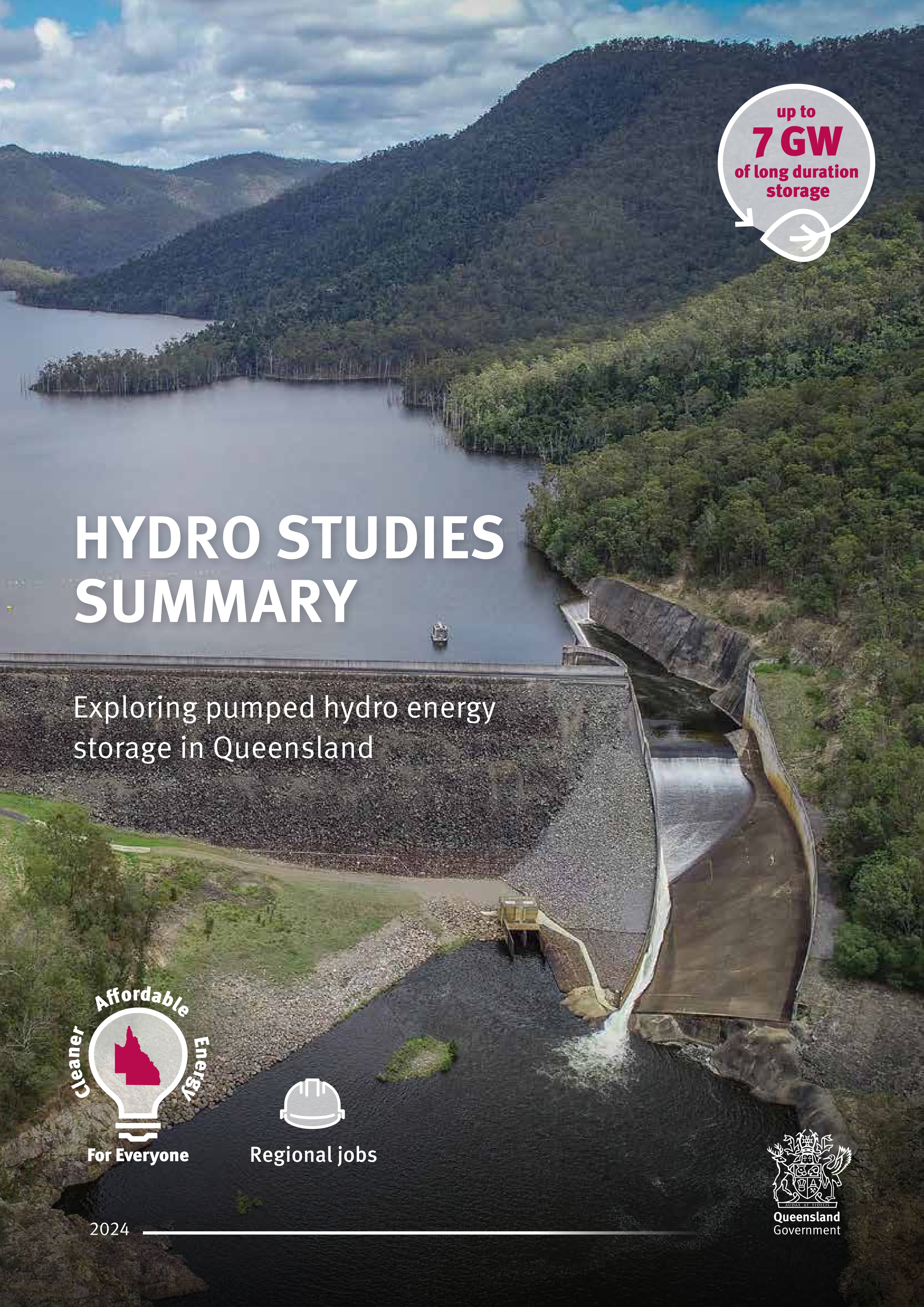

up to
7 GW
of long duration storage

HYDRO STUDIES SUMMARY

Exploring pumped hydro energy storage in Queensland

Cleaner Affordable Energy
For Everyone

Regional jobs

2024

Queensland Government

This publication has been compiled by the Department of Energy and Climate.

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Disclaimer

This report has been prepared incorporating information from the Queensland Hydro Study, to describe the process undertaken and key findings from the Queensland Hydro Study. In doing so, this report incorporates the data, analysis and factual positions from the Queensland Hydro Study as relevant/or applicable at a point in time and has not been updated for the purposes of this summary report.

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Contents

Purpose

The purpose of this document is to summarise the Department of Energy and Climate's Queensland Hydro Study, prepared between 2017 to 2020. The Queensland Hydro Study included:

- high-level analysis of Queensland's need and potential for energy storage
- analysis of the role of large-scale, long duration pumped hydro energy storage (PHES)
- analysis of the role of alternative storage technologies
- analysis of the role of the Queensland Government in the delivery of large-scale, long duration PHES.

To achieve the above purpose, this document has been divided into the following sections:

- Energy storage
- Large-scale, long duration PHES
- Queensland pumped hydro site identification and assessment
- Next steps

The Queensland Hydro Study formed a key input into the Queensland Government's site selection for long duration pumped hydro. This summary document outlines further information to the public on the selection process.

The Queensland Hydro Study was prepared over three stages, starting in 2017. Stages 1 and 2 were completed in 2017 and 2018 by Aurecon, reporting to the then Department of Energy and Water Supply (DEWS). Stage 3 was completed in 2020 by the then Department of Natural Resources, Mines and Energy (DNRME). From late 2020, the Queensland Hydro Study was taken forward by the then Department of Energy and Public Works (DEPW). Following machinery of government changes in late 2023, the Queensland Hydro Study is in the remit of the Department of Energy and Climate (DEC).

Due to the long running nature of the analysis, the team undertaking the Queensland Hydro Study comprised members from DEWS, DNRME, DEPW with inputs from government-owned corporations (Seqwater), engineering firms (Aurecon, GHD, SMEC) and datasets provided by academic researchers from the Australian National University (ANU).

In late 2022 Queensland Hydro Pty Ltd was established by the Queensland Government to investigate, build, own and operate long duration PHES. Queensland Hydro was not involved in the Queensland Hydro Study.

The alternative pumped hydro locations considered within the Queensland Hydro Study are not identified in this summary document. This is to avoid release of information about projects that will not happen, that would cause undue and unnecessary community distress, and/or potentially impact the commercial viability of land holdings. Further, the total storage capacity of all sites considered in the Queensland Hydro Study is significantly more than the storage required to support the decarbonisation of the electricity sector.

The Queensland Hydro Study was prepared at a point in time (2017 to 2020) and formed one of the many inputs into the Queensland Energy and Jobs Plan (QEJP) which outlines how Queensland's energy system will transform to deliver clean, reliable and affordable energy to provide power for generations.[1]

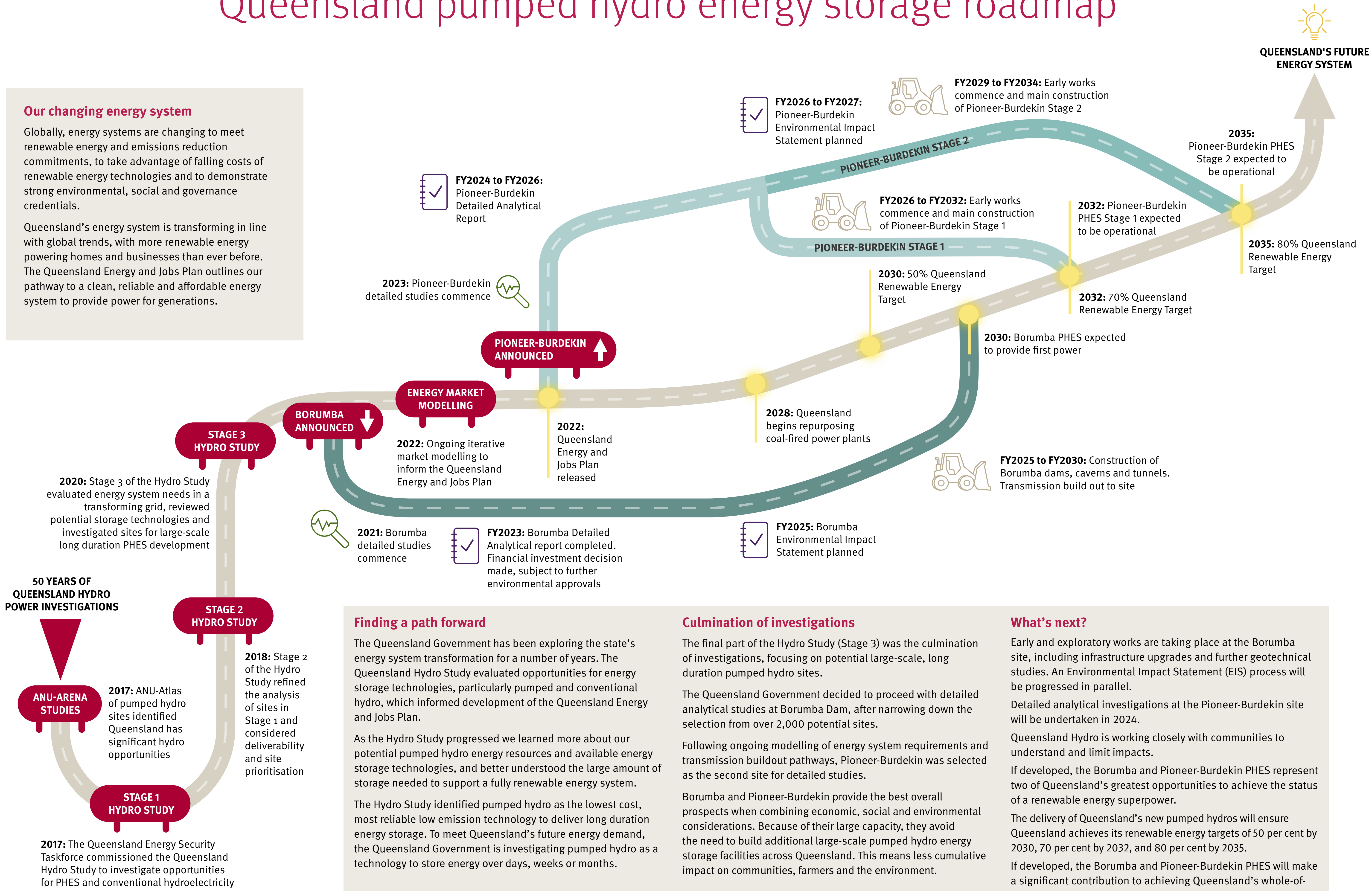
1. https://www.energyandclimate.qld.gov.au/energy/energy-jobs-plan

Queensland pumped hydro energy storage roadmap

Our changing energy system

Globally, energy systems are changing to meet renewable energy and emissions reduction commitments, to take advantage of falling costs of renewable energy technologies and to demonstrate strong environmental, social and governance credentials.

Queensland's energy system is transforming in line with global trends, with more renewable energy powering homes and businesses than ever before. The Queensland Energy and Jobs Plan outlines our pathway to a clean, reliable and affordable energy system to provide power for generations.



Finding a path forward

The Queensland Government has been exploring the state's energy system transformation for a number of years. The Queensland Hydro Study evaluated opportunities for energy storage technologies, particularly pumped and conventional hydro, which informed development of the Queensland Energy and Jobs Plan.

As the Hydro Study progressed we learned more about our potential pumped hydro energy resources and available energy storage technologies, and better understood the large amount of storage needed to support a fully renewable energy system.

The Hydro Study identified pumped hydro as the lowest cost, most reliable low emission technology to deliver long duration energy storage. To meet Queensland's future energy demand, the Queensland Government is investigating pumped hydro as a technology to store energy over days, weeks or months.

Culmination of investigations

The final part of the Hydro Study (Stage 3) was the culmination of investigations, focusing on potential large-scale, long duration pumped hydro sites.

The Queensland Government decided to proceed with detailed analytical studies at Borumba Dam, after narrowing down the selection from over 2,000 potential sites.

Following ongoing modelling of energy system requirements and transmission buildout pathways, Pioneer-Burdekin was selected as the second site for detailed studies.

Borumba and Pioneer-Burdekin provide the best overall prospects when combining economic, social and environmental considerations. Because of their large capacity, they avoid the need to build additional large-scale pumped hydro energy storage facilities across Queensland. This means less cumulative impact on communities, farmers and the environment.

What's next?

Early and exploratory works are taking place at the Borumba site, including infrastructure upgrades and further geotechnical studies. An Environmental Impact Statement (EIS) process will be progressed in parallel.

Detailed analytical investigations at the Pioneer-Burdekin site will be undertaken in 2024.

Queensland Hydro is working closely with communities to understand and limit impacts.

If developed, the Borumba and Pioneer-Burdekin PHES represent two of Queensland's greatest opportunities to achieve the status of a renewable energy superpower.

The delivery of Queensland's new pumped hydros will ensure Queensland achieves its renewable energy targets of 50 per cent by 2030, 70 per cent by 2032, and 80 per cent by 2035.

If developed, the Borumba and Pioneer-Burdekin PHES will make a significant contribution to achieving Queensland's whole-of-economy emissions reduction targets.

Executive summary

The Queensland Hydro Study, prepared between 2017 and 2020, builds on the Queensland Government's analysis into pumped hydro energy storage (PHES) opportunities over the past 50 years.

The Hydro Study was undertaken by the then DEPW over several years, using inputs from government-owned corporations, engineering firms and datasets provided by academic researchers.

The aim of the Queensland Hydro Study was to identify the most prospective sites in Queensland for pumped hydro development. Based on analysis undertaken as part of Stage 3 of the Study, in 2021 the government announced feasibility studies to assess Lake Borumba's potential for pumped hydro development. This analysis was to explore the ability of the proposed site to provide the large-scale, long duration energy storage needed to meet Queensland's renewable energy target of 50 per cent renewable energy by 2030.

In developing the Queensland Energy and Jobs Plan (QEJP), energy system and market modelling was undertaken to focus on the energy storage and system requirements needed for large-scale coal re-purposing and new renewable energy targets. Modelling indicated the requirement for a second large-scale, long duration PHES, identified by the Queensland Hydro Study investigations, to support the decarbonisation of Queensland's energy system and achieve renewable energy targets of 70 per cent by 2032 and 80 per cent by 2035.

In conjunction with the QEJP, the government announced feasibility studies at the Pioneer-Burdekin site in 2022. Both Borumba and Pioneer-Burdekin are priority projects in the QEJP and Queensland SuperGrid Infrastructure Blueprint (the blueprint) (see Figure 1) that will enable the re-purposing of coal assets and decarbonisation of Queensland's energy system.

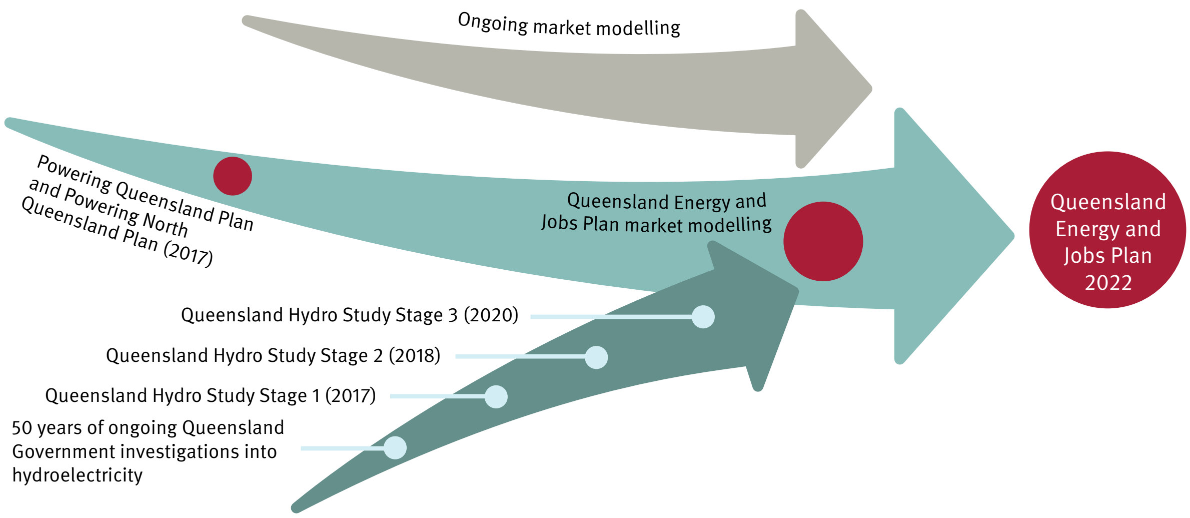


Figure 1: The Queensland Hydro Study contributing to the QEJP

Queensland Hydro Study – an input into the QEJP

As part of the QEJP preparations, iterative energy system and market modelling was conducted, which used the findings from the Queensland Hydro Study to identify the most cost effective pathway to achieving Queensland's net zero and renewable energy targets.

The analysis of potential energy storage technologies through the Queensland Hydro Study and the QEJP modelling identified Queensland's lowest cost PHES as the most reliable and mature low emissions technology to deliver long duration energy storage.

The energy system analysis undertaken for the QEJP also considered the capacity and staging requirements to support the energy transformation. This analysis confirmed the optimal infrastructure pathway required for the development of sufficient large-scale, long duration PHES capacity to support renewable energy deployment and decarbonisation goals.

For more information on the QEJP modelling, please see a summary published on DEC's website.[2]

2. https://www.energyandclimate.qld.gov.au/energy/energy-jobs-plan

Why energy storage is needed in Queensland

Globally, energy systems are transforming to higher levels of variable renewable energy as countries seek to limit global temperature increases and the associated impacts to people, livelihoods, and the environment. Renewable energy systems will not be able to provide secure, stable energy supply without large amounts of storage to supply electricity when it is needed and when there is no wind or solar available. Queensland's energy system and its energy generation mix will also transform to include more wind and solar to ensure we always have enough energy to meet Queensland's energy demand while also doing our part to limit climate change. Partnering energy storage with new wind and solar generation is key to supporting our transforming energy system.

Energy storage describes the process where energy is captured and stored so it can be provided to Queensland homes and businesses when it is needed.

Energy storage also provides a range of non-energy services that help manage the power system, such as voltage and frequency support, inertia and system strength. These services are increasingly important in energy systems with high levels of variable renewable energy (VRE) generation, as VRE energy sources are unable to provide energy or non-energy services on demand.

The optimal pathway for Queensland's energy transformation over the next decade – outlined in the QEJP and generated through market modelling – indicates that Queensland will need at least 6,000 megawatts (MW) of long duration storage for a highly renewable system. This will be complemented by approximately 3,000 MW of grid-scale storage, around 6,000MW of batteries in homes and businesses and up to 3,000 MW of new low-to-zero emission gas-fuelled plant to cover prolonged periods of low renewable generation (see Figure 2).

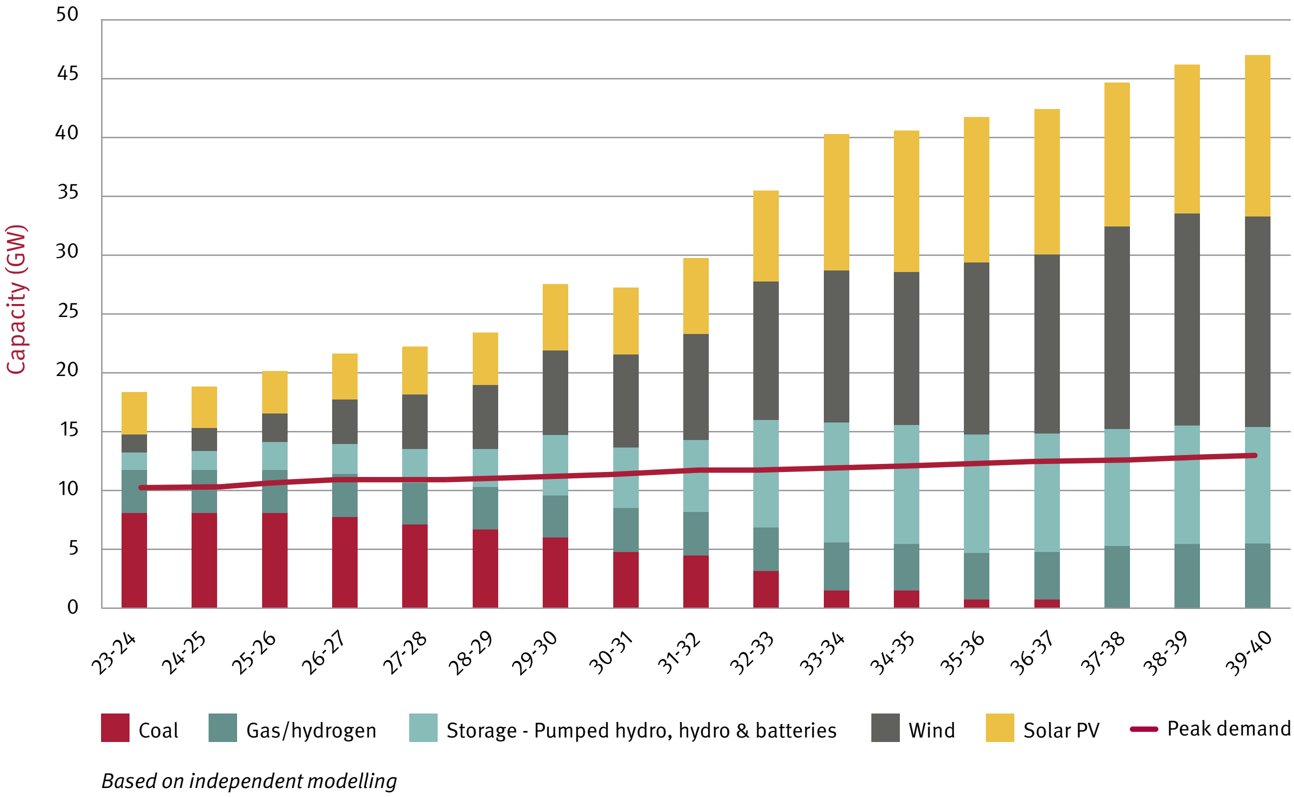


Figure 2: Queensland Energy and Jobs Plan capacity mix (GW)

Technology options to meet Queensland's storage needs

DEPW has undertaken system analysis and modelling to evaluate how different energy storage technologies can support a high VRE system.

In particular, DEPW evaluated capacity of the following storage and firming technologies to provide system reliability and system security services:

- PHES
- Batteries
- Conventional hydroelectricity
- Flywheels
- Synchronous condensers
- Concentrated solar thermal
- Compressed air energy storage
- Demand response
- Hydrogen
- Low-capacity factor gas generation

This analysis highlighted Queensland's critical need for large-scale, long duration storage (typically of 24 hours or more), while also identifying a role for a variety of different storage technologies.

PHES is the only proven storage technology capable of economically delivering long duration storage at scale. Without low-cost, large-scale, long duration PHES, modelling has indicated that potential pathways to net-zero emissions are prohibitively expensive, unworkable or rely on step-change technology improvements beyond what is forecast.

While batteries provide valuable services to the electricity system, there are significant challenges associated with meeting the amount of long duration storage required in Queensland using batteries alone.

Why can't we use batteries alone to meet our long duration energy storage needs?

While batteries will be deployed widely in Queensland and provide many valuable services to the electricity system, there are several reasons why PHES will provide the cornerstone of long duration energy storage needs identified by the QEJP:

- **Proven technology at very large scale** – PHES is a proven technology for large-scale long duration energy storage. While battery technology continues to develop, no large-scale decentralised fleet of batteries exists which provides the scale of energy storage required in Queensland (at least 6,000 MW for 24 hours), and operation of such a system is currently untested.
- **Supply chain hurdles** – Battery supply chains are not yet mature and will face substantial challenges in securing sufficient raw material supplies to meet production at the scale to deliver the necessary storage requirements comparable to PHES in the short-term.
- **Cost** – while batteries providing short duration storage (1-4 hours) can be cost competitive with PHES, they are not forecast to be cost competitive with long duration PHES for at least the next decade for the provision of long duration energy storage.
- **Additional costs** – local distribution networks would need to be upgraded significantly (plus new control systems), at significant cost, to enable gigawatts of power to be transported to the transmission network from residential batteries and EVs.
- **Centralised control** – to provide comparable services to large-scale PHES, a fleet of batteries would need to be charged/discharged as required by the overall system. Such control is unlikely in a system consisting of many battery installations and is far more complex than control of one or two large PHES assets.
- **Lifetime** – expected battery lifetime is currently 10 years compared to PHES of approximately 100 years. A fleet of batteries would need to be replaced many times over the life of a PHES asset.
- **Life cycle issues** –recycling and disposal of the materials involved in a large battery fleet will require further support and regulation to ensure environmental impacts are minimised.

The Queensland Government's interest in delivering large-scale, long duration PHES is therefore twofold:

1. Long duration PHES delivery is required to ensure a secure, reliable and affordable energy grid, as it will support Queensland's strategy of electricity generation decarbonisation and growth in renewable energy investment at the lowest cost as set out by the QEJP.
2. Large-scale long duration storage is less likely to be delivered by private project proponents due to long planning, construction and delivery times, large upfront development and capital costs, and significant approval requirements.

Exploring large-scale, long duration PHES

PHES is the world's most widely used energy storage solution, accounting for around 97 per cent – over 130 gigawatts (GW) – of global electricity storage capacity.[3] PHES can store a large amount of energy for long periods, making it the perfect backup for other renewable energy sources like solar and wind. Analysis by the Australian National University (ANU) reviewed pumped hydro energy storage development opportunities across Australia. This work is explored in the call out box below.

ANU Atlas of Pumped Hydro Energy Storage

In order to understand the potential for PHES to support the transformation to a renewables based energy system, analysis was undertaken to identify potential PHES sites.[4] The study identified around 22,000 potential sites across Australia, of which more than 1,500 were in Queensland.

This work identified sites which were away from rivers and did not impact on national parks or urban areas. The study did not identify the matched lower reservoir required to complete a PHES scheme arrangement, instead focusing on areas with suitable difference in elevation.

Site identification was targeted at finding potentially feasible sites, but did not subject the sites to geological, hydrological, environmental or other studies. For this reason many of the identified sites were unsuitable for development.

This work, and subsequent refinements to the analysis, was used as an input to site identification work performed for the Queensland Hydro Study.

Queensland has one operational PHES, Wivenhoe, which can generate 570 MW for 10 hours, equating to 5,700 megawatt hours (MWh). A second PHES is currently being constructed at Kidston (250 MW with 8 hours storage) with several other PHES projects undergoing planning and approval processes by private sector proponents.

PHES is a closed water system that moves water between two large reservoirs constructed at different heights to generate and store potential energy.

A pumped hydro generator uses electricity from the grid or nearby renewables to pump water from the lower reservoir into the upper reservoir when energy prices are low. When energy is needed, water is released from an upper reservoir back into the lower reservoir, passing through a turbine. Because of this 'closed loop' system, PHES is less dependent on variable river flows since the only water losses are from evaporation or seepage. By circulating and reusing water, PHES schemes are less susceptible to the impacts of climate change.[5]

In most cases, the same waterway/pipeline is used for both directions of water flow (i.e. for both pumping and discharging). Figure 3 provides a basic overview of a PHES system.

3. ANU (2017), An atlas of pumped hydro energy storage. Available at: re100.eng.anu.edu.au/index.html
4. Blakers A, Stocks M (2017), An atlas of pumped hydro energy storage. Available at: https://core.ac.uk/download/pdf/156742486.pdf
5. Pittock. J (2019), Pumped-storage hydropower: trading off environmental values?

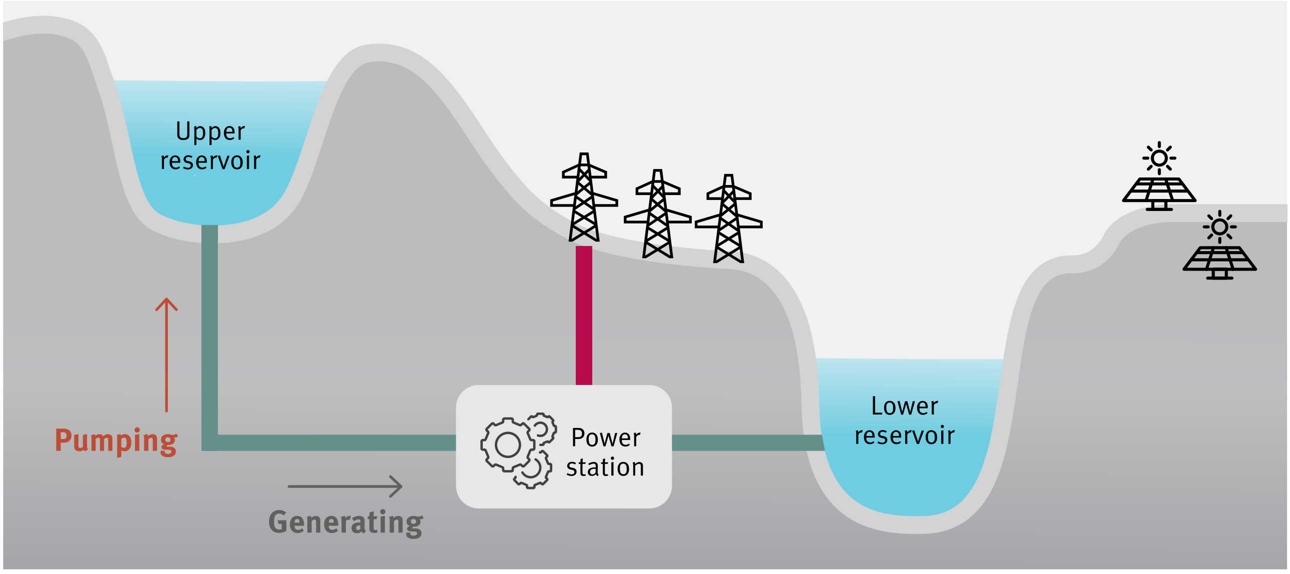


Figure 3: Simplified overview of a PHES system

Cost

Without Queensland's low cost, large-scale, long duration PHES sites, modelling has indicated that alternative pathways to net-zero emissions are significantly more expensive.[6]

There is a significant cost difference between the relatively few high-quality PHES sites and most other sites that are not commercially viable or deliverable from a hydrological, environmental or social perspective. The lowest cost PHES sites are characterised by a large vertical distance between upper and lower reservoirs, relatively small horizontal distance between reservoirs, and natural topography (e.g. valleys or depressions) that reduces the height and volume of dam walls and/or excavation required to create reservoirs. Larger energy generation capacity also allows for economies of scale to be realised.

Queensland has a small number of high quality, large-scale, long duration pumped hydroelectric storage (PHES) sites (i.e. Borumba and Pioneer-Burdekin) that are attractive on a cost and technical basis.

Environmental and community impacts

DEPW sought to identify PHES sites that reduce localised environmental and social impact whilst achieving the QEJP objectives of lowering electricity emissions and transforming our energy system at the lowest possible cost. Figure 4 shows the emissions reductions that will be achieved under the QEJP.

Closed loop pumped storage has been recognised as realising a lesser environmental impact than traditional run-of-river hydropower developments.[7] In 2020, environmental groups such as the World Wildlife Fund and the the Union of Concerned Scientists were party to a joint statement supporting development of new closed loop pumped storage stations. The joint statement acknowledged the important role best practice pumped hydro could play in supporting integration of variable renewable energy into the electricity grid.

Development of any PHES project, as with other large-scale infrastructure projects, involves localised disruption, including clearing and inundation, with impacts on flora and fauna, potential impacts on environmental low flows and local landholders and communities that need to be carefully managed and mitigated. PHES developments can involve trade-offs and a careful balance between greater use of renewable energy to mitigate climate change, and other local environmental impacts.[8] Regulatory and environmental approval processes are in place to assist in the management of these impacts.

6. Modelling undertaken for the Borumba Detailed Analytical Report (DAR) has indicated that PHES provides system cost reductions to support deep decarbonisation of Queensland's electricity system.
7. https://woods.stanford.edu/research/hydropower/hydropower-ucd-core-documents
8. Pittock J (2019), *Pumped-storage hydropower: trading off environmental values?*

Engagement and collaboration with traditional owners is critical for PHES development. Engagement will consider traditional owner use of water, both consumptive and spiritual, and the commitment under the National Closing the Gap Agreement that First Nations people maintain a distinctive cultural, spiritual, physical and economic relationship with their land and waters.

Limiting cumulative impacts

It is vital to consider the cumulative effect of projects necessary to achieve the objectives of the QEJP. Developing fewer, larger projects reduces the number of impacted communities and habitats across the state. For example, delivering Queensland's future energy storage requirements (at least 6,000 MW capacity with 24 hours storage) through smaller 250 MW projects with 8 hours of storage only would require the development of over 70 individual sites. An approach which preferences developing many smaller pumped hydro sites would potentially multiply environmental disruption and mean more roads, transmission lines and reservoirs are required.[9] A strategy without large-scale, long duration PHES would therefore impact a greater number of communities and habitats across Queensland, resulting in higher cumulative emissions, larger cumulative environmental and social impacts, and higher costs (as economies of scale would not be realised).

Electricity emissions (reduction on 2005 levels)

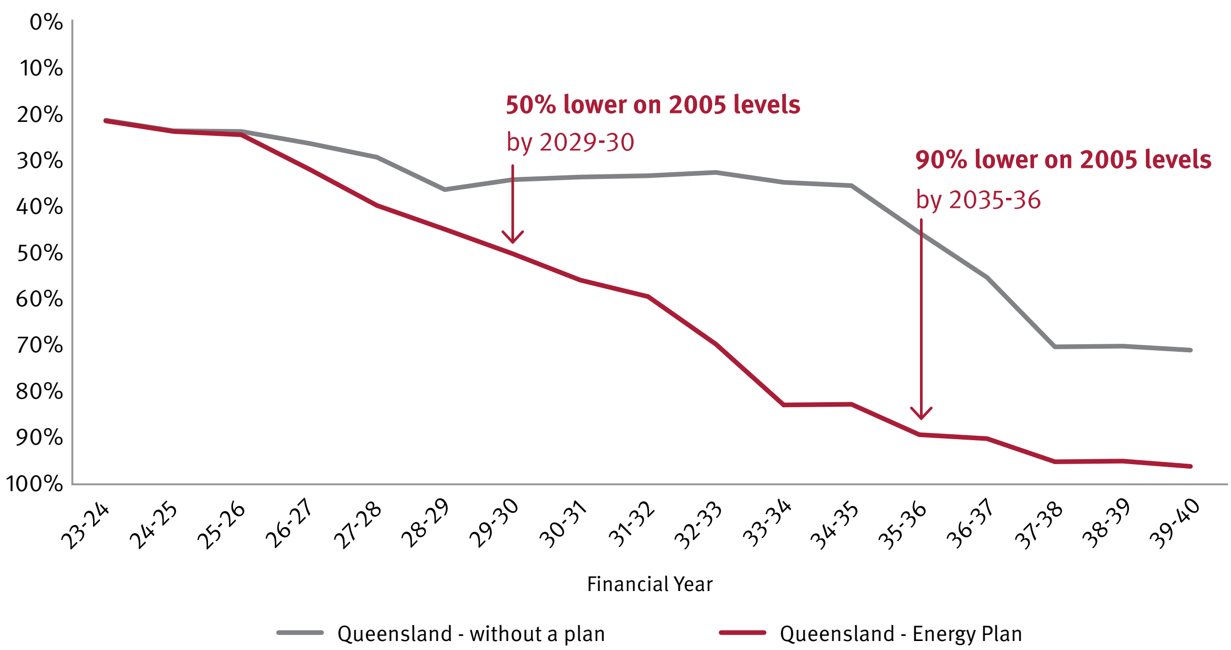


Figure 4: Expected electricity emissions (reduction on 2005 levels)

9. Pittock, J (2022), https://theconversation.com/how-to-ensure-the-worlds-largest-pumped-hydro-dam-isnt-a-disaster-for-queenslands-environment-191758

Queensland Hydro Study – background

The Queensland Hydro Study commenced in 2017 and occurred over three stages.

Stages 1 and 2

The first two stages of studies were preliminary in nature and explored the opportunities for conventional hydroelectricity and PHES in Queensland. The studies occurred in a context where Queensland had limited experience in both conventional hydro and PHES, emerging policy considerations, and the desire to understand the possibilities within Queensland. The studies used the Australian National University (ANU) and Australian Renewable Energy Agency's (ARENA) - Atlas of Pumped Hydro Energy Storage as a starting point, which identified approximately 2,000 potential pumped hydro sites in Queensland.[10] In particular:

- Stage 1 (December 2017) examined the role of hydro/pumped hydro in Queensland, the assessment of prospective sites and identified 16 potential sites for further study.
- Stage 2 (June 2018) reviewed the 4 conventional hydro and 12 PHES sites from Stage 1 and prioritised 8 of these sites for further study. The PHES sites evaluated in Stage 2 were small-scale with medium duration (up to 350 MW and 8 hours storage duration). No long duration sites were identified.

Stage 3

Following the first two stages of the study, it became clear that long duration PHES was worthy of further investigation as it could potentially provide low-cost system reliability and security in the context of increasing variable renewable energy penetration. Stage 3 was prepared throughout 2019 and 2020 to test the case for long duration PHES in Queensland and identify suitable sites for further investigation.

The Stage 3 study was an input into the development of the QEJP and the blueprint. This stage was split into three components:

1. The case for large-scale long duration PHES.
2. Desktop studies and site visits for prospective sites and further concept studies for two of these identified prospective sites.
3. Recommendations to government based on the previous two components.

Stage 3 focussed on finding potential schemes that:

- could support at least 1 gigawatt (GW) of capacity and 24 gigawatt hours (GWh) of storage
- had strong technical characteristics, driving lower capital costs and commercial viability
- were technically feasible, with a high likelihood of practical solutions for identified problems
- had appropriate water security
- had feasible network locations
- had environmental/social risks that could be avoided or minimised.

Finding potential sites and refining PHES schemes is complex, as each site is unique with different technical characteristics. In Stage 3, a five-phase process was used to screen previously identified schemes, as well as locational zones with attractive topography (see Figure 5).

The five-phase investigation process, explored later in this document, identified the Borumba and Pioneer-Burdekin PHES as the most technically favourable and economically viable PHES sites in Queensland.

10. ANU (2017), An atlas of pumped hydro energy storage. Available at: https://re100.eng.anu.edu.au/index.html

These sites were chosen to be progressed to detailed concept studies.

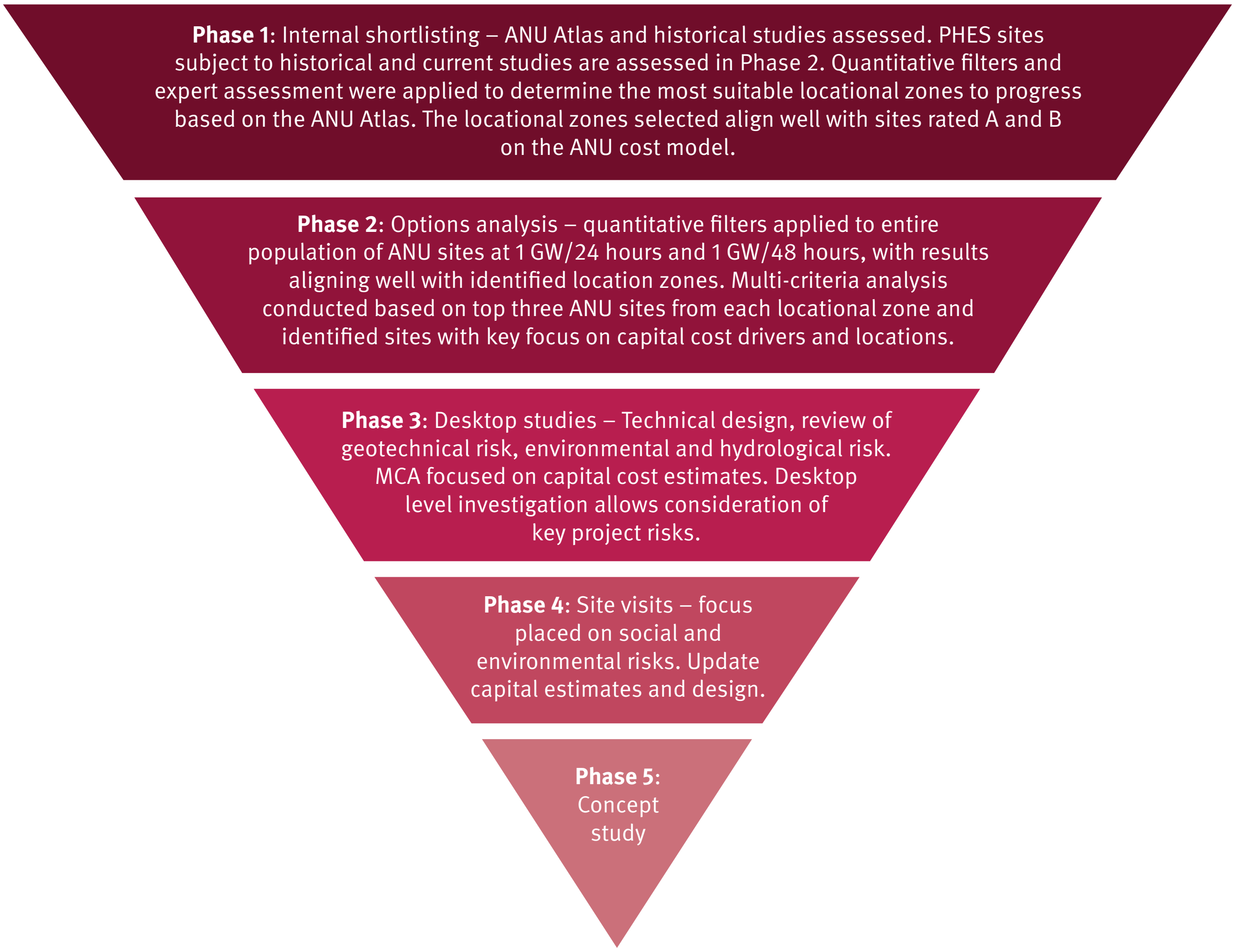


Figure 5: The five-phase PHES investigation process for Stage 3 of the Queensland Hydro Study

Progressing PHES sites to detailed feasibility studies

Based on the Queensland Hydro Study Stage 3 and early market modelling for the QEJP, in 2021 the Borumba PHES project was identified as the first prospective site for detailed feasibility studies and community consultation. The Borumba site was considered particularly favourable due to:

- favourable capital costs
- favourable technical characteristics
- existing lower reservoir
- proximity to the South East Queensland (SEQ) load centre and Southern Queensland REZ
- state government ownership of land in the project footprint
- large hydrological catchment for the lower reservoir.

Following the announcement of investigations into the Borumba PHES project, the scale of the requirement for long duration energy storage in Queensland (at least 6 GW for 24 hours by 2035) became apparent through analysis undertaken as an input into the QEJP. As a result, in 2022 DEPW undertook substantive evaluation of the most prospective sites from the Queensland Hydro Study Stage 3 report to identify the sites best placed to meet Queensland's identified storage need.

The Pioneer-Burdekin PHES was confirmed as the most attractive site and selected as the second large-scale long duration storage site where feasibility investigations would deliver the greatest value. The Pioneer-Burdekin site was considered favourable for detailed analytical investigations and community consultation due to the following factors:

- Attractive capital costs driven by economies of scale, and strong technical characteristics including favourable length-to-head ratio and small-to-moderate required embankment volumes.
- Significant scale of energy storage possible at site (this avoids future development of a third or fourth large-scale, long duration PHES site).
- High rainfall indicating suitable hydrology to support scheme reliability.
- Fewer construction years needed to connect to the load centre via transmission compared to other sites. This means the project can be delivered in stages by 2032 and 2035. Other sites are not likely to be to be delivered in this timeframe which would impact achievement of Queensland's renewable energy target and emissions reductions goals.
- Preliminary indications of favourable site geotechnical conditions.
- Greater opportunities to manage scheme impacts on sensitive environmental areas through careful design than other assessed options.

Whilst characteristics of the site are viewed as extremely favourable for PHES development, there are impacts which must be addressed, such as resettlement of impacted landowners. The Queensland Government will continue to work with the community to understand and manage these impacts. A process of community consultation was initiated from the commencement of the detailed analytical studies for this site.

The scale of the Pioneer-Burdekin project will also enable the Queensland Government to achieve the required 6,000 MW long duration capacity with potentially two projects only (Borumba and Pioneer-Burdekin) rather than three or more.

The impacts of Pioneer-Burdekin were compared against the cumulative impacts of the otherwise required development of at least two additional PHES sites. This reduces the cumulative impact and cost of large-scale, long duration PHES development and the overall energy transformation in Queensland.

In June 2023, the Queensland Government announced a final investment decision for the Borumba Pumped Hydro Project, informed by the outcomes of the detailed analytical studies undertaken in 2022 and subject to necessary approvals. Early and exploratory works and environmental approvals processes will be undertaken in the next phase of project development.

Part 1
Queensland's economic opportunity

Our jobs opportunity and climate change imperative

Energy systems across the world are transforming to respond to the increasingly tangible and costly impacts of a changing climate. Transforming energy systems to run on zero carbon energy sources is an immediate and important opportunity that can be seized to achieve the Paris Agreement targets of limiting the global temperature increase in this century to 2°C while pursuing efforts to limit the increase even further to 1.5°C. The QEJP sets out the optimal infrastructure pathway for Queensland to meet this opportunity and accelerate on the path to net zero emissions by 2050.

Decarbonisation of Queensland's economy and heavy industries will also drive more investment in renewable energy, creating jobs for Queenslanders. The Queensland SuperGrid will create around 100,000 jobs by 2040 with 95 per cent of investment in regional Queensland.

This opportunity will not be efficiently and effectively seized without partnering variable renewable energies with energy storage and firming. This symbiotic relationship is explored throughout the following section.

Role of energy storage

Energy storage allows time or location mismatches in demand and supply to be managed to ensure reliability and security of supply. For example, dams and reservoirs are built to store water from rain to ensure water supply is reliable and secure. Energy storage works in the same way.

As renewable energy is variable in nature, it needs to be 'firmed'. The concept of 'firming' means matching the variable output of renewable generators to instantaneous demand. This means variable energy must be stored when available and discharged when it is needed. This can occur via energy storage such as battery storage systems or PHES and fast start dispatchable generation that can be 'switched on' as required to meet demand. Unlike short and medium duration storage, long duration storage can:

- manage short-term periods of low renewable generation, such as a rainy day or windless night
- contribute to meeting demand in case of extended periods of low renewable generation
- provide seasonal smoothing of energy over weeks or months.

Energy storage minimises the curtailment of renewable energy generated at times where demand is low, and supply is high. In a system with no storage this renewable energy, that has no marginal cost to produce, will be curtailed/spilled and permanently lost.

Supply and demand variations also drive fluctuations in the price of energy. Storage operators buy electricity when it is cheap and store this electricity for times when it is more expensive (a concept known as 'arbitrage'). This shifting of cheap electricity to different times of the day has the effect of stabilising and lowering overall power prices by increasing supply at times when renewable output is low. This is outlined in Figure 6 where plentiful, cheap energy generated during the day (i.e. solar) is shifted to times of evening peak demand.

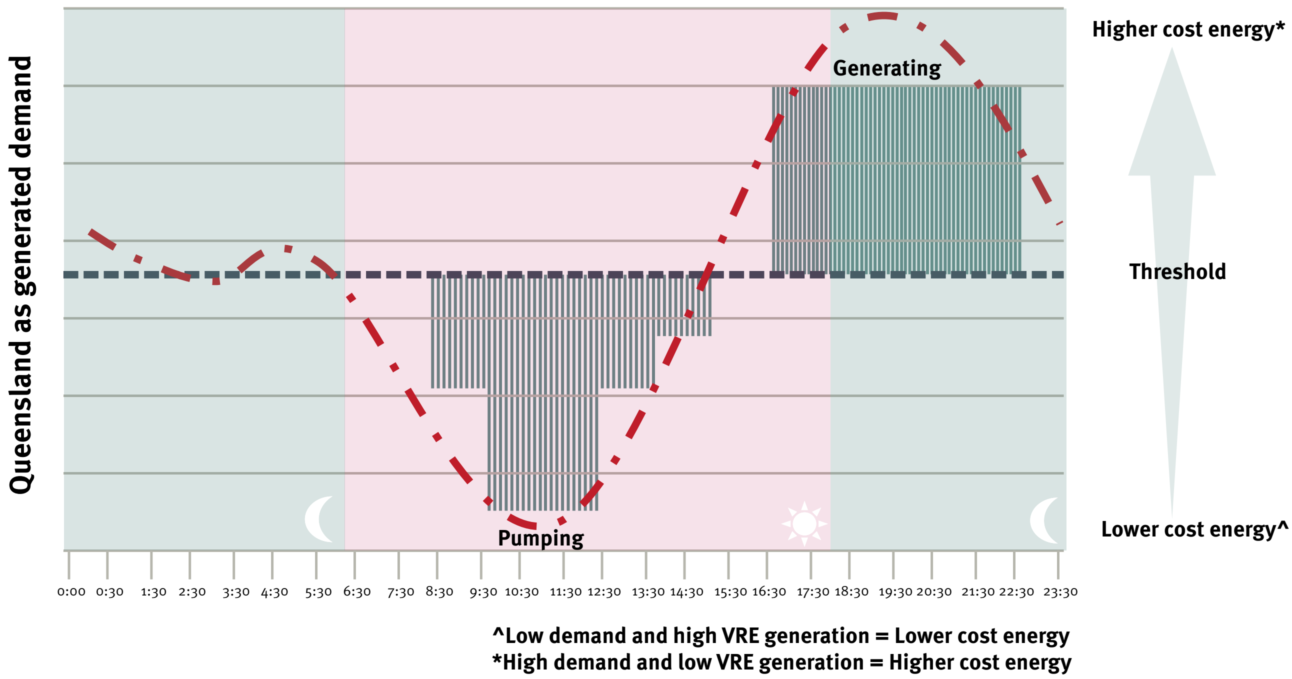


Figure 6: Plentiful and cheap energy being time shifted using storage to meet the evening peak demand

Energy storage provides two critical services to an energy grid.

1. **System reliability** – which refers to delivering enough power to always meet demand. This means electricity supply must be able to always meet demand across different timescales during both typical and unforeseen fluctuations in availability or demand.
2. **System security** – which refers to keeping the system within safe operating limits. This requires frequency, voltage, transient and power system oscillations to be kept stable; the ability to restart the system if necessary ('black start'); the ability to set frequency and voltage ('grid formation'), and the ability to balance the actions of different control systems (e.g. a generator's governor) throughout the power system.

There is a wide range of energy storage technologies with specific characteristics suited to provide the above services. The primary difference between storage technologies is the duration over which they can supply energy:

- **Shallow/short duration** – energy storage with durations less than four hours. Shallow storage is primarily used to provide generation capacity (megawatts), fast ramping and other services such as frequency control ancillary services (FCAS).
- **Medium duration** – energy storage with durations typically between four to 12 hours. Medium duration storage is targeted at intra-day energy shifting, providing energy supply generally for evening peak demand. Medium duration storage cannot reliably address short-term periods of low renewable generation, such as a rainy day or windless night, multi-day periods of low renewable generation or provide seasonal smoothing.
- **Deep/long duration** – energy storage with durations 24 hours or longer. Long duration storage can manage short term periods of low renewable generation, such as a rainy day or windless night, contribute to meeting demand in prolonged periods of low renewable generation and can provide similar system services as medium and short duration storage (dependent on technology and operation). Deep storage can also provide smoothing of energy over weeks or months.

Time-shifting energy – maintaining a reliable and secure system

The primary role of energy storage is the time-shifting of energy to ensure that supply and demand are always matched. This is important because demand for electricity varies considerably over time within days, weeks and on a seasonal basis, and the production of electricity from wind and solar generation also varies over the same periods.

In a system dominated by VRE, two technologies are expected to provide most of Queensland's energy generation capacity – solar and wind. Daily storage will be required to match the generation profiles of weather-influenced wind and solar generation to the demand profile created by customers across the state.

Solar generation is limited to daylight hours only, meaning that solar cannot be used to directly supply demand during other periods. In addition, the profile of generation can vary greatly from hour to hour and from day to day.

Wind turbines are not limited by the same constraints as solar, as they can generate electricity overnight. However, wind generation is also subject to fluctuations caused by the level of wind resource available.

Normalised annual daily large-scale wind and solar generation data are shown in Figure 7.

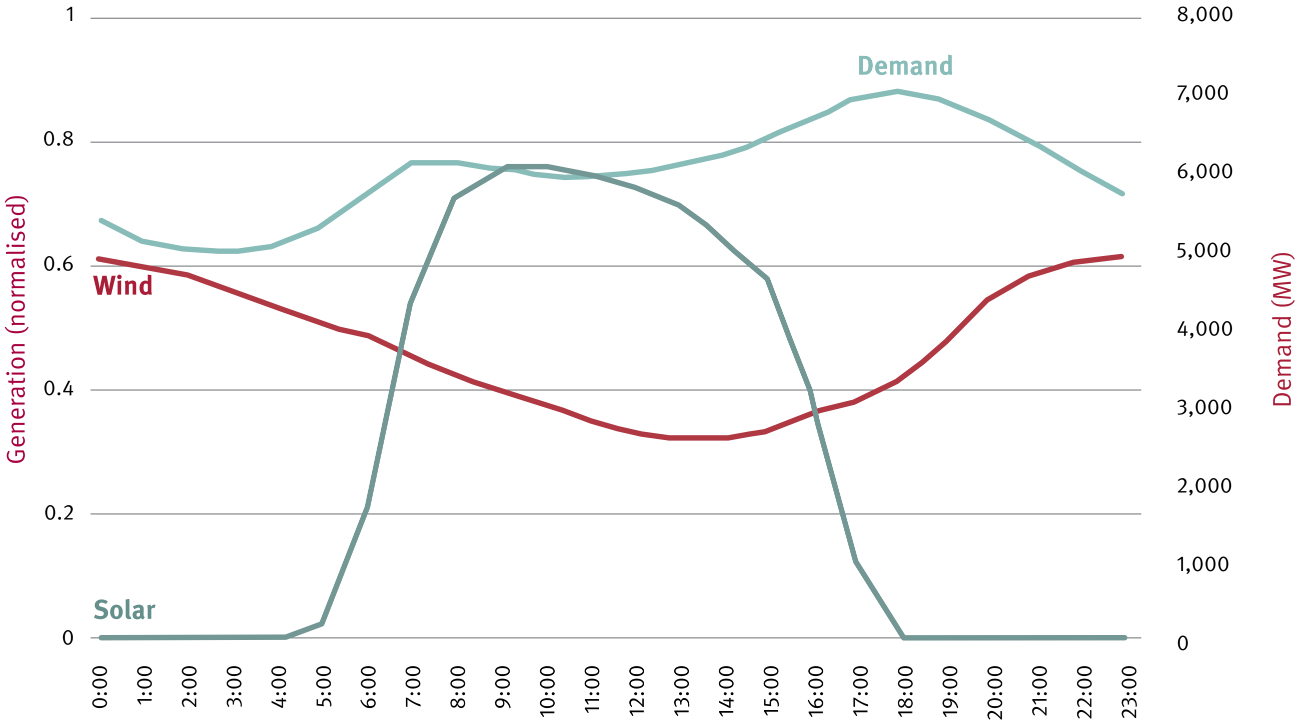


Figure 7: The normalised annual output profile of large-scale wind and solar generation in Queensland. Wind generation peaks overnight and solar generation peaks in the mid-morning, both outside peak Queensland electricity demand.

Shallow and medium duration storage technologies such as batteries can provide intra-day storage. They can absorb 'excess' solar energy from the grid throughout the day, store it, and discharge it later to meet demand. 'Excess' is a colloquial term for energy that would otherwise be constrained or spilled.

Due to their limited energy storage duration, shallow and medium duration storage technologies are unable to manage short-term low renewable generation such as rainy days (unable to charge) or windless nights (storage fully discharged).

The time between storage and discharge could be minutes, hours or days. Battery technology is most competitive in the one-to-four-hour duration range. Medium duration PHES assets (4–12 hours duration) may also be competitive in this intra-day space and are currently being developed by multiple private sector proponents in Queensland.

Long duration storage can provide for intra-day storage plus the ability to manage short-term low renewable generation such as rainy days or periods of windless nights, along with the ability to contribute to managing extended periods of low renewable generation.

Seasonal storage and 'dunkelflaute'

Extended periods of extremely low wind and solar output are infrequent, but not rare. The term 'dunkelflaute' translates to dark doldrums or dark wind lull and is used in Germany to describe multi-day periods of low wind and solar generation. It is important that any renewables-based system has a way to deal with these periods.

During these periods some form of dispatchable generation is likely to be required together with renewable generation and long duration storage. Depending on the length of time that 'dunkelflaute' conditions persist, several technologies will have a role, including large-scale, long-duration PHES. In the short-term, coal and gas will continue to play a key role in meeting this type of shortfall. In the medium-term, gas is likely to provide the bulk of this energy, as coal is progressively repurposed. In the longer-term, clean generation technologies such as large-scale, long duration pumped hydro and hydrogen may replace or augment gas-fired generation.[11]

Queensland's energy storage needs

The blueprint outlines the optimal infrastructure pathway for decarbonisation of Queensland's electricity system.

Under the optimal pathway outlined in the blueprint, Queensland will need at least 6,000 MW of long duration storage for a highly renewable system, complemented by approximately 3,000 MW of grid-scale storage, around 6,000MW of batteries in homes and businesses and up to 3,000 MW of new low-to-zero emission gas-fuelled plant.

The amount of utility scale storage generation and energy capacity required to support Queensland's energy transformation will be dependent on several factors:

- Changing demand patterns including residential uptake of solar, batteries, electrics vehicles (EVs), consumer energy resources (CER) and industrial demand for renewable energy (including green hydrogen).
- The mix of renewable generation that influences storage requirements due to the differing generation profiles of wind and solar. E.g. varying wind generation profiles in different locations across the state.
- The timing of re-purposing coal fired generation. Storage capacity is required to be deployed prior to repurposing coal-fired power stations to ensure continued reliability of supply.
- Development and research of storage technologies. Some technologies are considered mature. E.g. technologies such as PHES can be deployed with known costs and certainty regarding operational performance. In comparison, other technologies are undergoing rapid development and may be subject to cost reductions beyond what is forecast. E.g. battery technology.
- Forecast uncertainty leads to increased storage requirements. The inability to apply perfect foresight to demand and renewable generation forecasts means that the ultimate storage requirement is likely to be higher than most modelled outcomes.
- Transmission interconnection to other states can provide supplementary firming capacity. This interconnection capacity can transfer generation from other states that is either dispatchable (i.e. on demand) or has diverse weather characteristics compared to Queensland's renewable generation.

Despite these variables, modelling (in addition to the QEJP modelling) suggests that significant energy storage capacity is required to support the transformation of Queensland's energy system.

11. Given plant would be expected to operate in times of low renewable generation including dunkeflaute, large volumes of hydrogen storage would be required, which could potentially be provided by geologic hydrogen storage such as salt caverns or depleted gas fields.

The 2021-22 CSIRO GenCost assessment found that, in 2030, the National Electricity Market (NEM) will require 0.20 kilowatts (kW) to 0.34 kW storage capacity for each kW of variable renewable generation installed.[12] This assessment holds to a 90 per cent VRE scenario. For Queensland this could mean at 90 per cent renewable capacity, with in the order of 25 GW of utility scale renewables, that around 6.75 GW of storage will be required. (This assumes an average capacity factor of 30 per cent and average demand of 6 GW.)

The Australian Energy Market Operator's (AEMO) Integrated System Plan (2022), assumes in terms of Queensland storage[13]:

- the need for long duration storage is linked to the repurposing of coal generation
- by 2030, Queensland is forecast to have 2,000 MW of medium to long duration storage to support renewable energy developments (equivalent to Borumba PHES)
- when all Queensland coal capacity is repurposed, the level of medium and long duration storage is forecast to be 6,000 MW, with an additional 10,000 MW of shallow storage (assumed to be provided by batteries, including residential batteries and EV storage).

Hydro Tasmania, which operates an energy system with significant hydroelectric capacity, has stressed that the assumption of perfect foresight to demand and renewable generation forecasts, as well as generator bidding means that the ultimate requirement for storage is likely to be significantly higher than modelled outcomes.[14] However, the addition of long duration storage would reduce the amount of additional storage capacity required compared to adding additional shallow storage.

12. CSIRO (2022), GenCost 2020-21: Final Report. Available at: https://publications.csiro.au/publications/publication/PIcsiro:EP2022-2576
13. AEMO (2022), 2022 Integrated System Plan. Available at: https://aemo.com.au/en/energy-systems/major-publications/integrated-system-plan-isp/2022-integrated-system-plan-isp
14. Tas Hydro (2019) Battery of the Nation: Operation of storages without perfect foresight. Available at: https://www.hydro.com.au/docs/default-source/clean-energy/battery-of-the-nation/storage-with-imperfect-foresight.pdf?sfvrsn=72e59528_4

Timing of energy storage requirements

Substantial new renewable generation investment is critical to meet the renewable energy targets under the QEJP. Given the variable nature and capacity factors of renewable generation, around 25,000 MW of large-scale renewable generation (total) and around 7,000 MW of new rooftop solar generation is required to meet forecast demand in 2035 (when all publicly owned coal-fired power stations are repurposed into clean energy hubs). [15]

Increased energy storage capacity is required as dispatchable thermal (coal) generation withdraws from the market and is replaced by VRE. For this reason, the pace of storage deployment will directly influence the pace of coal-fired power plant repurposing. AEMO also notes that it is prudent for early investment in long duration storage to enable improved resilience to coal repurposing or energy project commissioning delays.[16]

The blueprint's optimal infrastructure pathway requires deployment of 2 GW of long duration storage at Borumba in 2030 and additional deployments of 2.5 GW each at Pioneer-Burdekin in 2032 and 2035 (see Figure 8).

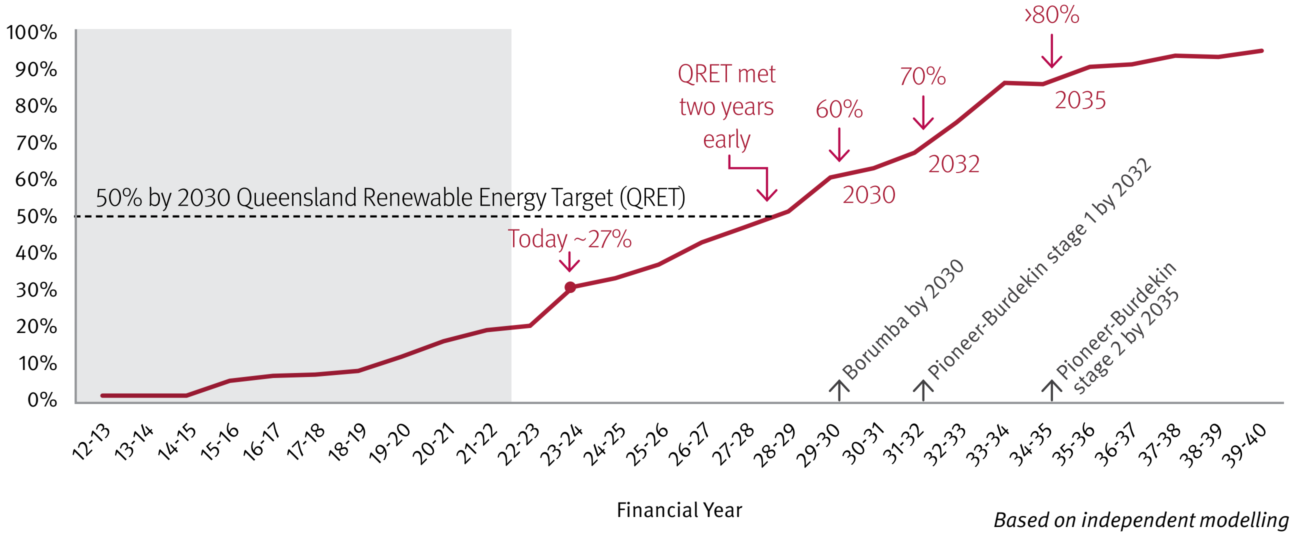


Figure 8: Renewable energy percentage under the Queensland Energy and Jobs Plan

Mix of storage required

Energy system security and reliability requires technologies that can respond in different timeframes and provide energy for different durations, leading to market opportunities for different forms of energy storage. Multiple technologies can provide similar energy market functions, therefore the deployment of one technology over another will be driven primarily by commerciality and feasibility.

Long duration PHES forms a cornerstone of the QEJP and the optimal infrastructure pathway to support the transformation of Queensland's electricity system. This is due to the amount of long duration storage required (at least 6,000 MW with 24 hours duration) to support the repurposing of Queensland's coal-fired generation fleet and support load growth from decarbonisation coupled with investment in renewable generation and transmission assets.

PHES has been identified as the optimal energy storage option to support Queensland's energy transformation due to its lower cost, long-life and significant energy storage potential. However, other energy storage technologies, such as batteries, will also have a role to play in Queensland's energy transformation.

15. Queensland Supergrid Infrastructure Blueprint, September 2022, available at: https://www.epw.qld.gov.au/__data/assets/pdf_file/0030/32988/queensland-supergrid-infrastructure-blueprint.pdf
16. AEMO (2022), 2022 Integrated System Plan. Available at: https://aemo.com.au/en/energy-systems/major-publications/integrated-system-plan-isp/2022-integrated-system-plan-isp

Building on the QEJP and the blueprint, DEC will develop an Energy Storage and Firming Strategy for release in 2024. This will outline Queensland's storage and firming needs, to maintain a reliable and resilient electricity system through the energy transformation. This strategy will also consider on how much storage the energy system needs in addition to the Borumba and Pioneer Burdekin PHES and what storage technologies should be used.

Why can't we use batteries alone to meet our long duration energy storage needs?

Batteries provide valuable services to the electricity system due to their very fast response times, locational flexibility and relatively small environmental footprint. It is expected that as Queensland decarbonises, a significant number of batteries will be installed across the state, including residential home batteries, batteries in EVs, community batteries and large-scale utility batteries.

This shift brings an opportunity for Queensland to build on our critical minerals and mining expertise to become a driving force in the development, manufacture and deployment of batteries. The Queensland Battery Industry Strategy will help leverage Queensland's competitive advantages and commercialise innovative technology to providing opportunities to accelerate industry growth and deliver the highly skilled jobs of the future.

While batteries will continue to be deployed and provide many valuable services to the electricity system, there are several reasons why large-scale PHES will provide the cornerstone of long duration energy storage needs identified by the QEJP:

- **Proven technology at very large scale** – PHES is a proven technology for large-scale long duration energy storage. The level of energy to be stored to meet the identified need of 6,000 MW of 24-hour storage is enormous. E.g. it is the equivalent of more than 350 batteries the size of CS Energy's proposed 200 MW/400 MWh Greenbank battery. While battery technology continues to develop, no such fleet of batteries exists anywhere in the world, and operation of such a system is currently untested. By contrast, PHES is already widely deployed, accounting for around 97 per cent of total global electricity storage in 2020.[17]
- **Supply chain hurdles** – batteries will face challenges in securing sufficient raw material supplies to meet the scale of battery production required to deliver the global markets stationary energy storage requirements, as well as the growing demand for transportation.
- **Cost** – while batteries providing short duration storage (1-4 hours) can be cost competitive with PHES in terms of maximum generation (megawatts maximum output), they are not forecast to be cost competitive with PHES for at least the next decade for the provision of long duration energy storage.[18]
- **Additional costs** – local distribution networks would likely need to be upgraded significantly (plus new control systems), at significant cost, to enable gigawatts of power to be transported to the transmission network from residential batteries and EVs.
- **Centralised control** – to provide comparable services to large-scale PHES, batteries would need to be charged/discharged as required by the overall system. Unlike with large-scale long duration PHES, such control is unlikely for a system consisting of numerous battery installations with potentially hundreds of thousands of individual users with their own requirements for storage. EVs are unlikely to follow this optimised pattern of operation without additional regulation.
- **Lifetime** – expected battery lifetime is currently 10 years compared to approximately 100 years for PHES. While upfront capital costs may be comparable in some cases, the fleet of batteries would need to be replaced many times over the life of a PHES asset, significantly increasing total cost.
- **Life cycle issues** – while batteries may be recyclable, most battery technologies incorporate chemicals which require careful handling and management to ensure chemicals are not inadvertently released to the environment. Recycling/disposal of batteries will need to be both increased and likely regulated to ensure environmental impacts are minimised.

17. IEA (2021), World Energy Outlook 2021. Available at: https://www.iea.org/reports/world-energy-outlook-2021
18. CSIRO (2022), GenCost 2021-22. Available at: https://publications.csiro.au/publications/publication/PIcsiro:EP2022-2576

Part 2
Large-scale, long duration PHES

Queensland Hydro Study (2017 to 2020)

Contemporary investigations into Queensland's pumped hydro and hydroelectricity energy storage potential began in 2017, through the Powering North Queensland Plan and the Powering Queensland Plan.

A key component of the Powering Queensland Plan was to establish the Queensland Energy Security Taskforce (QEST) to guide the state's robust energy security for both the short and long-term. The QEST was chaired by the then Energex CEO. Other members included the then Queensland Chief Scientist, then the Department of Energy and Water Supply Director-General, and the then Queensland Under Treasurer.

This body was tasked with implementing recommendations from Australia's former Chief Scientist Dr Alan Finkel's Independent Review into the Future Security of the National Electricity Market.

To achieve this, through the Powering Queensland Plan, the Queensland Government charged the QEST with developing a Demand Management and Energy Efficiency Strategy and providing advice on long-term market design for Queensland, including investigating:

- the development of new hydro-electric and pumped storage generation capacity across the state
- expanding interconnection between Queensland and other states.

The Queensland Government subsequently commissioned the QEST to conduct a study into Queensland's hydroelectric and pumped storage opportunities and implement the findings of that study (the Queensland Hydro Study).

The Queensland Hydro Study built on historical information and project reports commissioned by the Queensland Government as early as the 1970s into hydroelectric and pumped hydro sites and the ANU-ARENA Atlas project.[19]

The Queensland Hydro Study was completed across three stages. The first two stages of studies were preliminary in nature, exploring the opportunities for conventional hydro and smaller scale PHES in Queensland. Following the first two stages of the study, it became clear that long duration PHES was worthy of deeper investigation as it could provide lowest-cost system reliability and security in the context of increasing variable renewable energy penetration. Stage 3 was commissioned to test the case for long duration PHES and to find potential sites in Queensland.

In summary:

- **Stages 1 and 2** – completed in 2017 and 2018 by Aurecon, assessed the role of conventional hydroelectric generation and small-scale PHES in the transformation of Queensland's electricity system. These studies identified possible sites for both hydroelectric and PHES and identified candidate sites for further investigation. Analysis was undertaken using data from previous historical studies undertaken over the last 50 years and sites identified within the ANU-ARENA Atlas project.
- **Stage 3** – completed in 2020 by the then DNRME, investigated PHES and other technology options at a scale large enough (minimum of 1,000 MW generation capacity with 24 hours of storage) to be capable of maintaining reliability and system security during the transition to a low emissions electricity grid. This investigation was initiated as the sites identified in Stage 2 represented insufficient capacity to manage the balance between cost, reliability, and emissions reduction, with the need for long duration sites to be considered and identified.

19. https://re100.eng.anu.edu.au/global/

Queensland Hydro Study findings

A summary of the Stage 1, 2 and 3 findings are provided below.

Stage 1 – 2017

Report purpose

The primary objective of the Stage 1 study was to review the feasibility of hydroelectric storage and pumped storage schemes in the context of a rapidly evolving energy market to enable the Queensland Government to gain a clear understanding of:

- Queensland's hydroelectric power generation and pumped storage potential
- the role and viability of hydroelectric power generation and pumped storage in Queensland's future energy mix
- options for the development of hydroelectric power generation and pumped storage technologies in Queensland.

The report was conducted in two stages:

1. A review and summary of previous studies undertaken on hydroelectric and pumped storage generation in Queensland. This included more than 50 years of Queensland Government hydro power studies.
2. A multi-criteria analysis of possible sites for the development of hydroelectric and pumped storage generation capacity.

Stage 1 of work on the Queensland Hydro Study involved assessing all historical studies conducted by Queensland Government entities, ANU's topographical analysis (otherwise known as the ANU-ARENA Atlas), as well as other schemes publicly identified. The objective of the first stage was to identify general regions from the ANU-ARENA Atlas which appear to be technically feasible and in reasonable proximity to existing transmission infrastructure.

Historical studies carried out in South East Queensland were also reviewed, as well as concept studies carried out on pumped hydro projects throughout Queensland.

Queensland's competitive advantage

The report found that appropriate levels of dispatchable and flexible energy are crucial to balance the intermittency of VRE output. Hydroelectric power generation and pumped hydro energy storage have the potential to provide significant levels of the energy required to achieve this balance in a cost effective manner and provide the necessary flexibility and grid support to maximise the growth potential of VRE.

Benefits to Queensland

The Stage 1 report found that hydroelectric power generation and pumped storage could be integral to meeting Queensland's renewable energy target at lowest cost by providing:

- dispatchable and flexible energy supply and capacity, with zero carbon emissions (in the case of pumped storage, depending on charging or pumping electricity source)
- inertia and ancillary services that enable reliable and efficient grid operation and services in the event of line outages or other contingencies
- the ability to 'ramp' and 'flex' depending on daily demand profiles, which in the case of Queensland, are expected to require significant peak capacity as the amount of rooftop and utility scale solar increases over time
- other benefits to the network, including the ability to defer upgrades or augmentation.

Stage 1 – 2017

Establishing the potential

The Stage 1 report outlined the extensive work previously carried out by the Queensland Government for the development of hydroelectric generation in the state and recommended a shortlist of new potential hydroelectric and pumped storage schemes for further investigation.

Review of historical studies

Some sites investigated were identified from feasibility studies completed in the 1970s, 1980s and 1990s and from a review of work completed by the ANU and ARENA to refine opportunities for pumped storage. The review of studies for 11 sites, completed from the 1970s onwards, resulted in six potential hydroelectric schemes and four potential pumped storage schemes for consideration. Many sites had multiple studies completed with most of the analysis occurring in the 1980s.[20]

Review of ANU-ARENA Atlas

Approximately 2,000 Queensland sites identified in the ANU-ARENA Atlas were screened and refined to 94 for further consideration. Overlaying an analysis of preferred connection points in the network resulted in 19 new pumped storage locations being recommended for further investigation.

Analysis of geographic information systems (GIS) data

New potential hydroelectric schemes were also identified using topographical and meteorological data to identify favourable locations. These locations were then analysed in further detail and three potentially viable sites shortlisted for further investigation. Four existing dams were also identified as potential 'mini-hydro' sites in the range of 1-5 MW. The four existing dams identified for this retrofit opportunity were:

- Eungella Dam
- Fred Haigh Dam
- Awoonga Dam
- North Pine Dam.

These retrofit opportunities ultimately did not progress to the next phase of analysis due to commerciality reasons.

Scheme evaluation

The **23 pumped storage sites** (19 from the ANU-ARENA Atlas and four from historical studies) and the **nine conventional hydroelectric** schemes (six from historical studies and three from GIS analysis) were evaluated against a range of technical, economic, social and environmental criteria.

This resulted in the **identification of 16 shortlisted opportunities** (shortlisted sites appear in the map at Figure 9 and include 12 PHES and four conventional hydroelectric schemes) with development potential comprising of up to 673 MW of hydroelectric power generation and 3,408 MW of pumped storage. Shortlisted locations include:

- Far North Queensland - three sites
- North Queensland - in the Ross transmission zone - four sites
- North Queensland - near the Nebo transmission substation - eight sites
- South East Queensland - one site.

Next steps

Stage 1 recommended further detailed analysis of the shortlisted 16 sites to be progressed as part of Stage 2 of this work, to better define the unique opportunities for the Queensland Government to accelerate the development and deployment of hydro energy storage.

20. Investigations in the 1970s, 1980s and 1990s evaluated opportunities for a number of sites/projects, including; Burdekin Falls Dam Project, Blue Valley, Tully-Millstream Project, Herbert River Project, Bloomsfield, Somerset Dam Pumped Storage, Mount Byron Pumped Storage, Borumba Dam Pumped Storage, Kenilworth Dam Pumped Storage, Mount Mee / Rocksberg Pumped Storage, and Cardwell Range Pumped Storage.

Stage 1 – 2017

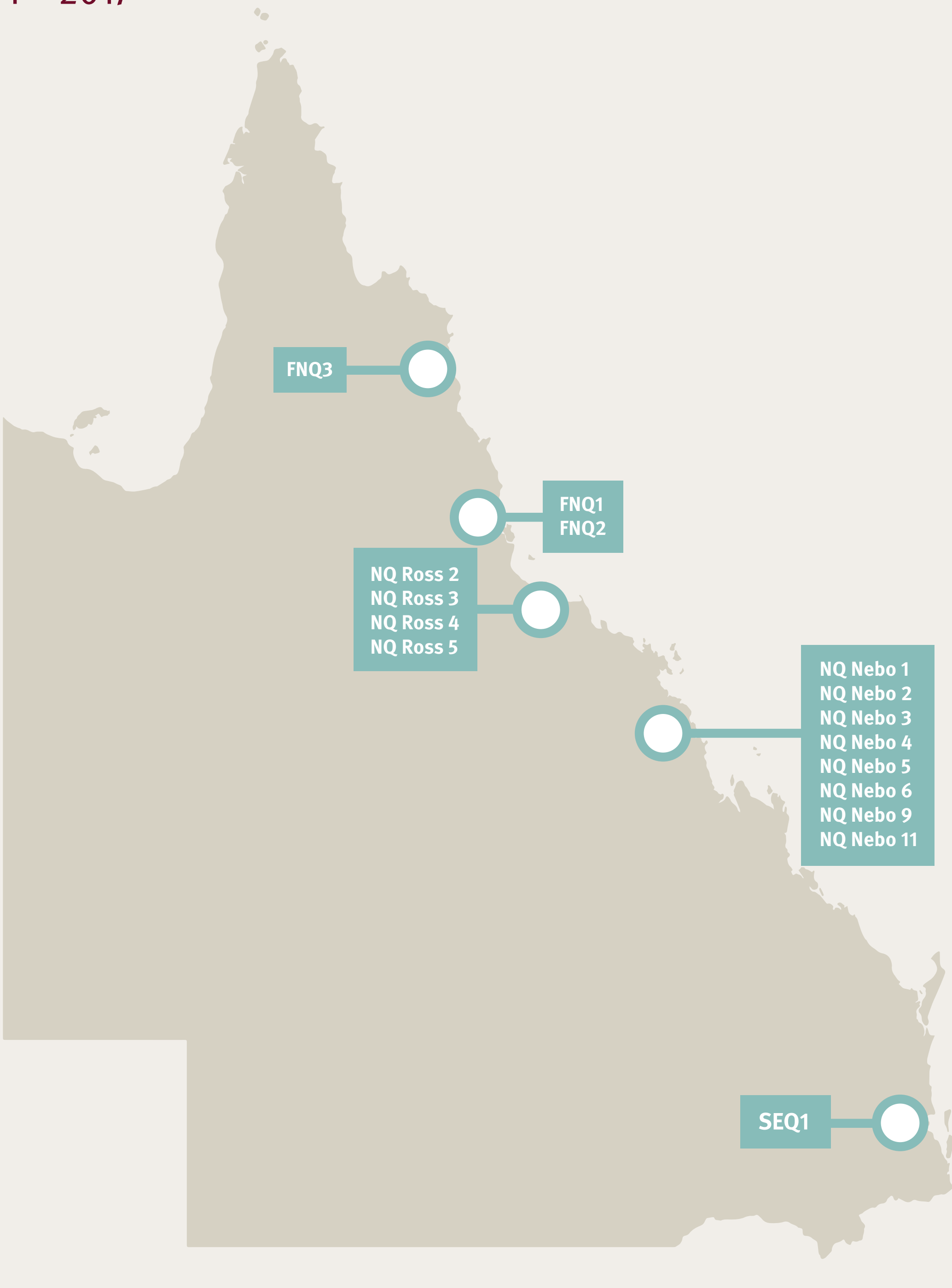


Figure 9: 16 shortlisted opportunities from Stage 1 of the Queensland Hydro Study

Stage 2 – 2018

Report purpose

The Stage 2 report built on Stage 1 of the Queensland Hydro Study. The objective of the Stage 2 report was to:

- further investigate the potential schemes identified in Stage 1
- develop scheme concepts to allow the schemes to be assessed and prioritised
- provide a summary of recommendations and next steps for the development of hydroelectric and pumped storage schemes in Queensland.

The approach included the following key steps:

- Shortlisting – refinement of the 16 schemes identified in Stage 1 to a maximum of 10 schemes for assessment in Stage 2 through consideration of potential deliverability risks and a deeper analysis across environment, planning, geography and electricity network considerations that were not possible in the initial stage of investigation. Two schemes previously omitted during Stage 1 were reintroduced in the Stage 2 shortlisting process.
- Scheme concept development and assessment – development of technical concepts for each shortlisted scheme to enable a comparative assessment via a multicriteria analysis (MCA) and risk assessment process.
- Prioritisation – consideration of strategic differentiators and the results of the MCA and risk assessment process to identify methods of prioritising the shortlisted schemes.
- Findings and recommendations for future work – a summary of key findings across the study and future work that would need to be undertaken in the longer term to progress the development of hydroelectric and pumped storage schemes in Queensland.

The report was conducted in two stages:

1. A review and summary of previous studies undertaken on hydroelectric and pumped storage generation, assessment of the potential role and market need for hydroelectric and pumped storage schemes in Queensland within the context of the National Electricity Market (NEM), and an initial shortlisting of potential hydroelectric and pumped storage schemes for future development.

2. Further shortlisting of identified hydroelectric and pumped storage schemes from Stage 1, development of project concepts for the shortlisted schemes, a MCA and prioritisation process to assess the potential of the schemes, and summary of recommendations and next steps for the development of hydroelectric and pumped storage schemes in Queensland.

Queensland's competitive advantage

The report reaffirmed the findings and benefits of Stage 1, that appropriate levels of dispatchable and flexible energy are crucial to balance the intermittency of VRE output. Hydroelectric power generation and pumped hydro energy storage have the potential to provide significant levels of the energy required to achieve this balance in a cost effective manner and provide the necessary flexibility and grid support to maximise the growth potential of VRE.

Stage 2 – 2018

The potential

This report assessed the 16 shortlisted opportunities identified in Stage 1 of the study against planning, environmental and transmission network considerations to produce a refined site list of eight PHES and one conventional hydroelectric scheme for detailed assessment (Burdekin Falls).

High-level concept designs were developed for each PHES site using desktop information so they could be compared on a relative basis. This revealed a PHES project potential of 4,600 MW of capacity and 36,600 MWh of storage. When location and connection to the network were considered, almost 2,300 MW of capacity and 18,000 MWh of energy storage could be reasonably achieved.

Figure 10 shows the 9 shortlisted sites in North Queensland (NQ) and Central Queensland (CQ) near the Ross, Nebo, Broadsound and Bouldercombe transmission substations.

Figure 10: 9 shortlisted sites from Stage 2 of the Queensland Hydro Study

Stage 2 – 2018

The priorities

The shortlisted PHES schemes were prioritised using a multi-staged iterative MCA and risk assessment, overlaid with analysis of each scheme's capability in achieving key state objectives.

At this stage of development, all shortlisted schemes shared similar key risks including geotechnical and site conditions, water supply, plant size and configuration, connection point, capital cost, market risk, land availability, social impacts, environmental approvals and permitting.

The report noted that further investigation was required to quantify and mitigate risks during future development stages.

Next steps

Stage 2 recommended the state focus on the following:

- Driving regulatory reform – monitor, influence or create policy and regulatory reform to value the unique characteristics of PHES in the transition to higher levels of VRE.
- Defining the need – investigate and quantify when and how much dispatchable generation will be needed to support Queensland's future energy requirements. Determine the scale and operating regime of PHES projects to meet requirements, and the market conditions required for them to be competitive and commercially viable.
- Identifying the role for government – this could include competitive processes to procure energy services for identified market needs, or targeted actions to de-risk critical project areas (e.g. environmental or geotechnical investigations and approvals support) as an enabler for private-sector investment. Direct investment in the development of PHES could be a compelling investment to support the ongoing operation and profitability of those assets in the context of Queensland's renewable energy target.

Stage 3 – 2020

Report purpose

Following completion of stages 1 and 2 of the study, the then Queensland Energy Security Taskforce (QEST) identified the need for a third stage. This third stage was focused solely on PHES, in the context of competing technology options, at a scale large enough to be capable (when combined with renewable generation) of maintaining reliability and system security. This was a different scope of investigation as compared to previous stages of the Queensland Hydro Study and resulted in identifying schemes much larger than those identified in stages 1 and 2 of the study.

Sites examined in stages 1 and 2 of the study were not progressed as they did not meet the criteria for further study in Stage 3. Sites from stages 1 and 2 were less than 1 GW and did not meet the 24 GWh of storage capacity criteria.

Stage 3 was conducted over five phases. Each phase progressively shortlisted identified PHES schemes. This process is explored in greater detail later in this document.

What did the Stage 3 study investigate?

Stage 3 of the Hydro Study was split into three components based on the Terms of Reference **(Appendix A)** provided by the QEST:

- The first component was to explore the case for large-scale, long duration PHES as Queensland's electricity sector transitions to net-zero emissions by 2050. This involved a comparison of alternative technology options.
- The second component was to analyse sites in Queensland that may be appropriate for large-scale, long duration PHES, and to undertake detailed concept studies for prospective sites.
- The third component was to make recommendations to government, using the findings from the first two components.

Sites examined in Stage 3 of the Hydro Study were shortlisted and prioritised based on a range of criteria including scale, capital costs, water security and hydrological impacts, round trip efficiency, transmission issues, environmental and community impacts, and legal and regulatory constraints. Each subsequent phase involved increasingly granular analysis on a smaller subset of sites. This approach ensured all of Queensland was considered at a high level, but resources were concentrated on the most prospective sites.

Figure 11 shows the location of large-scale long duration investigation zones.

Exploring the case for large-scale, long duration PHES

The Stage 3 investigated a wide variety of potential and available energy storage technologies including:

- PHES
- batteries
- conventional hydroelectricity
- flywheels
- synchronous condensers
- concentrated solar thermal
- compressed air energy storage
- demand response
- hydrogen
- low-capacity factor gas generation.

Analysis on the above storage technology options can be found at **Appendix B**.

The Stage 3 report found:

- As Queensland's coal generators are repurposed, they will need to be replaced by a combination of renewable energy and complementary technologies (ideally including long duration storage).
- The scale of storage necessary to reach net-zero emissions is significant – both in terms of capacity (power) and depth (duration).

Stage 3 – 2020

- Based on currently existing technologies, PHES is the best technology to provide long duration storage. Without long duration PHES, potential pathways to net-zero emissions appear prohibitively expensive, too slow or rely on step-change technology improvements that are not guaranteed.
- The case for long duration PHES is stronger than the case for short duration PHES.

Analysing sites with the potential for large-scale, long duration PHES

A detailed summary of the site investigation and shortlisting process is available in Part 3 of this document.

The Stage 3 report found:

- All identified sites for large-scale, long duration PHES have some degree of social and/or environmental risk. These risks should be balanced against the magnitude of the challenges Queensland will face in the transition to net-zero emissions.
- Queensland's most prospective sites could potentially underpin the electricity system's transition.
- The location of the most prospective sites aligned with broader system planning.

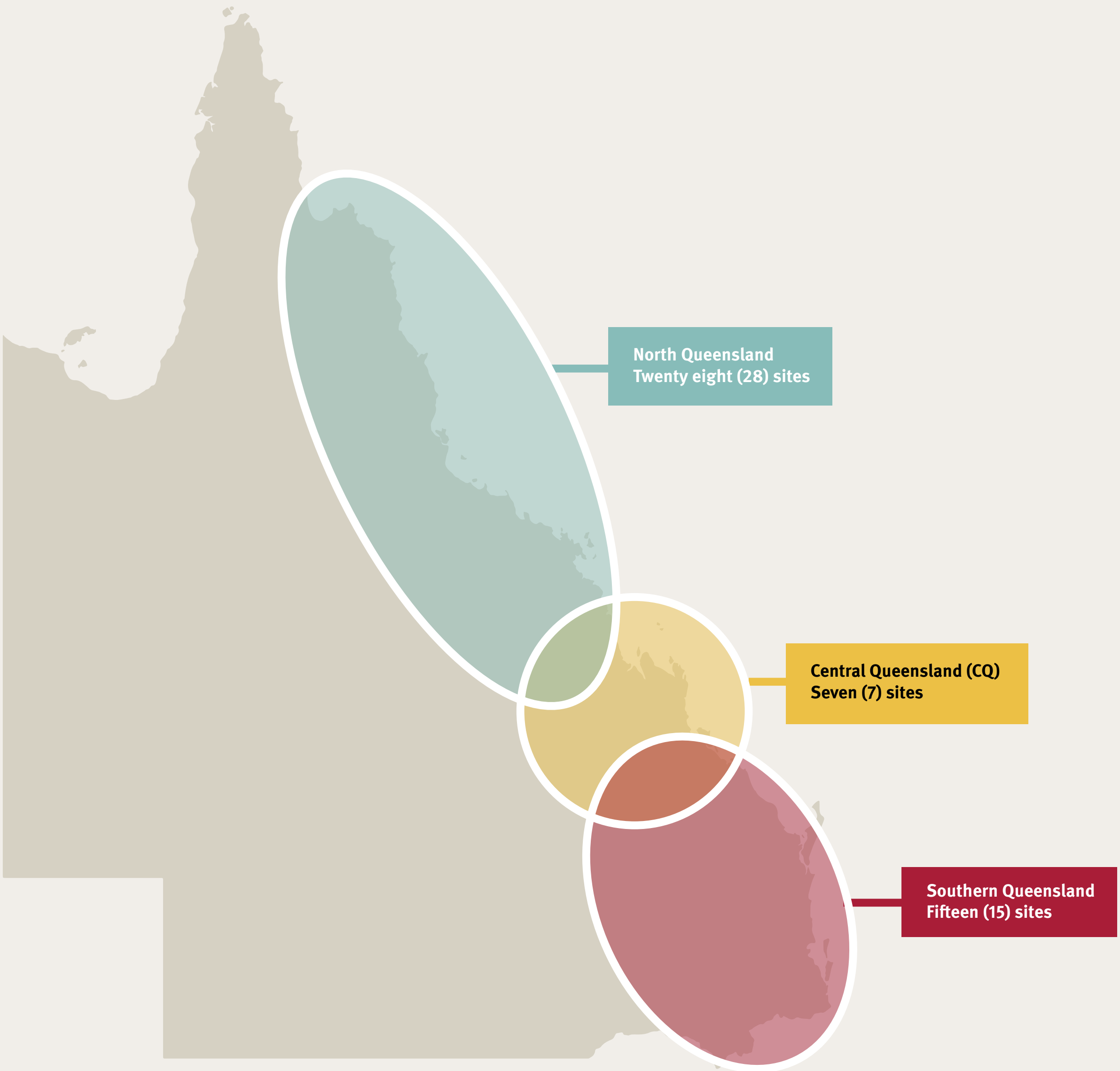


Figure 11: Stage 3 Queensland Hydro Study – Large-scale long duration storage investigation zones

Stage 3 – 2020

The role for the Queensland Government

In exploring the role for the Queensland Government, the Stage 3 report found:

- The private sector faces a range of challenges that make it difficult to invest in large-scale, long duration PHES.
- The government could undertake work to decrease project development lead times to de-risk future investment, postpone critical decision points and increase the likelihood of achieving the lowest system cost.
- The alignment of commissioning large-scale, long duration PHES with the repurposing of coal-fired power stations would help to support a smooth and just transition to net-zero emissions.
- A large-scale, long duration PHES would likely be of substantial value to a government owned corporation (GOC) and future governments seeking to place downward pressure on electricity prices.

Recommendations

Recommendations from the Stage 3 report included:

- Undertake feasibility studies, system planning and supporting work to facilitate timely development of Queensland's most prospective large-scale, long duration PHES sites in a way that maximises long-term system benefits.
- Undertake ongoing work to inform electricity system planning decisions.
- On an ongoing basis, maintain the possibility for Queensland's best long duration storage options to be operational when key coal plants withdraw from the market and are repurposed.

General PHES characteristics

Key definitions

Head is the elevation difference between the water level in the upper and lower reservoirs.

Length is the distance that that the water travels between reservoirs.

Length-to-head ratio (L:H or L/H) is used as a general measurement of practical efficiency for a PHES project. L:H ratios below eight (i.e. 'steeper' projects) are considered the most attractive. Under 10 is a general rule of thumb for a well sited PHES.

PHES components

PHES schemes store potential energy by elevating water, thereby increasing its potential to generate due to gravity. Theoretically, any material could be used for the elevated body, but water is the most cost effective and efficient because it is:

- dense (1 tonne/m^3), plentiful and benign
- incompressible (so it doesn't incur compression energy losses)
- reasonably non-volatile (evaporating only slowly, and not producing vapour bubbles unless subjected to about 10 m of negative head)
- naturally replenished
- scalable (because large quantities of water can be relatively easily stored)
- viscous enough to conform to blades and waterways when flowing at moderate velocities, but not so viscous as to cause large losses when converting potential energy into the kinetic energy of a flowing fluid.

These characteristics have led to extremely large PHES units and schemes that operate efficiently and reliably. The potential energy is converted into kinetic energy in a turbine by accelerating water to a high velocity, and then forcing it through an abrupt change of direction that spins the generator. Both the turbine and generator are very efficient (at around 94 per cent and 98.5 per cent respectively) and require very little cooling. As a result, most of the potential energy is converted into electrical energy in the generator, and then stepped up from generator voltage (around 13 kV) to transmission voltage (132-500 kV) in a similarly efficient transformer.

Schemes require at least two reservoirs with a substantial height difference (head) between them. This is because:

- the power generated (megawatts) is proportional to the flow rate and head
- the energy stored (megawatt hours) is proportional to the water volume and head.

The water in these storages is held back by dam embankments in valleys or enclosed completely by an embankment in a 'turkey's nest' dam.[21] Fluctuations in water level means the dams are typically made of concrete or with a concrete face, or embankments.

The waterway between the reservoirs is typically sized to maintain hydraulic losses to less than 3 per cent (to maintain high round trip efficiencies). For low head schemes of less than 100 m, a typical 250 MW unit would require a waterway diameter in the order of 9 m. This may reduce to ‹5 m for higher head schemes (›400 m).

The quantities of steel, the weight and size of plant, the quantities of rock and excavation are all very large. Around 70 per cent of the cost of a PHES is in civil works – primarily earthmoving and building concrete structures. As a result, PHES construction needs to be supplied with local content, and therefore strongly supports local employment. The remaining ~30 per cent of cost is almost entirely imported plant.

Design life

An economic life of 25-30 years is usual for the electro-mechanical plant. Civil works are generally designed for a life of 100 or 200 years, and then progressively repaired within the annual operation and maintenance costs (O&M) costs of a few per cent of capital cost. Maintenance can be managed to maintain operations by careful staging. Control systems can be replaced every 10-15 years to maintain technology currency and support, but amount to only a few per cent of the project cost. The 'half-life refurbishment' will see generators rewound, pump-turbines fitted with new bearings, seals and runners replaced, and other modifications to improve efficiency.

Development experience

Australian PHES projects

Australia has only three existing pure pumped hydro schemes, commissioned between 1975 and 1985. They were originally built to support coal power stations with spinning and fast-start reserve and system strength contributions. All three schemes are coupled to at least one large reservoir, with the ability to generate for between 10 and 26 hours. The operation of existing PHES schemes has evolved as increasing levels of renewable energy generation enter the market.

Existing operational Australian PHES schemes are:

- Tumut 3 (600 MW pumping capacity) – constructed in 1973 as part of the Snowy Hydro scheme.
- Shoalhaven (240 MW) – constructed in 1977 and located on the south coast of NSW.
- Wivenhoe (570 MW with ten hours storage) – constructed in 1984, located at Wivenhoe Dam in Queensland.

There are several new PHES schemes under construction in Australia, including the 250 MW Kidston Pumped Storage Hydro Project in Queensland, and the 2,000 MW Snowy 2.0 pumped hydro project in New South Wales.

21. Valley dams typically require less civil works, so are generally cheaper.

Global PHES projects

In schemes that have been purpose-built for PHES (rather than built into conventional hydroelectric schemes or multipurpose projects such as Tumut 3 and Shoalhaven) a duration of 6-8 hours is typical, corresponding to a daily arbitrage cycle.[22]

Many long duration projects of any size are built into large reservoir storage projects with multiple purposes (e.g. irrigation and flood mitigation). They often include cascades of conventional hydro, where pumped hydro can be opportunistically deployed for a very small incremental cost (e.g. the three tandem units in Tumut 3 power station).

The United States' Department of Energy (DOE) Global Energy Storage Database contains information on roughly ~350 operating PHES facilities worldwide.[23]

Capacity

In terms of scale, potential large-scale, long duration PHES generation and storage capacity greatly exceeds the likely scalable deployment of batteries. Figure 12 shows the potential energy storage capacity of the proposed Borumba and Pioneer-Burdekin PHES compared to Wivenhoe (a CleanCo asset of similar scale to most private PHES proposals) and the Hornsdale Power Reserve in South Australia, which was the biggest battery installation in the world when constructed in 2017 (with additional capacity added in 2020).

- At 48,000 MWh the Borumba PHES has 250 times the energy of the South Australian Hornsdale Big Battery.
- At 120,000 MWh the Pioneer Burdekin PHES has 620 times the energy of the Hornsdale Big Battery.
- To reach our long duration energy storage requirements of 6,000 MW (at 24-hour storage) we would need at least two long duration PHES or 740 Hornsdale Big Battery developments.

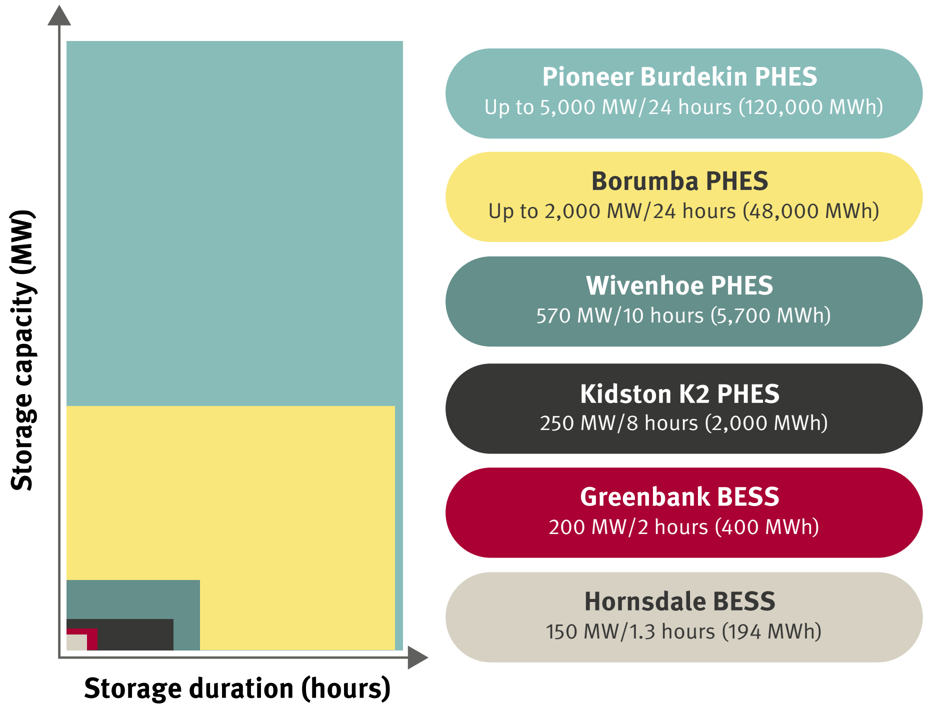


Figure 12: Storage duration and capacity comparison for Australian energy storage projects

There is significant potential large-scale PHES capacity in Queensland, which if fully developed would place Queensland amongst the electricity markets with greatest deployment in hydro storage in the world (see Figure 13). This in turn would enable Queensland to produce ‘green’ firmed energy on a globally competitive basis.

22. European Commission (2013), Assessment of the European potential for pumped hydropower energy storage. Available at: https://op.europa.eu/en/publication-detail/-/publication/f8386062-237c-4676-a3ed-f1083a9eea16/language-en
23. US Department of Energy (n.d.), DOE Global Energy Storage Database. Available at: https://www.sandia.gov/ess-ssl/global-energy-storage-database-home/

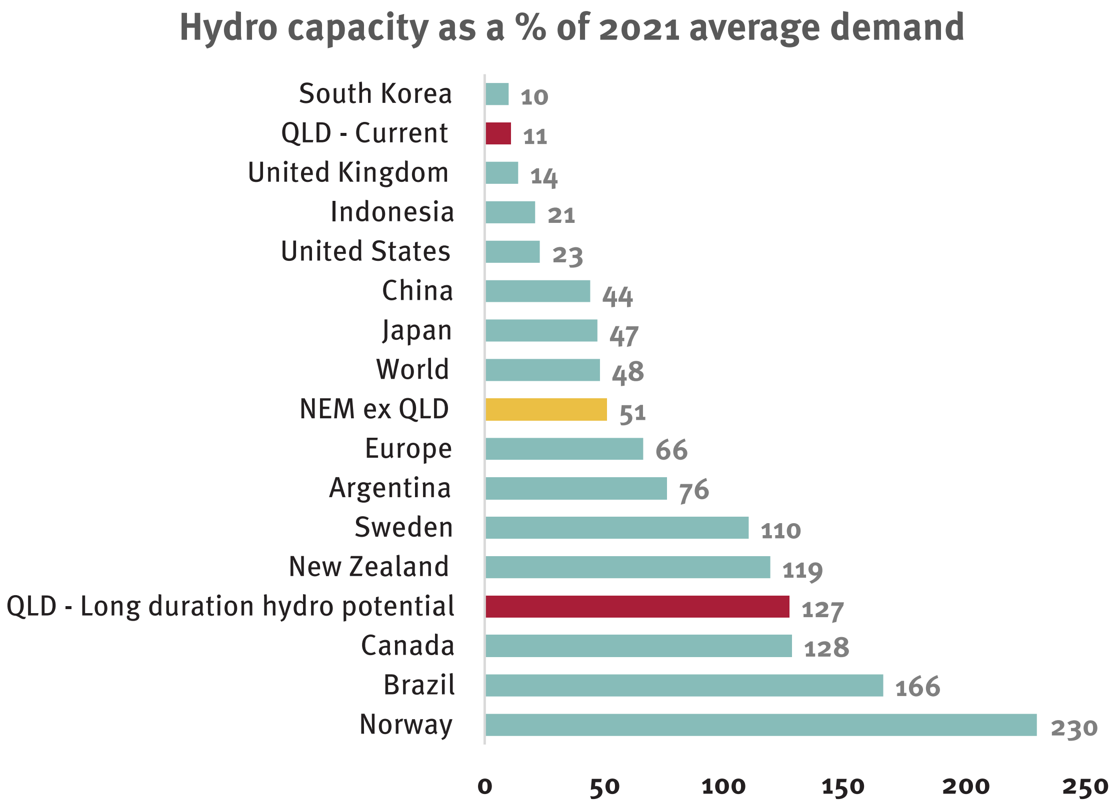


Figure 13: Hydro capacity as a per cent of 2021 average demand, from Queensland Government analysis

Environmental and social impacts

The exact impacts of PHES are heavily dependent on site-specific characteristics. Constructing reservoirs fundamentally involves inundating land that was not previously flooded. This means that all PHES projects have environmental and social impacts which require close investigation, mitigation and/or offsetting.

Closed loop pumped storage has been recognised as realising a lesser environmental impact than traditional run-of-river hydropower developments[24]. Environmental groups such as the World Wildlife Fund (WWF), the Union of Concerned Scientists and American Rivers were party to a joint statement of collaboration issued in 2020 supporting development of new closed loop pumped storage stations. It was noted that adding electrical generation to non-powered dams and developing closed loop pumped storage capacity would add to supply of renewable electricity, improve the integration of variable solar and wind into the electricity grid, and reduce environmental impacts on fish, other wildlife, and related ecosystems.

Small PHES schemes are likely to have lower environmental and social impacts because their footprints tend to be smaller. However, in the absence of large-scale PHES many smaller PHES would need to be developed to meet the scale of storage requirements. The environmental and social impacts of many small PHES are likely to be cumulatively the same as or greater than large PHES development.

Offset requirements may require the proponent to procure land in acceptable locations and/or with acceptable fauna, flora and environmental conditions. Larger projects will likely require greater offsets if they inundate (or otherwise impact) a larger footprint. If more land is impacted, there is a greater likelihood that the impacts will be more varied.

Delivering the capacity required in Queensland (at least 6,000 MW at 24 hours) through smaller PHES projects, for example with 250 MW capacity with 8 hours of storage, would require the development of over 70 individual projects to achieve the same volume of energy storage. This approach would result in greater environmental and social impacts to a larger number of communities and habitats. It is also implausible that this many projects could feasibly be developed in a timely fashion to enable the energy transformation.

24. https://woods.stanford.edu/research/hydropower/hydropower-ucd-core-documents

Cost

Large-scale long duration PHES projects are lower cost than other long duration storage technologies due to the economies of scale which can be achieved at individual sites. AEMO's 2022 Integrated System Plan (ISP) compares the cost of alternative storage technologies over the next decade over many scenarios.

AEMO's analysis shows that while batteries and small PHES are competitive on a $/MW basis (i.e. $ capital for a given maximum generation capacity), they are higher cost once costs are considered in terms of the volume of energy stored ($/MWh). This is an important consideration because while batteries are likely to financially compete to provide short-term energy shifting (and have other advantages such as site flexibility and speed of deployment), they are a more expensive means to provide long duration energy storage.

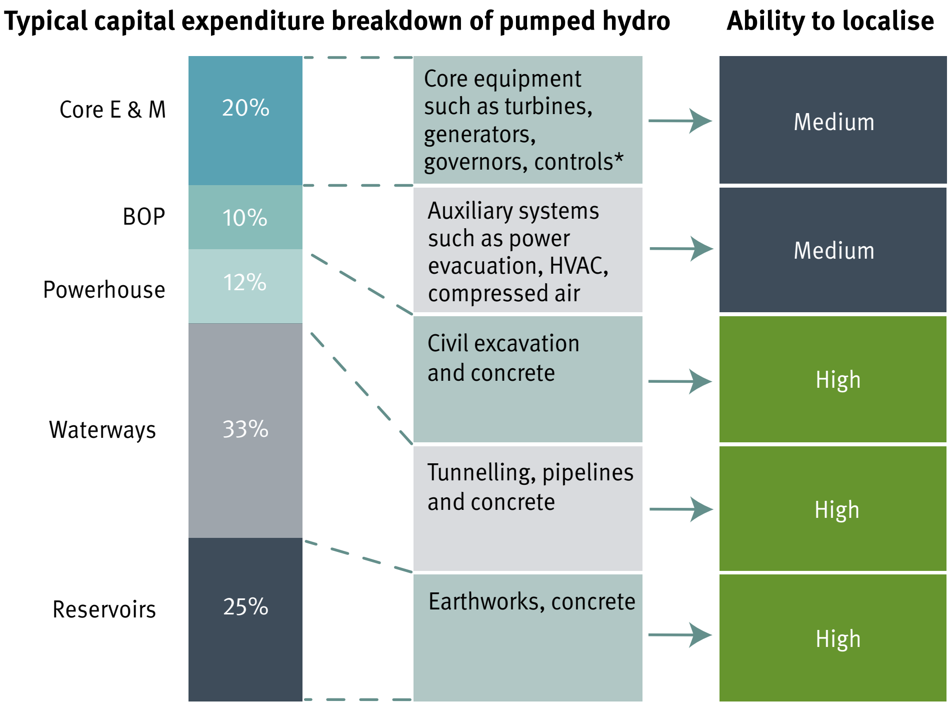
PHES costs are highly site-specific and are dependent on hydrological characteristics, site accessibility, water availability, land topography, geological conditions and other local factors.

One important consideration with respect to costs is the requirement for transmission infrastructure investment to support PHES. While Borumba is located close to the existing transmission network, other PHES sites may require significant transmission infrastructure. Queensland's electricity system will become increasingly decentralised, and the transmission network must evolve to transport renewable and stored energy around the state to when and where it is needed.

Broader economic benefits

The primary focus of examining broader economic benefits of storage relates to the potentially significant construction jobs which are required for their deployment.[25]

PHES facilities are large-scale projects which generally take 7 to 10 years to develop and involve significant construction activity over several years. GE Renewable Energy estimates that up to 70 per cent of capital expenditure would be spent locally, due to the high civil engineering component of PHES (see Figure 14).[26]



**Queensland does not have a localised turbine manufacturing supply chain, however, a pipeline of PHES projects may present opportunities for local production of some electromechanical components.*

Figure 14: Ability to localise components of PHES, adapted from GE Renewable Energy (2020)[28]

25. GE Renewable Energy (2020), Pumped Hydro Storage in Australia. Available at: https://www.ge.com/renewableenergy/sites/default/files/related_documents/GEA34801%20PHS_Development_Australia_WP_R2.pdf
26. GE Renewable Energy (2020), Pumped Hydro Storage in Australia. Available at: https://www.ge.com/renewableenergy/sites/default/files/related_documents/GEA34801%20PHS_Development_Australia_WP_R2.pdf

Stage 3 of the Queensland Hydro Study suggested that approximately 2000 construction jobs would be created for each 1000 MW of large-scale long duration PHES capacity; however it would be expected that larger projects would result in fewer jobs per MW to reflect economies of scale in construction. With a pipeline of PHES projects to be developed in Queensland, there may also be potential to create additional local capability to supply services and manufacturing, including the potential to localise manufacturing of additional PHES components.

Opportunities beyond individual project benefits are more likely to materialise now that a pipeline of storage projects has been signalled to the market by the Queensland Energy and Jobs Plan.

Conclusion

PHES provides a range of system security and system reliability services required as the energy system transitions to net-zero emissions. PHES is the preferred technology of choice for long duration energy storage for the following reasons:

- It is the only proven storage technology capable of providing sustained dispatchable generation to manage short-term low renewable generation such as rainy days or windless nights, along with the ability to contribute to managing extended periods of low renewable generation.
- PHES schemes have a long design life, for both electro-mechanical plant and civil works, which is not currently available from competing technologies.
- Large-scale long duration PHES projects are unlikely to be developed by the private sector for several reasons (long construction time frames, approvals uncertainty, cost, no current market for all provided services), which indicates a need for government intervention in deployment of this critical infrastructure.
- The storage capacity available from PHES developments exceeds the likely scalable deployment of other technologies like batteries.
- Large-scale long duration PHES schemes are lower cost than other storage technologies due to the economies of scale which can be achieved at individual sites.

Part 3
Queensland pumped hydro site identification and assessment

Overview – Stage 3 Queensland Hydro Study – PHES site identification and high-level assessment

This summary has been prepared to provide further information to the public with respect to the PHES site selection process. The alternative pumped hydro locations considered within the Queensland Hydro Study are not identified in this summary document. This is to avoid release of information about projects that will not happen, that would cause undue and unnecessary community distress, and/or potentially impact the commercial viability of land holdings. Further, the total storage capacity of all sites considered in the Queensland Hydro Study is significantly more than the storage required to support the decarbonisation of the electricity sector.

Scope

The first two stages of the Queensland Hydro Study were preliminary in nature, exploring the opportunities for conventional and smaller-scale PHES in Queensland. The studies occurred in a context where Queensland was developing its expertise in both conventional hydro and PHES, emerging policy considerations, and the desire to understand the possibilities within Queensland.

It subsequently became clear that long duration PHES was worthy of deeper investigation as it could provide lowest-cost system reliability and security in the context of increasing variable renewable energy penetration.

Stage 3 (2020) was prepared as directed by the QEST to test the case for long duration PHES and to find potential schemes:

- that can support at least 1 GW of capacity and ideally 24 GWh of storage (with a minimum of 10 GWh)
- with strong technical characteristics, driving lower capital costs and commercial viability
- that are technically feasible, with a high likelihood of practical solutions for identified problems
- with appropriate water availability
- in feasible network locations, including consideration of network augmentation costs, network losses (proximity to load) and the system cost benefits of being co-located with renewable energy zones (REZs)
- be located at sites that could be developed and connected to align with coal-fired power station repurposing
- where environmental and social risks could be minimised.

Stage 3 incorporated information from a review undertaken by Seqwater on the potential for conventional and pumped storage hydroelectricity on all 26 of its dams; a technical report that the then Department of Natural Resources Mines and Energy (now DEC) commissioned from GHD (an engineering firm); market modelling; site analysis led by SMEC (an engineering firm); a dataset provided by the Australian National University (to ensure that the broadest possible set of sites was considered); and many other publicly-available sources.

Stage 3 was also supported by a complementary body of market modelling optimisation work conducted in 2019 that focussed on analysing prospective PHES sites. A key finding from this work was the identification of a scheme of world-class potential in the Pioneer Valley (the Pioneer-Burdekin site). Inputs from this work occurred throughout the Stage 3 study to ensure the sites investigated were comparable to those assessed within Stage 3.

The Stage 3 study ultimately led to a selection of short-listed sites for further feasibility investigation by government.

Out of scope

The following hydroelectric scheme configurations were out-of-scope for analysis as part of the Stage 3 Study.

Conventional hydroelectric schemes

Conventional hydroelectric schemes were out of scope, since the purpose of Stage 3 of the Queensland Hydro Study was to focus on large-scale, long duration PHES. Stages 1 and 2 of the study investigated Queensland's potential for conventional hydroelectric projects. Stages 1 and 2 also investigated the possibility of installing 'micro' hydroelectric generation at existing reservoirs.

Seawater PHES schemes

The site shortlisting process did not consider potential seawater PHES schemes for two reasons:

1. There are substantial engineering challenges associated with building and operating a seawater PHES. These challenges add costs.
2. While they are theoretically possible, seawater PHES projects have never been deployed at scale.

Globally there is only one operational large-scale seawater hydroelectric plant that has pumped storage potential (the Rance Tidal Power Station in France). However, it is best characterised as a tidal power station with some pumping capability, not a PHES project. This is because it can only pump at particular times of the day (in the short period where there is very little movement in the tide), and generation times are dictated by the tide. As a result, its operation bears very little resemblance to the operation of a traditional PHES.

A ~30 MW seawater demonstration PHES has previously operated in Okinawa, Japan, however, it was dismantled in 2016 because it was not profitable.

Given that there are no proven examples of large-scale seawater PHES schemes, it was deemed inappropriate to allocate time and money to searching for them in Queensland.

Disused mines and quarries

Desktop analysis was undertaken into the potential for disused mines and quarries, but this occurred in an earlier stage of analysis. ANU's topographic analysis (which fed into the shortlisting process) covered all of Queensland, including disused mines and the government had previously conducted a high-level desktop analysis of Queensland's disused mine potential. No suitable sites with opportunities for large-scale long duration storage were identified through these processes.

Most existing disused pit voids are typically unlikely to be large enough to support long duration storage nor could they be expanded on a cost competitive basis with the best long duration PHES sites in Queensland due to the extent of excavation that would be required. Additional risks include safety and mine remediation requirements.

At the time of preparing this report the government was not aware of an operational project that used an underground mine as a lower reservoir. At the time of the study, the technology or engineering solution to enable the use of an underground mine as a PHES was not well understood or advanced anywhere in the world. A small demonstration project was considered to be a more appropriate next step for underground PHES technology, rather than assuming their viability for a large-scale, long duration PHES scheme (i.e. the purpose of the site analysis for Stage 3 of the Queensland Hydro Study).

The ANU-ARENA Atlas did not include operational mine sites which may be subject to closure soon (through depletion of resources or uneconomic operation). Since the Stage 3 study was completed, several private investors have assessed the possibility of developing mine sites, including the proposed PHES at the Mount Rawdon Gold Mine. As with existing disused mines, some of these sites appear to be suited for smaller PHES schemes, however a number are further constrained by their distance from Queensland's electricity transmission network.

Key considerations

Consequences of scope

Based on the scope, the site shortlisting process focussed only on sites with the potential for large-scale, long duration PHES, aiming for at least 1 GW of capacity and 24 GWh of storage. The process explicitly ruled out sites only capable of supporting smaller projects.

Stage 2 of the Queensland Hydro Study undertook analysis to identify the best potential projects with a nominal capacity of 250 MW, and eight hours of storage. However, 250 MW/8 hours is a very specific subset of sites smaller than 1 GW/24 GWh (the focus of Stage 3). There are a range of potential configurations in between these options that were not assessed as part of the study.

No site is free of environmental and social risk

It is inherently difficult to identify suitable sites appropriate for large-scale, long duration PHES. This is because there are very few locations in Queensland with the right technical characteristics (e.g. topography, location and hydrology).

The majority of mountainous terrain in Queensland that is most technically attractive for large-scale, long duration PHES (i.e. terrain that could support very high head projects) is located in the Mackay, Isaac, Whitsunday, North Queensland and Far North Queensland regions. Mountainous terrain in these regions is generally in its natural state, aligning with areas of protected status and high rainfall.

Given the unavoidable environmental/social impact of constructing dams, it follows that sites with realistic potential will have a degree of environmental and social impact. However, these impacts need to be weighed against the broader benefits of a large-scale, long duration PHES (greater energy system affordability, reliability and security), and the downside of alternative approaches (e.g. increased cost and emissions from a likely increase in gas generation).

Environmental and social risks will be considered before a PHES project reaches a final investment decision. These risks will be weighed against the environmental and social gains achieved through energy transformation and decarbonisation, which have been identified to be unfeasible without PHES deployment.

Overview of the site shortlisting process

The five-phase shortlisting process

A five-phase process was used to determine Queensland's most suitable locations for large-scale, long duration PHES. As illustrated in Figure 15, the phases were:

Phase 1 – Analyse existing PHES studies and topographical information to identify reasonably prospective sites and locational zones.

Phase 2 – Identify and compare key cost drivers for the most prospective sites.

Phase 3 – Generate desktop studies for sites with the best commercial and technical characteristics.

Phase 4 – Undertake site visits for the most prospective sites.

Phase 5 – Produce detailed concept studies for the most prospective sites.

Throughout this process, sites were shortlisted and prioritised based on a range of criteria including scale, capital costs, water security and hydrological impacts, round trip efficiency, proximity to load, transmission issues, environmental and community impacts, and legal and regulatory constraints.

Each subsequent phase involved increasingly granular analysis on a smaller subset of sites. This approach ensured all prospective sites/areas were considered at a high level, but resources were concentrated on the most prospective sites.

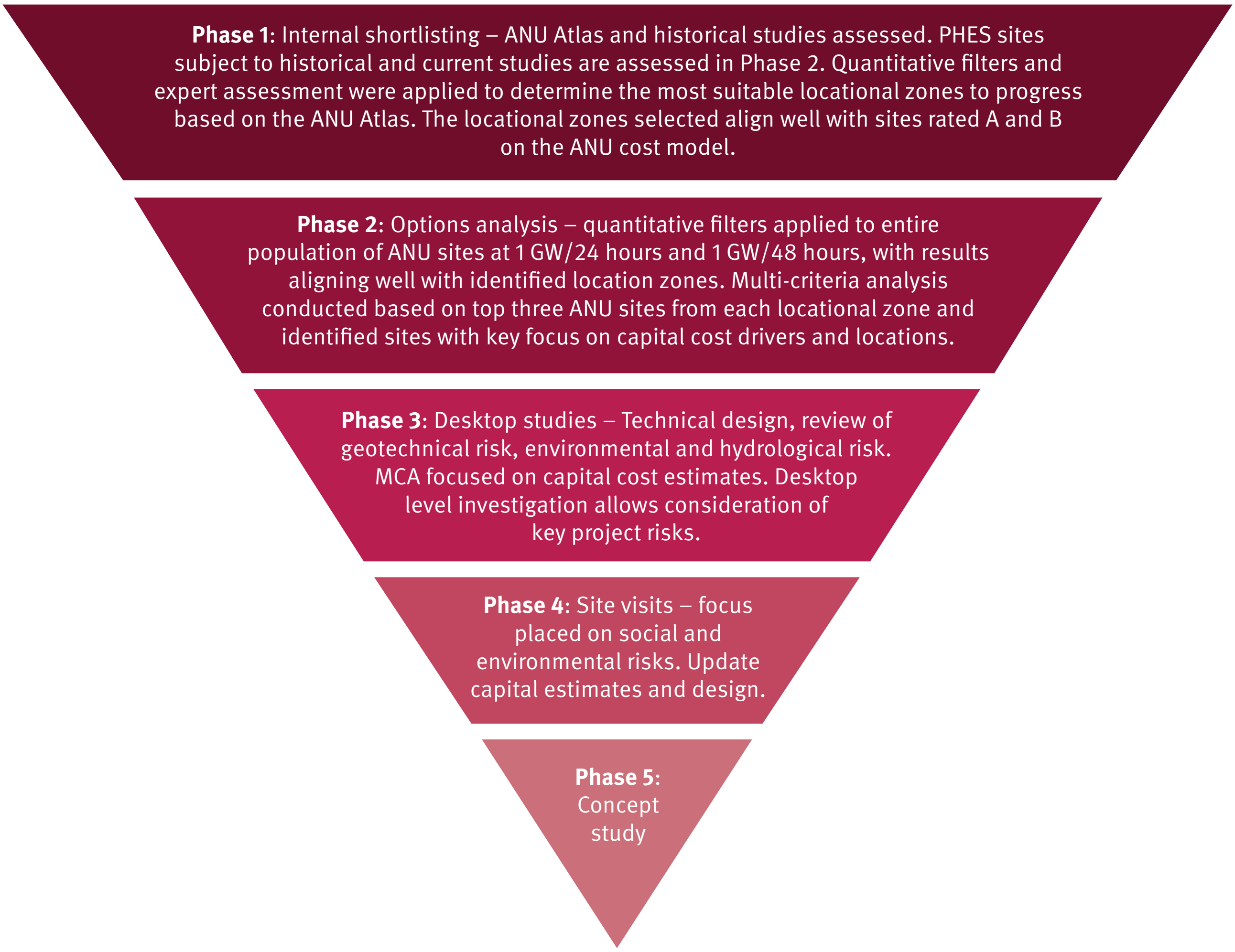


Figure 15: The five-phase PHES investigation process for Stage 3 of the Queensland Hydro Study

Optimisation of the five-phase shortlisting process

Pioneer-Burdekin

In the assessment of historic sites in Phase 1, the Pioneer-Burdekin PHES was identified as having outstanding technical attributes. The exceptional quality of the site warranted accelerated evaluation through the remaining four phases of the Stage 3 shortlisting process.

The Pioneer-Burdekin site subsequently compared favourably against the other sites at each stage of the evaluation process, and the site's overall favourability was confirmed through the subsequent evaluation of key PHES benefits and impacts.

General selection principles for PHES

Site selection is an iterative process that typically progresses from initial site screening, to developing high-level designs for evaluation, and then shortlisting the best sites for more detailed investigation.

Stage 3 of the Queensland Hydro Study used an iterative methodology to screen out all but the best projects from further phases of investigation. This methodology examined the following criteria:

- **Topography** – to reduce costs and risks, the proposed areas for water reservoirs need to be close enough together (in a horizontal distance) to minimise waterway lengths, and flat enough to hold the required storage without requiring excessively large dam walls.

- **Geology** – highly variable geology with faulting, igneous rock overlays and mineralisation, present risks to tunnelling and underground cavern construction and higher cost to build.
- **Hydrology** – poor hydrology can cause limitations and additional costs associated with the initial fill of the reservoir, ongoing operations and design for floods.
- **Environment** – primarily relates to inundation of land within the reservoirs. A preference for sites that minimise such impacts, especially to environmentally protected areas (e.g. national parks and World Heritage Areas).
- **Community impacts** – the infrastructure needs to meet the broader community expectations in respect to impact on the natural and built environment, and human amenity.
- **Capacity and storage duration** – a preference for larger capacity, longer duration sites based on identified system needs and economies of scale that could be provided.
- **Distance to major load centres, connection, and transmission network strength** – large distances and weak networks can result in higher network augmentation costs and greater transmission losses and delayed project implementation.

Considerations for these screening criteria are explored below.

Topography

The topography of Queensland is more homogenous and less extreme than many other places (e.g. NSW or Victoria), which means that there are fewer steep natural formations. As a result, there are more sites with low head (e.g. 150 m) compared with mid-range head (e.g. 350 m) compared with high head (e.g. 700 m). And for sites with higher head, there are even fewer with attractive length-to-head ratios.

Relatively high head is essential for large-scale, long duration PHES. This is because, without it, PHES projects need:

- excessively large waterway (tunnel) diameters to generate sufficient power (which are expensive)
- very large reservoirs (which are typically expensive unless a cheap 'valley dam' can be constructed, which depends on the topography) to store sufficient energy.

In summary, Queensland's topography means that there are more sites capable of supporting small-scale PHES schemes compared to large-scale schemes (of either long or short duration). Therefore, there are fewer sites with attractive characteristics for large-scale, long duration storage compared to shorter-duration projects.

Geology

Highly variable geology with faulting, igneous overlays and mineralisation present risk and cost to quantify and overcome. These conditions may translate to higher costs as well as increased safety concerns during construction if untreated. Australia has active seismic regions, which must be considered when investigating PHES site suitability. Deep weathering can lead to expensive excavation to reach competent rock, while on slopes, it can lead to expensive and extensive anchoring requirements. The best sites for PHES will be in stable, competent geological structures of relatively high strength, free from coal measures and mineralisation.

The geological risk varies from site to site. However, the risk of encountering geological issues increases with the amount of underground work that needs to be conducted, and the general site footprint. Given that large-scale, long duration sites tend to have a larger footprint (and are more likely to require underground caverns to best utilise topography), their geological risk tends to be higher compared to smaller-scale sites. However, this is not always the case, particularly if a site has a relatively small footprint due to favourable topography.

Hydrology

Generally, Queensland's east coast enjoys ample rainfall to fill and maintain water levels in large on-river storages, with periodic moderate to large flood events in larger catchments where large reservoirs will typically be built. Therefore, sites on or to the east of the Great Dividing Range will tend not to be screened out based on hydrology.

Similarly, because pumped hydro schemes require water for initial filling and replenishment, those that are in excessively arid or excessively permeable geological conditions, are at an immediate disadvantage compared to others without these deficiencies.

Environmental and community considerations

Queensland is a sparsely populated state with most of the population located close to the coast, to the east of the Great Dividing Range. It has a significant number and area of national parks and World Heritage Areas, most of which are on or near the Great Dividing Range or Wet Tropics.

The prevalence of national parks (often in areas with good hydrology and/or topography) places considerable constraints on the potential sites available for PHES. This is particularly true for large-scale PHES, since locations with high rainfall and good length-to-head ratios tend to be in/near national parks. Similarly, projects with a larger site footprint are more likely to impact stakeholders and/or the environment. Unless topography is particularly favourable, long duration schemes are typically going to have larger footprints (compared to smaller schemes), and so environmental and stakeholder issues are likely to require detailed investigation and mitigation.

Network issues

Network capacity is the most easily and objectively assessed criteria. In general, sites that are technically attractive, but require significant network or transport augmentation, will be at a disadvantage compared to sites that are close to the network.

Large generators (>1 GW) will only be able to be connected in a few locations, on the highest voltage lines (which for Queensland is currently 275 kV or 330 kV), and then only in relative proximity to load centres. However, smaller generators (<250 MW) would be likely to connect on lower voltages and further from load centres at many locations. The implication is that small schemes are most likely able to be connected without a substantial network augmentation, whereas large schemes may require a Regulatory Investment Test – Transmission, to justify the necessary network strengthening.

It is not recommended to 'screen out' (or limit the size of) sites based on the current spare capacity of the transmission network – except for when a site is an unreasonable distance from load and future REZs. The rationale for this is that the network will inevitably expand as Queensland transitions to net-zero emissions (e.g. to access REZs), and it is possible that the lowest future system cost may be to build transmission to PHES schemes, rather than building less-ideal PHES schemes in locations where there is currently spare network capacity. This choice was justified considering the transmission infrastructure development planned for in the QEJP.

QEJP – Major network transmission and system strength

As Queensland's electricity system becomes increasingly decentralised, the transmission network must evolve to transport renewable energy around the state when and where it is needed. Four new high-voltage (up to 500 kV) backbone transmission projects will be constructed by mid-2030, connecting the two 24-hour PHES assets and areas of strong renewable resources with Queensland's demand centres.

These projects include:

- two transmission connections of approximately 90 and 100 km each (190 km total) to connect Borumba to the grid in Southern Queensland
- a 290 km line to move more energy between southern and Central Queensland
- a 750 km line to connect Central Queensland to a North Queensland 24-hour PHES and North Queensland load
- a 370 km line to connect Townsville to Hughenden (there is an opportunity to extend this connection to the North West Minerals Province).

These new high-voltage transmission lines will allow the huge volumes of renewable and stored energy to be moved between northern and southern Queensland more efficiently and will ultimately unlock the renewable energy resources at Hughenden. The optimal transmission staging and delivery timing, for lowest cost outcomes, is linked to PHES delivery.

There is also the growing role of distributed and customer energy resources in the electricity system, led by consumers installing more solar on their rooftops, growing interest in home battery systems and the uptake of electric vehicles. To obtain the best value from these energy resources, changes are also needed at the distribution network level.

Phase 1: Identification of sites based on historical studies

Overview

Since the 1970s, a range of Queensland Government entities have conducted and/or commissioned studies on Queensland's PHES potential. To form an initial view of the sites and/or regions with the most potential, documents from these studies were reviewed.

ANU's Pumped Hydroelectric Storage Survey of Queensland

In 2017, the ANU released an 'Atlas' of Australian locations that may be appropriate for PHES, including approximately 2,000 sites in Queensland. This work was based on topographic analysis of potential greenfield (new) upper reservoirs and did not consider factors like: the availability of a potential lower reservoir, electricity transmission, water availability, environmental and social impacts, and the likely cost of developing the potential projects. As a result, many of the identified locations were unrealistic.

Recommendations

After analysing the existing body of work, 10 specific sites and 10 prospective geographical regions were identified that warranted further investigation. These geographical regions generally aligned with prospective sites identified in stages 1 and 2.

Phase 2: Analysis of Phase 1 options

Overview

Phase 2 involved:

1. Identifying potential large-scale, long duration PHES options based on:
   - the list of sites and areas shortlisted in Phase 1
   - an additional review of the ANU topographic dataset for Queensland (to ensure no sites had been missed in Phase 1)
   - all of the PHES sites shortlisted in Stage 1 (noting Stage 2 included the same sites) of the Queensland Hydro Study (which had originally been considered as small-scale sites).
2. For identified options, determining high-level technical attributes that drive capital costs.

This information was used to evaluate the schemes using an MCA.

This phase did not consider environmental and social risks in detail. This was to ensure that potential sites were not unjustly discounted without an appropriate level of environmental and social assessment, which was impractical to conduct on this many sites. However, as the ANU-ARENA topographic datasets only considered potential reservoirs outside of national park boundaries (except for existing reservoirs located directly adjacent to national parks) the process naturally selected sites with lesser environmental impacts.

Identifying PHES options to consider in more detail

Reviewing ANU's topographic dataset

The following quantitative filters were applied to the ANU's topographic database of Queensland's 1 GW/24 GWh and 1 GW/48 GWh sites database to reduce the number of potential sites from more than 2,000 to 46:

- head greater than 250 m
- upper reservoir volume greater than 8 GL
- upper dam wall length less than 1000 m.

Sites from Stage 1 of the Queensland Hydro Study

In Stage 1 of the Queensland Hydro Study, 12 relatively small-scale PHES schemes were shortlisted. Phase 2 of Stage 3 explicitly considered whether these sites could be 'scaled up' for large-scale, long duration PHES.

Sites from Stage 2 of the study are shortlisted Stage 1 locations. To ensure all sites were reviewed again it made no sense to limit investigations to Stage 2 sites only.

Analysis of Stage 1 and 2 sites added a further four sites to the study (most sites were already incorporated through assessment of the ANU site data).

Using a multi-criteria analysis to inform decisions on which sites should progress

A high-level, quantitative MCA was used to evaluate the shortlist of 50 sites. The Phase 2 MCA was designed to consider sites based on:

- scale (starting scale, and ability for capacity and/or storage to be upgraded)
- capital costs
- water security
- round trip efficiency.

Metrics

Three different metrics relate to most of the criteria (see Table 1).

Table 1: Key metrics for PHES

Technical metrics	Criteria addressed
Head	Capital cost (capacity)
	Water security
L:H ratio	Capital cost (capacity)
	Round-trip efficiency
Energy storage/dam wall embankment volume	Scale
	Capital cost (storage)

The energy storage/dam wall embankment metric is a high-level measure for how much energy can be stored for a given amount of civil work (and therefore indicative capital costs). It is important to note that the calculation is not based on marginal energy storage, or marginal dam wall volume.

The metrics indicate implied scalability and proved to be a good pointer to upgradability in later phases of investigation.

After evaluating the sites using the MCA, it was decided which sites should progress to Phase 3 (desktop studies). In this secondary process, selected sites were deprioritised if there were obvious critical deliverability issues. For example, sites that were greater than 100 km from the 275 kV network or were in regions that were remote from loads and population centres were de-prioritised compared to alternatives. This is because proximity to the 275 kV network is a priority to both minimise costs (which increase with distance) and reduce load losses (which increase with distance).

Recommendations

Based on the MCA process 15 sites were selected for desktop study in Phase 3. There was strong overlap with these sites and the locational zones identified in Phase 1 of Stage 3 and Stages 1 and 2.

Phase 3: Desktop scoping studies

Overview

Desktop studies were conducted for the options identified in Phase 2. Each desktop study included consideration of:

- more detailed technical design of scheme components to more accurately assess capacity and storage potential
- early scoping of key environmental and social issues that may be triggered by the PHES scheme and associated infrastructure (e.g. new reservoirs and transmission supporting infrastructure)
- transmission connection options
- PHES and transmission indicative (comparative) capital cost estimates, based on the design
- a review of water security, including rainfall and catchment hydrology
- a review of geological and geotechnical attributes and constraints
- the high-level impact on existing dam operations and/or end users (if applicable).

It is important to note that all sites assessed in Phase 3 desktop scoping require a variety of detailed feasibility analytical studies, and engagement with communities and traditional owners to fully assess viability for hosting a large-scale long duration PHES.

Site design

Modelling, engineering experience and judgement were used to determine each site's best case layout. The locations of reservoirs identified in the ANU-ARENA Atlas were used as a guide however, different dam alignments and heights for each site were assessed against the existing topography (obtained from publicly accessible 10 m contours) using the 12D Model (an engineering software package). The dam alignments and heights that were ultimately chosen were considered to achieve a balance between minimising the height and length of the embankments (while still achieving adequate storage capacity), reducing tunnelling distance and maximising head. Although a design benchmark of 1 GW/24 GWh was used, actual design capacity and storage for different sites varied slightly due to the engineering design process.

Costing rationale

Preliminary estimates of potential PHES site capital costs were calculated using a standardised model to enable a comparison of costs across prospective sites. This supported identification of the most cost-effective sites for further analysis.

Each PHES scheme is unique in terms of its topography, hydrology, geology, and other factors. This means that the turbine, generator, balance of plant, water conveyance system and other structures are bespoke and specifically designed for that scheme. The bespoke nature of PHES cost assessments were managed using a consistent methodology for comparing PHES site costs.

Capital cost estimates for Phase 3 desktop studies were based on:

- direct costs (e.g. power station, waterways)
- indirect costs (e.g. project management)
- principal costs (e.g. supervision and construction support)
- contingencies.

Cost estimates produced during the Stage 3 study were not intended to be relied upon for investment decisions and are subject to change in response to increasing project definition or external influences such as material or labour costs.

Desktop studies – progression to next phases

The desktop analysis considered the attributes of the various sites, examining how they might perform against the selection principles outlined earlier in this report, and identify constraints that may limit a site's ability to host a PHES.

Examples of constraints considered by this analysis included, but were not limited to, the following:

- **Cost** – this constraint occurred where estimated capital costs of a PHES development indicated a scheme could not be delivered in an economically viable manner. Cost evaluation estimated total capital expenditure using a consistent methodology and explored capital expenditure on a dollars-per-kilowatt-hour basis. In this analysis, direct costs were strongly influenced by technical characteristics such as the distance between reservoirs and the volumes of new dam walls.
- **Technical considerations** – indicators of technical constraints included schemes with excessively long tunnel lengths, insufficient elevation difference between reservoirs, large excavation requirements, or substantial embankment volumes required for reservoir construction. For example, an investigated scheme had a low rated head of 291 m, a long distance (>8 km) between reservoirs, and large volumes for dam walls in both the lower and upper reservoirs. The site technical characteristics led to a highly disadvantageous cost outcome and a poor assessment of scheme deliverability.
- **Environmental impact** – PHES development potential was constrained by site impact on protected areas, particularly flora and fauna. Where the impact of a PHES's infrastructure footprint on environmental matters was significant, it was likely the development would be unable to achieve required environmental approvals in a timely fashion, or at all. Applying this constraint helped preference developments with lower environmental impact. For example, one site which was investigated required the upper reservoir to be sited in biodiverse rainforest which was not in a protected area. The evaluation demonstrated the area was host to high-risk triggers for protected plant species. The significant environmental impacts of a potential PHES development at the site were deemed to be unmanageable and the scheme did not progress.
- **Social impact** – PHES development potential was constrained by the site impacts on social and economic considerations. Interactions of PHES infrastructure on social considerations such as property, agriculture or water use were considered in the evaluation. Like all the constraints, social impacts were considered against the broader benefits of large-scale long duration PHES and the downside of alternative options (e.g. running coal-fired power for longer).
- **Hydrology** – The ability to initially fill PHES dams and reliably operate the power station is constrained by water availability and site hydrology. The analysis considered factors such as an estimate of initial fill time and interactions with other water users, both urban and agricultural. Where there was evidence that a site had insufficient water security to maintain scheme reliability, it constrained PHES development potential.
- **Geological and geotechnical conditions** – PHES development is constrained by site geological and geotechnical conditions due to the significant civil infrastructure required and dam safety considerations. Geological structure, such as faults and rock formations, as well as soil types, were considered where the information was available. For example, one site was considered to have higher geotechnical risk as the lower reservoir location extended more than 3 km across alluvial soils, which are prone to seepage and may be prone to liquefaction. As a result, the site was not progressed.
- **Location** – PHES development potential was constrained if there were limitations on the ability of a PHES scheme to connect to the electricity network or if site access was excessively difficult. Due to the specific topography required for PHES development, accessibility of the upper reservoir sites can significantly influence overall scheme deliverability. Additionally, large-scale long duration PHES proximity to enabling transmission is an indicator of the time and expense required to connect the scheme.

Interactions with constraints occurred on a spectrum, from limited impact to significant impact. Sites that demonstrated moderate to significant impacts against multiple constraints were typically not considered suitable for progression due to the significant risk that the constraints could not be managed into an acceptable range for PHES development.

There were also sites which performed well against most constraints but had interactions with a singular constraint that made them unsuitable for PHES development. One example of a constraint which rendered a scheme unviable was where an identified site had highly advantageous technical characteristics, but hydrological analysis indicated there was insufficient water available to ensure scheme reliability. This scheme therefore did not progress.

The site evaluation process was designed to direct time and resources to the most deliverable sites. This meant that those which demonstrated significant interactions with multiple constraints or unmanageable interactions with a single constraint were not progressed.

Those sites which performed well against all constraint factors or did not demonstrate an unmanageable negative interaction with a constraint, were considered most favourable for progression to further analysis through site visits and concept studies.

Phase 4: Site investigations

Site investigations were conducted at seven (7) sites, with at least one site visit occurring in each region (CQ, SQ and NQ).

The purpose of the site visits was to identify issues that could not be investigated in a desktop study. By observing each site in person, staff (including specialists in engineering, geology, and environmental issues) were able to gain a deeper understanding of the topography and local environment, as well as assessing potential social constraints. The site visits ensured a more robust analysis of:

- dam and major PHES infrastructure locations and designs
- construction techniques
- geological landscape and conditions
- catchment hydraulics
- areas of conservation or nature reserve (e.g. national parks, state forest)
- essential habitat and expected wildlife impacts
- possible issues arising during approvals processes
- local and downstream hydrological issues, for the environment and community
- land usage
- community impacts and risks
- impacts on existing infrastructure and assets
- potential transmission routes
- site-specific critical issues.

The output of the site visits was a technical report. This information was considered and assisted in making recommendations as to which sites should proceed to a concept study.

Phase 5: Concept studies

Concept studies were completed for the Borumba and Pioneer-Burdekin projects. The purpose of the concept studies was to refine the civil and electromechanical design elements of each project, subject to constraints such as geological and ecological conditions.

Each concept study outlined:

- concept level plans and project costs for each project component (e.g. reservoirs, waterways, intakes, power station and associated caverns, electromechanical plant, transmission and alignment)
- a desktop geological assessment (including the development of a detailed surface terrain model)
- a detailed desktop review of potential environmental and ecological impacts
- catchment and hydrologic analysis (including initial fill time and risks around further top-up requirements)
- a project execution strategy and implementation schedule (including site investigations, planning and environmental studies and approvals, feasibility study, construction, and operation)
- an estimate of construction and operational jobs
- recommended next steps for site development.

The output for each concept study was a detailed report, which provided sufficient detail to inform a recommendation on whether the site should proceed to more detailed feasibility studies. Costs were categorised as ‘Class 5’ (i.e. -30 per cent to + 50 per cent) and were based on a more developed design than in Phase 3 assessment.

Stage 3 PHES site progression

	Phase 1 Review of historical sites	Phase 2 Initial MCA of 50 shortlisted sites	Phase 3 Desktop studies on 15 sites	Phase 4 Site visits to 7 sites	Phase 5 Concept studies for 2 sites
North Queensland	NQ2 NQ5 NQ6 NQ7 (Pioneer-Burdekin) NQ9	NQ1 NQ2 NQ3 NQ4 NQ6 (Option 1) NQ6 (Option 2) NQ7 (Pioneer-Burdekin) NQ8 NQ9 NQ10 NQ11 NQ12 NQ13 NQ14 NQ15 NQ16 NQ17 NQ18 NQ19 NQ20 NQ21 NQ22 NQ23 NQ24 NQ25 NQ26 NQ27	NQ1 NQ2 NQ3 NQ4 NQ5* NQ6 NQ7 (Pioneer-Burdekin) NQ8	NQ3 NQ6 NQ7 (Pioneer-Burdekin) NQ8	NQ7 (Pioneer-Burdekin)
Central Queensland		CQ1 CQ2 CQ3 CQ4 CQ5 CQ6 CQ7	CQ1 CQ2 CQ3	CQ1 CQ2	
Southern Queensland	SQ3 (Borumba) SQ4 SQ5 SQ6 SQ7	SQ1 SQ2 SQ3 (Borumba) SQ4 SQ5 SQ6 SQ7 SQ8 SQ9 SQ10 SQ11 SQ12 SQ13 SQ14 SQ15	SQ1 SQ2 SQ3 (Borumba) SQ4	SQ3 (Borumba)	SQ3 (Borumba)

*NQ5 did not appear in Phase 2 as no reasonable configurations were found at the time Phase 2 was being conducted.

Selecting PHES sites for detailed feasibility studies

Balancing benefits and impacts at potential PHES sites

All PHES sites considered in Stage 3 of the Queensland Hydro Study have some social or environmental impact. This is an unavoidable consequence of developing large-scale long duration PHES in Queensland given its requirement for specific geography and topography and the existing land uses at these suitable areas.

It was necessary for the government to reach an informed position on site suitability for detailed feasibility investigations by seeking a well-informed understanding of the balance between local impacts and opportunities and the required outcomes of the state.

Development of the required capacity of long duration storage at Queensland PHES sites is critical to realising major renewable energy opportunities for Queensland and key state objectives. Delivery of the required capacity of large-scale long duration PHES will enable the energy transformation to be achieved, ensure long-term stability and affordability of energy for Queenslanders, as well as generate significant economic growth and job creation in the regions. Realising these opportunities will ensure Queensland realises a cleaner, and more prosperous future.

While there are benefits to all Queenslanders from PHES developments, there are local impacts that need to be investigated, managed, and mitigated. Local impacts from PHES developments include but are not limited to the potentially significant impacts on communities from PHES construction (including displacement) and on the local environment (with possible impacts on flora and fauna from both construction and operation). It is important that impacts are minimised or avoided wherever possible, however some negative local impacts are an unavoidable reality of any large-scale construction project.

Finding sites that maximise the local and state benefits and opportunities, while offering the best prospect of managing and mitigating unavoidable local impacts was an essential consideration for sites to progress to detailed feasibility studies.

Following receipt of the Queensland Hydro Study Stage 3 report, which identified the Borumba and Pioneer-Burdekin sites as the most suitable to progress to detailed feasibility studies, the government undertook to review and progress sites with consideration for the difficult balance between wider benefits and localised impacts.

Exploring key decision-making themes

The government balanced PHES site impact and benefit considerations across six key themes. The major themes which were considered and informed decision making are shown in Figure 16.

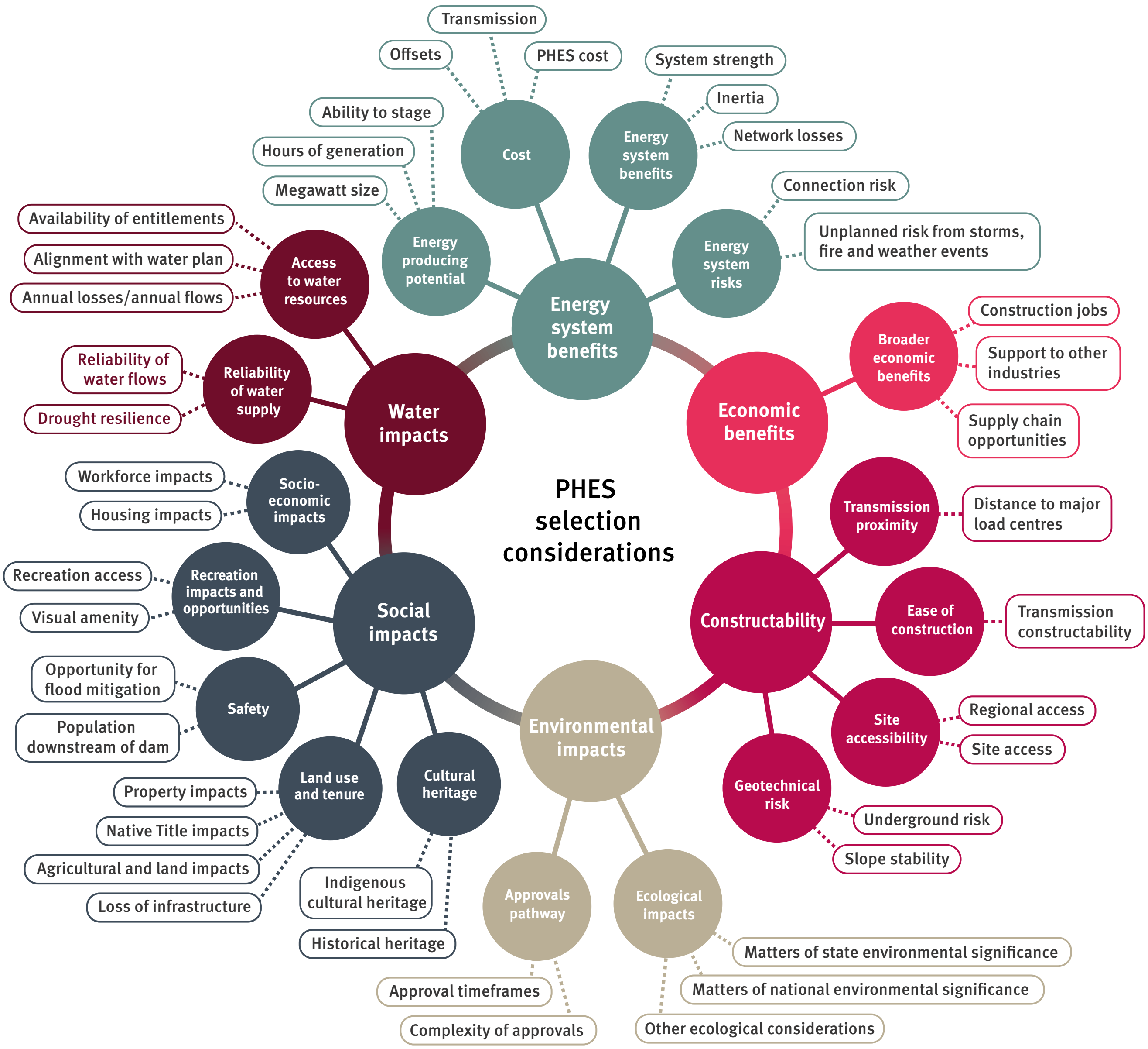


Figure 16: Key themes for PHES site selection considerations

These themes, and the various considerations within each theme, supported an objective comparison of the opportunities and challenges associated with each potentially viable project at a concept level. This enabled a comparison of benefits and impacts between the most prospective PHES projects, and ultimately assisted government decision-making to progress PHES project options to feasibility studies. The decision-making themes are explored in more detail below.

Energy system benefits

PHES deliver important energy system benefits, such as capturing energy produced at one time for use later to match energy demand, as well as system strength, frequency and voltage support. These benefits are necessary to support the transformation of Queensland's energy system and achieve the overall objectives of the QEJP. The potential for each PHES option to realise a variety of energy system benefits was considered, alongside the alignment to wider system planning.

Consideration was also given to the scale and staging of the proposed PHES options by reviewing the total generation capacity of the scheme and hours of potential generation. Larger schemes with long duration capability offer greater benefits and more opportunity to enable repurposing of existing carbon intensive power generation and ensure overall system reliability.

Project costs were another comparative measure used to understand the economic viability of different PHES options. Cost considerations were not limited to project development, but also included costs for transmission, environmental offsets and other associated project costs. This delivered a robust understanding of broader option costs to enable the decision-making process.

Within this theme, there was also attention given to the risks to PHES sites from natural disasters, as well as unplanned and planned outages. A variety of risks were explored including cyclones, storms and bushfires. Consideration was given to how these risks might affect each option, providing confidence that site risks were understood.

Economic benefits

Localised economic benefits which PHES developments offered were considered, including:

- the number of direct full-time equivalent construction jobs which a PHES development could provide during the construction period
- the potential of a PHES development to support the load growth of energy intensive export industries
- the ability of a PHES development to support local supply chains during the construction phase and the extent to which regional suppliers might benefit from the project
- any cost or efficiency benefits that a PHES project could provide local REZs.

Constructability

Preliminary constructability considerations were explored to provide insight into the ability of PHES project options to be delivered efficiently and economically.

Constructability indicators considered the distance of different PHES project options from key load centres in SEQ and Gladstone as a proxy for the required transmission build out. Proximity to these areas was considered positive for overall scheme constructability.

Other constructability indicators were also considered, such as:

- Reservoir site access, and ease of access between reservoirs. These measures identify the existing terrain and access issues which may impact the deliverability of equipment and materials to site.
- Geotechnical matters which may slow work and increase costs on underground works for tunnels and power stations, and the slope stability of the sites for key access portals for the proposed PHES options.

Environmental impacts

Due to the typical colocation of PHES sites with areas that have high value natural environments, the government required a strong preliminary understanding of potential environmental impacts of PHES site options to support PHES option analysis. Higher environmental impacts were less favourable for project progression.

Indicators used to understand potential environmental impacts included interactions with Matters of National Environmental Significance (MNES), interactions with Matters of State Environmental Significance (MSES), and ecological impacts not captured or adequately reflected by MNES and MSES. The environmental impacts of the required transmission network augmentation to connect each PHES option was also considered, with longer transmission lines leading to higher expected impacts.

The types and extent of environmental approvals required for each project were also reviewed, with an approvals pathway considered more favourable where there were lesser impacts on sensitive environmental areas.

Water impacts

Another key theme for PHES development option analysis was potential impacts on water supply, and the water reliability on the project.

Water reliability is a key determinant of the reliability of a PHES scheme. The reliability of water flows was an important preliminary metric used to indicate water reliability and drought resilience.

An initial measure of scheme reliability considered projected annual water losses as a proportion of annual flows, with a lower proportion being favourable for PHES reliability.

The ability of proposed PHES options to fit in within local water plans was also considered. This was investigated by reviewing how delivery of the PHES would comply with the water allocation security objectives and the environmental flow objectives, and whether PHES could be developed in accordance with respective water plans. The likely availability of water entitlements/allocations within the catchment was also considered to understand potential impact on existing water entitlements.

Social impacts

As has been identified, different PHES options presented both positive and negative local social impacts.

Indicators used to explore social impact included the impacts of PHES options on property and households. These impacts were reviewed by identifying any potentially required land resumptions and property impacts, along with whether resettlement was required, and the number of households potentially displaced by the project.

Impacts of the PHES development footprint on cultural and historic heritage sites, and the potential Native Title impacts and processes involved were also considered.

PHES represent a significant change of land use for a local area, so this theme also considered the amount of land which would be subjected to land use change, loss of quality agricultural land and loss of infrastructure associated with each option.

The ability of PHES options to potentially provide additional flood mitigation benefits for downstream land holders, and the size of the population downstream from dam infrastructure were considered. This consideration was in accordance with statutory dam safety guidelines.

Detailed feasibility studies

Based on analysis from Stage 3 of the study, in 2021 the government announced feasibility studies to assess Lake Borumba's potential for pumped hydro development. This analysis was to explore the ability of the proposed site to provide the large-scale, long duration energy storage needed to meet Queensland's renewable energy target of 50 per cent renewable energy by 2030. The Borumba site was considered particularly favourable due to:

- attractive capital costs per GWh
- favourable technical characteristics
- existing lower reservoir
- proximity to the South East Queensland load centre and Southern Queensland REZ
- Queensland government ownership of land in the project footprint
- large hydrological catchment for the lower reservoir.

As has been identified, all large-scale long duration PHES sites have localised social and environmental impacts. For the Borumba PHES, one of the major local impacts identified was the likely inundation of a portion of the Conondale National Park within the proposed lower reservoir footprint. There were also important social impacts requiring further investigation regarding recreational use of the existing Lake Borumba infrastructure, and the important role the facility plays as a water supply reservoir.

The identified advantageous characteristics demonstrated the site warranted further detailed technical studies to explore opportunities to avoid, manage and mitigate the social and environmental impacts. As such, the government announced detailed analytical studies to support a Borumba PHES business case in June 2021. The detailed analytical report from these studies was delivered to government in early 2023.

Following the announcement of detailed feasibility investigations into the Borumba PHES project in 2021, the scale of the requirement for long duration energy storage in Queensland (at least 6,000 MW for 24 hours by 2035) became better understood through modelling undertaken as an input into the QEJP. This indicated that at least 4,000 MW of long duration energy storage was required in addition to the planned 2,000 MW at the announced Borumba PHES site in order to support the decarbonisation of Queensland's energy system and to achieve renewable energy targets of 70 per cent by 2032 and 80 per cent by 2035.

A review of the potential PHES sites shortlisted as highly prospective sites in the Stage 3 report indicated that only the proposed Pioneer-Burdekin PHES was capable of providing the scale of storage required by the system. In addition, the other shortlisted PHES sites from the Stage 3 Queensland Hydro Study were not in locations which could be readily connected into the energy system in the timeframe required to deliver the energy transformation.

The Pioneer-Burdekin site was considered favourable to progress to detailed analytical investigations due to:

- Attractive capital costs driven by economies of scale, and strong technical characteristics including favourable length-to-head ratio and small-to-moderate required embankment volumes.
- Significant scale of energy storage possible at the site (developing this site has the effect of potentially avoiding development and impacts of a third or fourth large-scale, long duration PHES sites in Queensland).
- Optimum delivery timeframe – fewer construction years are needed to connect the site to the load centre via transmission compared to other sites. This means the project can be delivered in stages in 2032 and 2035. Other sites cannot be delivered in this timeframe which would impact renewable energy target and emissions reductions goals.
- High rainfall indicating suitable site hydrology to support PHES reliability.
- Preliminary indications of favourable site geotechnical conditions.
- Greater opportunities to manage scheme impacts on sensitive environmental areas through careful design than other assessed options.

The scale of the Pioneer-Burdekin project will enable the government to achieve the required long duration capacity of at least 6,000 MW with potentially two projects only (including Borumba) rather than three or more. A single large-scale PHES at Pioneer-Burdekin reduces the cumulative impact and cost of long duration PHES development and the overall energy transformation in Queensland.

Analysis undertaken for the QEJP considered the energy system and staging requirements needed for the energy transformation. This analysis confirmed Pioneer-Burdekin and Borumba PHES supported the optimal infrastructure pathway to deliver the objectives of repurposing coal generation and reach 80 per cent renewable energy by 2035. This is due to a combination of their scale, cost and location within the energy system.

The most significant impacts identified during the Stage 3 investigations at the Pioneer-Burdekin site were to private property owners and users of the area. The government acknowledges these impacts and has committed to work with local communities and stakeholders to understand and manage these impacts in a responsive and ongoing capacity. The area surrounding the site also represents a significant tourism drawcard for the region, with many endemic species of flora and fauna located in the surrounding Eungella National Park. Impacts upon sensitive environmental receptors are likely to be able to be limited or avoided through careful design of the scheme.

Following consideration of these factors, in September 2022, the government announced the commencement of detailed analytical studies and community consultation at the Pioneer-Burdekin site.

Both Borumba and Pioneer-Burdekin are priority projects in the QEJP and in the Queensland SuperGrid Infrastructure Blueprint, which will enable the re-purposing of coal assets and decarbonisation of Queensland’s energy system.

Borumba PHES – Deep dive

Borumba PHES is located 45 minutes south-west of Gympie (see Figure 17).

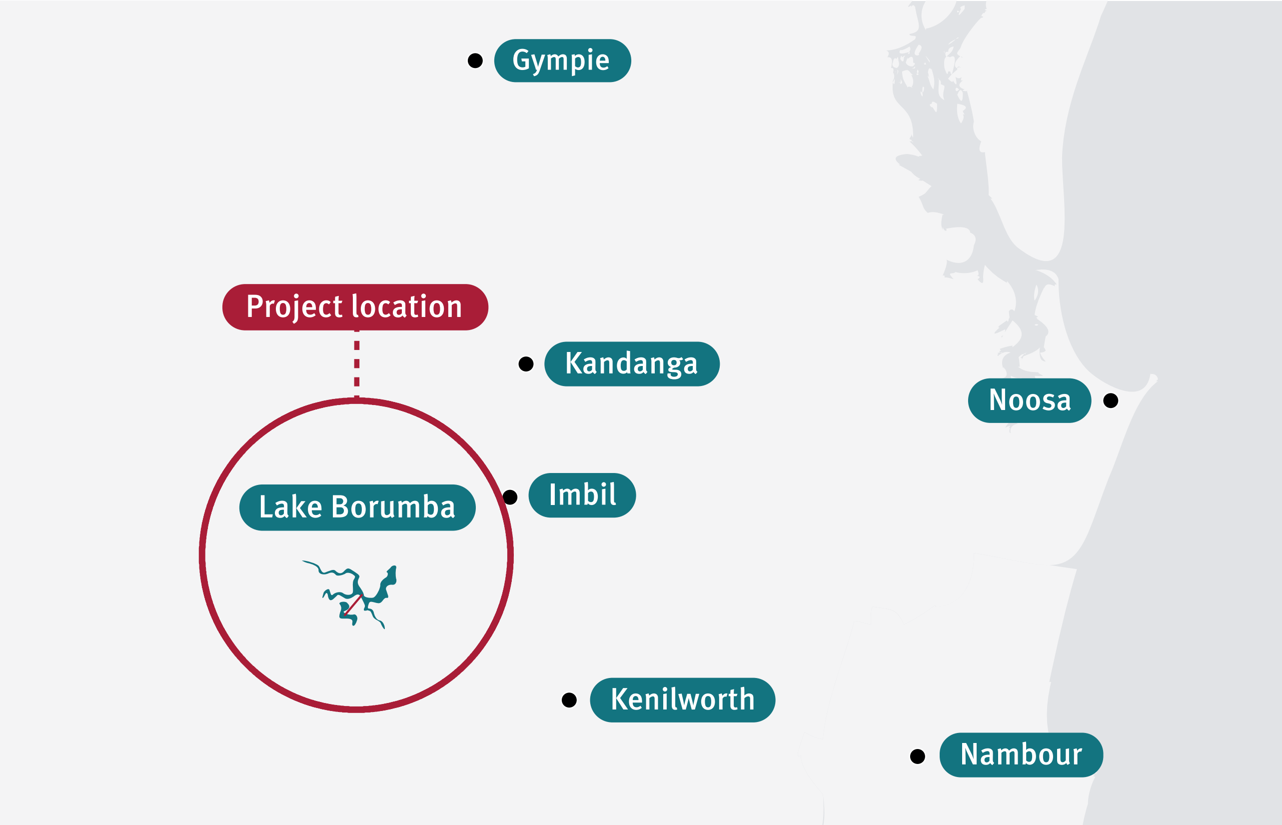


Figure 17: Borumba PHES location

Borumba has long been identified as a potential PHES facility due to the existing reservoir, topography and geological characteristics of the local area which make it suitable for large-scale long duration pumped hydro energy storage (see Figure 18). The site has favourable hydrology with a large catchment area contributing to the fill of the lower reservoir.

Figure 18: Borumba Dam

Land surrounding the proposed upper dam and reservoir inundation area was purchased by the Queensland Government for the purpose of pumped hydro development in the 1980s. The proposed site has the added benefit of being located within the Southern Queensland REZ, close to the high-voltage transmission network and the South East Queensland electricity load centre. Proximity to the network will support achievement of the QEJP optimal infrastructure pathway which includes deployment of 2000 MW of 24-hour storage at Borumba in 2030.

The Borumba PHES site has an elevation differential between the upper and lower reservoirs of 325 m, and a tunnel length between reservoirs of 2,600 m. This gives the Borumba PHES site a highly favourable length-to-head ratio of 8 (see Figure 19). As a rule of thumb, length-to-head ratios of 8 or lower are attractive and lead to practical efficiencies in site development and reduced project costs.[27]

27. Borumba PHES specifications: length – 2,600m, head – 325m, ratio 8 Stage 1 Pioneer-Burdekin PHES specifications: length – 3,585m, head – 676m, ratio 5.3. Stage 2 Pioneer-Burdekin PHES specifications: length – 5,805m, head – 714m, ratio 8.1. Snowy 2.0 PHES specifications: length – 28,000m, head – 679m, ratio 41.2.

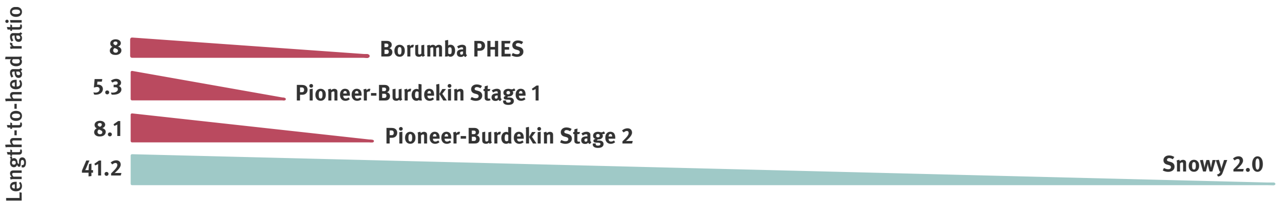


Figure 19: Comparing length-to-head ratios of prospective pumped hydro developments

The project will require construction of a new Borumba Dam to increase the storage capacity of the lower reservoir, Lake Borumba. This will support reduced fluctuations in the water level from PHES operation.

New upper main dam and saddle dams will be constructed to create an upper reservoir of sufficient capacity for the scheme (see Figure 20). A turbine power station and interconnecting water transfer tunnels will be constructed underground to connect the reservoirs.

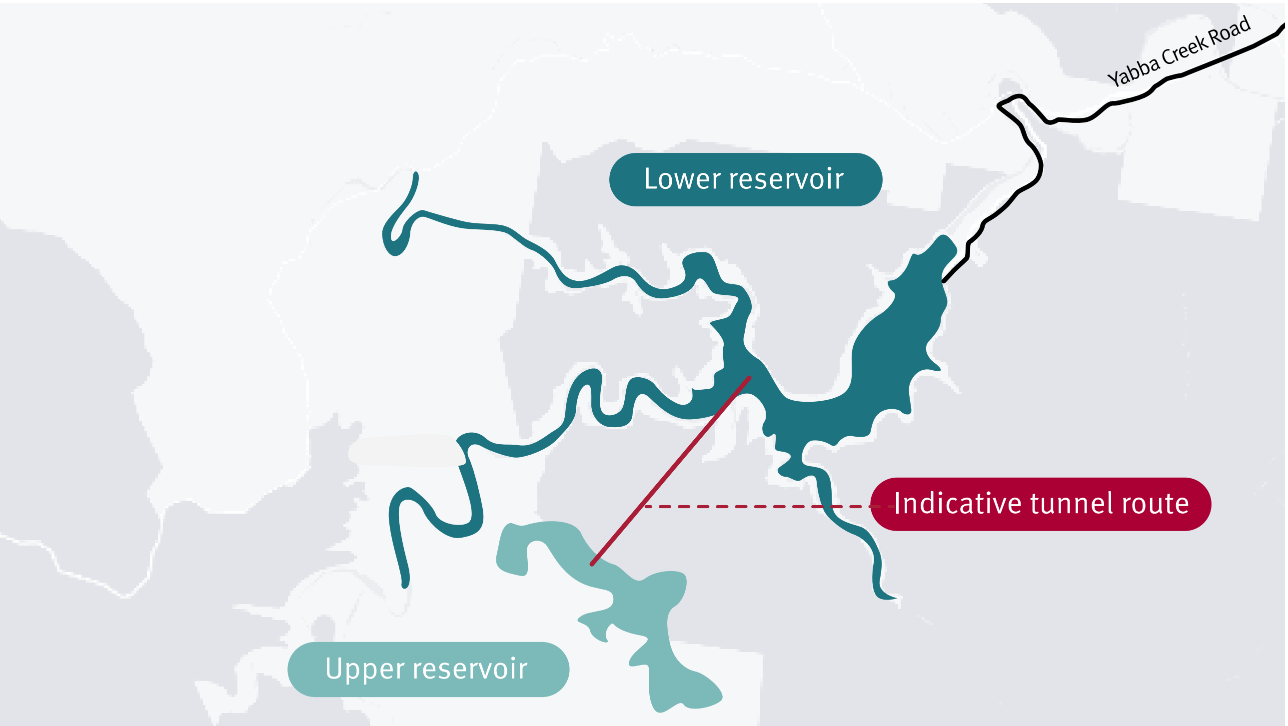


Figure 20: Borumba PHES project layout

If constructed, the Borumba PHES will:

- deliver more clean energy to Queensland
- support potential future employment and contracting opportunities, including an estimated 2,000 jobs during construction
- support local procurement
- help ensure there is sufficient energy storage available to maintain an affordable and reliable supply of electricity to all Queenslanders.

Site Strengths	
Strong technical characteristics	✓
Existing lower reservoir	✓
Large hydrological catchment	✓
Attractive capital costs per GWh	✓
Proximity to SEQ load centre and Southern Queensland REZ	✓

Pioneer-Burdekin PHES – Deep dive

Located 70 km west of Mackay, in the western Pioneer Valley, the Pioneer-Burdekin PHES is Queensland's largest potential long duration pumped hydro site (refer to Figure 21). The site offers internationally competitive scale and cost, which has the potential to support load growth in energy intensive exports such as alumina, aluminium, green steel, minerals and metals processing, green hydrogen and green ammonia.

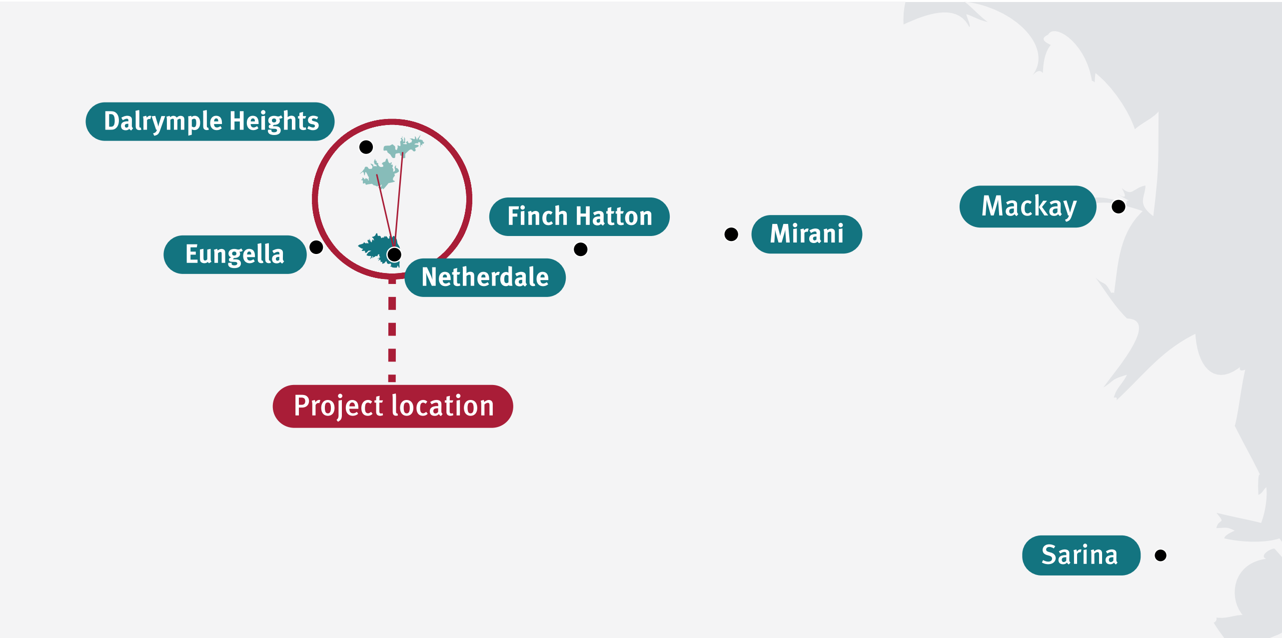


Figure 21: Pioneer-Burdekin PHES location

If built, the Pioneer-Burdekin PHES will help ensure there is sufficient energy storage available to maintain an affordable and reliable supply of electricity to all Queenslanders.

It is also located close to high quality wind and solar resources in the Central Queensland REZ region and has the potential to unlock large volumes of renewable energy in the region, creating construction jobs in addition to those required for the PHES.

The Pioneer-Burdekin PHES project uses two separate upper reservoirs and a single common lower reservoir (refer to Figure 22). The project has a potential generation capacity of up to 5,000 MW and 120 GWh (24 hours) of energy storage.

With peak electricity demand in Queensland ranging from 4,000 MW to 10,000 MW, the Pioneer-Burdekin PHES will play a vital role in the transformation of the energy system to renewable energy and a more diverse generation mix across the state.

The Pioneer-Burdekin PHES project is expected to achieve internationally competitive capital costs due to its highly favourable topography and scale efficiency. Key cost drivers include:

- Economies of scale – Pioneer-Burdekin PHES would be the world's largest PHES with 5,000 MW generating capacity, with two stages sharing one bottom reservoir, thereby reducing construction costs.
- Attractive length-to-head ratios for both scheme stages.
- Relatively low-cost dams – Conventional low-cost valley dams, rather than higher cost turkey's nest dams.

The Pioneer-Burdekin site has an elevation differential between the upper and lower reservoirs of 676 m for Stage 1 and 714 m for Stage 2. The site has a tunnel length between reservoirs of 3,600 m for Stage 1 and 5,805 m for Stage 2. This gives the Pioneer-Burdekin PHES site a highly favourable length-to-head ratio of 5.3 for Stage 1 and 8.1 for Stage 2 (see Figure 19). As a rule, length-to-head ratios of eight or lower are attractive and lead to practical efficiencies in site development and reduced project costs.

Preliminary investigations have shown that there are favourable geotechnical conditions for PHES development in the area. Site geotechnical conditions will be the subject of detailed technical studies and on-the-ground investigation as feasibility analysis progresses.

Land use in the project area (within reservoir footprints) is largely rural, with careful site design ensuring zero surface-level impacts to Eungella National Park.

Hydrology modelling performed under future climate scenarios suggests that the scheme fill of the combined storage volume can be achieved within approximately 1.5 years (two wet seasons) of commissioning the dams.

The Pioneer-Burdekin PHES will supercharge our progress towards Queensland's renewable energy targets and commitments in the QEJP by catalysing the delivery of renewable energy projects in Queensland. This will create thousands of jobs and deliver affordable, reliable and sustainable energy to Queenslanders.

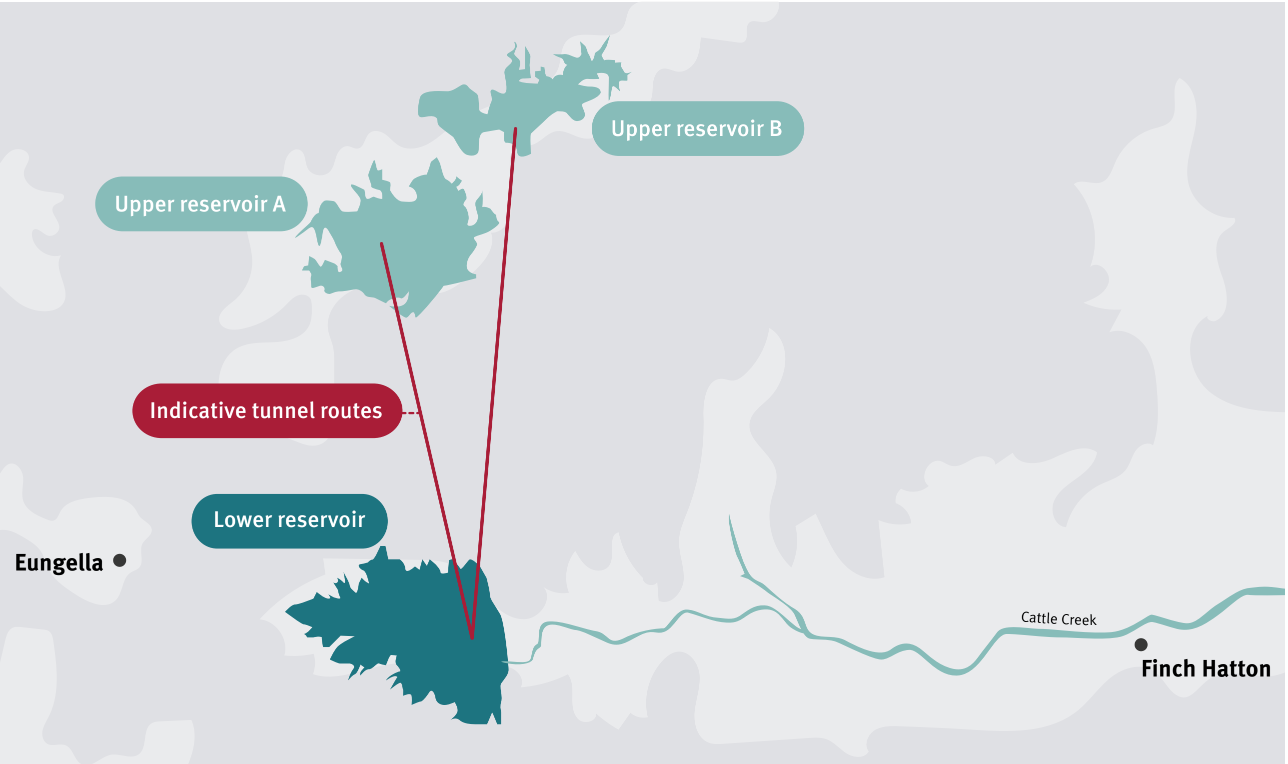


Figure 22: Pioneer-Burdekin PHES project layout

The key risks at the Pioneer-Burdekin site are the impacts to private property owners and users of the area. The government acknowledges these impacts and has committed to work with local communities and stakeholders to understand and manage these impacts in a responsive and ongoing capacity. Community consultation on detailed feasibility studies commenced in September 2022.

The government has not made a final investment decision for this site.

Site Strengths	
Internationally competitive	✓
Strong technical characteristics	✓
Favourable hydrology	✓
Attractive capital costs per GWh	✓
Proximity to Gladstone load centre and Northern Queensland REZ	✓

Part 4: Next steps

The Queensland Hydro Study identified opportunities for the delivery of large-scale long duration storage sites in Queensland.

From these assessments, the Queensland Government identified the Borumba and Pioneer-Burdekin PHES sites as the most viable sites for detailed feasibility studies. These selected sites offer favourable technical and commercial characteristics with lower impacts than other investigated sites.

Borumba PHES

A PHES project at Borumba Dam near Imbil in South East Queensland is expected to provide a 2,000 MW / 24hr asset and will be a foundational investment in Queensland's future electricity system.

Throughout 2022, detailed feasibility studies were undertaken to assess the site's suitability for PHES development. Studies included:

- **Environmental studies** to identify options to minimise impacts and offset environmental impacts during construction and operation. Studies included initial flora and fauna surveys and Native Title and cultural heritage assessments.
- **Social studies** to consider how a significant project like a large-scale long duration PHES development might positively and negatively impact the community and how these changes can be mitigated and/or managed.
- **Geotechnical studies** to increase initial understanding of the underground conditions to inform engineering requirements for dam foundations, tunnels and the power station.
- **Hydrological studies** to identify the sustainable yield of the catchment, timeframes for filling of the reservoirs, reliability of the PHES once operational, impact on other water users, and the impact of climate change on the PHES. These studies were completed in the context of the relevant water plan for the area, including any water plan reviews.
- **Engineering design studies** to identify site optimisation, including dam type and location, tunnel design, pump and turbine selection, and auxiliary infrastructure such as connection to the electricity transmission network.
- **Financial studies** to refine estimates of the expected total cost of the pumped hydro project. Financial assessment enabled the government to maximise the economic benefits to the state and local area.
- **Dam safety** is a fundamental requirement of any dam design. There are strict regulations in relation to the design, construction and operation of dams, such as those proposed as part of PHES construction.
  A preliminary assessment of dam safety was undertaken as part of the detailed feasibility studies, in accordance with dam safety regulation. The Department of Regional Development, Manufacturing and Water, the Queensland dam safety regulator, and Seqwater will continue to be engaged on dam safety and design.

Engagement with First Nations people and local communities was undertaken throughout the feasibility studies.

The engineering, geotechnical, environmental, hydrological, social and commercial studies undertaken during 2022 confirmed the project's feasibility for further assessment and development.

Additionally, independent technical review of the project design by international and national experts and energy system modelling confirmed the project will deliver the largest possible generation and storage capacity for the least cost, when compared to other storage technologies.

In June 2023, the Queensland Government announced its decision to proceed with the project, committing to the next phase of project development, including a comprehensive environmental impact assessment through an EIS to progress necessary applications for approvals.

Where permitted, early works that support the exploratory works have commenced at the project site. Exploratory works including road and bridge upgrades around the project site and further geotechnical studies will begin in 2024. Exploratory works, in particular geotechnical and groundwater investigations and ecological surveys require approvals to proceed and access to land, to inform project assessments and future decisions on project feasibility.

Delivery of the main works for the Borumba PHES Project requires resolution of complex issues and will require land access, social licence and environmental approvals to proceed. Potential critical issues include social impacts (landholders, cultural heritage, recreation, water supply security), direct impacts on National Parks, State Forest, water quality, and matters of national and state environmental significance, including loss of habitat for listed threatened species.

An EIS process is to be undertaken for the main works to investigate the project's environmental, social and economic impacts in comprehensive detail, and identify appropriate management, mitigation and offset measures to address project impacts.

Queensland Hydro submitted an application in August 2023 for the Coordinator-General to commence an EIS process for the main works for the Borumba PHES under the *State Development and Public Works Organisation Act 1971* (SDPWO Act). The Coordinator-General's EIS process under the SDPWO Act provides for the assessment of Australian, Queensland and local government matters, including assessment of matters under the *Australian Environment Protection and Biodiversity Conservation Act 1999*.

The Borumba PHES is estimated to cost $14.2 billion, with the Queensland Government committing an equity investment of up to $6 billion over the construction period in the 2023-24 Budget to deliver the project.

The commissioning timing of the Borumba PHES project will influence the pace of the energy transformation.

Pioneer-Burdekin PHES

As part of the optimal infrastructure pathway outlined in the blueprint, additional large-scale, long duration storage is required to be operational in 2032. The preferred site is the Pioneer-Burdekin PHES, which could be delivered over two stages. The first stage is 2,500 MW/24hrs (60 GWh) could be delivered in 2032 and the second stage is a further 2,500 MW/24hrs (60 GWh), may be commissioned in 2035.

The components of each stage would comprise the same infrastructure as the Borumba PHES (power station, turbines, headrace tunnel, tailrace tunnel, main access tunnel and emergency, cable, and ventilation tunnels).

Specialist engineering and environmental consultants are carrying out detailed analytical studies to confirm pumped hydro potential at the Pioneer-Burdekin site. Studies required will be comparable to those for Borumba PHES, including geotechnical investigations, engineering design, environmental, social, hydrological and cultural assessments.

Engagement with potentially impacted landowners, Traditional Owners, the community and other stakeholders will be critical to inform studies for the Pioneer-Burdekin site.

During this period, project staging for the Pioneer-Burdekin PHES will be refined, with detailed engineering design supporting plans for PHES construction, transmission deployment and procurement of electromechanical plant.

Like Borumba, the delivery of the Pioneer-Burdekin PHES project requires resolution of complex issues and will require land access, social licence and environmental approvals to proceed. Potential critical issues include social impacts (landholders, cultural heritage, recreation, water supply security), direct impacts on National Parks, water quality, and matters of national and state environmental significance, including loss of habitat for listed threatened species.

If the Queensland Government moves forward with the project, an EIS approval process would need to be undertaken to investigate the project's environmental, social and economic impacts in comprehensive detail, and identify appropriate management, mitigation and offset measures to address impacts.

Glossary

Key definitions and acronyms used throughout this document and Appendices.

AEMC	The AEMC is the Australian Energy Market Commission.
AEMO	AEMO is the acronym for the Australian Energy Market Operator.
Arbitrage	Energy arbitrage refers to the practice of purchasing electricity during off-peak periods, storing that electricity and discharging it during peak periods.
Black start	The ability to restart the system if necessary after a black system event.
Black system event	A black system event is the complete loss of supply to a large portion of the network and even a region. Black system events are caused by a series of cascading failures across the power system.
Blueprint	Short form of the Queensland SuperGrid Infrastructure Blueprint.
CER	CER is the acronym for consumer energy resources (e.g. household batteries, rooftop solar PV). Also see DER.
Contingency event	A contingency event is a major system disturbance with a significant impact on the system (e.g. the sudden removal of a generating unit, large load or transmission element from the system).
Control system stability	Control system stability is the ability of control systems to reach a state of equilibrium when the power system is subjected to a large disturbance event.
Converters	Converters are devices that transform AC into DC (voltages and currents).
CQ	CQ is the acronym for Central Queensland.
CSIRO	Acronym for Commonwealth Scientific and Industrial Research Organisation.
DEC	DEC is the acronym for the Department of Energy and Climate.
Demand	Demand is the term used to describe the consumption of energy.
Depth	In the context of energy storage, depth refers to the amount of energy that an asset can store. A deep storage can store a lot of energy, whereas a shallow asset cannot.
DEPW	DEPW is the acronym for the Department of Energy and Public Works.
DER	DER is the acronym for distributed energy resources (e.g. household batteries, rooftop solar PV). Also see CER.
Design life	The design life of a generator is the lifespan for which it was designed if it operates within certain parameters.
Dispatchability	The dispatchability of a generator is the extent to which it can be called on to follow a set power output and adhere to a dispatch schedule at some time in the future. For a generator to be dispatchable, its generation must be controllable, firm and flexible.
DNSP	A DNSP is a distribution network service provider.
Dunkelflaute	A German term to describe multi-day periods of very little wind and solar generation.

Key definitions and acronyms used throughout this document and Appendices.

Economies of scale	A proportionate saving in costs gained by increased size and capacity of a development.
Energy storage	The process where electrical energy is captured so that it can be used when needed.
EPBC Act	The EPBC Act is the *Commonwealth Environmental Protection and Biodiversity Conservation Act 1999*.
EV	Acronym for electric vehicles.
FCAS	FCAS are Frequency Control Ancillary Services. They are used to raise or lower frequency.
Flexibility	Flexibility is the ability to respond rapidly to changes in the supply-demand position (such as changes in VRE generation output, generation failures, and variations in demand).
Frequency stability	Frequency stability is the ability of the power system to maintain a specified frequency following a contingency event.
FY	FY is the acronym for financial year.
Generation	Energy generation is the process of producing electric power.
GOC	Acronym for Government Owned Corporation, e.g. Stanwell or Powerlink.
Governor	A governor is the system at each power station to control the output of a generation unit, in response to changes in the load judged by measuring and responding to changes in system frequency. The governor can be locally or centrally controlled.
Grid formation	Grid formation is the ability to establish and maintain a set frequency and voltage to which the rest of the system is able to be synchronised.
Grid-forming inverters	Grid-forming inverters are inverters that, when in 'grid-forming mode', can regulate the voltage magnitude and the frequency to specific set points. The effect is the same provided by synchronous generators through their governor control systems.
Head	In the context of PHES, head is the elevation difference between the water level in the upper and lower reservoirs.
Headrace	The headrace of a PHES scheme is section of the waterway that connects the upper reservoir to the penstock.
Inertia	When talking about the power system, inertia is the ability to resist changes in frequency due to the mechanical inertia of large spinning masses that are electromagnetically coupled with the power system and synchronised to the grid frequency.
Inverters	Inverters are devices that transform DC into AC (voltages and currents) in order to connect DC systems to the AC power system. Sometimes 'inverter' is used to refer to converters as well.
ISP	ISP is the acronym for AEMO's Integrated System Plan.
Length	In the context of PHES, length is the distance that that the water travels between reservoirs.
Length-to-head ratio	In the context of PHES, the length-to-head ratio (L:H or L/H) is the ratio of length to head. It is used as a general measurement of practical efficiency for a PHES project. Lower L:H ratios (steeper projects) are typically more attractive.
Long duration	Energy storage with durations 24 hours or longer.
MAT	MAT is the acronym for a PHES project's main access tunnel.

Key definitions and acronyms used throughout this document and Appendices.

Market modelling	Modelling used to forecast electricity sector outcomes.
MCA	Acronym for multicriteria analysis.
Medium duration	Energy storage with durations typically between four to 12 hours.
Minimum load	Minimum load is the lowest stable operating output of a generator before it violates physical constraints.
NEM	The NEM is the national electricity market, comprising all Australian states and territories except for WA and the NT.
Network	Transmission and distribution networks are the infrastructure networks needed to transport the electricity from generation to the load points.
Non-energy services	Services separate to energy that help manage the power system, such as voltage and frequency support, inertia and system strength.
Non-synchronous	Non-synchronous generators are generation technologies which are de-coupled from the grid via an inverter (solar PV and batteries) or induction machines (wind turbines).
NQ	NQ is the acronym for North Queensland.
O & M	Acronym for operation and maintenance costs required by energy generation assets.
Optimal infrastructure pathway	The planned least cost infrastructure development pathway to decarbonise Queensland's energy system set out by the Queensland SuperGrid Infrastructure Blueprint.
Peak demand	The highest electrical power demand that has occurred over a specified time period. Daily peak demand in Queensland typically occurs in the early evening.
PEM	In the context of hydrogen, PEM is the acronym for a polymer electrolyte membrane electrolyser.
PHES	Acronym for Pumped Hydro Energy Storage.
QEJP	QEJP is the acronym for the Queensland Energy and Jobs Plan.
QEST	QEST is the acronym for the Queensland Energy Security Taskforce.
QRET	QRET is the acronym for Queensland's Renewable Energy Targets.
Queensland Hydro Study	The three-stage study used to identify, evaluate and select the most prospective sites for hydro development in Queensland.
Ramp rate	A generator's ramp rate is a measure of how fast it can increase or decrease its generation.
Reserve capacity	Reserve capacity (normally measured in MW or GW) is generation capacity (or demand response) to insure against unexpected demand growth and/or reductions in supply.
Reservoir	An impoundment used to store water which is used to generate energy in a closed loop PHES system.
REZ	Acronym for renewable energy zone.
Seasonal smoothing	Ability to store and later deliver energy across long periods of time, including over seasons.

Key definitions and acronyms used throughout this document and Appendices.

Self-discharge	Battery self-discharge is the process by which internal chemical reactions reduce the stored charge (and therefore stored energy) in a battery. It depends on a range of factors, including the battery's chemical components, and temperature.
Shallow/short duration	Energy storage with durations less than four hours.
SQ	SQ is the acronym for Southern Queensland.
Supply	Energy supply is the delivery of energy to point of consumption.
Synchronous	Synchronous machines are synchronous electro-mechanical generators and motors that operate with large spinning rotors (or turbines) that are synchronised to the frequency of the power system. They are typically heavy, and naturally provide inertia and grid-forming to the power system.
System oscillations	Small deviations that occur in the power system, even in the absence of contingency events.
System reliability	System reliability refers to ensuring there is enough energy available to meet demand at all times.
System restoration	System restoration is the ability to restore the system to a secure and reliable operating state following a black system event.
System security	System security is the ability of the power system to operate within defined technical limits, even if there is an incident such as the loss of a major transmission line or large generator. Security is a pre-requisite for achieving a reliable supply of electricity for consumers.
System stability	System stability is the ability of the power system, for a given initial operating condition, to regain a state of operating equilibrium after being subjected to a physical or electrical disturbance. Stability is a pre-requisite for achieving a secure (and therefore reliable) supply of electricity for consumers.
System strength	System strength is a measure of the sensitivity of the voltage to a change in generation or load; and it varies in different parts of the network. If a location is 'strong' a generator at that location could change its output, but the voltage level will largely remain unaffected.
Voltage stability	Voltage stability is the ability of the power system to maintain or recover voltage magnitudes to acceptable levels following a contingency event.
VRE	VRE stands for 'variable renewable energy' (e.g. solar PV, wind).

Appendix

Appendix A – Stage 3 Queensland Hydro Study Terms of Reference

Queensland Government

Hydro and Pumped storage hydro study – Stage 3 – Long term storage and replacement of coal fired generation

Terms of Reference

Stage 3 of the pumped storage hydro study will focus on identifying the potential of large-scale long-term pump hydro generation to support the transition of the Queensland energy market to a high penetration of variable renewable energy generation sources by 2030 and beyond in a reliable, secure and affordable manner.

Context

- DNRME has undertaken two stages of a study into hydro-electric and pumped storage generation capacity, these are: Stage 1 – desktop study identified 16 potential shortlisted sites with 4,600 MW of capacity and 36,600 MWh of storage.
- Stage 2 – further analysis shortlisted down to 9 sites with almost 2,300 MW of capacity and 18,000 MWh of energy storage.
- The findings of Stage 2 of the Hydro study were delivered to the Queensland Energy Security Taskforce (QEST) on 5 July 2018.
- The QEST has requested further work, to build the information available to Government focusing on larger and long-term storage.

Objectives

There are three key objectives for Stage 3 of the Hydro Study, as outlined below.

- **What is the role of large-scale long duration pumped storage in the transition to a 50 per cent QRET and beyond to net carbon neutral by 2050?** The study will assess how large-scale long duration pumped storage could assist in supporting the transition to a 50 per cent renewable energy target by 2030, and beyond in a reliable, secure and affordable manner. In particular, the study will consider the potential role of large-scale long duration pumped storage in replacing the generation capacity of Queensland's coal fired power stations as they reach the end of their economic and technical lives. Assessment should also consider implications, including employment skills and resourcing.
- **What sites are available for large-scale long duration pumped storage in Queensland?** The study will identify potential large-scale long duration pumped storage hydro sites in Queensland and develop an understanding of the commercial viability of these projects from a whole-of-government perspective.
- **What practical steps could the government take to progress large-scale long duration pumped storage?** The study will provide a list of short, medium and long-term actions for the Queensland Government to progress the development of large scale long duration pumped storage in the state. This will include consideration of the Government's role in asset ownership and commitment to maintain ownership in the sector, and the appropriate parameters for investment going forward.

Scope and Activities

1. The role of pumped storage in Queensland in the context of the QRET and beyond
    - Assess whether long duration pumped storage could be deployed to assist in the transition to a 50 per cent renewable energy target by 2030 and net carbon neutral by 2050. This should include:
        - » the system security and reliability challenges that Queensland could face as higher penetrations of solar and wind enter the Queensland market between 2020 and 2030

- » the implications for the system beyond 2030 and the potential role of long duration pumped storage in replacing the generation capacity of Queensland's coal fired power stations as they reach the end of their economic and technical lives
- » the network stability and voltage challenges relating to the transition and how long duration pumped storage can assist in managing these challenges vs alternative technology options
- » what capacity and storage duration of pumped storage hydro would be optimal to minimise electricity system costs while maintaining an appropriate level of energy security
- » the practical ability to deploy large-scale pumped storage in timeframes aligned to the likely repurposing of some of Queensland's coal fired power stations by 2050.

2. Site selection

   - Identify the long duration pump storage sites that exist in Queensland. This should include consideration of:
     - » a potential 'Big Burdekin' hybrid hydro (500 MW to 1 GW hydroelectric + pumped storage)
     - » sites previously identified by the Queensland Electricity Commission
     - » revisiting of sites considered in stages 1 and 2 to understand whether these schemes can be modified to deliver large and longer term storage
     - » potential sites that utilise existing state government owned dams
     - » other options including seawater pumped hydro sites.
   - The minimum storage required to be considered large-scale long duration will be 10 GWh with a preference for 24 GWh/1 GW days or larger.
   - Consider employment, skills and resourcing implications across potential sites and regions.

3. Other requirements to develop pumped storage

   - The study should identify the range of other factors that could be required to develop pumped storage, such as additional transmission infrastructure.
   - In this context, the study should consider the work recently undertaken by AEMO through its Integrated System Plan, particularly in the context of identifying potential REZs.

4. Commercial analysis

   - Undertake a commercial analysis of the sites identified in section 2. The analysis should include (but not be limited to): The commercial considerations for hydro and pumped storage under different operating profiles.
   - The relative value of various revenue streams (e.g. energy arbitrage, network support, deferred network augmentation) and limitations on the ability to capture these revenue streams.
   - The analysis should consider issues regarding the commercial delivery of large and long duration storage and the role of Government in overcoming barriers.
   - The types of commercial/contracting arrangements that best support large and long duration storage and any limitations in the current market framework in regards to these arrangements.
   - The minimum capacity (MW) and storage (MWh) necessary to support different financial contracts as part of a bundled portfolio of renewable generation assets.
   - The study will undertake project-specific modelling for shortlisted sites found to be most prospective.

5. MCA and risk assessment

   - A key finding from Stages 1 and 2 is that each site/scheme is likely to have unique characteristics. As with Stage 2, a multi-criteria and risk assessment will be undertaken to compare the relative merits of potential sites.
   - Informed by market and financial modelling the MCA and risk assessment will focus on the following key commercial issues for prioritising and excluding sites:
     - » scale - starting and upgradable generation capacity and energy storage
     - » capital costs

    - water security
    - round trip efficiency
    - transmission and network
    - critical issues and risk management.
  - The MCA and risk assessment will also consider the following issues in prioritizing sites:
    - environmental and community impacts
    - legal and regulatory constraints.

6. Priority actions for the Queensland Government
  - Provide policy advice on how the government could support the development of large and long duration storage hydro plant, drawing upon the findings of both stage 2 and 3. This advice should include:
    - specific actions the government could undertake in the short-term to progress large-scale pumped storage that would support the transition to the QRET and beyond to net carbon neutral by 2050 (for example, funding to support a feasibility study in "location X")
    - appropriate pre-conditions and parameters for investment going forward.
  - The policy advice should consider:
    - government commitment to ownership of key power assets and maintaining majority ownership of generation assets in the transition to QRET
    - ownership of existing dams, which have potential to be developed into pumped hydro sites
    - private sector investment implications
    - lead times and costs for development
    - the approvals processes required – including State and Federal processes
    - consideration of the role of Government Owned Corporations in owning large-scale long duration pumped storage, including key opportunities, implications and risks.

Timeframes

- 12 months from endorsement of these Terms of Reference.

Support

- The project team will engage consultants to undertake this analysis.
- The project team will be required to consult with the following entities throughout the preparation of Stage 3:
    - Powerlink to understand transmission infrastructure requirements, constraints and planning.
    - Stanwell Corporation and CS Energy to understand the key maintenance and capital milestones for the remaining economic and technical lives of state owned coal fired power stations.
    - The Just Transition Energy Advisory Committee to understand the implications for workers and communities associated with replacing coal with pumped storage.
    - SunWater and Seqwater in terms of the provision of engineering and other information relating to potential pumped hydro sites involving their dams.
- An initial budget has been allocated to support the study. However, a full budget will be developed and presented to QEST through the development of the Project Plan. If additional funding is required, this will be highlighted to the QEST at that time.

Oversight and Management of project

- These Terms of Reference, a project plan, budget and associated work will be approved by the QEST and the project team will be required to provide updates on a regular basis and in relation to key milestones.
- A project board will be formed to oversee the work program.

Appendix B – Analysis of storage technology options

Disclaimer

The following information was an input into Stage 3 of the Queensland Hydro Study and was prepared in 2019. It represents analysis at a point in time. Facts and figures in this section have not been updated to represent 2024 data or inputs into QEJP market modelling unless otherwise identified. The information has however been amended to improve readability. Specifically updated graphics relating to current battery costs and deployment projections and PHES have been provided.

For contemporary analysis regarding costs refer to Aurecon and CSIRO Gencost which informed inputs into the QEJP market modelling. The CSIRO works with the Australian Energy Market Operator (AEMO) to update annually the Gencost report which provides current and projected costs for electricity generation, storage and hydrogen technologies.

The latest 2023-24 GenCost draft report found that energy infrastructure build costs have generally stabilised since the previous year, however there are some outliers. In particular, nuclear small modular reactors (SMRs) emerged as the highest-cost technology with the most extreme cost escalations (39% over 2023/24). This is reinforced by new data from the Carbon Free Power Project SMR project in the US, which was the most advanced project worldwide (until it was cancelled) with reported project costs increasing 70 percent from previous estimates. Of note, the Hinkley C flagship nuclear project in the United Kingdom reported significant cost escalations, with an original budget of £9 billion which now reaches up to £48 billion (in current prices or approximately $A92.6 billion). While not a SMR, Hinkley C does demonstrate the strongly escalating costs of nuclear energy.

Overview

There are different types of energy storage technologies which can contribute to efforts to meet Queensland's identified storage need. New energy storage infrastructure will need to deliver a range of system reliability and system security services to meet the system challenges along the path to net-zero emissions.

The objective of this analysis, conducted in 2019 and 2020, was to investigate the capability of technologies to deliver system reliability at scale and to provide system security benefits. Broad definitions of system reliability and system security services, and some key measures of those services, are available in the call out box on page 66.

This section reviews the ability of the following technologies to provide system reliability and system security services and other development aspects:

- PHES
- Batteries
- Conventional hydroelectricity
- Flywheels
- Synchronous condensers
- Concentrated solar thermal
- Compressed air energy storage
- Demand response
- Hydrogen
- Low-capacity factor gas generation

The analysis of each technology in this chapter includes information relevant to their potential role in Queensland's future energy system.

These technologies were chosen because of their potential to work alongside VRE to meet the reliability-related challenges along the path to net-zero emissions. Synchronous condensers have been included because they are often confused with flywheels (a technology that is considered). Other technologies that could only help to support security-related challenges (but not reliability-related challenges) were not considered.

System reliability

System reliability refers to ensuring there is enough energy available to always meet demand. In practice, this means having an accurate understanding of supply and demand (both in real time, and for a period into the future); generating enough power to match real-time demand; transporting this power to consumers; and having sufficient reserves to account for fluctuations in supply or demand. System reliability services include:

- **Dispatchable supply** – The generation (or demand response) capacity available above the level of capacity required to balance supply and demand in real-time, and for a short period into the future.
- **Strategic reserve** – Refers to either capacity reserves or energy reserves to provide confidence that the system is reliable. Reserve capacity is generation capacity (or demand response) to insure against unexpected demand growth and/or reductions in supply. Reserve energy is a resource that insures against shortage of fuel supply.

System security

System security is the ability of the power system to operate within defined technical limits, even if there is an incident such as the loss of a major transmission line or large generator. Security is a pre-requisite for achieving a reliable supply of electricity for consumers. In practice, this requires a portfolio of equipment with sufficient inertia, system strength, black start capability and grid-formation capability. System security services include:

- **Frequency control/stability** – The ability of the power system to maintain a specified frequency following a contingency event. Frequency stability is provided by Frequency Control Ancillary Services (FCAS) which support energy system operators to correct deviations in frequency from 50 Hz.
- **Voltage control** – The ability of the power system to maintain voltage magnitudes within acceptable levels, including recovery to acceptable levels following a contingency event.
- **System strength** – System strength is a measure of the sensitivity of the voltage to a change in generation or load; it varies in different parts of the network.
- **Inertia** – Inertia is the ability to resist changes in frequency due to the mechanical inertia of large spinning masses that are electromagnetically coupled with the power system and synchronised to the grid frequency.
- **Black start capability** – The ability for a generator to start itself up and carry out initial energisation of a section of the power system after a loss of power supply to a portion of the network.
- **Grid formation capability** – The ability to establish and maintain a set frequency and voltage to which the rest of the system can be synchronised.

Technologies out of scope

DEC remains focussed on investigating technology options that are commercial and can provide certainty that renewable energy targets and emissions reduction targets can be met.

There are a range of additional technologies that could theoretically help to address the reliability-related issues along the path to net-zero emissions, but these options are highly uncertain or unlikely. These technology options were not progressed for further analysis in Stage 3:

- Wave generation
- Tidal generation
- Geothermal
- Biomass
- Fossil fuel generation with carbon capture and storage
- Nuclear
- Combined cycle gas turbines

These technologies are briefly described below, along with a justification as to why they have not been considered to the same extent as the technologies listed in the 'in-scope' section of this chapter. In the following section, costs are included from the Stage 3 study (conducted 2019) unless otherwise specified. Some technology costs have changed since completion of this report, but the relative cost differentials between most technologies is largely unchanged.

It should be noted that research and development for many of these technologies is ongoing, and information contained here does not preclude further advances which increase their ability to deliver energy storage for Queensland in future.

Wave generation

Wave generation produces electricity by capturing the kinetic energy of waves. It typically requires placement of a floating object on the surface of the ocean, which drives a turbine to generate electricity as it rises up and down with waves.

Wave energy resources are relatively low in Queensland compared to southern states,[28] and it is considered unlikely that wave technology could economically contribute significant renewable generation capacity to meet Queensland's renewable energy targets.

Work is ongoing to demonstrate a commercially viable technology that generates electricity from waves. Globally, there have been several pilot projects and research concepts to generate electricity from waves. However, these projects have encountered difficulties, or are still in the developmental stages. For example, in March 2019, the Western Australian Government withdrew its support for Carnegie Energy's proposed 20 MW Albany Wave Energy Project, after it found the company was not able to deliver the project.[29]

Tidal generation

Tidal generation produces electricity from water flowing due to the tide. This is like conventional hydroelectric generation, except generation is dependent on the tide. Tidal generation is typically achieved by building turbines (and potentially a series of dams) across a river/estuary.

Tidal energy is not considered likely to be deployed on a significant scale in Queensland as it is constrained by:

- relatively high costs
- environmental impacts
- limited availability of sites with sufficiently high tidal ranges/flow velocities.

28. CSIRO, *Wave Energy in Australia*, April 2019. Available at: https://www.csiro.au/en/Research/OandA/Areas/Marine-technologies/Ocean-energy/Wave-energy
29. Government of Western Australia (2019). *Funding agreement with Carnegie Clean Energy terminated*. Available at: https://www.mediastatements.wa.gov.au/Pages/McGowan/2019/03/Funding-agreement-with-Carnegie-Clean-Energy-terminated.aspx

Geothermal

Geothermal energy is heat extracted from the earth, typically by circulating a fluid through geothermal reservoirs to bring the heat to the surface. This can be used to generate electricity and is used extensively in countries like Iceland.[30]

The Australian Renewable Energy Agency (ARENA) suggest that geothermal energy is not presently economic in Australia due to a lack of geothermal sources, difficulties with producing a sufficient rate of hot fluid from the reservoirs rate, high capital costs, and high transmission costs (because the best geothermal resources are typically located in remote locations).[31]

There are alternate geothermal technologies, such as Organic Rankine Cycle geothermal power plants, which are widely deployed around the world to generate energy from low temperature geothermal resources. These technologies are yet to be widely deployed in Australia, although there are potentially suitable applications both behind-the-meter and in the distribution network.

Biomass

Biomass generation involves combustion or gasification of biomass to generate steam, which drives a turbine, which generates electricity (like conventional thermal generation).

Energy from biomass and organic waste has played an important role in Queensland's energy supply for many decades, with current installed capacity of around 500 MW in the state. While biomass diversifies Queensland's energy mix, it faces challenges that limits significant further increases to its current scale of deployment. The main constraints relate to the volume of reliable feedstock, high capital and transport costs. Through the QEJP, DEC is working with industry to investigate options and pathways to expand generation from under-utilised biomass waste streams and support technology innovation.

Fossil fuel generation with carbon capture and storage (CCS)

One way to generate electricity with net-zero emissions is to capture and store all the emissions from fossil fuel generation. This requires the addition of complex plant to capture the CO2 emitted in the combustion process, transportation of the captured CO2, and storage in deep underground geological structures (or by other physical, chemical, or biological means).

This combination of plant decreases the overall efficiency of power generation, and the cost of storage is high. As a result, fossil fuel generation with CCS is uncompetitive compared to other technologies that can provide firmed electricity. Substantial improvements in CCS would be required for it to be commercially viable.

Nuclear

Nuclear generation is a well-understood, zero-emissions technology — however has no waste product solution.

Traditional nuclear generation is likely too expensive and inflexible to be compatible with high VRE penetrations. Future potential for nuclear power may be in small (100 MW) modular reactors (SMRs), like those used by submarines and icebreakers.

However, SMRs are technologically immature and therefore very expensive with no clear time frame for construction and delivery of safe, reliable energy generation. The assumed cost of SMR at $16,000/kW is over 4.5 times the cost of long duration (24 hour) PHES and 5 times the cost of 8-hour battery storage on a $/kW basis.[32]

Costs of conventional nuclear generation are also very expensive. The Hinkley C nuclear generator currently under construction in the United Kingdom is now forecast to cost approximately $92.6 billion (AUD)/$28,900 kW and be commissioned in 2027, 2 years behind schedule.[33]

The *Nuclear Facilities Prohibition Act 2007* prohibits the construction or operation of nuclear reactors and other major facilities in the nuclear cycle other than uranium mining and exploration.

30. Iceland's National Energy Authority (n.d.), *Geothermal*. Available at: https://nea.is/geothermal/
31. ARENA (2019), What is geothermal energy? Available at https://arena.gov.au/renewable-energy/geothermal/
32. *Updated with 2022 data* – CSIRO (2022), GenCost 2021-22. Available at: https://data.csiro.au/collection/csiro%3A44228v11
33. https://reneweconomy.com.au/cost-of-uks-flagship-nuclear-project-blows-out-to-more-than-a92-billion/

Combined cycle gas turbines (CCGTs)

CCGTs operate similarly to open cycle gas turbines (OCGTs) but with a higher thermal efficiency. They are technologically mature, and can provide long duration dispatchable supply (i.e. strategic reserves) when coupled with access to a firm gas supply and/or large storage quantities of distillate.

However, CCGTs are more capital intensive (and therefore need to generate for longer periods to recover costs), and not as flexible as OCGTs.[34] As a result, OCGTs are better placed to provide peaking capacity, and/or strategic reserves. The lower efficiency of OCGTs is not as important if they only operate at a low-capacity factor (which would need to be the case to achieve net-zero emissions).

Technologies in scope

This section considers the following technologies assessed as part of the Stage 3 report:

- PHES
- batteries
- conventional hydroelectricity
- flywheels
- synchronous condensers
- concentrated solar thermal
- compressed air energy storage
- demand response
- hydrogen
- low-capacity factor gas generation

The analysis of each technology presented in this chapter also includes practical information relevant to their potential role in Queensland's future energy system.

Pumped hydroelectric energy storage

Overview

PHES is the world's most widely used storage solution, accounting for 97 per cent (>130 GW) of global electricity storage capacity.[35] Queensland has one operational PHES, Wivenhoe, which can generate 570 MW for 10 hours (5,700 MWh). A second PHES is currently being constructed at Kidston (250 MW with 10 hours' storage) with several smaller PHES currently undergoing planning and approvals by private sector proponents.

PHES makes use of a hydropower generating plant but captures the discharged water in a lower reservoir. During periods of low energy prices, (e.g. when there is an excess of VRE), the water is pumped back to the upper reservoir. Because of this 'closed loop' system, PHES is less dependent on variable river flows since the only water losses are from evaporation or seepage.

In most cases, the same waterway/pipeline is used for both directions of water flow (i.e. for both pumping and discharging). Figure 23 provides a basic overview of a PHES system.

34. The industrial gas turbines used in OCGT plant are subject to thermal stress limitations that can prohibit rapid cycling or multiple stop/starts in each period.

35. ANU (2017), An atlas of pumped hydro energy storage. Available at: https://re100.eng.anu.edu.au/index.html

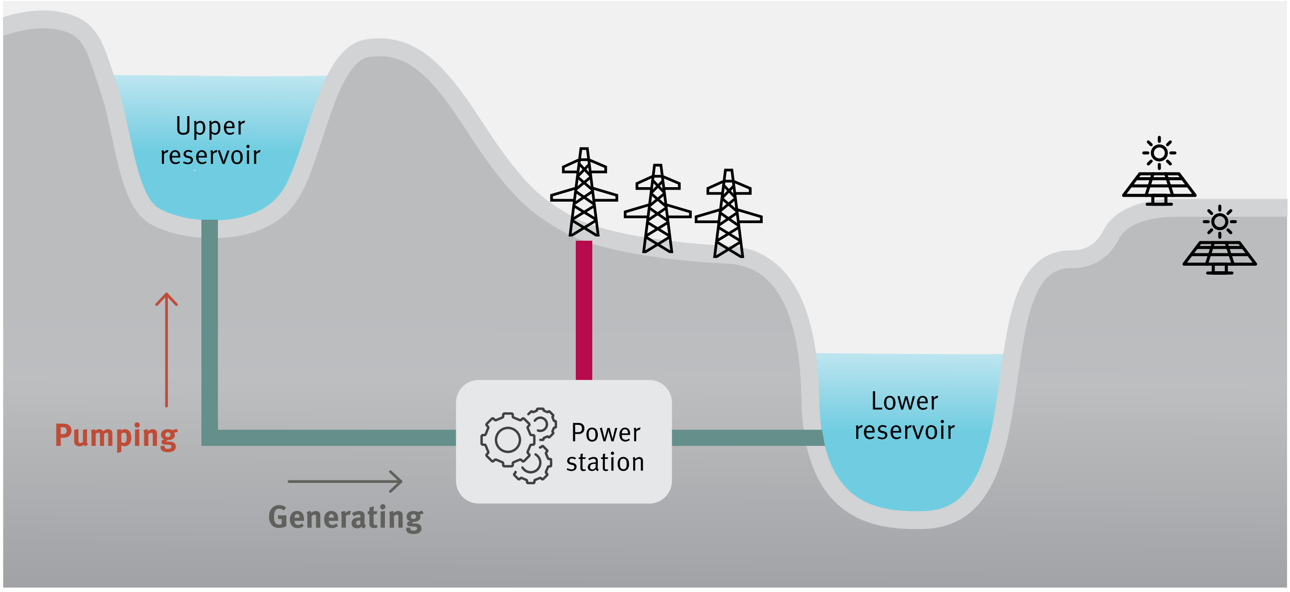


Figure 23: Simplified overview of a PHES system

PHES configurations[36]

The water hydraulic machine, turbine and generator 'set' can have three possible configurations.

Quaternary set

The first configuration is a quaternary set, which was the most common configuration prior to 1920. In this configuration, the pump and the turbine are completely decoupled (see Figure 24[37]). Despite the systems being independent, only one can operate at a time, which results in plant redundancy. Additionally, this arrangement requires considerable space, and a large amount of mechanical plant. As a result, quaternary sets tend to be expensive, and are typically only a viable solution for retrofitting pumped storage to an existing hydroelectric plant. However, they tend to be highly efficient, because the pump and turbine are designed to optimise individual performance.

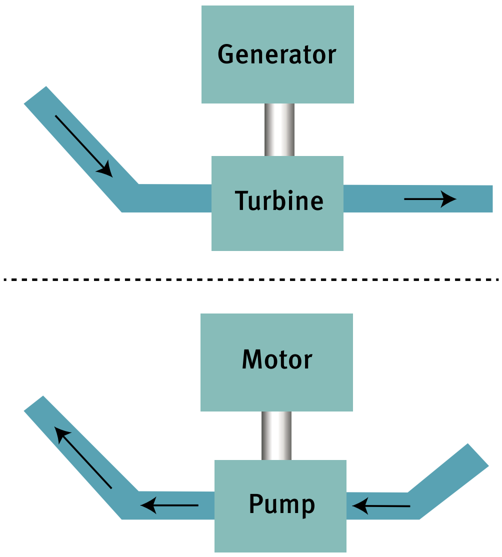


Figure 24: Schematic of a quaternary set

36. Content for this section has been informed by advice from Stage 1 of the Hydro Study, and from course notes from Oregon State University's ESE 471: Energy Storage Systems

37. Webb K (n.d.), Section 3: pumped-hydro energy storage. Available at: http://web.engr.oregonstate.edu/~webbky/ESE471_files/Section%203%20Pumped%20Hydro.pdf

Ternary set

The second configuration is a ternary set, which was the most popular design from about 1920 until the 1960s. In this arrangement, the pump, the turbine, and the motor/generator are all attached to a single spinning shaft, with a clutch to decouple the pump when it isn't in use, and valves to isolate the pump and/or turbine when they are not required. This arrangement also allows the pump and turbine to operate simultaneously, which allows for limited control of net pumping. Like quaternary sets, ternary sets tend to be highly efficient, because the pump and turbine are designed to optimise individual performance.

Installing a ternary set can be costly for large PHES schemes, because it is typically required underground, and significant excavation is required to provide access for maintenance. In modern times, ternary sets are typically only used for very high head schemes and/or above-ground schemes. Figure 25 shows the scheme arrangement for a ternary set.[38]

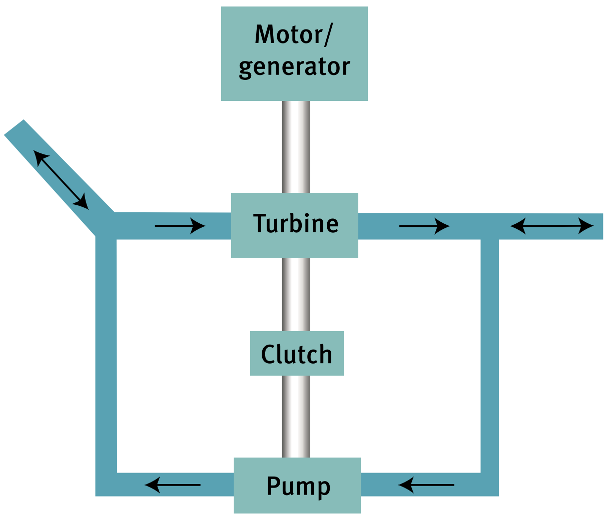


Figure 25: Schematic of a ternary set

Binary set

The third configuration is a binary set (also called reversible pump-turbines), which is the most common for modern PHES. It involves a single reversible pump/turbine, coupled to a single motor/generator. The reason binary sets are popular is that they are the lowest cost configuration – they require less equipment, simplified hydraulic pathways, and fewer valves, gates, controls, etc. However, they have lower efficiency than ternary or quaternary sets because the pump/turbine is designed as a compromise to what would have been best for pumping against what would have been best for generating. Additionally, because the rotational direction is opposite for generating vs. pumping, it takes a longer time to 'switch modes', because the plant needs to come to a complete stop before changing direction. Figure 26 shows the scheme arrangement for a binary set.[39]

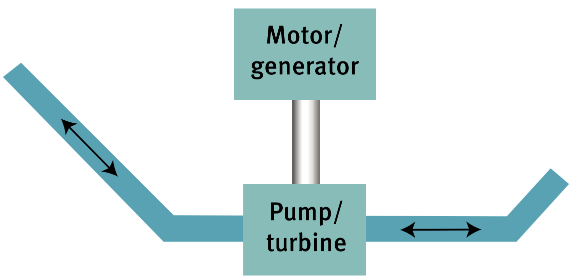


Figure 26: Schematic of a binary set

38. Webb K (n.d.), Section 3: pumped-hydro energy storage. Available at: http://web.engr.oregonstate.edu/~webbky/ESE471_files/Section%203%20Pumped%20Hydro.pdf
39. Webb K (n.d.), Section 3: pumped-hydro energy storage. Available at: http://web.engr.oregonstate.edu/~webbky/ESE471_files/Section%203%20Pumped%20Hydro.pdf

Size of scheme

A PHES plant's generation and storage capacity depends on the volume of water that can be stored in the upper and lower reservoirs, and the height distance between them.

For convenience, pumped hydro schemes can be categorised as:

- small schemes (typically around 250-500 MW with storage of 4-8 h duration)
- large, long duration schemes (able to operate continuously for >24 h, and typically >1 GW).

It is also possible to have high capacity (power) schemes with a short duration of storage. However, that type of scheme can be conceptualised as multiple small schemes. Long duration schemes are typically less common than small schemes.

Fixed speed vs. variable speed plant[40]

As traditional hydropower generation units must produce electricity at the grid frequency, the rotational speed of the generator and turbine must be constant. This is referred to as 'fixed speed' technology. A key feature of fixed speed plant is that, when pumping, the pumps must be operating at full power. However, when generating, they can vary their output (although with less efficiency the further they get from their design output, as shown in Figure 27[41]).

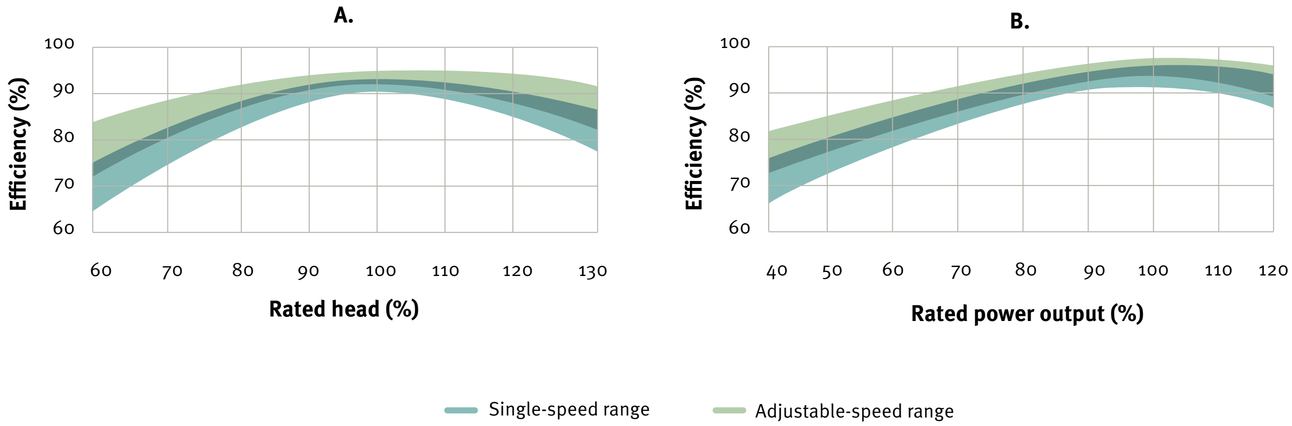


Figure 27: Turbine efficiency vs. (a) the rated head and (b) the rated output power for fixed and variable speed plant adapted from Valavi M and Nysveen A (2018)

One of the most important advances during the last decades has been the development of variable speed systems, which provide several advantages.

- The primary advantage is that the pump power can be controlled.
    - » This allows the plant to operate more flexibly (e.g. it could store energy if there was some surplus generation from VRE, but not enough to justify pumping at full load).
    - » It allows the plant to provide frequency control services in pumping mode.
    - » The additional flexibility can help to reduce the number of starts and stops, which helps to increase the lifetime of machinery.

40. The content in this section has been substantially informed by Valavi M and Nysveen A, Variable-Speed Operation of HydroPower Plants, IEEE Industry Application Magazine September/October 2018. Available at: https://ieeexplore.ieee.org/stamp/stamp.jsp?arnumber=8387741

41. Valavi M and Nysveen A, Variable-Speed Operation of HydroPower Plants, IEEE Industry Application Magazine September/October 2018. Available at: https://ieeexplore.ieee.org/stamp/stamp.jsp?arnumber=8387741

- Hydraulic machines are optimised for a single operating point (the best efficiency point), which is a function of the head, water discharge (i.e. flow rate) and rotational speed. At fixed speeds, deviations in the head and water discharge can lead to reduced efficiency, and increased vibration and cavitation problems.[42]
  If rotational speed can be adjusted, it is possible to:
    - » improve efficiency across the power output range (see Figure 27)
    - » reduce vibration and cavitation problems, resulting in improved reliability, reduced maintenance, and increased lifetime.

While variable speed turbines have advantages, they are generally significantly more expensive than fixed speed turbines (both capital costs for generating units and their larger size adds to excavation costs for underground powerhouses). In addition, the use of multiple fixed-speed turbines in larger PHES facilities offsets much of the flexibility benefits of variable speed machines. For example, the proposed designs for the Borumba Dam PHES incorporate 6-8 turbines of 250-330 MW capacity to deliver the total generation capacity of 2,000 MW. The ability to operate any combination of turbines provides the flexibility to operate close to maximum efficiency in many periods.

There are two different variable speed technologies: doubly fed induction machines (DFIMs) and converter-fed synchronous machines (CFSMs). Each technology has its own strengths and weaknesses.

- DFIMs are the lowest-cost variable speed plant, and the technology is like what is used in most modern wind generators, with an operating pumping range of 70-110 per cent of capacity. The disadvantage of DFIMs is that they can only emulate inertia over a limited range of speeds, do not provide system strength, and have limited ability to provide voltage control.
- CFSMs can respond more quickly than fixed speed plant or DFIMs. Faster response times provide greater capability for frequency compensation, damping of power oscillations, and hence an overall improvement in power system stability. The full-rated converter also provides voltage control capability and can be configured to provide limited system strength. However, when connected via the frequency converter, a CFSM unit can't provide inertia. The disadvantage of CFSMs is the converters are very large and add about 30 per cent to the plant cost.

Figure 28 provides a high-level schematic for each variable speed technology.[43] When considering the CFSM configuration, note that an arrangement can be added that bypasses the frequency converter, allowing the synchronous machine to operate as a traditional fixed speed system.

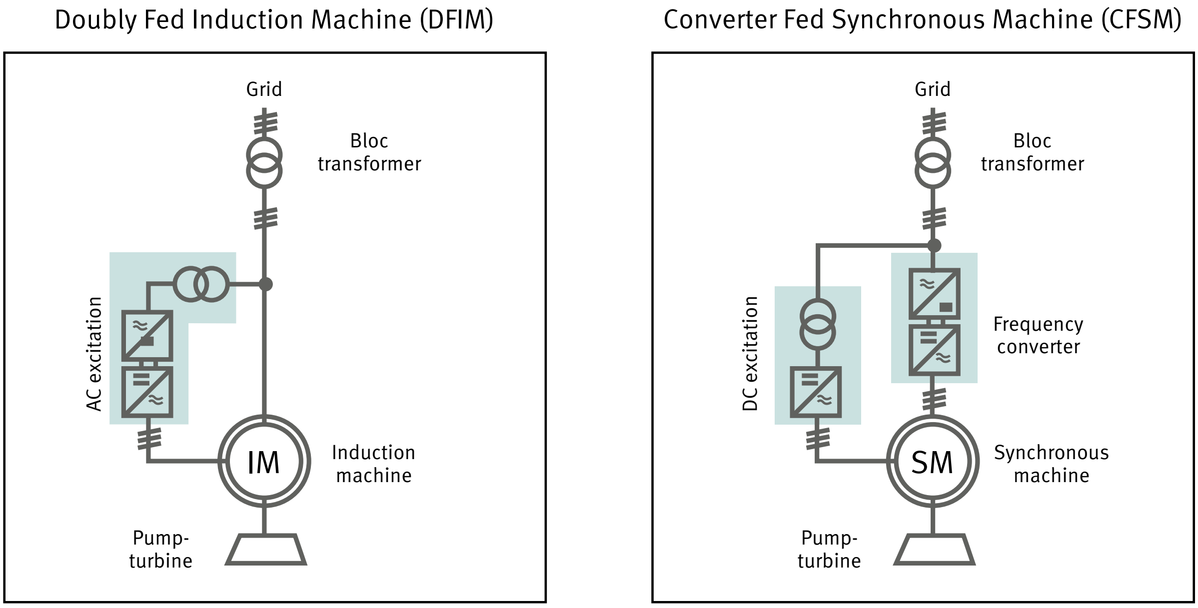


Figure 28: Schematic of DFIMs and CFSMs

42. During operation, the head drops as the upper reservoir drains. Issues related to head variation are more pronounced for lower-head plants with 'steep' upper reservoirs.
43. ABB Switzerland, 2018, Converter Fed Synchronous Machine – Overview, (Presentation)

Table 2: Summary of key technical parameters for PHES.

Technical parameter	Typical value(s)
Power range	Typically, between 20-500 MW per unit, but can be more depending on the site
Dispatchable supply range	Typically, 6 hours up to 30 days (depending on project specifics including water storage, head and generation power rating)
Efficient output range	Generation can typically operate between 30-100 per cent capacity, but with less efficiency the further from the design rating
Efficient charging range	• Conventional fixed speed pumps can only operate at zero or full load • Variable speed pumps can efficiently vary output (70-110 per cent for DFIMs, 30-110 per cent for CFSMs).
Lifespan	About 30 years for electromechanical plant, and 100-200 years for civil works[44]
Start-up time	• Fixed speed pumps and DFIMs can ramp to full output in about 10 seconds if already synchronised, or 2 minutes from standstill (to allow time for synchronising). • The frequency converter means that CFSMs starts 'synchronised' and can ramp to full output in ~10s from stationary.
Efficiency	80 per cent cyclic efficiency
Operational emissions	Zero (assuming access to zero emission recharging electricity). However, this does not include emissions from biomass and organic matter in the reservoirs. Depending on the reservoir location (which impacts temperature, and the quantity/carbon content of biomass) depth (deeper reservoirs typically have more dissolved methane, which is released when the water is exposed to low pressure during generation) and age (older reservoirs typically produce less emissions because the organic matter has already had time to decay), these emissions can vary. However, they are highly site-specific.[45]

Project development features

Location

Like conventional hydroelectricity projects, potential locations for PHES schemes are constrained by geographical and environmental factors. At a high level, PHES schemes are only viable where:

- there is sufficient head (height difference) between the top and bottom reservoirs
- there is sufficient rainfall/catchment to ensure a secure water supply
- social and environmental impacts (e.g. during construction, and as a result of inundating land to create a dam) are acceptable.
- capital costs (which are highly site-specific) are competitive with other storage projects.

The technical, environmental and commercial characteristics vary substantially between potential prospective sites. The latter section of this report provides further detail on the process undertaken as part of this study to identify the Queensland sites most appropriate for large-scale, long duration PHES schemes.

Project lead time

Construction and development durations are highly dependent on individual site factors. In general, smaller schemes with small (and/or brownfield) site footprints can theoretically be designed, approved and constructed in shorter timeframes, compared to other sites.

Timeframes range from a best-case 4.5 years (for small, brownfield project) to upwards of 10 years (for a large project with underground works and large environmental impact).

Other

It's worth noting that PHES projects can partially underwrite dams that would have broader benefits to other water users. Conversely, PHES schemes rely on a secure water supply to counter evaporative and/or seepage losses.

44. GHD (2018), AEMO costs and technical parameter review, p. 95. Available at: https://www.aemo.com.au/-/media/Files/Electricity/NEM/Planning_and_Forecasting/Inputs-Assumptions-Methodologies/2019/9110715-REP-A-Cost-and-Technical-Parameter-Review---Rev-4-Final.pdf

45. Song et al (2018), Cradle-to-grave greenhouse gas emissions from dams in the United States of America. Renewable and Sustainable Energy Reviews 90 (2018) 945-956. Available from: https://doi.org/10.1016/j.rser.2018.04.014

System reliability

The speed at which PHES can start depends on whether the generating unit is fixed speed, DFIM or CFSM. Ramp rates tend to be about 10 per cent of capacity per second for all unit types.

Once operational, PHES schemes can provide dispatchable supply (with varying efficiencies at different outputs) for as long as they have sufficient water. Long duration schemes have two important reliability benefits over short-duration schemes:

- They can provide dispatchable supply when shorter-duration storages would otherwise be out of energy (e.g. in the event of a prolonged period of low renewable generation).
- On low-demand days when shorter-storages have already charged to 100 per cent capacity, long duration storage would be able to provide dispatchable demand to take advantage of cheap prices.

The drawback of large scale, long duration schemes is that it is difficult to find sites with attractive physical characteristics.

System security

The system security benefits that a PHES unit can provide depends on the type of pumping/generating technology (i.e. fixed speed, DFIM or CFSM). PHES can provide the following system services:

- Fast start capability
- Variable generation
- Variable pump demand
- Frequency control
- Voltage control
- System strength
- System inertia
- Gird formation
- Black start

Cost

It is inherently difficult to make generalisations about PHES capital costs because they vary substantially between sites. In general, a site with a relatively large head, relatively small dam walls, and a relatively short distance between the reservoirs will have a cheaper specific cost (capital costs per MW) compared to another site.

It is generally more difficult to find long duration sites with attractive capital costs. This is because, for a given head, the reservoirs would need to be larger to provide a longer storage duration. Unless the geography is particularly advantageous, this requires larger dam walls to be built.

Because of this, when generalising PHES costs, estimates for the capital costs of large-scale, long duration PHES can be above the cost for small-scale PHES.

This is not always true for specific sites (e.g. if they have exceptional physical characteristics). Therefore, costs are not provided given the difficulty in providing representative cost estimates for PHES sites identified in Queensland.

Summary

PHES can provide dispatchable supply for as long as it has sufficient water in the top reservoir. Similarly, it can provide dispatchable demand if its top reservoir isn't full. This makes long duration PHES more valuable because it can provide dispatchable supply for longer periods and can provide strategic energy reserves.

However, sites that can host economically viable, long duration PHES are inherently rare, because they need more attractive technical characteristics.

The system security benefits of a PHES depend on the type of generating units (i.e. fixed speed, DFIM or CFSM), as summarised in Table 3. The below table summarises the system benefits of fixed-speed PHES.

Table 3: Summary of PHES's ability to provide key services

Technology service required	Comments
System reliability	
Peak dispatchable supply (2 to 4 hrs)	PHES can operate over short periods to act in a peaking capacity
Part-day dispatchable supply (4 to 8 hrs)	PHES can provide firming of 2-12 hours and often so long as dam capacity and levels can accommodate.
Full-day dispatchable supply (8 to >12 hrs)	PHES can dispatch in excess of 12 hours so long as dam capacity and levels can accommodate. However, consistently generating above about 10 hours a day would require the pumps to be working at or above nameplate capacity for the rest of the time.
Strategic reserves (Potentially >2 days)	PHES can potentially dispatch for many days. However, this is dependent on a range of factors (e.g. scheme size, recent rainfall in the catchment and/or drought conditions).
Peak dispatchable demand (2 to 4 hrs)	As long as there is sufficient water and 'space' in the upper reservoir, can quickly provide dispatchable demand.
Part-day dispatchable demand (4 to 8 hrs)	As long as there is sufficient water and 'space' in the upper reservoir, can quickly provide dispatchable demand.
Full-day dispatchable demand (8 to >12 hrs)	As long as there is sufficient water and 'space' in the upper reservoir, can quickly provide dispatchable demand.
System security	
Control of frequency (ms to mins)	When generating below full capacity, can ramp at ~10 per cent of capacity per second to increase or decrease output to provide frequency control. Can also trip within milliseconds if a large frequency reduction is necessary. When off/pumping, can provide a crude 'on-off' frequency control, which is limited by the time it takes to start/trip (<3 min/1 second). When in 'synchronous condenser mode', can provide maximum frequency raise by ramping up to full capacity within 10 seconds.
Control of voltage (ms to mins)	Can provide voltage control within seconds by changing reactive power output when generating, pumping or in synchronous condenser mode
System strength (ms to secs)	Provides system strength when pumping, generating and operating in synchronous condenser mode. However, when pumping, the contribution is less.
Inertia (ms to secs)	Provides inertia when pumping, generating and operating in synchronous condenser mode. However, when pumping, the contribution is less.
Black start capability (Self-start)	Larger PHES schemes can provide black start services when combined with a small on-site diesel generator to supply auxiliary loads during black start events. Smaller PHES scheme will not have sufficient capacity or energy to successfully reenergise the transmission system and restart other generators.
Grid formation capability (ongoing)	Fixed speed and CFSM plant automatically provide grid formation services (since they use synchronous generators), but only when they are synchronised and generating. When operating as a synchronous condenser they do not provide grid forming as they do not provide frequency regulation without a mode change. When pumping, CFSMs can also provide gird formation services with appropriate configuration of their control systems

Battery energy storage system (BESS)

Overview

Batteries utilise electrochemical cells which can store and discharge energy. There are a range of different chemical processes that can be used in batteries, with varying levels of technical maturity.

- **Lead-acid batteries** are a very mature form of battery technology. They are low cost and are used in vehicles and off-grid power systems. They have cycle efficiencies of between 70-90 per cent, and average lifetimes of 5 to 15 years, or 1,500 cycles.
- **Flow batteries** consist of a flowing electrolyte that moves between a storage tank and a reaction chamber. Due to their larger size, flow batteries are better suited for commercial applications. They have very long-life cycles (between 10,000 and 100,000 cycles), cycle efficiencies of 65 to 85 per cent and short response times.
- **Lithium-ion (Li-ion)** batteries are used extensively in portable electronics and electric vehicles. They have a lifetime of 10 years or 6,000 cycles, cycle efficiencies of 90-95 per cent and are modular technology meaning energy storage capacity can be expanded easily. Costs for Li-ion batteries have reduced over recent years, partly due to improving economies of scale and electric vehicle technology advancements.
- Many other battery technologies exist but are in earlier stages of development and readiness for deployment.

Regardless of the technology used, batteries that provide energy storage for the power system consist of three components: a battery, an inverter (which converts DC to AC) and a connection to the grid. With prices dropping, Li-ion is expected to be the dominant battery technology adopted in the National Energy Market (NEM) moving forward.

Large-scale BESS are just beginning to see global deployment. As a result, it is likely that there will be cost and technological improvements going forward.

Table 4: Technical parameters of battery energy storage

Technical parameter	Typical value(s)
Power range	10 to 200 MW
Dispatchable supply range	Technically limited only by space, materials and network capacity, but currently commercially viable for 1 to 2 hours
Efficient output range	Can operate efficiently over full output range above about 20 per cent
Lifespan	10 years (although this would be less if the battery was cycled heavily)
Start-up time	Almost instantaneous
Efficiency	90 per cent
Operational emissions	0 (assuming access to zero-emission electricity)

Battery costs

The cost of batteries has fallen in recent years but remains significantly higher than large scale PHES in terms of stored energy, as shown in the below Figure 29.[46]

While the cost of lithium-ion batteries can be expected to drop further in the future, the Australian Energy Market Operator and CSIRO GenCost modelling expect battery cost reductions to slow post 2030. The National Renewable Energy Laboratory (USA) has forecast the cost reductions to reach a range of 28-75 per cent by 2050, with only the high end of this forecast making the build cost per MWh competitive with current large scale long duration PHES.[47] Any comparison of cost competitiveness needs to also consider economic life, round trip efficiency and degradation.

46. *Updated with 2022 data* – CSIRO (2022), GenCost 2021-22. Available at: https://publications.csiro.au/publications/publication/PIcsiro:EP2022-2576

47. *Updated with 2022 data* – NREL (2021), Cost Projections for Utility-Scale Battery Storage: 2021 Update. Available at: https://www.nrel.gov/docs/fy21osti/79236.pdf

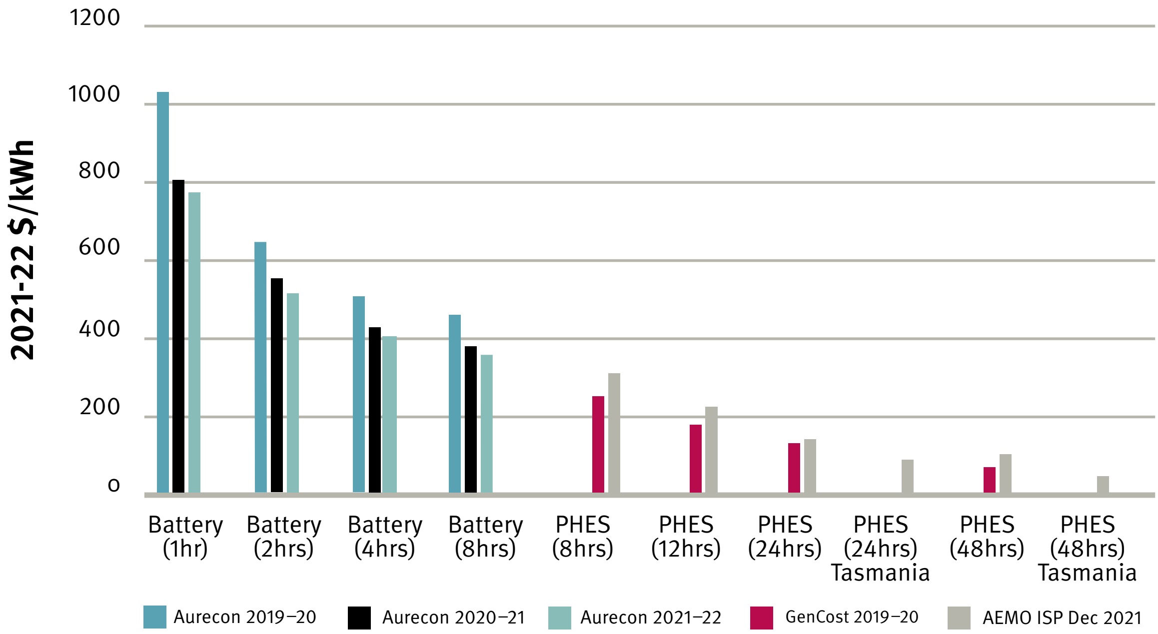


Figure 29: Comparison of cost changes for battery vs. PHES, source CSIRO GenCost 2021-22[48]

However, even with these reductions there remains uncertainty as to the capacity of lithium resources and battery manufacturing to provide the scale of the required storage needs, and AEMO cost projections show that it is unlikely that batteries will become cost-competitive in time to be considered a viable alternative for the deployment of large-scale long duration storage required before 2035 (see Figure 30).

Updated 2022 AEMO capital cost forecasts for batteries are shown in Figure 30.

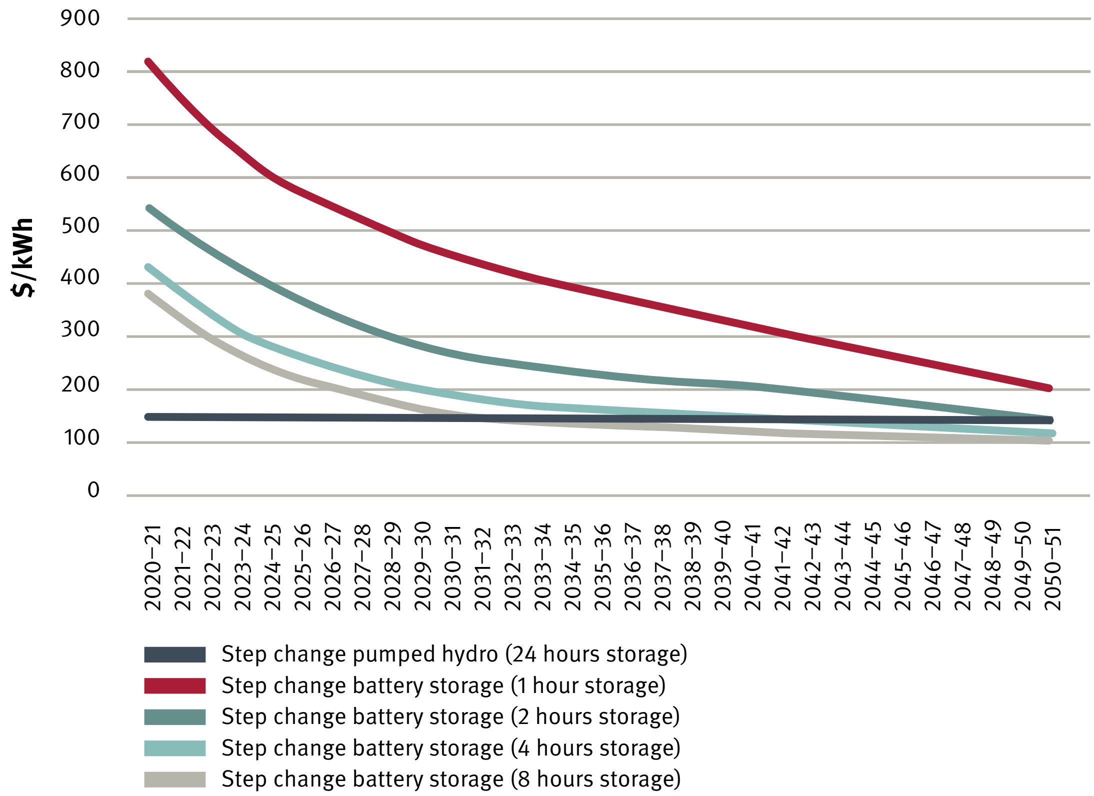


Figure 30: 2022 CAPEX cost for energy storage technologies to 2050, source AEMO ISP 2022[49]

48. *Updated with 2022 data* – CSIRO (2022), GenCost 2021-22. Available at: https://publications.csiro.au/publications/publication/PIcsiro:EP2022-2576

49. *Updated with 2022 data* – AEMO (2022), 2022 Integrated System Plan. Available at: https://aemo.com.au/en/energy-systems/major-publications/integrated-system-plan-isp/2022-integrated-system-plan-isp

Project development features

BESS have relatively few limitations to where they can be installed. Primarily, they need to be in an environment where the batteries can operate within their designed temperatures. To improve commerciality, it is important that they are also in a grid location with access to surplus energy, and with low connection costs.

The geographic footprint depends on the amount of storage. Because batteries are modular, BESS can be designed to a range of different scales. The Hornsdale Power Reserve in South Australia (100MW, 129 MWh)[50] was the world's first big battery, and for a period was the largest battery installation in the world. This system covers about a hectare – equivalent to around 100m2/MW, or 78m2/MWh.

The regulatory approval and design process for a 100 MW Li-ion BES system typically takes 12-months, and construction time is less than 12 months.[51]

Compared with the other technologies previously discussed, BES systems' 10-year lifespan is relatively short. As a result, battery disposal and/or recycling is an issue under investigation.

All battery technologies can be deployed at scale by adding more batteries. For example, one typical Tesla Megapack can deliver 0.8 MW/3 MWh of storage for approximately $1 Million USD. These units can then be combined to provide greater capacity (100 units would supply 80 MW/ 300MWh).

Flow batteries are currently less widely deployed than Lithium technologies, due to their higher cost (capital cost up to double solid batteries) and weight making them unsuitable for some applications. The primary advantage of flow batteries is much lower degradation compared to solid batteries, with flow batteries expected to have a lifetime of 20 years or more compared to around 10 years for solid batteries.

System reliability

BESS units are currently commercially viable at providing dispatchable supply and demand (i.e. storage) for typically up to 2 hours. This is particularly useful for VRE generators seeking to 'smooth' the shape of their generation (e.g. to account for temporary cloud cover over a solar farm). BESS are technically capable of providing longer durations of energy storage. However, adding storage capacity (i.e. by stacking battery units) is currently uneconomical compared with other technologies.

Battery costs are predicted to fall, and the extent of this cost reduction will dictate how competitive batteries become over longer storage durations.[52] However, BESS will face challenges to be competitive above 8 hours, due to:

- competing demand for batteries in the transport sector (which may limit the extent capital costs fall, since there may be a limited supply of materials required to manufacture the batteries)
- batteries' tendency to self-discharge, which makes them less efficient to store energy for long periods of time.

Batteries can provide fully dispatchable power and, depending upon the inverter, can quickly operate over the full of their output range (efficiently above about 20 per cent). For instance, a 100 MW BES system with a modern inverter can provide its full 100 MW within 0.5 seconds. The output is also controllable down to around 20 per cent or lower stable operating levels.

System security

BESS are inverter-connected, so do not inherently provide system strength and system inertia. Control systems in older inverter systems will control current outputs within the thermal capacity limitations of the inverter, and this action has the effect of reducing system strength.

However, modern inverters are now available with control systems with the capability to mimic the response of synchronous machines to frequency and voltage disturbances, with some features faster. Without sophisticated central control systems, faster response times come with downsides in managing control system stability (e.g. fast responses could cause voltage oscillations within intra-areas of the network).

50. Note, the Hornsdale Power Reserve has since expanded to 150MW/194MWh

51. GHD (2018), AEMO cost and technical parameter review, Report Final Rev 4, p. 71. Available at: https://www.aemo.com.au/-/media/Files/Electricity/NEM/Planning_and_Forecasting/Inputs-Assumptions-Methodologies/2019/9110715-REP-A-Cost-and-Technical-Parameter-Review---Rev-4-Final.pdf

52. *Updated with 2022 data* – CSIRO (2022), GenCost 2021-22. Available at: https://publications.csiro.au/publications/publication/PIcsiro:EP2022-2576

Developments in inverter technology and the use of converters typical of high-voltage direct current (HVDC) systems have now achieved the ability to emulate synchronous machine inertia. As discussed, this 'synthetic inertia' is effectively a very fast response of active power injected into the network if there is a sudden loss of generation on the network. This is an extension of fast frequency response (FFR), which allows BES systems to provide fast FCAS services.

In addition to synthetic inertia, several manufacturers are developing inverters that can provide 'fast fault current' with some additional magnitude and duration required to support system strength (equivalent to two times the full system load for one or two seconds). Such systems could supplement system strength as an alternative to the widespread installation of synchronous condensers.

The energy stored in the battery to which these inverters are connected enables the inverter to provide fault current (as a multiple of maximum continuous rating (MCR) for similar durations to synchronous condensers).[53] However, to provide the same fault current contribution as a synchronous condenser, a BESS would need to provide an MCR of around five, which means the inverter would need to be significantly oversized. However, for efficiency and cost reasons, inverters are typically designed to have an MCR the same as the nameplate capacity of the battery.

BESS currently don't have standalone black start capability because they do not provide sufficient energy or reactive power capability to restart other generators and energise portions of the transmission network. However, BESS are sometimes used in combination with OCGTs to provide black start services. In this scenario the BESS supplies the auxiliary loads at the OCGT, allowing it to start up without any external power supply. The OCGT can then energise portions of the transmission network and other power stations.

BESS can provide grid formation services, utilising grid forming inverters. Currently this technology is most deployed in micro-grids that are disconnected from the main power system. However, grid forming inverters have not yet been successfully deployed and operated in parallel with a main power system.

Advantages of BESS

While batteries are higher cost than PHES, and likely have shorter lifetimes, they do have advantages which mean they will play an important role in Queensland's energy system:

- **High return efficiency** – batteries generally have a high return efficiency at around 90 per cent. This means that a battery will be able to discharge 90 per cent of stored energy back into the system. Based on operation this efficiency may reduce significantly over the technical life of the asset.
- **Locational flexibility** – as batteries can be physically located almost anywhere across the network, they can be located close to where their services are required, minimising the need for major transmission infrastructure, and enabling them to offer local network support.
- **Speed of deployment** – batteries can be deployed quickly due to ease of approvals, smaller scale, lack of major new transmission assets and a competitive market of suppliers.
- **Fast response services** –batteries can be utilised to provide micro-second responses to the network.
- **Social licence** – due to their small environmental footprint, batteries enable the rollout of storage without impacting the social licence for large-scale storage.
- **Incremental deployment** – the modular design and locational flexibility of BESS means that they can be deployed with less dependence on long-term forecasts regarding market and technological changes, and thereby could be deployed in an incremental manner as required.

These characteristics make batteries highly suited for smaller scale and faster acting applications, such as managing short duration fluctuations in renewable supply, network support and some ancillary services.

Summary

Because BESS can provide fast, dispatchable supply and demand, they are ideally suited for short term energy arbitrage and to smooth VRE generation shapes.

However, BESS are limited in their commercially viable storage duration – currently in a range up to 8 hours. The extent to which capital costs fall will dictate the length of storage that BESS can provide in the future. However, it is unlikely that they will ever be able to provide commercial storage longer than about 8 hours.

53. This duration is subject to thermal constraints of the power semiconductor switches, typically devices called Insulated Gate Bipolar Transistors (IGBTs).

BESS are already well-placed to provide frequency control services. With further development, they may also be able to contribute to the equivalent of system inertia. Advancements in inverters and control systems may also allow batteries to provide system strength and voltage control services in the future, but this is not yet commercially viable.

Conventional hydroelectricity

Overview

Conventional hydroelectricity is the most mature form of renewable energy generation, originally seen in milling using water wheels. It does not include pumped hydroelectricity, which is discussed in the next section of this paper. Globally, there is around 1,100 GW of installed capacity.[54]

Hydroelectricity harnesses the kinetic energy of water flowing down a height differential. The water is used to drive a turbine, which in turn drives an electric generator. There are two main forms of conventional hydropower configurations.

- In reservoir storage, the height differential between the dam water surface and a stream below is created by a dam which also provides for the storage of a significant amount of water (which may also be used for irrigation or drinking water). A large amount of storage means the generation is more certain, and less vulnerable to fluctuations in river flow. However, it has a greater impact on river morphology and ecology.
- In run-of-river generation, a weir is used to divert available river flow to the power station at an elevation well below the weir, with only perhaps daily storage impounded. The generation is therefore much less certain, relying on the seasons and immediate yield of the catchment.

Queensland has seven conventional hydroelectric plants, summarised in Table 5.

Table 5: Conventional hydroelectric plants in Queensland

Generator	Capacity (MW)	Type of plant
Barron Gorge	66	Run-of-river
Kareeya	86	Reservoir storage
Koombooloomba	7.3	Reservoir storage
Tinaroo	1.6	Reservoir storage
Paradise Dam	2.8	Reservoir storage
Wivenhoe	4.7	Reservoir storage
Somerset	4.3	Reservoir storage

It is important to note that all forms of conventional hydroelectricity rely on available water upstream, which can be released. Once this water runs out, no electricity can be generated. In this sense, water can be considered as the 'fuel' of conventional hydroelectric generation.

The remainder of this section only considers reservoir storage. The rationale is that run-of-river is not firm, so cannot provide the same degree of dispatchable supply that will be necessary to complement VRE in a net-zero emissions world.

Table 6: Key technical parameters for reservoir storage

Technical parameter	Typical value(s)
Power range	500 kW to 1,000 MW
Dispatchable supply range	Potentially days (limited by available water supply)
Efficient output range	Can operate continuously from 30-100 per cent output
Lifespan	100+ years for civil works, and 30 to 50 years for the electromechanical plant
Start-up time	If already synchronised to the grid, typically 10s; if not synchronised, <2.5 minutes
Efficiency	Modern hydroelectric generating units have efficiency >94 per cent. However, this only impacts design capacity (not operating costs), since the fuel (i.e. water) is considered to be zero cost
Operational emissions	Some emissions from organic decomposition in the reservoir

54. REN21 (2019) Renewables 2019 Global Status Report. Available at: https://www.ren21.net/wp-content/uploads/2019/05/gsr_2019_full_report_en.pdf

Project development features

Hydroelectric plant is heavily constrained by geographical/environmental factors.

- They can only be situated in a location with sufficient river flow and upstream rainfall.
- Storage schemes significantly impact on river ecology (both upstream and downstream), and interrupt migratory aquatic species. Fishways are challenging and expensive, with a high probability of limited success for high head dams which are better for hydro generation.

Queensland's highly variable river flows, and arid inland does not favour conventional hydroelectric generation compared to some other locations in Australia.

Numerous studies were conducted during the 1980s and 1990s on developing further hydroelectric power stations in Queensland, with most of the proposed sites in Far North Queensland. Stages 1 and 2 of the Queensland Hydro Study reviewed these studies and conducted further site shortlisting for potential conventional hydroelectric projects. Most of the conventional sites proposed in earlier studies are now not possible due to the declaration of national parks.

Due to environmental impacts, the lead time for hydroelectricity projects is very long. The estimated lead time for large plant is 10-15 years (5-8 years for regulatory approval, and a further 5-7 years for construction).

System reliability

Hydroelectric generating units are relatively flexible.[55]

Traditional generators are synchronous. If they are already synchronised to the grid (i.e. if they are generating or in 'synchronous condenser mode'), then they can ramp at around 10 per cent of capacity per second. If they are starting 'cold', then this takes longer because the plant needs ~2 minutes to synchronise to the grid before ramping.

Once operational, conventional hydroelectric schemes can provide dispatchable supply (between 30-100 per cent of capacity) for as long as they have sufficient water. This depends on the particular scheme and recent events (e.g. whether it has been operated recently, whether there has been recent rainfall, or whether river flows have been reduced due to drought). For a large scheme with good site characteristics, reservoir storage can potentially provide days of dispatchable supply.

Conventional hydroelectric generation cannot provide dispatchable demand because it can't store electricity from the grid.

System security

As with all synchronous generation discussed in this report, traditional hydroelectric generators provide inertia, system strength, and voltage control services. If they have been designed to be able to operate in 'synchronous condenser mode', they can provide these services without consuming water.

If generating, traditional hydroelectric generators can ramp at approximately 10 per cent of capacity per second, which allows them to provide relatively fast frequency response (well within the current 6 second FCAS market). If in synchronous condenser mode, the plant can start generating in 1-2 seconds, before ramping (which also allows it to provide 6-second FCAS, in addition to slower FCAS services). The technology has been specifically designed to enable this feature.

Traditional hydroelectric generators automatically provide grid formation services (since they are synchronous). They can also provide black start services when combined with a small on-site diesel generator.

Cost

With an existing dam with suitable head, or suitable run of river flow and head, hydroelectric schemes can be relatively inexpensive, even for low-capacity units of a few MW.

Hydroelectric generator units have high upfront capital costs, but zero fuel costs, and reasonably low (and mainly fixed) operating costs. Construction (i.e. capital) costs would be expected to increase in the future as potential sites are very limited.

55. Flexibility depends on the type of generating unit. Broadly speaking, the generator could be a traditional fixed speed unit, or a variable speed unit. For conventional hydroelectric generators, this report only considers fixed speed units, since the costs of variable speed units tend to outweigh the benefits, unless the scheme also involves pumping.

Summary

Theoretically, a reservoir storage hydroelectricity scheme would be well-placed to provide a range of crucial system services as Queensland transitions to net-zero emissions. However, this assumes that the hydroelectricity scheme exists and has a sufficient water supply.

Queensland has limited opportunities for commercially viable, standalone conventional hydroelectric plant.

Table 7 summarises key system services that conventional hydroelectricity could provide based on traditional fixed speed generating units.

Table 7: Summary of conventional hydroelectricity's (reservoir storage) ability to provide key services

Technology service required	Comments
System reliability	
Peak dispatchable supply (2 to 4 hrs)	Hydroelectricity can operate over short periods to act in a peaking capacity
Part-day dispatchable supply (4 to 8 hrs)	Hydroelectricity can provide firming of 2-12 hours and often so long as dam capacity and levels can accommodate.
Full-day dispatchable supply (8 to >12 hrs)	Hydroelectricity can regularly dispatch in excess of 12 hours so long as dam capacity and levels can accommodate.
Strategic reserves (Potentially >2 days)	Reservoir storage can potentially dispatch for many days. However, this is dependent on a range of factors (e.g. scheme size, recent rainfall in the catchment and/or drought conditions)
Peak dispatchable demand (2 to 4 hrs)	Conventional hydroelectricity does not involve a pump, so cannot provide dispatchable demand.
Part-day dispatchable demand (4 to 8 hrs)	Conventional hydroelectricity does not involve a pump, so cannot provide dispatchable demand.
Full-day dispatchable demand (8 to >12 hrs)	Conventional hydroelectricity does not involve a pump, so cannot provide dispatchable demand.
System security	
Control of frequency (microseconds to minutes)	Hydro generation provides FCAS, at least five-minute FCAS, and potentially 6-second FCAS if generating or operating as a synchronous condenser.
Control of voltage (ms to mins)	Hydro generation can source and sink significant reactive power to contribute to strong voltage control of the power system. Operating as synchronous condensers when dewatered means they can provide this service without consuming water.
System strength (ms to secs)	Traditional hydroelectric plant provides system strength when generating or operating as a synchronous condenser.
Inertia (ms to secs)	Traditional hydroelectric plant provides inertia when generating or operating as a synchronous condenser.
Black start capability (Self-start)	Hydroelectric generators can provide black start services when combined with a small on-site diesel generator to supply auxiliary loads.
Grid formation capability (ongoing)	Traditional hydroelectric generators automatically provide grid formation services (since they are synchronous), but only when they are synchronised and operating as a generator. When operating as a synchronous condenser they do not provide grid forming as they do not provide frequency control. The ranking is lower than PHES reflecting the lower capacity factor achieve by traditional hydroelectric generators.

Flywheels

Overview

Flywheel energy storage (FES) systems utilise a spinning flywheel rotor to store mechanical energy.

When a FES system injects active power into the grid (by controlling electrical fields in the rotor) the rotor slows down. Conversely, when it is 'charging', the rotor speeds up. The rotor typically spins in a vacuum to improve efficiency.

A FES system usually operates continuously in a mostly charged state, ready to inject active power. This allows it to provide frequency control services or load levelling as appropriate.

Flywheel systems have been used since the early 20th century and are technologically mature. For modern FES systems, a bi-direction power converter is used to connect the flywheel to the grid, so that the speed of the rotor is deliberately not synchronised with the frequency of the power system. As a result, a FES by itself does not provide inertia. This is different to when a flywheel is coupled to a synchronous condenser.

Table 8: Key technical parameters of FES systems.

Technical parameter	Typical value(s)
Power range	500 kW to 20 MW
Dispatchable supply range	Usual storage is in tens of minutes with a theoretical maximum storage duration of 4 hours
Efficient output range	Can operate efficiently over full output range
Lifespan	>20 years or 100,000 cycles
Start-up time	As low as 2 seconds from an operating start
Efficiency	85 per cent round trip efficiency
Operational emissions	0 (assuming access to zero-emission electricity charging)

Project development features

FES systems require around 30m^2 per 5 MW of capacity.[56] They have few site-specific requirements, which allows them to be placed in many locations across the grid. Because of their versatility of placement and low capacities, FES systems face relatively low regulatory and environmental hurdles. The regulatory approval and design process for a small FES system takes around 12 months to complete, while construction takes around 11 months.[57]

Because of physical size limitations of individual units, many flywheels need to be operated in parallel to provide meaningful capacity. For example, the Beacon Power Hazle Spindle is a 5 MWh (20 MW over 15 minutes) FES system in Pennsylvania. It was built in 2011 using 200 modular flywheels to provide frequency stability and support renewable generation.

System reliability

Due to FES systems' short duration, they tend to be used only for frequency stability. FES systems have some potential to provide dispatchable supply/demand for 5 to 15 minutes, but little potential for anything longer. Larger systems made of multiple modular flywheel units could provide storage up to several hours, but are much more expensive than other technologies (e.g. batteries) that could provide the same services.

System security

Flywheels can provide fast dispatchable supply or demand (as low as two seconds) when operating. This allows it to provide FCAS relatively quickly.

FES systems effectively draw power from the inertia stored within rotating masses (a mechanism which is used by other technologies to provide inertia, system strength and voltage control). However, FES technology has limited ability to provide these services, as the FES system is typically connected to the grid via an inverter. This is distinct from a synchronous condenser connected to a flywheel. While it is technically possible for the FES system's inverter to be designed to provide these services, this is unlikely to be commercially viable.

56. GHD, Haughton Solar Farm Technology Assessment, August 2018, p. 19.
57. These timeframes are based on the Hazle Spindle plant in the USA, and the approval process for synchronous condensers in Australia. Source: U.S. Department of Energy, Hazle Spindle, LLC, August 2013. Available at: https://www.energy.gov/sites/prod/files/2015/05/f22/Beacon-Power-Flywheel-Aug2013.pdf

FES systems are unable to store enough energy to provide black start capability. As FES systems are not synchronised to the grid frequency, they are not well placed to provide grid formation unless they have advanced inverters and control systems. Both black start and grid formation would likely be uncommercial given FES systems' scale.

Cost

Cost for a large flywheel plant (20 MW unit with 15 minutes of storage capacity) is estimated at around $3.7million/MW; however, there is potential for costs to reduce in the future as lifecycles improve.[58] Flywheel technology is modular, so increasing capacity by adding units does not significantly reduce the levelised cost of storage. The fixed operating costs for flywheels primarily consist of the ongoing long-term maintenance of the rotating plant units.

Summary

FES systems are well placed to provide FCAS, and minutes of dispatchable supply and/or demand (which is arguably a type of FCAS). However, they have substantial limitations: their storage range is measured in minutes, they do not scale well, and they are relatively expensive. FES systems will increasingly compete with batteries to supply FCAS. Although costs may come down, the cost trajectory of batteries is likely to come down even further. As a result, FES systems are unlikely to remain competitive in the future.

That said, there are advantages of connecting an FES system with a synchronous condenser, which may provide a niche for flywheels.

Synchronous condensers

Overview

Synchronous condensers were common in the early start-up of electricity networks in the 1950s and 1960s to provide required system security. With the gradual addition of larger power generators, the need for synchronous condensers declined. However, the technology is proven, and over a century old.[59]

A synchronous condenser operates in a similar way to a large synchronous electric motor with no mechanical load attached, or an electric generator with no turbine (or fuel) available to drive the generator. The machines are synchronised to the system frequency and typically operate continuously freely spinning. This requires a continuous supply of energy (to account for losses). As with all synchronous machines, the rotor and connected mass provide inertia and system strength (with fault current typically 3-5 times the rated current).[60]

To provide technically compliant system strength, the spinning component of a synchronous condenser requires a base level of physical inertia. However, a synchronous condenser can be equipped with a larger flywheel connected to the machine rotor. Compared to what the synchronous condenser could provide alone, adding a flywheel:

- increases the machine's total inertia due to the additional spinning mass (which is the main benefit)
- provides a small increase in fault current
- extends the duration for which the machine can provide fault current, which allows more time for a protection system to 'clear' the fault (a relatively small advantage, since protection systems should be designed to clear the fault before this extra duration would be necessary).

The incremental cost of adding a high-inertia flywheel is only a small component (around 3 per cent) of total costs.[61]

Grid-scale synchronous condensers are typically 70-300 MVAr[62] (sometimes expressed as MVA, because a synchronous condenser's total output is almost all reactive power) and can provide substantial inertia if connected to a flywheel.

58. IRENA (2017), Electricity Storage and Renewables. Available at: https://irena.org/-/media/Files/IRENA/Agency/Publication/2017/Oct/IRENA_Electricity_Storage_Costs_2017.pdf
59. AEMO (2019), In sync: how the revival of 100 year old technology supports the power system. Available at: https://aemo.com.au/
60. System strength is generally measured by the three-phase fault level, expressed in MVA, which is the fault current multiplied by the system voltage.
61. Electranet (2019), *Addressing the system strength gap in SA*. Available at: www.electranet.com.au/wp-content/uploads/2019/02/2019-02-18-System-Strength-Economic-Evaluation-Report-FINAL.pdf
62. Electrical power generator output into the Grid can be resolved into two components, real power (measured in megawatts (MW)) and reactive power (measured in megavoltamperes reactive (MVAr)). MVAR is the key to maintain grid voltage and thus grid stability.

Project development features

Synchronous condensers have a range of attractive features. They have:

- a small geographical footprint and very few limitations as to where they can be connected
- a relatively short lead-time (roughly two years split up into a one-year design and regulatory approval process, and one year for construction)
- no emissions (assuming the power used to excite the stator is derived from renewable sources).

System reliability

Synchronous condensers do not contribute to system reliability because they cannot inject or absorb active power into the system for sustained periods. Their primary purpose is to provide system security benefits (discussed below).

System security

Synchronous condensers can provide active compensation, (i.e. can compensate reactive power as needed in the system) to assist with voltage control. Other technologies (which this report does not consider in detail) that can also provide active compensation are static voltage-ampere compensators (SVCs) and static synchronous compensators (STATCOMS).

The cost of synchronous condensers is approximately twice that of SVCs and STATCOMs. However, in addition to active compensation, synchronous condensers also contribute directly to the system strength at their connection points. In other words, as well as providing an ability to assist in the control of the voltage at its connection point, a synchronous condenser also increases the system strength in that part of the power system, which inherently resists changes in voltage.[63]

Synchronous condensers also provide inertia when they are operating. However, the amount of inertia is relatively low unless the synchronous condenser is also connected to a flywheel.

Except for the 'automatic' burst of active power as part of the inertial response, synchronous condensers cannot inject/absorb active power because they don't have an energy resource to maintain a set power output. As a result, they are not suitable for FCAS services.

Synchronous condensers cannot provide black start or grid formation services.

Cost

Capital installed costs are around $500,000 to $750,000 (with a flywheel) per MVAr (based on a 70 MVAr unit) for the machines, housing and auxiliary equipment. Annual operating costs are typically fixed and around $4,500 per MVAr. Operating costs are dominated by the cost of electrical losses operating the machines continuously connected to the system.

Summary

Synchronous condensers are not designed to provide system reliability. However, they are very well-placed to provide system strength, voltage control and inertia (particularly when connected to flywheels). They have relatively low costs, can be strategically located in network locations that require the most support, and can be designed, approved and constructed within two years.

As a result, synchronous condensers have the characteristics and scale to meet future system strength and inertia requirements.

Concentrated solar thermal

Overview

Concentrated solar thermal (CST) generation focusses the sun's radiation to produce heat. This heat is either immediately used to convert water to steam (which drives a turbine) or stored in a thermal storage system for later use.

63. AEMC (2017), Draft Rule Determination: National Electricity Amendment (Managing power system fault levels) Rule 2017. Available at: https://www.aemc.gov.au/sites/default/files/content/7cc0370d-7447-4618-a181-f5216cef89b7/ERC0211-Managing-power-system-fault-levels-draft-determination-FOR-PUBLICATION.pdf

The three most advanced forms of solar collector technologies are:

- central receivers (also known as a 'power towers')
- parabolic troughs
- linear Fresnel reflectors.

All technologies use mirrors to focus solar radiation onto a focal point which warms a heat transfer medium (usually molten salt) during the day.

A central receiver system uses flat, two-axis sun-tracking mirrors (also called heliostats) to concentrate solar radiation onto the central receiver, which is mounted on a tower. The heliostats track the sun throughout the day to keep the solar radiation concentrated on the tower. The receiver contains a heat transfer medium which is most commonly molten salt. The molten salt is kept in a 'cold' tank at 290°C and then pumped out of the cold tank, through the receiver (where it is heated to 565°C) and stored in a 'hot' tank. It is this hot tank that powers the steam generator.

Parabolic trough systems concentrate solar radiation on a focal receiver that runs the length of the mirrored trough. Thousands of parabolic trough collectors can be used in a large plant and are single axis to track the trajectory of the sun. As for the central receiver, a fluid such as molten salt (but sometimes synthetic oil or steam) are heated and stored in a reservoir for later use.

Linear Fresnel reflector systems utilise parallel mirrors to focus solar radiation on a single elevated receiver that runs the length of the mirrors. LFR systems use water as the heat transfer fluid.

Regardless of the technology, the CST system usually becomes 'saturated' with heat sometime during the day. At this point, no more energy can be stored, and the operator can choose to generate steam (and therefore electricity) at no opportunity cost. However, the main benefit of CST is that the hot tank can store heat for (typically) 6-10 hours, which can then be used to generate electricity outside solar hours.

Table 9: Technical parameters of CST

Technical parameter	Typical value(s)
Power range	5 to 400 MW
Dispatchable supply range	6 to 10 hours
Efficient output range	From 10 per cent to full output
Lifespan	25 years
Start-up time	5 hours from a cold start and 1 hour from a hot start
Efficiency	Not relevant as a fuel source is free
Operational emissions	0

Project development features

Solar thermal plants typically need large amounts of land for a given amount of storage (200-1600 ha/MWh). The best sites are in arid locations due to direct nominal irradiance. However, these areas are typically distant from transmission lines that have suitable capacity.

There are relatively high development risks for solar thermal projects. This is because there are few technology providers, and few commercially successful projects (in 2018, there was only 5.5 GW of installed capacity worldwide, which had increased to just 6.8 GW by 2021).[64] No CST project has ever proven commercially viable in Australia.

Around the world, some CST projects (e.g. SolarReserve's 110 MW, 1.1GWh Crescent Dunes project in Nevada) continue to experience technical problems, and have failed to meet their design capacity factors. As a result, DEC does not consider CST to be a 'mature' technology, despite many of its components being technologically mature.

The current estimate for development lead time for CST is 5.5 years (6 months for concept designs, 2.5 years for regulatory and project approvals, and 2.5 years for construction).

64. REN 21 (2019), Renewables 2019 Global Status Report. Available at: https://www.ren21.net/wp-content/uploads/2019/05/gsr_2019_full_report_en.pdf

System reliability

A typical large solar thermal plant can store about eight hours of energy at full capacity (thereby allowing it to provide up to eight hours of dispatchable supply once 'charged'). However, CST stores solar radiation (not electricity), so it is unable to provide dispatchable demand.

It is technically possible to store heat for longer than 8 hours by improving/increasing the molten storage (with a relatively modest increase in capital costs). This allows a longer disconnect between the time of energy capture (i.e. daylight hours) and the time of discharge (e.g. overnight). However, unless more heliostats are added (at a relatively high capital cost), generating more overnight necessitates less (potentially zero) generation during the day. As a result, the storage duration for a particular CST project depends on how it is engineered, which is informed by how the owner wants it to operate, which depends on market signals (e.g. the difference between daytime and overnight prices). Storage of above around 8 hours is not commercial at this stage, and relatively high costs make it unlikely to be competitive in the future.

In general, thermal storage is not suitable for strategic reserves, because heat in the hot salt tank will inevitably dissipate with time.

Solar thermal plants have slow start-up times taking 5 hours for a cold start, 2 hours for a warm start and 1 hour for a hot start.[65] If the plant is already operating, it can ramp at around 8.3 MW/minute. Alternative analysis suggests slightly faster start-up times and ramp rates.[66]

System security

A CST system generates electricity using a conventional steam generator (that is synchronised to the grid frequency). As a result, CST plants provide both inertia and fault current (used to support system strength). CST plant can also provide voltage control services (since it can inject/absorb reactive power) and FCAS (however the CST ramp rate is relatively slow, which makes it less suitable for fast FCAS responses).

It is important to note that CST plant can only provide these services if it is already generating (below capacity for some services, e.g. an FCAS raise).[67] CST plant is at a disadvantage compared to generators that have faster start-up times.

Although CST systems uses steam turbines, they can operate with much lower minimum loads compared to the steam turbines in a coal plant. This gives CST the option to operate at low levels overnight to provide the voltage control, frequency control, stability, system strength and grid forming services normally associated with a coal plant. However, this comes at the cost of reduced ability to provide capacity during the evening peak (because the stored energy needs to be rationed).

When generating, CST provides grid formation. However, CST plant is not suitable for black start services due to slow start-up time.

Cost

Solar thermal plants have very high capital costs and high fixed operating costs due to the large operational workforce to maintain the equipment.

Several factors contribute to the high capital costs.

- The steel and glass used to form the mirrors, the heat-carrying system, molten salt tanks, and steam turbine generator units are inherently expensive.
- The costliest components are the control actuators (and their associated control system) which are attached to each mirror to ensure the sun is correctly focused.

Costs are not expected to significantly decrease, or production efficiencies to increase because of the bespoke nature of these components.

65. AEMO, AEMO costs and technical parameters review, September 2018. Available at: https://www.aemo.com.au/-/media/Files/Electricity/NEM/Planning_and_Forecasting/Inputs-Assumptions-Methodologies/2019/9110715-REP-A-Cost-and-Technical-Parameter-Review---Rev-4-Final.pdf

66. https://arena.gov.au/assets/2019/01/cst-roadmap-appendix-1-itp-cst-technology.pdf

67. Technically, a CST plant could be designed with a clutch, allowing it to operate in 'synchronous condenser mode'. However, this is not considered in this report because of the additional capital costs.

While variable operating costs are low due to zero-cost energy input from the sun, the amount of energy able to be captured means the generation is unlikely to exceed a capacity factor of 40 per cent. To provide an acceptable return on investment, the generation will need to capture high energy prices.[68]

Summary

Solar thermal power plants are designed to provide medium duration (~8 hours) dispatchable supply by storing thermal energy. However, CST stores heat from solar radiation (rather than electricity from the power system), so does not provide dispatchable supply. It is also not well suited to long duration storage

Because it uses a synchronous generator, CST plant can provide inertia, system strength and voltage control when operating or in spinning reserve. CST systems are also capable of providing FCAS when generating, but have a much slower ramp-rate than other potential FCAS providers (e.g. batteries).

To recoup the very high capital outlay, solar thermal plants need to be operating at a relatively high-capacity factor. This requires the plant to generate during the day, as well as into the night. Whilst this can be achieved, the low daytime price of electricity will likely limit the ability of solar thermal plants to be profitable (unless night prices are very high).

Due to high capital costs, uncertain commercial applicability in Australia and the inability to fully capture arbitrage pricing, CST is not expected to be competitive with other VRE/firming combinations to provide firm, dispatchable energy.

Compressed air energy storage

Overview

Compressed air energy storage (CAES) systems use compressed air to store energy. To ‘charge’, CAES plant use electricity to power a motor that drives a series of compressors to store high-pressure air. To generate power, the compressed air is then released, which drives a turbine.

The air can theoretically be stored in any air-tight repository, with the volume dictating how much energy can be stored. In practice, the best storages tend to be underground caverns in favourable geological formations.

Operational plant

At the time Stage 3 was completed (2020), there were currently only two operational large-scale CAES systems in the world.[69]

- The 290 MW, 580 MWh (2 hour) Huntorf plant (Germany) was completed in 1978. It has a round-trip efficiency of 42 per cent.
- A 110 MW, 2860 MWh (26 hour) plant was built in McIntosh, Alabama (USA) in 1991. It has a round trip efficiency of 54 per cent.

Technology variations

The two existing plants are diabatic. This means that:

- When the plant is compressing air (and the air consequently heats up), the heat is removed via a cooling system, and released to the atmosphere. This represents a loss of energy.
- When the plant is generating power, the compressed air expands (and consequently cools down) and needs to be heated up to improve power generation. This is achieved by burning a fuel (in these examples, natural gas), which emits CO_2.

There are a several different CAES technologies at various stages of research and development, which aim to improve efficiency compared to diabatic technologies.

Advanced adiabatic CAES (AA-CAES) systems aim to capture the heat generated during compression and use it during the generation phase instead of combusting natural gas. This is expected to improve cycle efficiencies to 60-70 per cent but requires more expensive plant than diabatic systems.

68. Jacobs, “Report to the Independent Review into the Future Security of the National Electricity Market”, 21 June, 2017, https://www.energy.gov.au/sites/default/files/independent-review-future-nem-emissions-mitigation-policies-2017.pdf
69. https://www.irena.org/DocumentDownloads/Publications/IRENA_Electricity_Storage_Costs_2017.pdf

There are currently no operational AA-CAES plants, but there are several different projects at various stages of planning and development. For example:

- ARENA and the South Australian Government have contributed a cumulative $9 million to support Australia's first CAES project (a 5 MW, 10MWh (2 hour) project).[70,71]
- In 2017, a proposal for the world's first large-scale AA-CAES project (200 MW, 1 GWh) was designed by RWE Power, General Electric and other partners. The project did not proceed due to unfavourable business conditions (as distinct from technology risks).

Liquid air energy storage (LAES) is currently at the experimental/demonstration phase. When charging, air from compressors is liquefied at -196°C, and then stored in tanks. In the discharge stage, the air is heated back up, the pressure increases dramatically and is used to drive turbines. Although LAES is theoretically well-suited to long duration storage, it currently suffers from very low cycle efficiencies.

Supercritical CAES (SC-CAES) is a newly proposed concept that integrates the advantages of both AA-CAES and LAES (high energy density, and high thermal efficiency). In this hybrid approach the air would be compressed to reach a supercritical state (high pressure and high temperature), and then stored in tanks. The collected compression heat would then be recycled during the expansion phase, to drive a turbine more efficiently.

The remainder of this section focuses primarily on diabatic CAES, since it is the only proven technology. When convenient, it also provides limited commentary on AA-CAES.

Table 10: Technical characteristics of CAES

Technical parameter	Typical value(s)*
Power range	100 – 300 MW
Dispatchable supply range	2-26 hours (current plant) with the potential for days of storage with a sufficiently large, airtight reservoir
Efficient output range	Minimum stable generation is ~10 per cent of capacity, but CAES have very poor efficiency at low outputs.
Lifespan	20-40 years for electromechanical components
Start-up time	10 minutes from a cold turbine start and near instant from a hot start
Efficiency	~40-55 per cent for diabatic, ~60 per cent for adiabatic
Operational emissions	Zero for adiabatic (assuming access to zero emissions electricity for charging). For diabatic, 158 $kgCO_2e/MWh$ (assuming 35 per cent[72] of the generated power comes from burning fuel via a process that has similar efficiency to a CCGT).[73]

*Given that there are only two operational plant worldwide, these values are indicative only.

Project development features

CAES plants have very specific site requirements, which limits adoption in most areas of the grid. The two most restrictive requirements are a significant reservoir for storing the compressed air, and access to natural gas supplies (for diabatic plant). It is not clear whether there are many (or any) appropriate large-scale sites in Queensland.

Disused underground caverns in disused mines can be suitable. The South Australian proposed CAES is making use of such a site. Alternative sites are salt caverns and hard rock caverns.[74] Pressure losses in rock or salt caverns are like natural gas storage and contribute around 1-3 per cent to overall round-trip efficiency.[75]

CAES plant has a relatively small site footprint, requiring ~4000m^2 for 100 MW.

70. https://arena.gov.au/news/south-australian-zinc-mine-to-be-converted-into-australias-first-compressed-air-facility-for-renewable-energy-storage/
71. Note, this facility did not proceed. See: https://arena.gov.au/projects/hydrostor-angas-a-caes-project/
72. EPRI-DOE, Handbook of Energy Storage for Transmission & Distribution Applications, December 2003, section 2.5
73. AEMO 2019 market modelling input data set suggests modelling new entry CCGTs in Queensland with an emissions intensity of 450 $kgCO_2e/MWh$
74. EPRI-DOE, Handbook of Energy Storage for Transmission & Distribution Applications, December 2003, section 15
75. The Fracture Influence on the Energy Loss on the Energy Loss of Compressed Air Energy Storage in Hard Rock. Hindawi Publishing Corporation Mathematical Problems in Engineering Volume 15, Article ID 921413

Since no CAES plant have been developed in Australia, it is difficult to accurately estimate development timeframes. Nonetheless, it is estimated that large-scale CAES plant would take around two years for design and regulatory approvals, and another two years for construction.[76]

System reliability

If already operating, CAES systems can ramp to full output within seconds. CAES systems can ramp from cold to full load in 10 minutes.

The amount of time for which a CAES plant can technically provide dispatchable supply/demand is dependent on the size of the reservoir. With a sufficiently large underground cavern, it's plausible that CAES plant could provide multiple days of energy storage. A diabatic CAES plant is also dependent on the amount of gas it can access, but this is likely less of a limiting factor than the reservoir size.

Realistically, however the relatively poor round-trip efficiency of diabatic CAES plant means that it would likely be unable to compete with other storage technologies to 'charge'. As a result, it's questionable whether CAES plant could buy and store enough energy to provide dispatchable generation for long periods, even if it had the technical capability.

This may change with the 'new generation' of more efficient AA-CAES plant at various stages of development. However, no large-scale AA-CAES plant are currently operational anywhere in the world.

System security

A CAES system uses a conventional gas generator, so it has a large synchronous mass. As a result, CAES plant provide system strength and inertia when they are operating. They can also inject or absorb reactive power to help control voltage.

Like combined CCGTs, CAES system have low efficiencies when operating at low power outputs. This means that it is not efficient to have the generators synchronised and running at low power outputs. As a result, CAES generators synchronise to the grid only when required to generate, and this is the only time that they provide system strength and inertia.

CAES systems are capable of participating in the five-minute delayed FCAS market however, this will not be at full capacity if the plant is being operated from a cold start as it takes 10 minutes to reach full capacity from a cold start.

When generating, CAES systems automatically provide grid formation services (since they are synchronous). A CAES system could provide a black start service with a small on-site diesel generator or alternate means of supplying auxiliary loads without drawing supply from the grid. However, to provide a versatile black-start service, the CAES system would need to store sufficient energy to be able to restart other power stations and the intervening transmission system.

Cost

It is difficult to generalise capital costs for CAES projects, because they depend on the geography, and amount of excavation required for the reservoir. Higher estimates of $4.5-7 million have been made for sites located at disused mines in Queensland. Alternatively, the 110 MW/26 hour plant in Alabama (built in 1991), cost $65 million, which is equivalent to US$1.1million/MW in 2020 dollars.[77]

Summary

If it has a large enough air-tight reservoir, CAES is technically able to supply dispatchable supply/demand for long durations.

However, CAES plant have a range of weaknesses. There are only two operational large-scale CAES systems in the world. Both existing plant consume natural gas, and have low round-trip efficiencies. A range of different CAES projects that don't require natural gas (and potentially higher efficiencies) are in development, but none of them have been proven at scale. Additionally, CAES plant have relatively high capital costs, and are geographically constrained.

76. AEMO, AEMO costs and technical parameter review, September 2018. Available at: https://www.aemo.com.au/-/media/Files/Electricity/NEM/Planning_and_Forecasting/Inputs-Assumptions-Methodologies/2019/9110715-REP-A-Cost-and-Technical-Parameter-Review---Rev-4-Final.pdf

77. EPRI-DOE, Handbook of Energy Storage for Transmission & Distribution Applications, December 2003, section 15

Given these issues, CAES systems are not competitive with alternative forms of short, or long duration storage. With high capital costs, very specific site requirements and a low round trip efficiency, there are more cost effective options at providing medium to long duration storage

Demand response and consumer energy resources

Overview

Demand response occurs when electricity consumers increase or decrease their electricity consumption in response to market signals. When signals are appropriately aligned with the power system requirements, demand response encourages consumers to alter their electricity consumption in a way that helps maintain the balance of supply and demand.

The history of demand response

The concept of demand response has been around since power systems were first installed and operating; however, it has been known by various names. In Australia “ripple load control” systems were first installed in 1957 in Queensland and NSW. These systems were used to turn hot water storage systems off (and on) to reduce peak demand. With the invention of time-of-use metering, peak pricing tariff structures have also been adopted in parts of Australia, which promote consumers to shift demand away from peak periods.

In the mid-1980s, the term “demand management” extended the concept of demand response to include load control of other devices including pool pumps and air conditioners. Demand management also referred to energy efficiency programs and time-of-use tariffs. The common factor amongst demand management programs was the customers’ ability to exercise choice in participating. The programs all involved the customer making a trade-off between the value of the incentive to participate compared to the lost utility by not participating.

Present-day demand response

In addition to the mechanisms mentioned above, demand response is occasionally used on a large scale. For example, AEMO (via the Reliability and Reserve Trader (RERT) function) enters contracts with some companies who agree to be curtailed (for a price) if there would otherwise have been a power shortfall. Analysis estimated that over the 2019-20 summer, AEMO had contracts with ~20 companies, for ~1,500 MW of demand response via the RERT, at a cost of $44 million.

One of the ~20 companies is an aggregator, which offers to pay large network loads (including water utilities, data centres, hospitals and shopping centres, food processing and packaging sites, manufacturing facilities and technical colleges) to cut their power usage.

The future of demand response and distributed energy resources

Just as demand management grew to encompass pool pumps and air conditioners in the 1980s, demand response of the future will likely encompass more services. This will be driven by:

- improved control systems on individual ‘smart’ devices (which allow their electricity supply/demand to be controlled – potentially by a third party)
- increasing distributed energy resources (DER) – particularly household BES systems, and electric vehicles.

These developments will likely impact the scale and availability of demand response, particularly if all household batteries and EVs could be controlled by an aggregator (or AEMO). By having control over this scale of DER, an aggregator/AEMO could drastically influence the overall demand shape and/or increase/reduce demand at key times.

Challenges with Consumer Energy Resources (CER) aggregation

There are several challenges with aggregating CER to provide demand response services.

A major challenge is that the owners of CER assets (e.g. households that own batteries) install them for their own personal benefit. It is in their best interest to operate them in a way that suits them, rather than in a way the benefits the system. This (alongside uncertain maintenance by the CER owner) impacts resource availability. Trials in the UK have shown that domestic customers signed up to provide a frequency support service using household BES systems were only available 24 per cent of the time, and with a slower response than a centralised BES system. This means that to guarantee a 1 MW frequency service, the aggregator has to “hold” 4.2 MW of capacity.[78]

78. UK Power Networks (n.d.), *Low Carbon London*. Available at: https://innovation.ukpowernetworks.co.uk/projects/low-carbon-london/

Another challenge is that many small, distributed BES systems are more costly (and less valuable, as discussed in the paragraph above) to the system than a smaller number of larger BES systems. However, if consumers opt to install batteries, EVs, or other controllable CER, then it makes sense to harness latent capacity in a way that provides benefits to the system.

Table 11 summarises potential technical parameters of a future aggregator's demand response portfolio. The sort of aggregator portfolio described in the table is not yet available; it would require modern control systems to be installed at scale and enabling markets/regulations. The AEMC is considering how to best enable/integrate DER.[79]

Table 11: Technical parameters of demand response and distributed energy resources

Technical parameter	Typical value(s)
Power range	Tens to thousands of MW (depending on size of aggregator portfolio)
Dispatchable supply range	Seconds to hours
Efficient output range	Potentially 0-100 per cent (depending on the size of aggregator portfolio)
Lifespan	N/A
Start-up time	• Potentially < 1 second for large loads directly providing demand response with locally measured triggers • Several seconds, minutes or hours for aggregators, depending on control systems and the aggregators' contracts with CER owners. It is advised that current demand response contracts require advanced warning hours ahead of potential demand reduction. Additionally, the contracts may make participation optional, which creates uncertainty around the actual response that can be delivered.
Efficiency	N/A
Operational emissions	0 (reducing demand at key times could even reduce emissions if fossil fuels are still being used)

Project development features

Demand response requires appropriate control infrastructure at each individual asset, as well as with the aggregator/AEMO.

- Individual assets require modern 'smart' meters, and control and communication systems appropriate to whatever demand response service they are providing.
- The aggregator needs appropriate communication and control systems to: respond to market signals/AEMO requests, and control individual assets to provide an aggregated response.

Demand response is possible wherever there is load (and appropriate physical and digital infrastructure).

Once market mechanisms and technical control processes are established, development of demand response is not expected to have material barriers to development. Future design and approval process are expected to take between 3-12 months.

The extent to which demand response can be implemented is fundamentally limited by the number of consumers willing to participate. As context, consumer take-up and longevity of participation has historically been an issue for demand management initiatives. However with heightened consumer impact from higher prices and awareness of the importance of managing energy consumption, participation may remain higher than in the past. This may be particularly true for consumers who have installed rooftop PV systems with battery storage systems.

System reliability

Demand response can be considered firm and dispatchable with a degree of uncertainty in a similar manner to VRE generation. The demand response capacity that can be relied upon has to be managed by the aggregator (whether this is AEMO directly, or through a third party aggregator). Allowance must be made for the number of consumer systems that can respond at any given time, and the reliability of the systems to respond.

79. AEMC (2019), Using demand management to take the pressure off the power system. Available at: www.aemc.gov.au/news-centre/media-releases/using-demand-management-take-pressure-power-system

With this caveat in place, demand response has the potential to 'shift' or 'curtail' a relatively small percentage of total system demand for short periods of time.[80] Unless the storage duration of small-scale, distributed batteries increases substantially, it seems unlikely that the majority CER would be able to last for more than a few hours. As a result, CER would only be useful for longer durations if the aggregator operated the CER below capacity (e.g. by implementing a 'rolling' demand response, in the same way that AEMO might implement rolling load shedding). This effect is equivalent to a storage system generating at a lower capacity to increase the duration of its output.

With appropriate control systems (and markets designed to incentivise this behaviour), demand response could potentially provide several hours of dispatchable demand. For example, devices that have discretionary time-of-day energy consumption (e.g. EVs that are 'plugged in') could help to fill in the solar carve out.

System security

CER aggregators will likely be able to offer FCAS in the future. However, as discussed earlier in this section, this will not be as reliable as FCAS from (for example) a grid-scale battery due to competing needs from the owners of each CER asset. Nevertheless, participation rates will become more predictable over time. FCAS via demand response has also yet to be implemented at scale. It is not expected that aggregated demand response would provide fast frequency response (FFR) services, although it would technically be possible with appropriate control systems. This is because the aggregator would need to:

- bear the cost of improving the communication systems between its central control operation, and each distributed resource
- have agreements with the customer requiring almost instantaneous control of their CER.

Large industrial customers may be able to provide FFR. This would likely be at a higher price than an aggregator, since they would place a greater value on their load compared to (for example) a household battery with spare capacity.

As CER becomes more widespread, Distributed Network Service Providers (DNSPs)[81] need to limit the impact of overvoltage and voltage fluctuations on distribution networks. With appropriate control systems, it is possible for inverter-connected CER to help regulate reactive power on distribution networks. This issue is currently being addressed by DNSPs. Further consideration of distribution networks is out of scope of this report.

Demand response is not capable of providing inertia and is unlikely to provide synthetic inertia. This is because aggregators would both need to pay for improved communication systems (as discussed above for FFR), and have a large enough portfolio to support a sustained injection of active power equivalent to an inertial response. Demand response also has no ability to provide system strength, black start, or grid formation.

Cost

Assuming that the appropriate control infrastructure is in place, demand response has negligible capital costs. The main costs are from fixed and variable operating costs.

To estimate fixed operating costs, consider the yearly ~$44 million AEMO spends to access 1500 MW of demand response via the RERT. This equates to $29,333/MW. This is a high-end estimate, because it is a firm demand response service (i.e. guaranteed when AEMO needs it). The fixed operating costs would likely be much less for an aggregator that has a larger portfolio of less firm DER.

Variable costs arise when aggregators (or owners of larger assets that provide demand response) are called upon to reduce demand (or potentially increase supply in the case of DER). In the current RERT framework, the price for this service would need to be negotiated between AEMO and the participant. In the future, demand response could potentially participate in the wholesale market by providing 'supply' by reducing demand. Either way, the variable cost could be as high as the maximum price in the NEM, currently $15,100 per MWh.[82] In theory, consumers will participate in demand response when the money received from participation will be greater than the value of the commercial impact of lost supply. This is difficult to quantify and would depend on the situation.

80. It is estimated potential DER participation of 5-10% of total demand, noting that this is inherently uncertain.
81. The DNSP in Queensland is the state-owned Energy Queensland.
82. AEMC: https://www.aemc.gov.au/news-centre/media-releases/2022-23-market-price-cap-now-availablehttps://www.aemc.gov.au/energy-system/electricity/electricity-market/spot-and-contract-markets

Summary

Demand response is well placed to provide relatively dispatchable demand for short durations.

Similarly, it is well placed to provide short durations of dispatchable supply, but only infrequently (due to high variable operating costs). As a result, the 'niche' for demand response is for rare occurrences where supply cannot keep up with demand for short periods (e.g. a one-in-ten year exceptionally high peak evening demand, which could only otherwise be satisfied by building additional plant, which involves investing capital).

Although prolonged periods of low renewable energy generation are a rare occurrence, demand response is not a good solution for sustained periods. Firstly, it would be very expensive due to the high variable operating costs. Secondly, relying on demand response to cover a two-day period of low renewable energy generation is equivalent to designing the system so that consumers accepted occasional prolonged periods of insufficient energy supply (but paying them for the inconvenience).

Hydrogen

Overview

The potential for hydrogen as a fuel source has gained traction in recent years, following the need in the transport and gas sectors to achieve carbon neutrality. To understand how hydrogen is relevant to the electricity sector, it is important to first understand how it is made, how it is stored, and how it can be used to generate electricity.

Making hydrogen

There are three 'categories' of hydrogen, which relate to how they are produced.

1. The first category is renewable hydrogen. This involves using energy from renewable sources to split water into hydrogen and oxygen using a process called electrolysis.
2. The second category is hydrogen produced from fossil fuels. This can be done directly (e.g. via coal gasification or steam methane reforming), or indirectly (via electrolysis, but using electricity generated from non-renewable sources).
3. The third category is the same as the second category, except it uses offsets and/or CCS to make the hydrogen 'carbon neutral'.

The remainder of this section only considers the first category as CCS was out of scope for this study due to its technological immaturity, impacts on energy generation efficiency and high cost.

Electrolysis is an electrochemical process used to split water into hydrogen and oxygen.[83] An electric current passes through an electrolyser (stack) which has positive (anode) and negative (cathode) poles. Positive hydrogen ions collect at the cathode and form hydrogen gas and oxygen ions gather at the anode to form oxygen gas.

There are a number of different types of electrolysers (alkaline electrolysers, polymer electrolyte membrane (PEM) electrolysers, solid oxide electrolysers) being researched to improve their efficacy. However, the general process is similar for each.

Currently, only 2 per cent of global hydrogen is produced using electrolysis; and only a fraction of the electricity used for this electrolysis is from renewable sources.[84]

Storing hydrogen

At atmospheric pressure, hydrogen is found in gaseous form and has a high volume to energy ratio, which makes transport and storage uneconomic. Hydrogen in liquid form is very light, with a density of approximately 77 kg/m3 (depending on its storage temperature and pressure). This is just over one tenth of the density of petrol (702 kg/m3) and at this density, the energy content is 39.4 kWh/per kg – three times that of petrol (13 kWh/kg).

There are design challenges associated with storing pure hydrogen (both in liquefied and gaseous form). In gaseous form, due to hydrogen's small atomic size, molecules are difficult to store — they take up a lot of space, cause issues like hydrogen blistering, and tend to permeate through common storage materials.

83. Office of Energy Efficiency & Renewable Energy (n.d.), Hydrogen Production: Electrolysis. Available at: https://www.energy.gov/eere/fuelcells/hydrogen-production-electrolysis

84. IEA (2019), The Future of Hydrogen. Available at: https://www.iea.org/reports/the-future-of-hydrogen

Although liquid hydrogen is light and has a high energy content, liquid storage requires a significant amount of energy (because hydrogen liquefies at temperatures below -253°C). As hydrogen is also a highly volatile element, high concentrations are at risk of exploding if exposed to atmospheric oxygen.

Depending on the application of hydrogen, alternative chemical carriers, such as ammonia, are commonly used for transport and storage. However, energy is lost converting hydrogen to ammonia, and then back again. This is an ongoing area of research and development.

Using hydrogen to generate electricity

Hydrogen can be used to produce electricity using fuel cells, and technologies like those used for gas and petrol-fuelled power generation.

- Hydrogen fuel cells are electrochemical cells that react hydrogen with oxygen to produce electricity and water. This is the reverse process of electrolysis. Hydrogen fuel cells are a proven technology and are used in hydrogen vehicles.
- Hydrogen turbines are broadly the same technology used for open cycle gas turbines (that run off natural gas). Turbine manufacturers are working towards increasing efficiencies to 60 per cent (conversion of hydrogen to electricity only – excludes energy required to produce hydrogen), which has been achieved at a demonstration level.
- With minor modifications, it is possible to use hydrogen as the fuel in a reciprocating engine. Hydrogen-powered internal combustion engines can already be found in emission-free traction (automotive) applications. Engines can also be designed for multi-fuel use with the ability to use liquefied petroleum gas (LPG) or other fuels as well as hydrogen.

Turbine and reciprocating engine technologies are less efficient than fuel cells because they rely on capturing the heat from burning hydrogen, and OCGTs and reciprocating engines are below 50 per cent thermally efficient.

Challenges

The hydrogen industry is in early development, and globally faces a range of challenges to produce, transport and store renewable hydrogen.

- Producing renewable hydrogen is currently costly, although the technology learning curve is expected to reduce prices.
- At current prices hydrogen is not cost competitive with many other fuels, although this depends on the application.
- There is currently limited hydrogen infrastructure, however infrastructure development is gaining momentum.

On top of these challenges, using hydrogen to store/generate electricity is yet to be completed at scale. Where small projects are operational, they are not yet commercial. Another challenge for using hydrogen as electricity storage is that the round-trip efficiency is currently low (~30 per cent).

There are several small-scale demonstration projects around the world.

- The Kobe Port Island Plant (Japan) is a 1 MW demonstration plant, and has successfully used 100 per cent hydrogen to power its turbine.[85]
- The Port Lincoln Green Hydrogen Plant is a demonstration concept being developed in South Australia which includes a 15 MW electrolyser plant, distributed ammonia production facility, a 10 MW hydrogen-fired gas turbine and a 5 MW hydrogen fuel cell bank.

While hydrogen is a promising technology, it is still undergoing the research and development required to reach technological and commercial maturity. The economic viability of power-to-hydrogen systems will need to be developed further before wide scale deployment is possible. This is primarily because, whilst small-scale power-to-hydrogen production has been in existence for over 100 years, commercial-scale power-to-hydrogen technologies are at the early stage of the technology learning curve.

85. NEDO (2018), World's first heat and electricity supplied in an urban area using 100% Hydrogen. Available at: https://www.nedo.go.jp/english/news/AA5en_100382.html

Table 12: Technical parameters for hydrogen generation

Technical parameter	Typical value(s)
Power range	None in current commercial operation for power system storage. Indications suggest economies of scale are required.
Dispatchable supply range	Up to one hour to days. It depends on which technology is used, and if a sufficiently large reservoir (e.g. an underground cavern) can be used to store the hydrogen.
Efficient output range	Fuel cells can operate over their entire output range. Turbines can operate over a wide range of output however efficiencies drop below 30 per cent output.
Lifespan	25 to 40 years (plant similarities to OCGT). Electrolysers have a lifespan of around 8 to 10 years if operated continuously.
Start-up time	Fuel cells start near instantly, while turbines take around 10 minutes
Efficiency	~20-30 per cent (electricity to hydrogen to storage to electricity)
Operational emissions	0 (assuming access to zero emission recharging electricity)

Project development features

To improve commercial viability, hydrogen produced by electrolysis needs to have access to a stable water supply, and low-cost, emissions-free electricity. The electrolyser also must be close to the end-use of the hydrogen (storage and electricity generation) to avoid high hydrogen gas transport costs.[86]

Developing large-scale hydrogen-related infrastructure requires appropriate legislative frameworks to be in place. In the future, it is anticipated that project development would require roughly six years (three years for regulatory approvals and design, and three years for construction). However, given the early stage of technology development, these timeframes are uncertain.

Hydrogen is a scalable technology in both production and electricity supply. For production, economies of scale yield benefits from 1 MW to 100 MW for a polymer electrolyte membrane (PEM) plant.

In addition to these high-level observations, the project development features of hydrogen storage and electricity generation depend on what the plant is designed to do. There are two potentials 'models' for an electricity generator fuelled by renewable hydrogen.

Model 1: Opportunistic generation

The first model is for a plant that opportunistically produces hydrogen when electricity prices are low (i.e. stores the electricity as hydrogen), and generates electricity when prices are higher and/or to provide FCAS. This would require both the electrolyser and the generator operating at relatively low-capacity factors. This would make the fixed cost per MWh very expensive.

This sort of plant may not be commercial, because it would be competing against other short-duration storage technologies (e.g. BESS).

- The round-trip efficiency (~90 per cent) of BESS compared with hydrogen (~20-30 per cent) puts BESS at an advantage.
- The capital costs associated with this type of plant (electrolysers and generation equipment, discussed later in this section) are currently less competitive than for BESS.

This view is consistent with CSIRO's National Hydrogen Roadmap.[87]

Model 2: A provider of strategic energy reserves

The second model is a plant that is capable of stockpiling large quantities of hydrogen, and then generating electricity when the system has insufficient available capacity to meet demand (e.g. during an extended period of low renewable energy generation). This model is like the role that an OCGT might play in a net-zero emissions future. However, a major difference is that the fuel source for the OCGT is independent of the electricity system, whereas renewable hydrogen is produced via electrolysis (which consumes electricity). As a result, this report does not treat hydrogen as just a peaking plant, but rather a storage plant.

86. IEA (2019), The Future of Hydrogen. Available at: https://www.iea.org/hydrogen2019/
87. CSIRO (2018), National Hydrogen Roadmap, page 36. Available at: https://re100.eng.anu.edu.au/index.html

Due to current high capital costs, the cost of producing hydrogen is high unless electrolysers are used at relatively high-capacity factors (or electricity is very cheap). As a result, this model makes sense in a scenario where hydrogen was already being produced in large quantities for other purposes (e.g. as a transport fuel), and a portion could be consistently set aside for future use.

For this model, the plant would need capacity to store large quantities of hydrogen, which may be costly. The most cost-effective solution may be if the plant was located with substantial underground storage (e.g. a natural air-tight cavern), and close to suitable transmission capacity. If the generating plant was located away from the storage facility, then it would require a (likely expensive) hydrogen gas pipeline.

CSIRO's National Hydrogen Roadmap estimated that at a capacity factor of 6 per cent for generation (a high-end estimate for what a Model 2 plant may experience), and in the absence of a carbon price, hydrogen would need to cost around $1.60/kg to compete with natural gas plant.65 Using CSIRO's 'best case' assumptions, this implies that the electrolysers could access flat electricity prices of roughly $35/MWh.

System reliability

The reliability services that a hydrogen-fuelled power plant could provide depend on the plant model. Ability to provide dispatchable energy is entirely dependent on the amount of fuel it has available.

While it would be technically capable, Model 2 would not provide relatively short duration dispatchable supply (due to low efficiency), but could provide a dispatchable strategic reserve. It would also not provide dispatchable demand, since it is based on the assumption that it accesses hydrogen generated by a flat load (i.e. high capacity factor) electrolyser.

Dispatchable supply or demand from the electrolyser is a type of demand response. Reducing electrolyser demand on very rare occasions may be more viable than burning hydrogen to generate electricity.

System security

The system security benefits for hydrogen turbines are like that of OCGTs. As with OCGTs, these benefits would only be provided while the hydrogen plant was generating, unless it was also designed with a clutch so it could operate in 'synchronous condenser mode'. In that case, it could provide system strength, inertia and voltage control.

The system security benefits of fuel cells depend on the inverter technology and are similar to the benefits for BESS systems.

Cost

Given large scale hydrogen production, storage and regeneration is at a concept stage, it is difficult to establish definitive costs. The following analysis should be taken as a guide only.

To estimate costs, the technology can be broken into parts.

- Fuel cells cost in the range of $1.5-2 million/MW, with a generation efficiency of around 70 per cent.
- The alternative for regeneration is via turbines, which will cost less (at around $900,000) but with a generation efficiency also less (at around 38 per cent).
- Electrolysers cost in the range of $1.5 million/MW installed with efficiency in the range of 45 per cent to 70 per cent respectively depending on technology choice.
- Large underground storages of hydrogen may need to use salt cavities to assist in minimising costs. The cost of this form of underground storage (used by other technologies) is around $1.5 million/MW.

The total cost for an electrolyser, fuel cell and storage may therefore be around $4.5 million/MW. This is slightly higher than an IEA estimate that the total capital cost of large-scale PEM system, storage and fuel cell could range from $2,700-$4,400/kW.[88] It is estimated that the total cost using a turbine instead of a fuel cell would be $3.9 million/MW.

Hydrogen currently would have a round trip efficiency of only 20 to 30 per cent (if an alkaline electrolyser is 70 per cent efficient and the PEM fuel cell is 47 per cent efficient, then the round-trip efficiency is about 30 per cent). Using a gas turbine, the round-trip efficiency would be 25 per cent.

88. IEA (2019), The Future of Hydrogen. Available from: https://re100.eng.anu.edu.au/index.html

The figures above include many implicit assumptions. However, to make comparisons with other technologies, two sets of values have been estimated. The first set is based on storage in a salt cavern (which was assumed lowest cost), and the second based on compressed hydrogen storage.[89]

Table 13 summarises the results. It is worth noting that the operating costs (which are for electricity generation, not for electrolysis) are the most relevant component, if envisioning a 'Model 2' scenario where the capital costs are spread over a broader hydrogen production operation. It is also worth noting that long-term electrolyser costs could reduce by 40 per cent by using multi-stack systems.

Table 13: Estimated costs for hydrogen plant

Project assumptions	Total capital costs ($/MW)	Fixed operating costs ($/MW/year)	Variable operating cost ($/MWh)[90]	Cycle Efficiency
Low cost	**4,500,000**	10,000	182	30 per cent
High cost	**5,625,000**	7,000[91]	215	25 per cent

Summary

Hydrogen has many potential future applications (e.g. in the transport industry and industrial processes). However, to be competitive for short to medium-term energy storage for large-scale electricity production, hydrogen will need to overcome the low cyclic efficiency. This appears very unlikely given the fundamental losses that occur during electrolysis, and when generating electricity using hydrogen.

It is noted that there are several predictions that hydrogen storage using existing underground caverns will be cost-effective for large scale strategic energy reserves beyond 2040.[92] This would be possible if capital/investment costs fall, and if the cyclic efficiencies improve.

In theory hydrogen turbines can provide the same system security benefits as OCGTs – i.e. when generating, hydrogen turbines would provide the services. However, since hydrogen plant are currently less efficient there are challenges to realise this goal.

Low-capacity factor gas generation

Overview

Low-capacity factor gas generation has been used for decades in Australia for peaking generation. Historically, it has been provided by open cycle gas turbines (OCGTs).

OCGT units use an external combustion engine composed of three main components: an air compressor, a combustor, and an expansion turbine. Air is drawn into the compressor and compressed up to 30 times that of atmospheric pressure. The air is then moved to the combustion chamber (or combustor) where fuel (which can either be natural gas or distillate) is mixed, ignited, and burned under pressure. The inflated hot gas then passes through the expansion turbine which utilises the mechanical energy to power a generator and the air compressor.

There are two types of OCGT plants.

- Heavy frame (industrial) units are the most common type of OCGT in Australia. These units typically have single-cycle efficiencies of between 30 and 32 per cent.
- Aero-derivative OCGTs are becoming increasingly popular due to better single-cycle efficiencies (38 to 40 per cent).[93]

89. A large scale underground storage salt cavern (if available) would likely be the most cost effective, and add approximately $0.20/kg to the cost of hydrogen production. If stored in tanks at 35 bar, the additional cost would be 0.30-0.37 $/kg. As a result, the project costs were increased up front for the storage component by 75 per cent.
90. Given by the cost of energy (assumed to be $50/MWh) ÷ efficiency + a $15/MWh variable operating cost chosen to be consistent with CAES
91. Note, lower fixed operating costs for this option
92. Schmidt et al (2019), Joule Volume 3, Issue 1, Projecting the Future Levelized Cost of Electricity Storage Technologies. Available at: https://doi.org/10.1016/j.joule.2018.12.008
93. Marsden Jacob Associates (2018), NEM outlook and Snowy 2.0, p. 27. Available at: https://www.snowyhydro.com.au/wp-content/uploads/2018/01/MJA_ReportFinal_Jan2018.pdf

The thermal efficiency of OCGTs is forecast to improve by 6 per cent by 2030 as newer class turbines with higher exhaust temperatures become available.[94] Table 14 summarises key technical parameters for existing OCGTs.

Table 14: Technical parameters for low-capacity factor gas generation

Technical parameter	Typical value(s)
Power range	5 to 375 MW
Dispatchable supply range	Hours to days (depending on the size of the gas reserve)
Efficient output range	Plants can operate at low outputs, but have very poor efficiency
Lifespan	30 years
Start-up time	10 minutes
Efficiency	30-40 per cent (thermal efficiency)
Operational emissions	0.4 to 0.7 tonnes CO2/MWh

Reciprocating gas engines are another example of low-capacity factor gas technology. They work similarly to OCGTs in that they operate using compressed air and hot gases from the combustion of distillate, natural gas, biofuels, or waste gas. The difference is that reciprocating engines drive pistons to generate pressure, the same as large truck engines.

Reciprocating engine unit sizes are scalable and range from portable generators (typically 300 kW) to larger power generating units (up to 20 MW). They are higher in capital cost to install compared with OCGT technology but are more efficient over the full range of generator output. They incur higher maintenance costs compared to OCGTs due to more complex mechanical components which wear faster.

Relative efficiency, fast start-up performance (within 3 minutes), the capability for multiple daily starts, can make reciprocating engines ideal for supporting fluctuating renewable generation. They are also appropriate for burning waste gas under lower pressures.

Despite these advantages, reciprocating engines are at a disadvantage to OCGTs (for low-capacity factor) use because their installed costs are approximately 30 per cent higher, maintenance is higher, and they require a larger geographic footprint. The remainder of this section talks specifically about OCGTs. However, the strengths and weaknesses described for OCGTs are largely the same as for reciprocating engines, which may also (or alternatively) be well placed to provide some services in the future.

Project development features

OCGT plants use a relatively simple design and have a relatively small geographical footprint (500 m2/MW). As a result, the requirement for fuel inputs tends to be the limiting factor when considering feasible location. For example, if the OCGT uses natural gas, then locations close to natural gas pipelines are advantageous to reduce fuel transport costs.

An OCGT emits 0.4 to 0.7 tonnes CO2e/MWh (when burning natural gas). Although this is less than coal (generally around 1 tonne CO2e/MWh), substantial gas generation is fundamentally incompatible with a net-zero emissions target unless there are substantial offsets (e.g. from planting forests) and/or improvements in CCS. However, a small amount of OCGT generation (e.g. to insure against extreme events) could potentially be offset to reach net-zero emissions overall.

On average, it takes around 4 years to have an OCGT plant approved and constructed. The approval and design process usually takes around three years, and construction typically takes one year. However, if a fully operational plant is relocated, the construction time may be lower.[95]

There are currently 15 OCGTs located in Queensland and registered in the NEM, with a combined maximum capacity of 1,987 MW.[96] The Queensland OCGTs use coal seam methane, natural gas, kerosene, and diesel fuel, dependent on their location.

94. CO2CRC (2015), Australian Power Generation Technology Report. Available at: https://www.aph.gov.au/DocumentStore.ashx?id=080fc017-86e9-435d-98c9-58dc320c49db

95. For example, the Oakey power station was built using a second-hand power station relocated from overseas to the site and construction took a total of 17 weeks.

96. AEMO (accessed 16 December 2019), NEM Registration and Exemption List. Available at: https://aemo.com.au/energy-systems/electricity/national-electricity-market-nem/participate-in-the-market/registration

System reliability

The role of an OCGT in today's market is generally as a peaking plant, because OCGTs can typically start in 10 minutes to full load. With the NEM now utilising five minute settlement periods, an OCGT plant will be at a disadvantage compared to technologies (e.g. batteries) that have almost instantaneous start-up times.

However, OCGTs are not limited to providing short duration dispatchable supply. If there is a sufficient fuel supply, OCGTs can operate for as long as needed. As a result, they can provide strategic energy reserves. In order to provide this service, the OCGT would either need a fuel stockpile (e.g. distillate or biofuel), or the ability to access gas infrequently, but for sustained periods.

To put the level of fuel stockpile into context, 80 million litres (or 80 megalitres) of distillate is a high-level estimate of what would be necessary to provide 48 hours of average demand for the whole of Queensland (equivalent to 400,000 oil barrels, or 32 Olympic sized swimming pools, or 58 days' worth of aviation fuel supply for all of Australia).[97] A gas market underpinned by Queensland's LNG industry would also be able to provide the necessary fuel security through the provision of coal seam gas.

System security

OCGTs use a synchronous generator (or alternator) to generate power. As a result, they improve fault current levels (i.e. system strength) and inertia when they are operating. They can also inject or absorb reactive power to help control voltage. Aero-derivative OCGTs have higher inertia constants than heavy frame units, but because of their lower power ratings, will generally contribute less to system inertia.

With fast response times, aero-derivative OCGT plants can also provide frequency control by being able to participate in all contingency FCAS markets except the six-second response market (unless they are operating at the time of the request, in which case aero derivatives can participate in all six current contingency FCAS markets).

OCGTs automatically provide grid formation services (since they are synchronous), and can also provide black start services when combined with a small on-site diesel generator or battery.

An important thing to note is that, except for black start services and slow FCAS services, OCGTs only provide system security services when they are operating. As a result, the future system should not rely on OCGTs to provide these services, except for the small amount of time when they are operational (e.g. if they are generating during a prolonged period of low renewable energy generation).

An alternative viewpoint would be to design the plant with a physical clutch, which would allow it the option to operate in 'synchronous condenser mode' (i.e. spinning in an electromagnetic field like a synchronous condenser, rather than burning fuel to generate). This would help to provide inertia and system strength. However, this would add capital costs, and has not been considered further in this report.

Cost

OCGT plants have a typical lifespan of more than 30 years depending on operating and maintenance regimes. The capital costs involved in the construction of a new OCGT is $894/kW for aero-derivative and $1,286 per kW for industrial frame machines.

Despite their relatively small share of total energy generation, OCGT often set the price for electricity during peak hours, and therefore impact overall electricity costs. A major consideration on the total cost of OCGT is the cost of gas. The Stage 3 report estimated operating costs (including gas) at $115/MWh, based on assumed gas price of $11.50/GJ. This is in line with AEMO forecast gas prices for generation in Queensland in the 2022 ISP.[98]

In 2022 gas prices were volatile, rising to over $40/GJ in June and July, due to international events affecting global commodity prices. Prices have since eased, but are still higher than historical averages. While gas prices are expected to fall to ISP forecast levels over the medium-term, the system is currently vulnerable to external price shocks due to linkages to international commodity markets.

97. Australian Department of the Environment and Energy (2019), Australian Energy Statistics, Table L. Available at: https://www.energy.gov.au/publications/australian-energy-update-2019

98. See: https://aemo.com.au/en/energy-systems/major-publications/integrated-system-plan-isp/2022-integrated-system-plan-isp/current-inputs-assumptions-and-scenarios

Summary

With low capital costs but high running costs, OCGT plants will continue to have low utilisation in the immediate future, with their primary role in the power system being to provide peaking capacity. OCGTs will soon be in direct competition with other peak supply technologies (e.g. batteries) for short-duration supply horizons of 1 to 2 hours. OCGTs will be at a disadvantage due to high fuel costs, and slower start-up times.

However, as coal plant are repurposed, OCGTs can help to support the transition firstly by enabling coal plants to operate at acceptable cyclic load patterns, and secondly by providing dispatchable supply to help firm VRE.

In the longer-term OCGTs may be able to provide strategic reserves (e.g. as insurance against prolonged periods of low renewable resource generation) if they have sufficient fuel supplies. Due to their primary role as suppliers of short-duration generation, OCGTs will continue to play a role in supporting achievement of Queensland's renewable energy targets. However, as OCGTs produce greenhouse gases, any generation during would need to be offset to achieve the 2050 net-zero target.

When they are operating, OCGTs also provide a range of system security services. However, since OCGTs will only be able to operate at a low-capacity factor (in order to remain consistent with net-zero emissions), the future system will not be able to regularly rely on these services.

For these reasons it is expected that hydrogen-fuelled turbines may become directly competitive with gas-fuelled turbines over the coming years.

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