Repurposing existing hydropower assets for the future electricity market

Hydro Tasmania's Tarraleah hydropower scheme

Feasibility Study Knowledge Sharing Report

October 2020

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This project received funding from ARENA as part of ARENA's Advancing Renewables Program.

1.0 Executive summary

The National Electricity Market (NEM) is facing a challenging and uncertain future as Australia grapples with the trilemma of delivering the reliable, sustainable and affordable energy the future market needs.

The key to meeting this challenge is investment in assets that provide:

- Flexible 'dispatchable' generation that can firm variable renewables.
- Energy storage solutions that can manage system variations by storing excess energy for use at later time.
- Interconnection to share generating resources more effectively.

Getting the most out of our existing hydropower generation is a key part of the *Battery of the Nation* initiative. The flagship project Hydro Tasmania has assessed is one of Tasmania's oldest hydropower schemes - the Tarraleah scheme in the Central Highlands which produces around 6.5% of Hydro Tasmania's total annual production.

Many of the scheme components are over 80 years old and in need of significant investment within the coming decade to ensure safe and reliable operation well into the future. The existing scheme also has a number of physical and operational constraints which mean it may not be well suited to the needs of the future electricity market. The scheme's inflexible baseload operation may see it competing with low cost variable renewable energy sources.

The Australian Renewable Energy Agency (ARENA) provided $2.5 million, matched by Hydro Tasmania, for a feasibility study to assess options for reimagining the scheme to deliver more renewable energy, more flexibly in the future. ARENA also funded an earlier pre-feasibility study, looking at how the hydropower scheme might be repurposed for a future market. This study recommended a full feasibility study to assess the risks and benefits of scheme redevelopment in comparison to progressive refurbishment of the existing scheme.

The Tarraleah feasibility study has developed and compared options for repurposing the scheme to meet the needs of the future electricity market through increasing its flexible 'dispatchable' generation capacity. The assessment of these options will allow Hydro Tasmania to develop an asset management strategy and plan in the context of future NEM projections and existing asset risk; critically covering the following:

- Improved cost and value certainty for the scheme's future role in the NEM.
- The case for repurposing versus maintaining the current scheme.

As part of the study, Hydro Tasmania has developed a guiding framework for asset management decisions on existing hydropower assets for the future electricity market. This knowledge sharing report presents the framework and provides a working example of its application to the Tarraleah hydropower scheme.

It is intended that this framework will be applicable to other existing hydropower assets in the NEM, both now and into the future. Many of the principles are general in nature and will be applicable to other existing or proposed generation sources.

Hydro Tasmania's framework, outlined in Figure 1, comprises six steps:

1. **Identify** asset physical attributes and constraints.
2. **Assess** asset and revenue risk and opportunities of existing asset.
3. **Develop** concepts to repurpose existing asset.
4. **Group** concepts into repurposing options.
5. **Assess** asset and revenue risk and opportunities of repurposing options.
6. **Recommend** preferred asset management strategy.

Figure 1: Framework for repurposing existing hydropower assets for the future electricity market

2.0 Introduction

There are many publications on the current and anticipated future state of the National Electricity Market (NEM) and many which focus on the anticipated role and impact of variable renewable energy (VRE) and pumped hydro energy storage (PHES) on the future NEM.

Conventional hydropower is generally assumed to be of high value (and thus remains in the market) and it is also assumed that there would be no changes to existing assets or operations.

There may be opportunities to repurpose these valuable assets and this report shares Hydro Tasmania's recent knowledge gained in this area using the Tarraleah hydropower scheme and feasibility study as an example.

Many of Australia's hydropower assets are ageing and the question facing hydropower asset owners is whether their assets should be refurbished to maintain existing capability or redeveloped to provide new capabilities which may be better suited to the future NEM, especially in light of a transforming market.

This report explores this changing market and the role of hydropower. It has been structured as follows:

- Chapter 3.0 presents **background** on **Hydro Tasmania,** how the **NEM** is anticipated to transform in the future and hydropower's role in this future state.
- Chapter 4.0 explains the overarching concept of **asset risk and revenue risk** and presents the **six-step framework** Hydro Tasmania adopted for repurposing the Tarraleah scheme.
- Chapter 5.0 provides an **example application** of the framework using the Tarraleah feasibility study.
- Chapter 6.0 summarises the **key learnings** from developing and applying the framework using the Tarraleah feasibility study.
- Appendix A details **emerging terminology** in the electricity market.
- Appendix B summarises relevant **trends and case studies** identified by Hydro Tasmania in its review of industry publications undertaken to support the preparation of this report.

3.0 Background

3.1 Hydro Tasmania

Hydro Tasmania is Australia's leading clean energy business, largest generator of renewable energy and largest water manager. For over a century, Hydro Tasmania has led clean energy innovation – building 54 major dams, 30 hydropower stations and two major wind farms. It also manages the gas fired Tamar Valley Power Station.

The electricity generated supplies both Tasmania and the National Electricity Market (NEM) through interconnection provided by the existing Basslink cable.

3.2 *Battery of the Nation* – Tasmania's competitive advantage

Australia's energy sector is undergoing significant transformation, with a rapid acceleration of coal plant retirement expected in the late 2020s. More interconnection across Bass Strait would unlock Tasmania's full renewable energy potential, providing clean, reliable and affordable energy to support a resilient future energy market.

Hydro Tasmania has hundreds of megawatts of latent capacity and ample opportunities to optimise the existing hydropower asset base and build highly cost competitive pumped hydro development.

Additional interconnection would support expansion of Tasmania's existing hydropower system, through development of pumped hydro, providing the firming capacity that will be needed to support a future Australian energy market characterised by decreasing coal plant and increasing wind and solar.

The Australian Renewable Energy Agency (ARENA) has supported *Battery of the Nation* studies with $5 million in funding, as part of its Advancing Renewables Program. Hydro Tasmania produced a series of white papers, jointly funded with ARENA, that take a detailed look at the future energy market and the role of *Battery of the Nation*.

The knowledge outlined in these papers has been drawn upon extensively in the Tarraleah feasibility study.

- *Battery of the Nation, Analysis of the future National Electricity Market* (Hydro Tasmania, April 2018a).
  - Analysis demonstrates that Tasmania can make a significant contribution to the NEM's transformation over coming decades. Cost competitive hydropower potential and significant wind resources can be part of a coordinated solution to address affordability, reliability and sustainability.
- *Battery of the Nation, Unlocking Tasmania's energy capacity* (Hydro Tasmania, December 2018a).
  - Outlines how additional Bass Strait interconnection would unlock latent flexible dispatchable capacity in the Tasmanian hydropower system.
- *Battery of the Nation, Understanding reliability in the future NEM* (Hydro Tasmania, February 2019).
  - Highlights that as the market characteristics change, the services that the market needs will also change. This change drives a need to challenge preconceptions, better understand what will actually be required in the future and clarify the language used to describe the system.
- *How Battery of the Nation can contribute to Victoria's energy needs and objectives* (Hydro Tasmania, August 2019).
  - Outlines how further interconnection between Tasmania and Victoria will add energy supply diversity, increasing both reliability and competition, and help to manage the energy transition by providing practical solutions that complement current Victorian renewable energy objectives.

- *Battery of the Nation, Operating of storages without perfect foresight* (Hydro Tasmania, September 2019).
  - Examines how understanding the realistic future operation of storage is critical to understanding the potential reliability of Australia's energy system. It demonstrates that longer storages are better able to manage forecast uncertainty and more likely to have energy in storage at times when it will be needed.
- *Battery of the Nation, Challenges in modelling the transforming NEM* (Hydro Tasmania, September 2019a).
  - Examines the challenges driving future uncertainty and how modelling must adapt to create robust options that work across a range of potential futures.
- *Battery of the Nation, Unlocking investment in storage for a reliable future NEM* (Hydro Tasmania, November 2019).
  - Explores various markets, services and contract options to highlight the investment risks and opportunities for energy storage and highlights the need for investment de-risking to progress immediate interim investments in strategic assets.
- *The case for deep storage, Why the NEM needs the Battery of the Nation* (Hydro Tasmania, April 2020).
  - Key insights that show deep energy storages are an optimal, least-cost choice able to manage realistic uncertainty in the power system and demonstrating that Tasmania has the cost effective deep storage pumped hydro that Australia needs to manage these uncertainties and support a reliable future NEM.

All white papers and market analysis can be found at www.hydro.com.au/battery-of-the-nation.

3.3 Future uncertainty and needs of the NEM

As outlined in *Battery of the Nation, Analysis of the future National Electricity Market* (Hydro Tasmania, December 2018a), the NEM is facing a challenging and uncertain future as Australia grapples with the trilemma of delivering the reliable, sustainable and affordable energy the market needs.

The NEM is undergoing a transformation away from the dominance of baseload fossil-fuel generation towards greater proportions of low cost variable renewable energy. To 'firm' this variable renewable energy, flexible supply and storage solutions are needed. This will shift the generation focus from 'peak demand' to 'peak supply-demand imbalance'. As more variable generation enters the market, flexible generation options such as hydropower will become increasingly valuable due to their ability to firm variable generation.

Interconnection will also become more valuable, enabling NEM regions to share diverse resources more effectively.

Hydro Tasmania's view is that timely investment in the assets that meet the needs of the future market is required to minimise future reliability problems and price issues for customers, principally through investment in:

- Flexible dispatchable generation that can firm variable renewables.
- Energy storage solutions that can manage system variations by storing excess energy for use at later time.
- Interconnection to share generating resources more effectively.

This report focuses on the repurposing of existing hydropower assets to maximise their potential as flexible dispatchable generation.

3.4 Flexible dispatchable generation

Flexible dispatchable technologies are defined as those generation sources that are capable of responding to market signals as required. Technologies in the NEM currently considered to be flexible dispatchable are those such as open cycle gas turbines (OCGT), diesel generators, hydropower and storage (pumped hydro and electrochemical batteries). The NEM is expected to require a mix of flexible dispatchable generation to meet future needs.

An understanding of the timeframes and different system flexibility requirements of electricity systems as they transition to higher proportions of variable renewable is outlined by the IEA (2018) in the follow figures. The NEM is likely to transition from "Phase 2" through to "Phase 4" by the 2030s as coal generation retires. Phase 2 is characterised by some impact on net load, whereas in Phase 3, flexibility is key and in Phase 4, short term stability is most important.

Flexibility type	Ultra short term flexibility/stability	Very short term flexibility	Short term flexibility	Medium term flexibility	Long term flexibility	Very long term flexibility
Timescale	Sub seconds to seconds	Second to minutes	Minutes to hours	Hours to days	Days to months	Months to years
Issue	Ensuring system stability (voltage, and frequency stability) at high shares of non-synchronous generation	Ensuring short term frequency control at high shares of variable generation	Meeting more frequent, rapid and less predictable changes in the supply/demand balance; system regulation	Determining operation schedule of the available generation resources to meet system conditions in hour-and day-ahead timeframe	Addressing longer periods of surplus or deficit of variable generation, mainly driven by presence of a specific weather system	Balancing seasonal and inter-annual availability of variable generation with power demand
Has relevance for following areas of system operation and planning	Dynamic stability (inertia response, grid strength)	Primary and secondary frequency response, which include AGC	AGC; ED; balancing real time market; regulation	ED for hour ahead, UC for day-ahead timeframe	UC, scheduling, adequacy	Hydro-thermal coordination, adequacy, power system planning

Table 1: Different timescales of power system flexibility (IEA, 2018)
Notes: *AGC = automatic generation control; ED = economic dispatch; UC = unit commitment*

Phase	Phase 1	Phase 2	Phase 3	Phase 4	Phase 5	Phase 6
Becomes a main priority	Typically no system flexibility issues	Short term flexibility	Short term flexibility Medium term flexibility	Ultra short term flexibility Medium term flexibility Long term flexibility	Long term flexibility Very long term flexibility	Very long term flexibility

Table 2: Indicative links between VRE integration phase and different timescales of power system flexibility (IEA, 2018)

Hydro Tasmania has identified indicative durations for a range of challenges that will cause system supply-demand balance in the future NEM which can be addressed with flexible dispatchable generation and / or energy storage (refer Table 3).

Challenges to system supply-demand balance	Indicative duration of event	Frequency of event
Brief variations in load or supply	0-1 hrs	Sub-daily
Daily balancing of solar cycle	10-14 hrs	Daily
Managing load uncertainty and supply constraints (transitional)	6-8 hrs	Weekly
Contingency events causing brief spikes in supply-demand imbalance	0-2 hrs	Weekly-monthly
Large cloud bands in a system with substantial solar reliance	24-48 hrs	Weekly-monthly (seasonal variation)
Successive days of minimal wind generation	24-72 hrs	Monthly (seasonal variation)

Table 3: Requirements for future dispatchable generation sources

Challenges for new development of wind and solar	Indicative duration of impact
Surplus solar generation (daily pattern)	8-10 hrs
Surplus wind generation (low pressure systems)	24-72 hrs

Table 4: Energy surplus challenges faced by wind and solar developers

3.5 Hydropower's role

Hydropower's role in the future market will be to provide flexible dispatchable renewable generation that is both low cost and reliable. As a proven technology with long asset lives and low operational costs, it is expected that existing hydropower assets will maintain a competitive advantage over other generating sources.

Table 5 provides a summary of the future generation sources and a qualitative indication of how they compete with hydropower.

Conventional hydropower is a form of renewable generation and, depending on its configuration, is a proven provider of the full range of market services including baseload, intermediate and peaking generation and ancillary services. Its dispatchable limitations are primarily around the ability to control or regulate hydrological (inflow) variability and environmental and social constraints. There are limited opportunities for the development of new, large-scale hydropower in Australia, hence the focus of this report is on repurposing existing hydropower assets to maximise their value in the future NEM.

Conventional hydropower has all the right characteristics to help manage the future market with comparably few restrictions (assuming that all environmental and social constraints are appropriately managed).

Pumped hydro energy storage (PHES) is primarily focused on the provision of energy storage, peaking generation and ancillary services. While not limited by hydrological variability, pumped hydro operation is usually limited by the duration of operation until the upper reservoir empties (typically in the range of 6-24 hours). Pumped hydro relies on volatility in the wholesale market spot price (arbitrage) between low price times (pumping) and high price times (generation) to operate and be profitable.

Generation source	Flexibility and ancillary services (refer note)	Factors influencing future supply	Competition to conventional hydropower
Brown coal	Baseload; low levels of flexibility; provides some ancillary services	Ageing generation fleet; high emissions intensity; global and national climate change policy poses significant investment risk; extremely difficult to finance	Some competition with uncontrolled hydropower schemes (those that have limited ability to regulate storage)
Black coal	Baseload; low to moderate levels of flexibility; provides some ancillary services	Ageing generation fleet; emissions intensity lower than brown coal but higher than all other technologies listed; global and national climate change policy poses significant investment risk	Flexible coal generation does compete with uncontrolled hydropower
Open cycle gas	Peaking generation with high levels of flexibility and high provider of ancillary services	Short construction lead time; lower emissions intensity than coal; future supply constrained by high fuel costs	Direct competitor but high energy cost and emissions intensity limit effectiveness
Combined cycle gas	Baseload to intermediate load; low to moderate levels of flexibility; provides some ancillary services	Lower emissions intensity than coal and open cycle gas; future supply constrained by high fuel costs	Some competition with uncontrolled hydro; much less flexible than large storage hydropower
Wind	Variable renewable energy; non-dispatchable as only generates when the wind is blowing; does not provide ancillary services on demand (some demonstration projects are underway but as yet the economics are not clear)	Finite number of sites with high capacity factor and close proximity to transmission network; need to manage extended periods of low wind generation across the NEM; capital costs have some potential to decrease further	Some competition with uncontrolled hydropower; increased diversity may reduce the overall need for flexible generation
Solar photovoltaics (PV)	Variable renewable energy; non-dispatchable as only generates when the sun is shining; does not provide ancillary services on demand	High availability of suitable sites around Australia; the energy generated is very highly correlated and may lose value; global technological advancements provide good potential for capital costs to decrease further	Some competition with uncontrolled hydropower
Conventional hydropower	Hydropower is typically highly flexible; some schemes have environmental and social constraints; high provider of ancillary services	Limited opportunities for new large-scale development; supply impacted by hydrological variability and climate change; repurposing opportunities to increase response flexibility	N/A
Pumped hydro energy storage	Highly flexible; high provider of ancillary services	High capital cost; long lead time; investment risk associated with market conditions; many potential large-scale sites around Australia; the duration of storage will still be limited	Direct competitor but may be unable to sustain generation for many days; potentially a complimentary technology – Tasmania's preferred pumped hydro sites are associated with existing conventional hydropower schemes
Batteries	Highly flexible; high provider of ancillary services	High unit cost; short design life; highly flexible but cannot provide large-scale storage	Different market role; a potential competitor to pumped hydro for shorter storage durations

Table 5: Summary of future generation sources

Note: *Ancillary services provide essential network stability and include frequency control (e.g. frequency raise/lower), network support and control (e.g. synchronous condensers and inertia support) and system restart (following a complete or partial blackout). Refer to AEMO's Guide to ancillary services in the National Electricity Market (April 2015) for detailed information on ancillary services in the NEM.*

3.6 Risk asymmetry of generation investment

As outlined in Hydro Tasmania's *Battery of the Nation - Unlocking investment in storage for a reliable future NEM* (Hydro Tasmania, November 2019), the rapidly evolving NEM presents significant risks to both energy customers and investors and developers. A key requirement is the need for investment in the solutions for storage and dispatchable capacity required for the future market in advance of a market shortfall, particularly in a case where generator retirement occurs earlier than expected.

For customers, this is present in the risk of failing to provide a modern power system that meets the energy trilemma of balancing affordability, reliability and sustainability. The trilemma presents a challenging set of goals to attain and will not be adequately addressed with short term planning or responses. As such, customers are at risk of a less affordable, less reliable and less sustainable power system if the right investments are not made.

For developers and investors, the focus is on delivering investments that meet the customers' needs and thus have stable revenue, while providing a suitable return on investment. To invest in long-life, long lead time assets which are typical of hydropower and some other forms of energy projects, there needs to be clear and reliable revenue opportunities to produce a strong business case for investment. Many of the lowest-cost prospective energy projects have long lead times, meaning that these business decisions must be made 5-7 years before they enter the market. These factors make it difficult to finance projects, even where a clear need for development exists.

Hydro Tasmania sees the main drivers of investment certainty in the future NEM as being linked to:

- Interconnection – in the Tasmanian context, Marinus Link is a significant consideration in the future of the Tasmania generation investment.
- Government policy – Tasmanian Renewable Energy Target (TRET).
- Market and regulatory policy.

4.0 Repurposing framework overview

In highly regulated electricity systems and in electricity markets with low levels of revenue volatility, existing electricity assets are typically managed with a focus on asset risk. This means assets are managed throughout their operational life to ensure they can safely and reliably perform their design function.

Investment decisions on very long life assets such as hydropower stations can be made at a portfolio level with limited focus on the lifecycle costs or return on investment of individual assets.

In electricity markets with moderate to high levels of revenue volatility, existing electricity assets can be managed with a focus on both asset risk and revenue risk. Investment decisions are made at the level of individual assets or schemes. Lifecycle capital costs (CAPEX) and operating costs (OPEX) are highly scrutinised as all asset costs need to be recouped through a reliable future revenue stream.

It follows that uncertainty in future revenue leads to hesitance in making significant CAPEX investments. Alternatively, a lack of awareness or focus on future revenue risk can lead to incorrect investment decisions.

This framework presented in **Figure 2** considers asset and revenue risk in assessing options to repurpose existing hydropower assets.

This is the situation faced by Hydro Tasmania for its Tarraleah hydropower scheme which has been assessed at feasibility level with ARENA support under the Advancing Renewables Program.

Figure 2: Framework for repurposing existing hydropower assets for the future electricity market

4.1 Step 1 – Identify asset physical attributes and constraints

An asset's physical attributes and constraints need to be well understood before being able to understand what opportunities may exist to repurpose the asset. It also ensures that repurposing options consider the asset's condition, performance and risk holistically. Example tables and diagrams of different methods are provided that can be adopted to answer the guiding questions.

The types of questions that need to be answered include:

- What are the original asset design attributes?
- What is the current asset condition and performance?
- What is constraining the asset from meeting or exceeding its design attributes?
- What sort of flexibility is possible?

4.1.1 Attributes and constraints

EPRI (May 2017) has summarised the types of attributes and constraints to consider in such an assessment (refer Figure 3). The figure has been annotated to show whether factors are considered to be attributes or constraints. Some additional factors have also been added to improve relevance to the Australian context.

Summarising and presenting these attributes spatially and schematically is recommended, to allow constraints to be overlaid with asset condition and risk information, allowing holistic asset management decisions to be made.

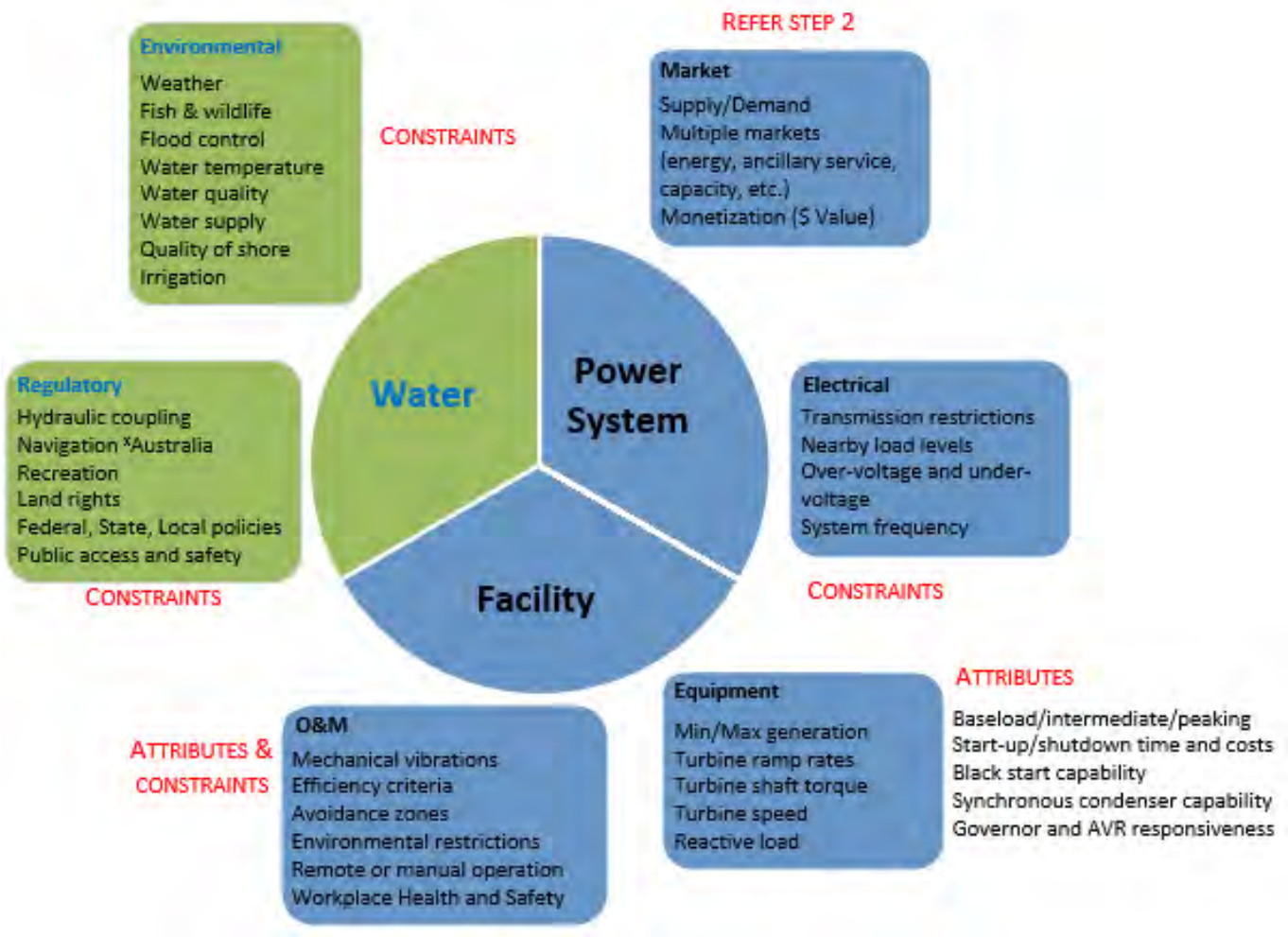


Figure 3: Complexity of operational factors for hydro plants (EPRI, May 2017)

4.1.2 Asset condition and performance

Each asset owner has its own approach to asset management, which may be based wholly or partially on *ISO 55000:2014 Asset management*. A key feature of Hydro Tasmania's Asset Portfolio Management (APM) process is the visibility of the condition, performance, revenue risk and duty of care risk (CPRD) of its assets. It does this through its 'Water 2 Wire Heat Map' (refer Figure 4 for Tarraleah example), a matrix which shows the current CPRD position for each machine or production line for a given power station on the horizontal axis and asset classes on the vertical axis, broadly ordered according to the energy flow from the dam to the switchyard. The APM process is primarily focused on asset risk with limited attention given to revenue risk.

The colours in the heat map indicate relative risk levels – green for low risk, yellow for moderate risk and red for high risk. High risk areas should be targeted first to ensure the organisation maintains a prudent portfolio risk

position within a sustainable level of investment. Hydro Tasmania uses its own Integrated Business Risk Management (IBRM) procedure for risk management. Other asset owners will have their own procedure, most likely based on *AS ISO 31000:2018 Risk management*.

Heat Map Report	**Tarraleah**																							
	1				2				3				4				5				6			
Station priority	5																							
Production line priority	33				34				35				36				37				38			
Installed capacity	15				15				15				15				15				15			
Year of construction	1938				1938				1938				1938				1938				1938			
APM rating type	C	P	R	D	C	P	R	D	C	P	R	D	C	P	R	D	C	P	R	D	C	P	R	D
Station																								
Production line																								
Major dams																								
Small dams																								
Spillway gates																								
Control gates & valves																								
Forebay/intake gates																								
Forebay/intake structures																								
Canals & flumes																								
Pipelines																								
Tunnels																								
HTV																								
Penstocks																								
Pipeline protection valves																								
MIV																								
TRV																								
Turbines/(Pumps)																								
Cooling water system & heat ex																								
Governors																								
Excitation																								
Mech. protection & control																								
Electrical protection																								
Alternators/(Motors)																								
Instrument transformers																								
Circuit breakers																								

Figure 4: Hydro Tasmania 'Water 2 Wire Heat Map' – Tarraleah scheme example

Note: *Example from a previous Hydro Tasmania assessment – not representative of current asset condition and performance.*

Hydro Tasmania's 'Water 2 Wire' approach also enables an assessment and visualisation of which asset classes are constraining the capability of its power stations.

A review of design capability and assessment of current capability can be performed for the water conveyance assets, mechanical assets and electricity assets and then combined into a 'constraining assets summary' (refer **Figure 5** for Tarraleah example).

Note that this approach focuses on scheme-specific physical/technical constraints and does not consider broader constraints.

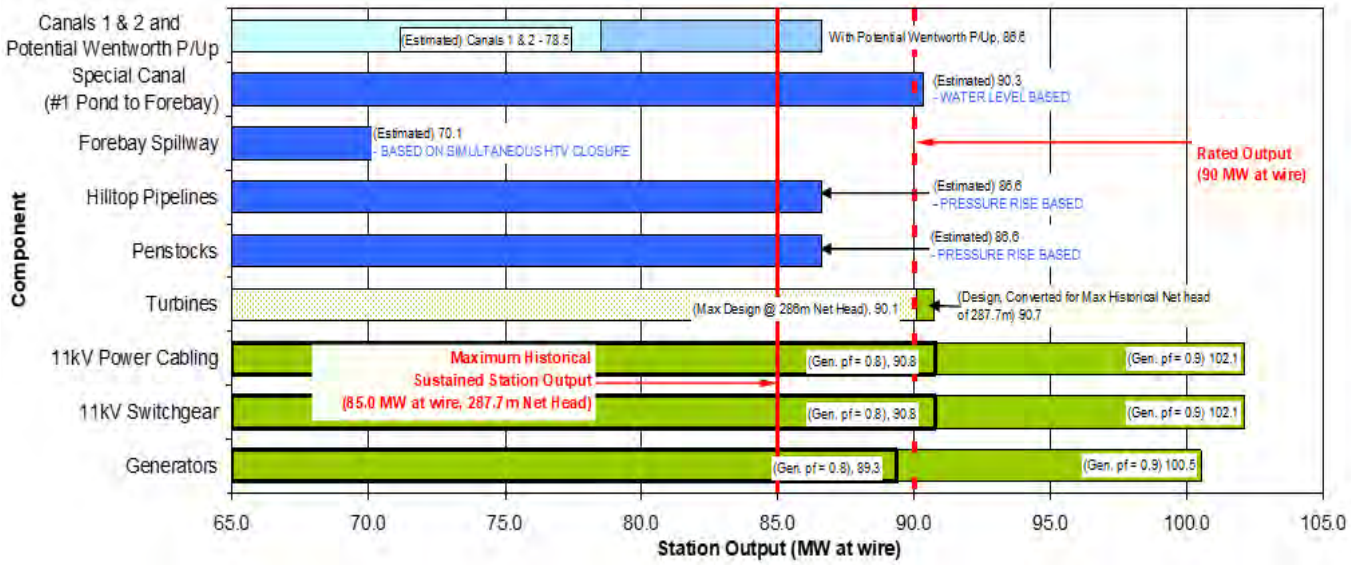


Figure 5: Tarraleah constraining assets summary

Note: *Example from a previous Hydro Tasmania assessment – not representative of current asset condition and performance.*

4.1.3 Flexibility characteristics

The future NEM is expected to need flexible dispatchable generation, so a key attribute to assess is the scheme's flexibility of operations and to identify which assets are constraints or opportunities.

Based on forecasts from the IEA (2018) and Hydro Tasmania's own studies, the common need will be for flexibility in the 'medium' or 'hourly to days' type timeframes as the NEM transforms from Phase 2 to Phase 3 and Phase 4 levels of VRE integration.

An example flexibility assessment for a hydropower scheme is provided in Table 6.

This table links the flexibility types and timeframes with the asset types which influence the overall scheme capability and was developed with input from the International Energy Agency (IEA, 2018) report on plant flexibility.

POWER STATION FLEXIBILITY ASSESSMENT								
Overarching market requirement	System stability			Reliable energy supply				
	Ancillary services (power quality)			Dispatchable capacity (bridging power)			Energy security (energy management)	
Flexibility description	Ultra short term	Very short term	Very short term	Short term	Short term	Medium term	Long term	Very long term
Flexibility timeframe	Sub-seconds to seconds	Seconds to minutes	Seconds to minutes	Minutes to hours	Minutes to hours	Hours to days	Days to months	Months to years
Specific market requirement	Ensuring system stability at high shares of non-synchronous generation	Ensuring short term frequency control at high shares of variable generation		Meeting more frequent, rapid and less predictable changes in the supply/demand balance		Determining operation schedule of the available generation resources to meet system conditions in hour and day ahead timeframes	Addressing longer periods of surplus or deficit of VRE generation, mainly driven by specific weather system	Balancing seasonal and inter-annual availability of VRE generation with power demand
System characteristic	Initial response	Frequency containment reserves	Frequency restoration reserves	Start up time - unit commitment	Economic dispatch	Medium term - unit commitment	Long term – unit commitment	Very long term – unit commitment
Flexibility measure	Minimum stable load (MW)	Fast raise within 30 seconds (MW)	Fast raise within 5 minutes (MW)	Start up time (hrs)	Ramp unit (MW/min)	Capacity factor – daily to weekly	Capacity factor – weekly	Capacity factor – annual
Dams and water storages				**Storage size relative to available inflows subject to environmental, social and operational constraints.**				
Low pressure conveyances (not shown on schematic)				**Hydraulic characteristics**		**Conveyance capacity**		
Power conveyances		**Hydraulic characteristics**				**Conveyance capacity**		
Power station and switchyard	**General plant characteristics**					**Installed capacity**		
Downstream environment		**Environmental, social and operational constraints**						

Table 6: Conventional hydropower scheme flexibility assessment table (example)

4.2 Step 2 – Assess asset and revenue risk and opportunities of existing asset

Hydropower assets are capital intensive with a long lead time for planning, design and construction but they have a long operational life. Other renewable and storage technologies such as wind generation, solar photovoltaics (PV) and battery storage are scalable in size (and capital investment) and have a much shorter project lead time and operational life. The longer lead time and longer life makes investment decisions for hydropower assets more challenging and they require more detailed assessment of both future asset risk and future market conditions (revenue risk and opportunities).

Hydropower asset risk assessment is a relatively mature field of expertise, the details of which are beyond the scope of this report. Key information is summarised below:

- **Risk assessment methodology:** Hydro Tasmania uses its own Integrated Business Risk Management (IBRM) procedure for risk management. Other asset owners will have their own procedure, most likely based on *AS ISO 31000:2018 Risk management*.
- **Turbine asset risk assessment:** Hydropower turbines are a rotating machine with a relatively predictable maintenance schedule and operational life. Asset condition can be affected by factors such as operating mode (baseload, intermediate or peaking) and operating range (rough running/cavitation). Asset performance can be monitored through measuring parameters such as headwater and tailwater pressure (head), flow, rotation speed and power output to compare actual efficiency with design efficiency.
- **Gates and valves asset risk assessment:** Hydropower gates and valves typically have a regular maintenance schedule but their asset condition and operational life varies depending on how frequently the gates and valves are operated and the environment in which they are installed. The need for refurbishment or replacement can be readily determined based on asset performance and inspection and monitoring of asset condition.
- **Electrical asset risk assessment:** The performance of electrical assets is highly important for asset owners to maximise their availability and responsiveness to the market and to maintain network stability. Like gates and valves, electrical assets typically have a regular maintenance schedule linked to age and the frequency of switching. Electrical assets are strictly regulated and the need for refurbishment or replacement may also be driven by changing standards or requirements from the network operator.
- **Dam asset risk assessment:** Dam assets typically have a very low probability of failure and very high consequences. Despite considerable advances in the past 20 years, quantitative dam safety risk assessment remains complicated and somewhat subjective. This makes dam safety risk somewhat difficult to compare with mechanical and electrical assets which are much more predictable in terms of their need for preventative maintenance and eventual end-of-life refurbishment or replacement. Dam safety is legislated in many Australian states and territories which is also a strong driver of dam upgrade decisions.
- **Civil asset risk assessment:** Civil asset risk assessment has adopted similar approaches to quantitative dam safety risk assessment. The challenge with civil assets is that they are often long structures which vary along their length. This makes them very difficult to investigate and monitor. The consequences of failure can be similar to that of a large dam and can be greater than that of mechanical and electrical assets. For example, the loss of a canal conveying water to a hydropower station could result in the entire loss of station output until the canal is repaired. Challenges in civil asset risk management are discussed further below.

Within the field of hydropower asset management, Hydro Tasmania finds civil asset management the most challenging to manage effectively. Civil assets are highly customised and vary substantially in terms of foundation conditions, construction materials, construction methodology, environment and operational regime.

A poorly constructed civil asset in demanding environmental conditions may require high levels of maintenance and have a short operational life whereas a well-constructed civil asset in a more benign environment may require very little maintenance and have a very long operational life. A small civil asset located close to other

infrastructure and development may have high social consequences of failure while a large asset in a remote location may have much lower consequences.

In comparison, hydropower turbines have much better understood operational life, maintenance schedule and failure consequences which are more closely related to its duty cycle (e.g. baseload versus peaking), rather than where it is installed.

In addition to the above, the oldest remaining hydropower schemes still in operation around the world are only now approaching 100 years of age. Therefore, we don't have a large body of knowledge on which to base 'end of life' decisions for civil assets.

Ultimately, the decision is a choice between increasing asset risk and associated monitoring and maintenance costs versus investing in a new asset with significantly reduced risk and costs. This decision is made easier for asset owners where opportunities exist to repurpose assets with enhanced capability and an increased future revenue stream.

For the purposes of this framework:

- Asset risk trends should be assessed in accordance with the asset owner's procedures and industry best practice. Hydro Tasmania has found it valuable to consider risk at both the strategic and operational levels and found that for civil conveyance assets, the presentation of risk data in spatial format is one method to improve the communication to key decision makers. Where suitable quantitative risk and or reliability data is available, then the use of risk weighted generation outlook can also be a useful tool.
- Future revenue risk and opportunities should be assessed qualitatively as the anticipated requirements of the future NEM, with more detailed consideration of future revenue streams considered in step 5 of the framework. Given the uncertainty of the future market, Hydro Tasmania considers this assessment to be the most important step in the entire framework as decisions made at this step provide the overall guiding strategy.

4.3 Step 3 – Develop concepts to repurpose existing asset

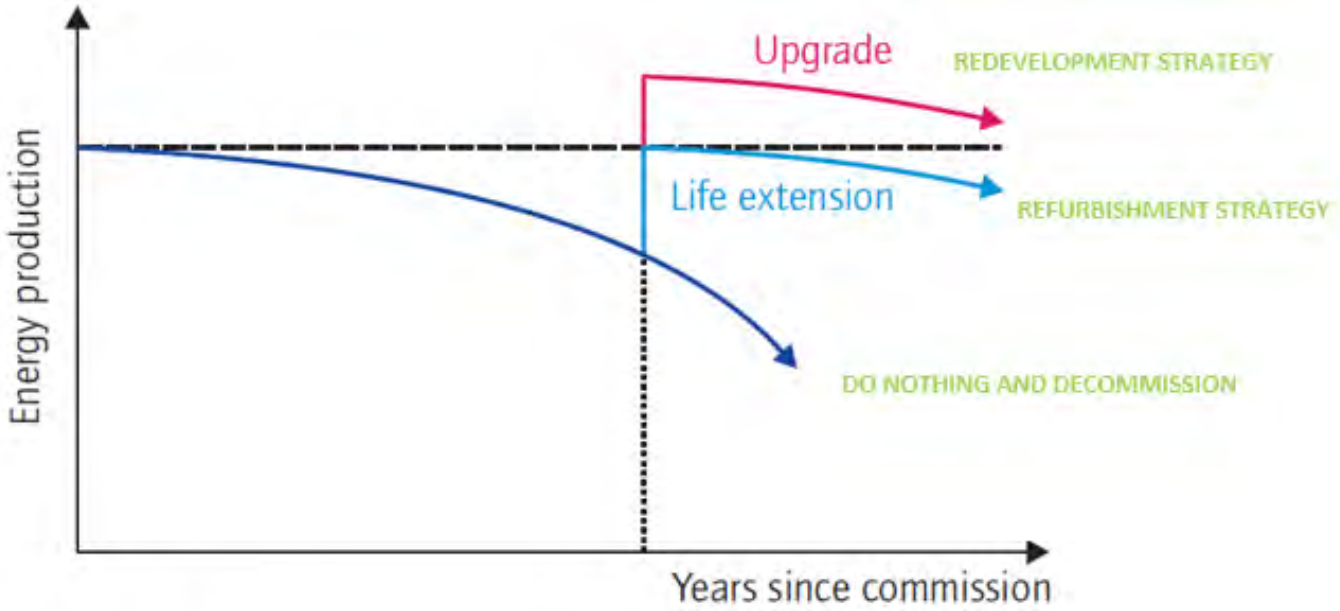
The purpose of this step is to develop concepts to repurpose the existing asset through a brainstorming or workshop process, typically undertaken as part of a **concept study**. Concepts should aim to reduce asset risk and increase exposure to future market revenue opportunities.

This process is best facilitated by hydropower engineers supported by civil, dams, hydraulics, electrical and mechanical engineers, environmental and social scientists and strategic market analysts. Concepts can be ranked and screened from most promising (i.e. high potential value and/or low risk) to least promising (i.e. low potential value and/or high risk).

As the future is anticipated to value flexibility, consideration needs to be given to the different flexibility aspects of hydropower scheme components. Table 7 shows a flexibility assessment table with different repurposing options which has been developed by Hydro Tasmania based on information presented in IEA (2018). This table links repurposing options with the flexibility and timeframes of asset types outlined in Table 6.

For schemes with high asset risk and/or high future revenue risk, asset owners should also consider scheme decommissioning as a credible option, enabling capital to be made available for other investments which are better suited to the future market. It should be noted that decommissioning may also have significant costs and environmental and social impacts.

The time-based impact on scheme energy production is shown schematically on Figure 6; along with the impact of various asset management strategies. The same type of relationship is appropriate to scheme capability and asset risk.



Source: Lier, 2011.

Figure 6: Asset management cycle for a hydropower scheme

POWER STATION FLEXIBILITY ASSESSMENT			
Operating market requirement	**System stability**	**Reliable energy supply**	
	Ancillary services (power quality)	**Dispatchable capacity (bridging power)**	**Energy security (energy management)**
Dams and water storages		Increasing the capacity and/or operational flexibility (i.e. operational range and storage level fluctuation) of existing **small-medium storages** provides greater dispatchable capacity.	Increasing the capacity and/or modifying the operating regime of existing **large storages** provides greater energy security through: (1) greater ability to store water for use during times of energy scarcity (and high market prices) and (2) higher average storage levels increases available capacity and energy output and may also provide environmental benefits.
Low pressure conveyances (not shown on schematic)		The provision of an **intermediate storage** close to the power station increases operational flexibility. **Closed-conduit conveyances** such as pipelines and low pressure tunnels provide much greater flexibility than free-surface conveyances such as canals, flumes and non-pressurised tunnels.	Increasing the **capacity** of low pressure conveyances in conjunction with other scheme capacity increases (Water 2 Wire) ensures that dispatchable capacity is available for very long durations when most needed by the power system.
Power conveyances	The power conveyance should be **as short as possible** to maximise the provision of ancillary services (particularly FCAS) and dispatchable capacity. Where not possible, transient water pressures should be controlled with a **surge tower** or equivalent located as close as practicable to the power station. Other repurposing opportunities are related to **hydropower machine control systems** including gates/valves and **allowable pressure rise** in penstocks.		Increasing the **capacity** of power conveyances in conjunction with other scheme capacity increases (Water 2 Wire) ensures that dispatchable capacity is available for very long durations when most needed by the power system.
Power station and switchyard	Hydropower machines can provide a range of ancillary services. Large hydropower machines (particularly Francis turbines) with synchronous generators provide significant **inertia** to the power gird. When installed with **synchronous condensers**, they can provide inertia (and be eligible for market revenue) with no power output.	Hydropower machines with **fast start-up and shut-down, fast ramping** ability and **maximum installed capacity** are well-placed to provide highly valuable dispatchable capacity to the market.	Maximising the **installed capacity** of hydropower machines maximises the capacity able to be dispatched into high market prices over both the daily (diurnal) and seasonal price cycles.
Downstream environment	The provision of FCAS services such as fast start-up and shut-down and fast ramping ability have the potential for social and environmental impacts. These include impacts on the **riparian and aquatic environments** and impacts on **recreational uses of storages and rivers**. Downstream impacts can be mitigated through the construction of **regulating storages** downstream of power stations.		Increasing the capacity and/or modifying the operating regime of existing large storages may have potential benefits such as: storage levels may be **higher on average, spill may be lower and more controllable** and more **water may be available in the summer months.** Benefits should be weighed up against potential impacts.

Table 7: Types of repurposing options which may typically be considered by asset owners

4.4 Step 4 – Group concepts into repurposing options

The purpose of this step is to group the most promising concepts identified in step 3 into credible repurposing options considering technical, market, environmental and social aspects. This is typically undertaken as part of a **pre-feasibility study**. This process is best facilitated by hydropower engineers supported by civil, dams, hydraulics, electrical and mechanical engineers, environmental and social scientists and strategic market analysts.

Grouping concepts together into repurposing options can be demonstrated by an example using Hydro Tasmania's 'Water 2 Wire' approach (as initially presented in Figure 4 and Figure 5).

This example, based on the existing Tarraleah hydropower scheme, shows how the power station installed capacity could be increased and the asset risk reduced through unlocking existing scheme constraints.

Figure 7 shows that the current maximum station output is around 85 MW. The constraints on increasing capacity to its rated 90 MW are the canals, the forebay spillway, the hilltop pipelines and the penstocks. The sum cost of eliminating these constraints (i.e. $a + $b + $c + $d) is effectively the cost to increase the station output by 5 MW.

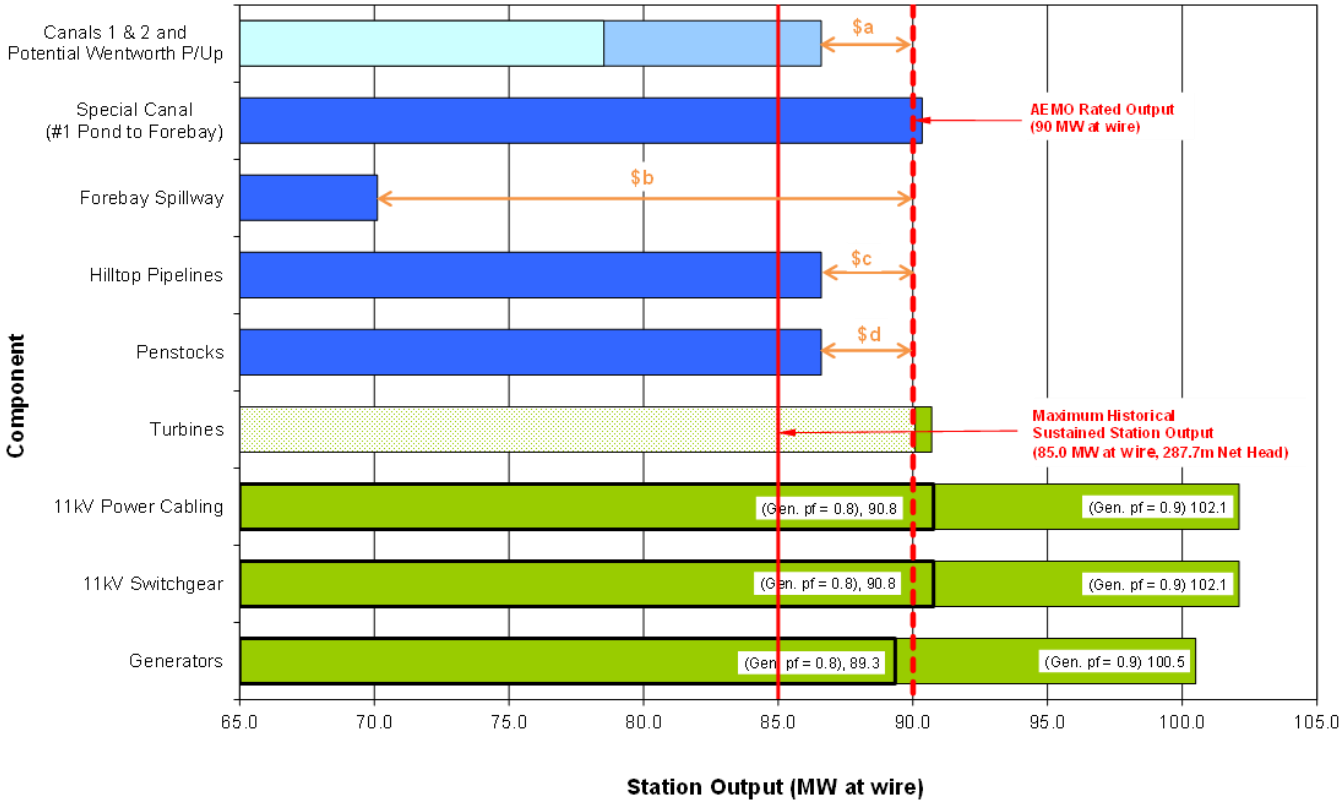


Figure 7: Identification of repurposing opportunities using Hydro Tasmania's 'Water 2 Wire' approach

Note: *Example from a previous Hydro Tasmania assessment – not representative of current asset condition and performance.*

Several examples of grouping concepts into credible repurposing options are presented in Table 8.

Repurposing option	Description	Asset risk reduction benefits	Repurposing cost	Revenue risks and opportunities	Environmental and social impacts and benefits
Unlocking constraints	Asset refurbishment or individual replacement to reduce asset risk, prolong asset life and unlock scheme constraints	Asset risk is reduced for the time being and asset life is prolonged; asset will continue to age and require ongoing O&M to maintain tolerable risk	Low and ability to stagger investment	Modest incremental improvements in short to medium term flexibility	No significant environmental or social impacts or benefits
Replace the scheme with new conveyances and power station	Construction of new conveyances and power station of similar capability	Asset risk reduced to low levels; significant operational and WHS benefits from modern scheme	High – requires significant upfront investment	Modest incremental improvements in short term to medium term flexibility	No significant environmental or social impacts or benefits
Replace the scheme with new conveyances and power station of increased capacity	Construction of new conveyances and power station well suited to future market to better utilise the water source	Asset risk reduced to low levels; significant operational and WHS benefits from modern scheme	High – requires significant upfront investment	New assets provide additional dispatchable capacity; significant improvement in ultrashort to medium term flexibility	Increased operational flexibility may impact on headwater storage level variation and downstream river flow and/or storage level variation
Increasing storage capacity	Dam raising to increase storage capacity and improve regulation of the water source	Dam raising requires compliance with dam safety regulations and guidelines, resulting in asset risk reduction	Medium	Opportunity only if it can be flexibly dispatched	Dam raising will increase the storage inundation area with potential environmental and social impacts
				Increases short to long term flexibility	Additional storage capacity may improve environmental and social outcomes
Decommissioning scheme	Decommission scheme due to high asset risk and/or high future revenue risk to make capital available for investments better suited to the future market	Asset risk eliminated	Medium - costs of making site safe and secure may be significant	No further revenue	Decommissioning impacts are very site-specific
				Avoided competition with low cost VRE generation	
				Capital is made available for other investments	

Table 8: Table of credible repurposing options with qualitative screening – generic example

Note: *Green – high value / low risk / low cost, **blue** – moderate value / risk / cost, **red** – low value / high risk / high cost*

4.5 Step 5 – Assess asset and revenue risk and opportunities of repurposing options

The purpose of this step is to undertake a detailed assessment of the asset and revenue risk and opportunities of the repurposing options retained from step 4. This is typically undertaken as part of a **feasibility study**. This process is best facilitated by hydropower engineers supported by a range of technical specialists but with a much greater emphasis on strategic market analysts, system modellers and financial analysts.

Quantitative **asset risk assessment** is beyond the scope of this report and has been retained in this framework to demonstrate that asset management decisions need to be based on an equivalent level of understanding of both asset risk and revenue risk. Asset owners should take particular note of the potential impacts of more flexible operation on the asset risk (and hence lifetime O&M costs) of hydropower machines. The industry publication: *Flexible operation of hydropower plants* by EPRI (May 2017) provides relevant information on this topic.

This section therefore focuses on how to assess **revenue risk and opportunities** in the future market. Section 3.0 presents the context on how the NEM is anticipated to transform in the future and hydropower's role in this future state. It also describes some of the factors which will influence future supply and demand, and which lead to significant uncertainty in estimating future market revenue streams.

This problem is addressed by considering the following three questions:

- What types of revenue streams may exist in the future NEM?
- What is the magnitude of potential revenue from each of these revenue streams?
- What is the anticipated timing and variability of these future revenue streams?

4.5.1 Types of future revenue streams

The future market is anticipated to require a substantial amount of new dispatchable capacity and a broad range of providers of ancillary services to maintain network reliability. Examples of possible future revenue streams have been outlined in Hydro Tasmania's white paper on understanding reliability in the future NEM. These future services are summarised below and include a few new terms which are defined in Appendix B.

Cap contracts with lower strike prices: As the market transforms, the energy delivery options will change and this will alter the market spot price duration curve. Historically, the NEM has experienced a fairly flat energy price (somewhere around the cost of coal-fired generation) with price spikes during times of energy scarcity. With more variable renewable energy, this flat energy price is expected to separate into two price categories: extended periods at very low prices with plentiful wind and solar; and higher 'firming' prices when other services are required to meet demand. New cap contracts could be made to protect against high prices from gas-fired generation, which will occur more often than the $300+ price spikes of today. This would provide incentives for firming options that can cost-effectively supply energy for extended periods.

Regulated capacity provision: Some markets around the world use mechanisms to allow the system operators to define a minimum level of capacity to ensure reliability and security. There are a range of options to implement this approach. The key to success of these mechanisms is to determine what is actually required with enough time to implement the most cost-effective solutions. Short term capacity alone is unlikely to successfully meet the future market needs.

Firm energy market: The NEM is largely an energy market, with some trading in ancillary services. There is no financial reward for day-ahead commitment of firm generation in the NEM. Some markets use a two-tier energy market with a day-ahead firm energy market being traded separately from a spot price energy market. A firm energy market encourages individual generators to provide a firm service to the market. It may be more efficient to source this as a system service, although having a clear market mechanism to reward firming may deliver additional benefits through innovation and risk management. If such a market were to be created, it would

provide incentives for new reliable firming options that could either procure variable energy and sell a firm product or sell a firming service to the variable energy generator to value-add to their product.

New demand-side response: New opportunities will exist for customers with flexible demand. The mechanisms are not yet clear, particularly in defining the response against some baseline of expected consumption. This difficulty is likely to be addressed through policy and rules along with technology solutions and some customers with flexible demand will be able to actively respond to market signals for firming.

Surplus variable generation: Wind and solar are the lowest-cost forms of new energy generation. AEMO's *Integrated System Plan* (AEMO, July 2018) identified that a system with wind, solar and firming options can produce the most cost-efficient outcome. However, wind and solar development may also reach financial limits from coincidental surpluses, driving the prices in the spot market to zero (or even substantially negative under a power purchase agreement).

The challenges that may face generators, due to value-suppression of their product, are likely to be either daily solar cycle (8 hrs) or extended periods of high wind (24-72 hrs), as outlined in **Table 3** (see **Section 3.4**). In this situation, it is expected that flexible demand that can ramp up to consume the surplus generation will be required to firm the supply-demand balance and leave sufficient profitability for new variable generators to be developed. Ideally, this flexible demand would be in the form of storage that can cost-effectively address the supply-side firming needs as well.

The firming services that will be required to manage the low cost variable renewable energy sources will need to be more flexible than existing baseload generation and operate more often than existing fossil-fuel capacity options. Sustained generation over a period of several hours to even a few days will be critical to successfully manage the transformation of the NEM when maintaining reliability, security and affordability.

There are currently a number of renewable energy policy instruments in place federally and in some states that subsidise the provision of renewable energy. Over a longer term investment time horizon, it is highly uncertain whether subsidies will exist which are targeted directly at utility-scale renewable energy generation. This report therefore assumes that investments in repurposing conventional hydropower assets will need to 'stack up' on their merits based on future market needs without requiring additional subsidies.

Based on common themes in the above discussion, the **three most likely future revenue streams** for conventional hydropower are considered to be the following:

- Energy market: Spot prices in the wholesale energy market are anticipated to become more variable in the future. Flexible generators are able to respond quickly to both high and low market prices and achieve dispatch-weighted prices in excess of the market average price. The introduction of 5-minute market settlements will further increase revenue opportunities for flexible generators.
- Dispatchable capacity: There is a requirement to better incentivise the provision of dispatchable capacity in the future NEM, including sufficient sustained capacity to cover wind and solar droughts in a future market with high levels of VRE generation. This may be via cap contracts, firming products, new market mechanisms or services procured directly by the network operator.
- Ancillary services market: Ancillary services markets are traditionally very 'thin' – once there is sufficient supply of ancillary services to the market, their market price typically collapses. Ancillary service providers need to be better incentivised to ensure network stability in the future NEM. There is anticipated to be very few generators with very high capacity factors in the future NEM but generators which are essential for network stability (such as inertia providers) will require adequate revenue streams to remain financially viable with lower capacity factors.

4.5.2 Assessing the value of potential future revenue

Estimating the value of potential revenue for use in a business case is a judgement which needs to be made by individual asset owners, considering their strategic objectives and governance systems.

For example, there are several ways they can be assessed in levels of differing complexity:

1. **Direct estimates of future revenue streams:** Direct estimates of future revenues are typically derived from highly sophisticated market models, often produced by consulting firms or developed internally depending on the organisation. These normally require an extensive set of assumptions around supply and demand characteristics and are useful for understanding how different generation assets perform in the market. For portfolios of generating assets, these types of models are required to understand the portfolio value of a project. Modelling at this level of detail, while a valuable decision making tool, also presents significant challenges. Hydro Tasmania has published an overview of these in its *Challenges in modelling the transforming NEM* report (Hydro Tasmania, September 2019).
2. **Break even or return on investment assessment:** This approach involves calculating the revenue streams through which an investment is viable and requires well-informed judgement by the asset owner to assess whether the 'back-calculated' revenue stream could realistically be achieved in the future. The benefit of this type of assessment is reduced complexity in the revenue modelling. For example, a pumped hydro scheme generating revenue from a daily arbitrage, using this assessment would provide an understanding of required daily variation in prices to make the project viable.
3. **Cost comparison to competition:** Assessing a project this way can remove revenue uncertainty from the assessment, by assessing the long term revenue viability of a project based purely on its competitiveness against other technologies. As an example, utilising the Levelised Cost of Energy (LCOE) or long run marginal cost (LRMC) of generation, the assessment can be undertaken based on cost and generation output alone and compared to the cost of competing technologies and available price information. The *CSIRO Generation Cost report* (December 2018) is a useful starting point, as is the *Australian Energy Regulators (AER) Wholesale electricity market performance report 2018; LCOE modelling approach*, *limitations and results* (2018). This is the simplest assessment and ignores effects of transmission and portfolio operation.

This report does not attempt to propose specific values for future revenue streams. The market is in a state of ongoing transformation and any such estimates will quickly become outdated. Asset owners must undertake a market analysis at the time of making their investment decision.

4.5.3 Timing and variability of future revenue streams

The final consideration for asset owners is the anticipated timing and variability of future revenue streams and how these align with asset management driven requirements and the typical long lead times of hydropower projects. Timely investment will result in optimised returns but this is a significant challenge. Overview of impacts of early and delayed investment timing can be summarised as:

- Early investment in advance of market signals can protect market share, reduce competition and maximise revenues during periods of transformation but can lead to low revenue in the early years of the investment and risk that future market conditions do not eventuate. Depending on investment size and business constraints, this option can also tie up capital and presents an opportunity cost.
- Delayed investment in response to market signals can result in increased competition and long term loss of market share which will minimise returns. Delaying investment reduces the risk of over investment and provides flexibility for capital to be employed elsewhere.

Key considerations regarding timing and variability of future revenue to be assessed are:

- Changes with time in the cost and type of competing generation sources. AEMO's Integrated System Plan (ISP) and CSIRO's Generation Cost report are examples of standard sources for this type of information.
- Changes with time of system interconnection. AEMO's ISP is an industry standard source for this type of information.
- Consideration of state, national and world political influences on policy, particularly with regard to climate policies and consideration of carbon pricing.

4.6 Step 6 – Identify preferred asset management strategy

The final step in the framework is to identify the preferred asset management strategy and to develop a business case to present to the asset owner's decision-makers for investment.

The best option is likely to be one which balances the maintenance of asset risk at tolerable levels and provides the greatest exposure to future revenue streams with the higher upfront cost of redeveloped assets. Optionality to stage the investment as asset risk increases and the electricity market transforms is highly valuable. For owners of a portfolio of hydropower assets, there are additional considerations relating to the interaction between schemes and the desired market positioning/share.

The elements of a business case are specific to each asset owner. The types of information typically included in a business case are discussed below.

Strategic business objectives: Asset management strategy needs to align with business or organisational overarching strategic objectives and values.

Physical parameters: Includes peak and sustained capacity, storage duration, annual energy, capacity factor, operational flexibility and operational life. This enables options with significantly different parameters to be readily understood and compared.

CAPEX and spend profile: Both the total CAPEX and the spend profile are of interest to asset owners when making investment decisions. Refurbishment options typically have a lower upfront CAPEX and a greater spread over the project life, whereas redevelopment options often have a higher upfront CAPEX and lower future spend profile. Asset owners may have portfolio-level CAPEX spend limits in any given financial year. This means that an increase in CAPEX on one asset may result in reduced or delayed CAPEX on other assets.

Revenue estimates: Revenue is estimated using the asset owner's future market revenue model based on the considerations presented in step 5. The use of a business-wide revenue model is important so that all assets and associated investment decisions can be compared on an equal basis. For owners of a portfolio of assets, it can be challenging to attribute net business revenue to individual assets, particularly when revenue is derived from a combination of wholesale energy markets and contracts.

Return on investment: Typically involves discounted cost-benefit financial analysis. Such analysis requires the selection of a weighted average cost of capital (WACC) which is based on a measure of overall investment risk. Asset owners may choose to set a different WACC for each project based on its relative investment risk or may have a single WACC for all investment decisions to facilitate comparison of potential investments.

Risk/opportunity assessment: Performed for each option using qualitative or semi-quantitative assessment techniques. Such an assessment clearly highlights the assessed risks and opportunities for each option in addition to, or instead of, embedding these into the financial analysis. Hydro Tasmania uses its Integrated Business Risk Management (IBRM) procedure for risk management. Asset owners should use their own procedure.

5.0 Repurposing framework – applied example

The Tarraleah feasibility study has reached the 100% feasibility design milestone. Key outputs represent the status at the completion of the study and are subject to the provisions of clause 5.4 relating to information classified as Recipient Confidential Information.

5.1 Overview of the Tarraleah scheme

The Tarraleah hydropower scheme is located in the Upper Derwent River and is one of several stations comprising the Derwent hydropower scheme, as shown in Figure 8. The Tarraleah scheme has very high utilisation and generates around 625 GWh per annum of largely baseload power, around 6.5% of total annual generation. The scheme plays a key role in the regulation of flows to the Lower Derwent cascade system of dams and power stations. Combined, these provide a total installed capacity of approximately 370 MW.

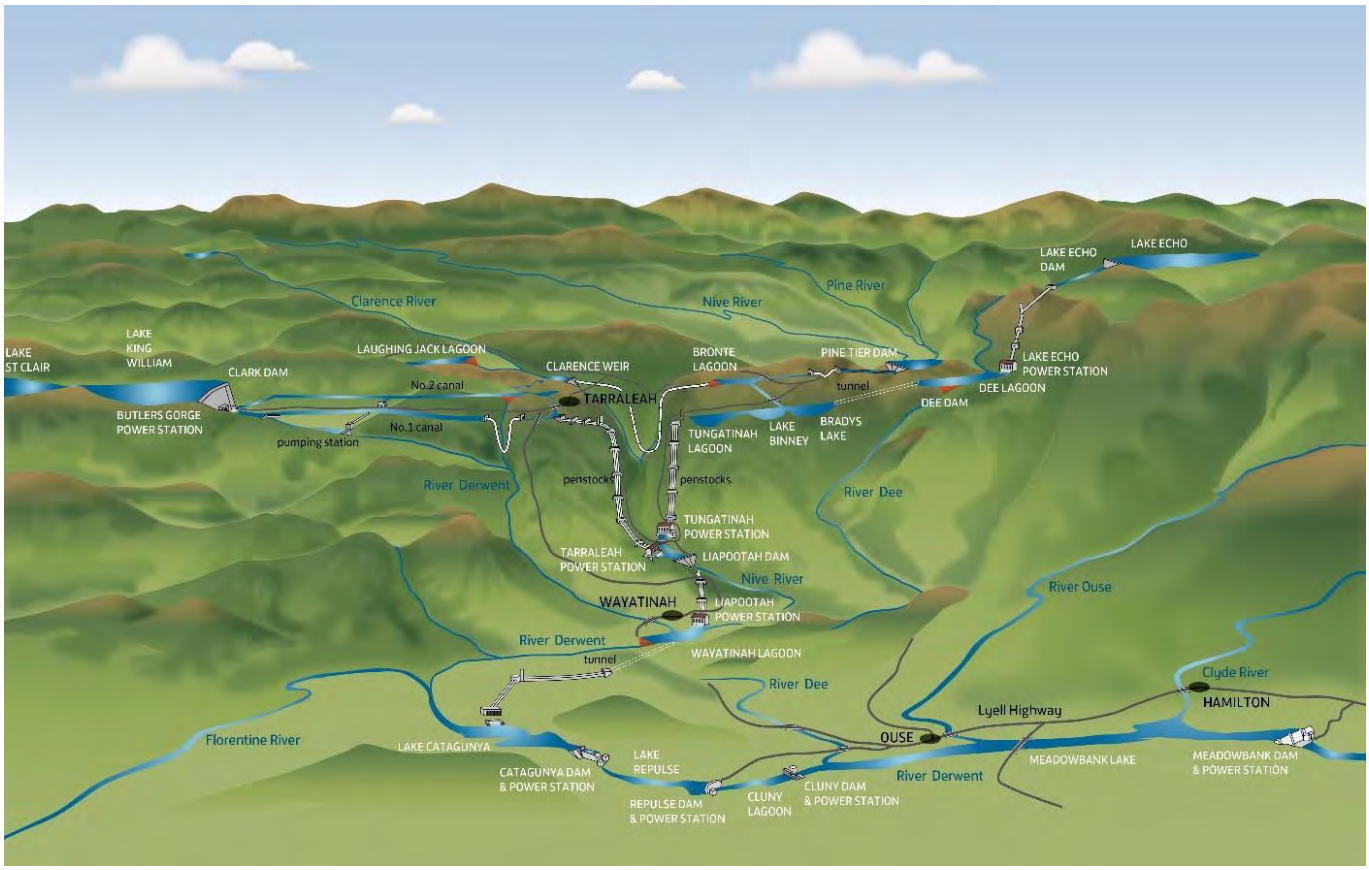


Figure 8: Derwent hydropower scheme diagram

Under certain future market conditions, there is a risk that the current 'business as usual' asset management plan for the scheme will provide decreasing returns on investment due to the inability to adapt its operating regime to suit future market needs.

The history of Tarraleah is staged construction. Initially to provide energy through three 15 MW machines (commissioned 1938) using water diverted by a weir from the Derwent River at Butlers Gorge through No. 1 canal, capacity was increased to five 15 MW units (1945) and a No. 2 Pond added, filled by water pumped from No. 1 Pond at the canal terminus to allow additional load variation (manual), then ultimately six 15 MW units (1951).

Figure 9: Construction of the powerhouse in the 1930s

The scheme was augmented several times over the succeeding decades, with Clark Dam constructed in the 1950s, raising Lake King William to provide head storage in place of the run of river diversion, along with an additional power station, Butlers Gorge, added at its outlet.

In the same period, a second canal system (No. 2) was constructed to increase the flow to Tarraleah. Clark Dam was raised again in the 1960s and the extra spill captured now meant the scheme generated near full capacity, the full year around.

The latest addition to the scheme was a mini hydro, Nieterana, constructed in the early 2000s to convert energy previously dissipated by a needle valve between Clark Dam and the No. 2 Canal.

This progressive development represents the scheme 'growing' with the state's energy system, to the point where the capacity factor is high to avoid spill past both Tarraleah and Liapootah stations, limited by the capacity of the canal system and the station.

While the scheme formed the base supply when the state's other major schemes were developed between 1950 and 1995, its role hasn't changed since the 1950s.

Figure 10: Construction of No. 1 Canal concrete flume section in the 1930s

Built in a manner that suited its staged construction and the 1930s construction methods available, essentially it represents significant storage for the entire Derwent Scheme but provides only baseload energy itself. It still does this well but its energy conversion is very inefficient by today's standards and dispatch of that energy is inflexible, constraining the entire Derwent scheme.

Repurposing the Tarraleah scheme presents an opportunity to maximise the renewable energy contribution of the scheme through increasing its flexibility and responsiveness.

5.1.1 Tarraleah scheme arrangement

The layout and hydraulic configuration of the Tarraleah scheme is shown schematically in Figure 11. The scheme consists of the follow key components:

1. Storage at Lake King William: This seasonal storage (540 Mm^3) has a large catchment area (582 km^2) and with an average inflow of approx. 30 cubic metres per second (cumec or CMS), it is a valuable water resource.
2. Butlers Gorge Power Station: 1950s era power station that generates electricity from the water released from Lake King William into the Tarraleah No. 1 Canal. The station has an installed capacity of 12 MW and maximum output of 30 cumecs.
3. Tarraleah No. 1 Canal: An approx. 20 km long conveyance constructed predominantly from concrete lined canal and flume sections, with a single siphon. This 1930s era asset conveys water from the outlets of Lake King William to the headponds of the Tarraleah Power Station. Due to asset age and impacts of bio-fouling from algal growth, the capacity of the canal is limited to approx. 20 cumecs when clean. The original design capacity was 25 cumecs.
4. Tarraleah No. 2 Canal: An approx. 15 km long conveyance constructed from concrete lined canals and flumes, wood stave siphons and unlined tunnel sections. This 1950s era asset conveys water from Lake King William to

the headponds of the Tarraleah Power Station. Due to asset age, the conveyance is currently limited in capacity to 8.5 cumecs.

5. Tarraleah headponds: Consisting of No. 1 and No. 2 Ponds, these storages are the receiving waters of the No. 1 and No. 2 conveyances respectively.
6. Tarraleah Power Station: A 90 MW station located on the banks of the Nive River. The station is equipped with 6 horizontal axis Pelton turbines installed over the years 1938 (Machines 1-3) and 1943 - 1951 (Machines 4-6).

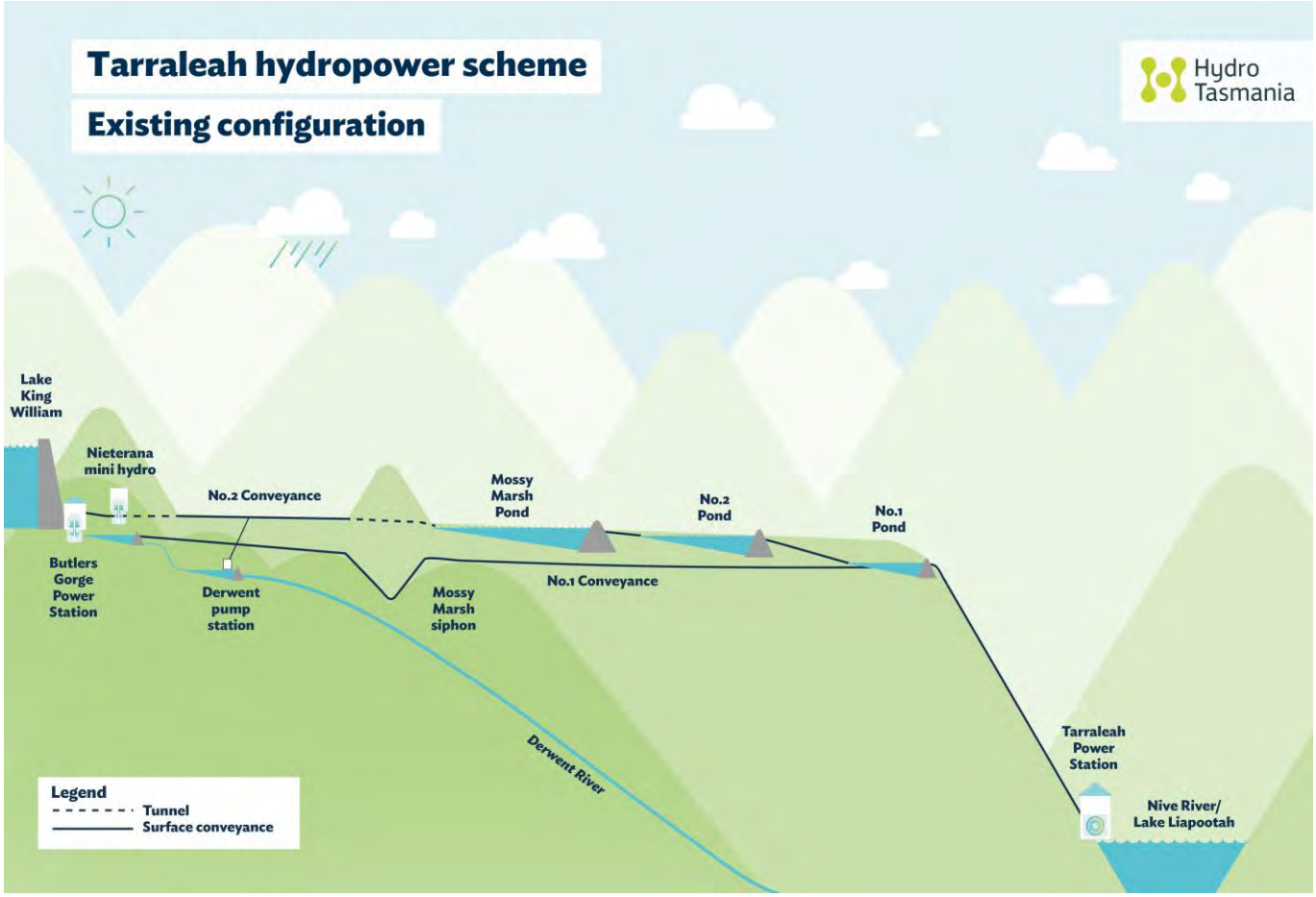


Figure 11: Tarraleah scheme arrangement

5.1.2 Existing scheme physical attributes and constraints

As part of the pre-feasibility study (Hydro Tasmania, 2018a) and recent feasibility study, a review of the existing schemes constraints was completed to understand the current limitations. A summary is provided in Table 9 but the key limitations were:

1. Manual operation of the station and conveyances in combination with limited headpond storage is limiting any form of flexible operation of the station.
2. Conveyance capacity is highly constrained relative to inflows, losing flexibility and also potential revenues from spill at Lake King William during high inflow periods.
3. Station capacity factor is relatively high, even if conveyance capacity was not a factor.

Asset type	Physical / technical	Operations & maintenance	Transmission / network	Regulatory	Environmental & social
Dams and water storages Lake King William headponds	Lake King William storage is very large with significant flexibility Headpond storages are small and only provide a few hours' peaking duration	Headponds need upgrade works which require scheme outages and result in production losses	N/A	Clark Dam and headponds are regulated dams under Tasmanian legislation	Storages have some value as recreational fisheries; environmental values in Mossy Marsh pond
Low pressure conveyances No 1. conveyance No 2. conveyance Special canal forebay	Conveyance system is very long, complicated and has a capacity of ~30 cumecs; equivalent to average inflows Canals and flumes are inflexible and require many hours for start-up and shut-down	Conveyance system is manually operated and is subject to biofouling which reduces conveyance capacity Conveyance system needs upgrade works which require scheme outages, resulting in production losses	N/A	No identified constraints	Canals and flumes pose some public safety risk and limit fauna movement
Power conveyances Hilltop pipelines Hilltop valves Penstocks	Power conveyance system has high headlosses compared with a contemporary design Pipelines and penstocks have some technical limitations with allowable pressure rise	Conveyance system needs upgrade works which require scheme outages, resulting in production losses	N/A	No identified constraints	Prominent location; low vandalism risk
Power station and switchyard Main inlet valves Turbines Generators Electrical equipment	Power station cannot utilise full capacity due to conveyance constraints Power station is inflexible, baseload Ageing Pelton machines have low energy conversion efficiency and provide limited ancillary services	Power station is manually operated, and has high noise levels Power station needs upgrade works; the presence of six machines is expected to limit scheme outages and production losses	Tungatinah switchyard is used for both stations; little available space for further augmentation Southern transmission network in Upper Derwent is only 110 kV with high line losses and limited additional capacity	Power stations are registered with AEMO Station transformers are Hydro Tasmania's responsibility Tungatinah switchyard is managed by TasNetworks	Power station and switchyard have built heritage value
Downstream environment Nive River Lake Liapootah	Limited storage in Lake Liapootah Operating the station when the Nive River is in flood causes spill over Lake Liapootah Flooding in Lake Liapootah can impact on station tailwater conditions	N/A	N/A	Water management obligations for the Derwent River including minimum flows downstream of Meadowbank Dam for Hobart water supply	Some environmental values in Derwent and Nive rivers; social values in Tarraleah and Wayatinah villages

Table 9: Summary table of asset physical attributes and constraints – existing Tarraleah scheme

Note: *Green – low constraint, blue – moderate constraint, red – high constraint*

5.2 Future NEM – example scenarios

For this applied example of repurposing the Tarraleah hydropower scheme, we are using example future market scenarios based around Hydro Tasmania's *Battery of the Nation* concept. These are detailed in the *Battery of the Nation, Analysis of the future National Electricity Market* (Hydro Tasmania, April 2018a).

These scenarios represent a few of the potential future market conditions that could occur with significantly expanded levels of interconnection, energy storage and variable renewable energy.

It is important to understand that these do not represent the only potential market outlook and consideration should be given to assessing as wide a range of future scenarios as possible.

The white paper, *Battery of the Nation, Challenges in modelling the transforming NEM* (Hydro Tasmania, September 2019) provides a good overview of some of the important issues and challenges to consider when modelling the future NEM.

5.2.1 Example scenarios

The *Battery of the Nation, Analysis of the future National Electricity Market* (Hydro Tasmania, April 2018a) considered ten (10) scenarios of differing levels of interconnection (IC) and Tasmanian wind and PHES development. For the purposes of this example, we have used two scenarios, which are described below:

- No Further Tasmanian Interconnection Counterfactual or base scenario where there is no further interconnection or development in Tasmania.
- Further interconnection to Tasmania (Future State NEM 5IC): Varying amounts of interconnection and wind development in Tasmania.

Core macroeconomic assumptions underlying these scenarios are outlined in the paper (Hydro Tasmania, April 2018a):

  - Fixed thermal generation retirement schedule of 50 years for coal and 40 years for gas plants.
  - Capex and fuel costs from AEMO National Transmission Network Development Plan (NTNDP) 2016.
  - Demand data from AEMO Electricity Statement of Opportunities (ESOO) 2017.
  - No carbon price, although the targets set by the Paris Agreement would be met on a pro rata basis across the various energy sectors**.
  - The Large Renewable Energy Target (LRET) met by 2020.
  - The South Australia to New South Wales interconnector is commissioned prior to the modelling (2021).

** It should be noted that *Battery of the Nation* has intentionally taken a conservative approach to carbon emissions. The modelling only targeted minimum emissions reductions targets to meet international obligations. If Australia is to meet its obligations from the Paris Agreement, there is an increasing acceptance that the electricity sector will have to contribute above the pro rata reduction.

5.2.2 Example price outlook, risks and opportunities

The general price outlook (Tasmanian context) is shown in the price duration curves (PDC) for various scenarios in Figure 12 and with variation time of these average energy prices as shown in Figure 13. The price outlook represented in the following figures are examples only under certain scenarios and do not represent Hydro Tasmania's position on future market outcomes for investment purposes.

The overall trend is for:

- Increasing durations of very low to potentially negative pricing as more interconnection and VRE development occurs.

- Price outside of the low-negative price periods are set by 'firm' generation sources, such as gas, energy storage or existing hydropower.
- Average energy prices are expected to increase during periods when existing generation is retiring.

Key revenue risks identified from the above trends are:

- Baseload generation will be regularly competing with low cost solar generation and existing generation will need to be able to shift generation from outside the middle of the day to maintain revenue streams as shown in Figure 14.

The key revenue opportunities are:

- Ability to provide firming or flexible dispatchable generation at lower cost than likely price setting gas or combination of VRE and storage; refer CSIRO Gen Cost (2018) for cost examples.
- Having dispatchable generation in place to capitalise on higher prices during retirement of existing plant.

It is important to note that all these trends are reliant on further interconnection to Tasmania. Without the interconnection, revenue risks and opportunities appear to remain similar to current market conditions.

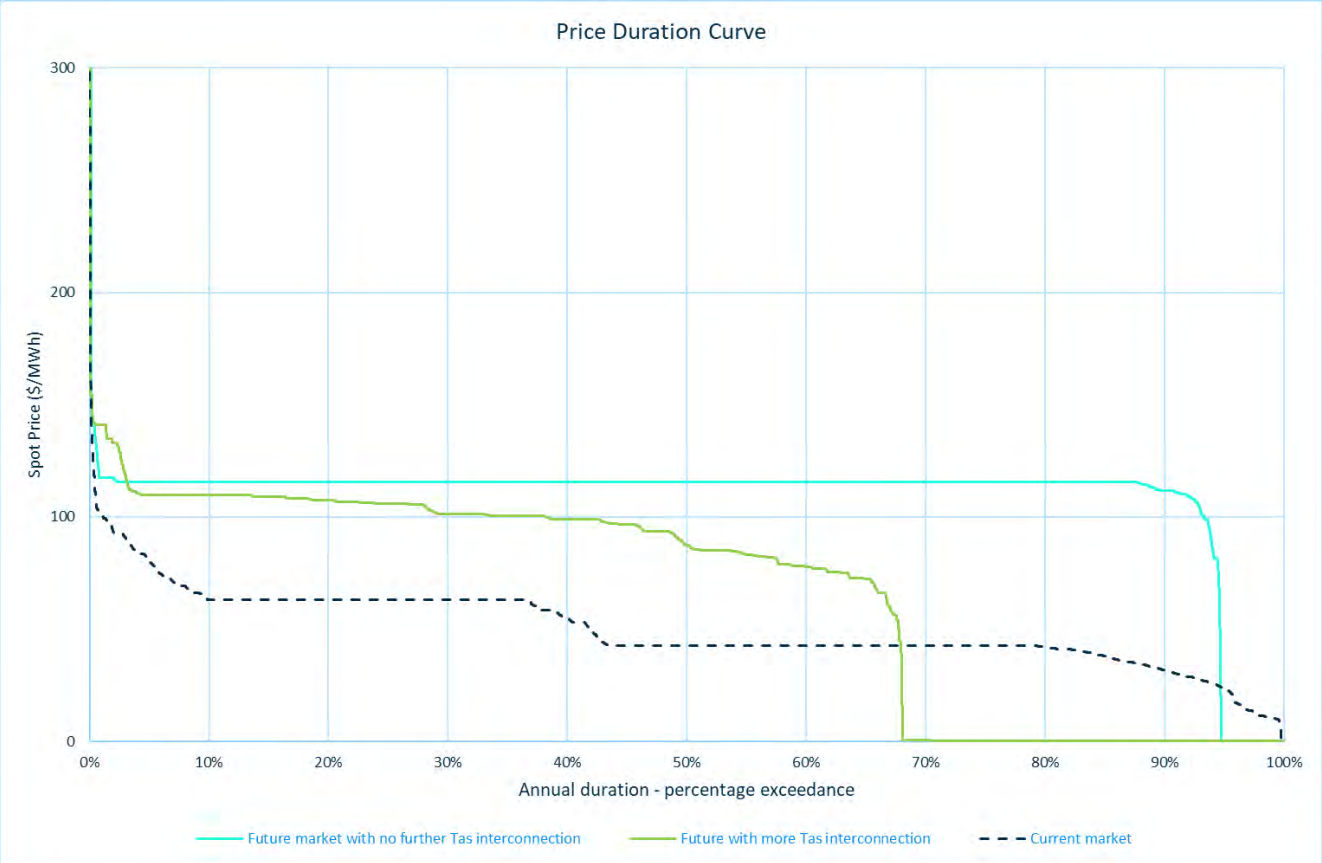


Figure 12: Comparison of price durations from various scenarios (Hydro Tasmania, 2018a)

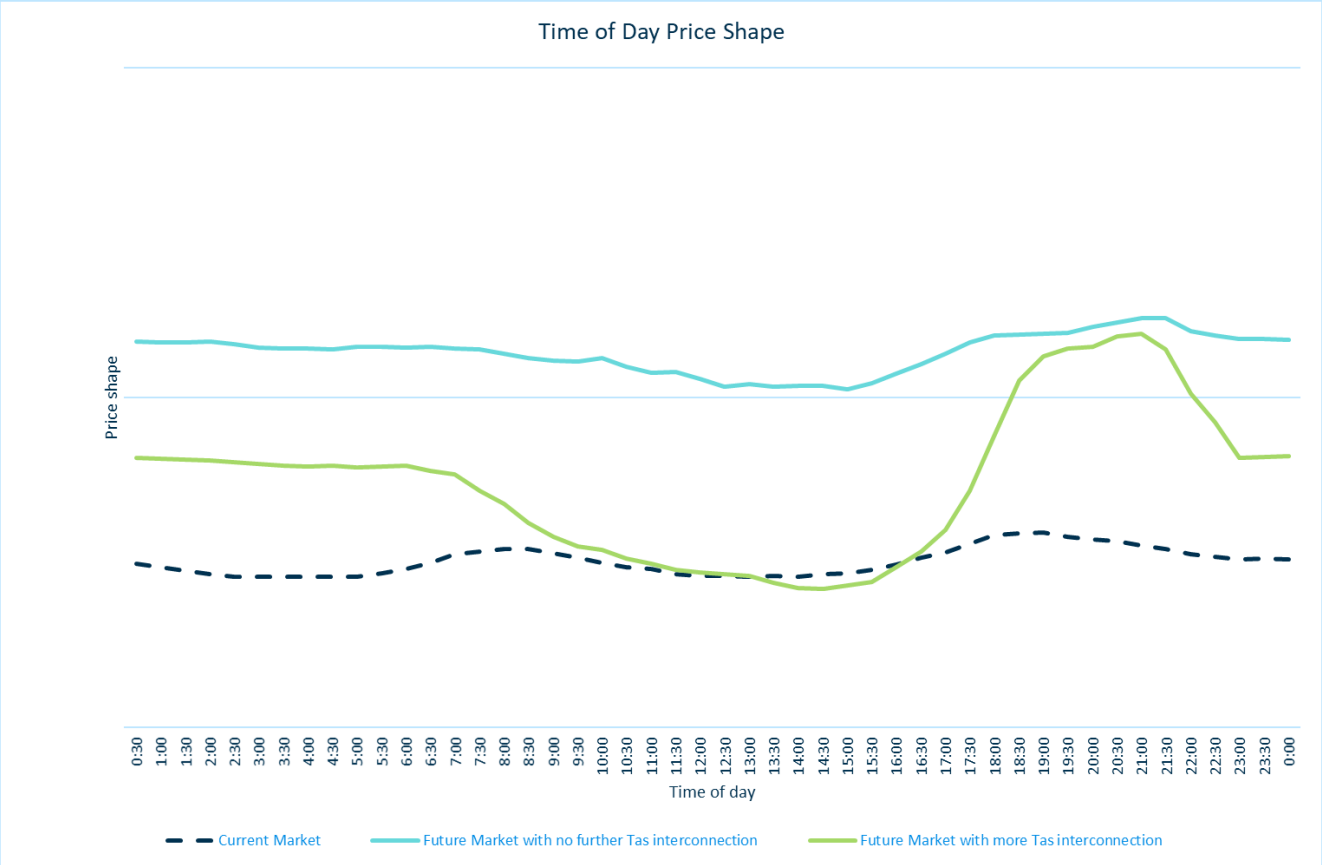


Figure 13: Example Future state NEM price outlook on a yearly basis (Hydro Tasmania, 2018a)

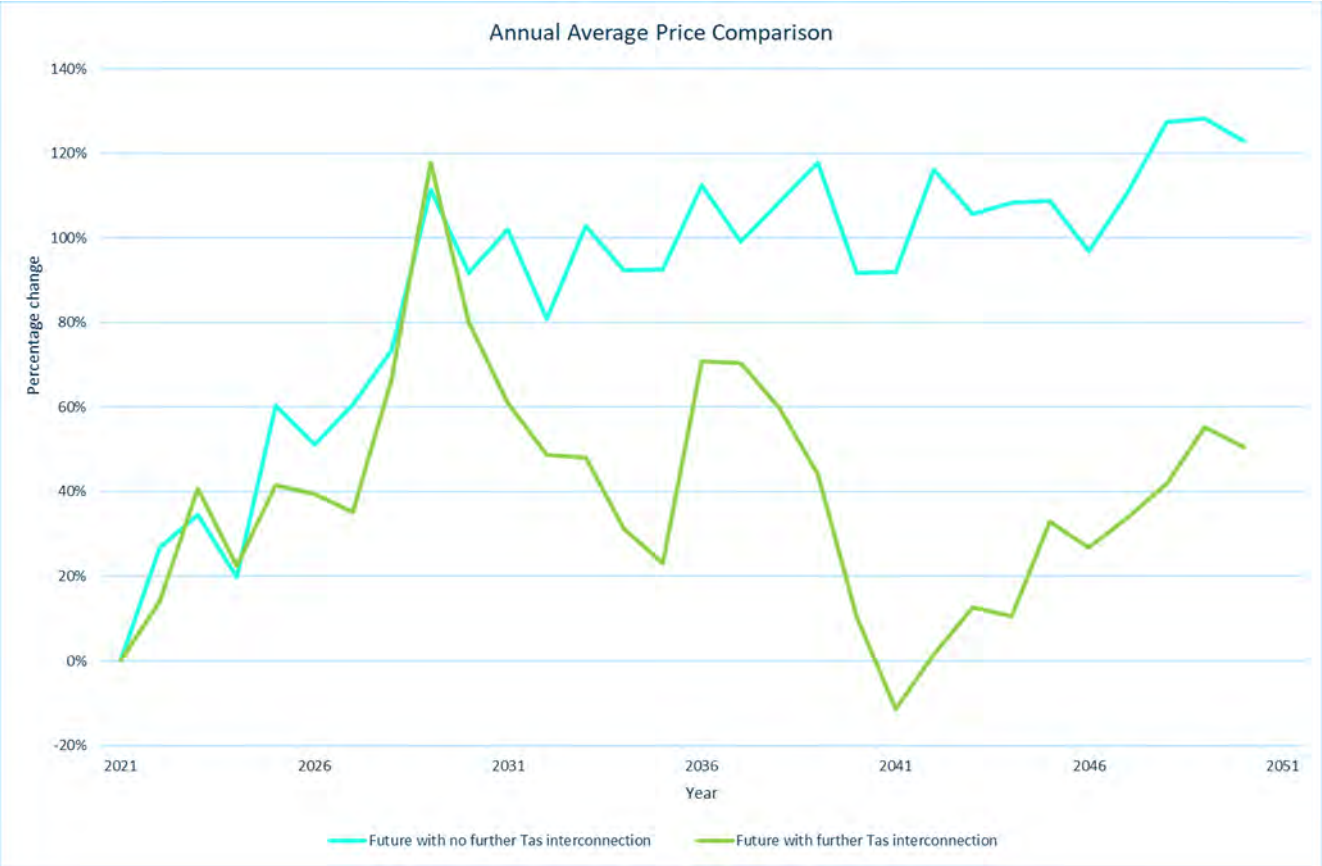


Figure 14: Future state NEM time of day pricing (Hydro Tasmania, 2018a)

5.3 Existing scheme asset risk and future revenue risk and opportunities

As part of the pre-feasibility study (Hydro Tasmania, January 2018a) and recent feasibility study, a review of the existing scheme's asset risk and future revenue risks and opportunities was undertaken to guide the development of repurposing options. A summary is provided in **Table 10** for the future asset risk trends, revenue risks and opportunities.

For the Tarraleah scheme, key asset risk drivers are:

1. Tarraleah Power Station Pelton machines, which are mostly original 1930s and 1940s equipment, are nearing end of life and likely to require replacement around the mid-2020s.
2. The Tarraleah No. 1 Canal is nearing end of life and requires significant expenditure to maintain. Due to its design and location (constructed on a steep hillside), it is also at an elevated risk of failure from landslips and determining the optimum timing for major replacement or remediation works is challenging. No. 1 Canal is expected to require replacement or ongoing major remedial works in the coming decades to manage its risk position.

The key future revenue risks are:

1. Due to conveyance limitations (capacity and ability to change load), the station effectively runs at 100% utilisation (but only 0.8 capacity factor) to minimise spill of water from Lake King William. In the future, this would put revenue at risk as the station would be generating in direct competition with wind and solar resources. Replacement of the No. 1 Canal with a new conveyance system would eliminate this constraint.

The key future revenue opportunities are:

2. Lake King William storage could provide inter-seasonal and potentially inter-annual energy storage (long to very long flexibility).
3. Tarraleah station could be repurposed to provide additional flexible (short to medium term) generation capacity.

Asset type	Asset risk trends	Future revenue risk	Future revenue opportunities
Dams and water storages Lake King William Headponds	Dam safety risks are generally moderate, with some increasing trend on the ageing headpond storage dams which are of earthfill construction	Climate change is a known risk to future inflows. This same risk applies to all repurposing options and indeed to other conventional hydropower scheme	Lake King William is a large storage which has high potential value in the future market to provide sustained capacity during prolonged high price periods such as wind and solar droughts
Low pressure conveyances No. 1 conveyance No. 2 conveyance Special canal forebay	Conveyance system has elevated asset risk with an increasing trend due to age (deterioration) and original design (contour canal above gorge) The complex system has a total length of ~30 km which makes risk difficult to quantify, monitor and mitigate effectively	Conveyance system is very inflexible with very long start-up and shut-down times and limited potential to vary output through ramping Scheme operates as a scheduled baseload station, meaning that it will operate in competition with wind and solar in the future, exposing it to lower prices Limited conveyance capacity means that if capacity factor reduces, energy losses through spill increases	N/A
Power conveyances Hilltop pipelines Hilltop valves Penstocks	Conveyance system has elevated asset risk with an increasing trend due to ageing (corrosion) and geotechnical conditions on the penstock hillside	Pipelines and penstocks have some technical limitations with allowable pressure rise which limits shut-down and ramp-down times	N/A
Power station and switchyard Main inlet valves Turbines Generators Electrical equipment	Power station has elevated asset risk due to ageing; machines have had multiple refurbishments over their life but now require replacement by around the mid-2020s Station transformers and switchyard have been upgraded in recent years and are low risk	Low energy conversion efficiency impacts on annual wholesale spot market revenue Conveyance constraints limit ability to operate at full capacity for more than a few hours Ageing Pelton machines provide limited ancillary services	Current high capacity factor provides exposure to all wholesale spot market prices – both low and high
Downstream environment Nive River Lake Liapootah	N/A	Changing environmental or social needs for water in the future may limit water access for generation and/or the ability to dispatch all available generation into the highest market price periods	N/A

Table 10: Summary table of asset risk trends, future revenue risk and opportunities – existing Tarraleah scheme
Note: ***Green*** *– low risk,* ***blue*** *– moderate risk,* ***red*** *– high risk*

5.4 Development of repurposing concepts

For the Tarraleah scheme, repurposing concepts were developed initially as part of pre-feasibility study (Hydro Tasmania, January 2018a) before being further refined during the feasibility study.

The steps followed by Hydro Tasmania involved:

- Preliminary options workshop onsite with hydropower experts from across the business to develop initial concepts and review existing information (Steps 1, 2 and 3). These concepts are summarised in Table 11.
- Engineering development phase where these concepts where grouped into different options (steps 3 and 4). These options were then presented at a review workshop to screen the preferred options. The preferred options are summarised in Table 12.
- Pre-feasibility study then assessed these options and provided a recommendation on which options should be progressed for the further study (Tarraleah feasibility study).

The outcome of the pre-feasibility study was that:

- Refurbishment option had lowest cost but high future revenue risks.
- No. 3 conveyance option maximised the future market opportunities for lowest upfront cost with ability to stage investment to align closer to market conditions.
- Long conveyance option was the highest cost and had limited future market value unless significant upfront investment was made well before any certainty on future market conditions.
- Decommissioning was not considered a viable strategy for Hydro Tasmania.

Based on these outcomes, the refurbishment and No. 3 conveyance options were selected for further assessment through a feasibility study.

Asset type	Asset risk reduction	Ancillary services	Dispatchable capacity	Energy security
Dams and water storages Lake King William Headponds	Dam safety upgrades to headpond dams with same storage capacity	Increase headpond storage capacity to increase provision of ancillary services (range, duration and frequency)	Increase headpond storage capacity to increase dispatchable capacity	Increase Lake King William capacity to store more water during winter (lower market prices) and release more water in summer (higher average market prices)
	Upgrade to Mossy Marsh pond with increased storage capacity (high environmental impacts)			
	Upgrade to No. 2 Pond dam with increased storage capacity			
Low pressure conveyances No. 1 conveyance No. 2 conveyance Special canal forebay	Progressively refurbish existing low pressure conveyance system to maintain existing capability (asset risk difficult to manage for long conveyances)	Increase low pressure conveyance flexibility and capacity to increase provision of ancillary services (range, duration and frequency)	Increase low pressure conveyance flexibility and capacity to increase dispatchable capacity	Maximise annual yield from Tarraleah scheme catchment area to maximise annual energy
	Construct new long pressure conveyance (tunnel only) directly to new power station (high geotechnical risk)			
	Construct new long pressure conveyance (pipeline and tunnel) directly to new power station			
	Construct new low pressure conveyance to headponds			Reduce low pressure conveyance system headlosses to increase annual energy and sustained capacity
Power conveyances Hilltop pipelines Hilltop valves Penstocks	Progressively refurbish existing power conveyance system to maintain existing capability	Increase conveyance characteristics and capacity to increase range of ancillary services able to be provided (particularly shut-down and ramp-down)	Increase power conveyance capacity to increase dispatchable capacity	Reduce power conveyance system headlosses to increase annual energy (small incremental benefit)
	Construct power conveyance from headponds to new power station			
Power station and switchyard Main inlet valves Turbines Generators Electrical equipment	Refurbish existing Pelton machines to further prolong asset life (no longer practicable to refurbish machines)	Install new Francis machines to provide a broader range of ancillary services	Install new, more efficient machines to increase dispatchable capacity	Install new, more efficient machines to provide more sustained capacity and more annual energy from the same water resource
	Replace existing Pelton machines to increase power and energy output and improve operability			
	Construct new power station with new Pelton machines			
	Construct new power station with new Francis machines			

Asset type	Asset risk reduction	Ancillary services	Dispatchable capacity	Energy security
Downstream environment Nive River Lake Liapootah	N/A	Manage Lake Liapootah to provide ancillary services without increasing spill risk and causing energy losses and downstream impacts	Increase capacity of Lake Liapootah and/or Liapootah power station to increase dispatchable capacity	N/A

Table 11: Summary table for considered concepts to repurpose Tarraleah scheme

Note: *Green – high value / low risk, blue – moderate value / risk, red – low value / high risk*

Repurposing option	Description	Asset risk reduction benefits	Repurposing cost	Revenue risks and opportunities	Environmental and social impacts and benefits
Refurbishment	Refurbish the existing assets to prolong asset life and maintain scheme capability	Asset risk of ~30 km long conveyances difficult to quantify and manage effectively Asset risk of generating plant substantially reduced; building structure continues to age	Moderately high upfront CAPEX and ability to stage refurbishment works based on asset risk assessments; high ongoing OPEX	Scheme will continue to operate as a baseload station; future competition with wind and solar generation during periods of low dispatchable demand poses a revenue risk	No change to existing operation
Long pressure conveyance	New station with new pressure conveyance (pipeline and/or tunnel) directly interconnecting Lake King William with a new power station	Existing assets continue to be operated at elevated and increasing risk levels until decommissioned; risk of delays in long tunnel works Asset risk reduced to low levels when new asset commissioned	Very high upfront CAPEX; low ongoing OPEX	High exposure to future revenue opportunities but decision on ultimate scheme characteristics (capacity) needs to be made for asset risk reasons well in advance of future market transformation	Impacts of increased scheme capacity on Lake King William operation and Derwent and Nive rivers to be assessed Some changes to hydrology of Tarraleah plateau Long tunnel construction has the potential to impact on local hydrogeology
No. 3 conveyance	New station with new conveyance interconnecting Lake King William to intermediary storage headponds with new pressure conveyance from headponds to new power station	Existing assets continue to be operated at elevated and increasing risk levels until decommissioned Asset risk reduced to low levels when new asset commissioned	High upfront CAPEX but greater ability to stage redevelopment works; low ongoing OPEX	High exposure to future revenue opportunities but with ability to stage redevelopment works as the market transforms	Impacts of increased scheme capacity on the Lake King William operation and Derwent and Nive rivers to be assessed
Decommission scheme	Continue to operate scheme until asset risk becomes intolerable then decommission scheme and invest elsewhere	Asset continues to be operated at elevated and increasing risk levels until decommissioned; business temptation to 'run a little longer' Asset risk eliminated when asset decommissioned	Minimises CAPEX and OPEX; decommissioning costs can be difficult to estimate and have no net benefits	Revenue from Tarraleah scheme is sacrificed; decommissioning also reduces inflows to Liapootah power station and impacts the optimal operation of the Derwent cascade system	Decommissioning will change the hydrology and impact on existing water management obligations; assets need to be safe and secure in the long term for public safety

Table 12: Repurposing concepts from the Tarraleah pre-feasibility study

Note: *Green – high value / low risk / low cost, blue – moderate value / risk / cost, red – low value / high risk / high cost*

5.5 Adopted repurposing options

Hydro Tasmania's feasibility study adopted the following process for development of the repurposing strategies for the Tarraleah scheme:

- Site visit and workshop to familiarise the project team with the scheme and review the repurposing concepts from the pre-feasibility study.
- Basis of Design phase that detailed the scope, standards, inputs, assumptions and analysis techniques to be used in the feasibility design. This is an important task as it defines the limits (inclusions and exclusions) of the technical feasibility assessment.
- Options phase to assess different technical configurations (installed capacity, station and conveyance alignments for example) of the repurposing options.
- Environmental and geotechnical investigations to provide information on the project risks, constraints and technical design parameters. This task is an important step to reduce the level of development risk and improve certainty of outcomes.
- Preliminary or 50% design stage to further detail technical parameters and optimise layouts.
- Final or 100% design stage to detail the preferred layouts, costs and project implementation schedule.

The final repurposing options assessed for the future asset management strategy for the Tarraleah scheme as part of the feasibility study were:

1. **Maintain the existing station (TAPS1)** by replacing the existing machines with modern equivalents and replacing the conveyances (No. 1 and No. 2 canals) by a new No. 3 conveyance when required by asset risk.
2. Redevelop the scheme with a **New 2 machine station (TAPS2)** of similar capacity to replace the existing station and replacing the conveyances (No. 1 and No. 2 canals) by a new No. 3 conveyance when required by asset risk.
3. Redevelop the scheme with a **New 3 machine station (TAPS2)** with increased capacity to replace the existing station and replacing the conveyances (No. 1 and No. 2 canals) by a new No. 3 conveyance when required by asset risk or market drivers.
4. Redevelop the scheme with a **New 4 machine station (TAPS2)** with maximised capacity to replace the existing station and replacing the conveyances (No. 1 and No. 2 canals) by a new No. 3 conveyance when required by asset risk or market drivers.
5. Accelerated redevelopment of the scheme with a New 4 machine station (TAPS2) and new No. 3 conveyance to eliminate asset risk and be ready for the future market.

A summary of these options is presented in Table 13 below.

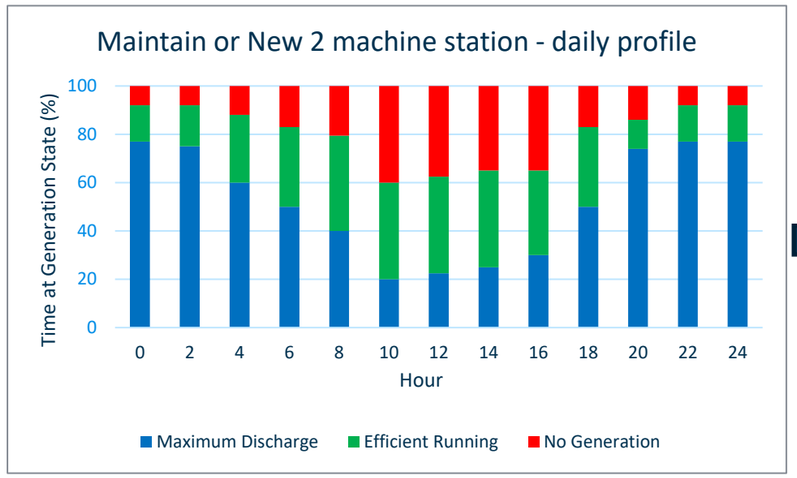
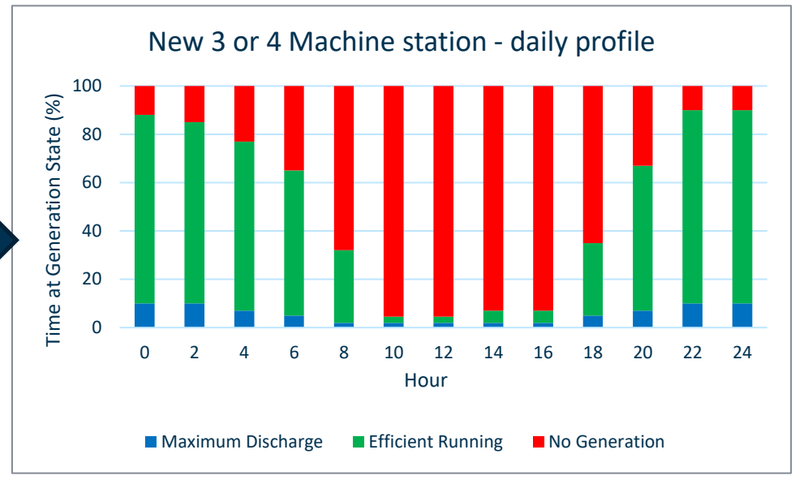
Parameter	Current scheme	Maintain existing station Replacement of TAPS1 machines No. 3 conveyance when needed	New 2 machine station No. 3 conveyance when needed	New 3 machine station M/C 1 & 2 initially M/C 3 and No. 3 conveyance when needed	New 4 machine station M/C 1 & 2 initially M/C 3&4 and No. 3 conveyance when needed or can be accelerated
Tarraleah Power Station installed capacity (MW)	90	105	110	165	220
Flexible installed capacity and duration	Effectively 0 MW	105 MW Inter-seasonal	110 MW Inter-seasonal	110 MW Inter-seasonal +55 MW for 30 hrs	110 MW Inter-seasonal +110 MW for 24 hrs
Annual energy long term (GWh-average)	No change	+10% efficiency improvement	+20% efficiency improvement	+20% efficiency improvement	+20% efficiency improvement
Capacity factor (-)	Effectively 1.0	0.7	0.7	0.5	0.4
Operational flexibility (descriptor)	Baseload Some long term flexibility during low inflow years	Intermediate Short – very long term	Intermediate Very short - very long term	Peaking Very short - very long term	Peaking Very short - very long term
Example daily generation pattern under future market operations					
Operational life (years)	5-10	60+	60+	60+	60+

Table 13: Physical parameters for the current scheme and the repurposing options

Interpretation notes:

1. **Physical parameters** represent the ultimate scheme configuration unless otherwise specified.
2. **Installed capacity** excludes the existing Butlers Gorge Power Station and Nieterana mini-hydro for the existing scheme.
3. **Peak capacity** is the maximum scheme power output with Lake King William at Full Supply Level (FSL).
4. **Storage duration** is the number of hours of scheme operation at (or near) maximum power output with No. 2 Pond level starting at FSL and finishing at Normal Minimum Operating Level (NMOL).
5. **Annual energy long term** is provided to demonstrate the increase in annual energy generation available post No.3 conveyance and Marinus Link construction. The decreasing energy output with scheme capacity is expected as the scheme moves from efficient 'baseload' to 'peaking' operation.
6. **Annual energy** estimates are for the Tarraleah scheme only.
7. **Capacity factor** is calculated as follows: (annual energy project life) / (peak capacity x 8760 hours per year).
8. **Operational flexibility** can be classed as 'baseload', 'intermediate' or 'peaking'.
9. Figures shown assume the **No. 3 conveyance** is constructed either due to risk or market drivers.

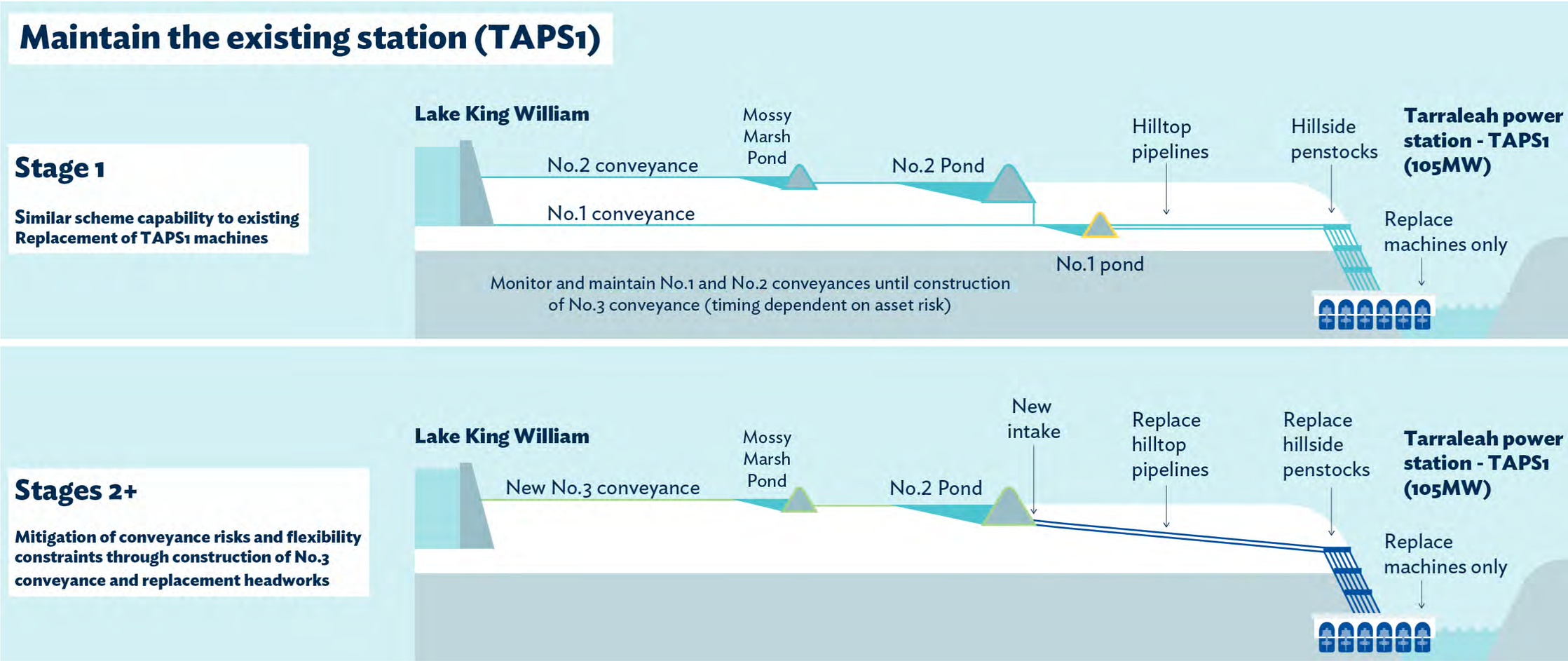


Figure 15: Maintain existing station option diagram

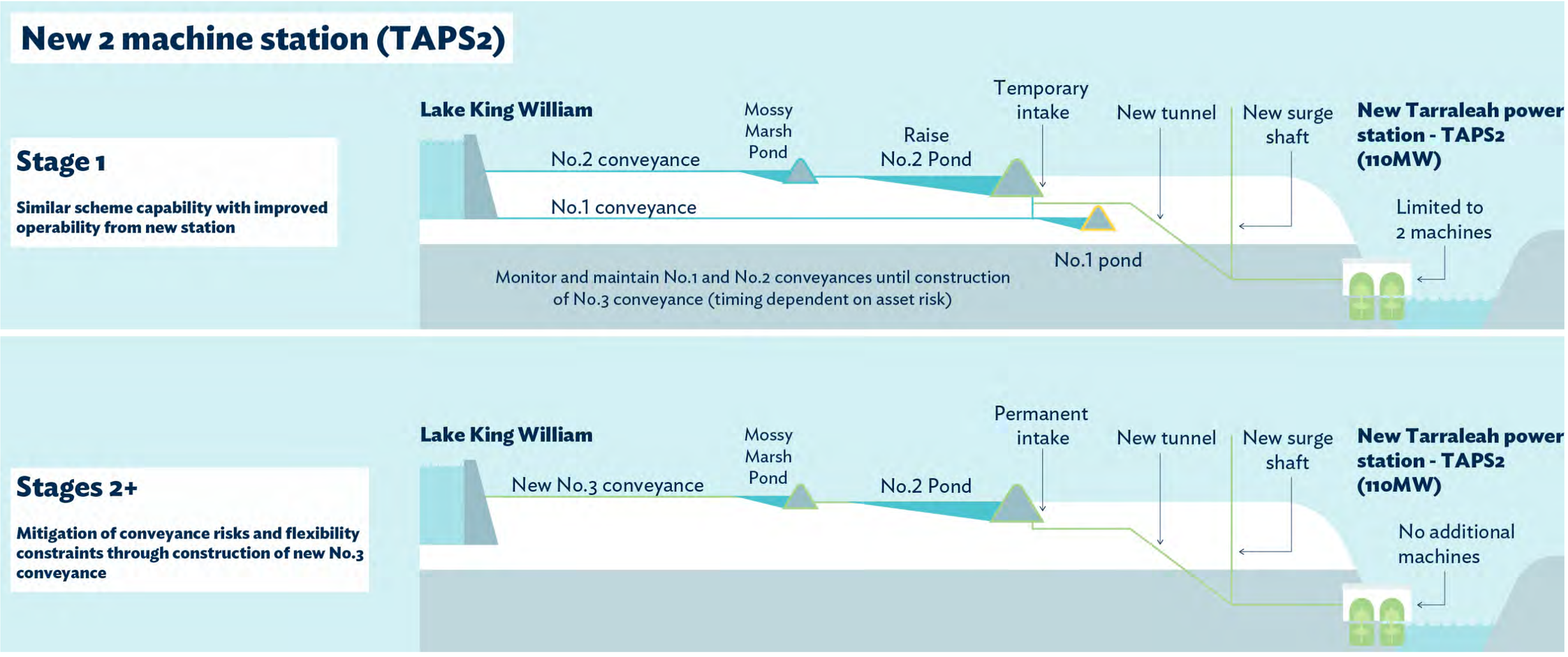


Figure 16: New 2 machine station option diagram

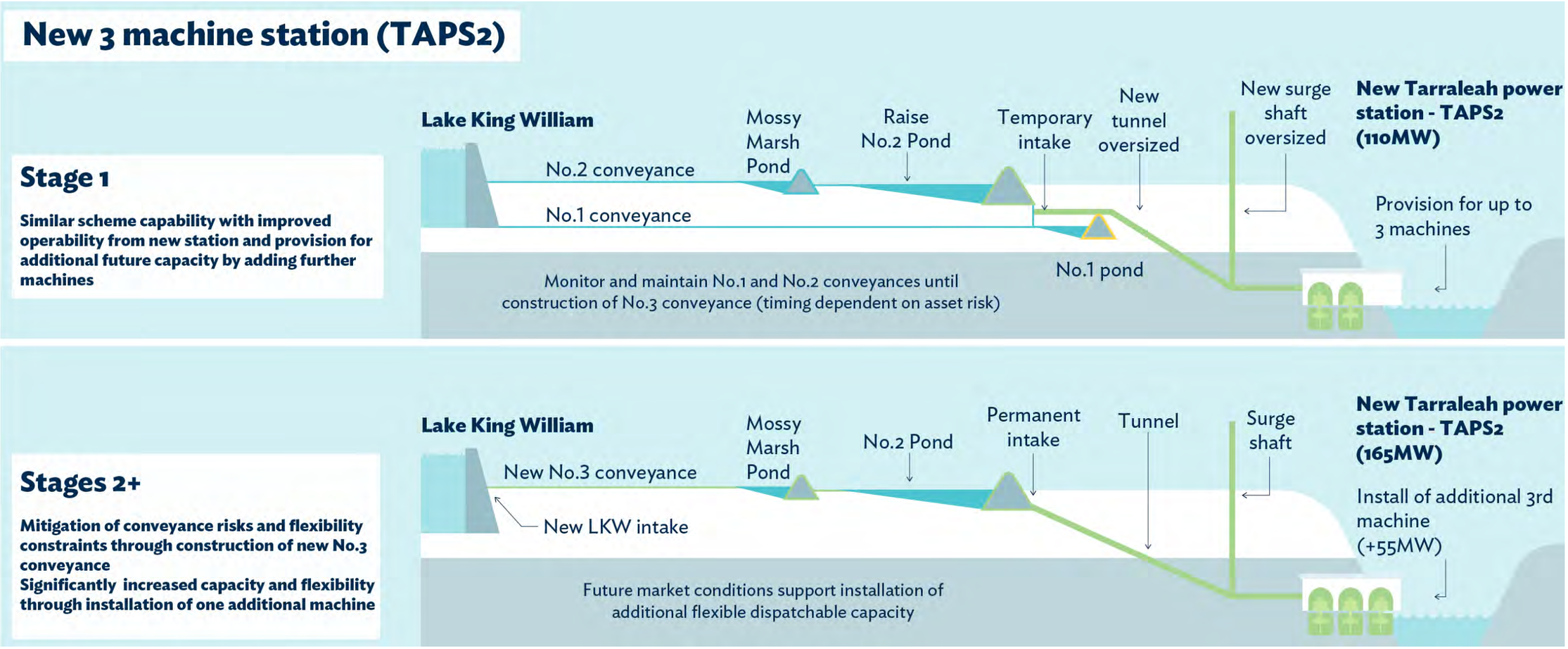


Figure 17: New 3 machine option diagram

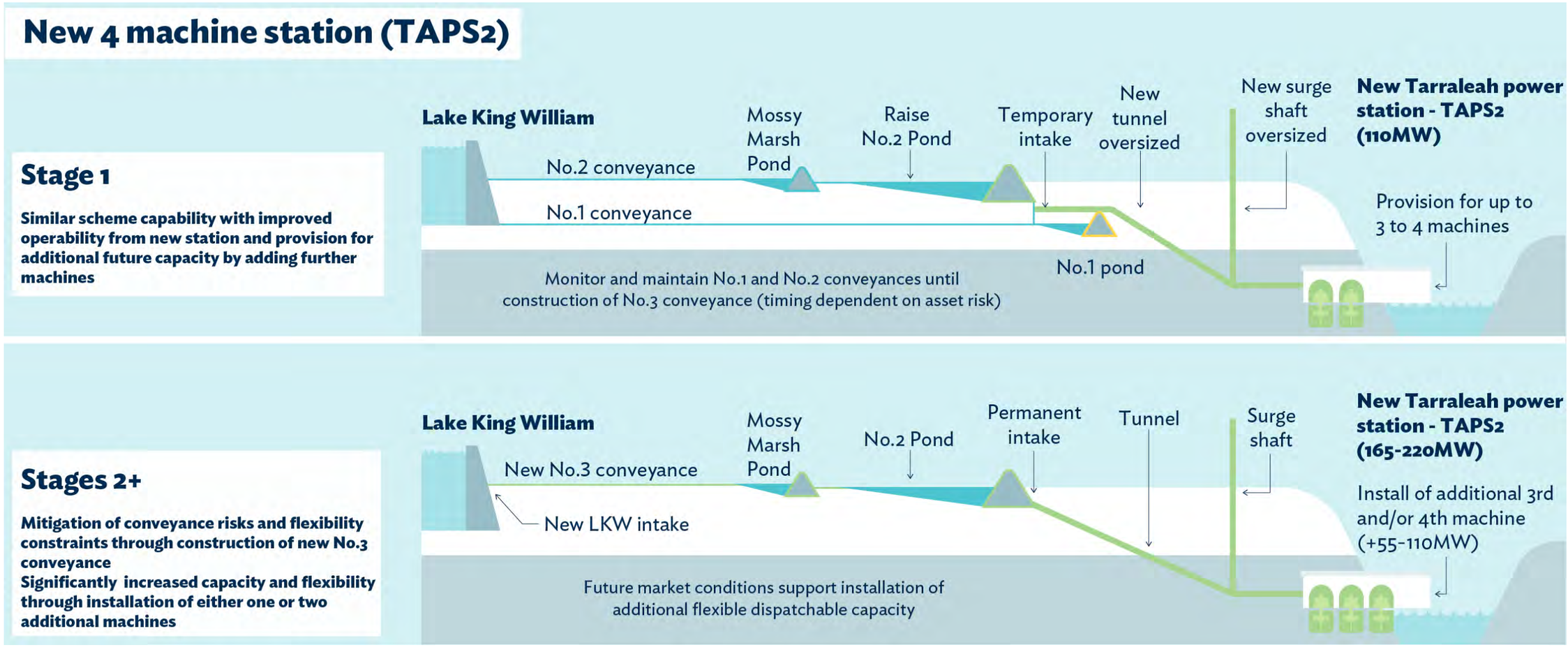


Figure 18: New 4 machine station option diagram

5.6 Assessment of future revenue opportunities and risks

For the purposes of assessing revenue for the repurposed Tarraleah scheme, Hydro Tasmania is assuming that for the foreseeable future, the current market design remains in place.

As such, the principal revenue from the scheme is assumed to be derived from the selling of energy on the spot market and associated wholesale swap and cap contracts. Additional revenue will also be produced through the selling of Large-scale Generation Certificates (LGCs), while ancillary markets are expected to continue to provide minimal revenue.

However, looking to the future, there is a need for extensive investment in dispatchable capacity across the NEM to meet the needs of the future (Hydro Tasmania, 2019a). Unless the market is significantly redesigned or existing incumbent coal generation heavily subsidised, then market forces through supply and demand should ensure that this service is suitably rewarded.

The key objective of the feasibility study has been to mitigate future market risks and maximise the opportunities by ensuring there is the maximum flexibility (capacity, operation and timing of investments) in the repurposed scheme to meet the anticipated future electricity market needs.

Key future revenue risks for the Tarraleah scheme are:

- Requirement to manage asset risk driving an early investment decision with future revenue uncertainty (price, service and connection). Principally, this is associated with over investment in an asset with a potential for depressed future prices or under investment leading to an asset with underperforming revenue and escalating asset management costs.

Key future revenue opportunities are:

- Increased market opportunities that can be unlocked through further system interconnection.
- Potential for increasing value in generation backed swap, cap and firming contracts as market is exposed to increasing VRE and potential volatility as existing plant retires, with potential for these to be exacerbated by un-scheduled retirements.
- Contracted capacity and ancillary services.

A summary table of the future revenue risk and opportunities of the feasibility study options is provided in **Table 14**.

Repurposing option	Description	Energy market revenue	Dispatchable capacity revenue	Ancillary services market revenue	Net revenue risk/opportunity
Maintain the existing station	Installation of six new machines in the existing station; other assets refurbished or replaced based on asset risk considerations	New machines will provide some more overall energy; revenue risk associated with constrained baseload operation remain until No. 3 conveyance is constructed	Full capacity cannot be dispatched on a sustained basis until No. 3 conveyance is built	Limited future ancillary services revenue opportunities due to 6 small Pelton turbines	Future scheme revenue is considered at best stable, but may not justify ongoing expenditure or take advantage of future opportunities
New 2 machine station	Installation of new power conveyance and new power station with similar capability; other assets refurbished or replaced based on asset risk considerations	New station machines will provide some more overall energy; revenue risk associated with constrained baseload operation remain until No. 3 conveyance is constructed	Full capacity cannot be dispatched on a sustained basis until No. 3 conveyance is built	Enhanced future ancillary services revenue opportunities due to the installation of two medium-sized Francis machines	Future scheme revenue is considered at best stable (and a little higher than the above scenario) but under very low price outlook, it may not be sufficient to justify high CAPEX of new infrastructure
New 2 machine station with space for additional machines in the future	Installation of new power conveyance and new power station with some enhanced capability and provision to augment the scheme in the future	New station machines will provide some more overall energy; revenue risk associated with constrained baseload operation remain until No. 3 conveyance is constructed	Full capacity cannot be dispatched on a sustained basis until No. 3 conveyance is built.	Enhanced future ancillary services revenue opportunities due to the installation of two medium-sized Francis machines and potential for up to four	Future scheme revenue is considered stable, with ability to install additional capacity in line with market opportunity for small upfront premium
Accelerated 4 machine station	Installation of new machines in station and upgraded low pressure and power conveyances to maximise future revenue opportunities	The provision of higher capacity station and No. 3 conveyance system provides the ability to vary output between 0-100% to maximise dispatch-weighted revenue	Full capacity (up to four machines) can be dispatched on a sustained basis over 24 hrs from headpond storage with rapid recharge from No. 3 conveyance system	Greatly enhanced future ancillary services revenue opportunities due the installation of up to four medium-sized Francis machines	Maximises future market revenue opportunity with enhanced controllability of the entire Derwent system
			Requires further interconnection to sell capacity		High risk that upfront CAPEX expenditure required before interconnection and future market demand is resolved

Table 14: Summary table of future revenue risk and opportunities for each of the credible repurposing options – Tarraleah example

Note: *Green – opportunity, blue – stable, red – risk*

5.7 Asset strategy assessment

The sections below provide an example of the Tarraleah asset management assessment under future market scenarios outlined in Section 5.2 and the general considerations outlined in Section 3.0.

This assessment does not reflect the final assessment of the Tarraleah feasibility study and is provided as an example application to demonstrate the framework's application.

5.7.1 Asset management strategy drivers

The assessment factors and considerations are:

- **Sustaining** the performance of the current asset base is fundamental to Hydro Tasmania's primary purpose and underpins the shareholder's energy policy.
- **Asset management drivers**: Ageing assets across the scheme poses increasing risks to revenue, safety and environment, requiring a high level of investment to sustain the scheme over the next decade. This opens up a once in generational opportunity to invest in an alternative strategy to repurpose for a future market.
- **Future market uncertainty**: Changing market conditions pose a real risk to competitiveness of the current scheme due to inflexibility of energy dispatch.
- **Risk of investment**: The need to retain flexibility in investment choices in a rapidly changing environment, while retaining future opportunity as far as possible.

The asset management strategy for the scheme needs to reconsider the justification for the substantial upcoming reinvestment needs of the scheme and also whether the long term value extracted from the water availability (the resource) could be improved by repurposing.

The risk to the long term viability of the scheme, due to inflexible, non-dispatchable operation, is also a key consideration for the strategy.

5.7.2 Future revenue risk and opportunity

Consideration of the revenue risks and opportunities (refer Table 14) indicate that:

a. The new station options present the highest revenue opportunity under all current quantitative and potential qualitative future market outlooks.

b. A new station with capability for additional machines maintains the current revenue stream and provides opportunity to take advantage of future interconnection or other market changes.

c. Maintaining the existing station poses future market revenue risk until the No. 3 conveyance is constructed and may not be able to fully capitalise on future market opportunities once built.

The revenue opportunity and risk assessment indicates that a new 3 or 4 machine station with only 2 machines installed initially would most effectively manage future revenue risk.

5.7.3 Project economics

Hydro Tasmania's analysis of the revenue and costs for the period 2020-2050 indicates that all options are economically feasible and preferable over decommissioning the scheme. Highlights from the economic analysis:

- Outage impacts due to working in an operating station are key differentiators between maintaining the existing and building a new station.
- The new station options provide improved value under all future market scenarios with more interconnection.

- The option to increase capacity (3 or 4 machines) has diminished value under scenarios with no further interconnection.
- Maintaining the existing station minimises upfront CAPEX.
- The estimated Levelised Cost of Energy (LCOE) is in the order of $50-70 (nom. FY 2020) for the different options, making them cost competitive against all other forms of competing dispatchable generation reported by the CSIRO (2019) and the firming costs indicated in the Future State analysis (Hydro Tasmania, 2018a)

Project economics indicate a new 3 or 4 machine station option would have higher returns under scenarios with more interconnection and maintaining the existing station is most favourable under scenarios of no further interconnection.

5.7.4 Ranking of options against strategic objectives

The available options have been ranked under Hydro Tasmania's Strategic Asset Management Objectives based on the results of the feasibility study in Table 15.

	Decommission	Maintain existing station	New 2 machine station	New 3 machine station (delayed capacity)	New 4 machine station (delayed capacity)	Accelerated new station with four machines
Sustain the full productive capability of the existing portfolio	✗	✓	✓	✓	✓	✓
Enhance plant capacity and performance	✗	✗	3 ✓	3 ✓✓	3 ✓✓	✓✓
Target the minimum sustainable level of expenditure	1 ✗	✓✓✓	✓✓	6 ✓✓	6 ✓✓	4,6 ✗✗
Increase operational responsiveness and flexibility	✗	✗	3 ✓	3 ✓✓	3 ✓✓	✓✓
Discharge safety, duty of care and compliance obligations	2 ✗	✓	✓	✓	✓	✓
Maintain asset portfolios in a prudent risk managed position	2 ✗	✓	✓	✓	✓	5 ✓✓

Table 15: Ranking of asset management strategies against Hydro Tasmania Strategic Asset Management Objectives

1. Minimum expenditure but at the expense of the scheme's significant revenue contribution.
2. Mitigated but decommissioning expenditures still required, no longer offset by income from the scheme.
3. Future capability available for low cost capacity increase.
4. Early investment before market uncertainty is resolved.
5. Lowest risk position, to replace No. 1 canal sooner.
6. Potential over investment if no further interconnection.

5.7.5 Identify preferred asset strategy

The NEM is undergoing a period of rapid transformation. The effect of the retirement of coal and its replacement by variable renewable generation is uncertain, as is the future mix of energy types and capabilities. This makes forecasting market conditions challenging, requiring flexibility and optionality to be built into the management of assets to ensure value of investments are retained across the widest range of potential future market states.

Following the example application of the framework to the Tarraleah scheme, the leading asset management strategy options are to either;

- Minimise expenditure by **maintaining the existing station** and mitigating conveyance risks and some flexibility constraint by constructing a new No. 3 conveyance system at point at which asset risk is no longer tolerable or there are market drivers (interconnection) that would realise the value of additional flexibility; or
- **Repurpose the scheme for the future market** with a **new 3 or 4 machine station** (TAPS2) to replace the existing station and replacing the conveyances (No. 1 and No. 2 canals) with the No. 3 conveyance when required by asset risk or market drivers, combined with installation of 3rd and 4th machines when the market values additional flexible dispatchable capacity.

A decision on the preferred asset management strategy needs to be made in the context of the current market conditions and future uncertainties. Without certainty over key investment drivers including further interconnection, it is not possible to confirm the commercial feasibility for repurposing the scheme.

In this context, Hydro Tasmania plans to continue to monitor the market conditions, regularly reviewing the feasibility of redeveloping the scheme as clearer market signals emerge over time. In the meantime, the existing scheme will continue to be maintained to ensure safe and reliable operation.

6.0 Learnings from applying the framework

The key learnings from developing and applying the framework to repurposing of the Tarraleah scheme are:

Certainty, timing and extent of market access are the most important and challenging aspects to consider when repurposing existing assets for the future.

The value of flexible dispatchable generation to support a NEM with more variable renewable energy can only be realised if a project has access to market. This market access is governed by transmission arrangements and constraints, which often bring market benefits beyond that which a single project can justify.

A finding from applying the framework is to emphasise the mapping of future interconnection directly linked to the project, in particular a focus on the timing relationship between asset management decisions and certainty of future interconnection.

Increased interconnection is an underlying fundamental of the future market outlook but making an investment decision in the face of significant uncertainty is a major challenge.

Need to maximise project flexibility, both in terms of generating capability and considering project development and delivery.

Existing hydropower investment drivers from asset risk and maintenance perspectives are likely to have better defined timing than changes in market conditions. Asset management often deals within a 5-10 year window but the NEM is experiencing significant and rapid transformation across the next 20-30 years. In assessing the future market, it is important to consider that the outlook is likely to change significantly within the timeframes of completing a feasibility or even a pre-feasibility study.

A key learning has been not only to maximise the flexibility of the generating plant but also the flexibility in the project development and delivery. Staging and deferring investment decisions as late as possible will minimise risks associated with under or over investment.

Regarding future market considerations, particularly in the Tasmanian context, findings have been that future market changes are closely linked to further interconnection and / or construction of large scale competing projects. Investment decisions therefore need to manage these risks by maintaining maximum flexibility in development schedules.

Overall scheme flexibility governs future revenue potential.

In developing this framework, Hydro Tasmania initially set out to identify a hydropower scheme and its physical asset attributes and their revenue potential under the future market scenarios. The initial concept was to identify the cost and revenue value from physical attributes such as energy production (GWh), flexible capacity (MW), ancillary services (per unit), and storage (MWh) and then be able to make an assessment of which attributes are more highly valued under different future scenarios.

Work completed as part of the feasibility study has found that these measures are difficult to distinguish and not overly useful in characterising the revenue potential of a hydropower scheme in a future energy market.

Hydro Tasmania has found that the IEA (2018) definitions of plant flexibility, particularly the scheme's capacity factor over varying timeframes (daily-yearly), is a more comprehensive indication of the revenue potential from a future energy market that is characterised by an increasing need for flexible dispatchable capacity.

Under this assessment, energy production, flexible capacity and storage are effectively assessed as one characteristic. The future NEM is anticipated to remain predominantly an energy market and thus the ability to produce energy when required will maximise revenue.

Ancillary services, in Hydro Tasmania's view, have been a challenging characteristic to assess for the future market. Some services such as inertia are only valued when a unit is generating and others such as system restart (black start) are very binary, either a region has this capability, or it doesn't.

For the purposes of the future outlook, ancillary services are not considered to be a major value driver under current market arrangements but are potentially a low cost by-product that flexible dispatchable hydropower can leverage.

Tarraleah Power Station is located on the west bank of the Nive River downstream from Tungatinah.

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8.0 Acronyms

AEMO	Australian Energy Market Operator
APM	Asset Portfolio Management
ARENA	Australian Renewable Energy Agency
ARP	Advancing Renewables Program
CAPEX	Capital expenditure
CPRR	Condition, performance, revenue risk and duty of care risk
ESB	Energy Security Board
FCAS	Frequency control ancillary services
FSL	Full supply level
FYE	Financial year ending
HT	Hydro Tasmania
IBRM	Integrated Business Risk Management
ISP	Integrated System Plan
LCOE	Levelised cost of energy
LRMC	Long run marginal cost
NEM	National Electricity Market
NEMMCO	National Electricity Market Management Company
NMOL	Normal minimum operating level
O&M	Operations & maintenance
OCGT	Open cycle gas turbine
OPEX	Operating expenditure
PHES	Pumped hydro energy storage
PSH	Pumped storage hydro
PV	Photovoltaics
SMP	System marginal price
VRE	Variable renewable energy
WACC	Weighted average cost of capital

9.0 Appendix A – Emerging terminology

From Hydro Tasmania's Battery of the Nation report on Understanding Reliability in the future NEM

In the future, energy generation sources will shift from large-scale baseload to variable renewables. Both supply and demand will vary and this will change the nature of the balance as well as how the balance must be managed. In fact, supply-side variation may be much larger than the demand-side variation, causing greater requirement for flexible supply and demand options. These flexible options must be able to respond to market signals very rapidly and also be able to cost-effectively support the supply-demand balance not just for minutes or a few hours, but several hours or even days.

Defining 'firm'

'Firm' is a seemingly simple term but is used to mean subtly different things. AEMO defines firmness as:

> "The resource's ability to confirm its energy availability. For example, how long can the source provide a requested amount of energy once dispatched and how far in advance can the energy be guaranteed by the source?"

However, this definition does not capture the full range and depth of meanings ascribed to the term.

Firmness typically has an implication regarding the consistency of the availability of supply, not just the ability to commit to being available. For example, solar generation can reasonably be predicted (energy will be produced during daylight hours and not at night) but cannot guarantee firm supply at evening peaks.

The power system is a true supply-on-demand system – at all times, the supply must balance the demand. Consequential surpluses or deficits of power will disturb the electricity voltage and frequency.

Customers turn on their home appliances without requesting permission and without causing a noticeable disturbance in the grid. This is because of an integrated system with many customers and generators all connected with transmission and distribution lines. The diversity of the changes in demand, coupled with constant adjustment of generator output, act to smooth out the impact of individual actions. Only the largest changes are material to the system.

Historically, the focus of supply-demand balancing has been predominantly on ensuring that variable demand is met with available supply. However, as more variable renewable energy enters the system, it becomes necessary to compensate for variable supply. This supply-side consistency is generally referred to as 'firming'.

Within this broad definition, different people (e.g. retailers, operators, traders, generators) assign subtly different meanings to the term:

- *Physical versus financial*

  To some, 'firm' is a financial concept: a contractual guarantee to provide a consistent supply of energy. Firming then becomes a financial service to help manage the risk of exposure to spot prices in supplying that energy.

  For other people, 'firm' is a physical concept: the ability to generate the required supply of energy. Firming then becomes a physical service to help manage times of shortfall in energy production.

  Both definitions of firm relate to protecting the customer from variability: one achieves this through price guarantees and the other achieves this through energy generation.

- *Asset versus system*

  Some view firmness as a property of an asset or a group of assets. The idea is that such an asset, or group of assets, would produce consistent output, regardless of market requirements.

There may be valid market and financial reasons to provide incentives for a generator, or group of generators, to provide firm supply but there is no technical reason why any given generator, or group of generators, must be independently firm. The system requirement is that supply balances with demand. Sharing resources throughout the system is more efficient than requiring individual generators to be independently firm.

Just as it is clearly more efficient to share resources across the grid instead of having a separate generator in each house, sharing firming resources throughout the system is more important than assigning (and even co-locating) individual firming options with individual variable generators.

- *Degree of firmness*

  Generally, a baseload power station would be considered firm. However, even baseload power stations do not always generate to their full capacity – they have planned and unplanned (emergency) outages which means the plant is unavailable. Requiring new assets to be 100% firm is an unrealistic expectation.

  There is yet to be a generally agreed definition of what level of unavailability is acceptable while still being considered firm.

In light of the varying interpretations of 'firm' and 'firming', it is important to consider what is fundamentally required to meet demand in a system with significant variable renewable energy. Energy sources are required to:

- Start, stop and change supply – quickly, reliably and on-demand ('dispatchable').
- Sustain generation over the required period of time – a number of hours or days ('sustained capacity').

The provision of these characteristics can be considered firming services. The requirements, and the way they are met, will change over time and as the generation mix changes.

Defining 'dispatchable'

Technically, 'dispatchable' may be defined as being able to generate when directed, with the caveat that generation is constrained by technical limitations. The caveat is the key issue in defining dispatchability.

AEMO's Advice to Commonwealth Government on Dispatchable Capability includes the following:

> "The NEM is not delivering enough investment in flexible dispatchable resources to maintain the defined target level of supply reliability, as the transition from traditional generation to variable energy resources proceeds."

While the document's title focussed on dispatchable, the key word in the statement above is 'flexible'. This highlights that for most uses of dispatchability, there is an implicit assumption that the generator has the technical ability to be able to respond when needed.

Generation assets that are traditionally baseload providers (such as coal and nuclear) are inflexible and slow to start. Combined cycle gas turbines and most biomass generators are marginally better but still take many hours to start. This means that in the context of needing to respond to variations in the supply-demand imbalance, these technologies are not truly dispatchable – at least not in the context that the word is normally used.

The flexible dispatchable technologies in the NEM include open cycle gas turbines (OCGT), diesel generators, hydropower and storage (including pumped hydro and electrochemical batteries). These technologies are typically capable of responding to market signals as required thus able to be dispatched when needed.

This definition of flexible dispatchable generation better captures the need for controllability that is typically assumed when discussing the need for dispatchable generation.

The confusion between the technical term and the intent of the language reduces the clarity of industry discourse. Depending on the timeframe of the required response, different technologies have different levels of dispatchability.

Dispatchability alone is not a guarantee of meeting the future system requirements. The system requires options that can be responsive and flexible.

Reliable energy supply: defining 'sustained capacity'

'Sustained capacity' is a response to the challenge of reliability. There is a need for services that can effectively balance the system, especially with a changing technology mix. Specifically, sustained capacity addresses the need for cost-effectiveness, not just for an hour or two but for extended periods of time, such as operating throughout the night when there is no solar generation or during days of minimal wind generation.

This gives rise to the need to develop a more nuanced view of the old paradigm of baseload energy providers and short term capacity providers. Sustained capacity is essentially a new category of dispatchable supply – sitting on the dispatchable energy delivery continuum between an energy provider and a capacity provider.

Figure 19 demonstrates the ability of different dispatchable technologies to deliver energy continuously from time of request. The conceptual 'sustained capacity' range is highlighted in green. The x-axis is a logarithmic scale to compress the range of operations. The key options to deliver from 6 to 48 hours are OCGT and hydropower (either pumped storage or conventional). To deliver in this range, the cost per MW and the cost per MWh are critical to the cost-effectiveness.

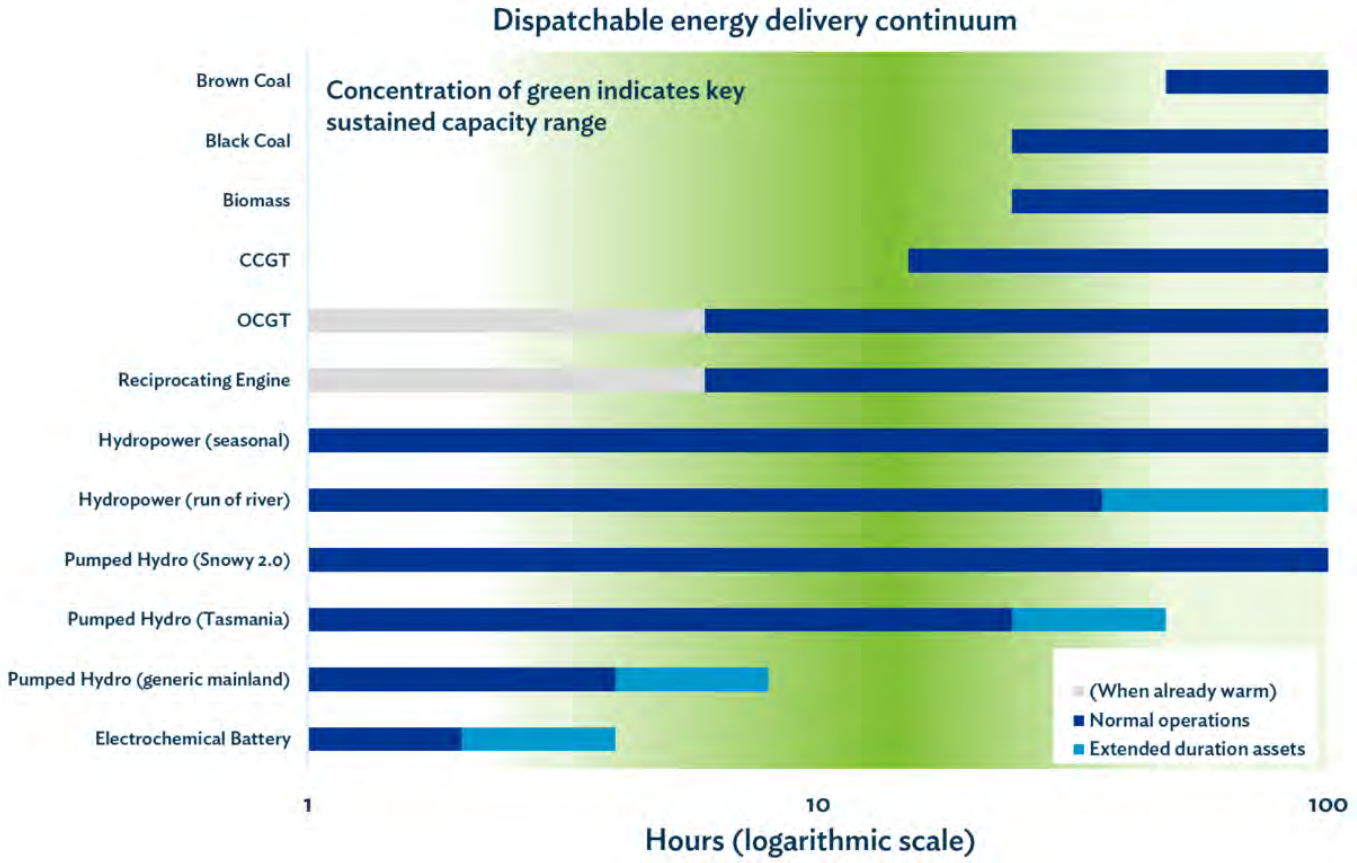


Figure 19: Dispatchable energy continuum

This definition does not attempt to quantify the specific value of sustained capacity, nor how much sustained capacity is needed. Such quantification relies on the actual generation mix, the load profile and a range of other system-wide variables. However, even observing the market today, it is possible to see extended periods with low output from wind and solar and geographic resource diversity will only address part of this challenge. Managing a varying supply-side as well as a varying demand-side will need supply options that are responsive, sustained and cost-effective for extended durations. This is particularly relevant to energy storage and challenges the simple classifications of long term energy and instantaneous capacity – recognising that there is actually a continuum of supply options required to ensure reliability.

10.0 Appendix B – Trends and international case studies

Trend 1: More variable renewable energy

In the International Energy Agency's most recent outlook (2018b), the forecast for generation from renewable energy sources is on the rise, with 25% today to 40% of the share of electricity generation in 2040. Coal follows a reverse trend. Leading this is the increasing competitiveness of solar photovoltaics (PV), with forecasts for its installed capacity indicating that it grows past that of wind in 2025, past hydropower around 2030 and exceeding coal before 2040 (International Energy Agency, 2018b).

Driving this change as well is policy on emissions reduction and renewable energy targets around the world.

Europe, for example, has set a target to reduce emissions by 40% below 1990 levels by 2030. It is forecast that the amount of renewable generation will reach 25% by 2020 in Ireland, the United Kingdom and Germany, while Denmark is expected to reach 70%. The vast majority of this renewable energy is to come from variable renewable energy sources. Notably, Denmark has set a goal of 50% wind power by the year 2020 and independence from fossil fuels by 2050; Denmark produced 43.5% of its electricity through wind generation in 2017.

In the United States of America (Somani, 2018), many states are reporting goals of renewable generation greater than 25% by 2025, with many aiming higher. Hawaii is targeting for 100% renewables by 2045 and California 50% by the year 2030. By 2024, there is an expectation that in California, there will be days where 100% of energy will come from variable renewable energy sources.

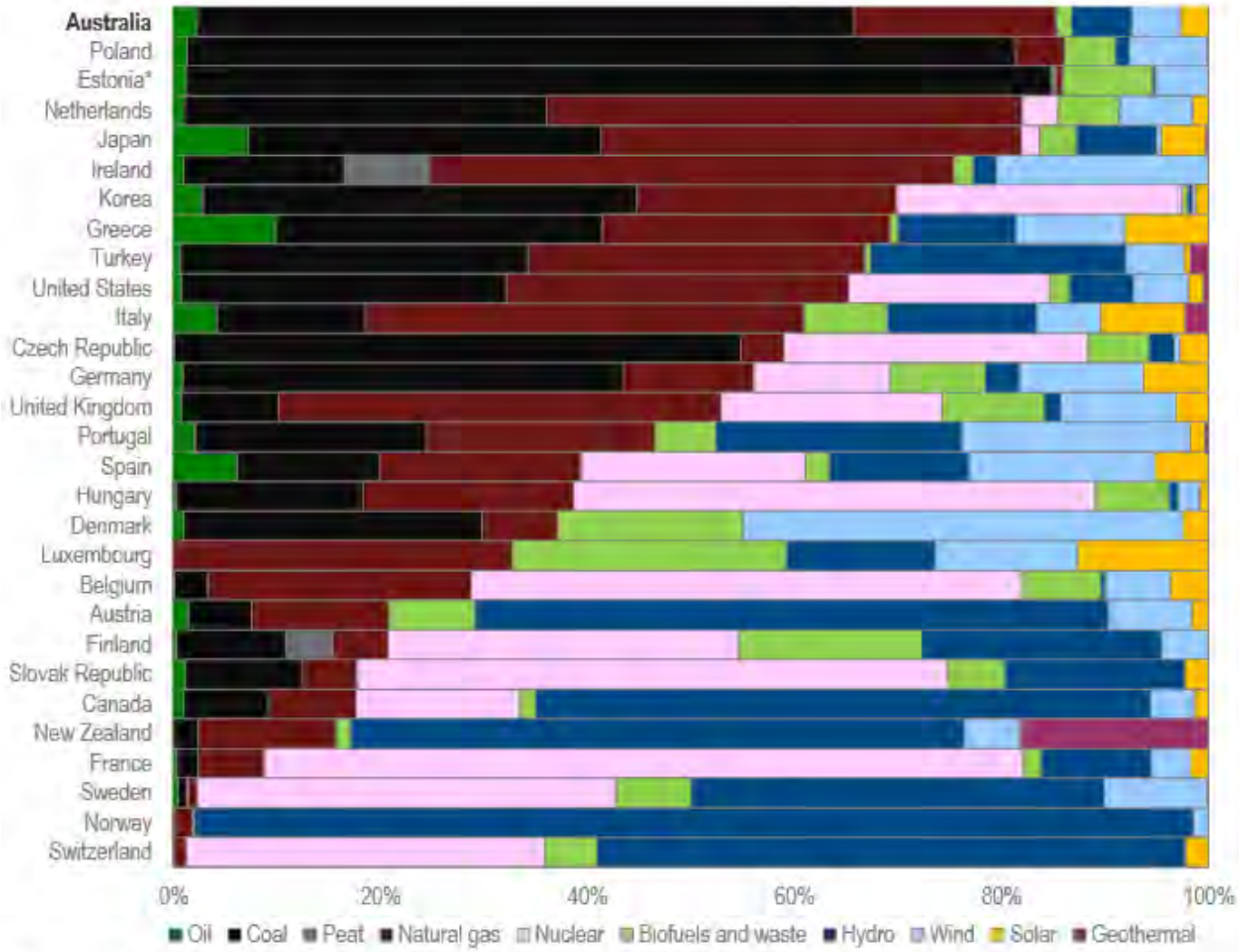
The current (as of 2017) generation make-up of countries around the world is presented in Figure C.1 for reference.

Trend 2: More interconnection

A common trend for electricity markets to obtain flexibility and improved load balancing is through inter-regional and cross-border interconnection. Examples of this can be found in Europe, North America, Asia and around the world.

A common trend in the use of interconnectors is the connection of areas with extensive variable renewable energy sources to those with extensive hydropower capacity and storage. A number of initiatives described in industry publications are:

- In Europe, the interconnection of Norway's hydropower capacity to the Netherlands, Denmark and Germany.
- In North America, hydropower capacity in Canada is connected to the mid-west of the United States of America and is used to balance the output of major wind developments. On the western seaboard, many system operators are beginning to enter the CAISO-administered Energy Imbalance Market (Somani, 2018).
- In Central America, interconnection system integrates six countries. The system starts in Guatemala, El Salvador, Honduras, Nicaragua, Costa Rica and then Panama.
- In Asia, the interconnection between Georgia's hydropower capacity to neighbouring Turkey and Russia and plans as well for the connection of Sarawak's extensive hydropower potential to mainland Malaysia.



* Estonia's coal represents oil shale.

Note: Data are provisionel.

Source: IEA (2017b), *World Energy Balances 2017*, www.iea.org/statistics/.

Figure C.1: Generation make up of countries around the world relative to Australia, 2017 (International Energy Agency, 2018)

Trend 3: Overall reduction in electricity prices but more volatility

The forecasted increase in low cost variable renewable energy sources is expected to lead to an overall reduction in electricity prices but the coming transition will see periods of higher price volatility.

CEDREN (2018) found that when Norway enters the European market, the conventional price pattern of high prices in the evening and low prices during the day will change (which is already being witnessed). Electricity prices will be subjected to more volatile conditions that are dependent on the amount of renewables available.

Pereira et al (2017) analysed the impact of hydro and wind generation on Spanish electricity prices from 2007-2014. Over that time period, wind generation increased electricity price volatility but this was balanced by flexible hydropower leading to an overall reduction in prices.

New solar photovoltaic (PV) technology is forecast to undercut the price of new coal in systems with relatively low costs of flexibility and will outcompete existing thermal plants with policy support (International Energy Agency, 2018b).

The United States is typically seeing low energy prices, especially in Texas, due to high penetrations of low production cost renewables and low natural gas prices. While there is volatility in the market, prices are low in day ahead and real time markets due to the comfort of market participants to rely on the market to meet their needs (Somani, 2018).

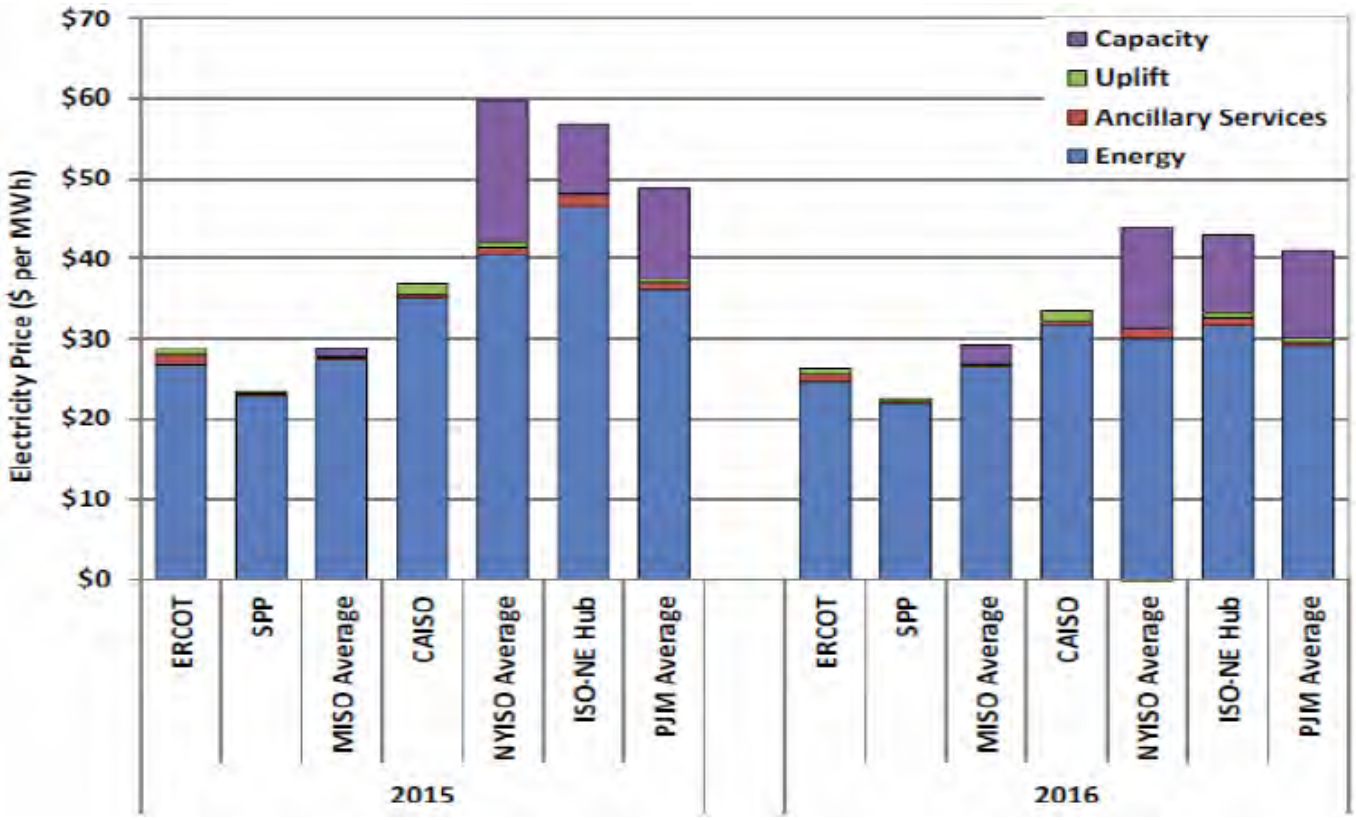


Figure C.2: Comparison of 2015 and 2016 electricity prices in the United States markets (Somani, 2018)

Trend 4: Increased requirements for flexibility including energy storage

Forecasts in the United States and specifically for California indicate that systems will require increasing amounts of flexibility and will experience excesses of 'must run' resources and the associated negative pricing, forced curtailment or export of energy (Somani, 2018).

In the United States, the systems have seen a vast increase in the installed battery capacity both as capacity and energy storage in recent years. The Federal Energy Regulatory Commission (FERC) has made adjustments to market requirements to accommodate energy storage. There has been some differences in how system develop storage, for example:

- In the ERCOT and PJM markets, the installations are geared for frequency regulation and are capacity oriented.
- In CAISO (Californian Independent System Operator), they are predominantly reliability oriented with batteries required to have at least 4 hours of energy capacity (Somani, 2018).
- Some states are also beginning to mandate storage requirements, with Massachusetts requiring 200 MWh by 2020 and New York 1.5 GWh by 2025 (Somani, 2018).

Case study 1: Connecting hydropower capacity

Europe has set a target to reduce emission levels by 2030. It is forecast that the amount of renewable generation will be 25% in 2020 in Ireland; the UK, Germany and Denmark are expected to eventually reach 70%. A large amount of this is coming from variable renewable energy sources and will require more flexibility. An increase of energy storage is required to balance the surplus energy and provide further flexibility. Norway currently has the largest storage capacity in Europe, being capable of storing 85 TWh.

Norway currently provides the Netherlands with access to this hydropower capacity through a 700 MW interconnection and is also connected to Denmark through a 1700 MW interconnection. A 1400 MW interconnection between the UK and one between Germany came online in 2018 (Ingeborg et al, 2017).

The Hydro Balance project was carried out from 2013 to 2017. The main objectives were to identify key processes, risks and advantages in all aspects of deploying Norwegian hydropower to become a flexible 'battery' for Europe.

Norway becoming a battery for Europe is anticipated to be achieved through increased interconnection between Norway and Europe and increased Norwegian hydropower capacity, enabling Europe to utilise Norway's large amount of hydropower.

Maaz et al (2016) found that an additional 19 GW of capacity into Europe's energy market coming from Norway will result in a reduction in curtailment from other renewable sources, increasing the overall electricity generation from renewables. It also resulted in an overall reduction in electricity prices.

Graabak et al (2019) researched the potential of Norway to provide flexible hydropower to Central-West European countries to balance their large shares of variable wind and solar expected to come online in 2050. This study found that without the flexible generation from hydropower, power prices would become extremely high and volatile. An increase in hydropower to the system by interconnection provided the benefits of reductions to peak prices and the involuntary shedding of demand.

Hydropower operation in the future market is expected to change. Through increasing interconnection, hydropower producers will be able to achieve additional revenue by participating in real time balancing markets in addition to day-ahead markets. A case study found that if a Norwegian hydropower producer participated in all markets, their income would increase by 22% (CEDREN, 2018).

The findings of the Hydro Balance project reflect strongly what is currently occurring in Australia and the need for flexible storage. This is evident it can be achieved through hydropower.

Case study 2: Denmark (International Energy Agency, 2018a)

Denmark has seen its share of electricity generation from wind and solar sources increasing over the past 15-20 years. In 2017, the Danish electricity consumption covered by Danish sources of variable renewable energy (VRE) reached 45.8% and in the previous four years, the VRE production in parts of the country covered more than 90% consumption. Remarkably, the power systems security of supply ranks amongst the best in the European Union.

The key trends that have enabled this marked increase in VRE integration are:

1. Increased interconnection between Denmark and neighbouring countries - this has allowed greater balancing due to geographically dispersed supply and demand profiles. In particular, the common Nordic balancing energy market has allowed Swedish and Norwegian reservoir hydropower to provide cheap short term flexibility to the entire Nordic system and reduces the cost of imbalances caused by VRE.
2. Market demand for flexible generation has led to operators improving the flexibility of existing thermal generation plants, typically by reducing the minimum stable load and increasing the ability to ramp steeply.

The effect of high VRE integration in Denmark, however, is a declining share of thermal power plants. These plants have traditionally provided ancillary services to the system and the ability to maintain system stability into the future is a concern (International Energy Agency, 2018a).

Into the future, Denmark has set a goal of 50% wind power by the year 2020 and independence from fossil fuels by 2050. These goals will see the share of VRE generation continue to increase and additionally increased interconnection, with connections planned for Great Britain.

Case study 3: Germany (International Energy Agency, 2018a)

In 2017, variable renewable energy (VRE) in the form of wind and solar photovoltaics (PV) commanded a share of 22.2% of total electricity production in Germany, an increase from 18.6% in 2016. Instantaneous maximum penetration reached 75.3%. However, through all of this, the German power system has remained one of the most reliable in the world. Currently, this level of VRE integration is managed by a surplus of dispatchable capacity, regional and inter-country load balancing by interconnection and the flexibility provided by conventional coal and gas fired capacity.

Current trends indicate that more flexibility is required in the German system with periods of negative prices on the day-ahead energy market occurring and costs for re-dispatch and curtailment rising in recent years. Grid capacity issues are a dominating factor, however, the large share of relatively inflexible baseload power in the form of nuclear, lignite and gas in heat-led co-generation plants are also contributing.

Case study 4: Ancillary service markets in the United States

In the United States, there are seven different power markets that are classified as an 'independent system operator'. These independent operators operate in different regions of different magnitude and geographies. Each provide ancillary markets under the category of spinning reserves, non-spinning reserves and regulation (Zhou et al, 2016).

Zhou et al (2016) conducted a survey on the ancillary markets operating in the United States. The revenue returned from competing in each of the ancillary markets was compared between the seven regions using available data. For each independent system operator, which ancillary market was worth more differs between each of the regions. The Electricity Reliability Council of Texas (ERCOT) was established as a power market operator in 2001. ERCOT serves over 85% of Texas electricity.

The Zhou et al (2016) survey found that ERCOT spinning reserve prices were higher and more volatile compared to the other regions. This is because it has a higher spinning reserve requirement compared to peak load and has a higher percentage of generation from variable renewable energy sources. The ERCOT ancillary market demonstrates how the influx of renewables can begin to alter how the market behaves in terms of prices and needs.

Case study 5: Market-based mitigation measures

Market-based mitigation measures for contingency events being considered by several markets around the world is shown in Figure C.3 (Somani, 2018).

	Ireland	UK	Nordic	Quebec	South Australia	ERCOT
Monitor inertia & possible contingencies in real-time	✓	✓	✓	✓	✓	✓
Forecasts inertia from DA into real-time	✓	✓				✓
Dynamic Assessment of Reserves based on inertia conditions and largest resource contingency		✓				✓
Limit RCC based on inertia conditions	✓	✓		✓	✓	
Synchronous Condensers (for inertia)	✓	✓			✓ (particularly looking at high inertia SCs)	
Enforce minimum inertia limit	✓	✓			✓ (for min. inertia req.)	✓
Inertia market/auction/ service inertia	✓				✓ (for above minimum inertia levels)	
Faster Responding Reserves	FFR	Enhanced Frequency Response Service		Synthetic inertia from wind	"Contingency" FFR (frequency trigger) and "Emergency" FFR (direct event detection)	Load Resources providing RRS

Planned mitigation measures are shown in blue, while already existing mitigation measures are shown in black; Source: ERCOT October 23, 2011

Figure C.3: Market-based mitigation measures for contingency events around the world (Somani, 2018)

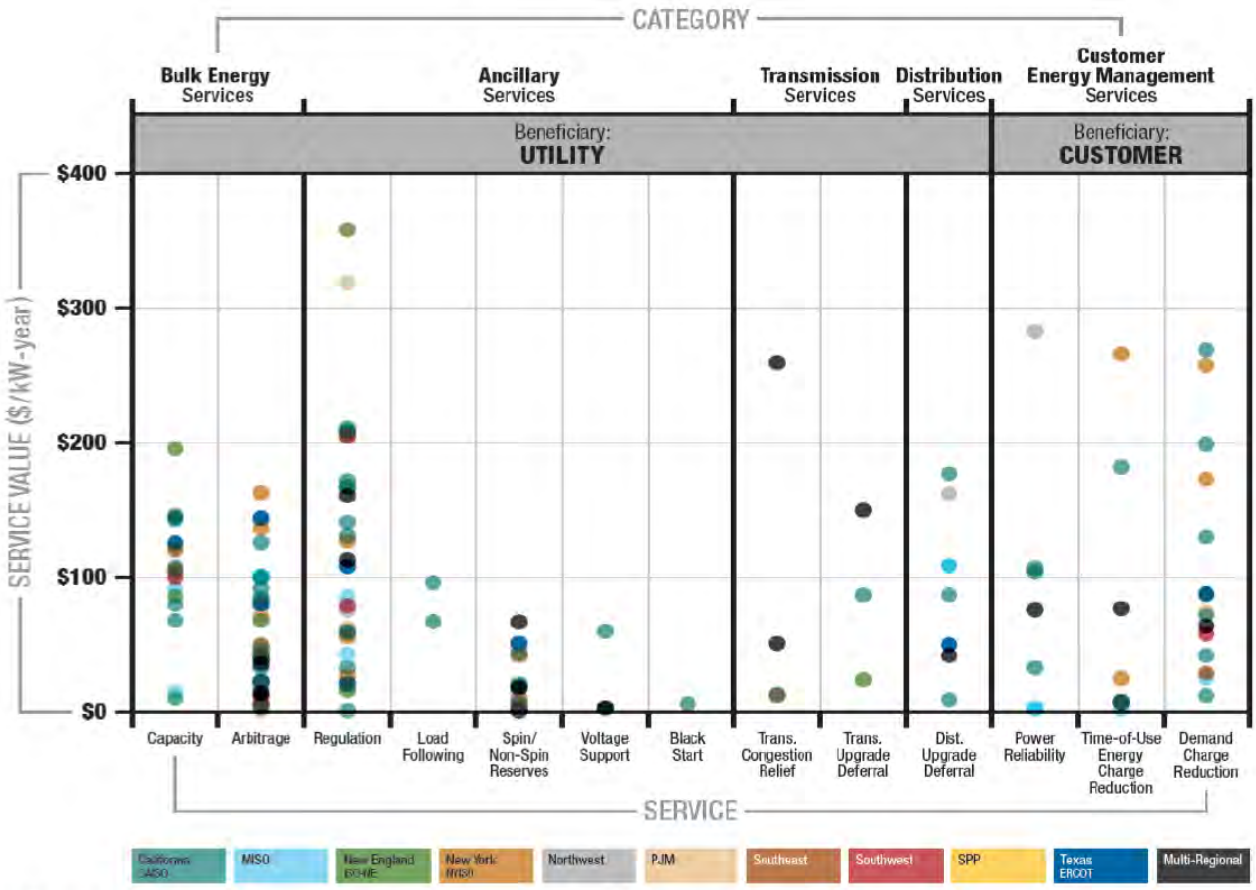
Case study 6: Examples of market approaches to transformation

IEA (2018c) reported on several markets around the world that have made recent changes to adapt to transformations in their power systems. In summary:

- The Public Utility Commission of Texas, in 2012-14, committed to maintaining an energy-only market with some regulatory intervention on price formation in case of capacity shortage.
- The Californian ISO is energy only market (IEA Hydro, 2017).

- In Europe, Nordic countries and the Netherlands have expressed their wish to rely on an energy-only market in the long run by removing price caps in the energy market.
- New Zealand has moved from a strategic reserve plant to favour improved incentives to market participants to improve the management of system security.
- Germany is promoting a market that fosters free price formation on wholesale markets and competition for flexibility. In conjunction, it has introduced four different types of reserves to provide a safety net and reduce carbon dioxide emissions.
- Capacity markets exist in the United States (PJM and MISO) in the form of capacity auctions. In the EU, France and England have introduced capacity markets. These markets work on relatively short term time horizons (3 year periods) with the intent to procure enough generating capacity to ensure reliable system operation and adequate reserves. Supply and demand options are allowed for. The value of these payments is relatively low due to low cost gas turbines and demand response options (IEA Hydro, 2017).

A summary of United States markets and the services traded is shown in Figure C.4.



(Balducci, 2016)

Figure C.4: Products and services of United States markets in 2016 (Studarus et al, 2017)

Case study 7: Variability of wind and solar in West-Central Europe

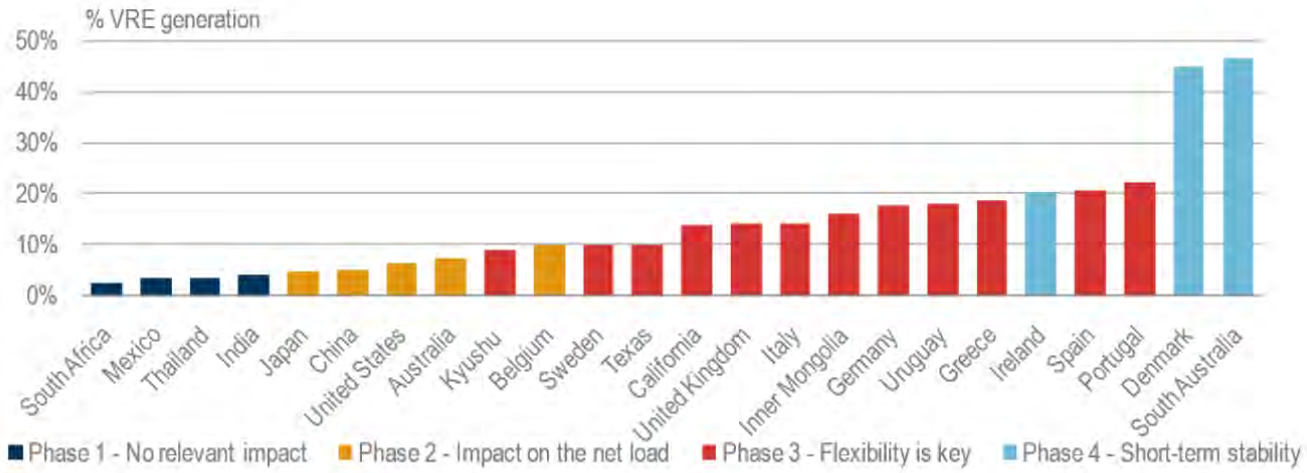
CEDREN (2018) studied the variability of wind and solar in West-Central Europe that is expected to come online by 2050. The assumed capacity from wind and solar photovoltaics (PV) was 852 GW combined. From the analyses, it was found that during the lowest production periods for wind and solar, only 2% was generating. These low periods occurred in winter and would carry on for 125 consecutive hours. During the highest generating time, only 65% was generating. This analysis demonstrates the need to be able to balance VRE generation in both low and high generating periods.

Case study 8: Phases of VRE integration around the world

As reported by IEA (2018a), countries can be categorised according to their variable renewable energy (VRE) development. As shown in Figure C.5, only a handful of countries are above Phase 2 of VRE integration. The phase of integration, while linked to the level of VRE generation, is also contingent on the size and characteristics of the system.

As demonstrated by South Australia, it is possible for regions or sub systems to be at a higher phase than the encompassing system. Typically, with all things being equal, a smaller system will tend to fall into a higher phase than a large system.

The challenges being faced by the systems of South Australia, Denmark and Ireland provide key insights to those that other systems may face in the future as they integrate more VRE generation.



Note: Kyushu is a large island located in southwest Japan.

Source: Adapted from IEA (2017c), *Renewables 2017: Analysis and forecasts to 2022*.

Figure C.5: Countries by shares of VRE integration (International Energy Agency, 2018a)

Case study 9: Hydropower providing ancillary services, California, United States

Ancillary services provided by hydropower include being able to 'black start', frequency regulation, inertial response, spinning and non-spinning reserve and voltage support.

In recent years, approximately half of California's conventional hydropower has been used to provide ancillary services including spinning and non-spinning, replacement reserves and regulation or load following, black start and voltage support (Electric Power Research Institute, 2017).

Case study 10: Replacement of an existing scheme to improve efficiency and flexibility (Lyse, Norway)

Lyse, a Norwegian industrial group, built a new hydroelectric power plant in 2018 to replace the existing Lysebotn 1 Power Plant. The Lysebotn 1 Power Plant became operational from 1953 to 1964. The new power station, known as Lysebotn 2, has now been operational since September 2018.

The Lysebotn 2 Power Plant uses the same water as the Lysebotn 1 plant but produces 15% more energy without any additional environmental encroachments. It also takes the new turbines 4000 hours to generate what Lysebotn 1 could originally achieve in 6000 hours.

The outcome of the new power plant is improved efficiency and flexibility without any additional environmental encroachments (Lyse, 2018).

Case study 11: Runner replacement to increase efficiency and flexibility (Cabril, Portugal)

Cabril is a hydropower plant in Portugal that was commissioned in 1954. Cabril underwent modernisation works that consisted of only the runners being replaced. The modernisation work resulted in increased efficiency and increased power output up to 20%.

The improvement in output was achieved without any changes in operations or replacement of turbines (Pacheco & Correia, 2018). The modernisation of Cabril is just one of many examples of how the improvement of a hydropower plant's efficiency does not have to be achieved through the replacement of turbines.

Case study 12: Increased capacity and flexibility (St. Anton, South Tyrol)

The St. Anton Power Station in South Tyrol was constructed between 1948 and 1951. The power station is the fifth-biggest hydropower plant in the province of Bolzano. It was originally designed with an installed capacity of 72 MW at a gross head of 600 m and peak flow of 15 m^3/s.

The design basis of the plant was for stationary (baseload) operating conditions. Today, more flexible operation is desired from hydropower plants as opposed to stationary (baseload) operating.

Flexible operations induce highly transient fluid flow in the both headrace and the surge tanks of high head hydropower plants and also in the tailraces. If not managed, these headrace transients can lead to damaging high pressures and transient flows in the tailrace can lead to environmental issues.

The upgrades at St. Anton Power Station consisted of a new vertical penstock from the surge tank into a new underground powerhouse. The power plant will be equipped with three Pelton turbines with four nozzles each.

To minimize the hydropeaking phenomenon caused by the flexible power plant, a new underground tailrace reservoir will be built to serve as a retention reservoir and also to minimise ecological impacts.

After the retrofit, the maximum output will be 90 MW and the peak flow will be 18 m^3/s and allow the plant to flexibly operate (Holler et al, 2018).

Case study 13: Premature deterioration from flexible operations

Electric Power Research Institute (2017) reviewed the effect of different operating zones that a hydropower plant may operate in as part of flexible operations in the United States. The zones included start/stop, speed-no-load, low load and intermediate load. The following were found to be the consequences of operating in those zones:

- Turbines – frequent start stop increase vibrations and dynamic stress, reduces fatigue life and increases the wear.
- Generators and related components – increases the vibrations, dynamic stresses and thermal stress, reduces the fatigue life and increases the wear.
- Gates and valves – low load and intermediate load increases pressure pulsation, vibrations and the dynamic stress, reduces the fatigue life and increases the wear.
- Circuit breakers – more frequent start-stop action increases vibrations, dynamic stress and thermal stresses, reduces life of the equipment.

From the above, it is evident that operating in a more flexible market as opposed to just providing baseload supply can lead to premature deterioration of hydropower plant assets.

To avoid this, appropriate maintenance and monitoring plans need to be in place. Modernising units to be designed to operate under these conditions can prevent damage from occurring.

Case study 14: Upgrade to flexibility (Hoover Power Plant, United States)

The Hoover Power Plant is located in the United States in the state of Arizona and is owned by the United States Bureau of Reclamation. A requirement of the upgrade design contract that was awarded in 2010 was for flexible operation ranging from 5% to 100% full load without cavitation and excessive pulsations.

The manufacturer successfully designed the blade profile of the turbine to accommodate the required conditions. The outcome was increased efficiency and a reduction in pressure fluctuations to operate better flexibly. The new unit began operation in 2012 (Nesbitt, 2017).

Case study 15: Upgrades to operating rules to improve flexibility (Osage, United States)

The Osage Power Plant is located in the United States in the state of Missouri. In 2002, due to concerns regarding the downstream water quality, seven out of the eight turbine units at the plant were upgraded with aerating turbines. Due to further environmental issues and recreational requirements, in 2008 the remaining eighth unit was upgraded with an aerating turbine and one unit upgraded further from the 2002 works.

In 2011, another two units were further upgraded from the 2002 works (Electric Power Research Institute, 2017).

The upgrade of aerating turbines resulted in less flexibility and efficiency. An advanced features control system (AFCS) was implemented to improve plant efficiency, automatically adjusting operational parameters to achieve environmental compliance and automatically adjusting load and smoothing air to accommodate unit rough zone operation.

Changes in the unit dispatch resulted in a 20% increase in energy production due to the overall plant efficiency but increased the number of start-stops.

Generation from Osage Power Plant was then traded in the Midcontinent Independent System Operator (MISO) energy market (ancillary services market was added in 2009). This required the plant to perform a huge number of start-stops per year. One machine would experience 5840 start-stops a year and another would experience 17,520 start-stops a year.

The beneficial side of the plant operating in the ancillary markets was an 11% uplift in wholesale revenue (Thompson, 2018).

Case study 16: Alpiqs Gondo, Switzerland

The Alpiqs Gondo plant in the Swiss Alps underwent modernisation upgrades to increase its flexibility and capacity. The upgrades allowed the plant to supply primary and reactive power to the nation's grid operator as opposed to just baseload. Operation of the power plant was further optimised by controlling the plant remotely (Bayer, 2017).

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