

DELWP and City of Greater
Bendigo

**Pre-feasibility study of renewable
energy pumped hydro in Bendigo**

Pre-feasibility Study Report – Final

Final | 16 March 2018

This report takes into account the particular instructions and requirements of our client.

It is not intended for and should not be relied upon by any third party and no responsibility is undertaken to any third party.

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Executive Summary

Arup was commissioned by the Department of Environment, Land, Water and Planning (DELWP) and the City of Greater Bendigo to investigate technical feasibility and economic viability of a pumped hydro energy storage system operating in the gold mine workings underneath Bendigo.

After reviewing inputs provided and researching global underground pumped hydro knowledge, the study team conducted an options assessment and identified a preferred concept for further development. This concept has a generation capacity of 30 MW and can store 6 hours or 180 MWh of energy with a round-trip efficiency of approximately 70%. The concept uses the Garden Gully reef mine voids as an upper storage volume and the bottom of the Swan Decline as a lower storage volume, linked by a new 1.5 m diameter shaft to allow water to flow between them and valving to isolate the flow. At the bottom of the shaft would be a new structure excavated off the decline to house the turbines; and 150 m below this is another new structure to house the pumps, linked to the top structure by a wide shaft for personnel and crane access. The system would be connected to the 66 kV sub-transmission network in Bendigo and would tie into a new sub-station on the site of the Eve St vent shaft where the power cable would be installed.

The pre-feasibility estimate for the capital cost of this project is \$50M AUD, making the installed capacity \$1.7M AUD per MW, well within the typical range for global installed and operating pumped hydro, generally being \$1.0-3.0M AUD per MW of generation capacity. Financial modelling on a 30 year economic life shows an internal rate of return (IRR) of 8.15%. We expect this to be conservative on the basis that hydro and pumped hydro installations generally operate much longer than 30 years and that this system is simple in operation and will therefore be operated and maintained very cost-effectively. These and other positive impacts to the IRR will become clearer in origin and magnitude on further detailed investigation into the project.

There are several ancillary benefits of the proposed concept, including:

- Dewatering of Central Deborah Tourist Mine
- Dewatering of Swan Decline below Northern Exploration Drive (~750 m)
- Reducing peak transmission network demand and easing constraints on Bendigo Terminal Station transformers
- Potential to contribute to long-term management of groundwater
- Project development process may assist with development of other sustainable energy projects around Bendigo
- Project would create approximately 50-60 jobs during construction and 5 jobs during operation
- It has potential to be a first-of-its-kind project, bringing national and global attention to Bendigo and Victoria as a leader in sustainable energy innovation

- With the apparent level of community support and appetite, there may be an opportunity for significant levels of community ownership which could achieve energy bill savings and retention of the value derived from the facility

The study found that the project has the potential to be both technically feasible and economically viable. The project is an exciting prospect for cost-effective energy storage in regional Victoria through adaptive reuse of existing infrastructure and we would endorse a detailed feasibility study as the next step in the development of this project. A detailed feasibility study will provide sufficient site investigations and design development to respond to key technical risks. Procurement and tender activities for construction of the project and contracting of its power and ancillary services will enable a final investment decision on the project.

The key technical risks requiring mitigation in a feasibility study are:

- Unknown hydraulic conductivity of Garden Gully at high flow rates
- Rock stability
- Dewatering in construction
- Unknown accuracy of 3D model

Purpose and use of this document

This report has been prepared by Arup Pty Ltd, ABN 18 000 966 165 (“Arup”) for the sole purpose of providing high level information in relation to a pre-feasibility study for an underground pumped hydroelectric energy storage (“PHES”) system in the Bendigo mine (“Purpose”) developed for the Victorian Department of Environment, Land, Water and Planning (“DELWP”) as the client. The report is intended to assist DELWP in understanding the potential benefits and risks associated with an underground PHES project, and to assist DELWP in determining whether to progress the project to a more detailed and in depth feasibility study. The findings within this report are intended to be reviewed and examined at the feasibility study, which will render this report superseded once the next phase of this project is underway.

The analysis which underpins the report uses inputs that are approximate, including very preliminary energy and power assumptions drawn from historical data, and cost estimates that have a wide accuracy range; and could vary following a more detailed feasibility study. The assumptions used in the analysis that underpin this report have been discussed with and confirmed by the client as a reflection of its reasonable expectation of potential future circumstances.

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1 Introduction

1.1 Report purpose

This report details the results of the pre-feasibility study conducted on an underground pumped hydro energy storage system operating in the disused gold mine workings underneath Bendigo. The intent of the report is to summarise the findings of the pre-feasibility study and inform decision-making on how to progress the project.

1.2 Project background and context

Bendigo's long history as a gold-mining town has left a legacy, which includes a significant amount of now unused underground mine workings. The Bendigo mining area consists of seven major mine reef workings with approximately 5,000 shafts, the majority of which are shallow, but with some over 500 m deep and a few over 1000 m deep.

As part of a broader push to transition Bendigo to renewable power sources, the Bendigo Sustainability Group (BSG), City of Greater Bendigo and DELWP are investigating the possibility of a pumped hydro energy storage system in the mine workings.

Pumped hydro energy storage (PHES) can store energy in some ways like a rechargeable battery. It operates similarly to a traditional hydropower system where water from a high elevation is channelled through a turbine to spin a generator and supply electricity, except that it can also pump water from a lower point to a higher point by consuming electricity. This means that while it is not itself a source of energy, it can be used as a tool to match energy supply with demand where direct control over the timing of generation is not possible, as is the case with renewable sources such as solar and wind energy. Pumped hydro energy storage is a mature technology, making up approximately 97% of grid-scale energy storage globally.

Disused mine sites have been of interest as candidates for pumped hydro for many years, as they address several needs of a PHES site. These include storage volumes with large elevation differences, low environmental impact, grid connection proximity, low ownership issues as they are generally already in industrial areas, and water source for system first-fill from surrounding groundwater. Despite these advantages, an underground pumped hydro energy storage (UPHES) system has never been built due to challenges such as rock stability, unfavourable hydrogeology, and groundwater contamination.

The unique characteristics of Bendigo's mine workings make it a compelling candidate for a UPHES system, which if built, would be the first of its kind in the world. The favourable characteristics include strong, relatively impermeable rock, deep workings, large elevation difference, large storage volumes for potential underground reservoirs, an engaged community and government and private support.

The vision for this pumped hydro project, more than simply being technically and commercially viable, is to enable greater renewable energy generation penetration into Bendigo. The system must therefore be sized to be able to deliver a significant portion of Bendigo's power demand. While a small system may be able to generate an acceptable return on investment, it would not have a meaningful impact on the sustainability of Bendigo's power system. In addition, cost recovery is generally better with larger capacity pumped hydro installations as much of the equipment and civil works scales less than linearly with capacity, which typically makes the business case more viable. With these considerations in mind, the study team is focussed on finding the largest system which can be designed given the constraints.

The purpose of this study is to investigate the feasibility and viability of the project considering the site-specific opportunities and risks. The ultimate question to be answered by this study is whether a pumped hydro system installed in the mine workings has enough potential opportunities and benefits with manageable drawbacks and risks, to recommend further development of the project. For this to be the case, it would need to be attractive compared to alternative available energy storage options such as batteries.

1.3 Project benefits

Some direct and indirect benefits of the proposed concept include:

- Land marking Bendigo as a world leader and a focal point for future innovative research with associated community benefits
- Large-scale energy storage improving Bendigo's resiliency to grid problems
- Could form part of long-term groundwater management strategy
- Inherently takes over dewatering of Central Deborah Tourist Mine
- Requires dewatering of modern mine which may provide some benefit to local mining company
- Potential to alleviate local transmission and distribution network constraints
- Provides local ancillary benefits to power system including inertia, voltage support
- Could form part of a broader cheap, reliable, renewable community power system which would be attractive to existing and new industry bringing investment and jobs
- Alignment to state and local policy objectives

1.4 Study methodology

The project began with a steering group workshop to establish key goals and drivers of the project, alongside a review of inputs provided. Key inputs included:

- Two existing project concepts

- Mine workings 3D model
- Reports on hydrogeology and groundwater management

A site visit was conducted to view project locations and meet local stakeholders.

This was followed by high-level concept identification.

The preferred concept was selected, and then an iterative approach was taken to concept development, identifying options for sub-systems and components and continually integrating and improving the overall design and reduce capital cost.

In parallel to the preferred option development, financial modelling was undertaken to inform the viability of the project as an investment.

2 Research

2.1 Site visits and stakeholder consultation

Various stakeholder engagement activities have been conducted as part of this study, including two visits to Bendigo taking place on Wednesday 18 October and Thursday 16 November 2017. These visits were undertaken to meet with local stakeholders to discuss the project and to visit key potential project locations. This section outlines the stakeholders and locations visited during the study.

2.1.1 Bendigo Sustainability Group

The Bendigo Sustainability Group (BSG) is a local community group in Bendigo focussed on sustainability and energy transition. Their RePower Bendigo project has a vision of 100% renewable energy supply to the city, supported by a pumped hydro energy storage system.

The BSG has been a key driver behind this project and developed an initial concept which came to government through the BSG's involvement in the Bendigo Groundwater project. They have conducted investigations on a volunteer basis and supported the pre-feasibility study team with representation on the project Steering Committee and through information and networking.

The study team has met several members of the BSG team to discuss the pumped hydro project and how it may fit into their larger vision, and to discuss resources they can provide to the study team such as a hydraulic and financial model of a small scale solar + pumped hydro installation.

2.1.2 Bendigo Groundwater Project

The Bendigo Groundwater Project is a project coordinated by DELWP to develop immediate, interim and long-term solutions to Bendigo's groundwater management problems. The project team has developed a wealth of knowledge and data about groundwater in Bendigo and are a key source of groundwater-related information for the study team.

The team met Natalie Trotter from Bendigo Groundwater Project to discuss the project and obtain information about the current groundwater problems and solutions, and general information about hydrogeology of the area. The Bendigo Groundwater Project has also provided a report which summarises post-mining groundwater in Bendigo which has been a key reference document for the study, due to its in-depth investigation into the hydrogeology of the different reefs, and the historic mine workings.

The interim solution that is currently in place will operate until 30 June 2021. Long-term solutions, to be in place after this date for 25+ years, are being investigated, including how a scheme would be financed and governed, and looking at beneficial use of the water extracted.

2.1.3 GBM Gold

GBM Gold is the owner of the mining tenements and associated infrastructure in the Bendigo goldfield. As the owner of the property in which the pumped hydro system would be installed, GBM is a key stakeholder in the project. GBM is interested in the pumped hydro concept and developed a high level option which incorporated the Swan Decline and the tailings dams at its Kangaroo Flat site.

The study team met with GBM at their office to discuss the project. GBM has indicated in-principle support for a commercially viable pumped hydro project in their mine workings. They have provided considerable data, information and support for the study team. The team were unable to drive down the decline to see the underground mine as it is currently not ventilated. The team viewed the site including tailings dams which are an option for an upper reservoir.

The impact of the proposed pumped hydro concept on the value of the mining tenements and infrastructure will be important. The project has the potential to either sterilise a significant portion of mine workings, or to provide a mutual benefit to potential future mining by dewatering and opening areas for exploration which had been previously abandoned. It is unlikely that the project could be executed without GBM Gold's support.

2.1.4 Coliban Water

Coliban Water is the regional water corporation responsible for managing, maintaining and operating water and wastewater assets across North-Central Victoria including the Bendigo area. Coliban Water are the government appointed delivery agent for the interim groundwater management solution. As the regional water corporation they may also have a role in the long term management solution.

The study team met with Coliban Water staff to discuss the project and visit relevant sites around Bendigo. It was agreed that the pumped hydro system should be designed to have no negative impact on Bendigo's groundwater management, and ideally a positive impact.

2.1.5 Central Deborah Tourist Mine

Central Deborah Tourist Mine is a historic mine on the Deborah reef which has been turned into a tourist attraction, offering tours down into the underground mine. It is operated by Bendigo Heritage Attractions, formerly Bendigo Trust. Since mining ceased in 2011 and the groundwater level begun to naturally recover, approximately 1.5-2.0 ML of groundwater has been pumped out of the mine per day from approximately 260 m deep to enable operation.

The study team visited the mine and were given a tour of levels 2 and 3. The staff are very knowledgeable about the regional geology and the mining history, and have been helpful in providing information to support the study.

A second visit to the mine was conducted on Thursday 23 November, to visit deeper levels of the workings in order to assess the geology and the mine construction.

2.1.6 Powercor

The project team has liaised with Powercor, the distribution network service provider (DNSP) covering the Bendigo area, to obtain data to identify design constraints and support system sizing and financial modelling, and also to obtain in-principle support for the project concept.

The study team met with Powercor's network planners in mid-January 2018 to discuss the project, and was advised to submit a preliminary enquiry for formal feedback on the proposed project. The study team submitted a preliminary enquiry and received a positive response back which is discussed in Section 3.2.3.6.

2.1.7 Regional Development Victoria

The project team met with representatives from Regional Development Victoria (RDV) to inform them of the project and discuss RDV's interest and potential involvement.

Advice from RDV was that the most appropriate way to engage would be for the Regional Partnerships Boards to help raise awareness of the project. The boards may be in a position to put the project forward for addition to a priority activity list. This could lead to potential funding and raise the profile of the project within State Government.

2.1.8 Goulburn-Murray Water

Goulburn-Murray Water (GMW) are responsible for managing groundwater and irrigation water in the Bendigo area. The study team engaged with GMW at a high level and did not identify any major concerns or showstoppers, but it was noted that transfer of groundwater into, out of, or between aquifer systems would need to be done in consultation with GMW and may require a licence under the Victorian Water Act (1989).

2.1.9 Dja Dja Wurrung Tribe

The Dja Dja Wurrung traditional owner group has a Recognition and Settlement Agreement (RSA) with the State of Victoria under the *Traditional Owner Settlement Act 2010 (Vic)*. The agreement applies to all Crown land within the boundaries of the RSA, and includes the Bendigo area. The Dja Dja Wurrung traditional owner group will need to be consulted in the feasibility stage and their advice sought on requirements regarding land use activities impacting Crown land.

DELWP will need to determine the class of engagement with the traditional owners that will be required for the project, which will depend on the impact of the project on their rights. The four classes are:

1. Routine/maintenance activity – the Dja Dja Wurrung Clans Aboriginal Corporation (Aboriginal Corporation) does not need to be notified
2. Advisory activity – the Aboriginal Corporation must be advised of the activity but does not have right to negotiation
3. Negotiation activity – compensation may be required
4. Agreement activity – compensation may be required, and Aboriginal Corporation has right to veto the project

Categories 3 and 4 require negotiations with the Aboriginal Corporation. It is very likely that the project will fall into one of these two categories, and we recommend engaging with the Aboriginal Corporation in the next phase of the project to initiate discussions.

2.1.10 Smarter Bendigo

Smarter Bendigo is a program run by local Bendigo stakeholder groups to plan for and facilitate a better future for Bendigo. Key members include the Bendigo Business Council, City of Greater Bendigo, and LaTrobe University. Some of their goals relate to energy, including being a net-exporter of electricity to the grid by 2030. Given the relevance of the pumped hydro project to this goal, there may be some interest from Smarter Bendigo in supporting the project.

2.2 Site features and constraints

This section outlines a number of key features and constraints which are specific to the location and context. These provide bounds for the feasible and viable pumped hydro concepts which could be explored in this study.

2.2.1 Bendigo power system

Grid power is supplied to Bendigo at 220kV to the Bendigo Terminal Station (BETS) operated by AusNet Services. From BETS there is a 22kV high voltage distribution network serving approximately 26,000 customers, and a 66kV sub-transmission loop serving the Bendigo and Eaglehawk Zone Substations (BGO and EHK). These zone substations each serve separate 22kV high voltage

distribution network to approximately 17,000 energy consumers in Greater Bendigo. From these three high voltage distribution networks energy is transferred to homes and businesses via distribution lines and substations.

BETS also provides energy to other sub-transmission networks in the region including Marlborough, Castlemaine and Charlton, but these are not with the City of Greater Bendigo so are considered not relevant to the study.

Bendigo Network Diagram

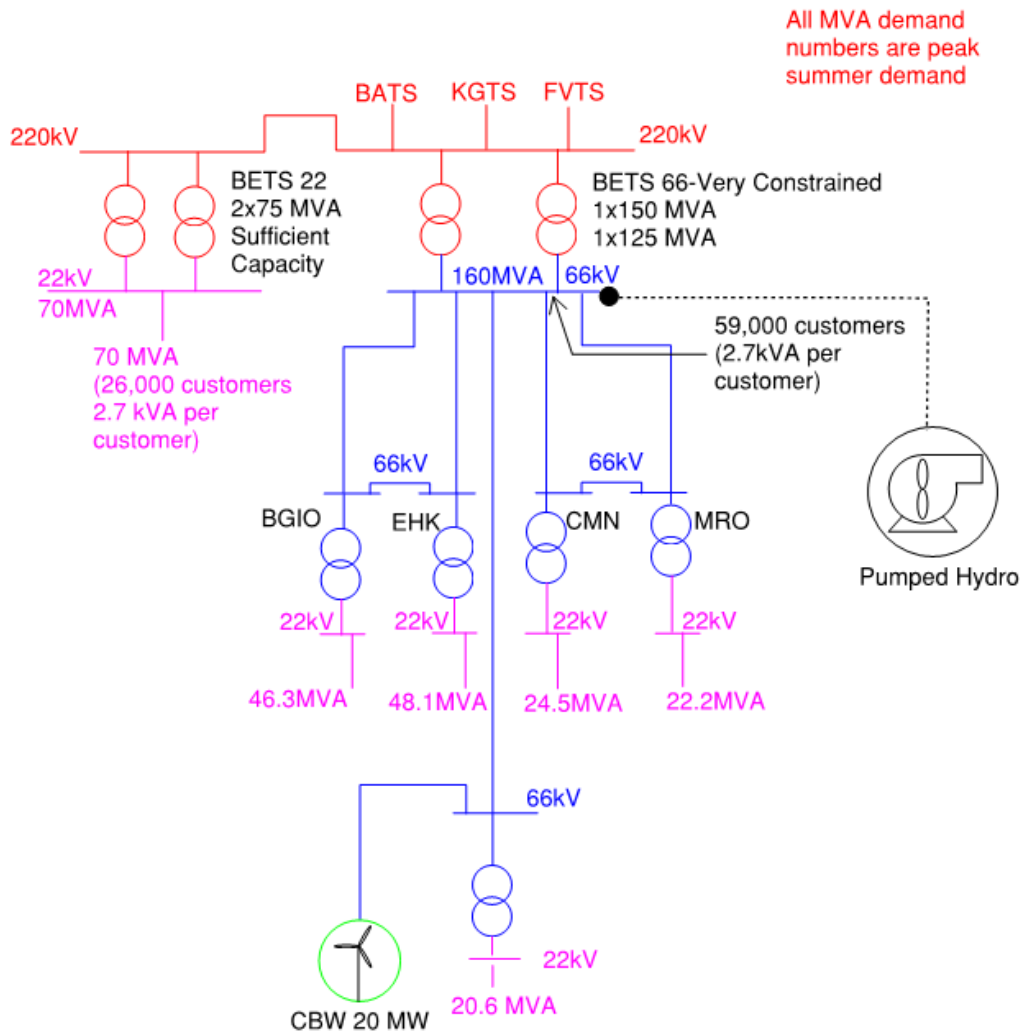


Figure 1: Bendigo power system schematic sketch (two circles symbol = transformer)

For the purpose of the study to investigate an energy storage system for Bendigo, we have considered Bendigo's power system to consist of

- BETS transmission terminal station (220-66 kV)
- The 22kV HV distribution network from BETS (BETS22)
- The 66kV sub-transmission loop linking BGO and EHK to BETS
- BGO zone substation (66-22 kV)

- The 22kV HV distribution network from BGO
- EHK zone substation (66-22 kV)
- The 22kV HV distribution network from EHK
- Energy consumers connected to any of the above sub-transmission or distribution networks

There is very little utility scale generation in the region, other than a 20 MW wind farm connected to Charlton Zone Substation. Pumped hydro would help take load off the transmission lines and terminal station transformers during peak demand events.

AEMO notes that there is a lack of reactive power supply in the region, meaning that the power factor can be far from 1. This means that more current must flow through the lines to deliver electricity and that power infrastructure operates closer to its limit. The pumped hydro system could feasibly provide reactive power support almost 24/7, as the synchronous generators attached to the turbines can operate as synchronous condensers when not in use. This would potentially help manage constrained network scenarios. Commercial viability of this operation would need to be assessed, as commercial arrangements for reactive power support are currently not common in the National Electricity Market (NEM).

According to information from Bendigo Sustainability Group, approximately 20% of Greater Bendigo residences have rooftop solar PV installations, with over 8000 installations providing a total capacity of approximately 29 MW at peak generation, and approximately 42,000 MWh per year of energy.

The study team has analysed 15-minute zone substation demand data from Powercor to determine the historical demand of the Bendigo network. Note that this data does not include the BETS22 distribution network demand as this was not publicly available. The number of customers connected to the BETS22 network is approximately 75% of combined customers connected to the BGO and EHK networks, so it could reasonably be assumed that the total Bendigo demand is can be approximated by demand at BGO + EHK x1.75, neglecting loads which may be connected at transmission (220 kV) or sub-transmission (66 kV) level. The following graphs show the results of the analysis for the demand at BGO and EHK, with various daily demand profiles.

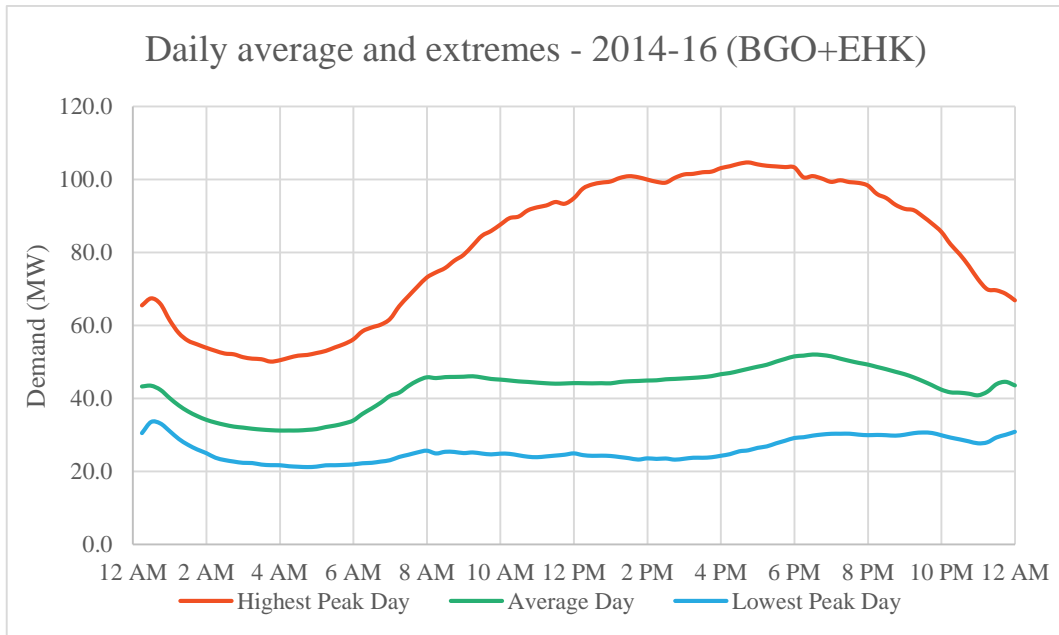


Figure 2: Average, minimum and maximum demand days in Bendigo, 2014-16

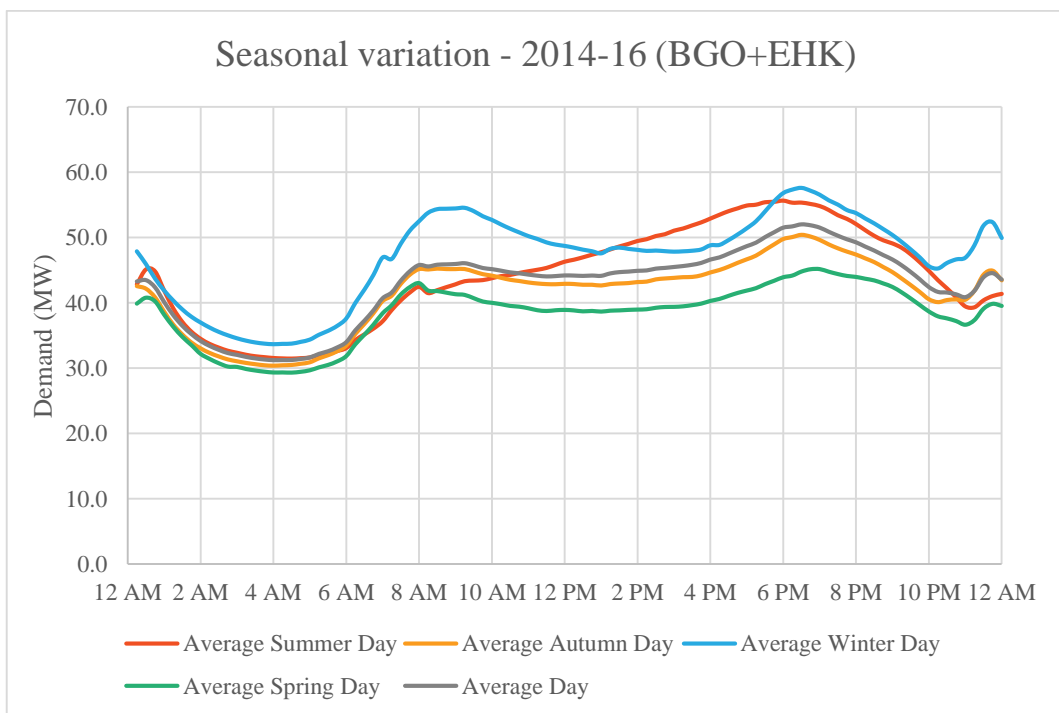


Figure 3: Average daily demand profile in Bendigo, seasonal variation

The following figures show the Bendigo network geographically

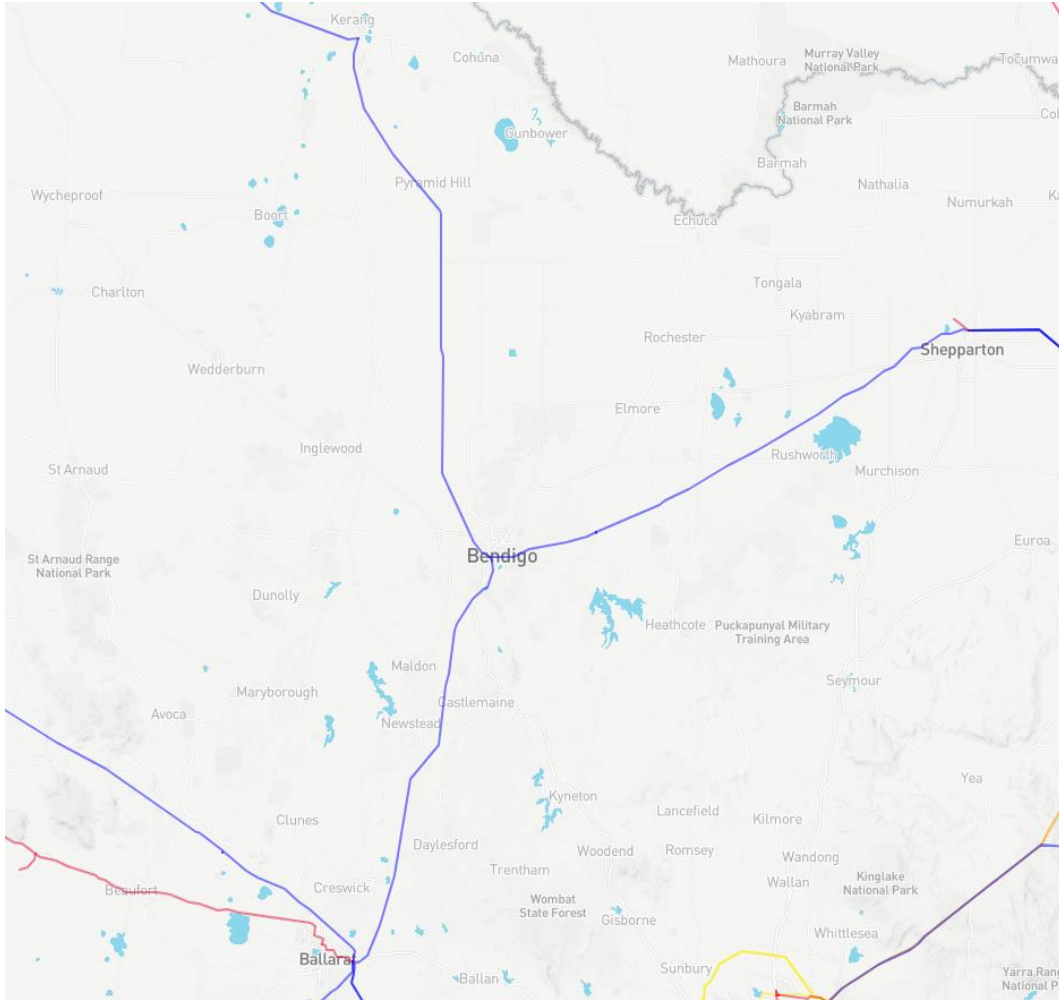


Figure 4: Transmission network map, blue = 220 kV (AEMO Interactive Map tool)

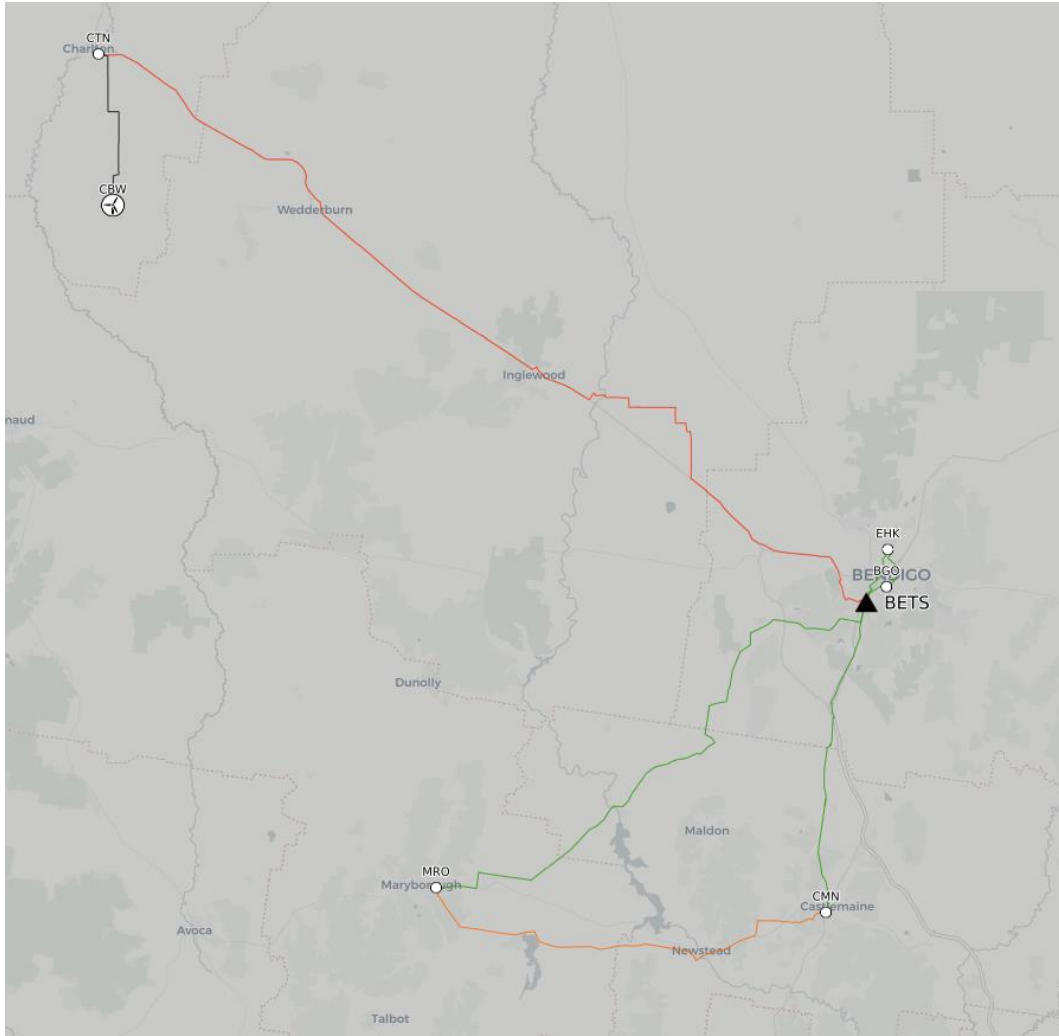


Figure 5: Sub-transmission network map from BETS (Powercor capacity map)

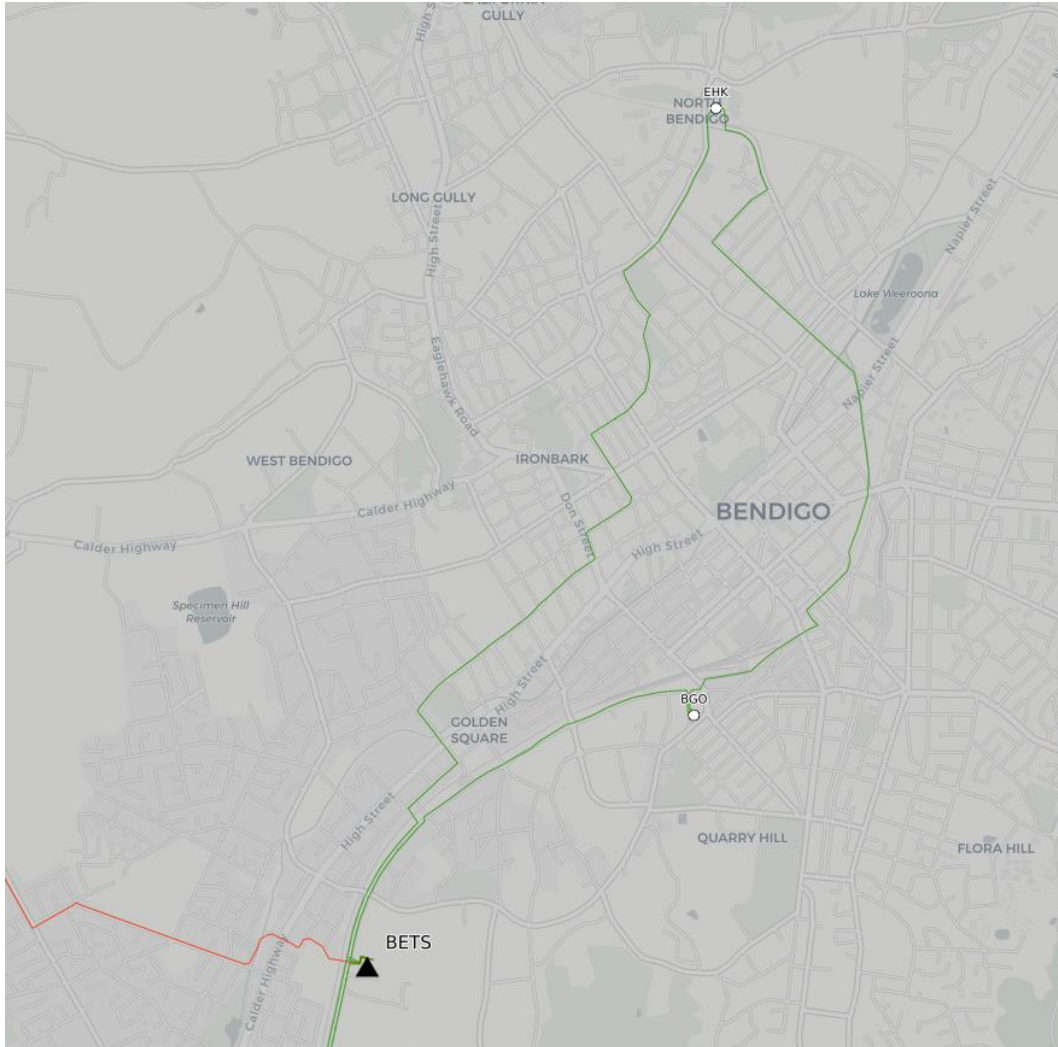


Figure 6: 66 kV Bendigo-Eaglehawk sub-transmission loop (Powercor capacity map)

2.2.2 Regional geology

The Bendigo goldfield consists of folded and faulted interbedded sandstones and slates. Weathering extends from surface to a maximum depth of approximately 120m and is typically in the range of 40 – 60m. Ore is hosted in the anticlinal fold axes associated with cross-cutting thrust faults. Ultramafic lamprophyre dykes intruded the axis positions, generally along fault planes and bedding. Four generic orebody shapes are encountered:

- Stockwork or “spur” reefs
- Fault and neck reefs
- Saddle reefs
- Leg or “back” reefs

2.2.3 Historical and modern mining

Mining in Bendigo has occurred broadly in two phases; ‘historic’ mining and ‘modern’ mining. Historic mining occurred from the mid-19th century until the mid-20th century. The mining method of this period generally involved over-hand cut and fill stoping and development comprising shafts and adits no wider than approximately 6 to 8 feet (2 to 3 m). Stopes were typically backfilled with waste material and development was supported with timber struts and shoring. Myriad shafts, stopes and development adits have been constructed in Bendigo during the historic era. There is varying confidence in the quality of the survey of the historic mine voids. Development of the deeper voids constructed by the larger mining companies are likely to be relatively well known, but there remains considerable uncertainty regarding the accuracy of the survey of the historic stope voids.

Modern mining commenced late in the 20th century and most recently ceased in 2011 with the closure of the Swan decline. Modern mining was typically undertaken using a long-hole open stoping technique and it is understood that at least some of the stopes have been backfilled. The modern development voids are considerably larger than the historic development. The Swan decline is approximately 5 m wide with operating development approximately 4 m wide. The maximum depth of the mine is approximately 1200 m. Ground support in the modern era comprised split set friction bolts, resin/grout dowels, mesh, shotcrete and cable bolts. It is understood that only a small portion of the underground development has been shotcreted.

2.2.4 Hydrogeology and groundwater management

The historic gold mining activity in Bendigo has left significant underground voids underneath Bendigo. Over 5000 separate shafts were sunk. The mining activity was focussed on seven main quartz reefs, and many other smaller reefs. Most of these reefs are flooded with groundwater. At depth, the reefs have been found to largely be hydraulically independent from each other. Closer to surface, the links between groundwater differs between the different reefs.

The underground workings act as conduits to collect and concentrate natural groundwater which discharge to surface in locations throughout Bendigo including the city centre area and surrounding locations. Some of the groundwater discharges contain odours, salts and some heavy metals including arsenic.

Two of the reef lines, Deborah and Sheepshead, were drilled through to the newer Swan decline during its construction in order to avoid rock collapse under from large differences in groundwater pressure. This connected the three separate workings hydraulically approximately 300 m below ground level. These workings are currently pumped down to about 260 metres below surface level to enable the continued operation of the Central Deborah Tourist Mine. The excess groundwater of approximately 1.5 – 2.0 ML/day is pumped to the Londonderry shaft at the southern end of the Garden Gully reef, which has a groundwater level of approximately 30 m below ground level. It then flows via the workings to the north end of the Garden Gully reef and is pumped from the North New Moon shaft to be treated and discharged to the environment, or if possible reused. This groundwater pumping, treatment and disposal process will be in place until 30

June 2021. Options for management of groundwater beyond this date are being developed by the Bendigo Groundwater Project. Regardless of the long term treatment process identified, the treatment expense will be a perpetual economic burden.

Any pumped hydro system to be proposed should as a minimum have no net negative impact on the groundwater management system, and ideally would have a positive impact.

2.2.5 Geotechnical considerations

The following geotechnical and hydrogeological considerations are relevant to the project:

- The production voids (stopes) are unsupported and whilst limited failure of the walls of stopes is typically acceptable in a mining setting, if the voids are used for water storage for the hydro scheme, the likelihood and consequence of uncontrolled rock mass failures need to be considered carefully. (note: stopes are voids that are accessed only for as long as necessary to remove ore, and are not constructed to remain stable after ore removal)
- It is considered preferable to utilize the development voids for underground storage where possible. The development voids are accessible and will typically be supported. Development voids are designed and constructed for continued use to support mining operation.
- An assessment of any underground voids for use as underground storage will need to carefully consider the hydrogeological connectivity of the selected voids to the surrounding rock mass or nearby voids. Any leakage in or out of the system will result in reduced round-trip efficiency. Also any large differential in groundwater hydrostatic pressure can induce large stresses on the rock.
- If voids below the current water table are chosen as preferred storage locations, a detailed physical inspection of the condition of the voids will not be possible without drawing down the water table. Consideration should be given to remote underwater inspection in later phases of the project.

2.2.6 Environmental and heritage restrictions

There is a Recognition and Settlement Agreement in place with the Traditional Owners in the area, the Dja Dja Wurrung Clans Aboriginal Corporation. This agreement applies to all Crown land in the area, and includes any freehold (privately owned) land more at depths more than 50 feet below ground level. The implications of these agreements for underground infrastructure are not well understood as little precedent exists. The Traditional Owners should be consulted during a feasibility study to determine the potential impact on project timeline and business case.

2.3 UPHES literature review

A number of other underground pumped hydro energy storage studies have been conducted around the world and have been reviewed as part of the first phase of this study.

The literature review confirmed that no dedicated underground pumped hydro energy storage system has been built or is currently under construction.

Studies have been performed for the following potential applications:

- Underground deep-shaft gold mine workings in South Africa
- Underground coal mines in Germany
- Underground mines of various materials in United States
- Underground coal mines in Spain

Generally speaking, the advantages of underground pumped hydro identified in these studies are:

- Capital efficiency through utilising existing voids and assets
- High available heads due to mining excavation
- Low visual impact
- Low planning/environmental impact
- Free source of water
- Potential to combine with other services such as groundwater management and treatment

Key risks in general are:

- Long and expensive access shafts, tunnels, and ventilation requirements
- Structural adequacy of rock mass
- Permeability of rock mass
- Mineral content and contamination of water supply
- Groundwater contamination.

Other challenges identified include:

- Higher maintenance costs than standard pumped hydro projects
- Lower service life than standard pumped hydro projects
- Unfavourable hydrodynamics due to void geometries
- Contaminated groundwater necessitating expensive materials
- Loosened rock in storages entering system and clogging filters or damaging assets
- Efficiency losses due to groundwater flow into or out of storage volumes

- Remediation required on old mine workings
- Size constraints for equipment due to existing access dimensions.

Research conducted into the viability of underground pumped hydro energy storage in deep level gold mines in South Africa was found to be particularly relevant to this study. With similar geology and similar project drivers, many lessons from the research can be transferred and applied to this study for Bendigo. While the scale of the South African opportunity is much larger due to significantly higher heads and large storage volumes, the technical challenges and constraints are very analogous. This research released in May 2017 found that the concept in that location is technically feasible and economically viable, and strongly recommended a more detailed follow-up study.

There is another disused gold mine in Australia with a proposal to develop it into a pumped hydro energy storage system, located at the Kidston mine in Queensland. This project is not particularly relevant to the study as it is not an underground pumped hydro system, rather a more traditional system linking two open pit reservoirs with an elevation difference.

3 Concept development

3.1 Options identified

As discussed above, the historic workings are divided into seven separate reefs, which run roughly North-South for many kilometres, but are narrow in the East-West direction. The reefs are separated by about 300-400 m in the East-West direction. Many of these reefs are hydraulically independent of one another. The possible options for this underground pumped hydro project can be split into a few different types:

- **Intra-reef versus inter-reef**
Intra-reef options utilise upper and lower storage within the same reef. The distance between the upper and lower storage volumes is very short, comprising little more than their vertical separation. However containing the upper reservoir without leakage into the lower reservoir may require extensive waterproofing / sealing works.
Inter-reef options utilise hydraulically independent reef systems as upper and lower storages, and potentially capitalise on existing head differences between the reefs near capacity and the reefs which are being pumped out. However, they carry the cost, complication and efficiency-penalty of traversing the horizontal distance between the reef systems.
- **Upper reservoir above-ground versus underground**
An upper storage dam if already existing, such as at the Kangaroo Flat mine site, could provide a low cost large upper storage volume. However, this comes with complications including long pipes yielding poor efficiency, and issues with contaminated water containment. Another option considered was an above-ground storage within Bendigo (above the

most accessible lower workings) but this has a significant land requirement within Bendigo if not using an existing dam.

- Large once-off project versus small and repeatable
Large projects can absorb significant amounts of capital for activities like additional mining or dewatering while still remaining financially viable and delivering economies of scale. Small, modular and repeatable pumped hydro projects are more flexible and prototypable for testing, but this comes at both a capital and operating cost penalty.

The study has broadly considered 4 different options for pumped hydro energy storage systems, listed below.

1. Large underground inter-reef, linking two reefs with a single large system
2. Small and repeatable underground inter-reef, linking two reefs with small systems, similar to the BSG concept
3. Large underground intra-reef, utilising multiple voids in the same reef
4. Large dammed intra-reef, utilising an above-ground dam and an underground void, similar to the GBM concept

The key challenge in identifying suitable options is finding underground voids separated by a large elevation difference, both with significant storage volume and ideally with other desirable features such as access via the modern development workings, access to ventilation shafts etc.

Table 1 shows indicative sizes and parameters for potential systems which align with options 1-4. Note that these are high level assessments, and that the round-trip efficiency estimates do not account for groundwater ingress or egress.

Table 1 - Pumped hydro options

	Inter-reef Large	Inter-reef Small	Intra-reef UG	Intra-reef Dam
<i>System properties</i>				
Head (m)	720	250	250	720
Volume (ML)	100	100	50	100
Penstock length (m)	1000	680	300	3000
<i>Operating point</i>				
Power generation (MW)	30	1.0	4.9	30
Storage Duration (hrs)	6	47.2	5.9	6
Overall round-trip efficiency	70%	48%	73%	68%
Energy (MWh)	180	47	29	180
Flow rate (m ³ /s)	5.3	0.6	2.4	5.3

3.2 Preferred concept

The vision for the project inherently leads to a desire for the largest feasible system within market constraints. It is clear from Table 1 that Option 1, the large

UG inter-reef system, can be significantly larger than any of the other identified concepts which were considered (other than the use of an above ground reservoir, which could be similar size but with additional cost associated with construction of a dam. For primarily this reason, this concept has been chosen as the preferred concept to undergo refinement and modelling. There are other benefits of this option which are detailed in this section.

3.2.1 Overall concept

The preferred concept is to use the Garden Gully workings as an upper storage, and the modern Unity/GBM workings below the North Exploration Drive towards the bottom of the Swan Decline as a lower storage. These two storages would be linked by below-ground pressure pipe, likely using a combination of existing and new tunnels/shafts.

The attractive features of this concept include:

- High head (> 700 m) provides significant cost advantage over “shorter” systems, and enables high generation and storage capacity (30MW for 6 hours)
- Well understood storage geometry with large lower volume and very large upper volume.
- Does not rely heavily on unknown older shafts/workings or stopes which may be collapsed, partially collapsed, or in poor or unknown condition. While it does utilise the Garden Gully reef historic workings, these have been shown to transmit water effectively during groundwater management activities (albeit at considerably lower flow rates).
- Good accessibility for personnel/equipment to the powerhouse via dewatered decline
- High head means Pelton turbines can be used, which have high efficiency over a wide operating range and would mean that the powerhouse does not need to be submerged below the lower storage, reducing construction cost and risk
- System would inherently handle dewatering of Central Deborah tourist mine due to the hydraulic dependence of the workings
- Would add value to modern mining assets as North Exploration Drive would necessarily be dewatered and accessible
- Using Garden Gully as upper store means groundwater ingress to Swan/Deborah/Sheepshead could continue to be handled from North New Moon, or from a range of other locations along the Garden Gully reef for reuse, and that significant pumping costs to get excess groundwater up to Garden Gully could be covered by pumped hydro operating costs, as it is a necessary part of the sustainable operation of the plant

3.2.2 System sizing

There are a number of key system parameters:

Available head: approximately 720 m from upper storage to turbine runner

Generation capacity: 30 MW nominated as a potentially feasible and appropriate capacity for the pre-feasibility. This may be able to be increased in a future phase of project development if it is viable and desirable, and the proposed ownership and operating model supports the additional capacity. Additional generation capacity may have high value for occasional events, but would otherwise likely have a lower utilisation than the proposed capacity.

Water storage volume: approximately 100 ML available in nominated storage volume at bottom of Swan workings. According to GBM and DELWP data, approximately 7-10 ML/m is available in Garden Gully reef (i.e. for 100 ML, would require approximately 10-15 m of vertical depth). A key risk is that the Garden Gully reef's hydraulic conductivity will not be high enough to deliver the required flow rate and that significant draw-down gradients will form when draining, and the penstock shaft will be flooded when pumping. This risk is further explored in later sections of this report. Should Garden Gully be found not to be suitable, its function within the scheme could be substituted by a new 100 ML above-ground reservoir, for which there are several potential sites (100 ML would be achieved with a 4 hectare site with pond depth of 2.5 m, for example).

Energy storage capacity: Similar to available head, this is largely fixed by the vertical distance between top and bottom reservoirs and the available storage volumes. The storage capacity is in the order of 180 MWh.

Storage duration: For the chosen concept, there is 6 hours of energy storage at full generating capacity. This storage would take 10 hours to fill by pumping. This parameter can be somewhat misleading depending on the way the system is operated. For example, if the generation capacity were oversized to allow the system to provide significant supply to respond to demand spikes, and then provide lower generation at other times, the duration of operation of the plant would be longer than the "storage duration". The details of how the system is operated will depend on other fundamental aspects of the project such as ownership and financing options.

Flow rate: The generating flow rate for this concept is approximately 5.3 m³/s, and the pumping flow rate is approximately 3.1 m³/s. In this system the flow rate was determined by the economic power generation capacity. Pressure loss and surge mitigation are both expected to be less significant than a typical pumped hydro system. The pressure loss is less significant because the available head is so great that losses are a much smaller percentage of the total, and also because the incremental cost of increasing the diameter of the main raise bore to reduce friction loss is relatively low. The surge is less significant because the Pelton turbine jet deflectors make surge much more straightforward to manage than with other types of turbines.

Round-trip efficiency: approximately 68%-70%. A major contributor to the efficiency loss in this system is the difference in head between generating and pumping, due to the use of Pelton turbines and the large vertically distributed lower reservoir.

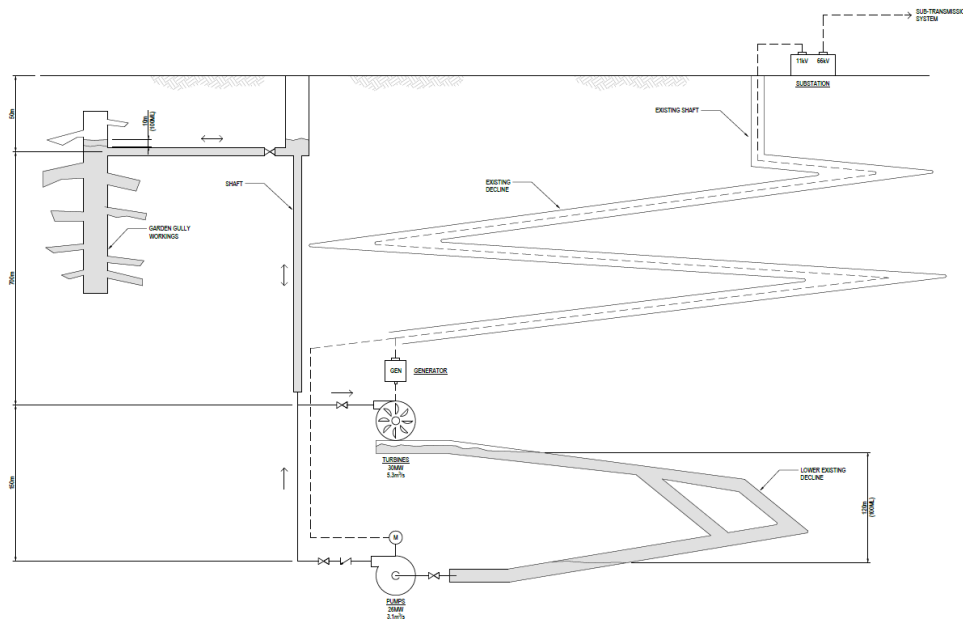


Figure 7: Schematic flow diagram of concept

3.2.3 Component selection and configuration

This section outlines the main system components which comprise the preferred concept. These include:

- Turbine: size and number of turbines, orientation
- Pump: size and number of pumps, whether to have multiple submersible pickups pumping to a central sump to maximise storage utilization, whether multiple pump stages are needed
- Penstock (pipe): choosing the level at which to cross between reefs, identifying existing or new suitable shafts, choosing between unlined shaft, lined shafts, or pipe within shaft
- Powerhouse: choosing location, structural design, access, equipment handling, utilities/services
- Upper storage: tie-in point to Garden Gully reef, isolation valve location and access
- Lower storage: which segments of lower mine to use, ensuring ventilation to atmospheric pressure, minimising depth of storage
- Transformer: in powerhouse or on surface
- Power transmission: power cables in decline, or vertically via shaft for more direct, less accessible route
- Tailrace: design of discharge from turbines and suction configuration for pumps
- Powerhouse ventilation: assessing whether existing ventilation system and fans can be used (fans would require refurbishment)

- Surge mitigation: whether surge shaft is sufficient, or underground compressed air chamber or similar is needed

3.2.3.1 Turbine/s

There are a number of different types of turbine used in hydropower plants. The best turbine type for an application depends on many factors, including available head, flow rate, cost, maintainability, reversibility, and more.

For this project Pelton turbines have been selected. Advantages of Pelton turbines over other turbine types for this application include:

- Cost effective for systems with high available head (>500 m)
- Easier to maintain, particularly with erosive water
- Powerhouse is situated above lower reservoir (this avoids construction of a powerhouse within the lower reservoir)
- High efficiency at part load (approximately 90% efficiency is typical from 25% of design flow to 110% of design flow)
- Nozzle flow deflectors mean surge mitigation is generally simple or not required
- Simple machine with few moving parts, which translates to minimal maintenance

The study team received feedback or responses from three suppliers with turbine selections for the project:

2 x 15MW horizontal turbines was chosen as the turbine selection for the pre-feasibility concept based on the information received. The study team notes that horizontal turbines may not be the best option for a space-constrained system such as the excavated underground powerhouse. In a feasibility design more work should be done engaging with suppliers to optimise the turbine selection and obtain budget prices from a wider range of sources.



Figure 8 - Horizontal Pelton turbine plant in Turkey (image provided by WKV)

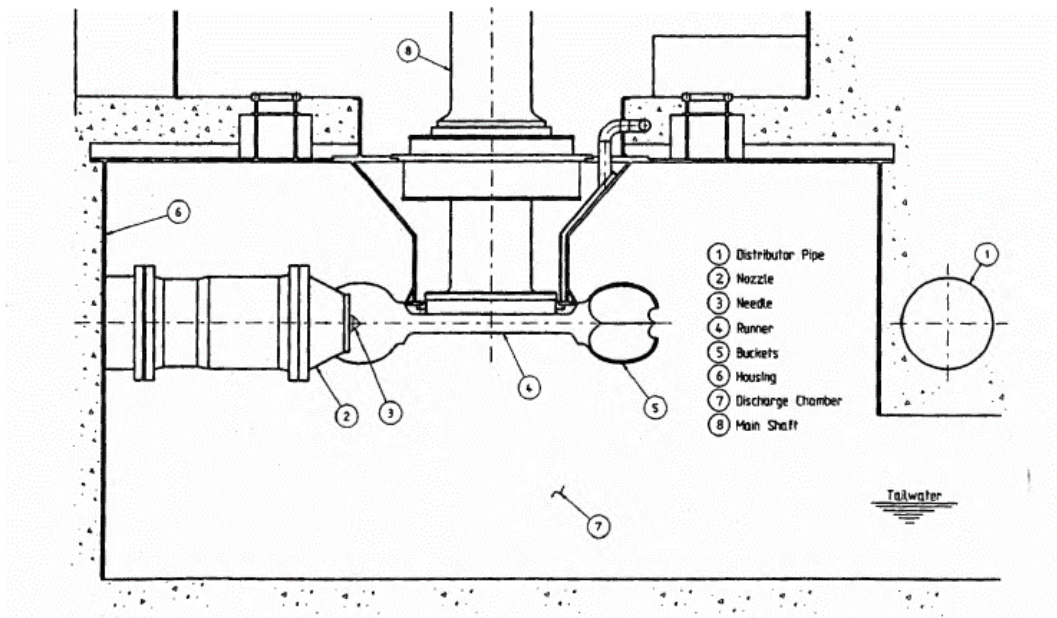


Figure 9: Vertical Pelton turbine elevation view (ASME Hydropower Mechanical Design textbook)

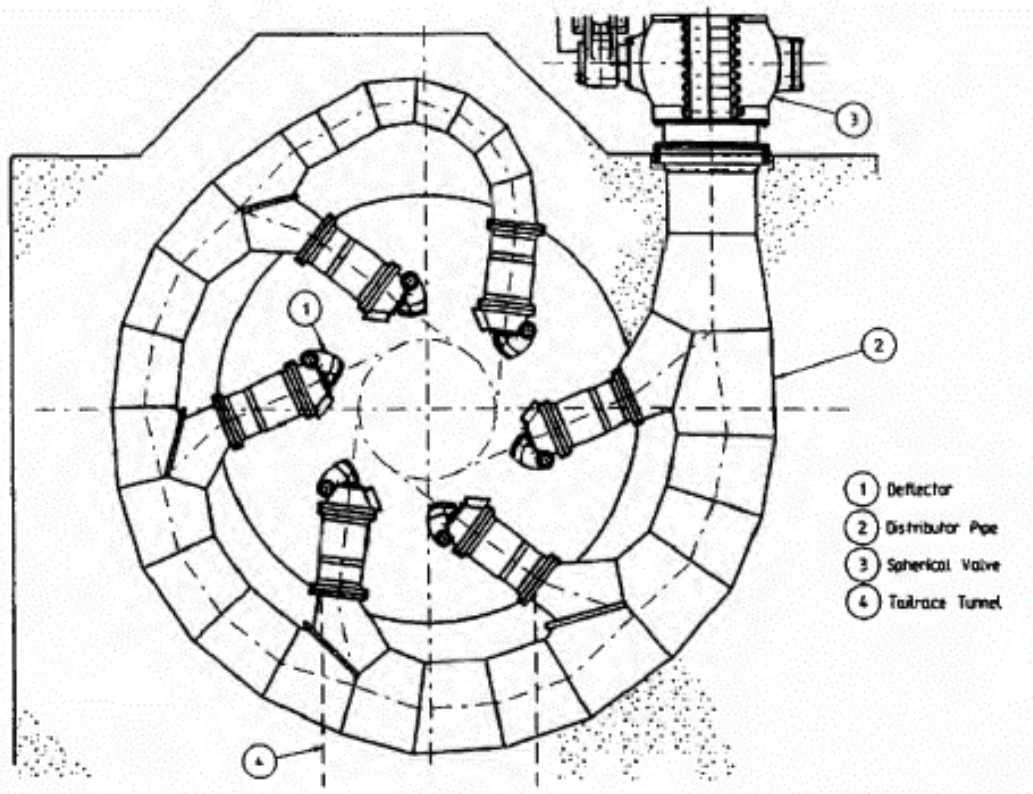


Figure 10: Vertical Pelton turbine plan view (ASME Hydropower Mechanical Design textbook)

3.2.3.2 Pump/s

In terms of pumping applications, this system would be characterised as high flow and very high head, which translates to very high power consumption and a challenging pump application. An application with similar head and flow rate would be boiler feedwater pumps for steam generation applications, such as in coal or nuclear power stations.

As part of the project the team engaged with pump suppliers, one of whom provided a pump selection comprising two multi-stage pumps, each delivering half of the total required flow rate. The supplier provided a budget estimate for the pump package.

The selected pumps would operate well over the range of heads required for the system and would not require a variable speed drive, which reduces cost and improves electrical efficiency..

For the operating head range of the system (approximately 675 – 800 m) the pumps are close to peak efficiency. This is beneficial not only because it means the energy losses are minimised, but also because it inherently means that the pumps are operating at a range in which will minimize wear, fatigue and vibration, extending the pumps' operating life and reducing maintenance costs.

The pumps must never be less than 30 m (above pump inlet) while operating. This means that the lower reservoir design must allow for 30 m of head above the

pump room to be the empty condition, and the 100 ML working volume must be located above this point.

3.2.3.3 Powerhouse and pump room

In the design of the powerhouse and pump room there are several considerations:

- Primarily designed and sized for the equipment in sensible configurations, e.g. turbine-generator/s, pump-motor/s, valves, penstock and tailrace
- Crane/s for equipment installation, removal and maintenance
- Personnel access to all equipment for inspection and maintenance
- Vehicle access from decline for equipment and personnel transport
- Safe working environment
- Safe and reliable operating environment

For this concept, minimising excavation required in the powerhouse is a key part of project viability. For this reason, finding innovative ways to design the powerhouse by using as much existing excavation as possible is important. To achieve this, the project team explored the 3D model of the mine workings looking for voids which lend themselves particularly well to being used.

A significant constraint for this concept is that the pumps and turbines are separated by a large vertical distance. This is in order to provide the required storage volume between the Pelton turbines which must freely drain down to the storage, while also providing the required net positive suction head above the pumps.

A design with the pumps located below the powerhouse connected by a vertical shaft has been adopted, as this allows the pumps to be accessed from the powerhouse using the powerhouse bridge crane.

The selected powerhouse location is shown in Figure 11, Figure 11, and Figure .

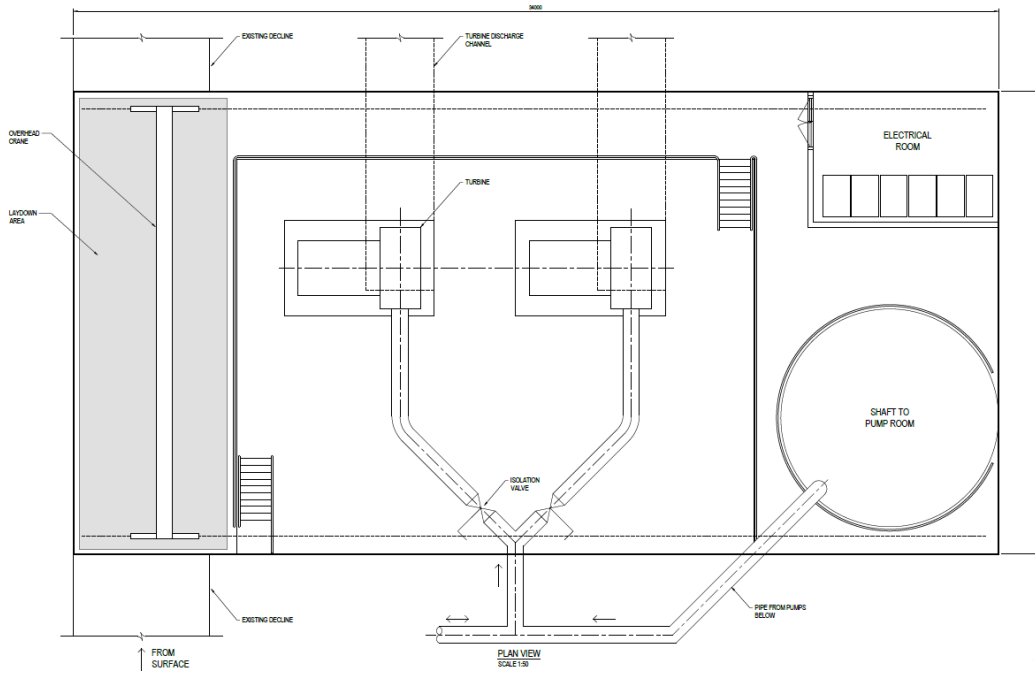


Figure 11: Preliminary powerhouse layout

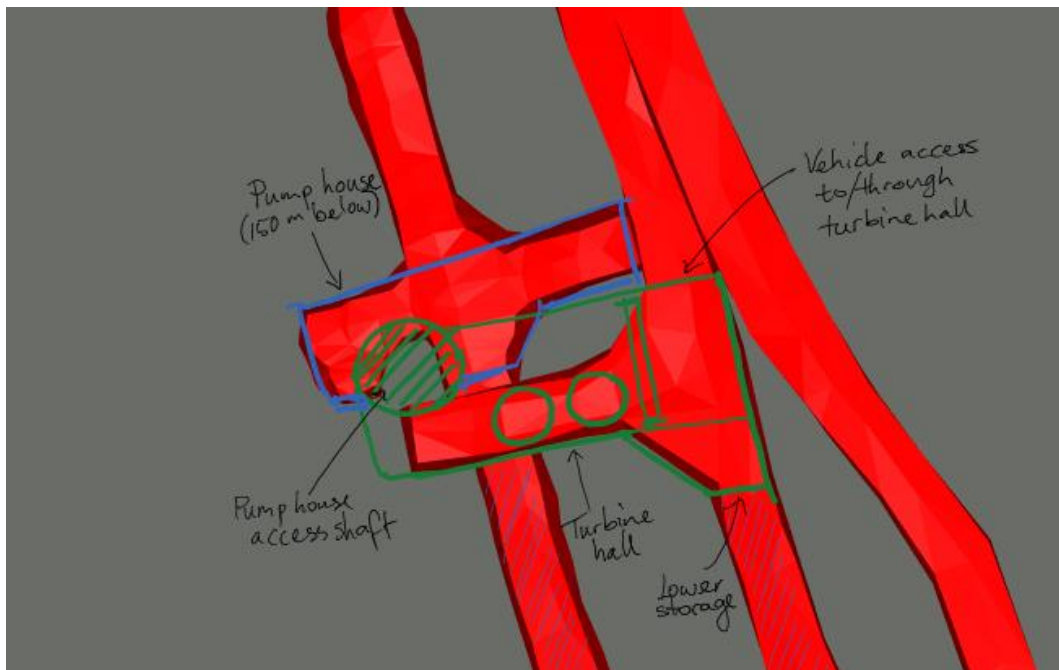


Figure 12: Powerhouse concept plan view

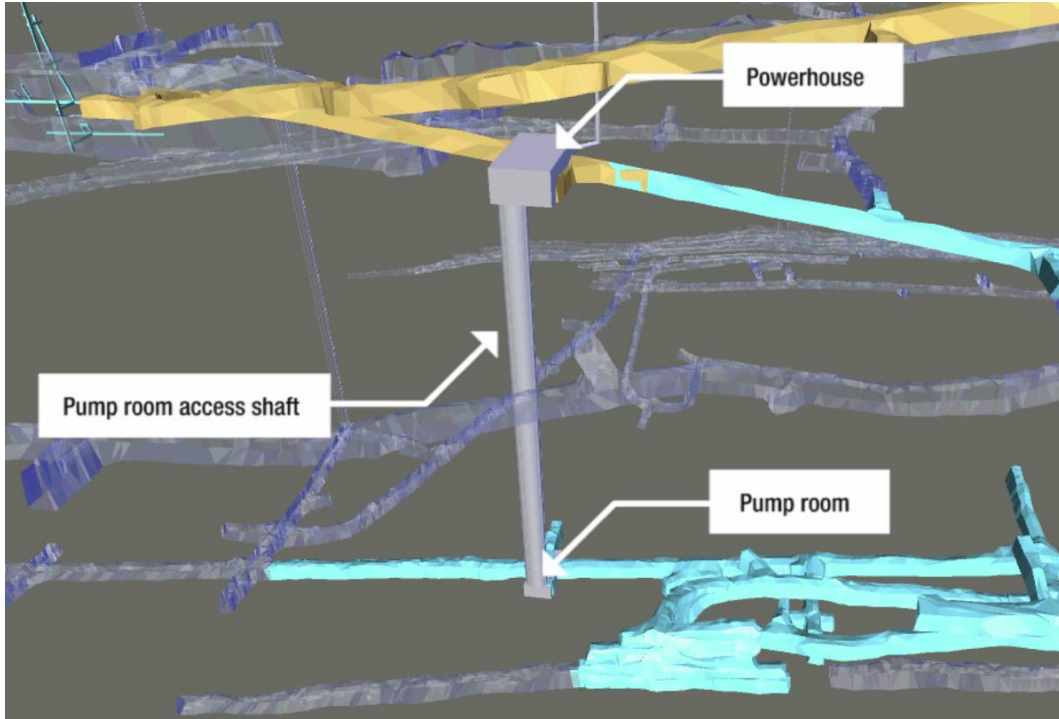


Figure 13: Powerhouse and pump room with access shaft

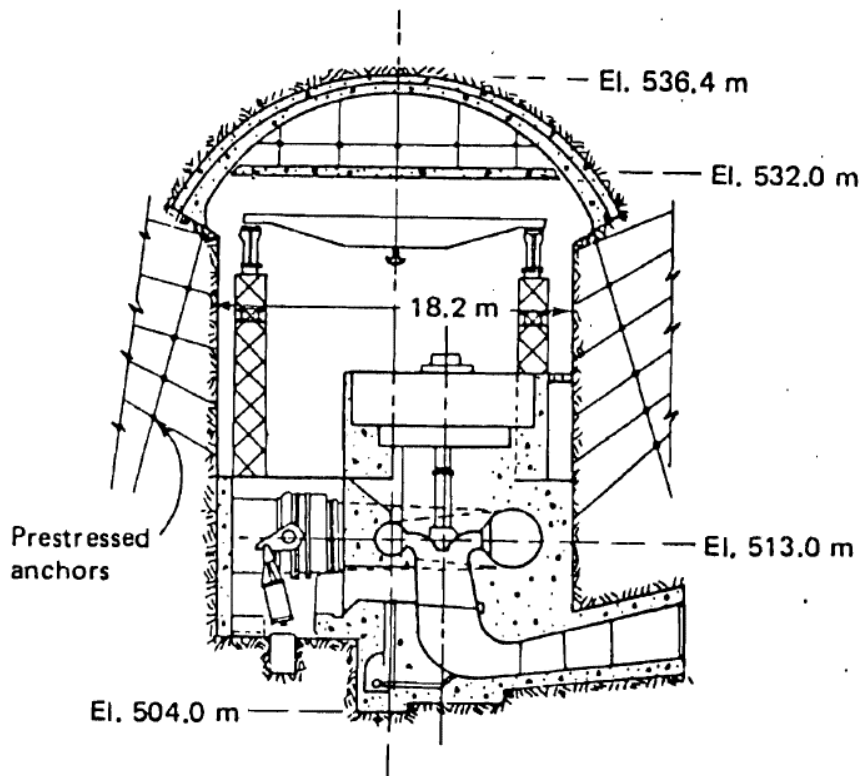


Figure14: Typical underground powerhouse (this image shows a different type of turbine, a vertical Francis turbine, but illustrates common elements such as the void, structural elements, bridge crane, turbine location, shut-off valve, generator. From Warnick Hydropower Engineering textbook)

Note that the team considered using stopes at the bottom of the modern mine for storage, as the 3D model indicates that they would provide large and dense storage volume over a small vertical distance, which improves system efficiency. However, we were advised by GBM that the stopes were designed as short-term openings without the stabilisation and support used in the exploratory workings and main decline so would not be recommended as a storage volume. In addition, the stopes have been 70-80% backfilled as part of the stoping process so the free volume is much less than that indicated in the 3D model. GBM advised against removing the mullock fill in the stopes because it would destabilise the stope walls and be too expensive/impractical. For the reasons given above it was decided that only exploratory workings would be used for storage.

3.2.3.4 Upper storage

A preferred and an alternative concept for the upper storage were developed:

Preferred: Garden Gully reef, tying in near top of reef

- Cheap to construct, existing voids

- Uncertain hydraulic conductivity along reef, need testing to prove that flow rate will not be throttled by groundwater equilibration due to flow restrictions in nearby shafts and tunnels
- High velocities and daily filling/dewatering in historic workings may undermine integrity of rock and collapse shafts/tunnels

Alternative: Above-ground reservoir at back of council site

- Expensive to construct
- Community possibly concerned about contaminants in groundwater
- Technically feasible, known risks
- Other above-ground locations also available in good locations e.g. next to Bendigo Terminal Station (transmission substation)

The preferred concept selected for the pre-feasibility study is using the flooded Garden Gully reef workings as the upper reservoir for the system. Using the existing voids means minimal civil work is required, providing a significant cost advantage over the above-ground reservoir alternative. It would also mean that excess groundwater inflow would continue to be pumped into the Garden Gully reef, so it ties in well with the existing interim groundwater management system which extracts from the New Moon shaft at the north end of Garden Gully, as well as any future solutions which would utilise Garden Gully reef as an extraction point.

Due to the unknown hydraulic conductivity of the Garden Gully, the project team decided that it would be prudent to consider a known risk alternative option in parallel to the preferred option. This would provide a relatively straight-forward alternative if early work in a feasibility study found that the Garden Gully concept was not technically feasible or acceptable from a risk perspective.

A number of candidate sites exist in Bendigo, the most promising of which appears to be a mining spoil storage site to the North-West of the council depot on Adam St, shown in the figure below. This is located above the powerhouse and adjacent to the Adam St Vent Shafts, and is currently being worked to remove the spoil over the next 2-3 years for remediation. Preliminary estimates suggest that a 3.5-4 hectare reservoir could be constructed on the site, which would allow for 100 ML of storage with approximately 3 m of depth.



Figure 15: Area near council depot that could potentially be used for above ground reservoir

3.2.3.5 Lower storage

Using the lower portion of the modern mine workings has the following advantages:

- Decline is available for access for vehicles and maintenance
- Exploratory workings are well-constructed for storage integrity, less work should need to be done to remediate to appropriate standards
- Existing shafts exist for ventilation and power cable routing
- Means that Central Deborah Tourist Mine would drain into the pumped hydro system thereby eliminating their pumping requirements.

The challenges in finding an appropriate storage volume in the lower levels of the decline is inherently linked to challenge of finding a powerhouse location, and discussion on this can be found in Section 3.2.3.3.

3.2.3.6 Transformer and power transmission

The preliminary concept for grid connection is to connect to the 66 kV sub-transmission loop from Bendigo Terminal Station (BETS) to Bendigo and Eaglehawk Zone Substations (BGO/EHK). The 220/66 kV transformers at BETS have less than optimal capacity (N-1 energy at risk of 32 hours or 294 MWh in 2018, summer 50th percentile forecast). This means that if one of the transformers were to fail, it is likely that BETS would be unable to supply the summer demand on hot days. A pumped hydro energy storage system embedded in the distribution and operating in peak demand periods would reduce the load on the transformers, improving this issue, and potentially avoiding the need for new transformers, load transfers, or demand reduction. This project would provide ~30 MVA of power to the 66 kV bus during peak periods, which would bring the peak forecast transformer load below the N-1 capacity for the 10-year forecast period.

Other benefits the project could provide to the local power system include inertia, frequency control, and voltage support (turbines can operate as synchronous condensers) which we understand is noted by AEMO as lacking in the region.

Transformer location

The system will likely be comprised of 2 x 18 MVA synchronous generators at 11 kV, 750 rpm, on Pelton-type hydro turbines, and 2 x 15 MVA asynchronous motors at 11 kV on multi-stage centrifugal pumps, with 2 x 18 MVA 66/11kV transformers at ground level substation. A transformer room underground integral to the powerhouse was considered in order to minimise losses in transmission by stepping the voltage up closer to the generators. However, above-ground transformers have been chosen for the preliminary concept for the following reasons:

- Transformer size not limited by decline dimensions
- Easier to maintain
- Transformers not in humid environment
- Cost of power loss in transmission balanced by reduced capital on excavation and structure, potential minor savings on transformers, cable, and other equipment

Connection route

The preferred connection option is shown in the following figures, along with two alternative options. The preferred option has a much shorter cable length which is beneficial for cost and efficiency, but has the complication of having a 440 m section of vertical installation in the Eve St vent shaft from the Swan Decline. This shaft does not have access infrastructure installed in it, so construction and maintenance will be more expensive and more complicated from a health and

safety perspective. This was determined to be an acceptable trade-off given the benefits of the cable route.



Figure 16: Preferred Option - Eve St Vent Shaft to BETS-BGO 66kV line



Figure 17: Alternative Option 1 - Swan Decline to BETS 66kV bus



Figure 18: Alternative Option 2 - Adam St Vent Shaft to BETS-BGO 66kV line

Powercor connection enquiry

A preliminary enquiry was submitted to Powercor for the preferred concept. Their response indicated that the proposed system may be able to connect without major augmentation works subject to further studies confirming available capacity. Some augmentation would be required to connect into an existing line, as a switching station would be required. This is a very promising outcome for the business case for this project, as grid connection is often one of the most costly and difficult aspects of power projects.

The response indicated that no significant network constraints exist which would prevent the system from being connected as proposed, but that given the long timeframe for development and construction this is subject to change. If another proponent were to sign a connection agreement first and pay all relevant fees then the capacity for this system may be reduced or constrained.

Powercor advised that the next stage in the connection process is to submit a detailed enquiry via their online portal. The charge for this would be approximately \$60,000 depending on the extent of work required, as well as approximately \$5000 to provide the project team with relevant steady state system model data and hold a briefing meeting. The turnaround time for the detailed enquiry would typically be no more than 30 days unless shared augmentation works are required and AusNet Services must also be involved.

Following this would be a connection application, which would be assessed by Powercor for a fee of approximately \$275,000, depending on the final scope

Powercor also indicated that AusNet Services and AEMO may need to be involved in the planning process for the project and may require a fee for their services.

Powercor attached to their response the following diagram showing an example connection facility single line diagram (SLD). A hand-sketched SLD produced for the preliminary enquiry is also included below. These network configurations are preliminary, and a detailed connection options study will be required in a feasibility study to optimise the connection and plant design.

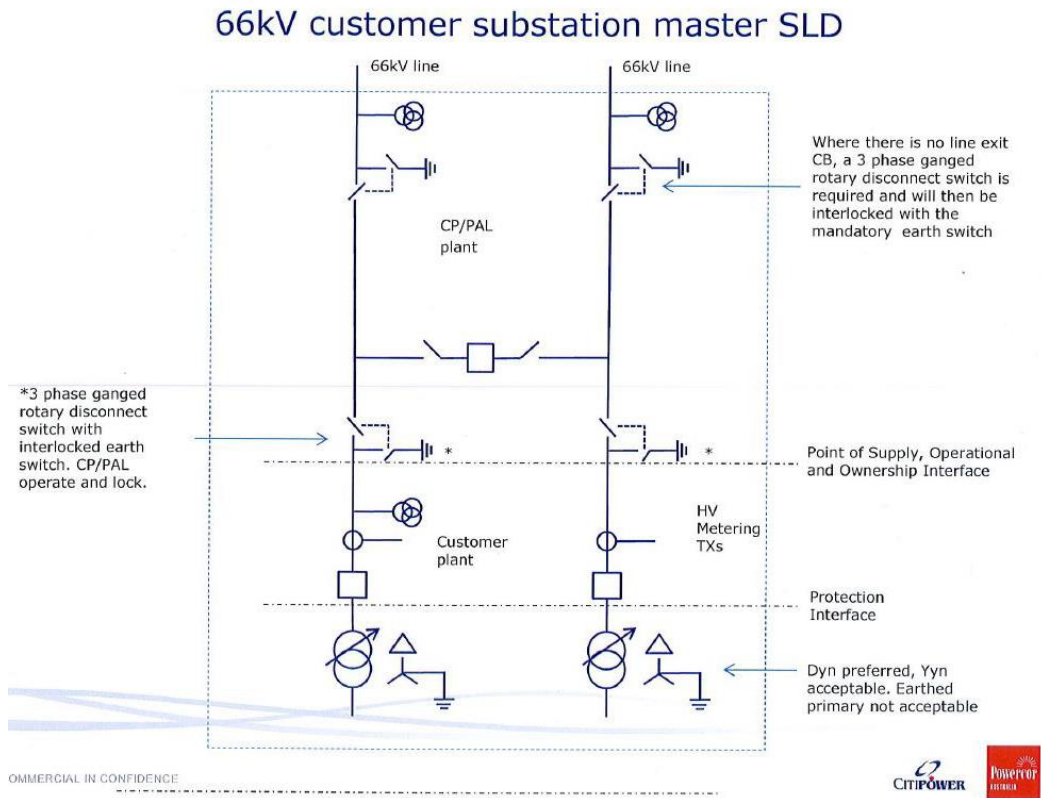


Figure 19: Example connection configuration from Powercor

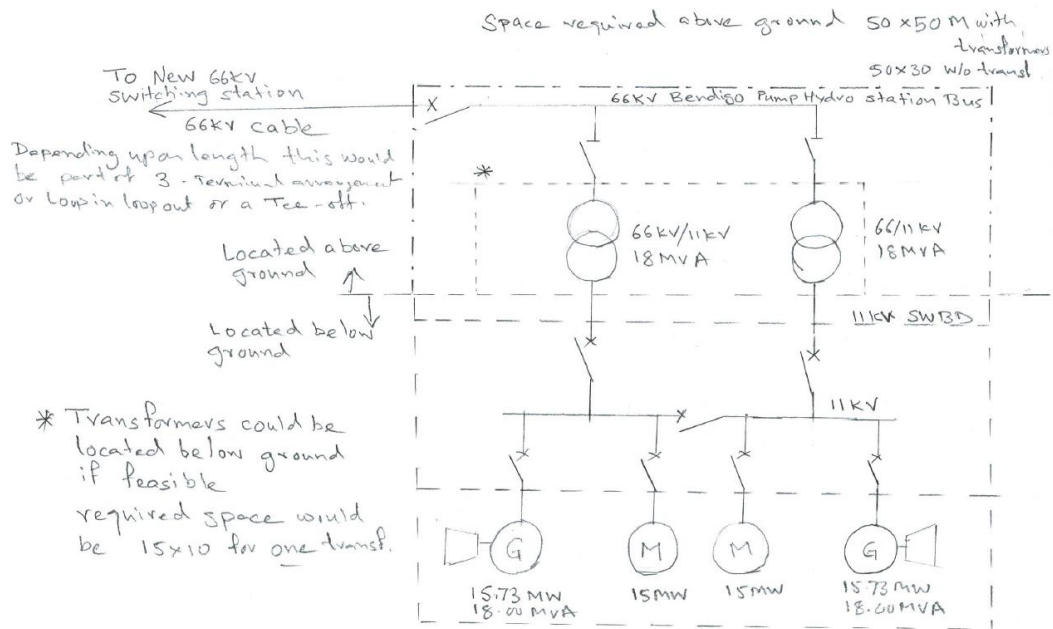


Figure 11: Preliminary electrical single line diagram of facility

3.2.3.7 Penstock and valves

Penstock – 670 m raise-bored shaft at 1.5 m diameter, with upper 50 m excavated at larger size to provide sufficient working space for Garden Gully connection tunnel. 400 m drill/blasted tunnel to tie into existing shaft in Garden Gully reef. Geotechnical work as part of a feasibility study is needed to inform whether a waterproof, non-load-bearing liner is required.

There are three potential locations for the raise-bored penstock:

- 288 King St (empty plot of land, very close to ideal location, combination of freehold and Crown land, in residentially zoned area and adjacent to homes, shown in Figure 12)
- Eve St Vent site (would be good if this site is to be developed into renewables centre of excellence as proposed by BSG)
- Adjacent to rail between the previous two sites.



Figure 12: 288 King St, Bendigo (potential raise-bore location)

The top section of the penstock shaft will double as a vent to atmosphere and surge shaft, and access route to the penstock valve room.

Main valves required:

- Turbine isolation valve/s
- Pump suction isolation valve/s

- Pump discharge isolation valve/s
- Upper penstock isolation valve
- Pump discharge check valve/s (non-slam)

3.2.3.8 Tailrace

Pelton turbines do not require major tailrace infrastructure. The only requirement is for a concrete pit below each turbine into which water from the turbine will freely drain, from which it will subsequently drain by gravity into the lower storage volume.

3.2.3.9 Surge protection

Surge occurs when changes in the flow of water occur quickly. This causes rapid, large and oscillating pressures to occur, and if not managed, can damage equipment, penstock and valves. The two key operating cases are considered below.

Turbine operation

When generating, the worst case surge scenario is generator load rejection (effectively the generator being disconnected from the grid and the electrical load being removed from the generator), requiring the rapid removal of power input to the generator to avoid a turbine/generator overspeed condition. For some turbines this requires closing the inlet valves very rapidly.

For Pelton turbines, as selected for this project, a simple deflector plate is included which activates in load rejection scenarios to deflect the water jets away from the turbine into the tailrace, thereby removing the power input to the turbine without rapidly reducing the flow rate. The flow can then be reduced gradually to effectively manage the surge pressure. Due to this benefit, surge protection measures are not expected to be necessary for a generator load rejection scenario.

Pump operation

The worst case surge scenario while pumping is power system, motor or pump failure causing the pump to stop, resulting in the large column of water decelerating and reversing flow direction back down the shaft. To avoid damaging flow reversal through the pump, the check valve would shut. The slowing and reversing column of water and its interaction with the closing or closed check valve cause surge. Surge can be minimised through various measures, including appropriate check valve selection (non-slam with sprung closure mechanism to close at the appropriate time), and pump inertia (which slows the rate at which the pump stops). The relatively short distance between the lower and upper reservoir and the high pressure rating required for the tunnel regardless of surge indicate that additional surge mitigation measures such as surge vessels are unlikely to be required. Further analysis of surge should be undertaken at the next stage of the project to confirm surge magnitude and mitigation measures.

3.2.3.10 Ventilation

The powerhouse and pump room will need to be appropriately ventilated personnel and equipment during construction and maintenance. It is envisaged that day-to-day operation will be performed remotely. A feasibility study should investigate the option of using existing ventilation infrastructure to achieve this, and what work would need be done to return the existing ventilation equipment to working order. If feasible, this would be preferred to installing a new ventilation system as it would likely provide significant cost savings.

3.2.3.11 Construction and operational dewatering

There are two distinct phases of groundwater management to consider: construction phase and operational phase.

Construction phase

To enable the project to be constructed, the Swan Decline is to be dewatered from its current level, approximately 250 m below ground, down to 850 m below ground level. It is estimated this will require the removal of 1-1.5 GL. An additional 200 ML will need to be removed from Garden Gully to allow the connecting tunnel to be constructed.

In addition to removing the 1 – 1.5 GL that has accumulated since modern mining ceased, the natural inflow of 2 ML/day will need to be managed once construction dewatering has begun and Deborah/Sheepshead reefs are draining into the decline, which is an additional 1.5-2 GL total over the estimated construction period of ~2.5 years.

The total construction phase dewatering is estimated to be approximately 3 GL.

Historical maximum daily dewatering volume is 6 ML (4 ML greater than daily recharge). At this rate of dewatering it would take 250 days to extract 1 GL, or 375 days (~1 year) to extract 1.5 GL. The dewatering would need to be mostly complete before construction could begin on the powerhouse cavern and the penstock raise bore. However, the excavated upper raise bore and garden gully connection could be constructed before this.

Operational

Approximately 2-2.5 ML per day is expected, including groundwater flow into Deborah, Sheepshead, Garden Gully reefs and the Swan Decline. This is no more than that managed by the existing groundwater management system.

Options for management:

- New evaporation ponds – unlikely to be viable, approximately 100-150 hectares would be required (similar size to Woodvale facility).
Note that the option of using an above-ground reservoir to double as both upper pumped hydro storage and evaporation pond for excess groundwater inflow was considered, however the area of the upper reservoir was far too

small (in the order of 4-5 hectares) to make a significant contribution to the required evaporation rate.

- New treatment plant to treat the water and discharge to a recycled water or raw water system.
If water could be blended into either raw water or recycled water supply without desalination this would significantly reduce the cost of a new treatment plant, as the main contributor of cost to the current interim solution is the reverse osmosis treatment. This requires liaising with Coliban Water and local recycled and raw water users to determine the acceptable levels of salinity in the water for the intended uses. If the daily flow in and out of Spring Gully Reservoir is sufficiently high, blending in the treated saline groundwater may not have a significant effect on overall salinity. It is unlikely that a reverse osmosis unit could be made to be commercially viable as a part of the pumped hydro project.
- Existing treatment plant upgrade – possible depending on condition of equipment. Unlikely to be viable as part of the pumped hydro if RO treatment process is to continue.
- For treatment options, either discharge to environment or sale of water

The Bendigo Groundwater Project is currently receiving proposals for long-term groundwater management solutions. These solutions are intended to account for the 1.5-2 ML/day that the current treatment system handles from the Central Deborah tourist mine. If an economically viable way can be found for the pumped hydro system to appropriately treat and discharge or sell the groundwater inflow then it is possible that it could absorb this operating cost. Significantly, the proposed project does not have a negative impact on groundwater management, which is a key requirement of the Bendigo Groundwater Project and many other stakeholders.

The issue of how to manage construction and operational phase dewatering requires further investigation in a feasibility study in consultation with Bendigo Groundwater Project, Coliban Water, Goulburn-Murray Water, GBM, and other relevant stakeholders.

3.2.4 Capital cost estimate

The capital cost estimate has been derived from a combination of supplier budget prices, industry norms, and experience. The pre-feasibility estimate for the capital cost is \$50M, with an accuracy of -50%/+100%. The section below outlines the breakdown of capital cost.

Turbines - \$9M

- Turbine supply including generators, transformers, isolation valves, delivery, installation, commissioning

Pumps - \$7M

- Pump supply including motors, delivery, installation, commissioning, ancillary electrical equipment

Powerhouse - \$4M

- \$2M excavation of powerhouse, pumphouse and access shaft
- \$2M structural works

Penstock - \$6M

- Excavation of penstock raise bore, upper penstock and valve room, Garden Gully connector tunnel

Valves and filters - \$4M

- \$3M high pressure valves
- \$400k pump and turbine filters
- \$500k lower pressure valve

Other - \$3M

- Balance of plant
- Building services
- Electrical works

Construction phase - \$3M

- Dewatering and temporary works, repairs and refurb of existing infrastructure

Indirect costs - \$14M

- Engineering design allowance (5% of direct costs)
- Contractor overheads and profit (12% of direct costs)
- Contingency (10% of direct costs)
- Preliminaries allowance (8% of direct costs)
- Escalation allowance (3.5% of direct costs)

Total - \$50M (-50%/+100%)

This cost estimate is preliminary and some aspects of it may be conservative due to the low level of design definition. Refinement and optimisation of the design during a feasibility study would provide a more confident estimate of capital cost, and may allow opportunity for cost reductions in some areas of the project.

4 Financial modelling

4.1 Overview of the modelling approach

The financial feasibility of the preferred concept is a key factor in assessing whether to continue progressing the project to a full feasibility study. A cash flow model was developed to assess the overall financial feasibility of the preferred concept.

The analysis assumes that construction for the project would commence in July 2019 and be constructed over a 2.5-year period with commercial operation commencing in December 2021. The economic life of the plant is assumed to be 30 years. Costs are assumed to escalate by CPI which is assumed to be 2.5 per annum, with adjustments occurring on 1 January in each of the forecast years.

The technical and operational characteristics of the preferred concept are based on the information presented below in Table 2.

Table 2: Parameters used for financial modelling

System parameters	Value
Plant nameplate capacity	30MW
Energy storage	6 hours
Round trip efficiency	70%
Economic life	30 years

4.2 Capital assumptions

The capital costs for the preferred concept are outlined in Section 3 of this report and have been summarised in Table 3, below. The breakdown of the capital cost reflects the major components of the project's capital investment.

Table 3: Capex breakdown

Cost category	Value (\$M)
Turbine/s	9
Pump/s	7
Powerhouse	4
Penstock	6
Valves and filters	4
Other	3
Construction phase	3
Indirect costs	14

Total	50
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Table 4 compares the capex estimate for Bendigo pumped hydro with reference costs for typical pumped hydro projects globally, as well as with utility-scale lithium-ion batteries and flow batteries. These figures are shown in \$AUD at current exchange rates, and compare both capex per megawatt (peak generating capacity) and capex per MWh of energy storage capacity. Note that the figures for battery technology costs have been taken from Lazard’s 2017 Levelized Cost of Storage Analysis, and pumped hydro figures are from research and experience.

Table 4: Capex comparison

Capital cost	Bendigo	Pumped Hydro	Lithium-ion	Flow battery
\$M/MW	\$1.7	\$1.0 - 3.0	\$3.2 - 4.1	\$2.6 - \$5.6
\$M/MWh	\$0.27	\$0.2 - 0.4	\$0.40 - 0.51	\$0.33 - \$0.70

4.3 Operating assumptions

For a pumped-hydro system, the main drivers of operational expenditure arise from four primary sources. In order of decreasing materiality these are:

- Labour costs including the full time equivalent staffing levels required to run the plant and the outsourced services required to ensure the safe, secure and smooth running of the plant
- Grid connection and market participant related charges
- Annual planned and unplanned maintenance
- Consumables required to maintain the equipment and to support the functions of the plant

Compared to capital expenditure, the impact of operational costs on the financial viability of the project are less. As the preferred concept is only at pre-feasibility stage, operational costs have been estimated as a percentage of total capital cost.

Based on experience from similar projects, an assumption of 2.5% of total capital expenditure has been used as an estimate of the annual operational costs of the project. This does not include the cost of major maintenance which has been discussed below.

4.3.1 Major maintenance

To accommodate for the risk of gradual round trip efficiency degradation, a major maintenance cost of 3.2% of the pump and turbine capital cost has been included on a 15-year basis. This assumption is based on an internal benchmark that is supported by experience on similar projects.

The shutdown period for major maintenance in year 15 of operations would be for a total of 4 weeks per turbine/pump pair. This is considered a conservative estimate due to the Pelton turbines selected, which are simpler and cheaper to maintain than other types of hydro turbines.

4.4 Revenue assumptions

Energy storage is a feasible technology in the National Electricity Market (NEM) due to the variation in wholesale price throughout the day as different energy producers experience different fuel costs and demand of their services. The majority of revenue generated by a PHES unit will maximise this characteristic of the NEM through spot price arbitrage (purchasing power to pump up when the price is low, and running water down through the turbine to generate power for sale when the price is high) and contracts. Additional revenue may be available through the provision of ancillary services.

4.4.1.1 Spot price arbitrage

The primary revenue option for energy storage is derived through taking advantage of the dynamic wholesale price in the NEM, by maximise the arbitrage between buying energy at a low price and selling high.

The curve differs day-to-day and season-to-season as demand on the market and fuel input varies. There will therefore be some days, and periods in the year, where arbitrage revenue is more attractive than at other times in the year, though nonetheless arbitrage revenue is likely to be present to some extent every operating day in the NEM.

4.4.1.2 Contracts

Spot price arbitrage is revenue derived from direct transactions with the market as settled by AEMO. Another option is to enter into contracts with third parties, who will typically purchase energy at a set price with escalation over a given period. The major benefit of contracted revenue is that it lowers the risk of the project as it provides protection from price volatility, and provides contracted future cash flows, making the project comparatively more attractive to investors.

Cap contracts

Cap contracts ('caps') are used to hedge against extreme prices that are occasionally seen in the NEM. They effectively act as a call option, whereby they are automatically exercised when the NEM wholesale prices rises above a set strike price, typically \$300/MWh. Retailers may choose to buy these caps from fast starting generators such as pumped hydro plants to protect themselves from peaks in the wholesale price. The more volatile a market, the higher the cap prices. Also, the faster a generator can start up to meet these cap contracts, the more likely they are to generate revenue from caps.

Cap contracts can act as an additional source of revenue to spot price arbitrage. This would mean that the plant loses the opportunity to earn arbitrage revenue for

capacity committed to cap contracts when the spot price is above \$300/MWh, but would instead have a stable revenue with a markup for the insurance that it provides to its cap contract buyers.

Firming contracts

Firming contracts can be entered into with renewable energy generators which have variable output which is not dispatchable. These can be used as an alternative revenue stream compared to arbitrage and cap contracts. Firming contracts arise from purchasing the energy from a generator with variable output (i.e. a solar or wind generator) at a low price and selling back to the market dispatchable energy in the form of baseload or peak firm energy, at a higher price. Energy would be purchased from the renewable generator through a form of Power Purchasing Agreement (PPA). The difference between the price paid for energy in the PPA, and the price sold back to the market in the form of dispatchable energy is referred to as the value of firming.

The value for firming in Victoria is currently unclear as the form and substance of such contracts is still being developed for this market.

4.4.1.3 Ancillary services

Ancillary services exist outside of spot price arbitrage, and cap contracts and firming contracts. PHES can potentially generate extra revenue from these avenues to varying extents.

Frequency control

The NEM is designed to operate at a frequency of 50 Hz. There are a series of frequency markets operated by AEMO that provide for a generator, typically a smaller one with quick start up and cool down times, to inject or withdraw power in instances where the market frequency goes outside the range of 49.85 to 50.15 Hz.

System restart services

System restart services allow for electricity supply to be restored following a large-scale blackout. Generators deriving revenue from system restart ancillary services (SRAS) re-energise the network to allow other generators to synchronise and re-enter the market.

Inertia

Inertia has traditionally been met in the NEM by large-scale coal, gas and hydro generators. However, in the wake of many such generators being moth-balled, the Finkel Review recommended minimum inertia levels to be established within each region of the NEM. There's currently no mechanism for revenue to be derived from meeting inertia needs, though there may be the need for such a mechanism in the future.

4.4.1.4 Renewable Energy Target Certificates

The Renewable Energy Target (RET) in the NEM is a market mechanism to incentivise investment in renewable energy generation. The mechanism works by granting certificates to generators of renewable energy, and requiring retailers and other wholesale buyers of electricity to surrender a certain number of these certificates each year, with the number of certificates required increasing year-on-year. This allows renewable generators to trade these certificates and have an additional revenue stream. It appears unlikely that PHES will qualify as a renewable generator because being a storage system it is generating electricity which has already been generated before. It may in fact be required to surrender certificates as a wholesale buyer in the market. There is significant regulatory uncertainty around how energy storage facilities like Bendigo pumped hydro would be incorporated into the RET mechanisms, and also around whether changes will be made RET by 2020 and the impact this will have on LGC market prices. For this reason the RET has been excluded from pre-feasibility financial modelling for this project.

4.4.1.5 Avoided TUoS

The pumped hydro system embedded in the distribution network may be eligible for Avoided Transmission Use of System (ATUoS) payments by Powercor.

As a Distribution Network Service Provider (DNSP) in the NEM, Powercor must pay the Transmission Network Service Provider (TNSP) AusNet Services Transmission Use of System (TUoS) payments based on its peak demand on the transmission network at the transmission terminal station. If a registered generator embedded in the distribution network generates directly into the distribution network at times of peak demand, it reduces the amount of peak power that must be imported from the transmission network, thereby reducing the required capacity of transmission assets serving that area and reducing the DNSP's TUoS liability to the TNSP. Under the National Electricity Rules (NER) the DNSP is required to pass on this benefit to the embedded generator.

Given that the pumped hydro system will be embedded in the distribution network, and that it is likely to often be generating at full capacity during times of peak demand, it is possible that it could be eligible for ATUoS payments. This would require the system to be a registered market participant in the NEM, which requires a fee. Given regulatory uncertainty about whether the pumped hydro system would be considered to be a generator it was decided to exclude this revenue stream from the financial modelling for the pre-feasibility study. It is potentially a significant additional revenue and should be assessed in a feasibility study in consultation with Powercor, AusNet Services and AEMO.

4.4.2 Revenue approach

While the most appropriate revenue structure for the proposed project can only be determined as the project is further developed, the revenue assumptions adopted for the pre-feasibility stage are based on 100% spot price arbitrage plus cap contracts.

This approach was considered the preferred option for the pre-feasibility study as the value for firming in Victoria is unclear as there are currently no established contracts in the market. Additionally, whether the proposed project will qualify for any ancillary services is yet to be confirmed, and as such it would not be prudent to include either of these revenue streams in the assessment until further studies are undertaken.

The spot price arbitrage assumptions used in the pre-feasibility study are based on historical data readily available through AEMO. The approach taken was to analyse the peaks and troughs (excluding occasions where spot price exceeds \$300/MWh) in the Victorian wholesale electricity price between 2000 and 2016 to estimate an average buy and sell price, which have been determined as \$37/MWh and \$90/MWh over this period respectively.

Additionally, the price of caps was estimated from the ‘VIC Base Load \$300 CAP Electricity (GV) Futures’ market operated through the Australian Stock Exchange. At the time of this report, the 12 months’ forward future price for caps was between \$3.20MWh and \$25.50MWh, with an average of \$9.70MWh. This price is paid for each hour of the contract period, normally one quarter (~2200 hours) or an annual strip (~8760 hours).

While every effort has been made to ensure that the revenue assumptions used in the pre-feasibility study are appropriate, the analysis is based on historical data and therefore may not be representative of future outcomes.

4.5 Project viability

To assess the feasibility of the proposed project, an Internal Rate of Return (IRR) of 8.15% has been calculated using the base case assumptions outlined in this report. The cash flow associated with the project is shown graphically below.

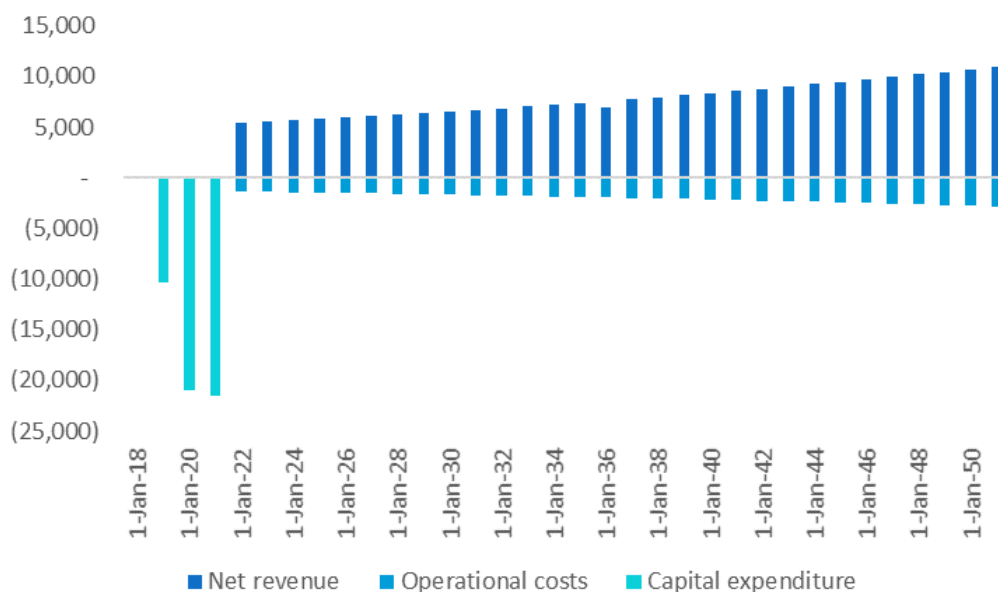


Figure 13: Estimated cash flows of the proposed project (Units \$'000)

4.6 Sensitivity analysis

The analysis undertaken in this pre-feasibility study reflects only one potential outcome for the proposed project. In reality, there is uncertainty associated with a number of project assumptions which may impact the projects feasibility. The impact of a range of these factors has been explored in Table 5.

Table 5: Sensitivity analysis results

Cost category	IRR (%)
Base case	8.2
Capex \$40M (-20%)	10.9
Capex \$60M (+20%)	6.1
Revenue -10%	6.0
Revenue +10%	10.1
Economic life 50 years	9.2

4.7 Local economic benefit

In addition to the monetary benefits assessed as part of the pre-feasibility study, there will be a range of non-monetary or indirect benefits associated with the proposed project that could be explored. The impact of these benefits on the proposed project's viability will largely depend on the level of private and public sector involvement.

A common economic benefit associated with infrastructure projects is the creation of jobs during the construction and operational phases of a project. These benefits generally also have a multiplier effect on both the local community and the wider economy.

A high-level approach to estimating the potential level of local job creation is outlined below in Table 6, assuming a peak construction period of approximately one year.

Table 6: Estimate of job creation during construction and operation

Construction	
Capital cost estimate (A)	\$50M

Estimate of potential local labour component (B)	15% of capex
Average cost of construction labour (C) (per annum)	\$144k ¹
Estimated number of total jobs during construction (A x B / C)	52
Operation	
Annual O&M cost estimate (D)	\$1.25M
Estimate of labour component (E)	~40% of opex
Average cost of engineering professionals (F) (per annum)	\$103k ²
Estimated number of annual jobs during operation (D x E / F)	5

Additionally, the proposed project may produce non-monetary or indirect benefits including:

- Potential to reduce electricity price volatility in the region
- Potential reduction of local economic burden of groundwater management
- Opportunity for facilitating connection of new renewable generation in the region
- Increased investment attraction to the Bendigo region
- Bendigo being recognised as a centre of innovation in sustainability and renewable energy
- Potential for use as part of a renewable community power project

4.8 Operating model and renewables integration

As discussed earlier in this section, there are broadly two different business models for a grid-scale energy storage system such as pumped hydro: merchant storage and contracted storage. A merchant storage system essentially buys and sells power on the spot market, trading on the short-term spot price volatility as well as long-term trends in the spot price, and consuming significant amounts of power without regard for the generation mix in the NEM at the time of pumping. Contracted storage systems are varied with regard to the type of contract, but generally speaking they provide more certainty on both short-term and long-term cashflows, as well as allowing for control over the source of pumping power for the system. It is possible for projects to operate with a hybrid of merchant and contracted storage, as has been assumed in the pre-feasibility financial modelling for this project.

¹ Construction sector – outlook, labour costs and productivity, Deloitte Access Economics 2016

² Construction sector – outlook, labour costs and productivity, Deloitte Access Economics 2016

There is a strong preference from the state and local government sponsors of this study for this pumped hydro energy storage project to form part of a larger renewable energy system for Bendigo, and ideally to power its pumping process with renewable generation sources. There are several ways that this outcome could be achieved, including integrated renewable generation, firming contracts, and PPAs.

4.8.1 Integrated renewables

An integrated project with renewable generation and energy storage behind-the-meter allows a renewable generator to present a dispatchable generation service to the market. Unlike variable, intermittent generators like solar and wind power plants without storage, a system with storage can buffer its production of energy and its supply to the grid. This gives it more flexibility to supply energy when the need is greatest and the resultant spot price is highest. Alternatively, it also allows a renewable generator to offer a firmed product to energy consumers without exposing itself to high peak prices in the NEM when it is not able to produce the agreed capacity. This type of project could operate on either a merchant or contracted basis, or a hybrid of the two.

Examples of this arrangement in Australia are the proposed Kidston Solar PV and Pumped Hydro Project in Queensland, with solar generation and pumped hydro storage integrated behind the meter, and the Aurora Concentrated Solar Thermal Project in South Australia, with thermal storage of energy somewhat inherent to this system in the high temperature of the molten salt.

For an integrated renewables solution, there would need to be a suitable site for a large (~30 MW) intermittent renewable project (likely solar or wind) close to the proposed pumped hydro system. Since the behind-the-meter installation would require private wires connecting the generation to the storage (i.e. not using the grid), the feasibility of the project quickly drops as the distance increases. This is particularly true in the case of the Bendigo pumped hydro concept, as the new power lines would need to be in the middle of the town, so may need to be underground (approximately x4 cost of above-ground) and would face a more difficult approvals process.

4.8.2 Firming contracts and PPAs

An alternative to the integrated renewables option which could achieve a similar outcome would be partnering with local existing or new renewable generation projects with either firming contracts or Power Purchase Agreements. Either of these arrangements could potentially allow for the sourcing of 100% renewable power to drive the pumps, and thereby ensure 100% renewable generation from the pumped hydro system when generating.

These approaches would allow the system to operate with a renewable power source without requiring that the generation source is geographically close to the pumped hydro system. The trade-off is that the pumped hydro system would be required to pay fees to the distribution/transmission service providers to compensate them for the use of the grid while pumping, but it is likely that this

would be the more economically efficient approach in most cases except where there is a suitable generation site immediately adjacent to the pumped hydro system, such as the Kidston project in Queensland.

The PPA approach would require that the pumped hydro project has a PPA with a renewable project (or more than one) for supply of the pumping power, and PPAs with energy consumers or retailers to sell the generated power.

The firming contract approach is still being tested and developed in the market, but it would be functionally similar. The main difference would be that the renewable generator would likely take the main role in interactions with the market to offer a firm product, with the pumped hydro project agreement mainly being with the renewable generator to ensure that the right parameters are in place for the storage system to firm the renewable generation.

Either of these arrangements could help both the new renewable generation projects and the pumped hydro project put together bankable business cases.

4.8.3 Potential renewable sources

There are several options for renewable generation sources for the pumping power. While these have not been assessed in detail as part of this study, they are worth considering for engagement as part of a feasibility study. Other new projects not mentioned below could also be considered.

4.8.3.1 Coonoer Bridge wind farm

This 19.8 MW project near Charlton Zone Substation on the Bendigo Terminal Station network won an ACT government reverse auction and was commissioned in 2016. It has been developed by WindLab. It is understood that the project has a PPA with the ACT government and may not have any additional capacity to provide power for the pumped hydro system, but it may be worth investigating in the next phase of the project. It is the only existing utility-scale renewable generator in the Bendigo region that the study team is aware of.

4.8.3.2 Berrimal wind farm

This is a proposed 72 MW wind farm near the Charlton Zone Substation on the Bendigo Terminal Station network. The project is awaiting approval from Buloke Shire for a revised planning application. It may be worth investigating possible contracting or partnership in the next phase.

4.8.3.3 Other utility-scale solar/wind

Other grid-scale wind or solar PV projects in early stages of development may also be considered for procurement of pumping power. These could be explored in a feasibility study. The study team notes that the City of Greater Bendigo, in conjunction with the Bendigo Community Power Hub, is investigating a range of sites that would be suitable for future solar farm development. This process is

intended to lead to solar developers establishing solar farms of varying scales in the area, and would be worth considering in the feasibility study.

4.8.3.4 Community rooftop solar PV

According to BSG estimates, there is approximately 30 MWp of rooftop solar PV capacity existing in Bendigo. It is conceivable that there could be some arrangement where rooftop PV owners were paid to provide power for the pumped hydro system, but such an arrangement would be quite unusual and novel in the NEM. With the rise of Power Ledger in WA providing a potential mechanism for peer-to-peer energy trading, it is worth investigating whether a platform like this could be used for procurement of renewable power for the pumping system. This would also inherently provide the opportunity for significant community involvement in the project, but would not be as capital efficient as larger utility-scale renewable systems.

4.8.4 Potential off-takers

It is important to consider the potential buyers of energy from the pumped hydro plant. This should be studied and assessed in a feasibility study but on preliminary consideration these could include:

- City of Greater Bendigo
- Major industrial/commercial users in Bendigo with a direct PPA
- Retailers

Off-takers do not necessarily need to be in Bendigo, and in the feasibility study it would be wise to engage with a broad spectrum of potential off-takers to assess their appetite for the energy this system would produce.

4.9 Financing and ownership

In general, a project like this would typically be funded through traditional project finance methods with a Special Purpose Vehicle (SPV) setup by the project sponsors. It would be financed with a combination of equity and debt, generally as much debt as can be secured.

Sources of equity include:

- Project sponsors/developers
- Institutional investors (e.g. super funds, investment funds, insurance, mutual funds)
- State government
- Local government
- Community investment

Sources of debt include:

- Commercial loans
- Corporate bonds
- Clean Energy Finance Corporation (CEFC)

Another potential source of funds for this project is grants and subsidies related to sustainable and/or community energy. Sources of these funds could include:

- ARENA
- CEFC
- State Government

4.9.1 Community ownership

There is great potential for significant community involvement and ownership for this project. If achievable, this would allow the Bendigo community to capture a significant portion of the value generated by the project in respect to the retail power component and keep it in the local economy. Community ownership would provide benefits to the business case, as community financing would presumably be willing to accept lower returns on investment than corporate debt/equity finance, meaning that a project with marginal viability would be more attractive. There are many different models that community ownership could take, some of which are currently being trialled around the country in other regional community power projects. These should be assessed in a feasibility study to determine the model most likely to be successful for this particular project.

One attractive option considered by the study team is for the pumped hydro system to be owned and operated by a community-owned renewable gentailing business. This structure could potentially fulfil the desire of the community to not only own the sustainable power assets but also to be able to purchase power from them and retain the value derived from the assets in the community. The vertically integrated renewable generation and retail operations would allow for contracted purchase of energy by the community from their own renewable generators, and the pumped hydro system would provide load shifting needed to use variable renewables when they are not generation, such as solar power at night. It would also be a physical hedge for the business against large spot market spikes. This concept was developed by Arup's Energy and will be developed independently of the pumped hydro project.

5 Key project risks

There are many risks associated with projects of this scale and complexity. This section explores only the key risks that are unusual, not obvious, or have a disproportionate impact on the project. This is therefore by no means a complete list of risks. Risks that could impact the project should be reviewed, added to and updated throughout the development of a project of this nature.

5.1 Hydraulic conductivity of Garden Gully

A key risk for the preferred concept is that the Garden Gully mine voids do not have sufficient hydraulic conductivity to deliver the flow rates required by the pumped hydro system, due to various factors including lack of connectivity between shafts, and flow restrictions caused by collapsed shafts, tunnels, and supporting structures.

A remotely operated underwater vehicle (ROV) survey should be conducted at the beginning of the feasibility study to assess the condition of the historic workings and check the validity of the 3D model with respect to shaft connectivity. The survey should focus on shafts close to the tie-in point, as these are the regions of the working which will see the highest velocity and therefore will be the greatest contributors to flow rate reduction.

Depending on the result of the ROV survey, hydraulic modelling and/or pumping tests could be conducted to assess the likely ability of the workings to deliver the required flow rate. If pumping tests are to be performed they should be done at the highest flow rate that can reasonably be achieved to minimise uncertainty when scaling up to the design flow rate, and should also focus on shafts closest to the proposed tie-in point.

Any restrictions could be dealt with by modifying the connection to the Garden Gully reef, or potentially installing multiple connections, or connections between sections of Garden Gully reef, however these would add cost to the project.

If the Garden Gully concept is proved to be unfeasible or cannot be appropriately de-risked, an alternative option of an above ground reservoir should be pursued. Early options assessments suggest that there are sites nearby which could be suitable, and that this may be a viable alternative option for the project.

5.2 Unknown condition of mine workings

Based on discussions with GBM mining, and the history of modern mining undertaken under Bendigo, the Swan Decline and associated development drives were designed and developed with a 20+ year design life. Despite the decline and drives being flooded to varying extents since modern mining ceased, it is expected that with controlled dewatering, the decline and drives would be in reasonable condition, and only occasional spot bolting would be required to make the areas safe for their intended use. There is a risk that serious degradation has occurred which requires considerable remediation in order to facilitate the project.

5.3 Accuracy of 3D model

The concept development has relied heavily on the 3D model of the mine workings provided by GBM, as the potentially feasible and viable options depend greatly on the arrangement of the existing underground voids, particularly in the modern mine. If this model proves to significantly deviate from the physical mine, it could have a major impact on the viability of the project and / or construction

cost. The parts of the mine that interact with the design should be verified with survey as part of the next phase of design development.

5.4 Rock stability under cyclic hydrostatic load

A residual risk from the pre-feasibility is the stability of the rock in the Swan Decline and the Garden Gully reef under daily cyclic hydrostatic loads, as the storage volumes fill and empty. The study team expects that the rock will be strong enough for the application, but more work is needed in a feasibility study to verify this assumption.

The key activity to mitigate this risk is to build a geological model of the area proposed for the project with the following inputs:

- Existing regional geological models
- Historical reports and other relevant data
- Output from ROV survey
- Depending on gaps identified, geological testing (drilling) may be considered

One could then model the rock mechanics under the expected load conditions. A literature review of precedence in similar applications is recommended.

5.5 Mining licence

GBM's mining licence grants the holder the right to explore and extract from the underground location where the pumped hydro system would be located. The ground required for the pumped hydro system would need to be protected to ensure that the holder of the mining licence could not use that ground for mining activities and render the pumped hydro plant inoperable. This could be accomplished via a commercial agreement with GBM provided they continue to hold the mining licence, but if GBM were to sell the licence this could become a significant risk to the project. If the plant was already built it may be protected as existing underground infrastructure so the new licensee would have that volume excluded from the minable volume. However, if it was not yet built but significant cost had been invested in detailed design and procurement then it may not be protected, and there could be significant sunk cost.

This risk should be further assessed and considered in the next phase of the project.

5.6 Water quality

The groundwater present in the mine workings has relatively high salinity, heavy metals and hydrogen sulphide. This is not anticipated to be a significant technical risk to the project in terms of factors like material selection or equipment selection. However, community concerns about environmental and health effects of the groundwater have been raised and stakeholder management will need to be undertaken to ensure that the Bendigo community is satisfied with the proposed solution.

5.7 Regulatory uncertainty

There is some uncertainty around energy regulation that could impact the business case of the project. While there are several areas of uncertainty, two key areas are the National Energy Guarantee and the Large-scale Renewable Energy Target.

The National Energy Guarantee (NEG) is the core policy recommendation from the Energy Security Board (ESB) in response to the Finkel Review. It has been adopted by the Federal Coalition Government. The NEG will require energy retailers to meet a reliability guarantee target and an emissions guarantee target. The reliability guarantee will require retailers to procure a minimum proportion of energy from dispatchable sources, meaning sources that can be started, stopped, and ramped up and down to meet changing demand. Pumped hydro plants are a very good example of dispatchable generation, so this mechanism is likely to work in the project's favour, although the nature of how and how much is unknown. The emissions guarantee target requires retailers to meet a maximum emissions intensity in their annual energy procurement. It is not clear whether a pumped hydro storage system which pumped using fossil fuel-derived energy would count as a carbon dioxide emitting generator.

As part of the implementation of the NEG, it appears that the Large-scale Renewable Energy Target (LRET) will not be changed and the target will remain at 33,000 GWh from 2020 onwards. This means that, while accredited renewable generators will still earn Large-scale Generation Certificates (LGCs), the price that they can sell them for will collapse toward zero, thereby removing the incentive for investment in more renewables as intended by the RET. However, if the LRET is still active in the market while the pumped hydro system is operating it is not known whether the system would be entitled to create LGCs when generating, and whether it would be liable to surrender LGCs for energy purchased from the market while pumping. There is no clarity yet on the implications for utility scale energy storage in the RET. This is a factor worth investigating further in a feasibility study.

6 Recommendations and next steps

Overall, the 30 MW concept identified in the pre-feasibility study has the potential to be both technically feasible and commercially viable, and the study team recommends a full feasibility study to develop the design and prove the concept to a point that a final investment decision could be made for engagement of an EPC contractor.

This would take 8-10 months and typically cost approximately 2-4% of project capital, depending on risk and level of design development required. For this project an allocation of \$1.5M for detailed feasibility study would be appropriate.

This section discusses various aspects of the project which will need to be considered when planning and delivering the feasibility study.

6.1 Project development

If the project goes ahead, a typical project development path from here would be

1. Decision whether to invest in Feasibility Study
2. Feasibility Study (estimate accuracy -20/+30%); Commencement of approvals process would also occur at this stage
3. FEED Investment Decision
4. Front End Engineering Design (FEED) (estimate accuracy -15/+20%)
5. Key Investment Decision
6. Detailed Design (estimate accuracy -5/+15%)
7. Final Investment Decision
8. Procurement and Construction
9. Operations and Maintenance
10. Decommissioning

These steps can be packaged together in various ways. Of particular note for the next phase, the feasibility study and FEED could potentially be done under one commission to reduce the timeframe for decision making, as proposed for the next phase of this project. The drawback of this approach would be that it puts more capital for design development at risk in the case that the more extensive study shows that the scheme is not viable, where this could have instead been confirmed with a less extensive feasibility study.

6.2 Agreements and approvals

A significant number of agreements and approvals will need to be put in place or begun in a feasibility study for this project. Some of these are listed in this section. The section assumes that the project is delivered through project financing with a Special Purpose Vehicle (SPV) as discussed in section 4.9. The project could be delivered with other financing models in which case the agreements required would differ slightly, but the section below will still give a guide as to the parties involved in a project such as this and how they are typically engaged.

6.2.1 Project team agreements

- Shareholders agreement (within SPV, between project investors)
- Financial agreements (between SPV and lenders)
- Construction contracts (between SPV and EPC contractor)
- Tripartite agreements (between SPV, lenders and EPC contractor)
- O&M contracts (between SPV and O&M contractor)

- Insurance contracts and guarantees

Note:

EPC = Engineering, Procurement, Construction

O&M = Operation and Maintenance

6.2.2 External stakeholder agreements

- Connection agreement (between SPV and DNSP/TNSP)
- Land access agreements (from GBM, Council, and any freehold land owners)
- Agreement with Traditional Owners (Dja Dja Wurrung)
- Power Purchase Agreement (energy supply)
- Power Purchase Agreement (energy off-take)

Note:

DNSP = Distribution Network Service Provider (Powercor)

TNSP = Transmission Network Service Provider (AusNet Services)

6.2.3 Permits and approvals

The following permits and approvals may be required for the project, and would need to be determined as part of a feasibility study:

- Planning permit under Greater Bendigo Planning Scheme
- Planning scheme amendment under the *Planning and Environment Act 1987*
- Referral and potential assessment under the *Environmental Effects Act 1978*
- Referral, determination and potential approval under *Environment Protection and Biodiversity Conservation (EPBC) Act 1999*
- Consent/s or permit/s under the *Heritage Act 1995*
- Cultural Heritage Management Plan (CHMP) under the *Aboriginal Heritage Act 2017*
- Works approval licence under the *Environment Protection Act 1970*
- Generation Licence with AEMO depending on operating strategy

A particular environmental factor raised during this study which will need to be assessed during any feasibility study is the proposed transfer of groundwater from one mine system to another, which may classify as transferring between different aquifers and require a licence. This same transfer process is currently occurring as part of the interim groundwater management solution.

Another important consideration is the interaction between the pumped hydro project and the mining license. It is expected that the most appropriate way forward would be to make an agreement with GBM for use of the underground

locations required for the construction, operation and ongoing protection of the pumped hydro system, after which the pumped hydro system is likely to be regarded as existing infrastructure under any new mining licences thereby protecting it from future mining activity. This should be further investigated in a feasibility study.

Note that it is unlikely that both a planning permit and a planning scheme amendment would be required for this project.

6.3 Feasibility study scope

The feasibility study should include the following aspects in addition to those normally covered by feasibility studies for projects of this nature:

Building a geological model of the area proposed for the project with the following inputs:

- Existing regional geological models
- Historical reports and other relevant data
- Remotely operated underwater vehicle (ROV) survey
- Depending on gaps identified, geological testing (drilling) may be considered

Rock stability investigations

- Modelling of rock mechanics under expected load conditions
- Literature review of precedence in similar applications

Garden Gully hydraulic conductivity investigations:

- ROV survey
- Pumping tests in Garden Gully reef at scaled-down flow rates to determine hydraulic properties of reef line. Testing should replicate expected operating conditions as closely as is feasible.
- Further investigation of available information

Site assessment

Development of design concepts

Environmental and planning approvals and stakeholder engagement

Grid connection (detailed enquiry and potentially connection application)

Capital and operating cost analysis

Business case financial modelling

Financing strategy and structure, including community ownership options