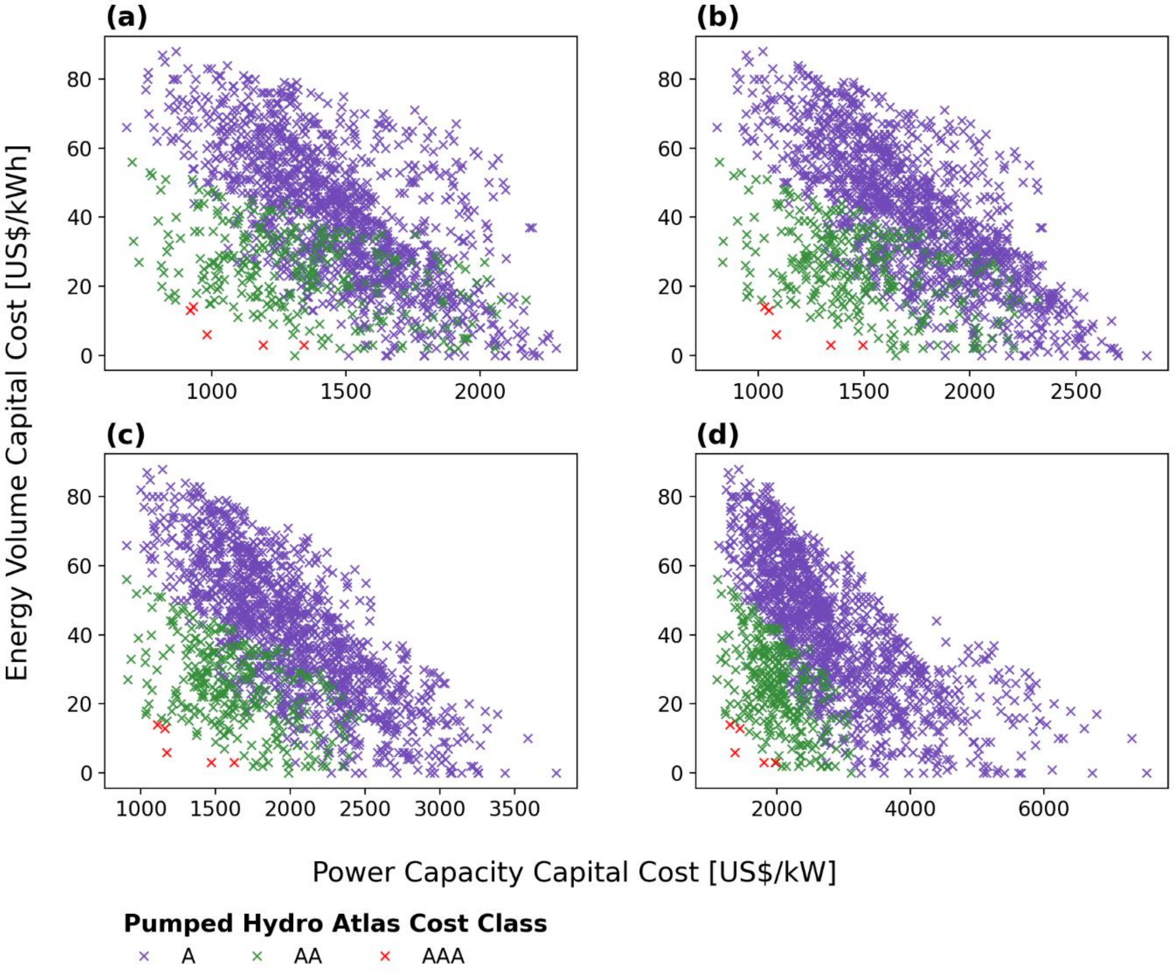
[16] https://www.nrel.gov/water/pumped-storage-hydropower-cost-model

[17] Geographic data and cost calculations are available for all sites: https://www.dropbox.com/scl/fo/p67jato2luh3e2qwypp0x/ADR9RlG84nIOxI3wshE8hEI?rlkey=wozzpnrxr3nphd7w8j5d4e5wc&st=j9yvdxcq&dl=0

[18] Final costs will vary and are dependent on site-specific geotechnical analysis and other relevant factors.

projects, diligent attention to quality assurance would be required for safety, efficacy and commercial feasibility.

Figure 3. Power capacity costs (powerhouse, switchyard, tunnels) and energy capacity costs (dam walls) for pumped hydro options within 50km of the NEM, assuming: (a) 8-hour duration, (b) 24-hour duration, (c) 48-hour duration, and (d) 160-hour duration. Includes an additional 50% overhead cost.



Recommendation 2.3

New build long-duration pumped hydro energy storage (~160 hours duration) should be added to the capacity outlook modelling. There is effectively unlimited availability of these sites on the east coast of the mainland near existing transmission.

Long-duration storage requires a large energy capacity and a moderate power capacity. For example, Snowy 2.0 has 350 GWh of energy storage but only 2.2 GW of power capacity. Importantly, power and energy capacity can be sized independently because power costs (e.g., tunnels, pump/turbines) are independent of energy volume costs (e.g., reservoirs). When coupled with batteries, pumped hydro power capacity within the grid can be reduced since the batteries can support the system to meet peak demand. During a *dunkelflaute*, pumped hydro can trickle-charge the batteries when solar and wind generation are not available, ensuring that sufficient power capacity is still available for morning and evening peaks.

If only 8-hour pumped hydro systems were built, then developing enough energy capacity for long-duration storage would result in a substantial over-build of the more expensive pumped hydro power capacity. For modelling the lowest-cost decarbonised NEM, it is very important to include new build deep pumped hydro capable of managing windless, cloudy winter weeks. Snowy 2.0 will have a 160-hour storage duration and GHD has already developed build limits and locational cost factors for 160-hour duration pumped hydro during their review of assumptions. Therefore, we suggest the inclusion of new build 160-hour pumped hydro systems as a starting point.

Recommendation 2.4

A small number of large-scale, long-duration pumped hydro systems would perform a unique role in energy security and are expected to act as a natural monopoly. Large-scale, long-duration pumped hydro should have a long economic lifetime (~75 years) and a real WACC similar to other natural monopolies, such as transmission. The 40-year economic lifetime and 8.5% real WACC used for the Step Change scenario in the *Draft 2026 ISP* is not suitable for large-scale long-duration pumped hydro systems (equivalent to the scale of Snowy 2.0). Furthermore, corporate government entities such as Snowy Hydro, Queensland Hydro, and Hydro Tasmania have access to much cheaper capital.

Pumped hydro costs are capital-intensive, which means that the real WACC/discount rate and economic lifetime have a dominant influence in the capacity outlook modelling. This is different to gas-powered generators where a large portion of their costs are deferred (i.e., maintenance and fuel costs). Based on our analysis in the pre-print, a 100% renewable NEM could be developed using only a few additional Snowy 2.0-scale systems. These large-scale systems should be treated as natural monopolies and may require a regulated rate of return, like transmission and distribution. This is because each system represents a substantial infrastructure investment, and it is unlikely to be efficient to develop enough systems for proper competition to occur between them. Borumba and Snowy 2.0, which are two committed large-scale pumped hydro systems, are also being developed by government-owned corporations with access to cheap capital. Natural monopolies and public investments generally have a low real WACC and long economic lifetime compared to private, non-monopolistic investments.

The size of pumped hydro projects that have recently finished construction (i.e., Kidston) and those that are moving through the design process has been set through local policy decisions. For example, New South Wales (NSW) requirements for 8+ hours of storage under the long-duration energy storage target. Just as AEMO relies upon government policy to shape their constraints and scenarios, the modelled guidance from AEMO can demonstrate the need for a certain type of system (e.g., long-duration energy storage) and can influence consequent policy changes.

The influence of real WACC/discount rate and economic lifetime on pumped hydro costs cannot be understated. The annualised capital costs for a pumped hydro system with a 40-year economic life and 8.5% real WACC (*Draft 2026 ISP* Step Change assumptions) is nearly ***three times larger*** than with a 75-year economic life (maximum useful life of civil works used by Snowy Hydro[19]) and 3.0% real WACC (equivalent to regulated transmission).[20] An even higher 9.5% real WACC is assumed for the Accelerated Transition scenario. As well as being unrealistic for future development, these assumptions do not capture the reality of existing and committed developments.

The largest pumped hydro systems being developed in the NEM are owned by government corporations. There is real potential for these systems to act monopolistically – Snowy 2.0 will represent around 80% of storage energy capacity when complete, and Borumba around 10%. Given this and the disproportionate influence the real WACC/discount rate and economic lifetime have on cost estimates, we believe these parameters require serious reconsideration. We understand that AEMO is bound by the Australian Energy Regulator's (AER) *Cost Benefit Analysis (CBA) Guidelines*[21] when developing the ISP and that these guidelines require discount rates to reflect private investment. However, we note that private investment is not current reality in the sector. Addressing the issue related to real discount rates/WACC and economic lifetime for new build pumped hydro may require action from other stakeholders, such as the AER.

We modelled a sample of near-optimal NEM grid configurations using PLEXOS and performed a one-at-a-time sensitivity analysis for their all-in system costs (refer to pre-print for additional details). Half of these grid configurations were 100% renewable systems ("High Pumped Hydro") and half were gas-dependent systems ("Low Pumped Hydro"). All-in system costs were expressed as a levelised cost of electricity (LCOE) for the entire system. Results of the sensitivity analysis are shown in Figure 4.

For a large range of parameters around the baseline, the 100% renewable electricity and gas-dependent NEM configurations have roughly the same cost. The 100% renewables configurations are more sensitive to the discount rate than the gas-dependent systems, meaning that over-estimating the real WACC/discount rate can heavily penalise fully decarbonised development paths (Figure 4a). Configurations that are more dependent upon gas generation can become substantially more expensive than the 100% renewable configurations at a high gas cost (Figure 4b). The all-in LCOE is also reasonably sensitive to the energy volume cost of pumped hydro, with the best long-duration (e.g., 160-hour) sites offering a much smaller $/kWh energy volume cost than the best short-duration (e.g., 8-hour) sites (Figure 4d). This reinforces the notion that pumped hydro cost assumptions in the ISP should reflect the best quality large-scale long-duration pumped hydro sites. Note that for higher baseline discount rates, the LCOE becomes more sensitive to the pumped hydro economic life.

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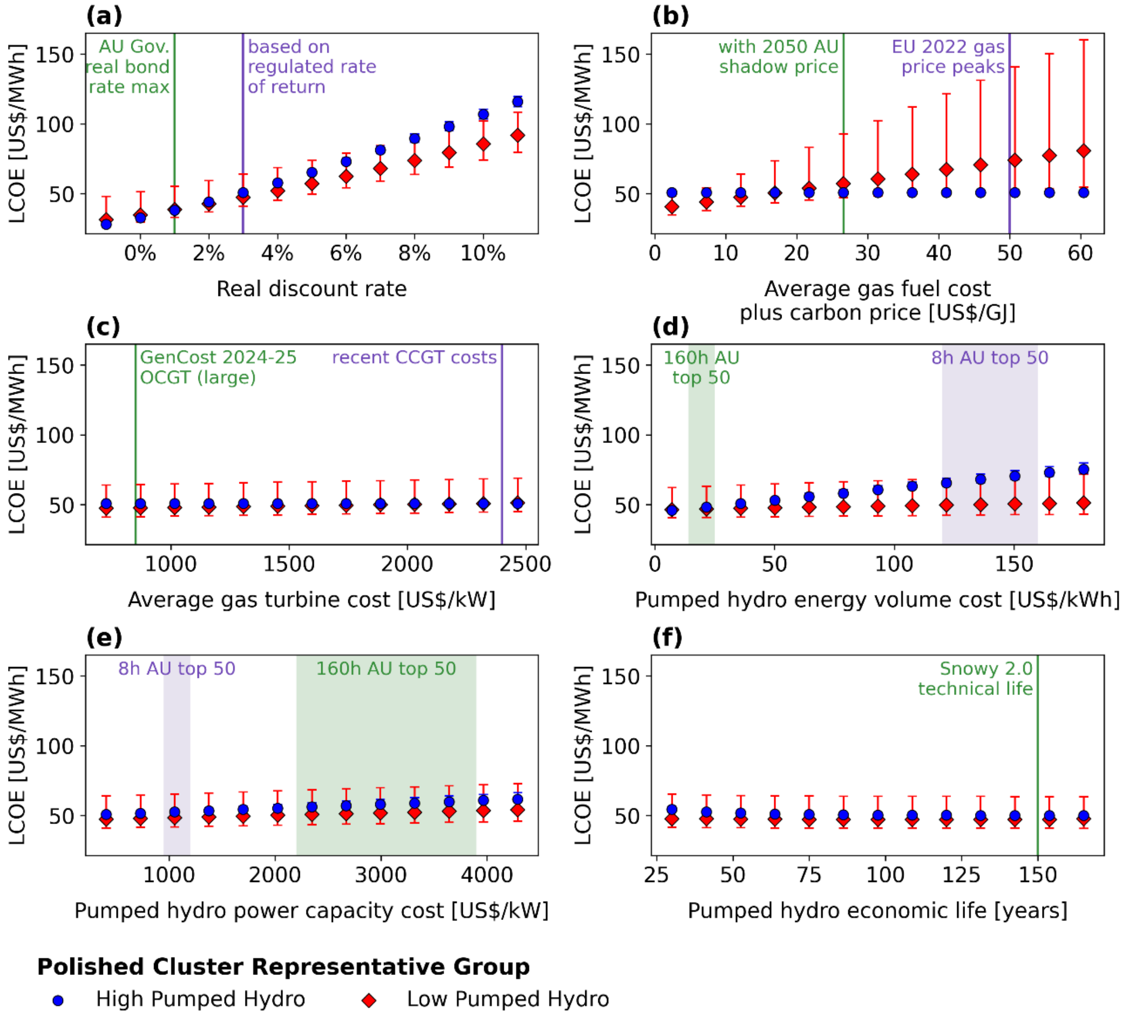
[19] https://www.snowyhydro.com.au/wp-content/uploads/2025/10/Snowy-Hydro-Annual-Report-2024-25.pdf

[20] Real WACC 8.5%, economic lifetime 40 years:
Annuity Factor = $0.085 / (1-(1/1.085)^{40}) = 0.088$

Real WACC 3.0%, economic lifetime 75 years:
Annuity Factor = $0.03 / (1-(1/1.03)^{75}) = 0.034$

[21] https://www.aer.gov.au/industry/registers/resources/guidelines/cost-benefit-analysis-guidelines

Figure 4. Sensitivity of all-in LCOE for representative near-optimal solutions to: (a) real discount rate, (b) gas fuel costs, (c) gas turbine capital costs, (d) pumped hydro energy volume capital costs (showing the large difference in cost between top-50 pumped hydro sites with low power (160-hour storage) and high power (8-hour storage), (e) pumped hydro power capacity capital costs, and (f) pumped hydro economic life. Baseline values assume 3% real discount rate and 75-year economic life for pumped hydro



Recommendation 3.1

A sensitivity scenario should be developed for the *2026 ISP* which considers 100% renewable electricity development paths (i.e., no new gas-powered generators) using good large-scale pumped hydro assumptions and chronology settings that capture long-duration storage behaviour. This could eventually replace the Accelerated Transition core scenario and may provide better options for achieving Australia’s greenhouse gas emission reduction targets, as required by the National Electricity Objective.

In the near-term, we recommend adding a sensitivity scenario to the *2026 ISP* that considers a 100% renewable electricity system (i.e., no new build gas-powered generators). It is important that this sensitivity scenario eliminates the computational flaws associated with modelling long-duration pumped hydro that have been previously discussed. That is, the sensitivity scenario should not use the “sampled chronology” LT Plan setting in PLEXOS, pumped hydro capital costs should be re-evaluated to reflect large-scale long-duration systems, and longer storage durations (e.g., 160 hours) should be included in the model. We also strongly recommend considering a low WACC (~3%) and long economic lifetime (~75 years) which represents these large-scale pumped hydro systems acting monopolistically and potentially owned by government corporations.

The 100% renewables sensitivity scenario could act as a starting point for a core scenario that replaces the Accelerated Transition scenario. Low-cost 100% renewable electricity development paths have the best chance of supporting Australia and the States/Territories in achieving their greenhouse gas emission reduction targets. These low-cost 100% renewable electricity development paths may provide the best options for achieving the National Electricity Objective, which is used to guide activities within the ISP.[22]

Recommendation 4.1

In the medium term, a *Long-Duration Energy Storage Options Report* should be developed, comparable to the *Gas Infrastructure Options Report* and *Electricity Network Options Report*. Detailed large-scale pumped hydro site selection with site-specific cost modelling would allow AEMO to adjust candidate development paths during the cost benefit analysis, bypassing issues modelling pumped hydro in the capacity outlook models (effectively treating long-duration storage in a similar manner to transmission augmentation).

In the medium-term, a *Long-Duration Energy Storage Options Report* should be developed as part of the ISP engineering assessment, equivalent to the *Gas Infrastructure Options Report* and *Electricity Network Options Report*. The *Long-Duration Energy Storage Options Report* could remain technology-neutral and identify the best options for large-scale long-duration energy storage capable of managing windless, cloudy winter weeks (equivalent in scale to Snowy 2.0).

For pumped hydro energy storage, the report could perform detailed site selection with site-specific cost modelling for high-quality pumped hydro sites in each NEM region. Each reservoir pair could be evaluated for a range of storage durations (i.e., different power capacities for the same reservoir pair). The best long-duration energy storage options could be used in the ISP cost benefit analysis to modify candidate development paths. AEMO could then make decisions as to whether gas-powered generators, transmission line augmentation, and other infrastructure could be replaced with large-scale long-duration energy storage according to the existing cost benefit analysis process.

By developing a *Long-Duration Energy Storage Options Report*, the computational challenges and issues associated with using average subregional costs in the capacity outlook modelling can be bypassed. Even if the SSLT is incapable of capturing long-duration storage behaviour, large-scale pumped hydro systems can be manually added and removed during the cost benefit analysis and tested using the time sequential model. Effectively, long-duration energy storage would be treated in a similar manner to transmission augmentation.

Both large-scale pumped hydro and gas-powered generators would serve a similar function in a future NEM – supplying large amounts of energy in calm, cloudy winter weeks and managing contingency events. It is not immediately obvious how these systems will receive most of their renumeration, since infrequent events may not provide sufficient compensation in the energy-only market. It may be necessary for AEMO to consider this within the time-sequential model, since historical bidding behaviour from existing gas and pumped hydro power stations may not be suitable for seasonal systems.

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[22] https://www.aemc.gov.au/regulation/neo

Recommendation 5.1

The existing transmission network will soon be saturated. We suggest that AEMO strengthen the ISP transmission expansion options by systematically screening new HVAC corridors that connect new generation to load centres effectively, rather than relying mainly on incremental augmentation options presented by individual TNSPs. We also suggest including long-distance HVDC links as future ISP project options, with promising connection regions near Mount Isa and Victoria Daly for the NEM.

The *Draft 2026 ISP* states that current network capacity is “well utilised” and that around 6000 km of transmission is required by 2050 under the Step Change scenario. As the existing network approaches saturation, substantial new solar and wind generation will be required to supply rising demand from electrification of transport, heat and industry. In this context, relying primarily on incremental augmentation can miss first-principles corridors that connect the best renewable resources to the right load centres.

A transparent, replicable corridor-screening framework can help bridge new generation to new demand efficiently. Our recently published peer-reviewed paper[23] focuses on HVAC’s role in connecting remote solar and wind to load centres, and notes the benefit of linking resources that are well correlated with the load profile to reduce balancing requirements. The method:

1. Identifies many candidate connection points with attractive resources and minimal environmental impact;
2. Constructs candidate routes by connecting each point to the main grid backbone while optimising both distance and the additional low-cost renewable resource potential unlocked along the route; and
3. Evaluates shortlisted routes using a “maximum demand fulfilment ratio (MDFR)” metric.

The HVAC routes that stand out from this framework are available on the interactive RE100 Map.[24]

The HVDC component is aimed at resilience during rare but critical low-renewable stressful periods that can disproportionately drive system costs, recognising that the system needs to be designed based on “extreme” rather than “average” conditions. The method:

1. Identifies the system’s worst week under current settings;
2. Screens inland HVDC points based on correlation with net load during that week; and
3. Evaluates top candidates through full 10-year chronological re-optimisation.

Both HVDC transmission capacity and renewable generation capacities at the HVDC node are optimised to minimise whole-system LCOE. For the NEM, evaluated HVDC routes reduce LCOE by 8–18%, with the best connection points concentrated near Mount Isa and Victoria Daly, as shown on the RE100 Map in the below footnote.[25]

The *Draft 2026 ISP* notes that future ISP projects can deliver net market benefits and that proponents may begin planning and engagement ahead of need. Including long-distance HVDC corridors as future options therefore improves the ISP’s robustness by enabling systematic consideration of HVDC as a response to d*unkelflaute*-type events, while supporting transparent comparison against HVAC/REZ augmentation pathways as scenarios and assumptions evolve.

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[23] https://doi.org/10.1016/j.apenergy.2025.126908
[24] https://re100.anu.edu.au/#share=g-d8fd371bddde70119b1dd58b87c8629c
[25] https://re100.anu.edu.au/#share=g-0702f6a9710cdd39df1ebb68582d51fa

Conclusion

The ISP is already a world-leading energy system plan. It plays a very important role in developing a future NEM with electricity that is low cost, high quality, safe, reliable, secure, and delivers on Australia's greenhouse gas emission reduction targets. The ISP is both shaped by Australian policy and provides the guidance necessary to inform future policy.

Properly including large-scale, long-duration pumped hydro energy storage in the ISP, along with systematically screening for a broad range of additional HVAC and HVDC transmission opportunities, is essential for providing policymakers with the tools necessary to support the fastest energy transition in history. Australia has the opportunity to develop a world-class reliable, low-cost 100% renewable electricity system. This is a system that would not only deliver on the National Electricity Objective, but would also demonstrate the due diligence required to fulfil our international climate obligations.

We hope that our recommendations can help to improve the ISP even further.

Kind regards,

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