Pumped Hydro Energy Storage

Parameter Review

Australian Energy Market Operator

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→ **The Power of Commitment**

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Executive summary

For Australia to achieve its decarbonisation goals, there is an important requirement for expansion of energy storage in the National Electricity Market. To ensure the Australian Energy Market Operator's (AEMO's) forecasting and planning functions are viable, a comprehensive set of input assumptions governing the behaviour of energy infrastructure assets, economics and location of future investments and retirement decisions is required.

The primary purpose of this study is to develop an updated dataset of economic and technical parameters for potential new Pumped Hydro Energy Storage (PHES) in the National Electricity Market (NEM) to support AEMO's technical planning. The main objectives are to identify:

– sites and locations for PHES projects,
– estimate maximum build capacities and
– provide locational cost factors.

This report supports the updated dataset and provides a detailed summary of the methodology, assumptions and findings.

Pumped Hydro Energy Storage is an essential component in Australia's energy future, being the largest and most technologically mature form of medium and long duration energy storage currently accessible. PHES makes up approximately 95% of existing energy storage capacity worldwide and is the only technology with a technology maturity appropriate to supply long duration storage (CSIRO 2023).

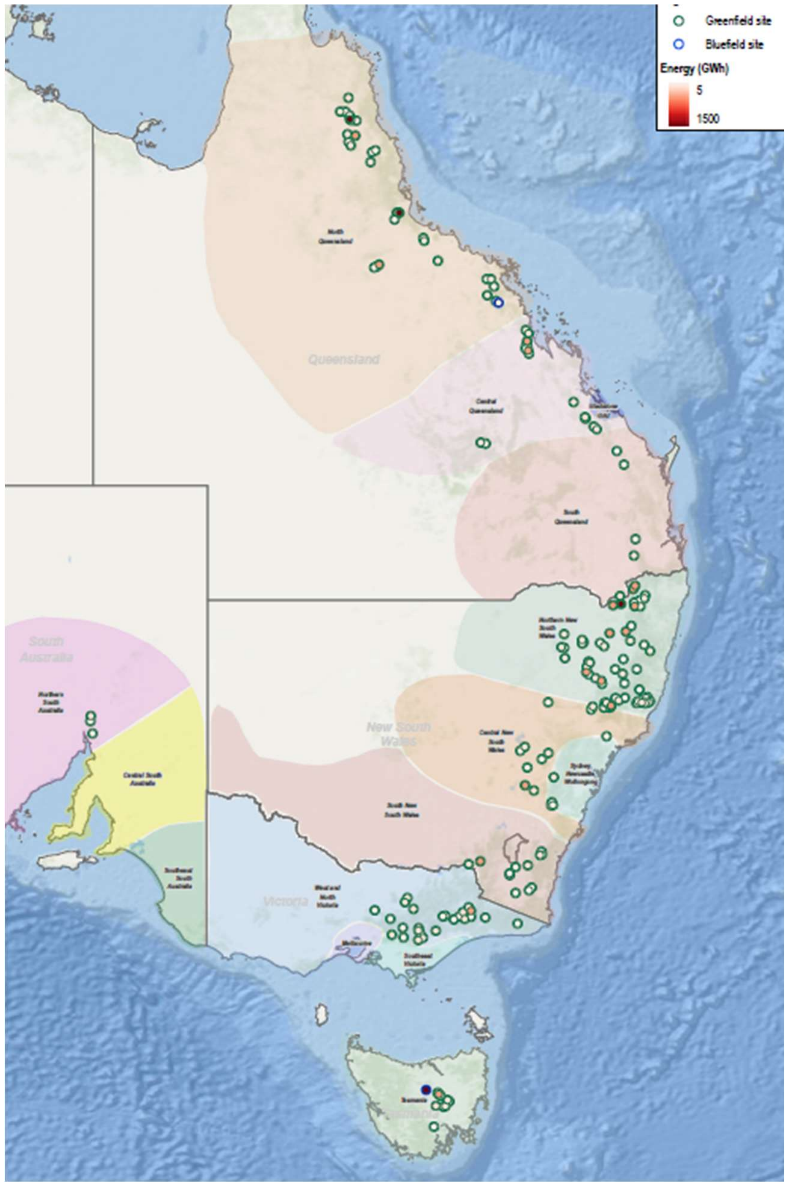
There is a clear trend that medium to long duration storage has been the typical historical use for PHES and that longer duration storage is anticipated to become more important as baseload is retired. For this reason, this study has included 10, 24 and 48 hour duration storage consistent with previous ISP development and has also included a further category for 160 hour storage. This very long storage duration takes advantage of a key aspect of PHES that duration can be extended (increasing MWh stored) by only increasing the volume of water stored, typically by increasing the size of the two dams, while all other costs remain relatively the same for the same installed power output (MW).

The first step in analysis of potential sites and locations was to consider publicly announced PHES projects based on a review of public databases and internet sites. **Forty publicly announced PHES schemes were identified with a combined total of more than 22,000 MW and 329,000 MWh of energy storage**. This excludes Snowy 2.0 and Borumba Pumped Hydro which are already considered in AEMO's forecasting.

Maximum Build Capacity is defined as the highest feasible installed capacity (in megawatt hours), that can be developed at a specific hydropower site, or the upper limit of energy storage capacity that a site can support. For this study, the Maximum Build Capacity has been aggregated for each National Electricity Market sub-region by identifying and combining possible projects within the sub-region and was estimated by combining two datasets; the publicly announced projects at their announced capacity & duration, and the Australian National University Pumped Hydro Energy Storage Atlas. GIS screening was applied to the Australian National University Pumped Hydro Energy Storage Atlas data to exclude sites that may be impacted by high environmental value or approvals challenges.

Combining the publicly announced projects and Australian National University database projects results in a total estimated **Maximum Build Capacity of 124,600 MW** and a **total energy storage capacity of 7,460 GWh**. This represents more than 10 times the total energy storage requirement identified in the AEMO (2024) ISP. Hence, total energy storage (GWh) with optimal PHES sites is not a limitation for future planning.

This represents a significant increase in maximum build capacity than previously assumed in the ISP, because previous studies were limited to PHES sites within renewable energy zones and not the entire NEM. Interestingly, the new project database is relatively closely aligned with the publicly available database, with the majority of projects in central and northern New South Wales and central and northern Queensland. There were significantly fewer projects identified in Victoria and South Australia, where topography and the GIS screening approach limit the potential scheme sizes.



AEMO's approach to modelling is that base costs are developed for construction within metropolitan areas and locational cost factors are applied where projects are proposed outside of metropolitan areas. The calculation of the locational cost factors has considered: equipment costs, installation costs, fuel connection costs, cost of land and development, and a topography cost factor.

The topography cost factor was introduced to account for the impact of topography on PHES construction within each NEM subregion. This may be impacted by the waterway length to head ratio, extent of dam embankment due to varying topography and installed capacity due to head and storage size. The topography factor was developed by preparing parametric cost estimates for each site included in the Maximum Build Capacity, then comparing costs for each subregion with national averages.

As Pumped Hydro Energy Storage projects are all unique with many project specific complexities and risks, determining a realistic locational cost factor is difficult and will not represent every individual project. Instead, these factors were developed for each NEM subregion to assist planning at this scale.

The parametric cost estimates from this study and other recent studies such as CSIRO Gencost and Aurecon 2024) have confirmed that battery energy storage systems (BESS) is lower cost for short duration energy storage and provides numerous ancillary services to power networks, but PHES is lower cost for longer duration. The change point in comparative costs for energy storage appears to be at approximately 8-10 hours duration. For storage durations longer than 10 hours, PHES becomes lower initial capex cost per MWh of storage and has a significantly longer project lifetime. Revenue modelling will typically show that the value of cost arbitrage (buy low, sell high) that is the main component of market revenue for energy storage will be difficult to justify for long duration storage projects. It is essential that government policy support these long duration projects if they are identified as required by AEMO's modelling.

This report is subject to, and must be read in conjunction with, the limitations set out in section 1.2 and the assumptions and qualifications contained throughout the report.

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Acronyms

Acronym	Meaning
AEMO	Australian Energy Market Operator
ANU	Australian National University
GG	Gladstone Grid
CNSW	Central New South Wales
CQ	Central Queensland
CRI	Commercial Readiness Index
CSA	Central South Australia
CST	Concentrated Solar Thermal
EPC	Engineering, Procurement, Construction
GIS	Geographic Information System
GWh	Gigawatt-hour
IASR	Inputs, Assumptions and Scenarios Report
IHA	Internation Hydropower Association
ISP	Integrated System Plan
MEL	Melbourne
MW	Megawatt
MWh	Megawatt-hour
NEM	National Electricity Market
NNSW	Northern New South Wales
NQ	North Queensland
NSA	Northern South Australia
PHES	Pumped Hydro Energy Storage
REZ	Renewable Energy Zones
RFP	Request for Price
SESA	South East South Australia
SEV	South East Victoria
SNSW	South New South Wales
SPHES	Seawater Pumped Hydro Energy Storage
SQ	South Queensland
TAS	Tasmania
WEM	Wholesale Electricity Market
WNV	West and North Victoria

1. Introduction

The Australian Energy Market Operator (AEMO) manages the National Electricity Market (NEM) across eastern and south-eastern Australia and the Wholesale Electricity Market (WEM) in Western Australia. AEMO's core objective is to promote efficient investment in and operation of Australia's electricity and gas services to ensure long-term benefits for consumers in terms of price, quality, safety, reliability, and security of energy supply.

To achieve Australia's decarbonisation goals, there is a pressing need for significant expansion of energy storage in the NEM. The current storage capacity within the NEM is 3GW, with a forecast requirement for 22GW by 2030 and 49GW / 646 GWh by 2050 to achieve the transition to net zero emissions.

Pumped Hydro Energy Storage (PHES) currently supplies 95 percent of all energy storage worldwide and is an essential method of long duration energy storage. AEMO has commissioned GHD to review and update technical and economic parameters for potential new PHES developments within the NEM, focusing on investigating sites, locations, maximum build capacity, and locational cost factors for potential pumped-hydro energy storage (PHES) projects in NEM.

AEMO's forecasting and planning functions rely on a comprehensive set of input assumptions that govern the behaviour of energy infrastructure assets, and on the economics and location of future investments and retirement decisions. Energy storage is a cornerstone of AEMO's strategic planning, particularly for the Integrated System Plan (ISP). Accurate and consistent input assumptions are vital for robust forecasting and planning.

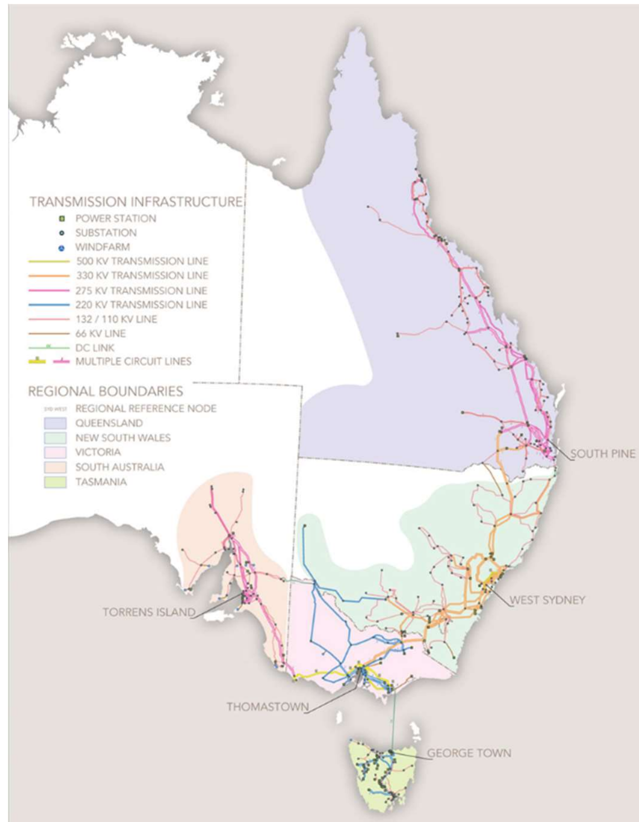

Figure 1 National Electricity Market (NEM) Regions

1.1 Purpose of this report

This report addresses Part 2 of the AEMO 2025 RFP, focusing on economic and technical parameters for potential new PHES in the NEM. The objectives of this study are to:

- Identify sites and locations for PHES projects
- Estimate maximum build capacities
- Provide locational cost factors, including capital and operating costs

The primary purpose of this exercise is the development of an updated dataset for AEMO to use in the execution of their planning functions. This report supports the dataset and provides an overview of the scope, methodology and assumptions used in its development, along with a list of definitions for terms used in the dataset.

1.2 Scope and limitations

Updated cost estimates for PHES (including CAPEX and OPEX) do not form part of this scope of services. This scope encompasses an updated dataset and supporting report identifying sites and locations for PHES projects, estimating maximum build capacities and providing locational cost factors.

Only databases listed within this report have been considered. Mine void PHES and sea water PHES have been excluded from the maximum build capacity assessment.

Locational cost factors have considered possible regional variations based on parametric costing of PHES components and major project construction locational cost factors. Site specific costs such as geology, water supply, complex access and biodiversity offset costs have not been considered.

The updated datasets obtained through this review will be integrated into AEMO's forecasting and planning studies and published on the AEMO website. This data will be utilised by AEMO and may also be shared with industry stakeholders to inform market simulation studies for medium and long-term forecasting purposes. Additionally, the dataset will serve as a critical input for AEMO's Integrated System Plan (ISP), with consultation on these inputs guided by the Australian Energy Regulator's Forecasting Best Practice Guidelines.

This report has been prepared by GHD for Australian Energy Market Operator and may only be used and relied on by Australian Energy Market Operator for the purpose agreed between GHD and Australian Energy Market Operator as set out in section 1.1 of this report.

GHD otherwise disclaims responsibility to any person other than Australian Energy Market Operator arising in connection with this report. GHD also excludes implied warranties and conditions to the extent legally permissible.

The services undertaken by GHD in connection with preparing this report were limited to those specifically detailed in the report and are subject to the scope limitations set out in the report.

The opinions, conclusions and any recommendations in this report are based on conditions encountered and information reviewed at the date of preparation of the report. GHD has no responsibility or obligation to update this report to account for events or changes occurring subsequent to the date that the report was prepared.

The opinions, conclusions and any recommendations in this report are based on assumptions made by GHD described in this report (refer section 1.3 of this report). GHD disclaims liability arising from any of the assumptions being incorrect.

1.3 Assumptions

The following assumptions have been used throughout this report:

– Publicly available material used in the assessment, as obtained from various online sources was assumed to be factually correct. It is likely that further project development has occurred and scheme data will have changed, but where this has not been publicly announced it could not be used. Where cost estimate data was available in public information, this study aimed to obtain the scheme technical data from the same time even when more recent project updates had modified this technical data.
– Geographical Information Systems (GIS) data has been obtained from publicly available sources. Further details of the data obtained are provided in Section 6.
– A desktop study was assumed to be adequate for identifying potential sites. No site specific PHES scheme has been carried out. No site visit or site-based investigations were included in the scope

Identified sites, that may be candidates for development, would be subject to further studies (e.g. pre-feasibility, feasibility etc.) in line with the typical approach applied to the development of infrastructure of this type. Further analysis of sites may reveal issues that could affect the site development. Therefore, the recommendations made in this report note the need for further site-specific analysis prior to site selection and development.

Other assumptions as listed in specific sections of this report.

2. Background

2.1 Pumped Hydro Energy Storage

Pumped hydro energy storage (PHES) schemes allow energy to be stored using the potential energy between two reservoirs separated in elevation, acting like a battery. This is undertaken by storing water in a ‘top reservoir’, water is released and passed through turbines, generating energy. The water is then stored in a ‘bottom reservoir’, where it can be pumped back up to the ‘top reservoir’ either during off peak periods, when there is excess power in the grid, or using alternative methods of renewable energy such as solar. This makes PHES an effective tool in managing the demand for electricity and ensuring requirements are met during peak periods, which is achieved using alternative renewable energy sources when they are available (i.e. solar during the day) to pump water / energy into storage for use when alternative renewable energy sources are not available (i.e. solar during the night).

A single electrical machine can function as either a motor, driving a pump, or a generator, being driven by a turbine. In most cases, the pump and turbine are the same item, operating in either the forward or reverse rotational direction, a so-called “reversible pump-turbine”, but in most of the current installations in Australia, the pump and the turbine are mounted on the same shaft and rotate only in one direction.

Energy market modelling indicates long duration storage technologies such as PHES schemes are expected to play an important role in the energy transition and contribute to Victoria meeting its renewable energy targets and energy storage targets. This report explores the locational potential of PHES in the NEM and provides AEMO with options to meet future storage needs.

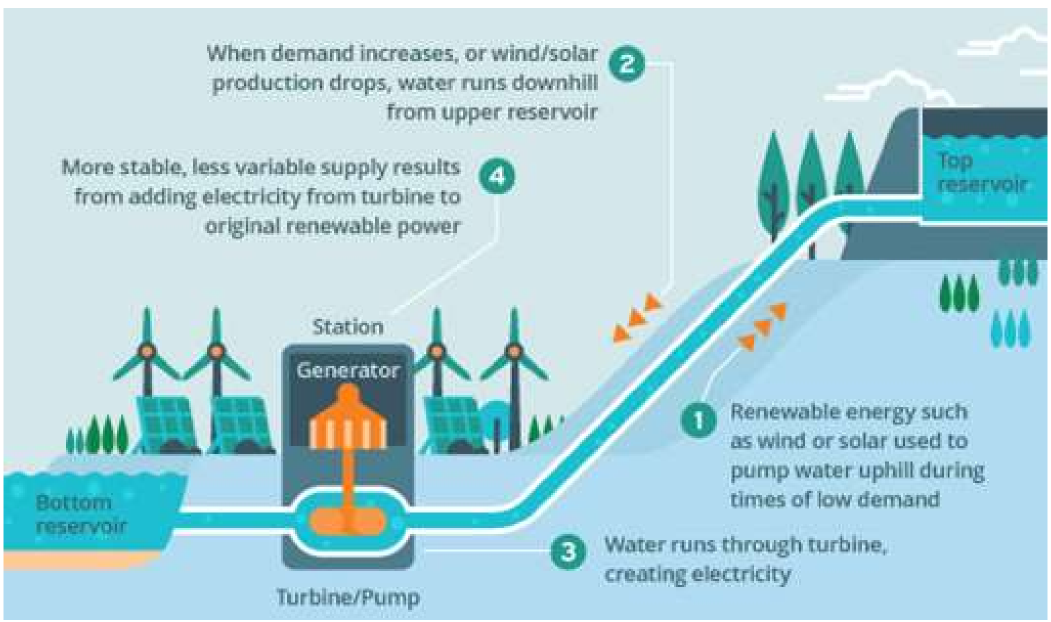

Figure 2 Pumped Hydro Energy Storage process[1]

Potential sites to facilitate PHES can be categorised as:

– **Greenfield**: closed loop system, with two new reservoirs located off-river, and not connected to an existing reservoir, an example project is shown in Figure 3

– **Bluefield**: one or both reservoirs utilise a part, or the entirety of, an existing reservoir or reservoirs, an example project is shown in Figure 4

– **Mine-Void**: one or both reservoirs utilise an existing mine void.

Reservoir types can be described as:

[1] How could pumped hydro energy storage power our future? Australian Renewable Energy Agency (ARENA)

- **Turkey's Nest:** above ground reservoir with embankment around the full perimeter
- **Gully Dam:** reservoir is formed by dam across a valley. A 'dry gully' is a gully which typically has no surface flow, while a 'wet gully' has constant or frequent ephemeral flow.

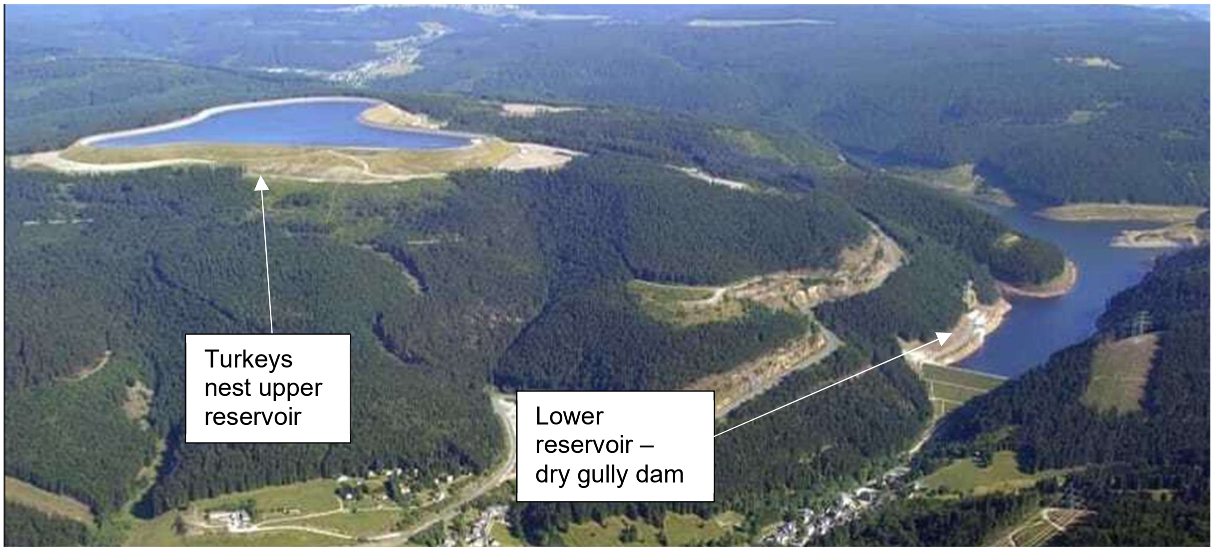

Figure 3 Example Greenfield site

Figure 4 Example Bluefield site

3. Trends and Insights

3.1 The need for PHES

Pumped Hydroelectric Energy Storage (PHES) is the largest and most technologically mature form of medium and long duration energy storage currently available that accounts for approximately 95% of total existing energy storage capacity worldwide. The Long Duration Energy Storage Council (LDES 2021) in a global study showed that long duration storage, including pumped hydro, will play a crucial role in helping create the system flexibility and stability required by an increasing renewable share in power generation, alongside other technologies such as Lithium-ion (Li-ion) batteries and hydrogen turbines. This aligns with AEMO’s 2024 Integrated System Plan that confirms firming technology like pumped hydro, batteries, and gas-powered generation will be required to smooth out the peaks and fill in the gaps from variable renewable energy.

CSIRO (2023) prepared a Renewable Energy Storage Roadmap for Australia. The study determined that PHES is internationally deployed and commercially competitive and capable of medium (4-12 hours), long (12-100 hours) and seasonal (>100 hours) grid storage. A key advantage is the economy of scale, with large opportunity to reduce cost per unit of energy (MWh) for larger systems.

Figure 5 from CSIRO (2023) identifies that PHES likely has commercial applicability for all storage durations greater than 4 hours, and is the only technology with a maturity (commercial readiness index CRI of 6 indicating competitive commercial deployment) appropriate to supply long duration storage. Hence, PHES is an essential part of Australia’s energy future.

DURATION	PHES	Li-ion batteries	CsT (molten salts)	VRFB
Maturity (CRI)[127] in grid scale applications	6	5–6 (short duration) 3-4 (medium duration)[128]	4–5 3–4 (small scale)	3–4 3 (long duration)
Short (<4 hours)	◑	●	◑	●
Medium (4 to 12 hours)	●	●	●	●
Intraday storage (>12 to 24 hours)	●	○	●	○
Multiday storage (>24 to 100 hours)	●	○	◑	○
Seasonal storage (>100 hours)	●	○	○	○

Legend: ● Likely commercial applicability ◑ Partial commercial applicability ○ Unlikely commercial applicability or insufficient data in specified duration for grid-scale use

Figure 5 ***Summary of applicable durations for energy storage technologies in utility scale grid applications (CSIRO 2023)***

(note figure continues in CSIRO report but has non commercially mature schemes with CRI of 1 to 3).

3.2 Optimal PHES Schemes

PHES schemes are typically associated with high capital costs due to their scale and many site specific development considerations. Given the wide range of potential project capital costs, it would be most reasonable to estimate that projects at the lower end of the capital cost scale are the most suitable to represent optimal pumped hydro sites that can, and should, be delivered into the system.

Some of the criteria for identification of an optimal PHES scheme are listed in Table 1. These criteria may identify fatal flaws for a site where development may not be possible, or a site that is favourable for the majority of the criteria may be suitable for further consideration as a potential optimal PHES scheme.

This study has aimed to screen sites as far as practical based on topography and social / environmental datasets.

Table 1 Criteria for identification of an optimal PHES scheme

Criteria	Considerations
Topography	– Available head – Reservoir geometry – Waterway length / head ratio – Site access and constructability
Geology	– Ground conditions, groundwater conditions, lithology and structural considerations
Hydrology	– Likely availability of water for initial fill and top ups – Water quality – Flood and weather risk – Impacts on downstream catchments
Network	– Proximity to transmission lines and substations
Social	– Impact on recreational areas – Amenity impacts – noise, visual, proximity to sensitive locations – Community support – Labour availability
Environment	– Potential environmental impacts on biodiversity and ecology – Cultural heritage
Planning	– Current land use and zoning – Land access / acquisition – Permit approvals

3.3 Existing and under construction PHES schemes

3.3.1 Australia

Australia has a long history of PHES operation with the following three schemes being constructed in the 1970s and 1980s:

- Wivenhoe (570 MW / 5700 MWh, 10 hours)
- Shoalhaven (240 MW, 24 hours)
- Tumut 3 (900 MW) – Conventional hydropower scheme with three of six units installed as pump turbines for PHES. Generation duration depends on conventional hydropower operation but could be multi-day.

Australia is undergoing a significant expansion of its pumped hydro infrastructure to enhance energy storage and grid stability, particularly as the country transitions to a higher proportion of renewable energy. Schemes currently under construction in Australia include:

- Snowy 2.0 (2000 MW / 350,000 MWh, 175 hours) – Very long duration storage capable of supplying energy for a week, supported by the Federal Government. The project involves linking two existing reservoirs (Tantangara and Talbingo) with 27 km of tunnels and constructing a new underground power station.
- Kidston (250 MW / 2000 MWh, 8 hours) is being developed by Genex /J-Power on a former gold mine in North Queensland, Australia. It utilizes two mining voids at different elevations as reservoirs, with a tunnelled waterway and underground powerhouse.

These existing and under-construction schemes are not included in the maximum build capacity estimate in this study.

Borumba Pumped Hydro (2000MW / 48,000 MWh, 24 hours) being developed by Queensland Hydro is currently undergoing early works onsite. This project is already assumed to be committed in AEMO planning and has been excluded from the maximum build capacity estimate.

3.3.2 International projects

The *International Hydropower Association* (IHA 2022) notes that Pumped Storage Hydropower is the largest form of renewable energy storage, with nearly 200 GW installed capacity with over 400 projects in operation. The IHA database presents a global portrait of PHES in operation, under construction as well as projects that are planned. Figure 6 shows PHES projects in operation (green circles) under construction (blue circles) and planned (yellow circles) with the size of the circles displayed indicating the installed capacity.

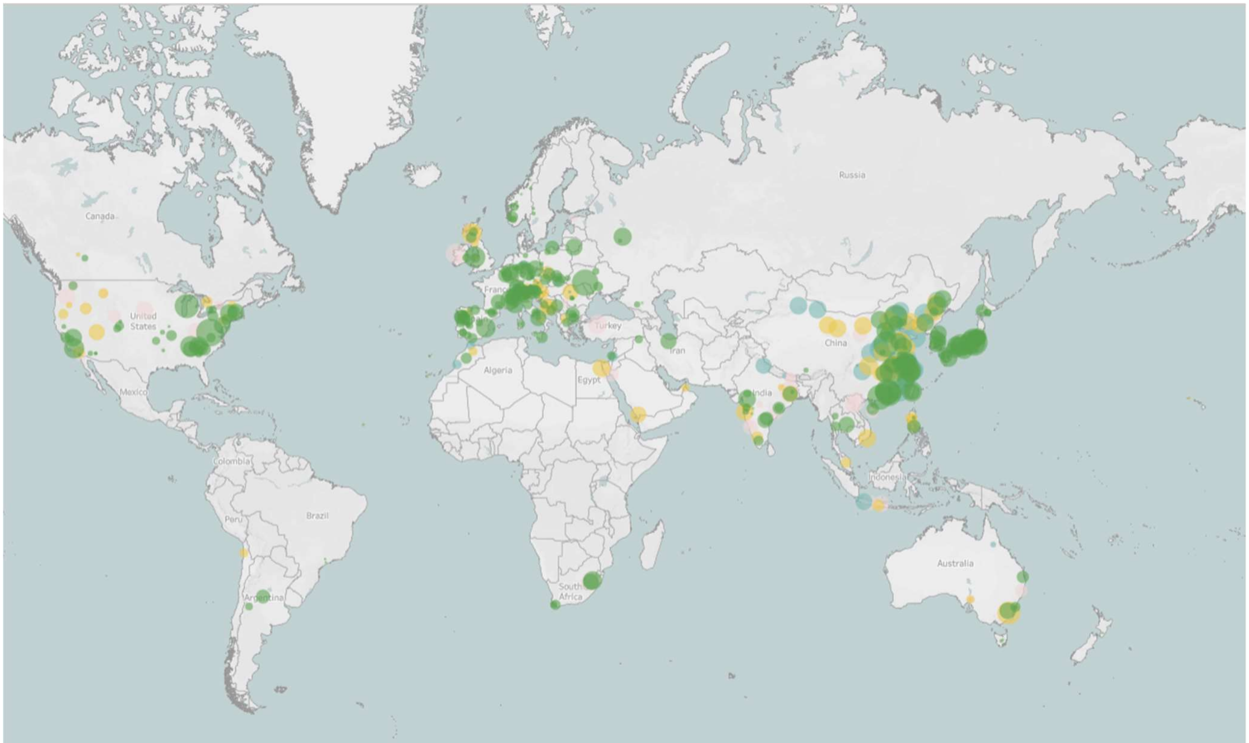

Figure 6 PHES in operation (green), under construction (blue) and planned (yellow) according to the IHA

The number of sites shown in Figure 6 is summarised in Table 2. Note that GHD has identified certain sites currently under construction that are not shown in Figure 6, particularly in China.

Table 2 Number of PHES sites internationally

Continent	In operation	Under construction	Planned
Europe	164	5	16
Asia	103	32	35
Americas	40	0	12
Africa	5	2	2
Oceania	3	2	2
Total	**315**	**41**	**67**

The approximate year of commissioning (or forecast year of commissioning) of these global PHES projects is shown in Figure 7. PHES has been constructed at a steady rate as the preferred energy storage system to balance large baseload systems over more than half a century, but the transition to intermittent renewables requiring storage is clearly evident in the large uptake of new PHES projets in this decade. It can be anticipated that similar increase in demand for new PHES will continue in the next decade.

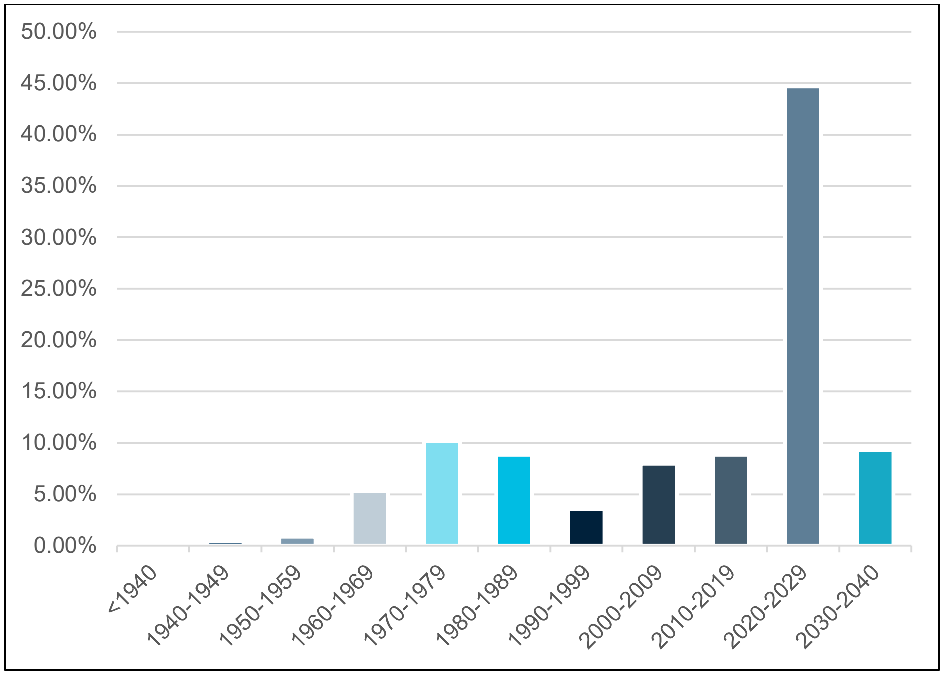

Figure 7 Distribution of sites according to their year of commissioning

3.4 Storage duration

Review of existing international PHES schemes larger than 1000 MW found of the 25 schemes with published data for capacity and storage, the storage duration varied from 4 to 28 hours with an average of 11.6 hours.

Section 5 of this report presents a review of publicly announced PHES projects in Australia. The scheme capacity varies widely based on the site and energy market limitations, with government projects typically larger than private developments. The minimum storage duration of existing and proposed schemes in Australia (excluding mine or quarry repurposing) is 8 hours with most government-implemented schemes being 24 hours or greater. For comparison, the NSW Government Long Term Energy Service Agreement (LTESA) for Long Duration Storage is targeting a storage duration of at least 8 hours, with a preference for greater than 12 hours.

With the significant improvement in battery technology and costs for short duration storage future use of PHES schemes will likely be different to past applications. CSIRO (2023) modelled levelised cost of storage (LCOS) for a range of technologies and concluded that "For the specific 8-hour (230 and 285 annual cycle) storage duration cases, PHES was estimated to have the lowest cost in the near term. In the long term, CST storage was estimated to have the lowest cost for the cases analysed". BESS was also lower cost than PHES for 8 hour storage in the long term.

While some 8 hour PHES schemes may be commercially competitive, the real value of PHES is in long duration storage. For example, Snowy 2.0 will provide 85% of NEM energy storage (350 GWh) at ten times lower capital cost ($34/kWh – SnowyHydro 2023) than equivalent BESS and with five times longer lifetime. For 24 and 48 hour storage, the CSIRO (2023) study concluded that PHES was the only technology with a current maturity (commercial readiness index CRI of 6 indicating competitive commercial deployment) appropriate to supply long duration (more than 12 hour) storage.

There is a clear trend that medium to long duration storage has been the typical use for PHES and that longer duration storage is anticipated to become more important as baseload is retired. For this reason, this study has included 10, 24 and 48 hour duration storage consistent with previous ISP development, and has also included a further category for 160 hour storage. This very long storage duration takes advantage of a key aspect of PHES that duration can be extended (increasing MWh stored) by only increasing the volume of water stored, typically by increasing the size of the two dams, while all other costs remain relatively the same for the same installed power output (MW).

4. Methodology

4.1 Previous studies

AEMO Draft 2025 IASR Stage 1 notes that, in line with all other new entrant technologies, sub-regional locational cost factors are applied to PHES options. Unlike those for other technologies, locational cost factors for PHES have been derived based on the relative cost of the natural resource and geology available within each location for PHES development. The factors have been sourced from Entura (2018) Pumped Hydro Cost Modelling report and remain consistent with previous IASRs.

The draft 2025 IASR also notes that AEMO applies build limits (i.e. maximum build capacity) for pumped hydro expansion candidates based on sub-regional estimates detailed by the Entura (2018) report, modified where appropriate to reflect the latest generator development announcements in Generation Information (or announced government development policies).

The Entura (2018) study was a valuable contribution, providing review of available cost information and announced projects at that time as well as an estimate of the maximum build capacity. The report identified potential PHES sites within proposed renewable energy zones with around 24,100MW with energy in storage of 390GWh. Entura only considered potential projects within proposed Renewable Energy Zones (REZs), and only publicly announced projects to 2018. The scope of this current study is to consider maximum build capacity within the entire NEM, not just REZs. There are also many more publicly announced projects as identified in Section 5 of this report. Hence, it is anticipated that a much larger Maximum Build Capacity will be identified than in the Entura study.

GHD (2018) were engaged by AEMO to update estimates of current technology costs and generator performance characteristics for both existing generators and for new entrants to the market. This study included but was not specific to PHES. It identified approximately 25,000 MW and 750 GWh of new entrant PHES capacity in the NEM. The GHD (2018) study also developed regional cost factors which are referenced in the Locational Cost Factors in the current study in Section 7 of this report.

Similarly, in 2024, Aurecon was engaged by AEMO to prepare an updated set of cost estimates and technical parameters for a selected range of generation and storage technologies, including PHES. The study covered parameters related to performance (such as output, efficiency, production rate, and capacity factor), development and operational timeframes, technical and operational characteristics, and cost components. The cost estimates for various technologies were based on the assumption that projects—excluding offshore wind—are located in metropolitan areas within the NEM region. To account for location-specific variations, cost locational factors were developed for components such as equipment, installation, fuel connection, land, development, and operation and maintenance. These were not developed to be specific to PHES. These location cost factors across different NEM subregions have been referenced in the current study.

4.2 Approach to this study

The requirement of this study was to provide updated data including potential new PHES sites and locations in the NEM, maximum build capacity and locational cost factors based on available new data and mapped to ISP sub-regions. The data is to be provided for PHES storage durations of 10, 24, 48 and 160 hours.

Analysis of potential sites and locations was undertaken by firstly considering publicly announced projects using the Renew Economy Atlas: **Pumped Hydro Energy Storage Map of Australia | Renew Economy**. Another good database of current projects in development across Australia with brief descriptions of the projects is provided by Allens **Pumped hydro: current projects in development across Australia**. GHD have carried out a further search of publicly issued statements on pumped hydro projects to capture any projects that are not included in the two references above that should be included. These are identified in Section 6 of this report. These projects have been included in the Maximum Build Capacity assessment.

In addition to the publicly announced sites and locations, the Maximum Build Capacity has been estimated using the Australia National University (ANU) PHES study (Pumped Hydro Energy Storage Atlases | ANU RE100 Group)**.** This was a desktop algorithmic study that identified numerous potential sites across Australia. This data was reviewed in this study using GIS screening to exclude sites that may impact land with high environmental value or approvals challenges. The screening approach is described in Section 6 of this report.

Due to the unique and large scale nature of PHES projects, overall cost of implementation will vary greatly between sites. As such, the locational cost factor for each proposed site has been determined as part of this study in Section 7. The locational cost factor is made up of equipment, installation, fuel, land and development factors and a topography factor which considers site specific topography of the sites. The topography factor is developed by preparing high level parametric cost estimates for each identified scheme within the maximum build capacity. GHD's internal database of unit costs derived from previous projects has been consulted, in conjunction with publicly available data.

This report discusses power (MW) and energy capacity (MWh) of PHES schemes. These are for generation of electricity. The pumping demand for energy storage in a full pump cycle can be assumed to be 1.25 to 1.3 times greater than these values given a typical round trip efficiency for an optimal PHES scheme of approximately 77-80%.

4.3 Availability of Water

Hydrology is not a significant constraint to off-river PHES, neither for initial filling nor replacement of evaporation nor seepage losses. Although, this is sometimes perceived as a reason why PHES cannot be successful in Australia, or at least in certain regions.

Typical initial fill water requirement for PHES in Australia is approximately 0.8 GL per GWh (Blakers et al. 2025). Thus a 1000MW for 12 hour PHES (12 GWh) would require around 10 GL for initial fill. This initial fill is then cycled for many decades with only modest ongoing top up required. For comparison, the Australian Bureau of Statistics found that Australia used 13,500 GL of water in 2020-21, comprising 7,800 GL per year for irrigation and a further 5,700 GL for urban and industrial uses. Noting that development of pumped hydro will be spread over 10-20 years, the small additional annual water requirement to fill PHES schemes can easily be sourced for this critical infrastructure.

The evaporative loss from a typical 1000MW PHES with no rainfall inflows is in the order of 1-2 GL/year. Evaporation suppressors and reservoir liners can be used to reduce evaporation and seepage losses further. A 1000 MW coal fired power plant can use up to 2.5GL of water per year, mostly for cooling. As renewables and PHES replace coal, there should be no significant net change in water usage for energy supply. Hence, water scarcity in Australia should not be seen as a reason to not develop pumped hydro.

Many good PHES sites are bluefield sites where an existing reservoir can be utilised as part of the scheme. The currently under construction or planned sites, Snowy 2.0, Kidston and Borumba all use existing reservoirs.

Sites near existing water sources where water can be purchased through an existing water trading system are also appropriate. There are numerous examples of good PHES sites that have access to water from sources that may not immediately be apparent, such as an existing water pipeline or allocation from a bulk water source, repurposing of an existing water source or potentially treated effluent water. As an upper bound cost**,** water delivery by truck is in the range of $10-20 per kL**.** For the 12 GWh system mentioned above, this corresponds to $100-200 million, which is 1% or so of the capital cost. Plainly, cheaper methods of water delivery will be available.

Typically PHES sites do not rely on large catchments to capture runoff for reservoir filling because the disruption to river and ecological systems would be significant. If such sites have not already been developed for water supply reservoirs then it is unlikely that they are suitable for PHES development.

In subsequent sections of this report, 22 very long duration storage (160 hour) sites are identified. The initial fill water requirement for 160 hour PHES is large, typically in the range of 300 to 1200 GL depending on capacity (MW) and reservoir shapes. Each of the twenty-two 160 hour sites identified were assessed to determine a possible water source. In most cases a large bulk water reservoir or major river was found within 50 km of the site, suggesting that water could be supplied by a pump and pipe system at modest cost. Four of the twenty-two sites may have hydrologic restrictions that mean that the full 160 hour project cannot be developed, but smaller schemes remain feasible.

This study has not attempted to exclude PHES sites based on assessment of water availability because water commonly is sourced from adjacent bulk sources rather than the local catchment. Instead, the approach has been to apply an overall reduction in installed capacity to 25% of the theoretical maximum to reflect that some may not have available water in addition to other constraints.

In addition, it was recognised that some areas of the NEM will not be suitable for PHES development due to their very dry climate. Five potential projects with suitable topography were identified in Northern South Australia near and north of the Flinders Ranges, these were excluded from the final database.

5. Proposed PHES Schemes

GHD carried out a search of publicly issued statements on proposed pumped hydro projects. The sites are shown graphically in Figure A1 in Appendix A. The list of identified sites is provided in Table 3 with further data in Appendix B. This excludes Snowy 2.0, Kidston and Borumba Pumped Hydro which are already explicitly included in AEMO's planning. This may not be an exhaustive list, and it likely contains superseded information where further project development has occurred since public statements.

Table 3 Publicly announced PHES projects

Project Name	Head (m)	Installed capacity (MW)	Duration (hr)	Energy (MWh)	NEM region	NEM sub-region
Baroota		250	8	2000	SA	CSA
Bendigo Mines		30	6	180	VIC	WNV
Berringama	350	250	10	2500	VIC	WNV
Big G	290	800	12	9600	QLD	CQ
Big S		400	10	4000	VIC	WNV
Big-T		400	10	4000	QLD	SQ
Bunkers hill		300	8	2400	VIC	WNV
Capricornia	300	750	16	12000	QLD	NQ
Capricornia Phase 2		650	16	12000	QLD	NQ
Centennial Newstan Colliery Fassifern		600	3.3	2000	NSW	SNW
Central west	360	325	8	2600	NSW	CNSW
Cudgewa				700	VIC	WNV
Cultana		225	8	1800	SA	NSA
Dartmouth		315	12	3780	VIC	WNV
Djandori Gung-i Superhybrid project		600	18	10800	QLD	CQ
Dungowan	500	300	10	3000	NSW	NNSW
Eildon		180	4	720	VIC	WNV
Glenbawn		770	10	7700	NSW	CNSW
Glennies Creek		620	8	4960	NSW	CNSW
Goat Hill	200	230	8	1840	SA	NSA
Hells Gates		808			QLD	NQ
Highbury Quarry		300	4.5	1350	SA	CSA
Kanmantoo		250	8	2000	SA	CSA
Lake Cethana	539	750	20	15000	TAS	TAS
Lake Lyell	255	335	8	2680	NSW	CNSW
Lake Rowallan	403	600	24	14500	TAS	TAS
Mt. Rawdon		2000	10	20000	QLD	SQ
Muswellbrook	500	500	8	4000	NSW	CNSW
Oven Mountain	600	900	8	7200	NSW	NNSW
Phoenix Pumped Hydro	350	810	12	9600	NSW	CNSW

Project Name	Head (m)	Installed capacity (MW)	Duration (hr)	Energy (MWh)	NEM region	NEM sub-region
Pioneer-Burdekin		5000	24	120000	QLD	NQ
Shoalhaven	218	235	13	3055	NSW	CNSW
South Midddleback Ranges Mine	175	90	4.3	390	SA	NSA
Stratford Renewable Energy Hub		300	12	3600	NSW	CNSW
Tallangatta	420	320	10	3200	VIC	WNV
Tintaldra				1000	VIC	WNV
Tribute		500	31	15600	TAS	TAS
Wabba				150	VIC	WNV
Western Sydney Pumped Hydro	400	1000	8	8,000	NSW	SNW
Total (excl. Snowy 2.0)		22,943MW		329,985 MWh		

These publicly listed schemes have a combined total of more than 22,000 MW and 329,000 MWh of energy storage. This is more than previously identified by Entura (2018) and close to the total energy storage requirement in the NEM by 2050 identified in the AEMO (2024) ISP.

The location of the publicly announced projects was determined and the total proposed development capacity in each NEM sub-region is listed in Table 4. There is a significant concentration of new projects in Central NSW and most of Queensland, while Victoria has to date had less developer interest publicly announced.

Table 4 Publicly announced PHES projects by NEM sub-region

Subregion Name	Subregion	Sum of Publicly announced project capacity (MW)	No of projects
Northen New South Wales	NNSW	1200	2
Central New South Wales	CNSW	3560	8
South New South Wales	SNSW	0	0
Sydney, Newcastle, Wollongong	SNW	1935	2
Northern Queensland	NQ	7458	5
Central Queensland	CQ	1400	2
Gladstone Grid	GG	0	0
South Queensland	SQ	2400	2
Northern South Australia	NSA	545	3
Central South Australia	CSA	800	3
South East South Australia	SESA	0	0
Tasmania	TAS	1850	3
West and North Victoria	WNV	1795	10
Greater Melbourne and Geelong	MEL	0	0
South East Victoria	SEV	0	0
Total		**22943**	**40**

6. Maximum Build Capacity

6.1 Introduction

Maximum Build capacity refers to the highest feasible installed capacity (in megawatts, MW) that can be developed at a specific hydropower site, considering physical, technical, environmental, economic, and regulatory constraints. It represents the upper limit of power output a site can support. For this study, the maximum build capacity has been aggregated for each NEM sub-region by identifying and combining possible projects within the sub-region.

The Maximum Build Capacity was estimated by combining two datasets:

1. The publicly announced projects at their announced capacity and duration as listed in Table 4 were included. While some of these projects are currently on hold or have been discontinued by the current developer, most of them could be implemented if economic and social drivers were sufficient. There was no rational method using public information considered suitable to exclude particular publicly announced projects. Hence, all the publicly announced projects were included
2. Screening of the Australia National University (ANU) PHES Atlas (Pumped Hydro Energy Storage Atlases | ANU RE100 Group) as described in Section 6.2

6.2 ANU PHES Atlas Screening

6.2.1 Input Data

ANU studied the potential for Short-Term Off-River Energy Storage (STORES) (Lu et. al. 2015, Lu et. al. 2017, Stocks et. al. 2017). The desktop study used GIS-based algorithms to identify potential off-river sites with proximity to suitable elevation difference for a PHES scheme. National parks were excluded from the study.

More recently, ANU developed a global atlas of Greenfield pumped hydro energy storage (Stocks et. al. 2019) which includes paired reservoirs for PHES schemes. Similar to the earlier work, the desktop study used GIS-based algorithms to identify potential sites (Lu et. al. 2018). Reservoir pairs were grouped by energy storage and duration. Energy storage volumes shown in the atlas are 2, 5, 15, 50, 150, 500, 1500 and 5000 GWh.

In 2022, the ANU 100% Renewable Energy Group published an atlas of Australian Bluefield pumped hydro energy storage (**https://re100.eng.anu.edu.au/bluefieldatlas/#australia**) which includes paired reservoirs in which one of the reservoir pairs is an existing reservoir. Similar to the Greenfield studies, the desktop study used GIS-based algorithms to identify potential sites.

Both the Greenfield and Bluefield datasets have been included in this study.

Each reservoir pair has an indicative cost ranking AAA, AA, A, B, C, D, E or F according to an approximate cost model. Premium sites (AAA and AA) are characterised by large-scale (0.5-5 GW of power for dozens of hours); large head (400-1600 m); large slope in the range 5-25 per cent (head divided by horizontal separation); and large water-rock ratio in the range 5-25 (ratio of the volume of stored water to the volume of rock needed to construct the reservoir walls). Premium sites in the Global Pumped Hydro Atlas have an indicative cost as little as one tenth that of Class E sites.

6.2.2 Approach

The screening of the extensive ANU database was carried out in two stages: (1) technical screening to identify potential sites based on specific criteria, and (2) GIS-based screening to exclude sites located in restricted zones such as national parks, urban areas, and those lacking proximity to existing transmission infrastructure. These steps are discussed in further detail in Section 6.2.4.

It is important to acknowledge certain limitations in the current assessment of maximum build capacity, which are worth considering in the context of this study. The technical screening criteria applied included only cost classes AAA, AA, A, and B—excluding sites in lower cost classes (C to F).

While these criteria effectively narrowed down the dataset, they also excluded a significant number of potentially viable sites. If sites with higher cost classifications were considered, the assessed maximum build capacity could be substantially higher.

Sites that passed the technical screening were then subject to additional GIS screening to exclude locations within sensitive or restricted areas, as outlined in Section 6.2.4. Therefore, the maximum build capacity presented in this report should not be interpreted as a fixed value, but rather as an estimate that is highly sensitive to the technical and spatial criteria applied during the assessment.

6.2.3 PHES alternatives excluded from maximum build capacity

While there are numerous other potential PHES sites, the following have been excluded from the NEM wide assessment of maximum build capacity.

6.2.3.1 Mine pit PHES

Open pit mines and quarry voids can be suitable as lower reservoirs for PHES schemes, for example Kidston PHES. However, these sites will be much more dependent on suitable geological conditions than greenfield sites as many mines have existing pit wall instability issues that would preclude use for pumped hydro. Also suitability would depend on existing mining activities and timing of mine closure which is difficult to confirm at a national study level. In addition, most mine pits are small compared with large PHES reservoirs and would typically have energy storage capacity less than the 5GWh minimum target.

While ANU have recently published a 'brownfield site' database, the site specific challenges of developing PHES in existing mines and quarries means that a GIS only screening would not be reliable. Only publicly announced mine pit projects have been included.

6.2.3.2 Seawater PHES

There is no precedent for seawater pumped hydro energy storage (SPHES) in Australia and only one international precedent. It was a 30MW pilot plant named Yanbaru, located on Okinawa, Japan. It was reportedly decommissioned in 2016 after operating for approximately 16 years.

EnergyAustralia and partners undertook a feasibility study for the 225MW (8hr) SPHES named Cultana Pumped Hydro Project, located near the north-western tip of the Spencer Gulf in South Australia. A knowledge sharing report was published (EnergyAustralia, 2017) with funding from ARENA, highlighting particular issues and proposed mitigations for SPHES. The challenges and mitigations included:

– Groundwater contamination by seawater. Mitigation comprises lining the upper reservoir with an impermeable material
– Biofouling of power waterways. Mitigation measures include: grouting GRP liners within the waterways; periodic dosing with hot water; chemical dosing, and anti-fouling paint
– Corrosion of mechanical and hydromechanical plant. Mitigation comprises specification of corrosion resistant materials (e.g. austenitic stainless steel turbine runners)
– Impact on marine fauna abstracted with the seawater. Mitigation comprises fine screening (and low velocity) at the seawater intake-outlet structure

EnergyAustralia and partners completed a follow up study (Phase 2) in 2019. A second knowledge sharing report was published (EnergyAustralia, 2020). In light of higher-than-expected capital cost, revenue uncertainty, uncertainty around energy technology development, reducing costs of grid-scale battery technology and development approvals time frame, EnergyAustralia took a negative Financial Investment Decision in November 2019.

All of the above would increase the capex and opex for a SPHES relative to a freshwater PHES. In addition, there are few coastal areas within the NEM where a large hydropower plant should be constructed noting existing social use of our coastline. SPHES has been excluded from this study.

6.2.3.3 Conversion of existing hydropower facilities to PHES

There are a number of existing conventional hydropower projects which could theoretically be converted to PHES by adding a pump back facility. Pump back schemes use a separate intake for a new pump on the lower reservoir which enables water to be returned from the lower reservoir to the upper reservoir, from where it can be run through the existing conventional hydro.

Generally, such schemes are unlikely to be economical because:

– The conventional scheme tailbay[2] is too small a volume and cannot be readily increased without impacting on the back pressure on the existing station
– There is no ready means of injecting pump discharge back into the existing waterway, especially if it is a tunnel, which then requires a separate and potentially expensive pipeline
– Environmental constraints may limit a surface waterway for the pump back waterway and the siting of an additional lower reservoir or embankment
– Pump power demand may be limited or limit the practicality of pumping back.

Pump back schemes can sometimes be readily added to cascade schemes where a potential lower reservoir already exists. In some cases, they may be implemented successfully as inter-basin transfer schemes, that is from a higher catchment to a lower catchment on a different river.

However, such schemes normally come at a higher cost than a standard PHES scheme. They are also specific to particular sites and difficult to identify at a national scale. For these reasons, these projects have been excluded from the study.

This does not exclude bluefield sites that use an existing hydropower reservoir as one of the PHES reservoirs, or connection of two existing reservoirs such as Snowy 2.0.

6.2.4 GIS Screening

The ANU Pumped Hydro Energy Storage Atlases are a valuable database to identify potential PHES sites in the NEM and includes over 16,000 potential PHES sites in the NEM. Given the wide range of potential project capital costs, it would be most reasonable to estimate that projects at the lower end of the capital cost scale are the most suitable to represent optimal pumped hydro sites that can, and should, be delivered into the system. As such, screening of possible sites for the maximum build capacity has aimed to produce a screened list of optimal sites.

An optimal PHES scheme would typically be assessed to be favourable for the numerous criteria discussed in Section 3.2. However, suitable databases for all of these criteria are not feasibly available for simple GIS based screening of sites, and instead a detailed study would be required to study the criteria for each site. This was beyond the scope of this study.

The GIS criteria adopted for screening the ANU database are listed in Table 5 along with the basis for selection of these screening criteria. Identified exclusion zones are graphically represented in Appendix A (Figure A2).

Table 5 Screening criteria for ANU databases

Criteria	Selection	Discussion
Energy (GWh)	>=15	Schemes generating less energy will not contribute meaningfully to the maximum build capacity and likely have higher cost.
Head (m)	250 - 800	Head less than 250m is unlikely to be economic for land and water use. There is little to no precedent for head greater than 800m. Conceptually a higher head project could use an intermediate pump/turbine and buffering reservoir. However, there is no implementation of such a scheme globally and this concept would not be considered technologically ready.

[2] Impoundment or reservoir immediately downstream of the powerhouse or dam at a hydropower plant.

Criteria	Selection	Discussion
Cost Class	AAA – B (excluding C-F)	Preliminary selection using ANU cost class to ensure maximum build capacity list is meaningful.
Cultural Sensitivity	Not within	To avoid mapped cultural heritage sensitivity.
Heritage Inventory	Not within	To avoid mapped cultural heritage sensitivity.
Heritage Register	Not within	To avoid mapped cultural heritage sensitivity.
Essentially Natural Catchments (State & National Parks)	Not within 1km	Avoid state / national parks with a buffer. It is acknowledged that tunnelling beneath state and national parks may be feasible (eg. Snowy 2.0) or that it may be possible to obtain exemptions to access existing reservoirs within these areas. However, this screening was adopted to produce a defensible dataset noting potential opposition to development in or near a park.
Named Waterways	Not within 50m	To avoid constructing new dams on named waterways to avoid environmental and existing water use impacts. It is likely that in some areas, construction on named waterways can occur and that some publicly announced projects to utilise named waterways. Again, this screening was adopted to produce a defensible dataset.
Land Use – Rural Residential and Farm Infrastructure	Not within	Whilst targeted PHES may be possible, a large project is unlikely to be feasible within residential / rural residential areas.
Land Use – Urban Intensive Uses	Not within	Whilst targeted PHES may be possible, a large project is unlikely to be feasible within residential / rural residential areas.
Immediate Protection Areas	Not within	Protected forest areas dataset in Victoria.
Victorian Ramsar Sites	Not within 1km	Avoiding listed protected sites.
Other	Avoid duplicates	A number of the schemes appear in multiple groups (i.e. they are the same sites or have one common reservoir with alternative reservoir sizes to achieve the energy storage noted). Duplicates are excluded by selecting the highest cost class, highest energy storage and then highest waterway slope.

6.2.5 Scheme capacity and duration

For a given head, the energy potential (GWh) depends on the active volume of the reservoir, while the installed capacity (MW) can vary significantly depending on the intended generation duration. The ANU database provides a range of Pumped Hydro Storage (PHS) schemes with energy capacities of 2 GWh, 5 GWh, 15 GWh, 50 GWh, 150 GWh, 500 GWh, 1,500 GWh, and 5,000 GWh. Schemes with less than 15 GWh of storage have been excluded from consideration, as they are relatively small and are more likely to be replaced by alternative energy storage technologies. To meet the AEMO target of a dataset for 10, 24, 48 and 160 hour storage duration, the installed capacities corresponding to each energy storage capacity are as presented in the accompanying table.

Table 6 Normalised duration and installed capacity calculation.

Energy GWh	Duration	Installed Capacity (MW)
5000	160	31250
1500	160	9375
500	160	3125
150	48	3125
50	24	2083
15	10	1500

6.2.6 Inclusion of publicly announced schemes

The proposed PHES schemes listed in Table 3 have been included in the Maximum Build Capacity database by normalising the power capacity (MW) such that the duration matches one of the energy storage durations of 10, 24, 48 and 160 hours. For example, Phoenix Pumped Hydro in the list below has a proposed duration of 12 hours and energy storage of 9600 MWh, but this was normalised to 10 hours and the capacity increased from 810MW to 960 MW (9600 MWh divided by 10 hours).

6.3 Results

A total of 181 new projects were identified after screening the ANU database, representing an estimated energy potential of approximately 30,000 GWh and an installed capacity of 490,000 MW. In Section 5, GHD's assessment identified 40 publicly announced projects. Seven of these publicly announced projects were also identified in the ANU database screening, and the seven ANU sites were excluded from this database to avoid double counting. Hence, 174 possible new sites are considered in the maximum build capacity. The identified sites are shown in Figure A3 of Appendix A.

Four new sites and the proposed Lake Lyell PHES were identified near the boundary of the SNW and CNSW subregions, review of these locations confirmed that the transmission connection point is more likely to be within CNSW and these projects were recorded in the CNSW subregion. Two publicly announced projects remain within the SNW region.

The screening from many thousand sites to 174 has clearly removed some sites that may be suitable for development. Many of the GIS screening layers applied could be viewed as soft rather than hard exclusion zones. In particular, many bluefield sites were excluded due to their proximity to state or national parks, but with sensitive development and assistance from the water authority responsible for the existing reservoir, these may be very good PHES sites. Hence, there are many more possible sites than identified in this approach.

The screening approach has not considered potential site-specific aspects that may prevent PHES development including geology, hydrology (availability of water), environment, and land zoning and ownership. Social licence may also be a significant factor in whether a particular site is feasible. Hence, many projects identify here would not be implemented due to these technical or development limitations. To develop a **practical Maximum Build Capacity** database for AEMO the total power (MW) and energy storage (GWh) capacity, both the 174 ANU database screening and 40 publicly announced sites) were reduced by 75 percent. This was intended to indicate that only one quarter of the possible projects identified from the screening approach may ultimately be suitable for development. It is important to note that the screening approach has already aimed to identify optimal projects by selecting only projects that ANU identified as lower cost (class AAA to B), removing projects smaller than 15 GWh and applying technical and land use screens to reduce the 2,950 sites down to only 174 in the final database. Hence, a further reduction of this list to a quarter is considered conservative in estimating the practical maximum build capacity.

Combining the ANU database and public announced projects and reducing the totals by 75 percent results in a total estimated **practical Maximum Build Capacity of 124,600 MW and a total energy capacity of 7,460 GWh**. This still represents more than 10 times the total energy storage requirement identified in the AEMO (2024) ISP. The maximum installed capacities and energy potential by sub-region are summarised in Table 7. This table also includes the previous maximum build capacity from the AEMO Draft 2025 IASR Stage 1. The new assessment has resulted in a slight reduction in the maximum build capacity of 10 hour PHES, but a significant increase for longer storage durations. As discussed in Section 4.1, the previous maximum build capacity from Entura (2018) only considered potential projects within proposed Renewable Energy Zones (REZs) rather than the entire NEM, and had a greatly reduced list of publicly announced projects to 2018. Hence, the increased maximum build capacity is expected.

Interestingly, the new project database is relatively closely aligned with the publicly available database, with the majority of projects in central and northern NSW and central and northern Queensland. There were significantly fewer potential projects identified in Victoria and South Australia, there are many good sites in these states but the exclusion of projects smaller than 15 GWh resulted in fewer being identified.

Table 7 Maximum build capacity for PHES in the NEM

NEM Subregion	Pumped Hydro subregional limits (MW)							
	10 Hour PHES		24 Hour PHES		48 Hour PHES		160 hour PHES	
	This study	Draft IASR	This study	Draft IASR	This study	Draft IASR	This study	Draft IASR
Northern New South Wales	2,500	1,020	9,400	500	19,500	500	9,400	N/A
Central New South Wales	1000	2,006	5,200	167	3,900	83	800	N/A
South New South Wales	1,500	2,000	2,100	583	2,300	167	800	N/A
Sydney, Newcastle, Wollongong	300	0	0	0	0	0	-	N/A
Northern Queensland	1,000	1,000	6,500	5,000	10,200	111	7,000	N/A
Central Queensland	1,400	960	1,200	1,250	6,300	89	1,600	N/A
Gladstone Grid	0	0	0	0	0	0	-	N/A
South Queensland	1,000	2,400	1,000	600	1,600	300	-	N/A
Northern SA	100	540	1,000	200	800	0	-	N/A
Central South Australia	100	135	0	0	0	0	-	N/A
South East SA	0	0	0	0	0	0	-	N/A
Tasmania	1,100	1,300	500	1,200	3,900	371	3,100	N/A
West and North Victoria	1,600	2,160	4,700	700	9,400	400	800	N/A
Melbourne and Geelong	0	0	0	0	0	0	-	N/A
South East Victoria	0	0	0	0	0	0	-	N/A
TOTAL	**11,600**	**13,521**	**31,600**	**10,200**	**57,900**	**2,021**	**23,500**	**0**

The combined number of projects across different NEM sub-regions is presented in Table 8.

Table 8 PHES projects (new database + announced proposed projects)

NEM Region	NEM Sub-region	No. of possible projects
NSW	Subtotal =	99
	CNSW	24
	NNSW	61
	SNSW	12
	SNW	2
QLD	Subtotal =	58
	CQ	17
	NQ	34
	GG	0
	SQ	7
SA	Subtotal =	9

NEM Region	NEM Sub-region	No. of possible projects
	CSA	3
	NSA	6
	SESA	0
TAS	Subtotal =	13
	TAS	13
VIC	Subtotal =	35
	WNV	35
	MEL	0
	SEV	0
Grand Total		214

7. Locational Cost Factors

7.1 Introduction

The AEMO Draft 2025 IASR Stage 1 notes that costs for various technologies are based on the assumption that projects (except offshore wind projects) are located in the metropolitan areas in the NEM region. For projects that are not located in the metropolitan areas, a location cost factor needs to be applied. The intention of this is to provide an indication of the variation in project cost between the sub-regions of the NEM.

The locational cost factors consider:

- Equipment costs
- Installation costs
- Fuel connection costs
- Cost of land and development
- Topography

The first four factors listed above are considered standard factors for major project development (i.e. not specific to PHES) and are discussed in Section 7.2.

As all PHES projects are unique large-scale infrastructure investments, projects will have varying costs for each element and overall costs will vary greatly between sites. This is due to both systemic risks and project-specific factors such as geology, topography, access constraints, water availability, transmission availability, land acquisition and biodiversity offset costs. Hence, determining a realistic locational cost factor is difficult and will not represent every individual project.

Despite that, there will likely be differences in cost for various regions in the NEM based on the topography of each region which can be explored. Reasons for these differences may include:

- The waterway length to head ratio typically reflects the civil construction cost of tunnels relative to the power capacity of the scheme – projects with lower waterway length to head ratios are generally cheaper. Similarly dam embankment costs vary with topography as some sites will be suitable for small valley dams impounding large reservoirs, while flatter sites may require a large volume of dam embankment forming a ‘turkeys nest’ dam all around the reservoir.
- The installed capacity for a project is a significant driver in determining the unit cost because some PHES costs are fixed while others are variable. Installed capacity is related to head and storage size. In regions where storages are relatively small and head is relatively low, costs are generally higher.

Section 7.3 presents a comparison of relative costs for PHES development based on topography differences in the NEM sub-regions.

Section 7.4 presents the adopted approach to combine the major project and site-specific project cost factors to develop a single locational cost factor for PHES development in the NEM sub-regions.

7.2 Major Project Locational Cost Factors

The incremental cost of developing and executing a major project in a given location is nominally based on factors such as:

- Transportation costs associated with distance from a major port
- Labour rates and labour availability in remote locations
- Increased cost of working in remote location due to lack of amenities and industry

These are costs common to all major projects, although some components may be more specific to PHES. Two previous studies prepared for AEMO have been referenced in developing these factors. The two referenced studies are:

- Aurecon (2024) Energy Technology Cost and Parameters Review - Revision 3

– GHD (2018) AEMO Cost and Technical Parameter Review – Revision 2

The Aurecon study referenced cost factors for the various potential renewable energy zones, while the GHD study was based on nominal regions before the NEM sub-regions were developed. Hence, some degree of interpretation is required to compare the two studies.

7.2.1 Equipment cost factors

Equipment cost factors for the regions reflect an incremental transport/shipping cost relative to delivery to a plant located near a major port. For PHES, the major equipment, i.e. the pump/turbines and motor/generators, transformers and balance of plant have a high manufacture and shipping cost prior to reaching Australia. Hence, the additional equipment cost of transport to more remote sites may not be as large a differentiator as other new energy projects.

The GHD (2018) approach was that all major port locations were assigned an equipment cost factor of 1.00. Regions further from a major port receive a factor ranging from 1.03 to 1.10 based on distance from the port, reflecting the scale of additional transportation required (i.e. level of remoteness).

Aurecon (2024) adopted factors assumed to vary between 1.01 and 1.15, depending upon the distance from capital cities.

A comparison of the outputs of the two previous studies is shown in Table 9. The differences between the adopted factors is generally small. The exception is Queensland, where the Aurecon assumption that equipment factors should be based on distance from Brisbane has resulted in very high factors for northern Queensland, whereas utilising ports at major cities further north should result in lower factors. Hence, the GHD (2018) factors were considered more appropriate and adopted for this current study.

Table 9 Comparison of equipment cost factors

Name	ISP Sub-region	Region	Equipment Cost Factor		
			Aurecon (2024)	GHD (2018)	Current Study
Northern New South Wales	NNSW	NSW	1.04	1.03	1.03
Central New South Wales	CNSW	NSW	1.03	1.03	1.03
South New South Wales	SNSW	NSW	1.05	1.03	1.03
Sydney, Newcastle, Wollongong	SNW	NSW	1.01	1	1
Northern Queensland	NQ	QLD	1.13	1.08	1.08
Central Queensland	CQ	QLD	1.07	1.05	1.05
Gladstone Grid	GG	QLD	1.03	1	1
South Queensland	SQ	QLD	1.02	1	1
Northern South Australia	NSA	SA	1.04	1.07	1.07
Central South Australia	CSA	SA	1.02	1.02	1.02
South East South Australia	SESA	SA	1.02	1.02	1.02
Tasmania	TAS	TAS	1.02	1.04	1.04
West and North Victoria	WNV	VIC	1.02	1.04	1.04
Greater Melbourne and Geelong	MEL	VIC	1.00	1	1
South East Victoria	SEV	VIC	1.00	1.03	1.03

7.2.2 Installation cost factors

Installation cost factors include material, labour, mobilisation and demobilisation of resources from metropolitan areas. Both previous studies developed these using a blend of labour and bulk material rates using previous issues of the cost estimating reference *Rawlinsons Australian Construction Handbook*.

Adopting a similar approach, Rawlinsons (2025) was used for the current study. The guide is intended for commercial building construction and does not have specific rates for heavy civil construction. However, it is the most suitable reference for general construction in Australia.

Rawlinsons provides unit rates for building construction activities within each capital city, which allows a relative factor to be developed between these locations. A factor for the capital cities was derived from the published unit rates considering a blend of 15% earthworks, 5% foundation works, 20% reinforced concrete, 20% overall building index and 50% labour rates. Underground works, e.g. tunnelling and powerhouse caverns, are a large component of most PHES projects. However, Rawlinsons does not have rates for these underground works which will introduce some uncertainty in the adopted values. Also, Tier 1 contractors typically engaged for large project delivery will usually have more even cost distribution across Australia than may be suggested by Rawlinsons.

The capital city factor was then extended to the ISP sub-regions using state-based cost factor maps provided in Rawlinsons to apply additional cost increases due to remoteness relative to the capital city. The recommended installation cost factors are shown in the final column of Table 10.

The current study recommended values are typically between the values suggested in the GHD (2018) and Aurecon (2024) studies. The exception is Queensland where the current study adopts lower factors, this is likely due to the unit rates selected to build up the capital city factor and the adopted high loading on labour which is typical for a PHES project compared with other renewable projects. This resulted in Brisbane having a slightly lower cost factor than Melbourne which is then reflected in the regional installation factors for the state.

Table 10 Installation Cost Factors

Capital City / NEM Subregion	Capital City Factor	Regional Ratio	Installation Cost Factor
Sydney (SNW)	1.06	1	1.06
NNSW		1.1	1.17
CNSW		1.08	1.15
SNSW		1.15	1.22
Brisbane	0.98	1	0.98
NQ		1.2	1.18
CQ		1.12	1.10
GG		1.17	1.15
SQ		1.07	1.05
Melbourne (MEL)	1.00	1.00	1.00
WNV		1.03	1.03
SEV		1.01	1.01
Adelaide	0.95	1	0.95
NSA		1.3	1.23
CSA		1.12	1.06
SESA		1.1	1.04
Tasmania	0.95	1.07	1.01

7.2.3 Fuel connection costs

Fuel costs considered for other generation types in the ISP may include fuel used to be converted from chemical form to electric energy form which may have a significant cost. For PHES, the fuel used for the excitation systems, site management and back-ups are immaterial. Hence, fuel connection costs have been assumed to be zero.

7.2.4 Cost of land and development

The cost of land and development is considered to be a collation of an allowance to procure or lease land, and environmental offset costs. These costs are heavily dependent on a number of factors that do not necessarily align with geographical variance. For example, while land cost might typically reduce as the project location becomes more remote, the costs associated with land development, access, and community engagement may increase. Additionally, the land may be high value grazing or farming land which would counteract the remoteness factor.

GHD (2025) estimated property costs and environmental offset costs for NEM transmission cost estimates. The same methodology has been adopted in this current study to estimate the cost of land and development.

Owners costs including financing, and site development costs (access roads, site establishment, camps etc.) may also be considered a cost of development. These are not site specific at a NEM sub-region scale and will not have an impact on locational cost factors. Hence these are not included.

Property costs

GHD used Australian Bureau of Agricultural and Resource Economics and Sciences[3] (ABARES) as an independent and reliable source for land prices, to collect the most recent farmland pricing data, for all subregions within the NEM. The average of all the subregions farmland pricing data, in $\$/m^2$ was then used to derive the Property Costs component.

The area required for PHES development was nominally assumed to be the sum of the upper and lower reservoir footprints plus fifty percent to represent other surface permanent and temporary facilities for greenfield sites and double the upper reservoir footprint for bluefield sites.

Environmental offset costs

Estimating biodiversity offsets at early project stages is highly uncertain, in the absence of detailed vegetation and threatened species surveys, which are essential for precise calculations. Obtaining published vegetation class mapping for the entire NEM to provide some differentiation between particular sites is beyond the scope of this study. However, as these costs can be significant and do vary by state there is some value in including a baseline estimate of state based costs considering the size of different schemes.

To calculate Environmental offset costs, GHD reviewed several biodiversity offset estimation methods, available to each state based on their respective jurisdictional environmental regulations, and also the federal government methodology. Only NSW has a federally approved methodology to estimate biodiversity offset costs. Applying a different methodology to NSW may skew the results, and hence only the federal method was adopted for all NEM sub-regions. The formula used for deriving the federal biodiversity offset rate is as follows:

Federal biodiversity offset rate ($\$/m^2$) = Impact area ($m^2$) × Impact area multiplier × Land price ($\$/m^2$)

Where:

- Impact area is the total land size effected by constructing the infrastructure
- Impact area multiplier is used to increase the biodiversity cost of impacted area. GHD has assumed the average impact area multiplier of 10 to be representative of majority of projects that have required biodiversity offset costs across QLD, VIC, SA and TAS jurisdictions. 10 is therefore proposed as the baseline estimate
- Land price sourced from ABARES described above

Cost of Land and Development

Table 11 presents the estimated combined property costs and environmental offset costs for each subregion and a cost factor determined by dividing the sub-region cost by the overall average cost. While the cost factors near Sydney and Melbourne appear low, reflecting that the ABARES database for broadacre farming land sales is not relevant for metropolitan areas, PHES projects in these areas would only be possible on available land such as repurposed mine voids rather than purchasing land zoned for another purpose.

As noted in the preceding text, there is significant uncertainty in these cost factors and they should be used with caution. A low weighting has been applied to this factor, partially due to this uncertainty.

[3] Published by the Australian Government Department of Agriculture, Fisheries and Forestry

Table 11 Land and development cost factors

Name	ISP Sub-region	Total Land and Development Cost $/m2	Land and Development Cost Factor
Northern New South Wales	NNSW	$15.40	1.15
Central New South Wales	CNSW	$15.63	1.16
South New South Wales	SNSW	$18.21	1.36
Sydney, Newcastle, Wollongong	SNW	$19.82	1.47
Northern Queensland	NQ	$12.01	0.89
Central Queensland	CQ	$5.94	0.44
Gladstone Grid	GG	$8.47	0.63
South Queensland	SQ	$8.47	0.63
Northern South Australia	NSA	$4.07	0.30
Central South Australia	CSA	$6.07	0.45
South East South Australia	SESA	$16.55	1.23
Tasmania	TAS	$19.67	1.46
West and North Victoria	WNV	$11.47	0.85
Greater Melbourne and Geelong	MEL	$19.90	1.48
South East Victoria	SEV	$19.90	1.48

7.3 Topography specific relative costs

A topography cost factor has been introduced that attempts to capture differences in PHES development cost for various regions in the NEM based on the topography of each region.

7.3.1 Parametric costing approach

Using the schemes identified in Section 6 – Maximum Build Capacity, relatively simple parametric cost equations, based on in-house databases, combined with parameters available in the ANU database, have been used to estimate a construction cost for each scheme. The following costs have been allowed for:

- Upper dam/reservoir
- Upper intake
- Conveyance
- Powerhouse civil
- Powerhouse mechanical and electrical (including balance of plant)
- Lower intake
- Lower dam/reservoir
- Switchyard
- A percentage allowance for contingency, minor unpriced items, and indirect costs including mobilisation, site facilities, project management, insurance, EPC engineering and design.

The estimates were intended to represent EPC construction CAPEX. Exclusions from the cost estimates are:

- Roads and civil works
- Water purchase and procurement
- Transmission because the AEMO ISP will develop connection costs.
- Owners' costs and financing

7.3.2 Typical arrangement

While site topography and geology are important to developing the arrangement of each particular PHES site, a typical scheme arrangement as shown in Figure 8 was adopted as a common assumption for all sites to allow the development of parametric cost estimates.

The preliminary scheme arrangements envisage:

– Embankment type dams where new upper and lower reservoirs are required. These are envisaged to be concrete faced rockfill dams. Bluefield sites allow for only one new dam
– A short headrace tunnel with vertical shaft close to the upper reservoir
– A high-pressure steel-lined tunnel extends from the toe of the vertical shaft to the powerhouse
– An underground powerhouse located relatively close to the upper reservoir to shorten the upper waterway length as far as practical, thereby eliminating the need for an upper surge tank
– A tailrace tunnel to the lower reservoir inlet / outlet structure
– A surge tank in the tailrace tunnel if required. This decision was based on the length of the tailrace tunnel and the associated hydraulic effects for waterway start time
– A Main Access Tunnel (MAT) is required for construction and operational access to the powerhouse (other underground tunnels and adits are also likely required but not specifically included in the arrangement)
– Surface switchyard
– Main generating/pumping equipment
  - Reversible Francis units
  - Fixed speed units

The number and arrangement of the generating units and power waterways (i.e. tunnels) depends on the scheme size (MW) and station discharge. The study aimed for approximately 300MW as a sensible connection size for a single unit (ie. single pump / turbine) to the NEM. Tunnels were sized to aim for a flow velocity of 5 m/s and the number of tunnels selected to maintain a maximum internal diameter of 9m.

This typical scheme arrangement allowed for parametric quantity estimation for each scheme. These quantities were then multiplied by standard unit rates to develop direct cost estimates for each scheme.

While the underground powerhouse arrangement may be relatively expensive, this arrangement minimises uncertainty associated with waterway hydraulics and also results in significantly smaller surface footprint and disturbance.

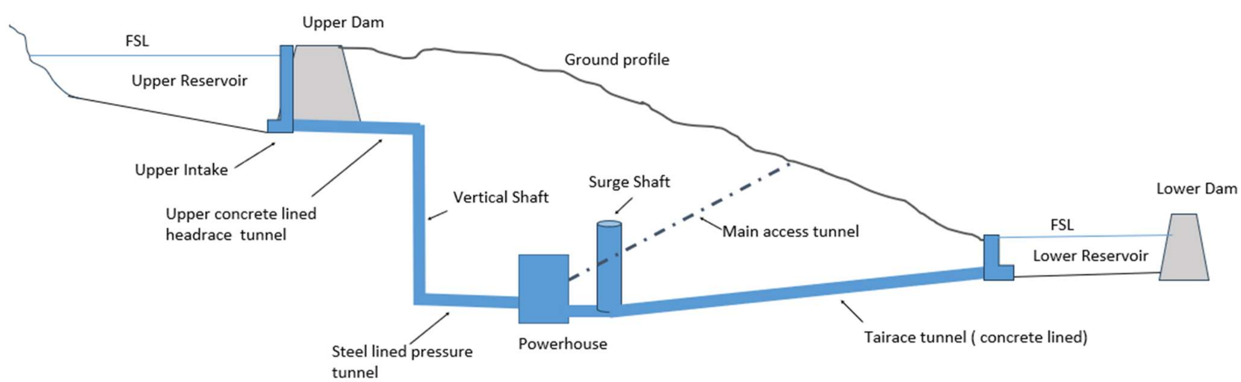

Figure 8 Typical PHES scheme arrangement

7.3.3 Results

The parametric cost build up has not been included in this report as it was an exclusion from the project scope and would convey a false sense of precision. The focus has been on producing relative costs to enable a comparison.

A relative power cost ($M/MW) was calculated for each site. This is the total construction cost estimate divided by installed capacity in MW and does not require an energy cost to be added.

For those NEM subregions where there were numerous projects identified, including all the projects in relative costs would result in these regions appearing expensive. This was not considered correct because the more optimal projects would be constructed first. For each sub-region, the lowest three project costs in each duration sub-category were considered where there are more than 3 projects. The average cost in $/MW for each sub-region and duration are shown in . These costs are considered to be an estimate of the EPC CAPEX for schemes based on the parametric costing approach adopted. No level of accuracy is implied by the estimate.

Some regions do not have 10 hour storage duration projects, this is because where multiple project options were identified for the same site, the largest one was selected as preferred for the maximum build capacity.

Table 12 PHES parametric costs for NEM subregions and durations

Region / Subregion / Duration	Relative power cost $M/MW	Number of sites
NSW		29
CNSW		7
24	3.81	3
48	4.64	3
160	7.16	1
NNSW		12
10	3.19	3
24	3.88	3
48	3.70	3
160	5.88	3
SNSW		10
10	3.70	3
24	4.16	3
48	6.06	3
160	8.46	1
QLD		25
CQ		10
10	3.39	3
24	4.23	2
48	3.95	3
160	10.56	2
NQ		10
10	3.54	1
24	3.77	3
48	4.13	3
160	6.98	3
SQ		5
10	2.86	1
24	4.33	2

Region / Subregion / Duration	Relative power cost $M/MW	Number of sites
48	5.33	2
SA		4
CSA		1
24	4.39	1
NSA		3
24	4.54	2
48	6.01	1
TAS		8
TAS		8
10	3.25	3
48	4.81	3
160	9.81	2
VIC		10
WNV		10
10	3.21	3
24	3.66	3
48	4.99	3
160	9.17	1

These direct costs were then normalised, by dividing the relative power cost for each sub-region by the average relative power cost of all sites for the same duration, to calculate a 'topography cost factor'. This enables a comparison amongst the identified schemes for each NEM sub-region as shown in Table 13.

The topographic factors vary from 0.71 to 1.27 with an average of 1.0. A lower topography factor for a given region and storage duration suggests that the region is either more suitable for PHES development or contains a greater number of efficient and cost-effective PHES candidate sites for that duration. For example, as shown in Table 13, the overall topography factor for the NNSW region is generally lower than that of other regions — particularly for the 48 hour and 160 hour durations. This is primarily due to the larger number of projects available in NNSW to choose the top three for assessment of topography factor. Of the 174 newly identified sites across all regions, 59 are in NNSW and many of these are larger storage duration sites. For the 48 hour duration, a total of 74 projects were identified throughout the NEM, with five subregions having none, while NNSW accounts for 25. This provides NNSW with a significant advantage in selecting the top three projects for assessment, resulting in a notably lower topography factor of 0.76. A similar rationale applies for the 160 hour duration category.

Conversely, Central Queensland (CQ) subregion has a low topography cost factor for 10, 24 and 48 hour generation and high factor for 160-hour generation. This was because only two 160 hour duration projects were identified in CQ, both with an ANU cost ranking of A compared with AA for the NNSW sites. The parametric cost estimates in this study also suggested higher costs for these sites relative to others. This suggests that CQ may be more appropriate for storage durations up to 48 hours and less suitable for seasonal (160 hr) storage.

Table 13 *Topography cost factor*

Location (NEM Subregion)	Generation Duration (hrs)			
	10	24	48	160
CNSW	-	0.93	0.96	0.86
NNSW	0.96	0.95	0.76	0.71
SNSW	1.12	1.02	1.25	1.02
SNW	-	-	-	-
CQ	1.03	1.04	0.81	1.27
NQ	1.07	0.92	0.85	0.84
SQ	0.86	1.06	1.10	-
CSA	-	1.07	-	-
NSA	-	1.11	1.24	
TAS	0.98	-	0.99	1.18
WNV	0.97	0.90	1.03	1.11
Average	0.98	1.02	0.99	1.02

Note: Where no data is available, the average value for that generation duration was adopted to generate locational factors. The rationale for this was that while there are no schemes identified in the ANU database, there may be publicly announced schemes in that subregion and a cost factor is required. Typically, a publicly announced scheme has likely been selected to have features that would have relatively low costs. Since there is no data, it was considered too ambitious to apply a low topographic factor, but the average was considered a reasonable assumption.

7.3.4 Review of cost modelling

AEMO's capacity expansion modelling approach will use GenCost data for PHES costs multiplied by the locational cost factors developed in this study to determine technology costs for PHES. The AEMO modelling may then inform a decision to include PHES in the future energy solution up to the ceiling of the maximum build capacity, if PHES is commercially appropriate.

Power capacity cost ($/MW)

While cost estimates were not within the scope of this study, the parametric cost estimates and topography locational factors have been reviewed relative to published data to confirm they are appropriate for use.

Figure 9 presents the average power cost ($M/MW) for each sub-region for each storage duration. There are minor differences, but a clear trend of increasing cost ($M/MW) for increasing duration, this is expected as the reservoirs must be larger to store more water. The costs ($M/MW) for each sub-region from Table 12 have been averaged for the entire NEM in Table 14. A comparison from published references is also included:

– The average power cost for 10 hour duration storage of $3.3M/MW is reasonably consistent with international benchmarking. For example, IHA (2021) estimated USD2.2M/MW for 1000MW for 10 hour storage. Similarly, CSIRO GenCost (2023-2024) estimated approximately AUD2.8M/MW for 8 to 12 hour PHES.
– Aurecon (2024) provided a range for EPC cost estimates of 42 and 48 hour PHES projects. Aurecon noted that PHES project costs vary significantly depending upon various project attributes, and noted that favourable geotechnical conditions, shorter tunnels, above ground power houses, or existing suitable lower reservoirs may have costs towards the lower end of the range. The current study has aimed to identify optimal PHES projects by screening out approximately 98% of sites in the ANU global atlas and these should be assumed to be at this lower end of the Aurecon cost range. The average cost identified in this study is consistent with the lower end of the Aurecon (2024) cost estimates.
– The only known data point for a 160 hour PHES is Snowy 2.0. SnowyHydro's 2023 media release noted a construction cost of $12Bn for a 2,200MW scheme, or power cost of 5.45 $M/MW. This is considerably lower than the average estimate in this study.

Table 14 Average PHES power costs comparison

Duration	Average power cost $M/MW	Comparison ($M/MW)
10	3.30	3.3 (IHA 2021)
24	4.08	4.0 – 6.5 (Aurecon 2024)
48	4.85	5.0 – 7.5 (Aurecon 2024)
160	8.29	5.45 (SnowyHydro 2023)

Some of the publicly identified projects listed in Section 5 have published cost estimates. These were escalated from the date of publishing to reflect 2025 costs using the ABS cost index 3109 – Other heavy civil engineering construction Australia. For the schemes with 8-12 hours storage duration, the average power cost was 2.6 $M/MW, somewhat below the values estimated in this study.

The basis of the publicly announced estimates is rarely published. Noting that many of the public cost estimates were issued with environmental approvals documentation, they can be expected to reflect project costs with low contingency and no owners or land development costs. Published estimates for government projects are typically higher and may be more inclusive of the full development costs. The cost breakdown by subregion did not match the regional trends presented in , likely reflecting the site specific nature of PHES costs and also possibly variance in the method of preparing the cost estimate. Noting this uncertainty, the publicly announced cost estimates were not included in the cost factors.

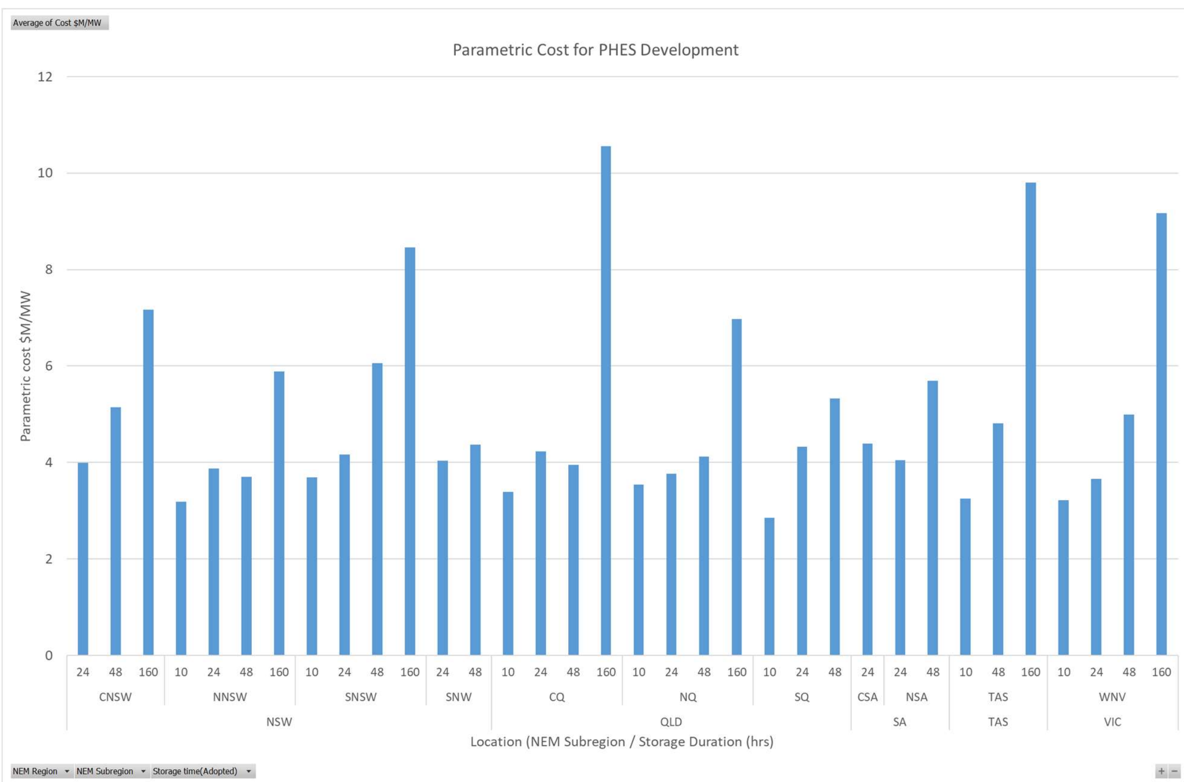

Figure 9 PHES relative power cost ($/MW) by sub-region

Energy capacity cost ($M/MWh)

The cost estimates can also be expressed as an energy capacity cost ($M/MWh). These are the estimated EPC construction costs divided by the total energy storage. Hence, they should not be added to the power cost to determine a total cost but instead represent another way of reflecting the cost of storage.

The costs ($M/MW) for each sub-region from Table 12 have been averaged for the entire NEM in Table 15. A comparison from published references is also included. These comparisons align well with the average parametric estimate from this study. This demonstrates that the proposed approach for AEMO's capacity expansion modelling, which will use GenCost data for PHES costs multiplied by the locational cost factors developed in this study to determine technology costs for PHES, is appropriate.

Figure 10 presents the normalised energy cost ($M/MWh) vs duration for each sub-region, this clearly shows the significant reduction in normalised energy cost with increasing storage duration. This aligns with the discussion in Section 3.4 highlighting that the value for PHES is in longer duration storage. The difference between sub-regions is less pronounced.

Table 15 Average PHES energy storage costs comparison

Duration	Average Energy cost ($M/MWh)	Comparison
10	0.33	0.34 (Gencost 2023/24 average of 8 and 12 hour PHES)
24	0.17	0.17 – 0.27 (Aurecon 2024) 0.19 (Gencost 2023/24)
48	0.10	0.10 – 0.16 (Aurecon 2024)
160	0.05	0.34 (SnowyHydro 2023)

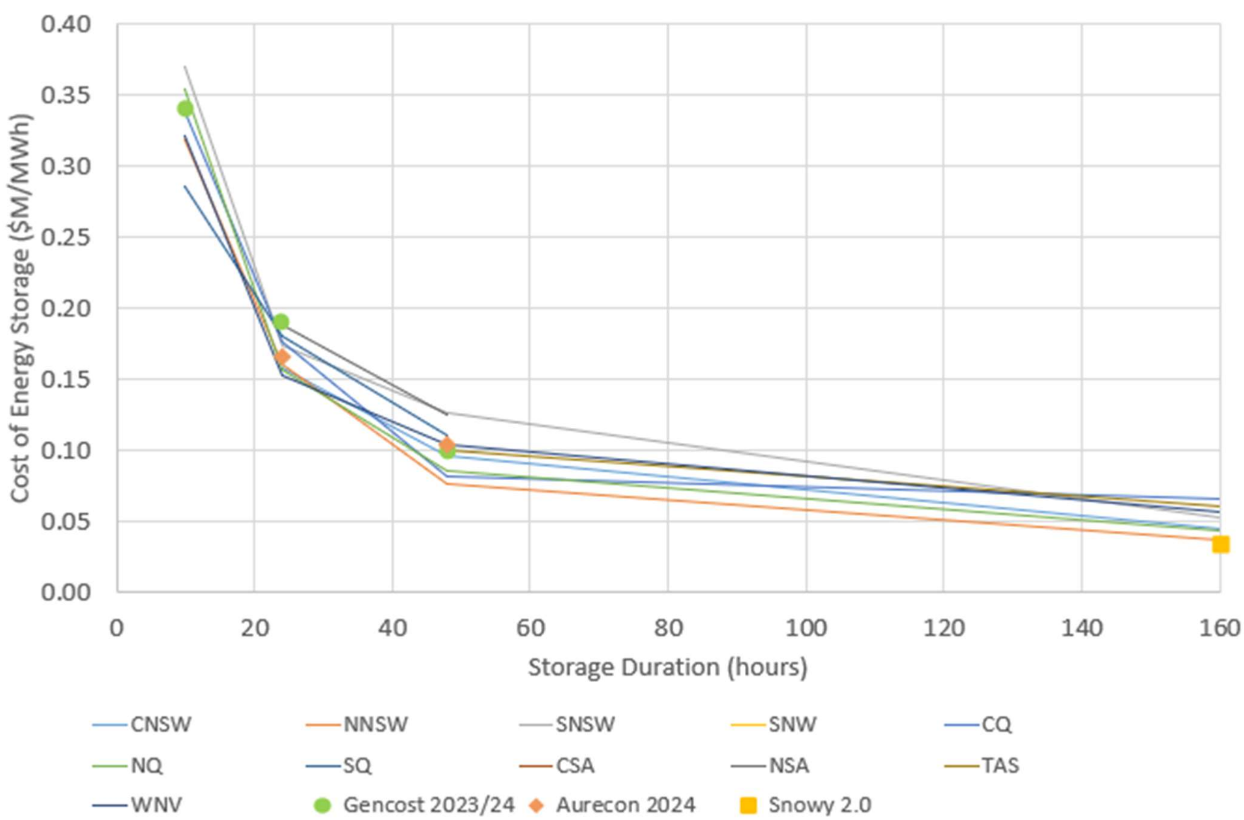

Figure 10 PHES relative capacity cost ($M/MWh) by sub-region

7.4 Weighting of cost factors for PHES

In AEMO's modelling, the cost to develop PHES is determined by multiplying the base cost ($/MW for the required duration) by a single locational cost factor. Hence, each of the cost factors developed in preceding sections require a weighting to determine an overall combined locational cost factor. This weighting does not apply to particular parts of a cost estimate, for example the installation cost factor is not directly applied to a portion of the base cost that represents installation related items in an estimate, instead they represent the approximate influence or weighting of the five factors to the overall cost.

PHES projects have a large component of on-site civil works including surface earthworks, tunnelling and powerhouse excavation, mass and structural concrete, and the associated site overheads for these works. A cost estimate is typically built up by multiplying the quantities of materials (concrete, tunnelling etc.) by a rate for that activity. The main influences on these factors are:

- Quantities of materials can be seen as influenced by topography – suitable topography will have shorter tunnels for example
- Rates for activities are influenced by the installation cost factor reflecting costs of labour, materials and construction equipment.

These were assumed to be the major influence on the overall cost factor and were split evenly at 40% each.

Equipment costs including the pump turbines, generators, balance of plant, switchyard etc. can be about a quarter of the overall cost estimate. However, the influence of the equipment cost factor on a locational cost factor is less because the supply costs to a port are the same, and the only variable is the transportation costs. Hence a relatively low weighting was applied to equipment costs.

The cost of land and development can be highly variable, environmental offset costs in particular. Using the methodology described in Section 7.2.4, the additional cost for land and development was found to be approximately 6% of the total cost.

This results in the estimated cost weighting in Table 16.

Table 16 Typical weighting of costs for PHES projects

Cost item	Equipment costs	Fuel connection costs	Cost of land and development	Installation costs	Topography
	14%	*0%*	*6%*	*40%*	*40%*

7.5 Combined locational cost factors

Section 7.2 provides estimates of locational cost factors for major project development which are not specific to PHES. Section 7.3 provides PHES specific topography cost factors based on topographic differences in the NEM sub-regions. These locational cost factors can be combined to provide a single locational cost factor for PHES development using the distribution of costs in Section 7.4. For AEMO's modelling, the Locational Cost Factor should be 1.0 for a representative capital city. For this reason, the factors have been adjusted such that the factor for Melbourne is 1.0 by dividing the sum-product of the factors and weightings by the value obtained for Melbourne. The outcomes are summarised in Table 17 to Table 20 for storage durations of 10, 24, 48 and 160 hours respectively.

Table 17 ***Locational cost factors for PHES development – 10 hour storage***

ISP Sub-region	Sub-Factors: Installation Factor	Equipment Cost Factor	Fuel cost factor	Land and Development	Topography	Locational Cost Factor
Weighting	40%	14%	0%	6%	40%	
NNSW	1.17	1.03	1.00	1.15	0.96	1.04
CNSW	1.15	1.03	1.00	1.16	0.98	1.04
SNSW	1.22	1.03	1.00	1.35	1.12	1.13
SNW	1.06	1.00	1.00	1.47	0.98	1.02
NQ	1.18	1.08	1.00	0.89	1.07	1.08
CQ	1.10	1.05	1.00	0.44	1.03	1.00
GG	1.15	1.00	1.00	0.63	0.98	1.01
SQ	1.05	1.00	1.00	0.63	0.86	0.92
NSA	1.23	1.07	1.00	0.30	0.98	1.03
CSA	1.06	1.02	1.00	0.45	0.98	0.96
SESA	1.04	1.02	1.00	1.23	0.98	1.00
TAS	1.01	1.04	1.00	1.46	0.98	1.01
WNV	1.03	1.04	1.00	0.85	0.97	0.98
MEL	1.00	1.00	1.00	1.48	0.98	1.00
SEV	1.01	1.03	1.00	1.48	0.97	1.01

Table 18 ***Locational cost factors for PHES development – 24 hour storage***

ISP Sub-region	Sub-Factors: Installation Factor	Equipment Cost Factor	Fuel cost factor	Land and Development	Topography	Locational Cost Factor
Weighting	40%	14%	0%	6%	40%	
NNSW	1.17	1.03	1.00	1.15	0.96	1.02
CNSW	1.15	1.03	1.00	1.16	0.99	1.01
SNSW	1.22	1.03	1.00	1.35	1.03	1.08
SNW	1.06	1.00	1.00	1.47	1.00	1.02
NQ	1.18	1.08	1.00	0.89	0.93	1.01
CQ	1.10	1.05	1.00	0.44	1.05	0.99
GG	1.15	1.00	1.00	0.63	1.00	1.01
SQ	1.05	1.00	1.00	0.63	1.07	0.99
NSA	1.23	1.07	1.00	0.30	1.00	1.06
CSA	1.06	1.02	1.00	0.45	1.08	0.99
SESA	1.04	1.02	1.00	1.23	1.00	1.00
TAS	1.01	1.04	1.00	1.46	1.00	1.01
WNV	1.03	1.04	1.00	0.85	0.90	0.93
MEL	1.00	1.00	1.00	1.48	1.00	1.00

SEV	1.01	1.03	1.00	1.48	1.00	1.01

Table 19 Locational cost factors for PHES development – 48 hour storage

	Sub-Factors					Locational Cost Factor
ISP Sub-region	Installation Factor	Equipment Cost Factor	Fuel cost factor	Land and Development	Topography	
Weighting	40%	14%	0%	6%	40%	
NNSW	1.17	1.03	1.00	1.15	0.77	0.96
CNSW	1.15	1.03	1.00	1.16	1.07	1.03
SNSW	1.22	1.03	1.00	1.35	1.26	1.18
SNW	1.06	1.00	1.00	1.47	0.91	1.02
NQ	1.18	1.08	1.00	0.89	0.86	0.99
CQ	1.10	1.05	1.00	0.44	0.82	0.92
GG	1.15	1.00	1.00	0.63	1.02	1.01
SQ	1.05	1.00	1.00	0.63	1.11	1.01
NSA	1.23	1.07	1.00	0.30	1.18	1.13
CSA	1.06	1.02	1.00	0.45	1.02	0.97
SESA	1.04	1.02	1.00	1.23	1.02	1.00
TAS	1.01	1.04	1.00	1.46	1.00	1.01
WNV	1.03	1.04	1.00	0.85	1.02	1.00
MEL	1.00	1.00	1.00	1.48	1.02	1.00
SEV	1.01	1.03	1.00	1.48	1.02	1.01

Table 20 Locational cost factors for PHES development – 160 hour storage

	Sub-Factors					Locational Cost Factor
ISP Sub-region	Installation Factor	Equipment Cost Factor	Fuel cost factor	Land and Development	Topography	
Weighting	40%	14%	0%	6%	40%	
NNSW	1.17	1.03	1.00	1.15	0.71	0.93
CNSW	1.15	1.03	1.00	1.16	0.86	0.98
SNSW	1.22	1.03	1.00	1.35	1.01	1.08
SNW	1.06	1.00	1.00	1.47	1.02	1.02
NQ	1.18	1.08	1.00	0.89	0.84	0.98
CQ	1.10	1.05	1.00	0.44	1.27	1.08
GG	1.15	1.00	1.00	0.63	1.02	1.01
SQ	1.05	1.00	1.00	0.63	1.02	0.97
NSA	1.23	1.07	1.00	0.30	1.02	1.03
CSA	1.06	1.02	1.00	0.45	1.02	0.97
SESA	1.04	1.02	1.00	1.23	1.02	1.00
TAS	1.01	1.04	1.00	1.46	1.18	1.07
WNV	1.03	1.04	1.00	0.85	1.02	1.01

MEL	1.00	1.00	1.00	1.48	1.02	1.00
SEV	1.01	1.03	1.00	1.48	1.02	1.01

8. Conclusions

This report has provided a detailed summary of the methodology, assumptions and findings to support development of an updated dataset of economic and technical parameters for potential new Pumped Hydro Energy Storage (PHES) in the National Electricity Market (NEM) to support AEMO's technical planning. The main objectives were to identify:

– sites and locations for PHES projects,
– estimate maximum build capacities and
– provide locational cost factors.

The dataset was developed to consider these parameters for each sub-region of the NEM and storage durations of 10, 24, 48 and 160 hours.

The first step in analysis of potential sites and locations was to consider publicly announced PHES projects based on a review of public databases and internet sites. **Forty publicly announced PHES schemes were identified with a combined total of more than 22,000 MW and 329,000 MWh of energy storage.**

Maximum Build Capacity is defined as the highest feasible installed capacity (in megawatt hours), that can be developed at a specific hydropower site, or the upper limit of energy storage capacity that a site can support.

For this study, the Maximum Build Capacity has been aggregated for each National Electricity Market sub-region by identifying and combining possible projects within the sub-region and was estimated by combining two datasets; the publicly announced projects at their announced capacity & duration, and the Australian National University Pumped Hydro Energy Storage Atlas. GIS screening was applied to the Australian National University Pumped Hydro Energy Storage Atlas data to exclude sites that may be impacted by high environmental value or approvals challenges.

Combining the publicly announced projects and Australian National University database projects results in a total estimated **Maximum Build Capacity of 124,600 MW** and a **total energy storage capacity of 7,460 GWh**. This represents more than 10 times the total energy storage requirement identified in the AEMO (2024) ISP. This is a significant increase in maximum build capacity than previously assumed in the ISP, because previous studies were limited to PHES sites within renewable energy zones and not the entire NEM. Interestingly, the new project database is relatively closely aligned with the publicly available database, with the majority of projects in central and northern New South Wales and central and northern Queensland. There were significantly fewer projects identified in Victoria and South Australia, where topography and the GIS screening approach limit the potential scheme sizes.

AEMO's approach to modelling is that base costs are developed for construction within metropolitan areas and locational cost factors are applied where projects are proposed outside of metropolitan areas. The calculation of the locational cost factors has considered: equipment costs, installation costs, fuel connection costs, cost of land and development and a topography cost factor. The topography cost factor was introduced to account for the impact of topography on PHES construction within each NEM subregion. This may be impacted by the waterway length to head ratio, extent of dam embankment due to varying topography and installed capacity due to head & storage size. The topography factor was developed by preparing parametric cost estimates for each site included in the Maximum Build Capacity, then comparing costs for each subregion with national averages.

As Pumped Hydro Energy Storage projects are all unique with systemic risks and many project specific complexities, determining a realistic locational cost factor is difficult and will not necessarily represent every individual project. However, factors were developed for each NEM subregion to assist planning at this scale.

The maximum build capacity has included 160 hour PHES for the first time. Some suitable sites were identified in various sub-regions of the NEM. Noting the very large size and cost of these schemes, further site specific studies are required before committing to a sub-region location for a site.

It is clear from this and other studies (eg. CSIRO Gencost and Aurecon 2024) that battery energy storage systems (BESS) is lower cost for short duration energy storage and provides numerous ancillary services to power networks. The change point in relative costs for energy storage appears to be at approximately 8-10 hours duration, and for greater storage durations PHES becomes lower initial capex cost per MWh and has a significantly longer project lifetime. Revenue modelling of long duration storage will typically show that the value of cost arbitrage (buy low, sell high) that is the main component of revenue for energy storage will be difficult to justify for long duration storage projects. It is essential that government policy support these long duration projects if they are identified as required by AEMO's modelling.

9. References

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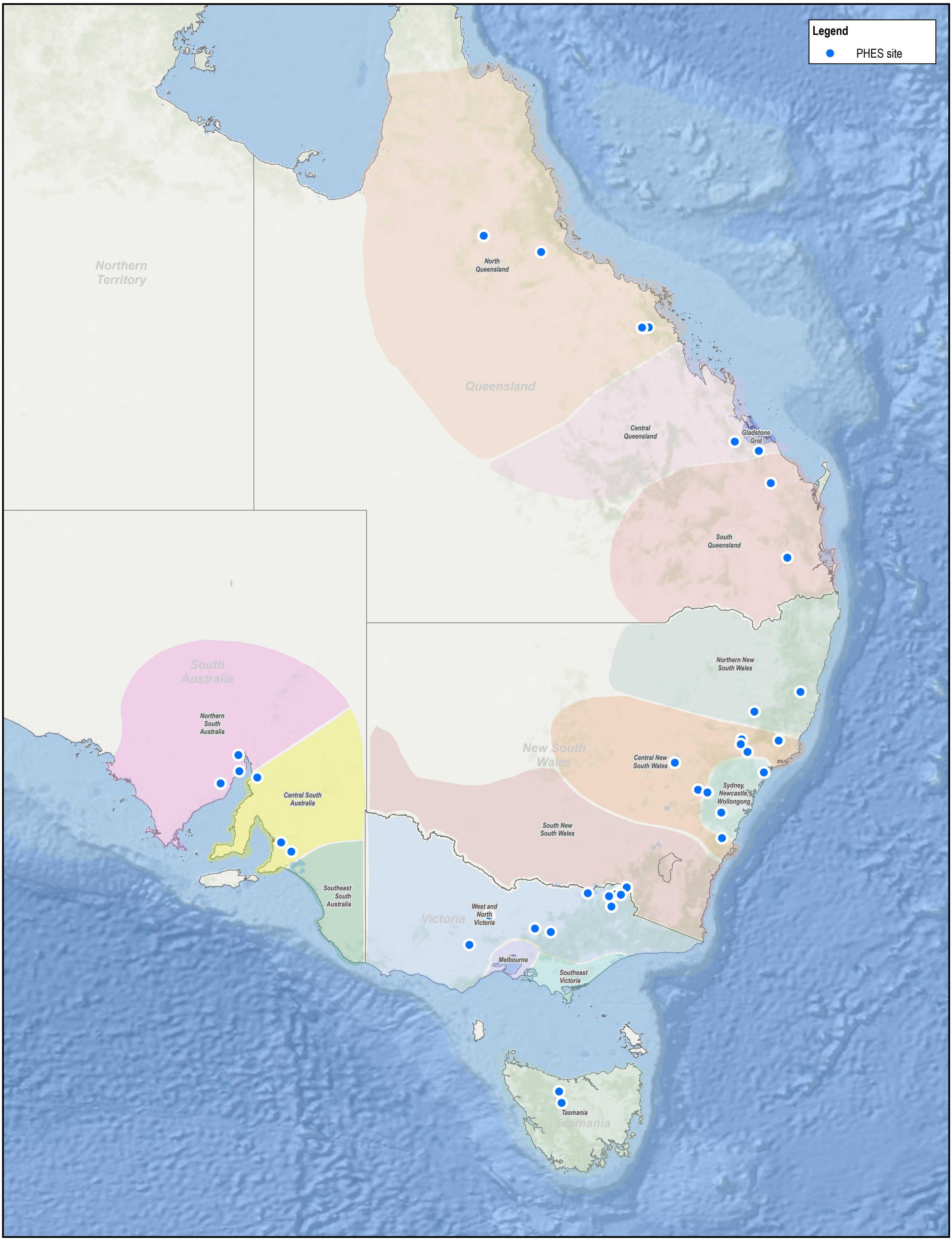
Appendices

Appendix A

GIS Figures A1, A2, A3



Paper Size ISO A4

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Kilometres

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Horizontal Datum: GDA2020
Grid: GDA2020

Australian Energy Market Operator
Pumped Hydro Energy Storage
Parameter Review

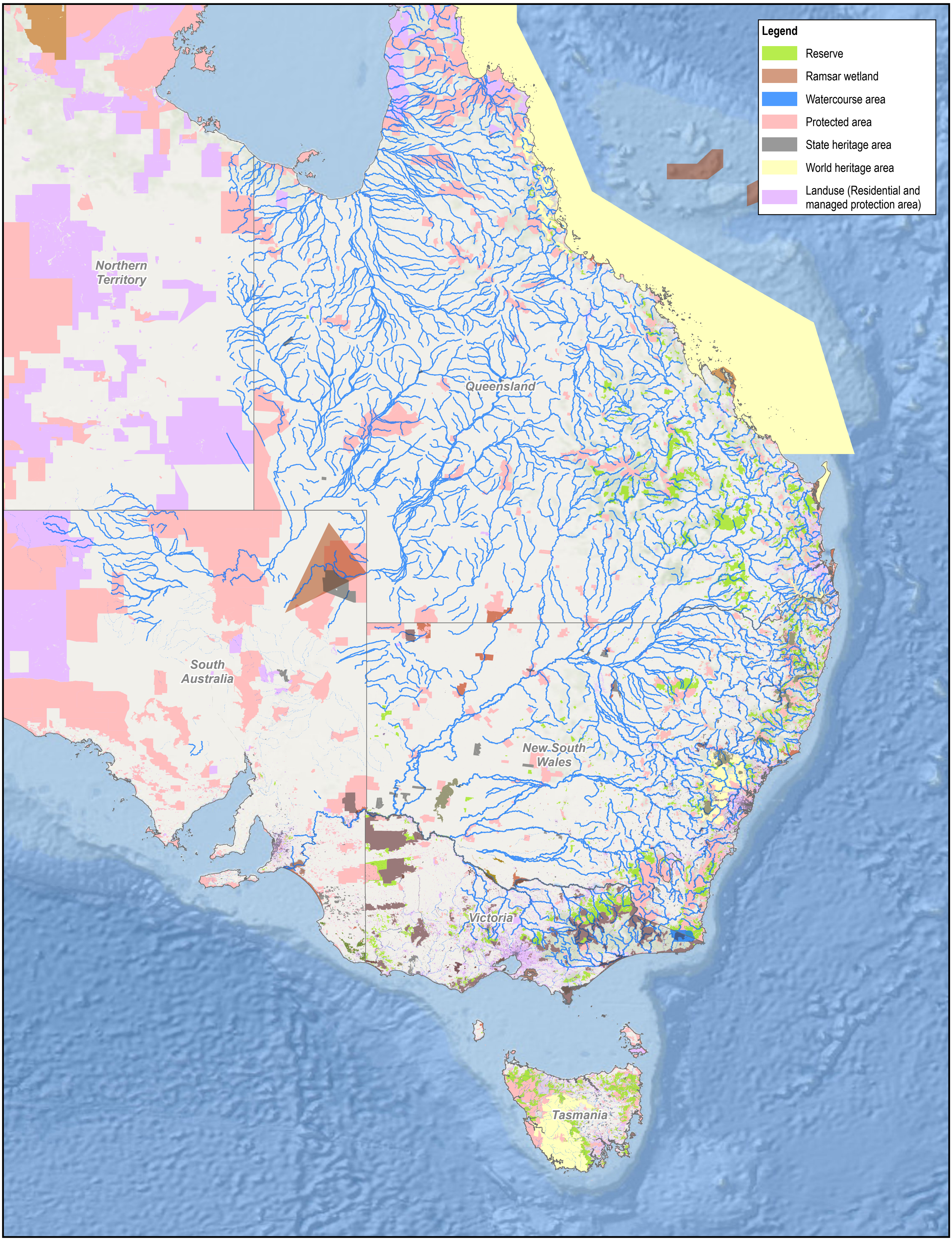
Project No. 12666712
Revision No. 0
Date 17/06/2025

Publicly Announced Sites

FIGURE A1

\\ghdnet\ghd\AU\hobart\Projects\32\12666712\GIS\Maps\Deliverables\12666712_AEMO\12666712_AEMO_Figures.aprx - 12666712_002_PHESSite_rev0
Print date: 17 Jun 2025 - 17:57

Data source: GHD - PHES site (2025); AEMO - NEM subregion (2025); World Ocean Base: Esri, GEBCO, Garmin, NaturalVue.
Created by: eguardian



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Horizontal Datum: GDA2020
Grid: GDA2020

Australian Energy Market Operator
Pumped Hydro Energy Storage
Parameter Review

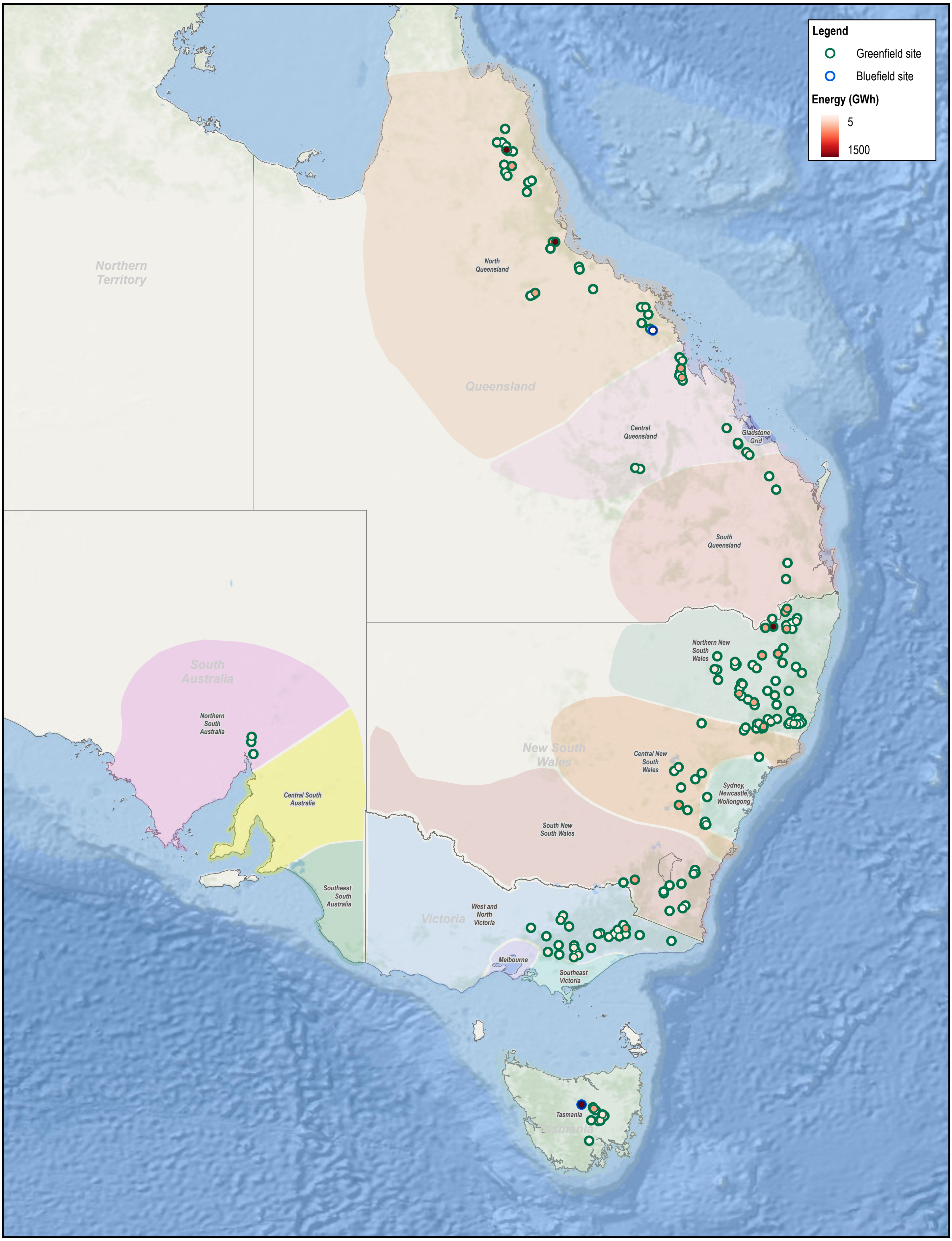
Project No. **12666712**
Revision No. **0**
Date **17/06/2025**

Exclusion zones

FIGURE A2

\\ghdnet\ghd\AU\hobart\Projects\32\12666712\GIS\Maps\Deliverables\12666712_AEMO\12666712_AEMO_Figures.aprx - 12666712_003_ExclusionZone_rev0
Print date: 17 Jun 2025 - 17:59

Data source: ABARES - Landuse (2024); GA - Reserve (2025); DCCEEW - Ramsar wetland, World heritage area (2024), Protected area (2025); Interstate datasets (QLD/NSW/VIC/SA/TAS)- Watercourse area, Interstate heritage area (2025); (World Ocean Base: Esri, GEBCO, Garmin, NaturalVue. Created by: eguardian



Paper Size ISO A4

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Horizontal Datum: GDA2020
Grid: GDA2020

GHD

Australian Energy Market Operator
Pumped Hydro Energy Storage
Parameter Review

Project No. **12666712**
Revision No. **0**
Date **17/06/2025**

PHES Maximum Build Capacity

FIGURE A3

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Print date: 17 Jun 2025 - 17:55

Data source: GHD - Bluefield and Greenfield site location (2025); AEMO - NEM subregion (2025); World Ocean Base: Esri, GEBCO, Garmin, NaturalVue.
Created by: eguardian

Appendix B

Publicly Announced PHES Projects

SN	Project name	Head (m)	Capacity (MW)	Normalised Capacity (MW)	Energy(MWH)	Duration (hr)	Normalised duration (hr)	Cost per MW	Cost per MWh	Total cost (published)	Approx cost Estimate date	Adustment based on ABS cost index	Adjusted cost Estimate	Adjusted Cost per MW	Adjusted Cost per MWh	Normalised Cost per MW	Source (info)	Owner	NEM region	NEM Sub-region
1	Central West	360	325	260	2,600	8	10	$3.69M	$0.46M	$1,200M						$0.00M	Central West Pumped Hydro Project, Australia -	ATCO Australia	NSW	CNSW
2	Glenbawn Pumped Hydro Project		770	770	7,700	10	10									$0.00M		Upper hunter hydro	NSW	CNSW
3	Glennies Creek Pumped Hydro Project		620	496	4,960	8	10									$0.00M		Upper hunter hydro	NSW	CNSW
4	Muswellbrook	500	500	400	4,000	8	10	$1.40M	$0.18M	$700M	2023	1.05	$734M	$1.47M	$0.18M	$1.83M	Muswellbrook Pumped Hydro - Infrastructure P	Mussellbrook Pumped Hydro	NSW	CNSW
5	Phoenix	350	810	960	9,600	12	10	$2.10M	$0.18M	$1,700M	2023	1.05	1782.14	2.20	0.19	$1.86M	Phoenix Pumped Hydro - Infrastructure Pipeline	ACEN Australia Pty Ltd	NSW	CNSW
6	Shoalhaven	218	235	306	3,055	13	10	$1.28M	$0.10M	$300M	2018	1.27	$382M	$1.63M	$0.13M	$1.25M	NSW declares Shoalhaven Hydro project critical	Origin Energy Eraring Pty Ltd	NSW	CNSW
7	Stratford		300	360	3,600	12	10	$2.83M	$0.24M	$850M	2023	1.05	891.07	2.97	0.25	$2.48M	energy monitor	Yancoal	NSW	CNSW
8	Big G	290	800	960	9,600	12	10	$2.88M	$0.24M	$2,300M	2024	1.01	$2,328M	$2.91M	$0.24M	$2.42M	https://bepower.com.au/	BE Power, in partnership with	QLD	CQ
9	Djandori Gung-i Superhybrid project		600	450	10,800	18	24				2022	1.12				$0.00M	First nation clean enery network		QLD	CQ
10	Baroota		250	200	2,000	8	10									$0.00M	Baroota, Australia	UPC\AC Renewables	SA	CSA
11	Highbury		300	135	1,350	5	10	$1.33M	$0.30M	$400M	2021	1.21	484.19	1.61	0.36	$3.59M	Only one of six pumped hydro power storage pr	Tilt Renewables	SA	CSA
12	Kanmantoo		250	200	2,000	8	10	$3.40M	$0.43M	$850M						$0.00M	Suspended pending completion of mining		SA	CSA
13	Dungowan	500	300	300	3,000	10	10	$1.93M	$0.19M	$580M	2022	1.12	650.40	2.17	0.22	$2.17M	Dungowan+CBA+Press+Release.pdf	EDF Group	NSW	NNSW
14	Oven Mountain	600	900	720	7,200	8	10	$2.19M	$0.27M	$1,970M	2024	1.01	$1,994M	$2.22M	$0.28M	$2.77M	Kemsay share council, Gateway	OMPS Pty Ltd	NSW	NNSW
15	Capricornia	300	750	1,200	12,000	16	10	$3.83M	$0.24M	$2,870M	2023	1.05	3008.67	4.01	0.25	$2.51M	Capricornia Pumped Hydroelectric Energy Stora	Capricornia Energy Hub	QLD	NQ
16	Capricornia Phase 2		650	1,200	12,000	16	10									$0.00M	Danish renewables giant buys Queensland clean energy hub – pv magazine Au		QLD	NQ
17	Hells Gates	314	808		8,080					$2,200M						$0.00M	National water grid authority		QLD	NQ
18	Kidston	200	250	200	2,000	8	10	$3.10M	$0.39M	$775M	2021	1.21	$938M	$3.75M	$0.47M	$4.69M	Australian Renewable agency	Genex Power Ltd	QLD	NQ
19	Pioneer-Burdekin		5000	5,000	120,000	24	24	$2.40M	$0.10M	$12,000M	2022	1.12	13456.54	2.69	0.11	$2.69M	Pioneer-Burdekin Hydro Electric Scheme Update - Mackay Conservation Grou		QLD	NQ
20	Cultana		225	180	1,800	8	10	$2.12M	$0.27M	$477M	2018	1.27	$608M	$2.70M	$0.34M	$3.38M			SA	NSA
21	Goat Hill	200	230	184	1,840	8	10	$1.78M	$0.22M	$410M	2018	1.27	522.35	2.27	0.28	$2.84M	Development approval granted for 230-MW Go	Delta Electricity	SA	NSA
22	South Midddleback Ranges Mine	175	90	39	390	4	10	$1.89M	$0.44M	$170M						$0.00M			SA	NSA
23	Snowy 2	700	2200	2,188	350,000	159	160	$5.45M	$0.03M	$12,000M	2024	1.01	12144.17	5.52	0.03	$5.55M	Snowy Hydro 2.0 costs blowout confirmed to be	Snowy Hydro Pty Ltd	NSW	SNSW
24	Centennial Newstan Colliery Fassifern		600	200	2,000	3	10									$0.00M	Energy storage plan for shuttered Fassifern coal mine - Australian Renewable		NSW	SNW
25	Lake Lyell	255	335	268	2,680	8	10	$2.99M	$0.37M	$1,000M	2023	1.05	1048.32	3.13	0.39	$3.91M	Lake Lyell Pumped Hydro - Infrastructure Pipelir	EnergyAustralia	NSW	SNW
26	Western Sydney Pumped Hydro	400	1000	800	8,000	10	10	$3.50M		$3,500M	2024	1.01	$3,542M	$3.54M		$4.43M	Proposed $4bn pumped hydro project could pov	ZEN Energy Pty Ltd	NSW	SNW
27	Big-T		400	400	4,000	10	10	$4.13M	$0.41M	$1,650M	2022	1.12	1850.27	4.63	0.46	$4.63M	https://bepower.com.au/	BE Power, in partnership with	QLD	SQ
28	Borumba	330	2000	2,000	48,000	24	24	$9.20M	$0.38M	$18,400M	2023	1.05	$19,289M	$9.64M	$0.40M	$9.64M	NS energy	Queensland Hydro Pty Ltd	QLD	SQ
29	Mt. Rawdon		2000	2,000	20,000	10	10	$3.07M	$0.31M	$6,140M						$0.00M	Mt Rawdon Pumped Hydro project | State Deve	Evolution Mining and ICA Par	QLD	SQ
30	Lake Cethana	539	750	625	15,000	20	24	$1.50M	$0.08M	$1,125M	2019	1.24	$1,400M	$1.87M	$0.09M	$2.24M			TAS	TAS
31	Lake Rowallan	403	600	604	14,500	24	24	$1.65M	$0.07M	$990M	2019	1.24	1231.69	2.05	0.08	$2.04M	Battery of the Nation – Pumped Hydro Energy Storage Projects report		TAS	TAS
32	Tribute Power Station Redevelopment		500	650	15,600	31	24	$1.83M	$0.06M	$915M	2019	1.24	$1,138M	$2.28M	$0.07M	$1.75M	Battery of the Nation – Pumped Hydro Energy Storage Projects report		TAS	TAS
33	Bendigo Mines		30	18	180	6	10									$0.00M			VIC	WNV
34	Berringama	350	250	250	2,500	10	10	$3.16M	$0.32M	$791M	2025	1.00	$791M	$3.16M	$0.32M	$3.16M	Microsoft Word - PE-UMPHES-RPT-001(A) UPPER MURRAY PHES SCOPING RE		VIC	WNV
35	Big S		400	400	4,000	10	10	$2.50M	$0.25M	$1,000M	2024	1.01	1012.01	2.53	0.25	$2.53M	www.allens.com.au	BE Power	VIC	WNV
36	Bunkers hill		300	240	2,400	8	10	$3.33M	$0.42M	$1,000M						$0.00M			VIC	WNV
37	Cudgewa			70	700		10				2025	1.00	0.00			$0.00M	Microsoft Word - PE-UMPHES-RPT-001(A) UPPER MURRAY PHES SCOPING RE		VIC	WNV
38	Dartmouth		315	378	3,780	12	10									$0.00M	AGL eyes quicker and cheaper pumped hydro "c	AGL	VIC	WNV
39	Eildon		180	72	720	4	10									$0.00M	AGL eyes quicker and cheaper pumped hydro "conversions" to back up wind a		VIC	WNV
40	Tallangatta	420	320	320	3,200	10	10	$3.16M	$0.32M	$1,012M	2024	1.01	$1,024M	$3.20M	$0.32M	$3.20M	Indigo-Power-Upper-Murray-PHES-Scheme-Project-Brief_20240227.pdf		VIC	WNV
41	Tintaldra			100	1,000		10				2025	1.00	0.00			$0.00M	Microsoft Word - PE-UMPHES-RPT-001(A) UPPER MURRAY PHES SCOPING RE		VIC	WNV
42	Wabba			15	150		10				2025	1.00				$0.00M	Microsoft Word - PE-UMPHES-RPT-001(A) UPPER MURRAY PHES SCOPING RE		VIC	WNV
	x- TOTAL		**27143**	**26,117**	**727,985**															

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