

PUMPED HYDRO COST MODELLING

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Executive summary

To inform future modelling of Australia's National Electricity Market (NEM), better information is needed on the cost of pumped hydro energy storage projects (PHES) across the NEM states. TasNetworks engaged Entura to develop a cost model for PHES to inform its market modelling for Project Marinus and with a view to sharing the conclusions of the study with the Australian Energy Market Operator (AEMO) for use in future Integrated System Plan (ISP) modelling.

Neither capital costs (CAPEX) nor operations and maintenance costs (OPEX) for PHES in Australia are well understood in the market. This is mainly due to the fact that no PHES have been built in Australia for over 30 years. Around the rest of the world, however, rapid uptake of the technology has continued during that period. As renewable penetration increases and thermal plant retirements continue, interest in PHES in Australia grows. PHES has the potential to play a major role in firming renewables so better understanding of both CAPEX and OPEX are required by electricity market stakeholders.

This study draws on the experience of Entura, who has current data on the costs of developing, implementing and operating hydropower projects around the world as well as exposure to the PHES market in Australia. Entura has drawn on the wealth of experience within Hydro Tasmania to support the estimation of OPEX for PHES.

A cost model has been developed for the capital costs of PHES across the NEM states. The model is applied to data from the Australian National University's atlas of pumped hydro in Australia to develop over 400 "projects", which have then been analysed to determine data on the likely cost of hydropower project across different regions in the NEM. Results have been analysed for the "top" 25% of projects identified in the geographic information system (GIS).

This study has identified total potential across the various identified PHES regions of around 24,100MW with energy in storage of 390GWh. This can be broken down in terms of storage size: \$1.48m/MW for 6 hours storage, \$1.70m/MW for 12 hours, \$2.11m/MW for 24 hours storage and \$2.75m/MW for 48 hours storage. The high cost of 48 hour storage projects is mainly due to a low number of such projects.

The study has found that the cost of PHES projects vary across regions, generally in relation to the number of potential project sites in each region. Based on the data for 6 hour storage duration projects, Tasmania has the cheapest opportunities at an average of about \$1.2M/MW installed. Project costs in NSW regions range from \$1.4m/MW to \$1.6m/MW. Victorian sites have an average capital cost of \$1.5m/MW, Queensland regions range from \$1.5m/MW to \$1.7m/MW and South Australian project costs average \$1.9m/MW. Project costs generally increase for increased storage durations.

Projects linking existing, very large storages, such as the Snowy 2.0 project, are not considered in this study. It's likely that there are project sites across the NEM that have not been included in this study and which may be better than those identified in this analysis.

OPEX includes the full business cost of operating and maintaining plant, as an incremental asset in an existing portfolio. Both variable operation and maintenance costs (VOM) and fixed operation and maintenance costs (FOM) have been analysed, although it has been found that VOM does not apply to hydropower plant – all operations and maintenance costs should be captured as FOM.

FOM is dependent of various factors, including whether the project is a stand-alone project or part of portfolio, the age of the plant and the installed capacity of the project.

This study has found that FOM should be taken as \$16,000/MW/yr. Factors should be applied to account for station age and installed capacity.

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1. Introduction

Pumped storage hydropower projects are a natural fit in an energy market with high penetration of renewable energy as they help to maximise the use of the renewables that are subject to the vagaries of the weather. Pumped storage provides a load when there is a surplus of supply and storage that can be recovered later. It also provides a reliable and immediate source of energy to supply electricity to the market when renewable sources cannot.

The Australian Energy Market Operator (AEMO) has completed the inaugural Integrated System Plan (ISP) for the National Electricity Market (NEM) (AEMO, 2018). AEMO, in developing the ISP, has taken a view of pumped hydro energy storage costs, both CAPEX and OPEX, and capabilities (storage size) which limits the attractiveness of pumped hydro and ensures that significant development of pumped hydro capacity in the NEM is not required for many years.

Pumped hydro considered by the Battery of the Nation initiative considers storage sizes ranging from 7 to 48 hours. ISP modelling considered storage as having only 2 hours storage in the case of battery energy storage systems and 6 hours in the case of pumped hydro. The value in larger storages is different to that of smaller storages, which will be considered by AEMO in future revisions of the ISP, assuming credible evidence is provided to support this change in assumptions.

This study is intended to inform market modelling with a better view of potential costs and capabilities for pumped hydro energy storage across Australia's National Electricity Market (NEM). It is not intended to be representative of individual opportunities. Pumped hydro energy storages (including conventional hydropower stations) are highly sensitive to the topography and remoteness of the site.

The methodology adopted in this study provides a reasonable way to estimate the cost effectiveness and capability of the better opportunities in certain regions across the NEM – however it is expected that within those regions there will be sites which are more or less expensive than the regional prices presented.

The report is split into two sections; a basis for estimating capital costs for pumped hydro projects, and robust estimates of operational costs for pumped hydro projects.

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2. Capital Costs

2.1 Introduction

2.1.1 Objective

The objective of this analysis of capital costs is to provide reasonable estimates for typical projects across various regions in the NEM.

To achieve this objective a basis has been developed for the estimates using rates developed from recent experience and detailed estimates by Contractors. A tool has been developed for estimating, at a high level, the capital cost of any project based on just a few key inputs:

- Head;
- The slope distance between storages;
- The design discharge of the project; and
- The storage duration (the length of time at which the project can operate at full load).

2.1.2 Limitations of this analysis

Hydropower projects are bespoke by nature – no two sites are the same; “off the shelf” equipment is not widely used. For this reason, applying unit costs to hydropower projects is an exercise that can potentially lead to either underestimation or overestimation of capital costs.

Many variables can impact on the costs for each site. These include:

- Local topography
Topography determines the potential size of project, the available head and the length of waterways, which are major cost drivers.
- Geological conditions of both dams / reservoirs, and intakes
For any type of dam / reservoir, geological conditions of the dam foundation and reservoir rim are important in regards to designing the dam appropriately. The type and shape of a dam is directly related to the specific site conditions and stability of the reservoir rim is impacted especially for pumped storage projects where daily water level fluctuations are expected. Without a site visit, geological review, and site-specific geotechnical investigation, the assumed design and associated cost is very approximate and could be misleading.
- Geological conditions of waterways and power stations
New pumped hydro projects are likely to involve underground stations with waterways being in the form of shafts and tunnels. This is a key risk that requires sub-surface geotechnical investigations in the feasibility stage. However, a site visit associated with a desktop review, mapping and analysis could provide a high level idea of the quantum of this risk. To account for this risk without specific details of projects known, contingency is added to the cost estimates.

- Environmental and approval issues

Environmental and approval issues can be underestimated significantly. Environmental and approval constraints cannot be identified without a proper review and mapping. GIS layers for nature conservation and cultural heritage sites have been used in the screening stage to exclude such sites but this does not mean that any identified sites outside these zones has no issues to proceed.

- Flood risks

Flood risks for on-river dams will have direct impact on the dam's consequence categories which will ultimately result in additional costs for the dam and its appurtenant structures.

2.2 Approach to estimation

In the absence of such data, high level cost estimation was undertaken for different opportunities based on Entura's previous experience and available international data. Summary of assumptions relating to this high level cost estimation is as follows:

2.2.1 Basis of estimates

Development of the capital cost of a project requires estimation of the cost of various project components, including;

- Upper and lower reservoirs;
- Waterways;
- Power station (including electromechanical equipment and sub-station);
- Access tunnels and construction adits;
- Access roads to site;
- Transmission lines;
- Miscellaneous items, such as hydromechanical equipment (gates, valves etc), monitoring instrumentation, water balancing pumps and pipework, etc.;
- Other development costs.

The basis for estimation of these components of the works follows.

Opportunities exist to re-purpose existing hydro plant for use as pumped hydro projects. These projects generally don't require new dams but they can have significant impact on existing operations while construction is occurring. Such projects are not considered in this study.

2.2.1.1 Upper and lower reservoirs

Different dam types can be used in the development of a pumped hydro project. The selection of dam type will be informed by the topography, geology, etc. For the purposes of this study, only off-stream dams are considered. It is assumed other dam types would cost the same or less than the off-stream dams.

Off-stream dams (e.g. Turkey's nest dams)

Off-stream dams are assumed to be constructed using homogenous rockfill with durable and economic liners on the water side. It is acknowledged that this generic arrangement might not be the optimal type and arrangement for some sites. However, given that these dams are to be constructed either on top of a ridge or at the bottom of hilly areas with rockfill sources available on site, a balanced earthmoving activity (cut and fill with compaction) is potentially the most economical solution.

Given an assumed water level fluctuation of 15 m, a nominal freeboard of 2 m, and a maximum dead storage depth of 3 m close to the intake area, the total height of the dam would be around 20 m on the water side. On the external side this height varies depending on the topographical conditions. This results in the cost of storage being a squared function. i.e double the cost gives four times the storage.

It is assumed that an average 15m dam with 2(H):1(V) internal slope and say 1.5(H):1(V) external slope needs to be constructed around the identified area. This is a cross sectional area of 300 m² for the entire length of the reservoir perimeter. Also it is assumed that the liner (including sandy layer underneath) is required over the entire internal slope of the reservoir and the reservoir floor area.

Existing dams/reservoirs and natural lakes

Using existing dams/reservoirs and natural lakes negates the need to construct a new dam, however connecting the new waterways to the existing storage requires a new intake.

Some stabilisation works would be required on the existing dam itself and/or the reservoir rim. This is a major unknown factor in the cost estimation as it is very site specific and depends on the local topography and geological and geotechnical conditions. A judgement on the need and extent of such works can realistically be made only after initial site investigations.

Natural sinks / mining pits

Natural sinks and mining pits are assumed to have stable walls either naturally or based on the mining requirements assuming that there is no water level fluctuation against them. Such transient and cyclic loading, which is inevitable for a pumped hydro project can de-stabilise the pit wall depending on the geological features, their alignments and characteristics. It is likely that pit wall stabilisation would need to be carried out within the fluctuation zone.

A lower intake needs to be constructed in a similar fashion to those in existing dams/reservoirs.

This analysis does not have the resolution to consider mining pits for use as pumped hydro storages.

Valley dams

For valley dams (on-stream storages) a number of considerations need to be taken into account, including:

- The foundation conditions;
- The size and position of the spillway;
- The location and size of the intake structure;

- Upstream and downstream dam slopes along with dam crest width;
- The alignment of the dam axis;
- Temporary diversion arrangements.

Cost estimation of the reservoir rim stabilisation and intake structure is similar to that of existing dams.

2.2.1.2 Intakes

This study assumes that two new intakes will be required – one at both the upstream and downstream ends of the waterway. Site specific temporary works such as a cofferdam may be required to construct the intake.

For the purposes of this study, it is assumed that the intake is a horizontal diffuser shape that is permanently submerged under water with adequate depth at the inlet. As an approximation, it can be assumed that the cost increases/decreases with the square root of the discharge for such a structure. This is based on keeping the design average velocity of the water at the intake to about 1m/s.

2.2.1.3 Waterways

For a pumped hydro project, it is normally optimal to have a layout with the shortest waterways connecting the two reservoirs. This not only reduces the head losses in the system (thus increasing the cyclic efficiency) but also reduces the project costs. Based on this, and taking into consideration that fixed speed reversible units (that are often the optimal / economic arrangement) require substantial submergence in relation to the minimum operating level of the lower reservoir; underground power stations and waterways are the most economic solutions. There are some occasions that surface waterways and power stations or a combination of both could be more favourable, such as when design discharges are relatively low, so the cost of surface penstocks is relatively low.

For the purpose of this study, fully underground arrangements have been assumed with about 25% of the average gross head being steel lined (including the branches) and the rest concrete lined. Other assumptions are:

- The average velocity in the largest section of the waterways is about 4 m/s
- At least two pump/turbine units are involved.
- A single shaft/tunnel arrangement is considered with no consideration of the practicalities of installing steel liners in large diameter pressure tunnels.

2.2.1.4 Power Station (including switchyard)

Electrical and mechanical (E&M)

Estimation of E&M costs relates significantly to the head and discharge of the station as well as type of technology adopted. It appears that for large scale pumped storage projects, fixed speed reversible units are the most economic choice most of the time.

Variable speed units and ternary (units with separate pump impellers and turbine runners) on the same shaft) sets are in the order of 30% and 50% more expensive respectively, which equates to an increase in total project cost in the order of 10% to 15%. Depending on the situation, there may be value in installing a combination of fixed and variable speed machines. This is outside the scope of this study.

For the purposes of this study, fixed speed units are assumed. The cost of these units is proportional to head and flow.

Also for the purpose of this study, the installed capacity of all projects is limited to 600MW.

Civil

Civil costs of the power station, switchyard and associated miscellaneous elements such as cable/exhaust shaft/tunnels or routes are absolutely site specific and any estimation could be up to 30% over/under estimation. The cost of powerhouse civil works is also proportional¹ to the head and flow of the project, since the size of the machines governs the size of the powerhouse.

2.2.1.5 Access tunnel and construction adits

The cost of access tunnels is site specific as the shortest access route to the station is defined by the topographic conditions of the site and the location of existing roads. For the purpose of this study, it is assumed that this length is around 75% of the horizontal distance between the two reservoirs. It is assumed that that the tunnel is 6m diameter. An allowance of 500m has been allowed for construction adits.

2.2.1.6 Access roads

It is assumed that access to site is available for both construction and operation. A unit rate for site access roads is adopted and applied to a length of access road that is proportional to the head of the project. i.e. site access roads are assumed to have an average gradient of 10%, meaning for a project with 400m head, the assumed site access road length will be about 4km.

A flat rate is adopted for required upgrade works for roads to site.

2.2.1.7 Transmission line

Transmission line costs are made up of:

- a fixed component that covers the cost of new substation works – both at the power station and the remote connection; and
- a variable cost that accounts for the cost of a new transmission line to the nearest transmission substation.

¹ Turbine dimension is proportional to square root of flow. Therefore, if flow is doubled, the volume of powerhouse increase roughly to $1.414 \times 1.414 \times 1.414 = 2.82$ times. Turbine size is not affected by head. Generator size is affected by head and flow and affected by speed. For constant speed, double power = $1.414 \times$ generator diameter with same length

Transmission line costs do not consider the cost of wider transmission augmentation. It is assumed that this cost will not be the responsibility of the developer of the pumped hydro project.

2.2.1.8 Miscellaneous

Items such as hydraulic instrumentation, hydro-mechanical works such as gates, valves, etc. that is not included in the power station E&M, water balancing pumps and pipework, etc. An estimation of 2% of total cost of the works excluding access roads/tunnels is adopted.

2.2.1.9 Other development Costs

The direct cost estimations above include contractor's indirect costs and profit.

- Preliminaries and general – 20%
- Design and approvals – 10%
- Owner's costs – 5%
- Contingency – 20%

2.2.2 Cost Calculator

Using the basis of estimates described in Section 2.2.1, a cost calculator developed for theoretical pumped hydro projects with various physical characteristics including:

- Gross head,
- Waterway length,
- Storage Volume; and
- Storage time²
- Distance to nearest NEM substation.

From these inputs, various parameters are determined for use in the cost estimate including:

- Design discharge (m³/s);
- Installed capacity (MW);
- Energy in storage (MWh);
- Storage perimeter (m);
- Embankment volume (m³);
- Embankment liner area (m²);
- Waterway diameter (m); and
- Site access roads lengths.

From these parameters, costs are estimated for the following elements:

² This study considers storage sizes of 6, 12, 24 and 48 hours.

- Upper reservoir;
- Lower reservoir;
- Intakes;
- Waterways;
- Power station (E&M);
- Power station (civil);
- Access tunnels and construction adits;
- Access roads to site;
- Transmission line;
- Miscellaneous; and
- Other development costs (preliminaries and general, design and approvals, owner's costs, contingency).

An example calculation from the tool is provided in Table 2.1 and Table 2.2.

Table 2.1: Sample calculation inputs

Inputs		
Serial	Description	Value
<i>Input Values</i>		
1	Head, H (m)	400
2	Waterway length, L (m)	1,500
3	Storage volume (Mm ³)	4.5
4	Storage time (hr)	12
5	Transmission length (km)	20
<i>Calculated values</i>		
5	Length: Head Ratio	3.8
6	Flow (m ³ /s)	104
7	Pump/Turbine Efficiency ³	94%
8	Motor/Generator Efficiency ³	98%
9	Installed Capacity (MW)	377
10	Energy in storage (MWh)	4,518
11	Storage perimeter (m)	1,942
12	Embankment volume (m ³)	912,564
13	Embankment liner area (m ²)	386,832
14	Waterway diameter (m)	5.8
15	Access road length (km)	4.0

³ Use of these values gives a round trip efficiency of 85%. This calculation does not take into account headloss or transmission losses, which would typically result in round trip efficiency of 75% to 80%.

Table 2.2: Sample cost estimate

Cost Estimate		
Serial	Description	Amount
1	Upper reservoir	\$53,364,852
1.1	Embankment	\$45,628,209
1.2	Liner	\$7,736,643
2	Lower reservoir	\$53,364,852
2.1	Embankment	\$45,628,209
2.2	Liner	\$7,736,643
3	Intakes	\$16,137,431
4	Waterways	\$47,636,431
5	Power Station (E&M)	\$137,313,041
6	Power Station (civil)	\$34,328,260
7	Access tunnels and construction adits	\$24,000,000
8	Access roads to site	\$2,000,000
9	Transmission line	\$16,000,000
10	Miscellaneous	\$8,082,897
11	Sub-total works	\$412,227,764
12	Other development costs	\$267,948,046
12.1	Preliminaries and general – 20%	\$82,445,553
12.2	Design and approvals – 10%	\$41,222,776
12.3	Owner’s costs – 5%	\$20,611,388
12.4	Contingency – 20%	\$123,668,329
13	Total	\$680,175,810

2.2.3 Benchmarking

The cost estimation tool has been benchmarked against public figures for Australian projects currently under development. The benchmarking is shown in Table 2.3. Calculation tables similar to that shown in Table 2.1 are provided in Appendix A.

It should be noted that contingency is included in the cost estimates for the benchmarking exercise. The unknowns for projects that have been subject to further analysis are likely to have been assessed and may result in reduced contingencies being applied; hence the higher costs from the cost calculator. Additionally, the benchmarked projects variously include or exclude the cost of transmission connection. Transmission is therefore excluded from the costs of projects used in the benchmarking exercise.

2.3 Selection of “projects”

One of the objectives of this study is to identify any differences in costs for pumped hydro projects across different regions. In order to reduce the potential options to a reasonable number, regions are defined according to AEMO’s proposed Renewable Energy Zones. It is expected the costs of attractive projects within REZ’s will be representative of the cost of all potentially attractive projects. The reason for grouping projects within REZ’s is the potential benefit of synchronous generation within these zones and the likelihood of sufficient transmission capacity once the REZ is implemented.

Table 2.3: Capital cost estimation benchmarking

Project Name	Location	Proponent	Installed Capacity (MW)	Reported Unit Cost (\$m/MW)	Estimated Cost (\$m) [#]	Estimated Unit Cost (\$m/MW)	Estimated/Reported
Kidston (K2-Hydro)	QLD	Genex Power Limited	250	1.6	488	2.0	1.22
Snowy 2.0	NSW	Snowy Hydro	2000	2.25	5,733	2.9	1.27
Cultana	SA	Energy Australia	225	2.1	625	2.8	1.32
Goat Hill	SA	Altura Group	230	1.8	529	2.3	1.28
Highbury	SA	Tilt Renewables	300	1.4	628	2.1	1.50
Kanmantoo	SA	Hillgrove Resources	220	1.0	440	2.0	2.00

[#]Estimated using the tool developed for use in this study

Selecting sites within each REZ was done using the ANU database of potential upper storages (Lu et al, 2018). Potential lower storages were sited near (within 5km) of clusters of upper storages. In all, 49 lower storage sites were identified. Using GIS, the selected lower storages were paired within upper storages within 5km to create “projects”. This methodology may result in sub-optimal design however, for this level of study, the approach is considered appropriate.

“Projects” identified in the GIS were defined in terms of head (the difference in elevation between the upper and lower reservoir), waterway length (the distance between the upper and lower reservoir), storage volume (ANU upper storage volume adopted) and storage time (6 hours, 12 hours, 24 hours and 48 hours). An algorithm in the GIS then applied the cost calculator as described in Section 2.2.

Siting of projects does not consider land tenure, geological conditions or local environmental/social values beyond excluding sites within CAPAD designated areas. Projects considered in this study may not be viable from a technical perspective. Further, there are likely to be many project sites outside REZ’s.

In total, 410 “projects” were identified across 12 REZ’s. The distribution of projects is shown in Figure 2.1.

REZ’s are grouped to enable regional statistics to be provided for PHES projects. PHES regions and the REZ’s included in those regions are shown in Figure 2.2 and described in Table 2.4. REZ’s not included in the PHES regions had no PHES projects identified for inclusion in this study.

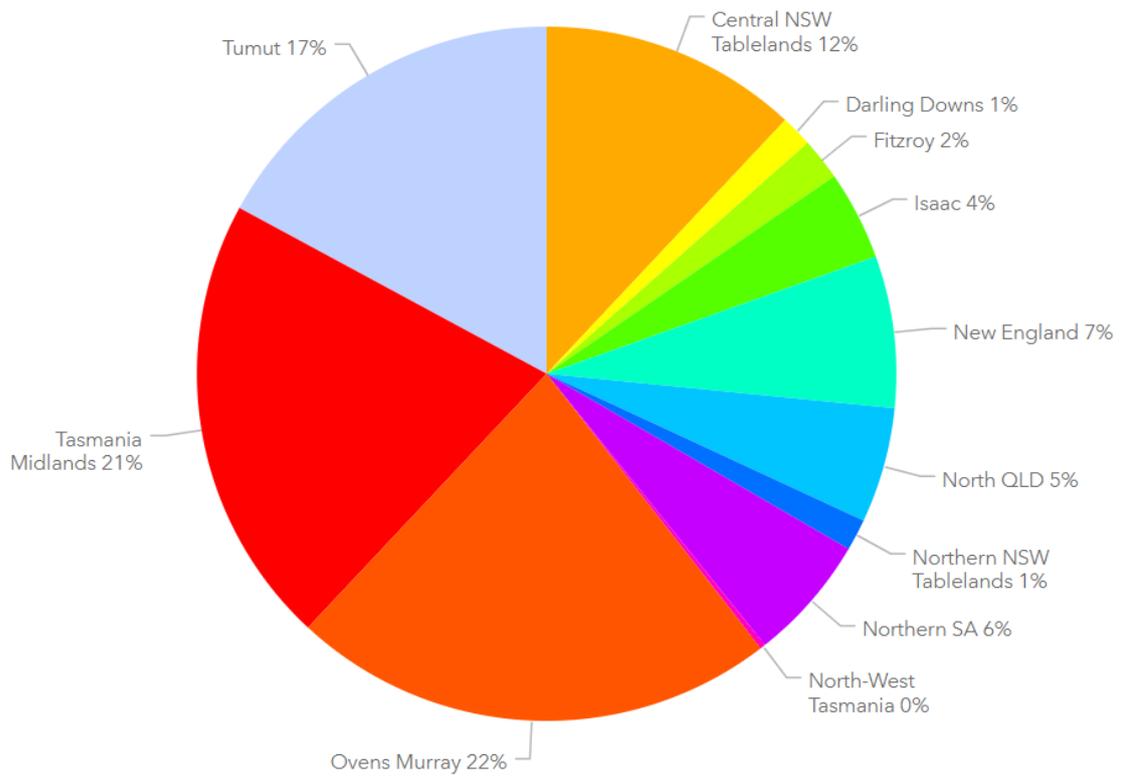


Figure 2.1: Distribution of identified projects by REZ

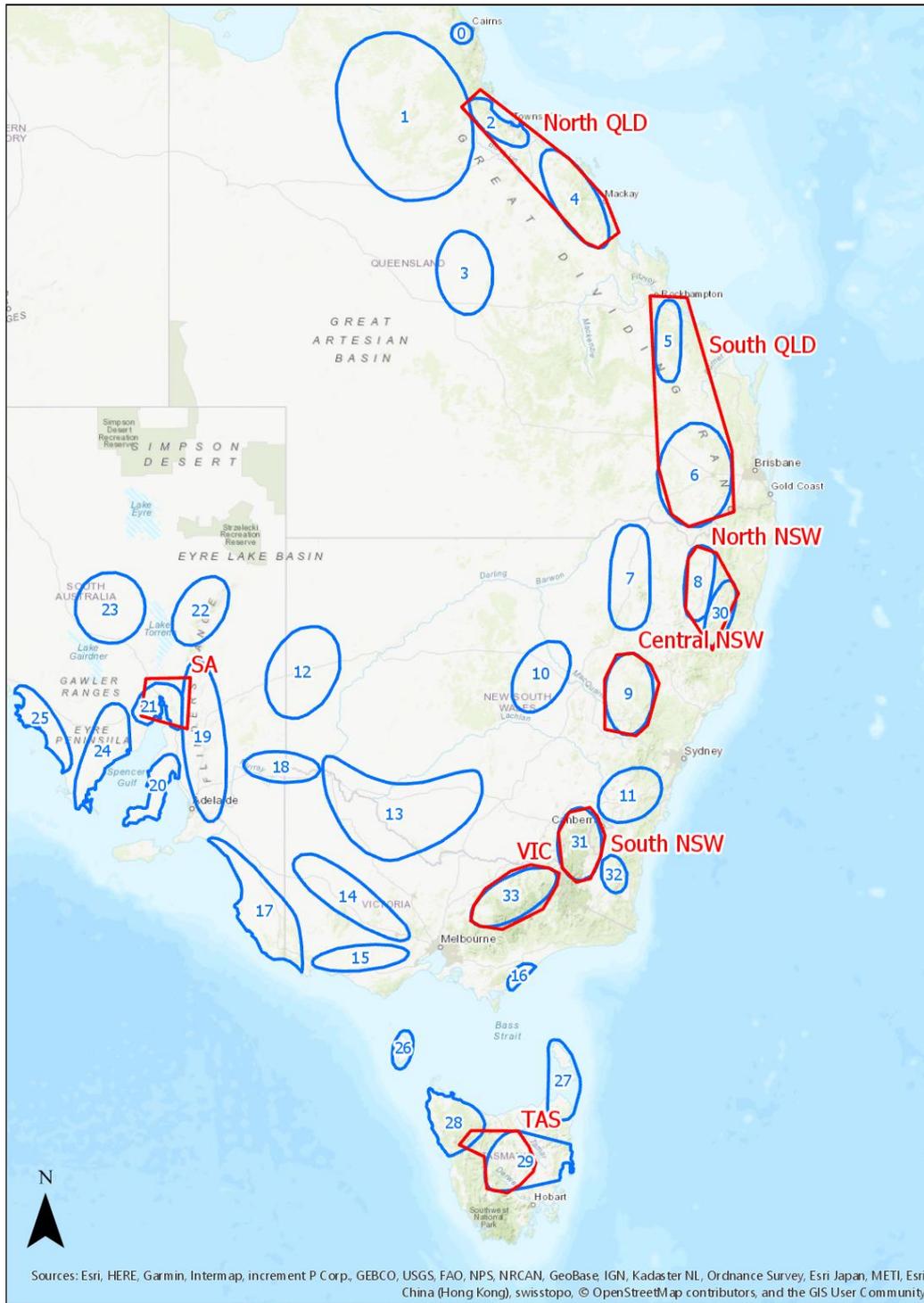


Figure 2.2: Map showing REZ's included in PHES regions

Table 2.4: REZ's included in PHES regions

PHES Region	Included REZ's
North Queensland	North Queensland Isaac
South Queensland	Fitzroy Darling Downs
North New South Wales	Northern New South Wales New England
Central New South Wales	Central New South Wales
Southern New South Wales	Tumut
Victoria	Ovens Murray
South Australia	Northern South Australia
Tasmania	Tasmania Midlands North-West Tasmania

2.4 Analysis of results

2.4.1 Regional cost of pumped hydro energy storage projects

Costs are presented for the “top” 25% of projects from the identified list. These spread across the various PHES regions. Results in terms of indicative installed capacity, energy in storage and the unit cost of capacity for the top 25% of projects are provided in the following charts and tables. It should be noted that the above categories are not mutually exclusive. A single project could be repeated across multiple “energy in storage” analyses.

For 48 hour projects, the sample size is significantly smaller than for projects with shorter duration storages. The costs of some 48 hour projects are considerably higher due to the reduced installed capacities. Excluding projects with unit costs of over \$3m/MW brings the average cost down to \$2.39m/MW, which brings the cost of 48 hour projects into line with the costs of 6, 12 and 24 hours projects.

Table 2.5: 6 hour storage PHES projects across various PHES Regions

PHES Region	Total capacity of projects (MW)	Total energy in storage (MWh)	Average unit cost of capacity (\$m/MW)
Central NSW	1,200	7,200	1.53
North NSW	600	3,600	1.36
North QLD	1,200	7,200	1.53
SA	500	2,900	1.93
South NSW	1,600	9,600	1.63
South QLD	600	3,600	1.73
TAS	2,200	13,000	1.16
VIC	1,200	6,900	1.53
	Total: 9,100	Total: 54,000	Average: 1.48

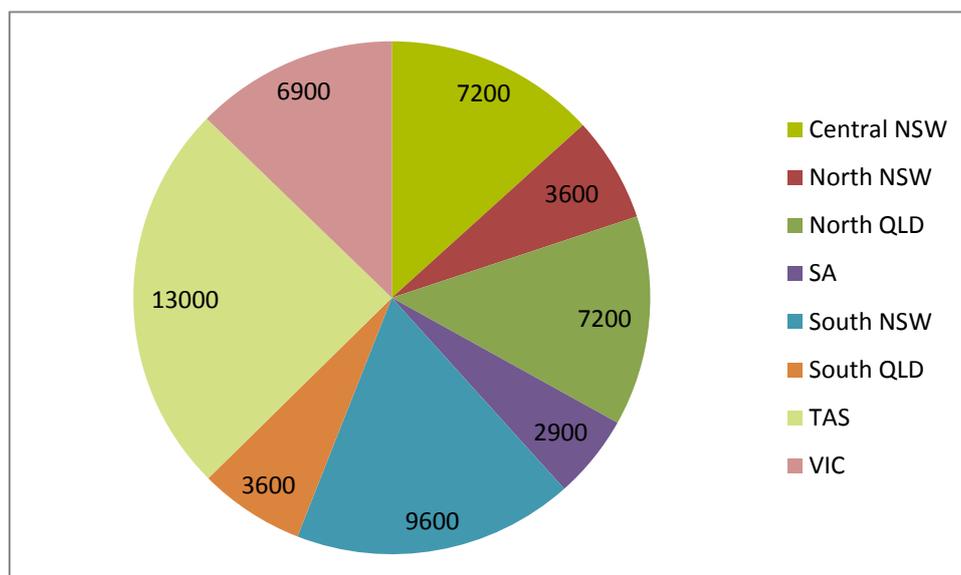


Figure 2.3: Indicative energy in storage of 6-hour storage projects across various PHES regions



Figure 2.4: Average unit cost of capacity for 6-hour storage projects across various PHES regions

Table 2.6: 12 hour storage PHES projects across various PHES Regions

PHES Region	Total capacity of projects (MW)	Total energy in storage (MWh)	Average unit cost of capacity (\$m/MW)
Central NSW	800	9,400	1.87
North NSW	600	7,200	1.52
North QLD	900	11,100	1.80
SA	200	2,900	2.64
South NSW	1,200	14,400	1.76
South QLD	600	7,200	1.90
TAS	2,000	23,800	1.28
VIC	1,200	13,800	1.75
	Total: 7,500	Total: 89,800	Average: 1.70

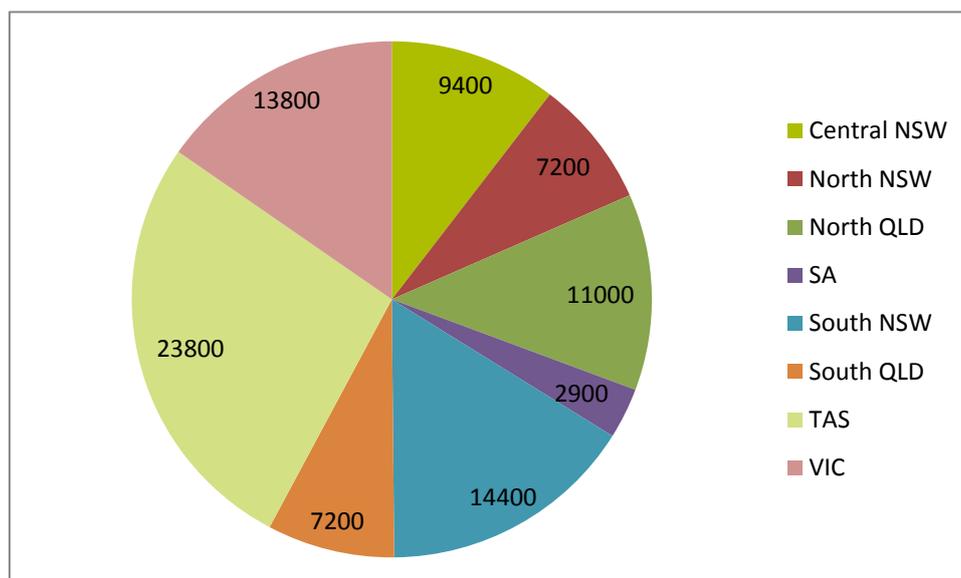


Figure 2.5: Indicative energy in storage of 12 hour storage projects across various PHES regions



Figure 2.6: Average unit cost of capacity for 12 hour storage projects across various PHES regions

Table 2.7: 24 hour storage PHES projects across various PHES Regions

PHES Region	Total capacity of projects (MW)	Total energy in storage (MWh)	Average unit cost of capacity (\$m/MW)
Central NSW	200	5,300	2.43
North NSW	600	14,400	1.85
North QLD	500	10,900	1.98
SA	200	4,500	3.75
South NSW	700	17,200	2.26
South QLD	600	14,400	2.17
TAS	1,600	37,500	1.39
VIC	700	17,400	2.25
	Total: 5,100	Total: 121,600	Average: 2.11

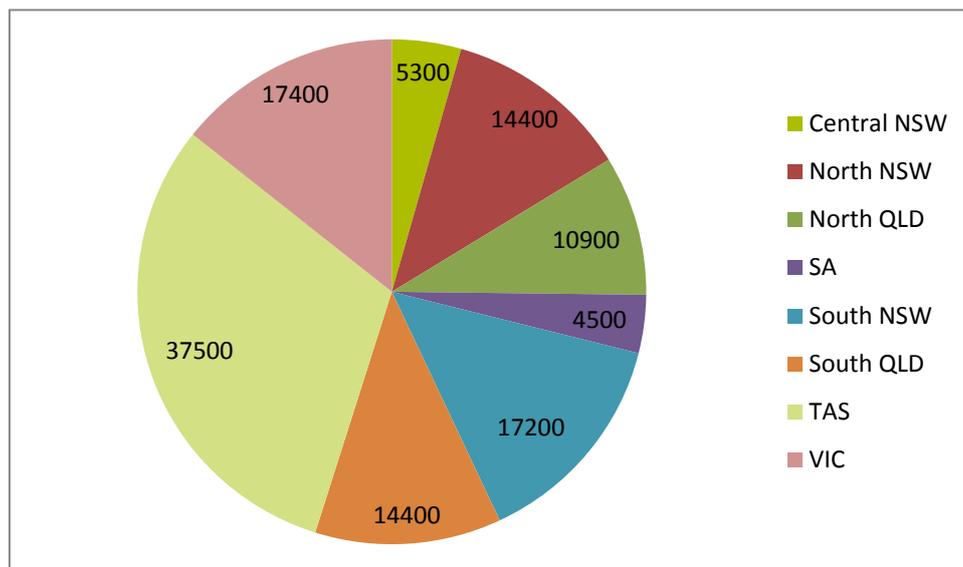


Figure 2.7: Indicative energy in storage of 24-hour storage projects across various PHES regions



Figure 2.8: Average unit cost of capacity for 24-hour storage projects across various PHES regions

Table 2.8: 48 hour storage PHES projects across various PHES Regions

PHES Region	Total capacity of projects (MW)	Total energy in storage (MWh)	Average unit cost of capacity (\$m/MW)
Central NSW	100	5,400	3.79
North NSW	600	28,800	2.11
North QLD	200	10,900	2.92
SA	-	-	-
South NSW	200	9,200	3.08
South QLD	300	16,000	2.96
TAS	800	37,500	1.57
VIC	400	17,400	3.38
	Total: 2,700	Total: 130,600	Average: 2.75

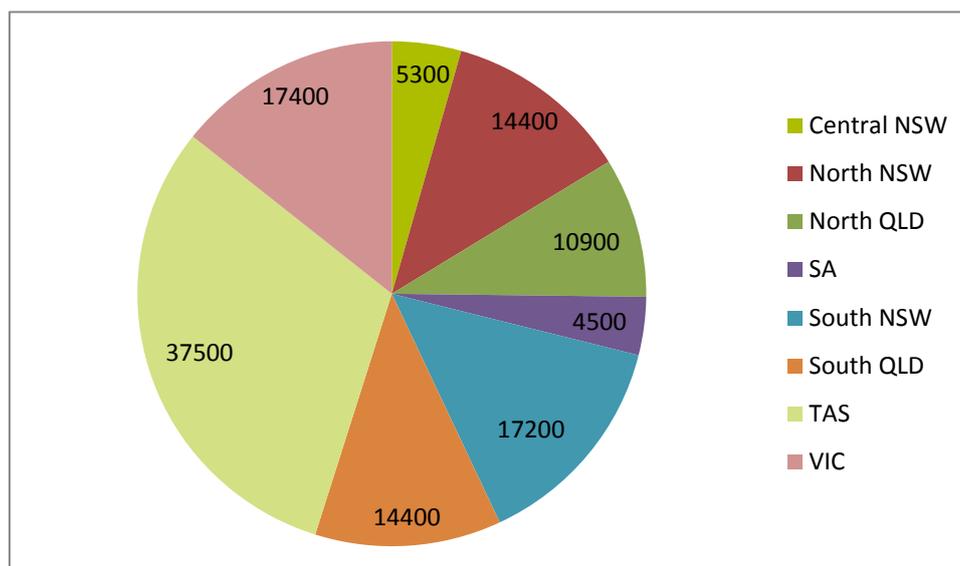


Figure 2.9: Indicative energy in storage of 48-hour storage projects across various PHES regions

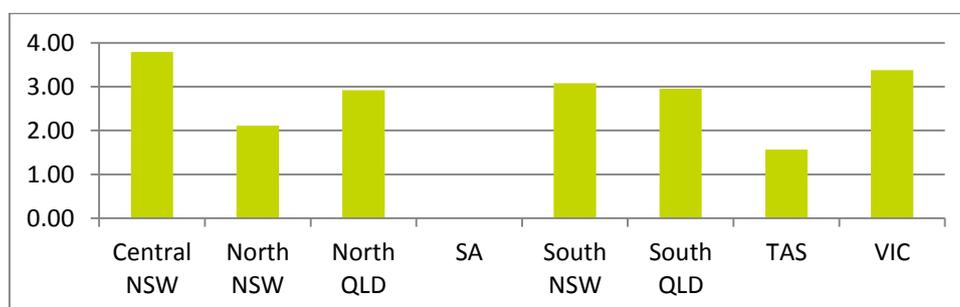


Figure 2.10: Average unit cost of capacity for 48-hour storage projects across various PHES regions

The reasons for the differences in cost for the various regions include:

- The waterway length to head ratio varies according to the region in which projects are located – projects with lower waterway length to head ratios are generally cheaper;
- The installed capacity for a project is a significant driver in determining the unit cost. Installed capacity is related to head and storage size in this analysis. In regions where storages are relatively small and head is relatively low (eg South Australia), costs are generally higher;
- Regional geology is a factor contributing to the size of storages, which is related to both the installed capacity and the capital cost.

Figure 2.11 shows the top 25% of projects in terms of the unit cost of capacity and the energy in storage, which gives an indication of the relative costs of larger storages. In general, the graph shows that projects with larger storages are more expensive.

2.4.2 Cost of storage

A byproduct of the analysis is an illustration of the impact of increasing the storage time for project with the same reservoir sizes. That is, the relative increase in the unit cost of capacity with reduced installed capacity and reduced waterway and associated infrastructure sizes.

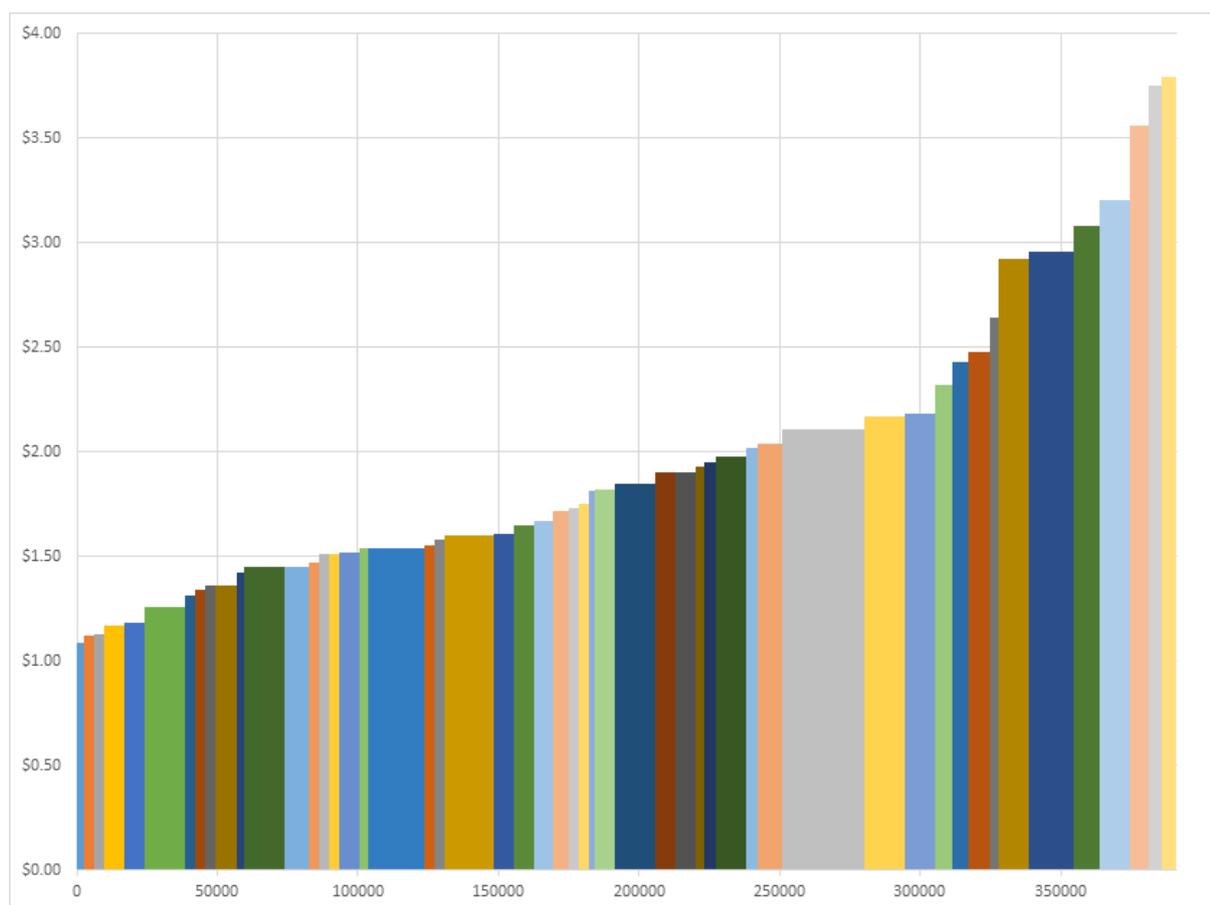


Figure 2.11: Unit cost of capacity vs energy in storage (top 25% of projects)

The main reason that unit cost of capacity increases with increasing storage time is the cost of new storages⁴ and the length of waterways remain the same but there is less installed capacity. Statistics highlighting the impact of increasing storage time are presented in Figure 2.12. On average, an increase in storage time from 6 hours to 12 hours results in a 40% increase in the unit cost of capacity. An increase in storage time from 6 hours to 24 hours results in a 120% increase in the unit cost of capacity.

In a very small number of cases, there may be a decrease in the unit cost of capacity with increasing storage time. This is only likely in the case where the cost of new dams is relatively high.

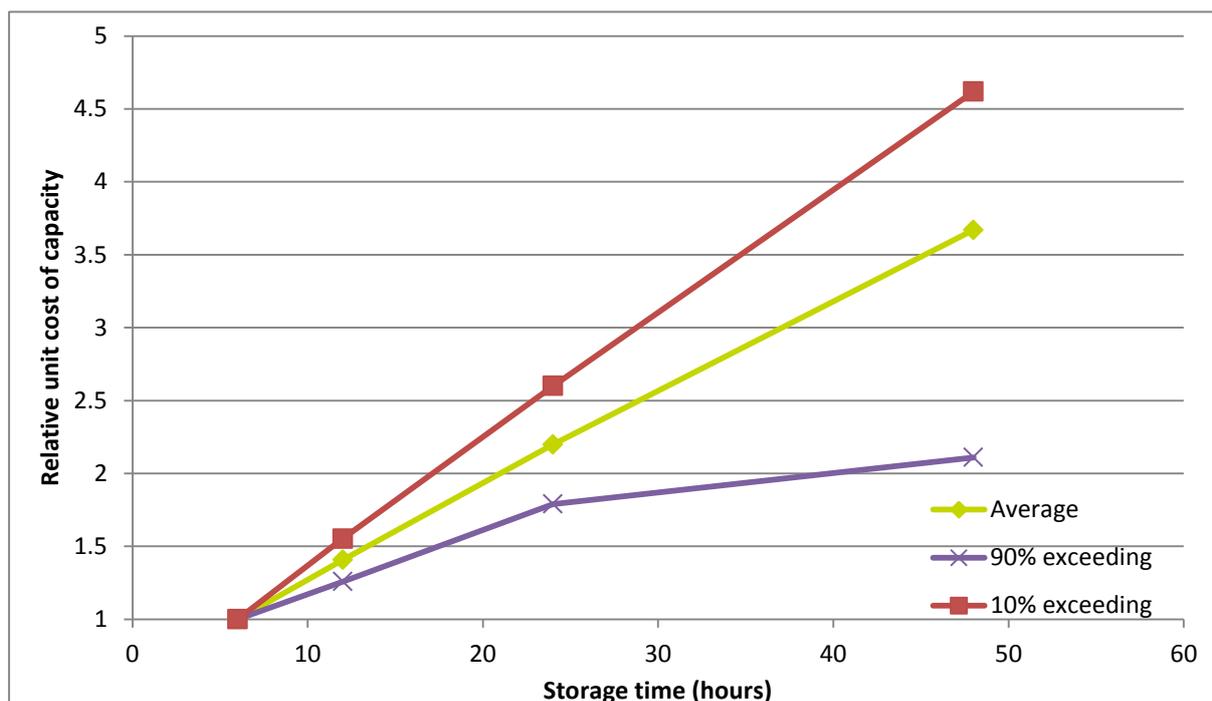


Figure 2.12: Impact of increasing storage time

⁴ It is assumed the analysis by ANU has maximised the potential volume of the upper storage. If it is possible to build a larger storage on the same site, the cost increase will not be as significant.

3. Operation and maintenance costs

Operation and maintenance cost estimates were based on several US and Australian reviews and estimates, verified with Entura expertise and leveraging Hydro Tasmania asset management experience.

3.1 External analyses

A number of sources have been consulted to determine the operation & maintenance costs for traditional and pumped hydro plant as shown in Table 3.1. Reputable sources vary greatly in their estimates of costs per MW. For example, three US estimates are compared below, along with estimates used by the Australian Energy Market Operator. Original estimates have been converted to 2018 AUD⁵.

Table 3.1: Range of estimated FOM and VOM from various sources (2018 AUD)

Source	FOM AUD/MW/year	VOM AUD/MWh	Total \$/MW/year, assuming nominal 0.25 capacity factor
Conventional hydro			
Cost and Performance Data for Power Generation Technologies, prepared for the National Renewable Energy Laboratory Black & Veatch 2012	22,056	8.82	41,377
Combined Data for Conventional and Pumped Hydro			
Electric Power Annual 2016 US Energy Information Administration 2017, revised 2018		14.76	32,320
Pumped Hydro			
Cost and Performance Data for Power Generation Technologies, prepared for the National Renewable Energy Laboratory Black & Veatch 2012	45,288	-	45,288
DOE/EPRI Electricity Storage Handbook in Collaboration with NRECA Sandia National Laboratories 2015	9,182	0.42	10,110
2018 Integrated System Plan modelling assumptions Australian Energy Market Operator 2018	5,000	5.00	15,950

⁵ Inflation: World Bank World Development Indicators: <https://data.worldbank.org/indicator/FP.CPI.TOTL.ZG>
Exchange rates: OFX: <https://www.ofx.com/en-au/>

In contrast, the assumption used for conventional hydro in the Australian Energy Market Operator’s modelling is significantly higher as shown in Table 3.2.

Table 3.2: FOM and VOM adopted by AEMO in 2018 ISP

Source	FOM AUD/MW/year	VOM AUD/MWh	Total, assuming nominal 0.25 capacity factor
Conventional hydro			
2018 Integrated System Plan modelling assumptions Australian Energy Market Operator 2018	58,250	7.19	73,996

The AEMO ISP assumption for O&M costs for conventional hydro generators is a significant outlier in terms of published cost assumptions, as well as Entura’s experience.

By comparing these to Entura experience, it is surmised that these differences can be attributed to differing scopes. However, very little detail is available regarding the scope of publicly available estimates.

This report estimates the full business cost of operating and maintaining plant, as an incremental asset in an existing portfolio.

3.2 Variable operation and maintenance costs

Variable operation and maintenance costs (VOM) are defined as O&M costs which are proportional to the amount of energy generated, in MWh. Hydroelectric power stations are often unmanned, and variable costs would be predominantly maintenance costs due to plant deterioration associated with running. Deterioration of hydro power plant is typically age-based, exacerbated by two factors: running outside the machine’s efficient operating range, and machine starts and stops. These factors are both highly dependent on machine design, both in terms of the breadth of operation a generator is designed for, and its robustness to off-spec operation. Neither of these factors is proportional to the capacity factor of the plant. Therefore they are not accurately represented by measuring VOM. It is therefore recommended that hydropower operation and maintenance costs are captured as Fixed Operation and Maintenance (FOM) costs only, rather than assigning some portion of these costs to Variable Operation and Maintenance (VOM).

3.3 Fixed operation and maintenance costs

3.3.1 Cost validation

The costs have been validated against Entura’s experience. The costs were taken to be the full cost of the business of operating a hydroelectric generating asset, as an incremental cost to an existing business.

It has been noted that Hydro Tasmania’s portfolio has historically been typified by plentiful capacity, constrained by energy (water) availability. As such, the value of certain industry-standard metrics (such as start reliability or planned outage factor) has been suppressed. In the future, if Tasmania is more connected with the rest of the NEM, there will be more value in improving these metrics. It is

acknowledged that this may increase maintenance costs. However given the broad alignment between Hydro Tasmania experience and external estimates, and the approximate nature of the cost estimates, this potential uplift is assumed to be negligible for the purposes of this report.

3.3.2 Station age

Entura experience also indicates that costs are well correlated with station age, with stations less than 50 years old typically having much lower operation and maintenance costs than older stations.

For stations over 50 years old, a factor of 1.5 should be applied to the original estimate.

3.3.3 Portfolio vs individual costs

It is noted that Hydro Tasmania's portfolio consists of 27 power stations, which are managed in six geographic groupings. The relative proximity of stations within each geographic grouping enables sharing of O&M resources between stations. However the average size of Hydro Tasmania's stations is around 85MW⁶, so the reduced costs of operating a geographic cluster of stations is offset by the relatively small size of each station.

It is also noted that Hydro Tasmania has a large portfolio of stations, with over 100 years of operational experience. However it is assumed that if an owner were to invest in a single hydropower or pumped hydro station, they would outsource operation and maintenance to a party with more experience and economy of scale. Other business costs, such as insurance, will generally be less overall in a portfolio of projects.

3.3.4 Station output effects

Entura's experience also indicates that very small stations (less than 20 MW), have much higher costs per MW (more than double the cost per MW of larger stations of similar age).

For stations with installed capacity less than 100MW, a factor of 1.5 should be applied to the original estimate.

For stations with installed capacity less than 20MW, a factor of 4 should be applied to the original estimate.

3.4 Summary of Results

On the basis of this, it is recommended that the AEMO ISP value is a good starting point, but should be augmented with a number of minor improvements:

1. VOM is not meaningful for hydropower projects, as it does not take into account the most damaging aspects of operation. As such, FOM only should be used – a single value of \$16,000/MW/yr. This is the equivalent of the existing AEMO ISP O&M cost assumption for pumped hydro, consolidated from a FOM and VOM into a single FOM.

⁶ Tasmania's hydropower system was designed to be almost the sole provider of electricity in the state. Therefore station MW capacity is typically low compared to total storage capacity and energy generation, with a portfolio capacity factor of around 45%.

2. This should be adjusted for age and size of the station (not machine).
 - a. For stations over 50 years old, a factor of 1.5 should be applied to the base estimate.
 - b. For stations with installed capacity less than 100MW, a factor of 1.5 should be applied to the base estimate.
 - c. For stations with installed capacity less than 20MW, a factor of 4 should be applied to the base estimate.

Note that this means for an old, small, station, the factor could be as large as 6.

As stated previously, this analysis assumes that the station is operated as part of a portfolio. If a station were not part of a portfolio, it is assumed that operation and maintenance would be outsourced.

4. References

AEMO, 2018, *Integrated System Plan for the National Electricity Market*, July

Lu, B., Stocks, M., Blakers, A., Anderson, K., 2018, *Geographic information system algorithms to locate prospective sites for pumped hydro energy storage*, *Applied Energy* 222 (2018) 300–312

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A Cost calculation for benchmarking

Note: Transmission costs excluded.

A.1 Kidston (K2-Hydro)

Serial	Decription	Value
<i>Input Values</i>		
1	Head, H (m)	185
2	Waterway length, L (m)	450
3	Storage volume (Mm ³)	3.1
4	Storage time (hr)	5.7
<i>Calculated values</i>		
5	Length: Head Ratio	1.4
6	Flow (m ³ /s)	150
7	Installed Capacity (MW)	250
8	Energy in storage (MWh)	1,426
9	Storage perimeter (m)	1,604
10	Embankment volume (m ³)	753,748
11	Embankment liner area (m ²)	276,387
12	Waterway diameter (m)	6.9

A.2 Snowy 2.0

Serial	Decription	Value
<i>Input Values</i>		
1	Head, H (m)	681
2	Waterway length, L (m)	27,000
3	Storage volume (Mm ³)	208.0
4	Storage time (hr)	178
<i>Calculated values</i>		
5	Length: Head Ratio	38.6
6	Flow (m ³ /s)	325
7	Installed Capacity (MW)	1,998
8	Energy in storage (MWh)	355,575
9	Storage perimeter (m)	-
10	Embankment volume (m ³)	-
11	Embankment liner area (m ²)	-
12	Waterway diameter (m)	10.2

A.3 Cultana

Serial	Decription	Value
<i>Input Values</i>		
1	Head, H (m)	260
2	Waterway length, L (m)	3,500
3	Storage volume (Mm ³)	2.9
4	Storage time (hr)	8.4
<i>Calculated values</i>		
5	Length: Head Ratio	12.5
6	Flow (m ³ /s)	96
7	Installed Capacity (MW)	225
8	Energy in storage (MWh)	1,893
9	Storage perimeter (m)	1,559
10	Embankment volume (m ³)	732,582
11	Embankment liner area (m ²)	263,040
12	Waterway diameter (m)	5.5

A.4 Goat Hill

Serial	Decription	Value
<i>Input Values</i>		
1	Head, H (m)	200
2	Waterway length, L (m)	1,100
3	Storage volume (Mm ³)	3.9
4	Storage time (hr)	8.5
<i>Calculated values</i>		
5	Length: Head Ratio	4.5
6	Flow (m ³ /s)	127
7	Installed Capacity (MW)	230
8	Energy in storage (MWh)	1,958
9	Storage perimeter (m)	1,808
10	Embankment volume (m ³)	849,551
11	Embankment liner area (m ²)	340,836
12	Waterway diameter (m)	6.4

A.5 Highbury

Serial	Decription	Value
<i>Input Values</i>		
1	Head, H (m)	156
2	Waterway length, L (m)	1,000
3	Storage volume (Mm ³)	3.3
4	Storage time (hr)	4.31
<i>Calculated values</i>		
5	Length: Head Ratio	5.4
6	Flow (m ³ /s)	213
7	Installed Capacity (MW)	300
8	Energy in storage (MWh)	1,292
9	Storage perimeter (m)	1,663
10	Embankment volume (m ³)	781,473
11	Embankment liner area (m ²)	294,359
12	Waterway diameter (m)	8.2

A.6 Kanmantoo

Serial	Decription	Value
<i>Input Values</i>		
1	Head, H (m)	250
2	Waterway length, L (m)	650
3	Storage volume (Mm ³)	3.0
4	Storage time (hr)	8.4
<i>Calculated values</i>		
5	Length: Head Ratio	1.6
6	Flow (m ³ /s)	98
7	Installed Capacity (MW)	220
8	Energy in storage (MWh)	1,851
9	Storage perimeter (m)	1,572
10	Embankment volume (m ³)	738,870
11	Embankment liner area (m ²)	266,972
12	Waterway diameter (m)	5.6

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