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Submission to AEMO 2025 ISP Methodology Consultation

100% Renewable Energy Group (Australian National University)

Pumped hydro energy storage will comprise more than 95% of energy storage (GWh) in the NEM In 2028 when Snowy 2.0 comes online. Pumped hydro must be properly modelled. However, there are major shortcomings in the treatment of pumped hydro energy storage in the Integrated System Plan models. These principally relate to (i) a dramatic underestimate of availability on the mainland near Melbourne-Sydney-Brisbane transmission; (ii) a substantial overestimate of cost; (iii) an inappropriate focus on pumped hydro with high power (GW) and low energy (GWh) rather than the converse; and (iv) insufficient chronological modelling, which inappropriately favours gas. We believe that pumped hydro-battery hybrid systems could displace gas from the NEM at negative cost. Proposed use of imperfect forecasting and the inclusion of headroom/footroom reserves presented in the issues paper are also not expected to provide useful improvements to the time-sequential model. We recommend that AEMO work with ANU and others to deliver a thorough revision of modelling of pumped hydro.

Overview

The 100% Renewable Energy Group (RE100 Group) at the Australian National University (ANU) is responsible for developing and maintaining the Global Pumped Hydro Energy Storage Atlases (the "Global PHES Atlases" or "the Atlases"). The original version of the Atlases, developed in 2018, were the basis of the *Pumped Hydro Cost Modelling* by Entura[1] and the build limits established for all Integrated System Plans (ISPs) since then. The Atlases have been extensively reworked and improved since 2018. These out-dated assumptions are expected to have a material impact on capacity outlook modelling within the ISP. Chronology simplifications within the Single Step Long Term and Detailed Long Term capacity outlook model designs are also suspected of favouring gas and disadvantaging energy storage systems relative to expected results.

The 2024 ISP indicated that approximately 15 GW of gas will still be required in 2050 in the Step Change scenario. We believe that our recommended improvements to pumped hydro assumptions and capacity outlook model design may indicate that either some or all of this gas is superfluous, and that it may drive up the cost of electricity and increase emissions relative to a 100% renewable National Electricity Market (NEM).

Projected dependence on fossil gas turbines in 2050 could be an embarrassment to the Australian Government's intent upon achieving zero emissions before 2050.

Our analysis with the publicly available Detailed Long Term PLEXOS model suggests that this gas is primarily being used by the model to meet energy and power deficits in winter months.

Low-power, high-energy pumped hydro systems (with 160 hours of storage, like Snowy 2.0) combined with high-power, low-energy batteries (i.e., hybrid energy systems) may be able to meet these energy and power deficits at lower costs than gas; however, the model absolutely prohibits such systems by imposing an unjustified capacity limit of 48 hours. A model is only as good as its assumptions, and these assumptions

[1] https://www.marinuslink.com.au/wp-content/uploads/2019/02/Report-Pumped-Hydro-Cost-Modelling.pdf

materially influence the behaviour of energy planners and developers as we strive towards a low-cost, zero-emissions NEM.
The RE100 Group has developed the following recommendations with respect to the 2025 ISP Methodology:

1. Build costs of new pumped hydro systems on the mainland are substantially overestimated. The 2018 Entura cost model (which was applied to an out-dated version of the pumped hydro Atlases for previous ISPs) and the Aurecon cost model used for GenCost 2023-24 should be updated to reflect the most recent version of the Atlases.
2. Tasmania is wrongly assumed to have much better pumped hydro options than all other NEM regions. The locational cost factors for PHES should be revised to demonstrate that new build PHES in other NEM sub-regions matches or betters Tasmania, are far more plentiful, and are close to Melbourne-Sydney-Brisbane transmission.
3. AEMO should include costings for energy-focused, rather than just power-focused, pumped hydro systems. This means focusing on systems with large head and large water-to-rock ratios. Furthermore, AEMO should end the practice of only modelling storage systems with less than 50 hours of energy storage. This strongly and inappropriately favours gas for riding through several weeks of inclement weather.
4. Pumped hydro costs are site-specific. Rather than applying a single capital cost to each NEM sub-region, a cost curve (step function) should be developed for each sub-region based upon the thousands of options available in the Atlases.
5. The pumped hydro sub-regional build limits used within the ISP capacity outlook models are wrong. They inappropriately curtail the deployment of new-build pumped hydro within the model. These build limits should be dramatically revised to reflect the latest ANU Global PHES Atlas results.
6. The capacity outlook models within the ISP should maintain full chronology and a high time resolution (30-minutes or 1-hour) to improve energy storage system modelling and reduce the chance of gas being unfairly advantaged within the model. Due to the computational complexity of full chronology within linear programs, different model simplifications with lower impact on the results may need to be made within the Single Step Long Term and Detailed Long Term models to reduce the number of non-zeroes. Alternatively, AEMO could replace the Single Step Long Term linear program with a non-linear capacity expansion model that maintains full chronology and a high time resolution. As a third alternative, the most difficult few years should be identified with low resolution modelling. These years (and the years either side) can then be modelled at high resolution while maintaining full chronology.
7. "All models are wrong, but some are useful". AEMO should focus on what useful information can be extracted from the time-sequential model, and not continue attempting to make it less wrong through arbitrary increases in complexity that are very likely to counterintuitively cause more uncertain estimates. The proposed inclusion of imperfect foresight for energy storage scheduling and headroom/footroom energy reserves are not expected to bring the model closer to reality or provide useful insights into actual energy storage operator behaviours.

Cost Assumptions for Pumped Hydro Energy Storage

In the 2023 Inputs, Assumptions and Scenarios Report (IASR), pumped hydro build costs are based upon the *2018 Pumped Hydro Cost Modelling* by Entura (modified using a different base year and short-term cost pressure adjustments for GenCost 2022-23[2]). Locational cost factors sourced from the Entura report are applied to adjust costs in accordance with broad availability of natural resources and geology in each NEM sub-region. Some pumped hydro sites with site-specific information, such as Snowy 2.0 and the Cethana project, are given bespoke cost assumptions. GenCost 2023-24 notes that pumped hydro costs have been updated by Aurecon, though these new costings appear to reflect the same issues as the 2018 Entura report.

[2] https://www.csiro.au/-/media/EF/Files/GenCost/GenCost2022-23Final_27-06-2023.pdf

1. Build costs of new pumped hydro systems on the mainland are substantially overestimated. The 2018 Entura cost model (which was applied to an out-dated version of the pumped hydro Atlases for previous ISPs) and the Aurecon cost model used for GenCost 2023-24 should be updated to reflect the most recent version of the Atlases.

The Entura report estimated the cost of pumped hydro by developing a capital cost model, applying the model to data from the Australian National University's 2018 atlas of pumped hydro in Australia, then assessing the top 25% of projects identified in each NEM sub-region. It is not clear how the new Aurecon pumped hydro costs have been developed, but they appear to reflect the same issues as the Entura report.

The atlas of pumped hydro in Australia, developed in 2018, is now far out-dated. Since then, the RE100 Group has dramatically expanded the dataset in the following ways[3]:

- The 2018 atlas of pumped hydro identified only upper reservoirs. Since then, the single-reservoir search algorithms have evolved significantly, now incorporating paired upper and lower reservoirs for pumped hydro schemes and, importantly, including cost factors for ranking sites.[4]
- The maximum size allowed in the 2018 atlas has been increased from 200 GWh. The dataset now includes the following system sizes: 2GWh, 5GWh, 15GWh, 50GWh, 150GWh, 500GWh, 1500GWh, 5000GWh.
- The digital elevation model has been updated to use the global FABDEM dataset.[5] This digital terrain model is expected to have a higher accuracy for reservoir modelling due to the removal of forests and buildings, and was generally found to result in larger reservoirs for similar dam wall sizes (i.e., lower cost per unit of energy storage) in the modelling.
- The head range was increased from 600 metres to 1600 metres. All other characteristics the same, doubling the head will double the energy stored within the upper reservoir and the power that can be output by the system. Therefore, doubling the head will roughly halve the cost per unit of energy storage. Since reversible Francis turbines generally have a limit of approximately 700-800 metres, it is assumed that systems with higher heads would involve a two-stage cascade with a second powerhouse halfway along the connecting tunnel.
- The Atlases have been expanded to include sites formed using existing lakes and reservoirs (Bluefield), defunct mining sites (Brownfield)[6], systems that use the ocean as a lower reservoir, and ring-dam reservoirs constructed on flat land or around natural depressions (Turkey's Nests). The current version of the Atlases includes 287,000 GWh of energy storage potential in NEM regions outside protected areas and large urban centres.
- Many premium cost class sites (AA and AAA) have been identified which have extremely small dam walls relative to the volume of water stored in the reservoirs (high water-to-rock ratio), short pressure tunnels, and large heads. These sites are expected to cost much less than the cost per unit of energy storage of most existing on-river PHES systems.

Further to the significant updates to the ANU pumped hydro atlases, it is worth highlighting that most existing pumped hydro systems are on-river (open-loop). The vast majority of sites on the ANU pumped hydro atlases are off-river (closed-loop). Off-river systems will typically have lower costs than on-river systems due to favourable technical characteristics (e.g., larger heads and smaller dam walls, since the system is not constrained to gently sloping river valleys) and negligible flood control costs. Costs of existing on-river systems, such as Tumut 3, would not be a good benchmark for committed and future pumped hydro systems.

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[3] The Global PHES Atlases are available from: https://re100.eng.anu.edu.au/
[4] Cost factors explained in Supplementary Information: https://doi.org/10.1016/j.joule.2020.11.015
[5] https://data.bris.ac.uk/data/dataset/s5hqmjcdj8yo2ibzi9b4ew3sn
[6] https://doi.org/10.1016/j.renene.2024.120113

AEMO restricts storage to a maximum of 48 hours. This is too short when considering the prospect of large-scale PHES to help ride through inclement weather in winter without the support of gas. It is also inconsistent with Snowy 2.0, which has 160 hours of storage.

2. **Tasmania is wrongly assumed to have much better pumped hydro options than all other NEM regions. The locational cost factors for PHES should be revised to demonstrate that new build PHES in other NEM sub-regions matches or betters Tasmania, are far more plentiful, and are close to Melbourne-Sydney-Brisbane transmission.**

Kidston will be the first pumped hydro project finished in Australia in 40 years. Since Australia's last pumped hydro project was completed, awareness of the availability of off-river pumped hydro locations has grown dramatically through the development of the Atlases. While Tasmania has a large amount of existing conventional hydro capacity and options to repurpose existing reservoirs into pumped hydro systems (such as Cethana), the quality of pumped hydro options in Tasmania is not better than dozens of sites on the east coast of the mainland close to Melbourne-Sydney-Brisbane transmission.

We can justify this by simply comparing Snowy 2.0 cost estimates to GenCost 2023-24 mainland cost estimates (based on Auercon cost modelling). Snowy 2.0 is currently expected to cost approximately $12 billion.[7]

When evaluating costs in terms of unit of power capacity ($/kW), the cost of 2.2 GW, 350GWh (i.e., 160 hours of storage) Snowy 2.0 project is approximately $5500/kW. The current ISP assumptions price 48-hour SNSW pumped hydro at $6086/kW (GenCost 2023-24 base cost of $6688/kW in 2024[8], locational cost factor of 0.91).

On the basis of capital cost per unit of energy storage ($/kWh) Snowy 2.0 is $34/kWh compared to $126/kWh for a 48-hour SNSW system in the ISP (GenCost 2023-24 base cost of $139/kWh, locational cost factor of 0.91). Snowy 2.0 is about 4 times cheaper than ISP assumptions on the basis of cost per unit of energy storage. Even if Snowy 2.0 cost estimates increase again, it will still likely be much cheaper than the existing new build cost estimates used for the ISP.

Although Snowy 2.0 has two existing reservoirs which lowers the cost of civil works, it also requires a 27 km long underground pressure tunnel which is very expensive to construct. Snowy 2.0 also has 160 hours of energy storage, compared to the maximum new build energy capacity of 48-hours used by the ISP. There are many premium cost class sites on the current Atlases that have cheap reservoirs like Snowy 2.0, but also very short pressure tunnels which result in lower cost of civil works, faster construction time and reduced geotechnical risk. One such example of many available in SNSW is shown in Figure 1.[9]

[7] https://www.snowyhydro.com.au/wp-content/uploads/2024/05/Snowy-2.0-Updated-Business-Case.pdf
[8] https://www.csiro.au/en/research/technology-space/energy/GenCost
[9] View site on RE100 Map: https://re100.anu.edu.au/#share=g-b146346c856a5eb5c754d1be25092282

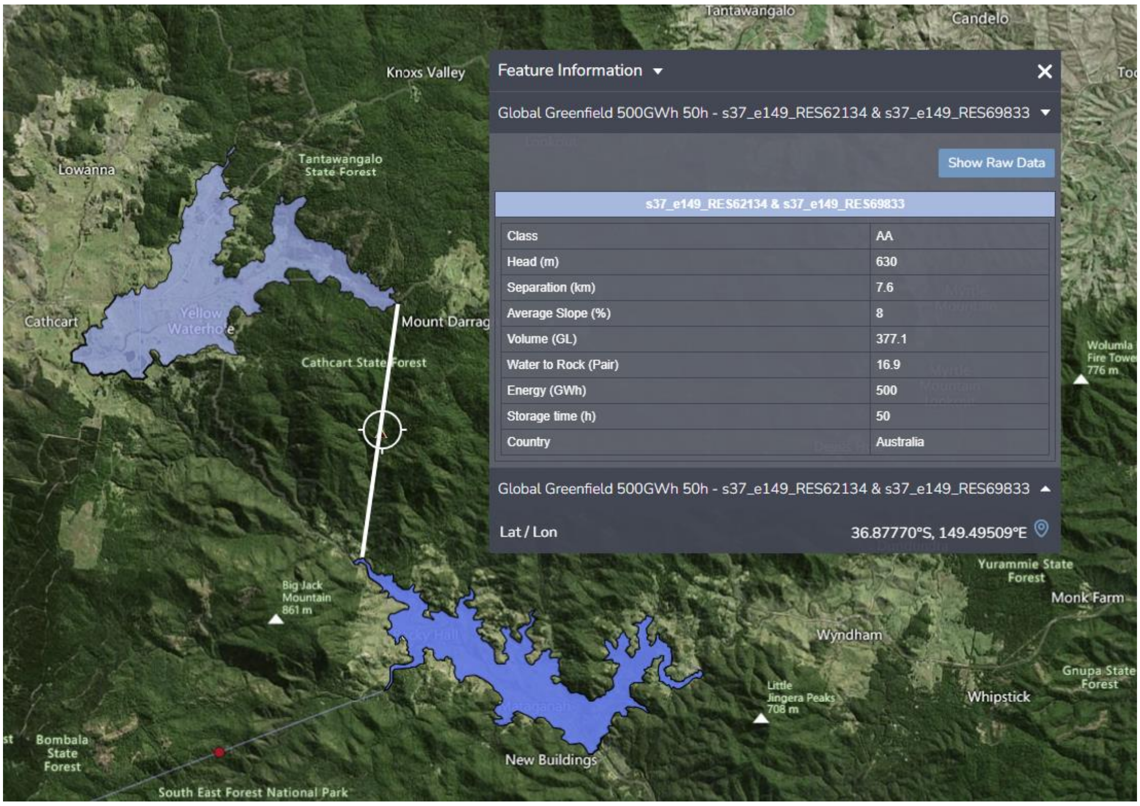


Figure 1. Example premium AA site in SNSW subregion. This class AA site has large head (630 m), Large water-to-rock ratio (17) and small separation between the reservoirs (8 km). On paper, this site (and many others like it) is considerably better than Cethana in Tasmania.

3. **AEMO should include costings for energy-focused, rather than just power-focused, pumped hydro systems. This means focusing on systems with large head and large water-to-rock ratios. Furthermore, AEMO should end the practice of only modelling storage systems with less than 50 hours of energy storage. This strongly and inappropriately favours gas for riding through several weeks of inclement weather.**

If Snowy 2.0 were coupled with 5 GW of 4-hour batteries (costed according to the GenCost 2023-24 model), the combined "hybrid energy storage" system would be 7.2 GW, 370 GWh and cost approximately $3,300/kW. This hybrid energy system could be considered a power-focused system due to the high-powered batteries. The current ISP assumptions price 48-hour pumped hydro in Tasmania at $3077/kW (GenCost 2023-34 base cost of $6688/kW in 2024[10], locational cost factor of 0.46). The Tasmania pumped hydro costs may be a suitable representation of power-focused energy storage systems.

Without the batteries, recall that Snowy 2.0 has 2.2 GW and 160 hours of storage with a cost of $34/kWh. On its own, Snowy 2.0 is an energy-focused system, rather than a power-focused system. The 48-hour Tasmania pumped hydro has a cost of $65/kWh. While the cost assumption for Tasmania may be appropriate for power-focused systems, it is not appropriate when considering energy-focused systems like Snowy 2.0 (e.g., seasonal energy storage).

[10] https://www.csiro.au/en/research/technology-space/energy/GenCost

Reservoirs and power systems can be sized independently for pumped hydro. Large energy storage capacity (i.e., reservoir construction) is extremely cheap for pumped hydro, while power systems (e.g., high-pressure tunnel and powerhouse) are quite expensive. Battery costs have the opposite relationship. Therefore, the most cost-efficient form of future low-cost energy storage will likely be provided by a combination of high-power batteries trickle-charged by low-power, large-energy storage pumped hydro. Current cost assumptions used by the ISP, including the Tasmania pumped hydro costs, do not properly describe energy-focused pumped hydro systems that are likely to be the dominant form in a low-cost future NEM.

4. **Pumped hydro costs are site-specific. Rather than applying a single capital cost to each NEM sub-region, a cost curve (step function) should be developed for each sub-region based upon the thousands of options available in the Atlases.**

Spatial resolution must necessarily be reduced to sub-regions or regions to simplify the capacity outlook linear programs in PLEXOS and make them computationally feasible. It is also unreasonable to expect AEMO or their partners to perform a detailed cost assessment of all Australian pumped hydro options in the Atlases. Nonetheless, there are major improvements that can be made to the implementation of cost assumptions for site-specific technologies such as pumped hydro in the ISP methodology.

At a high level, pumped hydro costs are driven by the size of the dam wall relative to the volume of stored water (captured by the "water-to-rock" ratio), the elevation difference between the reservoirs ("head"), the overall system size, and the length of the pressure tunnel. The Atlases apply a parameterised cost model (developed by an engineering firm for the ANU) to categorise possible sites according to a cost class (AAA to E). Cost class A is treated as the baseline. Class E sites are expected to be roughly twice as expensive as the baseline, while class AAA and AA are expected to be 33% and 66% of the baseline respectively.

While this cost model is useful for comparing between different sites within the Atlases, it is not expected to provide an accurate estimate of total capital costs since it excludes some components such as contingencies, land costs, transmission, workcamps and roads. Regardless, the comparative cost model indicates that possible sites in each NEM region have a broad range of costs based upon their technical characteristics (refer Figure 2). Applying a single cost assumption to each NEM sub-region does not capture this diversity of costs. Most notably, premium cost class AAA and AA sites are expected to have costs roughly 10 - 30% of existing on-river PHES systems due to their small dam walls relative to large volumes of water, very short pressure tunnels, and very large heads.

One method of capturing this variety of costs within each NEM subregion is to apply cost curves (or step functions) to pumped hydro, rather than a single cost per subregion. Cost curves should be based upon $/kWh of energy capacity since it is the reservoir shape and location that primarily constrains the build limit of pumped hydro (one can arbitrarily increase the number of tunnels and pump/turbines for any pair of reservoirs). During the capacity outlook modelling, new build pumped hydro should start at the cheapest point on the cost curve. As more pumped hydro energy capacity is added to a particular sub-region, the cost should increase and move further up the curve.

ANU can provide this cost curve for each region of the NEM.

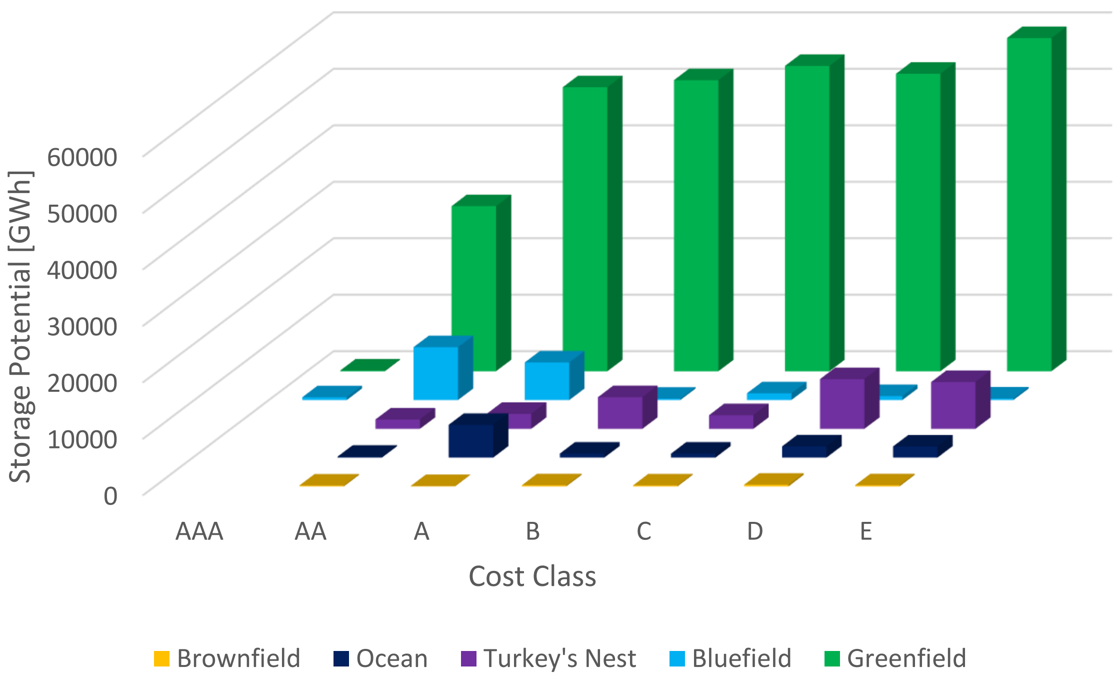


Figure 2. Distribution of Cost Classes for Non-overlapping Sites within each Australia PHES Atlas

Build Limits for Pumped Hydro Energy Storage

The sub-regional build limits for pumped hydro in the ISP methodology are based on out-dated information from the Entura report and the NSW Government Pumped Hydro Roadmap.[11] Both of these reports are based upon an early version of the ANU Atlases from 2018.

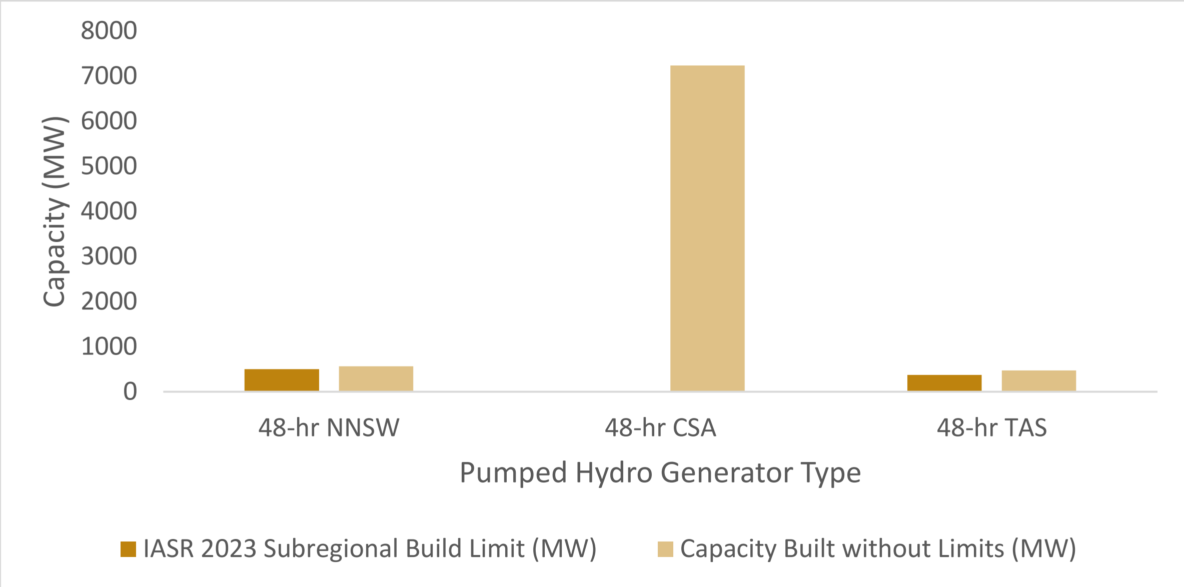
5. **The pumped hydro sub-regional build limits used within the ISP capacity outlook models are wrong. They inappropriately curtail the deployment of new-build pumped hydro within the model. These build limits should be dramatically revised to reflect the latest ANU Global PHES Atlas results.**

As explained in the discussion of recommendation 1 above, the Atlases developed by the ANU have undergone significant developments since 2018. Entura's analysis of the ANU atlas found an energy storage potential of 390 GWh in the NEM regions. This has since expanded to 287,000 GWh through improvements to site searching methods, consideration of new categories of pumped hydro sites (i.e., Bluefield, Brownfield, Ocean, Turkey's Nest), and an algorithm that pairs reservoirs together (the original Atlas just located individual reservoirs[12]). The 2023 IASR Assumptions Workbook[13] describes the build limits for pumped hydro used within the ISP capacity expansion modelling.

To test whether build limits are binding on pumped hydro in the capacity expansion models, the max build limit was increased to 10,000 MW for each type of PHES system in the publicly available ISP 2024 PLEXOS Step Change Detailed Long Term model. The model was run over the period 1 January 2043 - 1 January 2046 (the high gas generation in 2044 indicates that it is a challenging year for a renewable electricity system). Without the binding build limits, the capacity expansion model chose to only build only 48-hr PHES and exceeded the 2023 IASR build limits in each subregion where new PHES was deployed (refer Figure 3).

[11] https://www.energy.nsw.gov.au/sites/default/files/2022-08/NSW%20Pumped%20Hydro%20Roadmap.pdf
[12] https://doi.org/10.1016/j.apenergy.2018.03.177
[13] https://www.aer.gov.au/documents/aemo-2023-iasr-assumptions-workbook-august-2023-1

Figure 3. Removal of Build Limits Indicates that the 2023 IASR PHES Build Limit Constraints are Binding



A breakdown of build limits by NEM sub-region is provided in Table 1. The IASR Total Limit is calculated by converting the power (MW) potential for 8-hr, 24-hr and 48-hr PHES systems to an energy (GWh) potential. The Global PHES Atlases potential is based upon the energy storage capacity of all non-overlapping sites on the ANU Greenfield, Bluefield, Brownfield, Ocean, Seasonal, and Turkey's Nest Atlases. Where two sites overlap, the largest site is included in the estimated potential. All reservoirs are located outside protected areas and large urban centres.

Table 1. Pumped Hydro Build Limit Assumption Comparison

Region	**IASR Total Build Limit (GWh)**	**Global PHES Atlases Potential (GWh)**
Queensland	183	60,700
New South Wales	112	135,000
Victoria	58	52,300
South Australia	10	8270
Tasmania	60	31,000

Sites on the ANU Atlases have not undergone detailed pre-feasibility or feasibility studies. It is true that many sites might be infeasible for development due to geotechnical, social, or environmental reasons for which information is not available at the desktop analysis stage. Regardless, it is clear that the IASR build limits for pumped hydro are far too pessimistic. The ANU Atlases describe dozens of pumped hydro options in Australia that have energy capacities of 500 GWh, 1500 GWh, and 5000 GWh (refer Figure 4). Just one of these systems is larger than the IASR Total Build Limit for the entire NEM. These build limits require a dramatic revision.

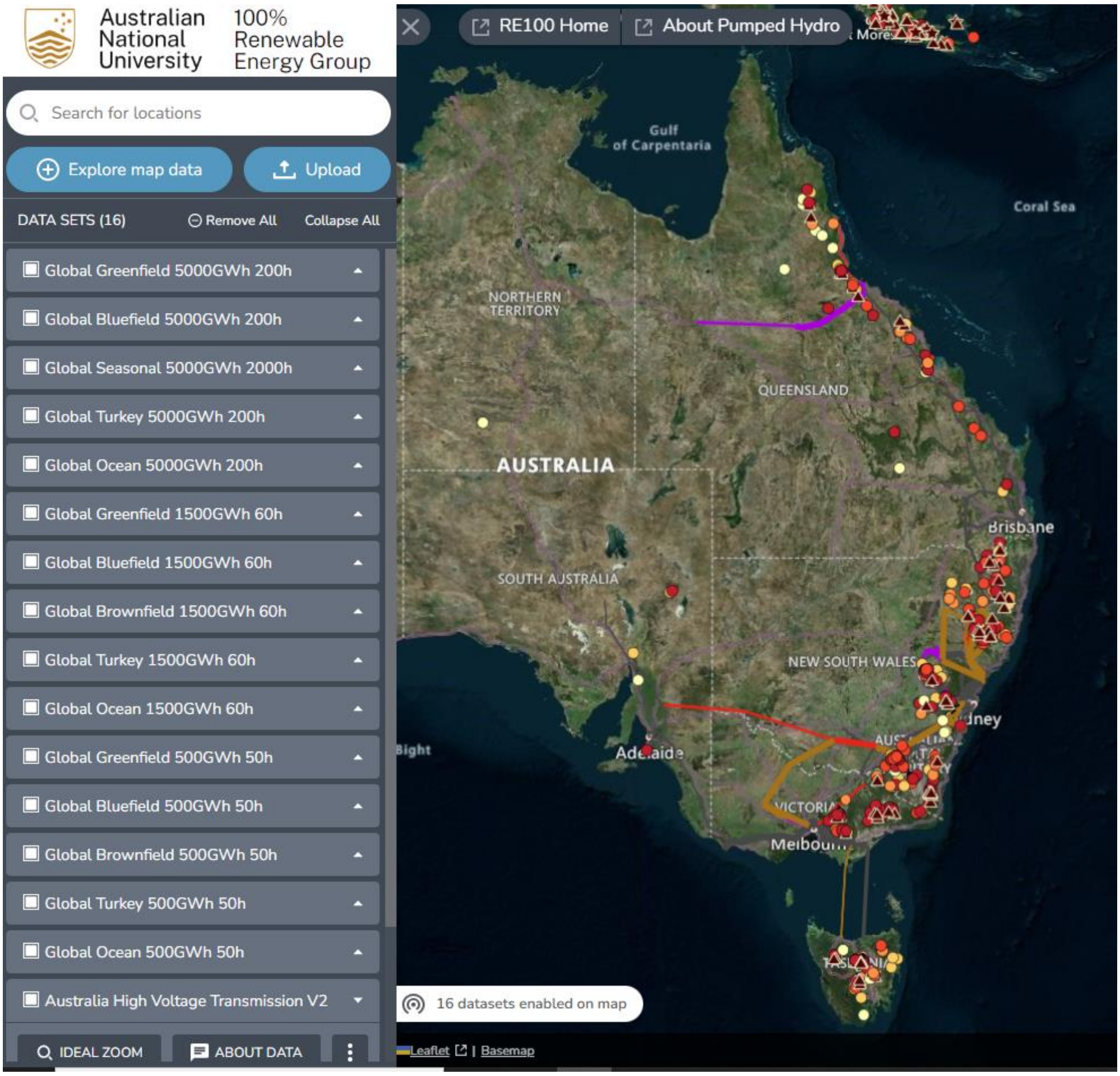


Figure 4. Distribution of large-scale 500 - 5000 GWh pumped hydro options in NEM regions[14]

Impact of Sampled Chronology on Energy Storage Capacity Expansion

The Single Step Long Term and Detailed Long Term capacity outlook models in PLEXOS use a sampled chronology and fitted chronology respectively. It is not clear from the 2023 ISP Methodology[15] what sampled chronology settings are applied by AEMO within the method, though the report provides an example of a load profile for 2 sample days per month. It is assumed that the same chronology simplifications will be applied in the 2025 ISP Methodology.

Sampled chronology refers to the process through which a capacity expansion linear program, such as the Single Step Long Term model implemented in PLEXOS for the ISP, reduces model complexity by only including

[14] View this dataset at: https://re100.anu.edu.au/#share=g-f926825bd90351605c0f5dc453725f4a

[15] https://aemo.com.au/-/media/files/stakeholder_consultation/consultations/nem-consultations/2023/isp-methodology-2023/isp-methodology_june-2023.pdf?la=en

a sample set of time periods within the problem formulation. For example, a representative set of days are extracted from the full 28-year time series, the capacity expansion problem is formulated and solved using the sampled days, and then unsampled days are mapped back to the solution to check whether chronological behaviour (such as storage system state-of-charge) remains feasible. PLEXOS uses a cluster analysis method[16] for sampling time periods (such as representative days or weeks, as defined by the user) to select the sampled time periods.

Although unsampled periods are mapped back onto sampled periods following the optimisation, this is a *post hoc* step and it remains the case that chronology is not maintained within the capacity expansion optimisation itself. For long-duration energy storage which may maintain large energy reserves (such as a seasonal energy storage system that only fully discharges during dunkelflaute weeks in winter), their core behaviour is lost within the problem formulation. The sampling process may be the reason the ISP currently indicates that energy storage durations longer than 48 hours are unnecessary. It is possible that sampled chronology has a lower impact on short-duration (intra-day) storage than long-duration storage, since high time resolution within the sampled periods is maintained, though the behaviour of hybrid energy storage where batteries interact with large-scale pumped hydro may be lost.

Fitted chronology involves maintaining full chronology, but reduces time resolution in order to simplify the problem formulation. The Detailed Long Term model within the ISP uses a method whereby load duration curves are fitted with a resolution of 8 time period "blocks" per day. The blocks form a step function, whereby the difference between the step function and the original high-resolution data is minimised according to the weighted least squares method. This means that periods of the day with high volatility will have higher resolution (shorter time intervals in the step function) than periods with low volatility.

While the presence of full chronology may improve long duration storage system behaviour, the behaviour of short duration storage may be impacted due to the reduced time resolution. Thus, hybrid energy storage systems may not be appropriately modelled using fitted chronology, whereby the short duration storage is trickle charged by long duration storage during periods of dunkelflaute. Furthermore, the issues with long duration storage modelling in the Single Step Long Term plan will be propagated in subsequent Detailed Long Term models.

Chronology simplification is understood to materially impact both the amount and timing of capacity expansion optimised by a linear program. Evidence of the impact of using fitted load-duration curves compared to full chronology in PLEXOS capacity expansion modelling was found as early as 2012.[17] It should be noted that the costs of wind and solar were tenfold higher in 2012, so the actual results of the analysis in that conference paper would be different today, although the mechanism driving those results remains the same. Furthermore, the analysis in that paper does not include energy storage systems, which we expect to displace gas when properly modelled at high resolution and full chronology.

6. **The capacity outlook models within the ISP should maintain full chronology and a high time resolution (30-minutes or 1-hour) to improve energy storage system modelling and reduce the chance of gas being unfairly advantaged within the model. Due to the computational complexity of full chronology within linear programs, different model simplifications with lower impact on the results may need to be made within the Single Step Long Term and Detailed Long Term models to reduce the number of non-zeroes. Alternatively, AEMO could replace the Single Step Long Term linear program with a non-linear capacity expansion model that maintains full chronology and a high time resolution. As a third alternative, the most difficult few years should be identified with low resolution modelling. These years (and the years either side) can then be modelled at high resolution while maintaining full chronology.**

[16] https://en.wikipedia.org/wiki/Cluster_analysis
[17] https://doi.org/10.1109/PowerCon.2012.6401421

A simplified single step model was developed in PLEXOS for the analysis below. The publicly available Detailed Long Term ISP 2024 model was modified to remove binding maximum build limits from all technologies that are allowed to be built in the final version of the model. To simplify the model and quickly acquire results to analyse as part of this submission, a short time horizon of 3 years (2043 - 2045) is evaluated in a single step. This time period was chosen since 2044 was found to be the year with the highest gas generation, indicating it had the most challenging conditions for a renewable energy system to balance. The PLEXOS model is run on a system with 128 GB DDR5 6000 MHz CL36 RAM and an Intel Core i5-14600K 14 Core (3500 MHz) processor. The analyses below are intended to demonstrate how certain assumptions influence model behaviour, and the actual values of the decision variables have no meaning beyond this discussion.

High-Level Analysis of Hybrid Energy Storage Systems Displacing Gas

Under the step change scenario, the ISP 2024 indicated that 15 GW of gas would generate 6.3 TWh of energy in 2050-51. This represents a duty cycle of about 4%. Assume a 6% discount rate, $13.5/GJ fuel cost, capital cost of $943/kW, VOM of $7.6/MWh, FOM of $24.1/kW and economic life of 25 years (using 2023 LCOE calculation assumptions for large OCGT from GenCost 2023-24). This roughly comes out to $290/MWh.

Snowy 2.0 is expected to cost $12 billion. At a 6% discount rate and a lifetime of 60 years (technical life is much longer), the pumped hydro system would need to fully cycle only about 7 times per year (or 14 half-cycles) with an arbitrage price spread of $290/MWh to break even (ignoring revenue from ancillary services or financial markets). Premium pumped hydro energy storage systems are likely competitive with gas, especially if an implicit or explicit carbon price penalises the gas further.

We previously discussed a hybrid energy storage system consisting of high-power (GW), low-energy (GWh) batteries combined with low-power, large-energy pumped hydro. The hybrid energy storage system capitalises on the very low capital costs of large reservoirs for storing energy, and the lower cost of battery power delivery systems. The pumped hydro system can trickle-charge batteries on days with low sun or wind, allowing the batteries to meet the morning or evening demand peaks. This enables a hybrid energy storage system to store large amounts of energy cheaply for winter weeks, and dispatch large amounts of power (competitive with the 15 GW of gas) for morning and evening demand. The competitiveness of this hybrid energy storage system behaviour with gas would need to be properly evaluated through an appropriate capacity expansion model with reasonable energy storage cost/build limit assumptions, but these rule-of-thumb calculations indicate that there is a strong case to explore this in more detail within the ISP.

For example, a PHES system with 350 GWh of energy storage and 2.2 GW of generation power can trickle charge twelve 4-hour batteries (48 GWh) every day for a wet and windless week. This hybrid system effectively has energy storage of 400 GWh and storage power of 12 GW. A battery-only system would run out of energy after the first day, while a PHES-only system would be underpowered.

An additional advantage is that the batteries can harvest negative prices for four hours around noon on sunny days with a power of 12 GW, and trickle charge the PHES system for the next 20 hours – and do this every day for a week before the PHES system is full.

In other words, this 400 GWh hybrid system can harvest peak power prices at 12 GW and get recharged at negative prices.

Sampled Chronology vs Fitted Chronology (12 blocks per day)

The simple single step model was run for two scenarios: one which used fitted chronology with 12 blocks per day fitted according to the weighted least squares method, and another which used sampled chronology with 2 representative days sampled per month. The time series for a challenging week (28 May 2044 - 3 June 2044) for each scenario is shown in Figure 6 and Figure 7.

From the figures, it is clear that storage system behaviour is very different under the two different methods for chronology simplification. Under the fitted chronology, long-duration PHES has been able to properly plan its behaviour to manage the challenging week at the start of winter, as indicated by the high state-of-charge (SOC) that it begins the week with (68%). Under the sampled chronology, long-duration PHES begins the week with just 30% SOC and the SOC function has a much larger contribution from daily cycling compared to longer duration cycling. The cloudy, windless days on the 1st and 2nd June 2044 (as indicated by the low REZ generation in Figure 6) are not properly captured with the sampled chronology (Figure 7).

Short-duration daily and intra-day cycling is retained for both batteries and PHES in the sampled chronology, since the high time resolution allows for charge/discharge decisions to be made at a high time resolution within the sampled days. The loss of time resolution when using fitted chronology limits the short-duration decisions that can be made by the storage systems - notably, the minor charging of batteries immediately before the morning demand peak observed in the sampled chronology plot is generally missing from the fitted chronology plot.

The annual generation mix for 2044 using the two chronology simplifications is summarised in Figure 5. Simply changing from fitted chronology (12 blocks per day) to sampled chronology (2 days per month) results in a 66% increase in annual gas generation. Increasing the number of sample days will likely have an impact on these results, but it is evident that sample chronology could have a material impact on the amount of gas deployed within the capacity expansion optimisation. The sampled chronology simplification may provide a material advantage to gas in the Single Step Long Term model for the ISP.

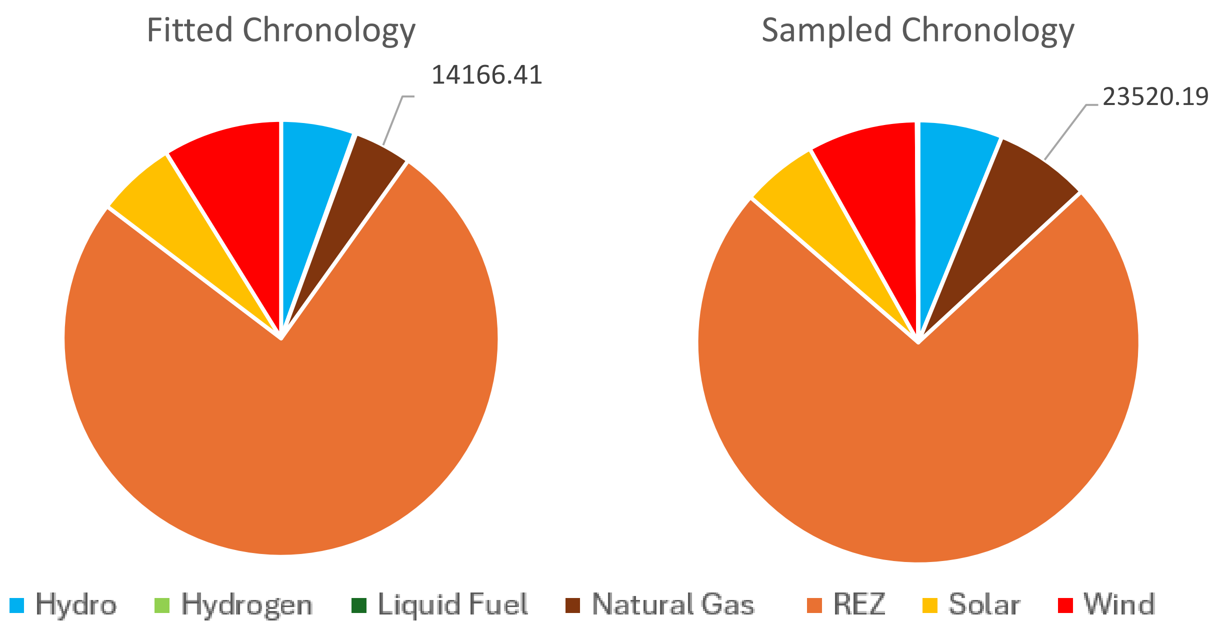


Figure 5. Generation mix for 2044 (GWh generated) for different chronology simplifications

Figure 6. Fitted Chronology (12-blocks per day) for Challenging Week

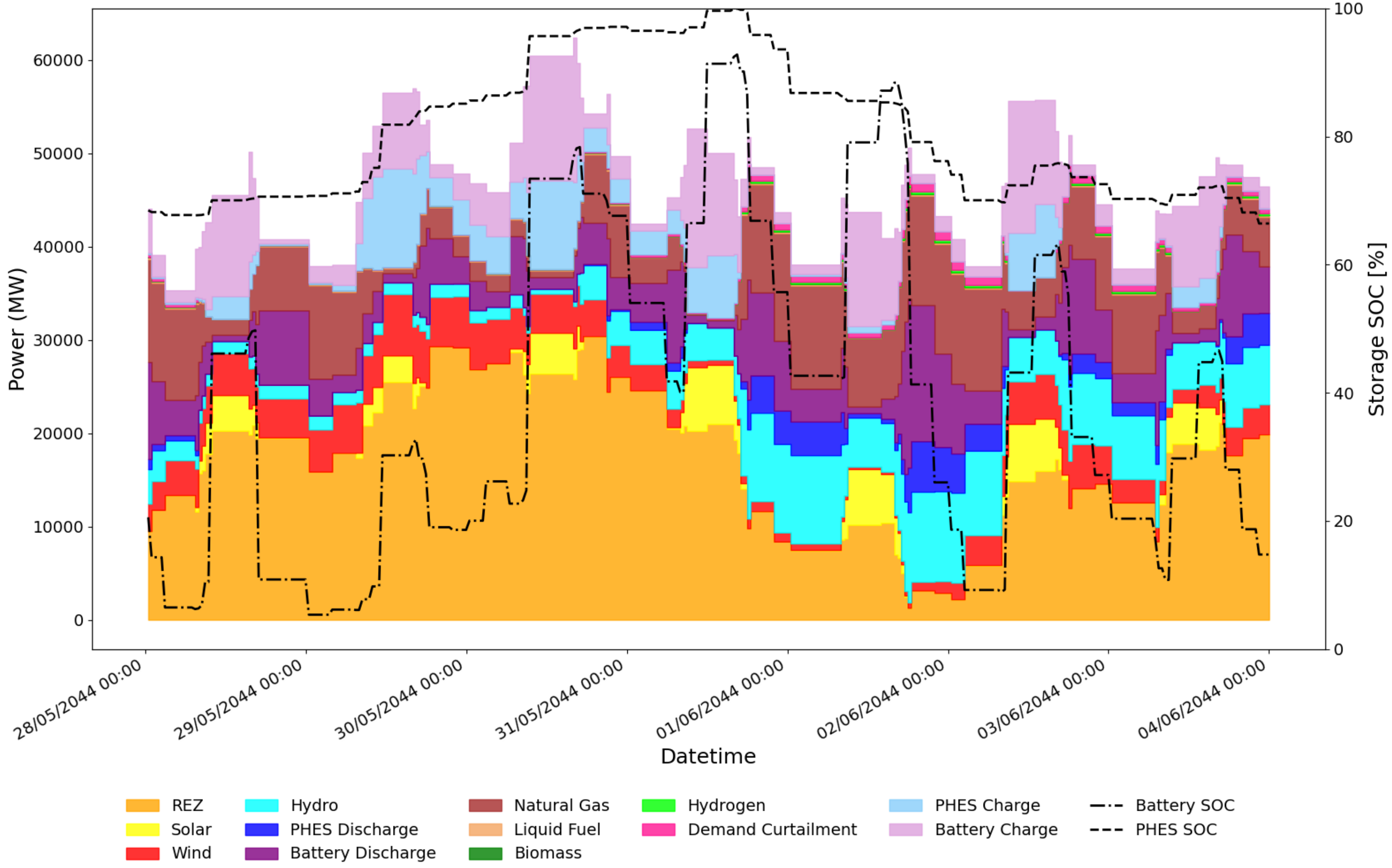
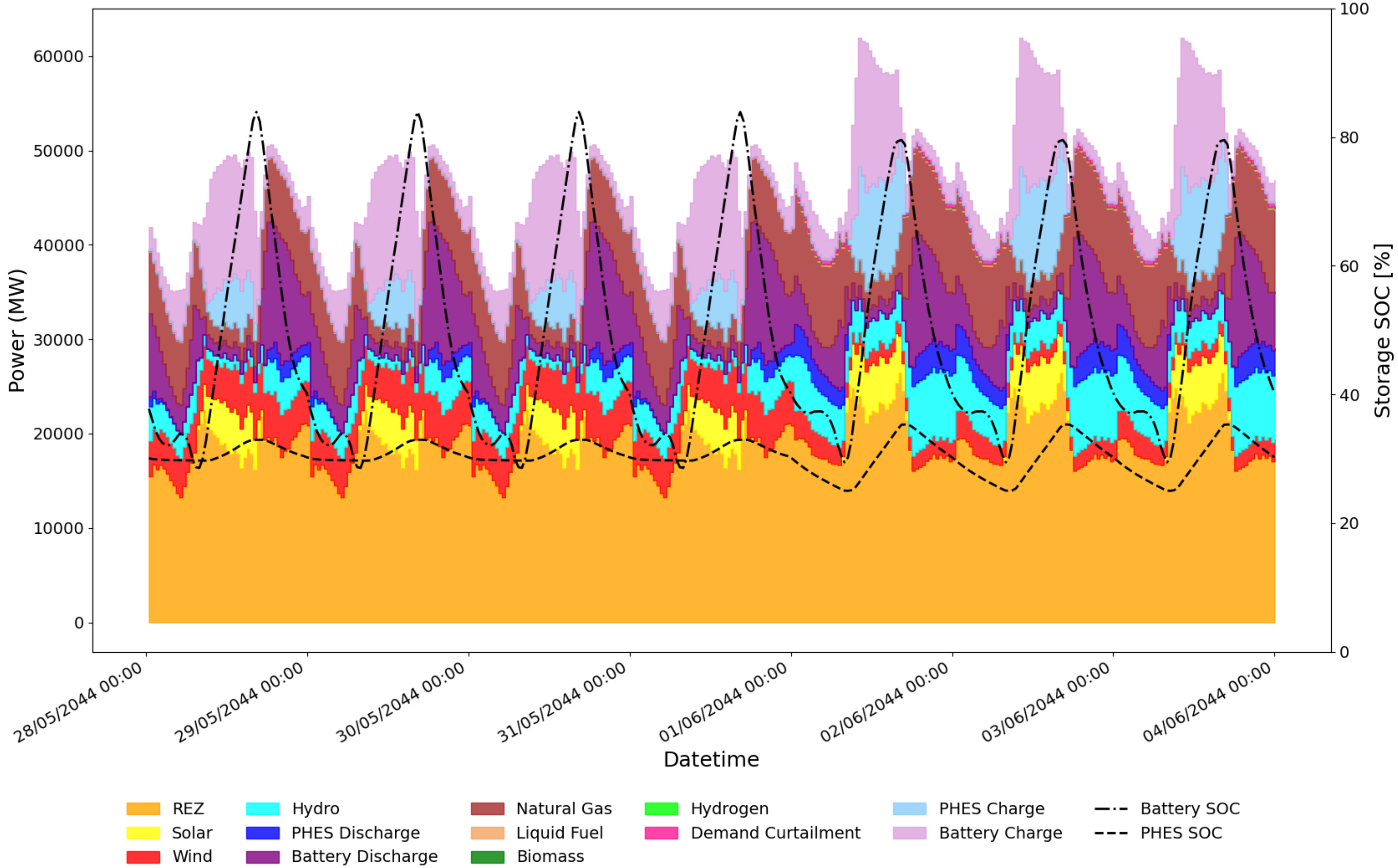


Figure 7. Sampled Chronology (2 days per month) for Challenging Week



Influence of Time Resolution (12 blocks vs 24 blocks per day)

An additional scenario using fitted chronology, with 24 blocks per day fitted according to the weighted least squares method, was run using the simplified single step model in PLEXOS. Due to time constraints, full chronology was not able to be modelled for this submission. Regardless, the results of increased time resolution indicate that there is value in exploring higher time resolution within the Detailed Long Term ISP capacity expansion model.

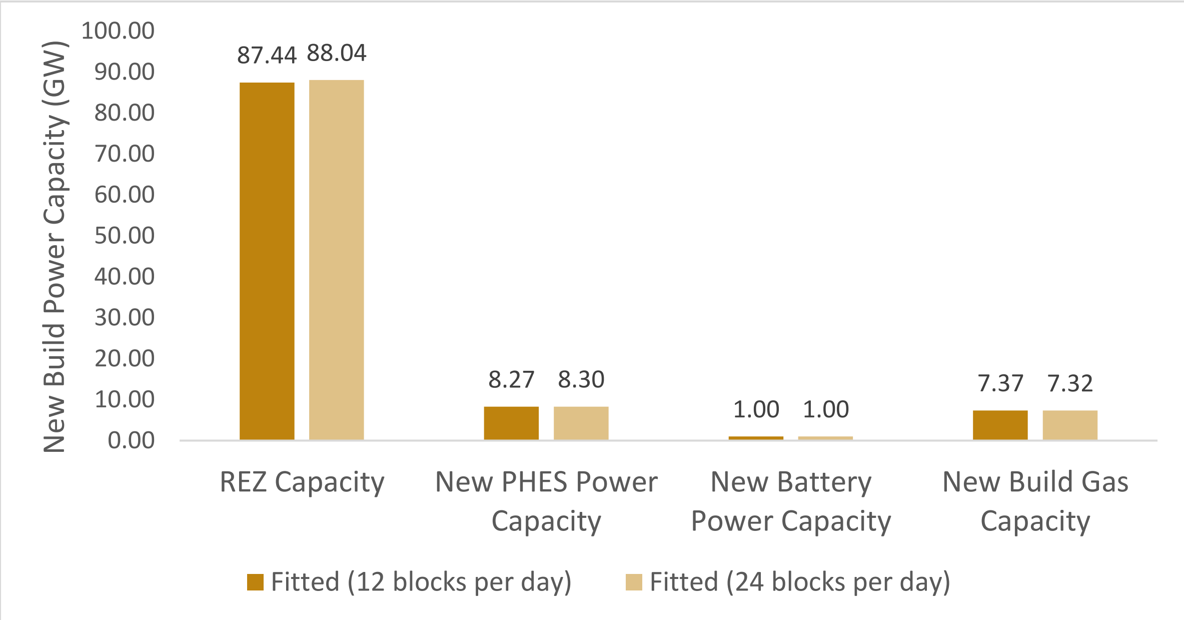


Figure 8. Change in New Build Power Capacity (2043-2045) from Increased Time Resolution

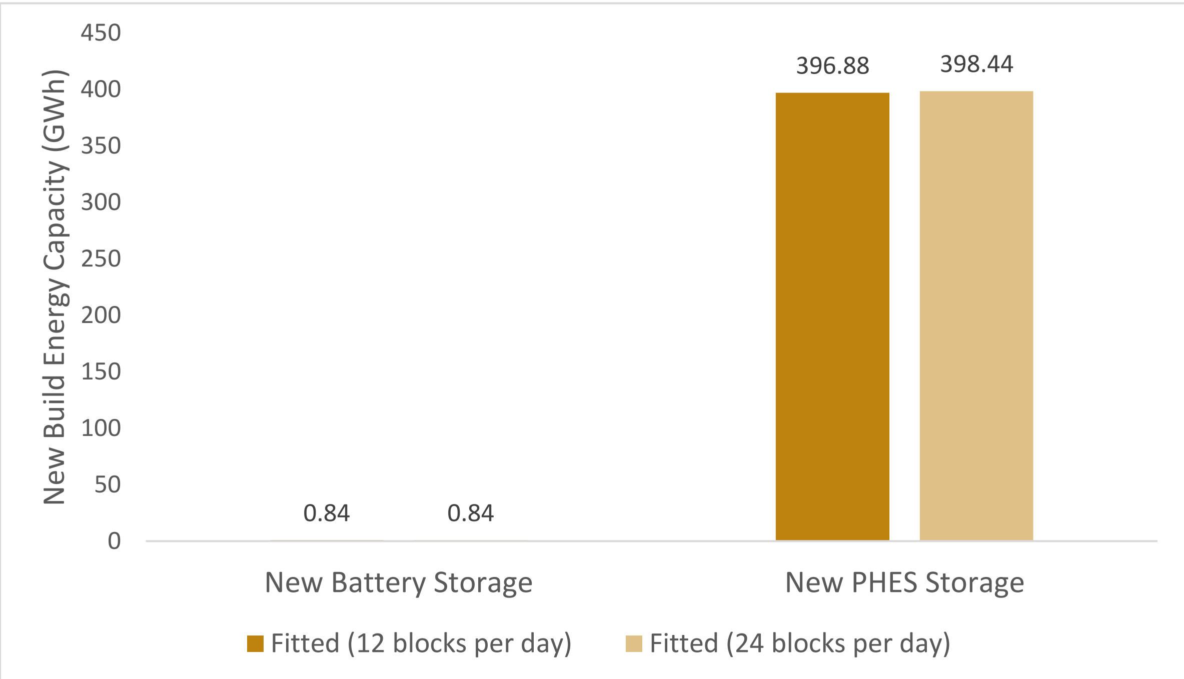


Figure 9. Change in New Build Energy Capacity of Storage (2043-2045) from Increased Time Resolution

Increasing the time resolution for fitted chronology from 12 blocks per day to 24 blocks per day resulted in a slight increase in the capacity of new build pumped hydro and REZ, and a slight decrease in new build gas. The results of this preliminary analysis do not indicate that fitted chronology simplification has had a material impact for this specific model (3-year time horizon from 2043 - 2045), but the results indicate that there is value in exploring the impact of this simplification within the ISP further. The Detailed Long Term model for the ISP uses 7-year steps with an 8 block per day resolution - increasing the time resolution for the ISP model may drive a more material increase in REZ and storage capacity, as well as a decrease in gas capacity.

Both low resolution fitted chronology and sampled chronology appear to advantage gas and disadvantage energy storage compared to full chronology in capacity expansion modelling. The sampled chronology simplification appears to have a more material impact on the results from this preliminary analysis, but the results indicate that further investigation of both mechanisms is worthwhile. Adding in PHES storage durations longer than 48 hours and lowering mainland PHES costs could exacerbate these results.

Computational Feasibility of a High-Resolution, Full Chronology Model

Linear programs may become computationally intractable at long time horizons and high time resolutions. This is because the electricity generated at each time interval for each generator at each spatial node is a decision variable, along with the capacity of the generator at that node. AEMO notes that the Single Step Long Term model already takes 3 days to complete a single optimisation. Our test of a 24-block day using fitted chronology and a step size of 7 years took 91.5 hours to complete the optimisation. It is clear that a powerful workstation or use of a supercomputer would be required for a 28-year step size. Given this aspect of the model design could have a significant impact on investment behaviour and government policy for the entire NEM over the next 26 years (including whether or not any new gas generators actually need to be built), investment in the computational infrastructure required to accurately perform this long-term planning process should be considered essential.

One method of addressing the computational complexity may be to simplify other aspects of the linear program that drive up the number of decision variables. For example, aggregating spatial nodes together, further aggregating generators of the same technology together, or excluding technologies with very small market shares from the capacity outlook model will reduce the number of decision variables. Some of these assumptions may have an immaterial impact upon capacity outlook results compared to the effects of sampled or fitted chronology. AEMO should perform an analysis of options to simplify the Single Step Long Term and Detailed Long Term capacity outlook linear programs to enable full chronology to be modelled, while minimising the impact of any new simplifications on the modelling results.

An alternative to a linear program is the use of a non-linear program for the capacity outlook modelling. The ANU has developed a non-linear program for energy balance modelling called FIRM,[18] the principles of which are relevant to this discussion.

A non-linear model would only require a decision variable for the capacity of each generator at each node, not the electricity generated for each time interval by that generator. Instead, generation is rules-based in a non-linear model. For example, solar generation is simply the interval capacity factor (based on a solar trace data sheet) multiplied by the capacity of the generator at that node (the decision variable). A deterministic function may iterate through each time interval to determine whether a storage system dispatches or not, keeping track of the state-of-charge along the way. A non-linear optimisation algorithm (e.g., differential evolution) is used to find the least-cost configuration of capacities, dispatched according to the deterministic rules, to perform the energy balance every interval. Other constraints, such as build limits, can still be defined within the program as normal.

[18] https://doi.org/10.1016/j.energy.2020.119678

Of course, non-linear programs have their own limitations. Notably, it is challenging to remove merit order behaviour from the rules (e.g., batteries always dispatching before pumped hydro or vice versa). This remains an area of research by the RE100 Group. Determining whether the global optimum has been found by the optimisation algorithm, rather than a local optimum, may also require additional validation steps. Regardless, we suggest that a model which can maintain a high time resolution and full chronology will provide more meaningful long-term energy planning results, despite these additional challenges.

As an interim solution, the most difficult few years should be identified with low resolution modelling using the existing linear program. The most difficult years determine the maximum required capacity of the energy system. It is important to model years rather than weeks to enable seasonal storage behaviour to be captured by the model. These years (and the years either side) can then be modelled at high resolution while maintaining full chronology.

Response to Issues Paper: Question 9

Do you agree with AEMO's approach to model storage devices with headroom and footroom energy reserves and imperfect energy targets in the time-sequential modelling component?

What improvements should be made to model energy storage limits to better reflect actual behaviour and address issues of 'perfect foresight'? Please provide any supporting evidence.

Current research suggests that the inclination to create an unnecessarily accurate model counterproductively increases model uncertainties and produces less accurate results.[19] The uncertainties associated with any long-term modelling scenario are always significant. Significant, pertinent, and unavoidable sources of uncertainty in the ISP models include using historical weather, generation, and demand data to forecast variable renewable generation and future demand profiles out over 28 years. The inclusion of unscheduled maintenance, an unnecessary disaggregation of hundreds of generators, and attempts to predict bidding behaviour out to 2050 in the time-sequential model increases model complexity and computation time while potentially offering no real insights to system behaviour beyond the uncertainties of the model's inputs. Moreover, ballooning model complexity and computation time limits the degree to which insightful and relevant behaviours can be understood within the model, namely around storage behaviour. It is difficult to actually identify mechanisms that may drive certain behaviours of market participants when there is a need to sift through dozens of independent variables.

7. **"All models are wrong, but some are useful". AEMO should focus on what useful information can be extracted from the time-sequential model, and not continue attempting to make it less wrong through arbitrary increases in complexity that are very likely to counterintuitively cause more uncertain estimates. The proposed inclusion of imperfect foresight for energy storage scheduling and headroom/footroom energy reserves are not expected to bring the model closer to reality or provide useful insights into actual energy storage operator behaviours.**

The issues paper suggests addressing the discrepancy in behaviour between ideal storage dispatch behaviour and real-world, risk minimisation and profit maximisation storage behaviour. The root cause of this discrepancy is not perfect foresight modelling, but is instead non-ideal behaviour of operators, driven by risk management. Indeed, if operators were to operate without risk management, the current use of a perfect foresight model would produce very realistic results; the combination of the dispatch re-bidding mechanism (for close to real-time adjustments in bidding behaviour) and long-term forecasting (which allows operators to anticipate winter deficits months in advance) although imprecise, would allow very close to ideal behaviour.

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[19] Paper: https://doi.org/10.1126/sciadv.abn9450
Corresponding media article: https://theconversation.com/how-a-quest-for-mathematical-truth-and-complex-models-can-lead-to-useless-scientific-predictions-new-research-192454

The ISP's approach of derating storage assets does not address the root cause of the model's discrepancy but only serves to unnecessarily and unhelpfully limit the design space of the model. The suggested change to include headroom and footroom reserves, rather than simply derating the asset, is still not expected to improve model accuracy relative to actual operator behaviour. A short-duration storage system focused on arbitrage revenue and ancillary service markets will be less focused on maintaining reserves since they generally participate in predictable short-term energy events. A long-duration storage system may form an energy reserve contract and focus on infrequent high-price events in winter. The energy reserve decisions for these different time-shifting services are completely different and will be driven by operator-level risk management strategies and the specifics of each energy reserve contract. Furthermore, the risk-management behaviour of storage operators is not at all random or stochastic and so the proposed imperfect forecasting approach will also not truly bring the modelled operation of the system closer to reality. It would likely add computational overhead for little improvement to model realism while further muddying the waters when trying to extract useful information related to system operation.

Including low-power (GW), high-energy (GWh) storage (i.e., large-scale pumped-hydro) would rectify much of the mismatch between operators' and ideal behaviours; such large-scale storage would be easily managed by long-term contract and behave closer to a system service than a spot-market traded commodity. Any development of further low-power, high-energy storage would dominate the system energy storage capacity; when complete, Snowy 2.0 alone will constitute the majority of energy storage capacity in the NEM. Given this dominance, inaccuracy in the behaviour of high-power, low-energy storage—which is dominated by spot-market trading and risk management rather than long-term contract— would be insignificant to overall model behaviour.

Moreover, the time-sequential modelling is ill-equipped to model the behaviour of high-power, low-energy storage by nature of the time resolution. High-power, low-energy systems exploit and mitigate volatility on the minutes-hours timescale, including extracting revenue from ancillary service markets. The low end of this timescale is not adequately reflected in the time-sequential modelling. The relatively long time frames are a significant fraction of the storage capacity and therefore cannot adequately model real behaviour. This unfairly disadvantages these storage systems compared to gas. In reality, the storage system may ramp between charge and discharge frequently as it exploits solar, wind, and demand volatility - this not only allows the storage to last longer than modelled but improves the storage system's ability to recover its capital cost which lowers the consumer cost of electricity beyond AEMO's model.

In the time-sequential model, it is essential for long-duration storage such as pumped hydro to have visibility of many months when scheduling dispatch. Since long-duration storage operators will be focused on maintaining energy reserves for winter dunkelflaute (where they receive revenue from energy reserve contracts and infrequent arbitrage of high-value energy in calm, cloudy weeks), scheduling behaviour within the model must allow the system to have knowledge of these periods. Rebidding under actual dispatch conditions should allow storage systems to adequately respond to the effects of imperfect foresight in reality, and the proposed inclusion of imperfect forecasting in the time-sequential model is expected to overcorrect for forecasting effects. The inclusion of footroom and headroom reserves for all energy storage systems is also not expected to provide useful results that represent real operator behaviour - a long-duration PHES with an energy reserve contract will maintain very different reserves to a short-duration battery or overnight PHES that is trying to maximise short-term spot market and ancillary service revenue.

Kind regards,

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