Ministry of Business, Innovation and Employment

Hydro generation stack update for large-scale plant

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Roaring40s Wind Power Ltd

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1. Introduction

The Ministry of Business, Innovation and Employment (MBIE), with support from Transpower, has engaged Roaring40s Wind Power Ltd (R40s) to provide an updated assessment of the existing and potential large scale hydro electricity generation in New Zealand. This is necessary to ensure that the information on generation plant in the '*generation stack'* database is current and accurate so that any modelling based upon it is robust and delivers reliable results. The generation stack is used to assist with understanding and determining what electricity generation capacity is required to be built and when, in order to meet forecast electricity demand. It is a key input to modelling performed by MBIE, Transpower, and the wider electricity industry[1].

The future of the New Zealand (NZ) electricity system has been the focus of a number of studies in recent years with reports undertaken by Transpower[2], the Interim Climate Change Committee (ICCC)[3], MBIE[4] and the Productivity Commission[5] being the most noteworthy. These reports address the growth of NZ's electricity market (out to 2035 in the ICCC report and to 2050 in the other reports) and what this means in regards to NZ's electricity demand - and mix of technologies - as it moves towards a 100% renewable generation goal and a low carbon economy.

Transpower's most recent modelling work undertaken for their March 2020 report *Whakamana i te Mauri Hiko* assessed a range of different electricity demand forecast scenarios. These forecast scenarios suggest an increase from New Zealand's current electricity demand of ~40 TWh/annum to between 56 and 80 TWh/annum by 2050. This range aligns with the modeling work undertaken by the other parties. Figure 1 shows actual demand between 1998 to 2018 and various modelled scenarios by MBIE and Transpower between 2018 to 2050. Also plotted is an extrapolation from the 2018 actual demand to the upper estimate of the ICCC forecast – which was modelled as being 57 TWh/annum by year 2035.

During the course of writing this report, Rio Tinto announced their intent to close the Tiwai Aluminium smelter (NZAS) in August 2021[6]. This will mean a reduction of 5 TWh/annum, or 13%, of NZ's electricity demand. Transpower's 'Tiwai Exit' scenario, modelled for the *Whakamana i te Mauri Hiko* report and included on Figure 1, can thus be considered the most plausible of the future demand scenarios – assuming the smelter does close, but with a 'staged exit'[7] over a five-year period between 2020 – 2025. This scenario shows:

- a decrease in electricity demand between 2020 and 2025,
- a recovery in electricity demand back to 2020 levels by 2029,
- significant growth (at the same rate as the Transpower Accelerated Electrification scenario) over the subsequent 20 years to give a total demand of approximately 65 TWh/annum by year 2050.

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[1] https://www.mbie.govt.nz/building-and-energy/energy-and-natural-resources/energy-statistics-and-modelling/energy-publications-and-technical-papers/nz-generation-data-updates/

[2] Transpower (2018). Te Mauri Hiko – Energy Futures (White Paper), which has since been superseded by the March 2020 report *Whakamana i te Mauri Hiko.*

[3] ICCC (2019). Accelerated electrification: Evidence, analysis and recommendations, Interim Climate Change Committee.

[4] New Zealand Government [MBIE] (2018). Electricity Price Review Hikohiko Te Uira. First Report for Discussion.

[5] New Zealand Productivity Commission (2018). Low-emissions economy – Final Report.

[6] https://www.nzas.co.nz/files/3413_2020070981142-1594239102.pdf.

[7] A 'staged exit' being one that would see a reduction in the smelter operations (and electricity consumption) over a period of years, as opposed to the total 'hard exit' in August 2021.

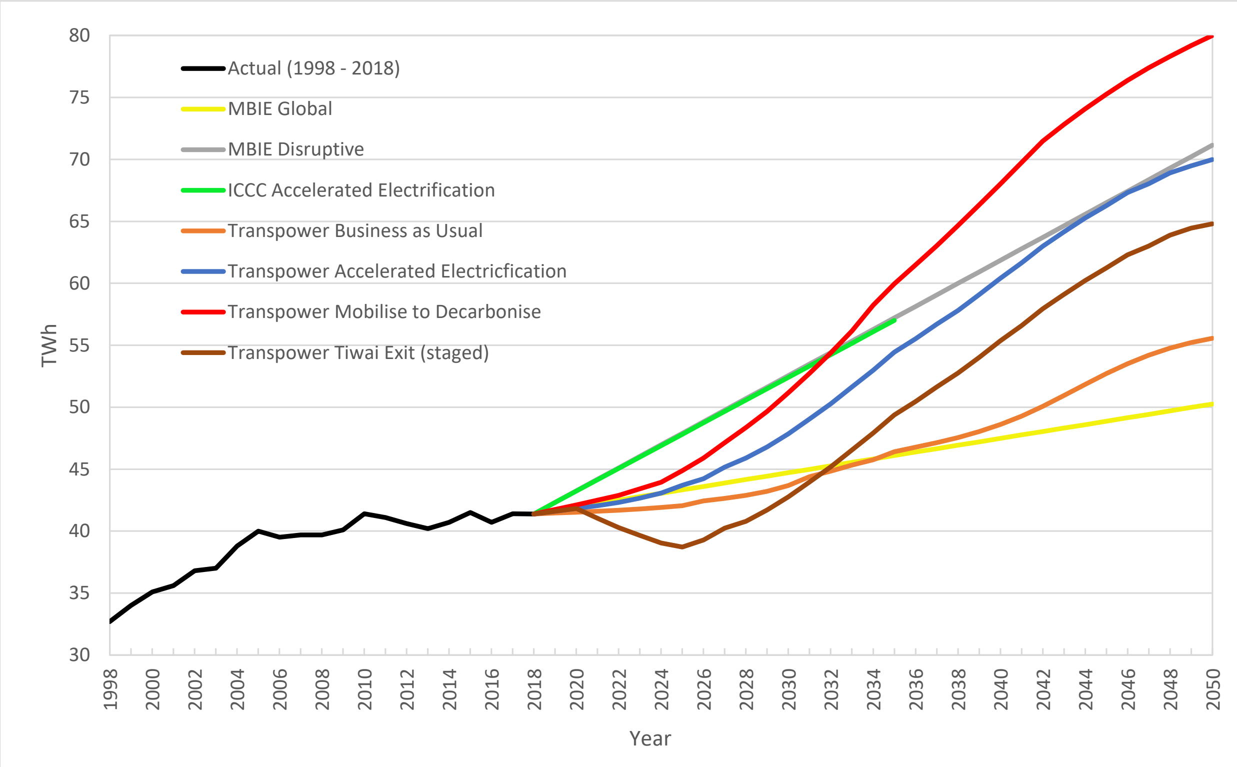

Figure 1. NZ Electricity Demand Forecasts

2. Objective

There are three objectives in relation to the assessment of existing and potential large-scale (or grid connected) hydro electricity generation projects – the first is to review the comprehensive Parsons Brinckerhoff (PB) report *2011 NZ Generation Data Update*[8] completed in early 2012, and update, as required, any information that may have changed in regards to the parameters describing the large-scale hydro plant. In particular, two new parameters are required in relation to each hydro plant;

- Consent expiry - which should refer to the year in which the consent to use water for the purposes of electricity generation expires, and;
- Reconsent likelihood - which is to be a qualitative assessment indicated as either “High”, “Medium” or “Low”.

In addition to the above information, a review and update of the variable and fixed operating and maintenance (O&M) costs is also required. This is to be provided as a single value given for each of these costs applicable to all plants (as it was provided in the PB report).

The second objective is to review the list of potential new large-scale projects described in the PB report – and add any others that are considered to be missing from the PB list. The following information is required for each project:

- The river that the project is on
- The intended peak capacity (MW)
- Estimated annual generation (GWh)

[8] Parsons Brinckerhoff (2012). 2011 NZ Generation Data Update. A report for the Ministry of Economic Development.

The third objective is to provide a general assessment of the likelihood or viability of Pumped Hydroelectric Energy Storage (PHES) – or more colloquially, 'pumped hydro'. This is to be a general assessment based on existing information on potential locations in New Zealand and not involve detailed modelling or appraisal of expected characteristics and associated costs.

3. Methodology

The following provides some context to the objective of the work before describing the methodology undertaken to achieve the objectives.

3.1. Existing grid connected hydro plant update

3.1.1. Context

Large-scale hydro generation in New Zealand is the backbone for electricity generation in New Zealand – as it has been for the past 100 years. Hitting a peak of 84% in 1980, the percentage of New Zealand's electricity provided by hydro generation has been between 50% and 60% for the last decade[9]. There is approximately 5,474 MW[10] of installed capacity of hydro generation in New Zealand, of which 5,312 MW (97%) is connected to Transpower's high voltage transmission grid.

There have not been any changes in the number of large-scale hydro plant in New Zealand for almost 30 years since the Clyde power station was completed, and certainly no changes in the number of grid connected plant since the PB (2012) study. In contrast to other forms of renewable generation such as wind and solar, the technology associated with hydro generation has changed little over time, meaning that the opportunities to enhance existing plant to provide significant increases in output or to develop sites that were previously considered uneconomical, are fewer. As such, it is appropriate and sensible that the methodology as directed by MBIE for this study is confined to being just an update on specific information in the PB (2012) report, as opposed to a standalone new assessment, which would essentially just be a repeat of the previous report.

3.1.2. Methodology

The work associated with the objective of reviewing and updating the information for existing grid connected hydro plant concerned the following process:

- A spreadsheet supplied by MBIE, based on the hydro plant previously identified in the 2012 PB report, was checked and expanded to include a number of relevant parameters, including those new parameters required as part of this study.
- Owners of each of the listed hydro plant were identified and contact was made by email requesting the information required.
- Once received, the information was checked, and any parameters not provided were sought through internet searches.
- In regard to the reconsent likelihood, discussions were had with relevant staff within the owners of the plant responsible for consent related matters in order to inform an assessment as "High", "Medium" or "Low" and additional context was also obtained in regards to any new restrictions or constraints that may be imposed by consent authorities in conditions of consent that may impact the operation of hydro plant.

[9] https://www.mbie.govt.nz/building-and-energy/energy-and-natural-resources/energy-statistics-and-modelling/energy-statistics/electricity-statistics/

[10] Based on information obtained during the course of this study. Note that the 4.8 MW Matiri scheme (Pioneer Generation) is currently under construction and will increase the total to 5,479 MW when completed (late 2020)

3.2. Potential new large-scale hydro plant

3.2.1. Context

The scope of work associated with the objective of identifying potential new large-scale hydro projects was also to review and update information contained in the PB (2012) report. Once again, there is logic in this – in the past decade since the PB (2012) report was written, there has been a sustained period of low electricity demand growth meaning that few developers have begun investigations into new sites, especially in regard to hydro generation.

Furthermore, over the same period, there has been more and more competition for water, especially from the dairy and horticulture industries, and more attention on the health and protection of river catchments and ecosystems. In addition, there has been a significant improvement in the economic viability of generation from wind and solar. All of this has combined to make new hydro generation more difficult to consent, and less attractive, in a commercial sense - compared to other forms of generation.

However, that is not to suggest that there aren't new hydro opportunities that could be developed in the future. Given the aspirations for New Zealand to achieve 100% renewable electricity (in a normal hydrological year) and the anticipated increase in electricity demand over the next few decades to meet the electrification of the country's energy needs[11], large-scale hydro generation cannot be ruled out as a potential source of meeting a portion of the future demand growth.

As such, we have elaborated on the list of potential schemes previously described in the PB (2012) report and added a number of additional potential opportunities identified in other reports[12] and based on our own experience of undertaking such investigations.

3.2.2. Methodology

Theoretically there is a vast amount of large-scale hydro potential in New Zealand. However, realistic options are much fewer due to factors such as:

- Remoteness and construction practicality
- Environmental constraints
- Recreational use constraints
- Transmission constraints
- Distance from the grid
- Other user competition for the water (e.g. irrigation)

Applying these factors when assessing a potential hydro resource often involves a significant degree of subjectivity. The actual feasibility of developing a site cannot usually be determined without investment in studies addressing the above factors to determine if there are any fatal flaws with a proposal.

As for the exercise to update information on existing large hydro plant, information on the status of investigations for those projects listed in the PB (2012) report was obtained through making direct contact with the owners of the potential options. We have then added to this list with additional potential sites that are described in other reports and based on our own experience. It is noted that situations change over time and a possible scheme considered unlikely to be developed now could at some point become viable. Conversely, the opposite also applies where a resource identified now could be precluded by a subsequent change in the situation pertaining to it.

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[11] In order to meet the goal of zero carbon emissions by 2050 as legislated by the Climate Change Response (Zero Carbon) Amendment Bill

[12] The report 'Waters of National Importance – Identification of Hydroelectric Resources' by East Harbour Management Services (2004) is a significant source of information

3.3. Pumped Hydroelectric Energy Storage (PHES)

3.3.1. Context

PHES is a proven and effective way of storing energy to generate electricity at some future time. Although there are no PHES schemes currently in New Zealand, they are not uncommon elsewhere, with approximately 165 GW of installed PHES schemes worldwide[13] - this being approximately 16 times NZ's total installed generation capacity (of ~ 10.2 GW[14]).

PHES plants can have an array of different design and sizes but all work on the same principle - by having the ability to pump water from one water storage reservoir at lower elevation into a second water storage reservoir at higher elevation and then allowing that same water to flow in the opposite direction to generate power. This can be done using the same pipe/tunnel and pump in reverse (so it acts as a turbine) to generate power. Some PHES have the advantage of capturing natural inflows to the upper water storage reservoirs thereby augmenting the opportunity to generate power.

Existing PHES schemes vary greatly in size. Bath County in USA is the largest scheme in the world with a capacity of 3GW, whereas El Hierro in the Canaries has a capacity of 11MW[15]. As for any hydro plant, the capacity of PHES depends on the flow and the head/fall (elevation difference). The head of existing PHES schemes varies from 70m (Kiev Pumped Storage Plant, in Ukraine) to 1265m (Edolo, Italy)[16]. The distance between reservoirs is important, impacting not only the operational efficiency but also the cost of construction. A reasonable parameter for assessing the potential of a PHES scheme is the head to length (distance) ratio. As a rule of thumb this ratio should be greater than 0.1[17] - i.e. 100m head over 1000m distance to ensure hydraulic efficiency losses do not adversely impact on project economics.

All PHES can be classified as either "closed loop" or "open loop". A closed loop system is one in which both water storage sites are independent of any free-flowing water source. Open loop systems have one or both water storage sites associated with a free-flowing water source i.e. river, natural lake or hydro power reservoir. Open loop systems are the more common – certainly in regions where water is plentiful and/or where hydro power is well established. This isn't surprising, as for any generation plant one of the key objectives is to devise the most economically attractive scheme for the purpose for which it is required and in consideration of environmental impacts. Often the most effective way of achieving this is by minimising the construction cost. Having one, or both, water storage sites already existing is thus a significant advantage.

Unsurprisingly, many of the attributes that are desirable for hydro generation are also desirable for PHES, such as large head, large volume reservoirs, short pipes/tunnels, in close proximity to existing transmission lines of adequate spare capacity, good access and good geological/geographical conditions – all of which give rise to attractive project economics. In addition, minimum conflicts with cultural, environmental, social, heritage, archaeological, and land management aspects are desirable.

The intent (and thus design) of PHES schemes is to have enough storage to mitigate undesirable market conditions caused by electricity supply and demand imbalance. In some cases, the market issue being addressed is short duration diurnal variations – traditionally due to high demand and high prices during the day and low demand and low prices during the night. For these repetitive cycles, the purpose of PHES is to pump water up into the upper water storage reservoir at night when prices and demand is low

[13] Hunt, J.D., Byers, E., Wada, Y. et al. Global resource potential of seasonal pumped hydropower storage for energy and water storage. Nat Commun 11, 947 (2020).

[14] ICCC (2019)

[15] McQueen (2019a)

[16] McQueen (2019)

[17] Rogeau, A. et al (2017)

and then generate with the same water during the day when prices and demand is high. More recently PHES has been getting attention in Australia to address a diurnal market issue – but one that concerns very low (and sometimes negative) prices during the day and high prices at night– caused by increasing penetration of solar generation in some areas, in particular Queensland[18]. Regardless of the reason why diurnal variations in the electricity market exist, the requirement for PHES in these situations will only be for relatively short durations of generation – sometimes as few as 6-18 hours.

New Zealand is different from many other countries in that it generally doesn't have a significant variation in electricity prices on a diurnal basis – or any other time period. This is partly due to the country's generation mix, where we have a low proportion of inflexible thermal base load generation and a high proportion of flexible hydro power. Without a regularly repeating variation in electricity prices, the frequency of low-cost pumping periods are fewer and this makes the economics of PHES challenging. This is further exacerbated for an open loop PHES if one of the reservoirs is an operational hydro lake. Unless the water being pumped up to the PHES reservoir would otherwise have spilled, the removal of water from an existing hydro reservoir is a temporary loss of generation potential from that plant, and any hydro plant downstream – until it is returned to the reservoir.

However, there is a widely accepted view that there will be a decarbonisation of New Zealand's energy system over the next few decades. This is something that has been well documented in a number of recent reports undertaken by Transpower, ICCC, NZ Productivity Commission, MBIE (as described in Section 1). The removal of carbon from our energy system is also something that is set as aspirational targets by government (i.e. "90% renewable electricity by 2025", "100% renewable by 2035") and is something that has more recently been required by legislation via the Climate Change Response (Zero Carbon) Amendment Act. This has been mandated partly in response to New Zealand ratifying the 'Paris Agreement' in 2016 (which is a commitment to reducing greenhouse gas emissions to 30% below 2005 levels by 2030) but also goes further, requiring New Zealand to "reduce net emissions of all greenhouse gases (except biogenic methane) to zero by 2050"[19].

This decarbonisation will likely result in a greater penetration of renewable generation (especially wind and solar) – and less thermal base load (gas and coal fired) generation. This will introduce more intermittency to the generation system which will likely increase the amount of price fluctuations in the electricity market. It will also make fast response storage systems, such as PHES, more attractive.

PHES could also help mitigate the 'dry year' risk, where 'dry years' refer to periods of weeks to months of constrained hydro availability. This is a phenomenon that New Zealand faces due to its high penetration of hydro generation which has relatively low storage capacity. During extended periods of low inflows, hydro storage can become depleted, and without the appropriate 'back-up' generation source, the New Zealand electricity system can be at risk of brown-outs, causing significant disruption to businesses and an accompanying adverse economic impact.

The coal/gas fired Huntly power station, being more flexible in its operations, is generally viewed as the plant that is required to provide the dry year risk cover. With the move towards a carbon-free energy future as required by the Climate Change Response (Zero Carbon) Amendment Act, the dry year risk cover will ideally need to be met by another source – and one that is renewable. Given that PHES is a storage system that uses water, this may not seem a likely candidate for mitigating dry year risk unless the water storage site(s) are of sufficient size – which would need to be enough to provide the necessary generation cover in the dry years. The maximum size of the dry year risk has been calculated as being approximately 3,000 GWh of electricity[20].

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[18] https://www.afr.com/companies/energy/the-winners-from-negative-electricity-prices-20190905-p52o7r

[19] https://www.mfe.govt.nz/climate-change/zero-carbon-amendment-act

[20] ICCC (2018)

In summary, the investigation of energy storage schemes including PHES is likely to gain more attention in New Zealand over the coming years/decades. The attractiveness of PHES schemes will depend on their location, economics, storage potential, the benefits they bring to the electricity market (i.e. in suppressing price spikes and in enabling more optimal operation of existing plant), and the ability to mitigate dry year risk.

3.3.2. Methodology

As described in Section 2, the objective is to summarise existing studies on PHES opportunities in New Zealand and provide our view. As such, our methodology has been a combination of literature search and discussions with subject matter experts.

4. Results

4.1. Existing grid connected hydro plant update

Table 1 describes the key attributes of the grid connected hydro plant. It is important to note that the nameplate generation capacity is not always reflected in the actual generation capacity. This can be due to operational constraints such as those imposed by consent conditions (e.g. Manapouri), old equipment with increased losses, or limitations on operation imposed by sub-optimal design which are manifested by de-rated equipment and/or inefficiencies (e.g. Aratiatia, Ohau B and Ohau C). The figures expressed in Table 1 show the actual generation capacities.

It is also important to note that refurbishments undertaken by the owners can increase power station output through the installation of new equipment or reconditioning of old equipment leading to a reduction in losses and improved efficiencies. For example, there have been a number of refurbishments undertaken on the Waikato hydro chain over the past decade, which has delivered an increase of 36MW - with more refurbishments scheduled to occur over the next few years[21, 22, 23].

There has been an increase of 118 MW in the total capacity of grid connected hydro plant since the PB (2012) report. This increase is all due to enhancements/refurbishments of the plant that existed in 2012 – i.e. no new grid connected hydro plant have been constructed within this period. The increase is due partly to the Waikato hydro chain refurbishments described previously, but mainly due to improvements at Manapouri power station, which now has a capacity 70 MW greater than that described in the PB (2012) report.

A number of changes to Manapouri station have occurred over the past two decades to improve capacity – a second tailrace tunnel was excavated between 1998 and 2002 to alleviate excessive friction losses in the single original tailrace. This was followed by a major mid-life refurbishment of the seven generating units which took place between 2002 - 2007. In 2010 changes to the resource consent conditions relating to the volume of discharge permitted into Doubtful Sound were approved. This enabled Meridian to generate up to the current 800 MW - which is still 50MW less than the installed (nameplate) capacity (850 MW). It is likely the figure in the PB (2012) report was the MW limit prior to the change of conditions relating to the discharge into Doubtful Sound.

The remainder of the difference is due to minor changes in output for various stations plus the previous omission of the *Lower Mangapapa* station (5.6 MW) – being part of the 'Kaimai' scheme in Bay of Plenty.

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[21] https://www.andritz.com/hydro-en/hydronews/updates-hydronews/karapiro-new-zealand-news

[22] https://www.nzherald.co.nz/business/news/article.cfm?c_id=3&objectid=12196316

[23] https://www.andritz.com/hydro-en/hydronews/hydro-news-29/hy-hn29-42-new-zealand-aratiatia/aratiatia-news

Table 1 Grid Connected Hydro Plant – Key Attributes

Owner	Existing plant	Rated capacity (MW)	Largest Unit (MW)	GIP Substation	Regional Authority	River/Scheme	Year Commissioned	Consent Expiry
	Waikato Hydro Regional Capacity							
Mercury	Aratiatia	78	31	WRK	Waikato	Waikato	1964	2041
Mercury	Ohakuri	106	28	WKM	Waikato	Waikato	1961	2041
Mercury	Atiamuri	74	21	WKM	Waikato	Waikato	1957	2041
Mercury	Whakamaru	124	31	WKM	Waikato	Waikato	1956	2041
Mercury	Maraetai I	176	36	WKM	Waikato	Waikato	1952	2041
Mercury	Maraetai II	176	36	WKM	Waikato	Waikato	1970	2041
Mercury	Waipapa	54	18	WKM	Waikato	Waikato	1961	2041
Mercury	Arapuni	192	24	ARI	Waikato	Waikato	1929	2041
Mercury	Karapiro	96	32	KPO	Waikato	Waikato	1947	2041
	TOTAL	**1076**						
	Bay of Plenty Hydro Regional Capacity							
Trustpower	Lloyd Mandeno (Kaimai)	16	8	TGA	Bay of Plenty	Wairoa River	1972	2026
Trustpower	Lower Mangapapa (Kaimai)	5.6	3	TGA	Bay of Plenty	Wairoa River	1979	2026
Trustpower	Kaimai 5 (Kaimai)	0.3	0.3	TGA	Bay of Plenty	Wairoa River	1994	2026
Trustpower	Ruahihi (Kaimai)	20	10	TGA	Bay of Plenty	Wairoa River	1981	2026
Trustpower	Matahina	80	40	MAT	Bay of Plenty	Rangataiki	1967	2048
Trustpower	Wheao	24	12	ROT	Bay of Plenty	Wheao	1982	2026
Trustpower	Flaxy	2	2	ROT	Bay of Plenty	Flaxy	1982	2026
Southern Generation	Aniwhenua	25	12.5	MAT	Bay of Plenty	Rangitaiki	1982	2026
	TOTAL	**173**						
	Hawke's Bay Hydro Regional Capacity							
Genesis Energy	Tuai	60	20	TUI	Hawkes Bay	Waikaremoana	1929	2032
Genesis Energy	Piripaua	42	21	TUI	Hawkes Bay	Waikaremoana	1943	2032
Genesis Energy	Kaitawa	36	18	TUI	Hawkes Bay	Waikaremoana	1948	2032
	TOTAL	**138**						
	Taranaki Hydro Regional Capacity							
Trustpower	Patea	32	10	HWA	Taranaki	Patea	1984	2040
	TOTAL	**32**						
	Bunnythorpe Hydro Regional Capacity							
Genesis Energy	Tokaanu	240	60	TKU	Waikato	Tongariro	1973	2039
Genesis Energy	Rangipo	120	60	RPO	Waikato	Tongariro	1983	2039
	TOTAL	**360**						
	Wellington Hydro Regional Capacity							
King Country Energy	Mangahao (inc mini)*	39	26	MHO	Horizons	Mangahao	1924	2027
	TOTAL	**39**						
	Nelson/Marlborough Hydro Regional Capacity							
Trustpower	Cobb	32	10	STK	Tasman	Cobb	1944	2038
	TOTAL	**32**						
	Christchurch Hydro Regional Capacity							
Trustpower	Coleridge	39	13	COL	ECan	Rakaia	1914	2031
Trustpower	Highbank	25	25	ASB	ECan	Rakaia	1945	2040
Trustpower	Montalto	1.8	1.8	ASB	ECan	Rakaia	1958	2040
	TOTAL	**65.8**						
	Waitaki Hydro Regional Capacity							
Meridian Energy	Aviemore	220	55	AVI	ECan	Waitaki	1968	2025
Meridian Energy	Benmore	540	90	BEN	ECan	Waitaki	1966	2025
Meridian Energy	Ohau A	264	66	OHA	ECan	Waitaki	1979	2025
Meridian Energy	Ohau B	212	55.5	OHB	ECan	Waitaki	1980	2025
Meridian Energy	Ohau C	212	55.5	OHC	ECan	Waitaki	1985	2025
Meridian Energy	Waitaki	105	15	WTK	ECan	Waitaki	1936	2025
Genesis Energy	Tekapo A	30	30	TKA	ECan	Waitaki	1951	2025
Genesis Energy	Tekapo B	160	80	TKB	ECan	Waitaki	1977	2025
	TOTAL	**1743**						
	Clutha Hydro Regional Capacity							
Contact Energy	Clyde	432	108	CYD	Otago	Clutha	1992	2042
Contact Energy	Roxburgh	320	40	ROX	Otago	Clutha	1956	2042
	TOTAL	**752**						
	Waipori Hydro Regional Capacity							
Trustpower	Deep Stream	5	2.5	HWB	Otago	Deep Stream	2008	2038
Trustpower	Waipori 1A	10	10	BWK/HWB	Otago	Waipori	1983	2038
Trustpower	Waipori 2A	58	20	BWK/HWB	Otago	Waipori	1967	2038
Trustpower	Waipori 3	7.6	7.6	BWK	Otago	Waipori	1952	2038
Trustpower	Waipori 4	8	8	BWK	Otago	Waipori	1954	2038
	TOTAL	**88.6**						
	Paerau Hydro Regional Capacity							
Trustpower	Paerau	10	5	NSY	Otago	Taieri	1984	2034
Trustpower	Patearoa	2.3	2.3	NSY	Otago	Taieri	1984	2034
	TOTAL	**12.3**						
	Fiordland Hydro Regional Capacity							
Meridian Energy	Manapouri	800	121.5	MAN	Environment Southland		1971	2031
	TOTAL	**800**						
	TOTAL (NZ)	**5312**						

* Notionally embedded (physically connected to Transpower's grid, but treated as embedded)

4.1.1. Consent expiry and reconsenting

The year of consent expiry is listed for each of the grid connected hydro plant in Table 1and shown graphically, as capacity (MW) in Figure 2. As can be seen, there are a number of prominent years – 2025 (Waitaki River chain), 2031 (Manapouri), 2041 (Waikato River chain) and 2042 (Clutha River i.e. Clyde and Roxburgh).

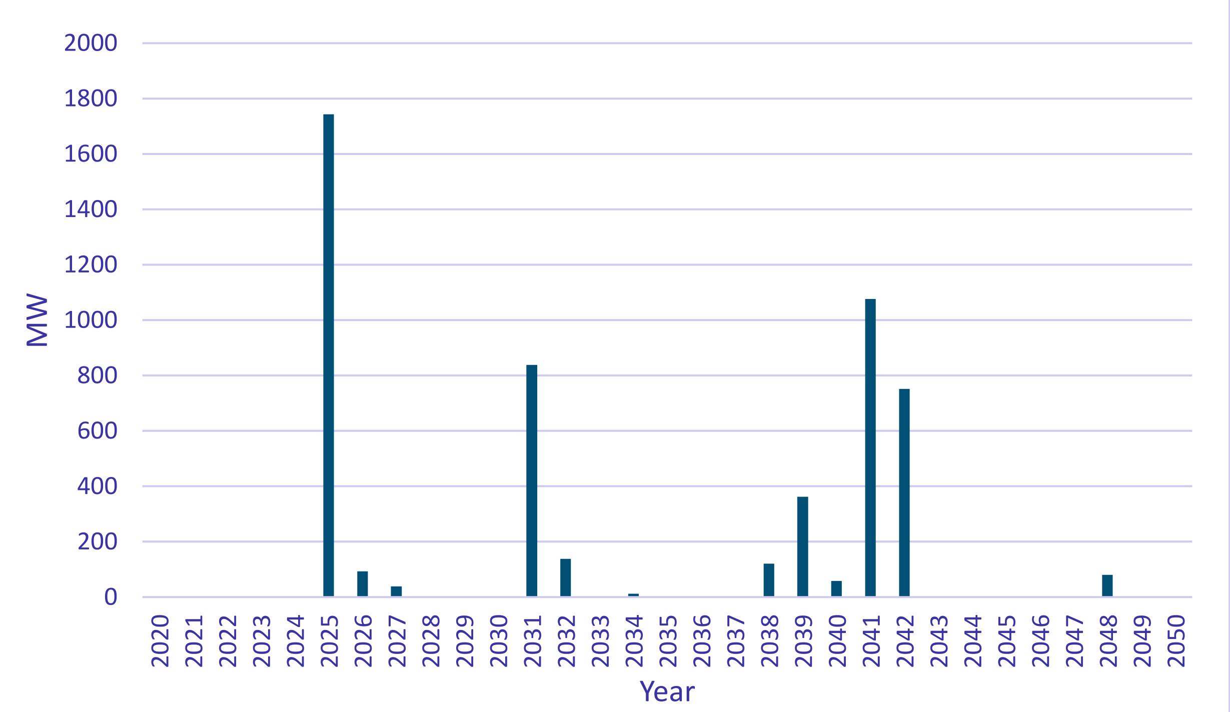

Figure 2 Hydro Capacity Consent Expiry

Discussions with hydro plant owners on the reconsenting implications and likelihood exhibit a common theme. The general feeling is that obtaining new consents (to take water for the purpose of hydro-generation) is considered highly likely. This is not surprising given the public good that electricity brings. However, it is also apparent that there is a general feeling that for some schemes, particularly those that are in regions where competition for water is high or where streams have been dewatered to a significant degree through hydropower diversions, there is likely to be some degree of restriction on the ability to take as much water in the future.

This may not necessarily affect the peak generation (i.e. the MW capacity), but it may reduce the ability to generate as often through the provision of greater environmental flows in rivers downstream of hydro dams and/or for the benefit of other users (i.e. for irrigation and recreation). There may also be restrictions imposed on the ability to change flows rapidly (‘ramping rates’) – and also to provide more water downstream of hydro power stations for environmental or recreation reasons. This will impact the flexibility in hydro operation. All of these matters will have an adverse impact on the amount of electricity generated on an annual basis.

In contrast to this, there is also the argument that the anticipated increase in electricity demand over the next few decades is a reason that generators could use to support their applications for consent to retain, or even increase, their access to water.

Thus there are two parts to the reconsenting aspect - it is highly likely new consents to take water for existing hydro generation will be granted, but there are likely to be varying degrees of impact imposed by new conditions of consent on the operation of the hydro plant. The magnitude of this impact will depend on the number and type of stakeholders for a given scheme/region. There may also be circumstances where more favourable conditions of consent are sought and granted - which would result in an increase in generation potential for a particular plant. However, in our view, the impact of reconsenting is likely to cause an overall decrease in the amount of electricity that can be generated.

4.1.2. Operations and maintenance costs

As noted in the PB (2012) report, Operations and Maintenance (O&M) costs are the ongoing costs associated with the running of generating plant which exclude any capital costs but may include financing costs.

Typically, O&M costs are split into fixed and variable. Fixed costs, which are not dependent on the number of hours of operation of the power plant, are typically expressed on a $/MW/year basis and, for hydro generation plants, typically include:

- Operation supervision and engineering
- Maintenance supervision and engineering
- Surveillance and maintenance of structures
- Maintenance of reservoirs, dams, and waterways
- Maintenance of electric plant
- Maintenance of miscellaneous hydraulic plant
- Insurances and property taxes
- Grid connection charges

Variable O&M costs are those that do depend on the number of hours of operation of the power plant and are typically expressed on a $/MWh basis. For hydro generation plant, these costs typically include:

- Increased operation supervision and engineering
- Hydraulic expenses
- Electric expenses
- Miscellaneous hydraulic power expenses
- Transmission charges

Information on the fixed and variable costs was requested from the hydro plant owners as part of this study. Some parties were reluctant to share the information due it being deemed commercially sensitive. However, the information that was received was useful and has provided data to help inform typical O&M costs for hydro plant.

In their 2012 report, PB similarly encountered difficulties in obtaining O&M data from hydro plant owners and so used a study from the United States, which provided typical O&M costs for North American hydro, to estimate the total (i.e. *Fixed* plus *Variable*) O&M costs for New Zealand hydro plant as being NZ$873/MW/month ($10,476/MW/year). They then used a split of 61%:39% for *Fixed:Variable* (which was referenced to a World Bank Group study), and applied this ratio to the above overall figure to give a fixed cost of NZ$532.50/MW/month (NZ$6,390/MW/year) and a variable cost of NZ$340.50/MW/month (NZ$4,086/MW/year). The estimated variable O&M cost was then converted to $0.86/MWh, based on an estimate of the average number of hours of operation per year for the New Zealand hydro plant fleet.

In a different study, "Financing Renewable Energy in the European Energy Market", by Ecofys et al (in January 2011), O&M costs of European hydro plant were reported as being US$45,000/MW/year for large-scale hydro plant and $52,000/MW/year for small scale hydro plant. Using an exchange rate of 0.77 (USD:NZD), being the average exchange rate for January 2011, and then adjusting for inflation to today, this gives a present day cost of NZ$65,500/MW/year.

The feedback R40s received from hydro plant owners as part of this study noted that although technically speaking there is a variable cost associated with O&M of hydro plant, this is so insignificant it can essentially be considered zero. This is because plant operation is ultimately dependent on water availability and unless this changed significantly, the O&M costs faced would essentially all be *Fixed*. The only exception to this is for the charges associated with the high voltage direct current (HVDC) inter-island link, which are currently apportioned to South Island generation at approximately $8/MWh and which should be treated as *Variable* costs. As such, it does not appear appropriate to split the overall

O&M costs in the manner proposed in the World Bank Group study, and which was adopted by PB in their 2012 report.

Table 2 compares the costs as reported by PB (2012) and Ecofys et al (2011) with a range for the O&M costs obtained directly from New Zealand hydro plant owners as part of this study. The figures from the PB and Ecofys reports have been inflated to 2020 (Q2) figures to enable appropriate comparison. It is also noted, below the table, what the O&M costs would be if the PB figures were combined and treated entirely as *Fixed*.

Table 2 Operations and Maintenance costs

	PB (2012) Inflated to 2020 (Q2)	Ecofys et al (2011) Inflated to 2020 (Q2)	R40s – 2020
Fixed ($/MW/year)	$7,083*	$65,500	$30,000 – 65,000
Variable ($/MWh)	$0.95		$0 (North Island) $8 (South Island)

*$11,600 if all costs treated as *Fixed*

As can be seen in Table 2, even the low end of the R40s range of O&M costs for New Zealand hydro plant obtained during this study is significantly greater than that proposed by PB in 2012, even after adjusting for inflation and after combining their *Fixed* and *Variable* figures to give a total cost of $11,600/MW/year. The Ecofys et al (2011) fixed figure of $65,500/MW/year, based on European hydro plant, is at the upper end of R40s range, which is based on real data obtained from operators of New Zealand plant.

It is also apparent, in the information received from hydro plant owners as part of this study, that there is a wide range of O&M costs for hydro plant in New Zealand. In general terms, the larger the hydro plant (in terms of capacity) the lower the O&M costs will be (on a per MW basis). It is well understood that small scale hydro have much higher O&M costs (on a per MW and per MWh basis) than large-scale plant due to the improved 'economies of scale' associated with large-scale plant.

In summary, we recommend the following approach be adopted in regard to O&M costs for hydro plant in New Zealand;

- Fixed: $30,000 - 65,000/MW/year (for plant greater than 30MW)
- Variable: $8/MWh (for South Island plant only) – subject to any changes in the cost allocation for the HVDC.

The *Fixed* range could be applied as a sliding scale – lower O&M costs should be applied for very large plant and higher costs applied to smaller plant. It can also be expected that the O&M costs for hydro plant below 30MW will be significantly greater that the range described above – figures received suggest a doubling of this range would not be inappropriate.

4.2. Potential new large-scale hydro plant

As discussed in section 3.2, we have undertaken an assessment of potential new large-scale hydro plant consisting of two parts. The first is an update of those projects either recently consented, or in the resource consent process, as described in the PB (2012) report. The second part is a list of those projects that we believe *could* be investigated and developed at some future date.

4.2.1. Update on the potential hydro plant being investigated in 2012

Table 3 provides an update on the status of the potential new large-scale hydro plant that were described in the PB (2012) report.

Table 3 Update of potential new large-scale hydro plant described in PB (2012) report

Plant	Rated capacity (MW)	Substation	Technology[1]	Largest generator (MW)	Owner	Estimated generation (GWh/year)	Consented (Y/N)	Consent Expiry	Still being Investigated?	Consentability (out of 10)
Wairau	72	BLN	HydRR	12	Trustpower	380	Yes	2021[4]	Yes	10
Lake Pukaki (Gate 18)	35	TWZ	HydPK	35	Meridian Energy	120	Yes	2021	Yes	10
North Bank	260	WTK	HydPK	130	Meridian Energy		Lapsed	2016	No	7
Rakaia	3[2]	ASB	HydRR	0.5	BCI[3]		Yes	2044	Operational	10
Arnold Valley	46	DOB	HydPK	23	Trustpower		Yes	2021[4]	No	10
Mokihinui	100	IGH	HydRR	33	Meridian Energy		No	N/A	No	2
Stockton Mine	35	WMG	HydRR	17	Hydro Developments Ltd	Repaced by the Ngakawau project described below				
Stockton Plateau	50	WMG	HydRR	25	Hydro Developments Ltd					
Ngakawau	24	WMG	HydRR	24	Hydro Developments Ltd	140	Yes	2026	Yes	10
Hawea Gates	17	CML	HydPK	9	Contact Energy	70	Lapsed	2017	Not actively	9

Notes:

[1] HydRR is run-of-river hydro, and HydPK is peaking hydro.

[2] Consent allows for a 16MW development, but only likey to be developed to a maximum of 3MW over the next 10 years (0.5MW developed to date).

[3] Barrhill Chertsey Irrigation Ltd - consent previously owned by the Ashburton Community Water Trust.

[4] Consent expiry is in reference to the land use consent (for construction). The consent to take water expires in 2046.

As can be seen in Table 3, all of the projects were granted resource consent approval – except Meridian's Mokihinui project on the West Coast[24]. The consents associated with two projects, North Bank and Hawea Gates, have now lapsed. Meridian Energy have indicated they are no longer investigating the North Bank project. Contact Energy have indicated they are not actively investigating the Hawea Gates option, but would not rule it out for potential future consideration. The consents for Wairau and Arnold Valley (Trustpower) and Lake Pukaki (Meridian) all lapse in 2021. Trustpower have indicated they are no longer pursuing the Arnold Valley scheme (which is not to be confused with the much smaller and operational 3MW Arnold River scheme).

The Rakaia scheme is operational - to a degree. The original concept consented by the Ashburton Community Water Trust was for a total generation of 16MW. The consent (to take water) is now being utilised by Barrhill Chertsey Irrigation Ltd (BCI) for an irrigation scheme, which has a very modest 0.5 MW mini hydro generation aspect associated with it. BCI have indicated that the hydro generation may be increased "over the next decade" but the total generation is unlikely to exceed 3 MW.

The two schemes associated with the Stockton Mine/Plateau (which were granted consent in 2010) have since been superseded by a single new proposal which is called the Ngakawau scheme and which successfully obtained a six year extension to the original lapsing date. The new lapsing date (for construction) is 2026.

4.2.2. Consentability

The consentability rating is simply an assessment made by R40 as to the likelihood of consenting. For existing consents that have not yet lapsed, a rating of 10 has been given - on the basis that if an extension to these consents is sought, the likelihood of it being approved is considered very high. For those projects where consents have lapsed, we have based our judgement on the fact that if consent was sought again, the rational for the consent has already been debated and accepted, and thus the likelihood of obtaining consent is reasonably good (noting that the likelihood of consent for North Bank may not be as straightforward as it is for Hawea). The very low rating for Mokihinui reflects the strong opposition to the proposal previously, which continued after Meridian withdrew the proposal from the consenting process, culminating in a large proportion of the Mokihinui River catchment being added to the Kahurangi National Park in March 2019[25].

[24] The Mokihinui project did receive resource consent approval, but this decision was appealed to the Environment Court and ultimately Meridian ceased interest in the project before the Environment Court hearing

[25] https://www.doc.govt.nz/news/media-releases/2019/mokihinui-river-catchment-land-to-be-added-to-kahurangi-national-park/

4.3. Other potential large-scale hydro plant

Information on other potential large-scale hydro plant is based on a combination of previous reports - especially the comprehensive East Harbour Management Service (2004) report – as well as our own experience of previously investigating such opportunities for the Electricity Corporation of New Zealand (ECNZ) and others.

For the purposes of this report, we have limited consideration to a minimum size of 50 MW capacity. There are a number of other possible schemes smaller than this capacity – these will be captured in a separate study - investigating the potential of new embedded hydro generation projects.

As discussed in section 3.2.2, there are many reasons for excluding consideration of a hydro resource, but this report has involved only the following filters:

- No rivers within a National Park or Forest Park. However, some rivers with headwaters within these areas or with reaches that pass through these areas have been considered.
- No rivers covered by a National Water Conservation Order (NWCO) have been included, but some rivers have parts that are not within the NWCO which may be included
- Some rivers have possible schemes that are mutually exclusive, or if they involve diversion to another catchment, will impact on any possible scheme on that river. To avoid 'double-ups' the authors have attempted to include the most viable option in these cases which will result in some rivers being excluded from the list.
- Schemes that involve taking water from a river that is part of an existing assets' generation flow have not been considered.

All of the rivers included in this report as having large-scale hydro potential have been the subject of investigation to some degree in the past, with some having reached resource consent application stage, and others having actually gained resource consent. Development in these cases has not proceeded for a number of reasons, ranging from being unable to gain access to critical land, to not achieving a business case.

Table 4 lists the additional potential plant we believe is worthy of inclusion for potential future development (in addition to those on Table 3 that are either still being actively investigated or not). As for those potential projects listed in Table 3, a 'consentability' assessment has been made. This is influenced by the history of the previous investigations (and opposition). It is acknowledged that some parties may have a different view on the consentability of a particular project.

Given the significant proportion of existing hydro generation in the South Island, we note that any new hydro generation would be more attractive if it were located in the North Island. However, as can be seen, the majority of the potential hydro projects are in the South Island, with only Mohaka, Motu and Whangaehu located in the North Island – and Motu having a very low likelihood of being consented. It is also acknowledged that the recent decision by Rio Tinto to close the Tiwai Aluminium smelter (effective August 2021[26]) makes additional new generation (of any type) in the South Island less attractive and as such, the South Island projects listed in Table 4 would best be considered as long-term prospects to assist with New Zealand's objective of being carbon zero by 2050 – or to meet future demand growth beyond that.

[26] At the time of writing, discussions were being had on the possibility of a staged exit over a period of years instead of a 'hard exit' in August 2021.

Table 4 Other potential large-scale hydro plant

Name	Rated capacity (MW)	Substation	Technology[1]	Largest generator (MW)	Location	Consentability (out of 10)
Clutha A	350	TMH-A	HydPK	150	Tuapeka	6
Clutha B	100	ROX	HydRR	25	Dumbarton Rock	6
Clutha C	80	HWB	HydRR	20	Barnego	6
Clutha D	80	CML	HydRR	40	Luggate	6
Clutha E	110	CML	HydRR	50	Queensberry	6
Grey River	250	DOB	HydPK	125	Stillwater large dam	7
Haast-Landsborough	60	DOB	HydRR	30	Landsborough River	2
Hawea River	80	CML	HydRR	35	Below Hawea dam	6
Mohaka River	70	RDF	HydRR	35	Mohaka River, near Te Hoe	6
Motu River	80	EDG	HydRR	40	Lower Motu River	2
Taramakau-Taipo	80	DOB	HydRR	40	Diversion to Arnold catchment	6
Waiau River (Canterbury)	65	WPR	HydRR	32.5	Mouse Point	5
Waiau River (Southland) A	80	INV	HydRR	40	Upper Waiau (between Tekapo and Manapouri)	2
Waiau River (Southland) B	60	INV	HydRR	30	Lower Waiau (d/s of Monowai)	4
Waimakariri River	50	HOR	HydRR	25	Lower Gorge	5
Waimakariri River B	84	HOR	HydRR	42	Waimakariri Gorge	5
Whangaehu River	50	TNG	HydRR	25	Various locations	7

Notes

[1] HydRR is run-of-river hydro, and HydPK is peaking hydro

4.4. PHES opportunities in New Zealand

There is very little literature on the investigation of potential PHES schemes in New Zealand, with the exception being in relation to the "Onslow Scheme". This Central Otago scheme has been the focus of a number of research papers, newspaper articles, and even a PhD thesis. Section 4.4.1 summarises the key features of the Onslow Scheme, while Section 4.4.2 summarises information on other schemes.

4.4.1. Lake Onslow PHES scheme

The most discussed PHES scheme in NZ is the Lake Onslow scheme located in Central Otago. This scheme was first described by University of Waikato Associate Professor Earl Bardsley in 2005[27], and was specifically proposed as a means of mitigating New Zealand's 'dry year' risk. A number of variations in size have been considered for this scheme – with the largest being the *Onslow-Manorburn* – which, with a storage of 12,000 GWh[28], would be extremely large even by international standards. The Onslow-Manorburn scheme would have almost three times the storage of all of NZ's existing hydro storage (~4,500 GWh)[29]. It involves damming the Teviot River and increasing the storage potential of the existing Lake Onslow (including flooding the Manorburn depression). Natural inflows would be augmented by pumping water from the nearby Clutha River (at Lake Roxburgh) up a 24km tunnel, climbing over 600m in vertical elevation in the process (see Figure 3). Generation capacity would be up to 1,300 MW.

The Onslow scheme has also been the subject of a PhD thesis undertaken by Mohammed Majeed (supervised by Bardsley), submitted in 2019[30]. Majeed's thesis modelled simulations using flow records for the Clutha and Waitaki rivers to assess the performance of a PHES at Lake Onslow having an operating range of 720 – 780 metres above sea level (masl) and a capacity of 4,000 – 11,000 GWh. Figure 3 shows a schematic diagram of the scheme as modelled by Majeed (and which was adapted for the Otago Daily Times newspaper on 19 September 2019).

[27] Bardsley, W.E. 2005.

[28] Storage capacity ranges between 5,000 – 12,000 GWh depending on design. The maximum storage of 12,000 GWh would include flooding the Manorburn depression.

[29] https://www.transpower.co.nz/system-operator/security-supply/hydro-information

[30] Majeed, M.K. (2019).

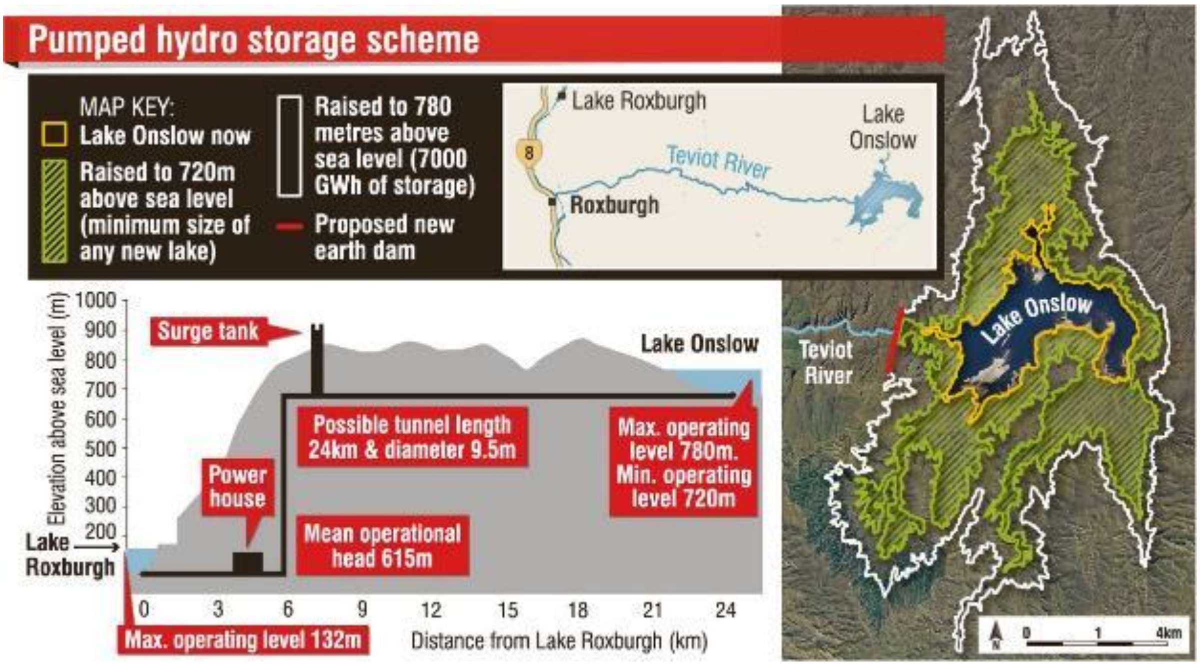

Figure 3. Lake Onslow PHES (Image reproduced from Otago Daily Times, 19 September 2019)

The results of Majeed's analysis and modelling supported the work previously undertaken by Bardsley and made the following key observations in regard to the benefits the scheme would bring;

- More efficient operation of all South Island hydro power stations with less spill.
- 'Dry year' risk cover
- Reduced need for sending power from the North to South Island during times of low South Island hydro inflows, reducing carbon dioxide emissions from North Island fossil fuel thermal stations.
- The new (up to) 1,300 MW capacity could be used for frequency keeping and also buffer the short-time variability of wind power, enabling wind power expansion without risking grid instability. The additional installed capacity could also provide peaking capacity generally, including offsetting plant outages.
- There will be some degree of flood peak reduction in the lower Waitaki River, as a consequence of reduced spill magnitudes from lakes Tekapo and Pukaki. At the same time, more stable lake levels should result in reduced lake shore erosion.
- The large increment of energy storage capacity may have the effect of stabilising electricity price fluctuations in the wholesale market, reducing the need to take out hedging contracts.

Majeed's thesis also considered the merits of pumped storage between Lakes Hawea and Wanaka – a scheme originally identified by Bardsley[31] - albeit to a much lesser analytical extent than that undertaken for the Onslow Scheme (it was an Appendix to his research and was provided "for completeness"). This is addressed in the Section 4.3.2.

A recent commentary (9 March 2020) [32] on the Onslow scheme was written by Bardsley in response to the following question posed in MBIE's discussion document on "Accelerating renewable energy and energy efficiency" - "What is the best way to meet resource adequacy needs as we transition away from fossil-fuelled electricity generation and towards a system dominated by renewables?". In the commentary, Bardsley describes the merits of the Onslow scheme, this version having a storage capacity of 5,000 GWh (to match that assessed and described in the ICCC 2019 report) and an installed capacity of

[31] https://www.waikato.ac.nz/news-opinion/media/2012/the-possibility-of-a-power-station-between-lakes-wanaka-and-hawea

[32] https://medium.com/land-buildings-identity-and-values/pumped-hydro-update-ec4538cbdb87

1,200 MW of generation. According to Bardsley, even at this somewhat reduced scale (compared to its full potential) this particular version of the Onslow scheme could not only address the (up to) 3,000 GWh hydro storage shortfall during dry years (see section 3.3.1) but also "enable an end to all coal use in New Zealand for industrial heat and power generation, provide resilience of electricity supply for accelerated electrification, produce net power gain to the national grid, provide buffering to enable 2,400 MW of new wind generation capacity, and create downward pressure on electricity prices".

The total construction cost of the scheme has been estimated by Bardsley to range between $3-4 Billion, depending on the size of the scheme[33]. McQueen (2019b) calculated the cost to be closer to $4.5B, increasing to $6.5B "if the operational and land value costs are included". The ICCC 2019 report undertook their own assessment of construction cost, using the "engineering calculations of the cost of the Lake Onslow proposal" from 2006 and updating them with the latest information available – being the cost estimates associated with the Snowy Hydro 2.0 PHES scheme.

While the ICCC did not reveal their construction cost estimate, they expressed the cost in terms of Marginal Abatement Cost as their exercise was specifically to address the dry year risk, which is currently provided by thermal generation. Their estimate of cost was described as follows: "the marginal emissions abatement cost for a pumped hydro storage solution at Lake Onslow was around $250/t CO2e". While this may appear a large value, it was the lowest (by far) of all the renewable solutions assessed by the ICCC to mitigate the dry year risk (including hydrogen) – and was also the solution which had the most robust estimate (i.e. narrowest range).

4.4.2. Other PHES schemes

The most comprehensive sources of information on other potential PHES schemes in New Zealand can be found in two research reports by Dougal McQueen – both from 2019. The first "There is potential for pumped hydro energy storage in New Zealand" (McQueen (2019a)) was undertaken whilst at the Electric Power Engineering Centre, University of Canterbury and was funded by MBIE as part of the GREEN Grid project. The second "Assessing Pump Hydro Energy Storage opportunities in New Zealand" (McQueen (2019b)) was a study undertaken by McQueen for Hyland McQueen Limited.

The first of these studies summarised previously investigated (and reported) PHES schemes in New Zealand, and also elaborated with potential PHES sites identified through his own analysis.

McQueen's research indicated that very few potential PHES in New Zealand had been formally assessed and reported in New Zealand. In fact, other than Lake Onslow, only three other schemes were identified – Lake Wanaka/Lake Hawea, Lake Pukaki/Lake Tekapo and a very small scheme in Stewart Island. Of these, there was no information on the 'Tekapo' scheme[34] but information has been inferred for the Storage, Head and Distance based on publicly available information. Details of the potential PHES schemes identified by others and summarised in McQueen (2019a) are shown in Table 5.

Table 5 Potential PHES schemes identified in McQueen (2019a) through literature search

Name (Lower Reservoir)	Name (Upper Reservoir)	Date Reported	Reference	Head (m)	Distance (km)	Head/Distance	Capacity (MW)	Storage (GWh)
Lake Wanaka	Lake Hawea	2012	Bardsley	65	2	0.033	120	211
Lake Pukaki	Lake Tekapo	2018	*Barnett*	*178*	*26*	*0.007*		
Stewart Island - lower	Stewart Island - upper	2016	Mason	75	0.5	0.150		*0.0033*
Lake Roxburgh	Lake Onslow	2006	Bardsley	*615*	*24*	*0.026*	*1,000 - 1,300*	*4,000 - 12,000*

Note: Figures in italics have been added (or corrected) as part of this study. The figures for Head and Distance for the Lake Onslow scheme are those proposed by Majeed (2019).

33 https://newzealand.water.blog/2019/05/30/the-journey-begins/

34 Reference to this concept was found in a submission by Dr A.G. Barnett in a submission on the Zero Carbon Bill (in 2018) where it was noted "The canal was designed to carry flows in both directions between Lake Tekapo and Lake Pukaki in case of a later need for pumped storage, and this capability was confirmed as part of the commissioning."

McQueen (2019a) proposed a classification of four PHES types, distinguishing open loop schemes into two sub-categories and distinguishing closed loop schemes into two sub-categories, as shown in Table 6 below.

Table 6 PHES scheme classification (McQueen (2019a))

PHES Type	Scheme	Description
1	Open loop	Use of existing upper and lower reservoirs
2	Open loop	Construction of an upper reservoir above an existing water body
3	Closed loop	Use of brown-fields sites (e.g. abandoned mine pits)
4	Closed loop	Construction of off river schemes (e.g. constructing upper and lower reservoirs)

McQueen subsequently developed modelling techniques to demonstrate how each of the four types of PHES could be identified.

4.4.2.1. PHES Type 1

Using geospatial information system (GIS) analysis to match pairs of lakes in close proximity to identify potential Type 1 (open loop) PHES sites, McQueen (2019a) identified 10 potential Type 1 PHES with the following criteria;

- > 100 MWh storage.
- > 50m Head
- > 0.066 Head/Distance ratio
- Avoidance of Department of Conservation land

Table 7 Results of a Type 1 (open loop) search for potential PHES schemes using the NZ Lakes polygons dataset (McQueen, 2019a)

Lower reservoir	Upper reservoir	Distance (km)	Head (m)	Head/Distance	Storage (GWh)
Wakatipu	Lake Johnson	1.2	91	0.08	0.1
Wakatipu	Lake Luna	4.2	502	0.12	0.8
Wakatipu	Lake Dispute	1.1	160	0.14	0.2
Wakatipu	Lagoon Creek	1.2	116	0.09	0.4
Lake Sumner	Lake Mason	2.2	151	0.07	0.4
Loch Katrine	Lake Mason	1.9	153	0.08	0.4
Lake Aviemore	Lake Benmore	0.2	93	0.40	31.0
Lake Roxburgh	Speargrass Creek	7.3	514	0.07	0.5
Lake Roxburgh	Butchers Dam	1.5	159	0.11	0.2
Karapiro	Arapuni	0.1	58	0.43	2.1

Table 7 summarises the results of the McQueen's analysis. Of these potential PHES, McQueen considered that only Wakatipu/Lake Johnson and Lake Roxburgh/Speargrass Creek were worthy of further consideration due to a perceived "number of potential barriers" to the development of the other schemes. These barriers include;

- Integration with existing hydro operation (Aviemore/Benmore and Karapiro/Arapuni);
- Distance from the grid and difficulty to access (Lake Mason, Lake Luna and Lagoon Creek), and;
- Located in recreational areas (Butchers Dam and Lake Dispute).

However, both Lake Johnson (immediately north of Frankton) and Speargrass Creek (to the northeast of Lake Roxburgh) have very modest storage (0.1 and 0.5 GWh respectively) and thus would probably have limited appeal.

McQueen (2019a) notes that "While the search of existing water bodies [i.e. Type 1 schemes] highlights few possibilities, the number of potential schemes of Types 2 through 4 is far greater. Searching for schemes of Types 2 through 4 is a complex task with engineering optimisation, GIS and location specific knowledge useful."

4.4.2.2. *PHES Type 2*

Using Lake Roxburgh as the lower reservoir, McQueen (2019a) undertook a complex modelling exercise using a combination of GIS and a construction cost estimation process to support an evolutionary algorithm which is applied to find a quasi-optimal location for an upper reservoir near Lake Roxburgh. This exercise identified a potential site at Fruitlands (to the north and west of Lake Roxburgh) which would have a head/distance ratio to Lake Roxburgh of double that of the Type 1 Speargrass Creek and have a storage capacity of 8.2 GWh.

A subsequent modelling exercise (McQueen, 2019b) used a similar, but more advanced modelling technique – which McQueen called the "Pump Hydro energy storage Assessment Tool" (PHAT). Using Lake Roxburgh as the lower reservoir, the PHAT modelling exercise identified the optimal solution as being Speargrass Creek, but with a large dam constructed across the river increasing the storage capacity of the existing reservoir from 0.5 GWh to 154 GWh.

PHAT was also used at two other locations – Lake Moawhango and Lake Whakamaru in the North Island to identify potential upper reservoir locations for pump storage schemes. The results of all Type 2 sites identified through McQueen's modelling are shown in Table 8 below. It is also noted that a PHES scheme utilising Lake Moawhango as the downstream reservoir would have a significant additional benefit by way of 'firming' downstream generation through the Tongariro scheme and Waikato river hydro stations – which totals approximately 1400 MW (pers. Comm. McQueen, July 2020).

Table 8 Parameters of Type 2 (open loop) sites identified by McQueen using advanced computer modelling as described in McQueen (2019a) and McQueen (2019b).

Name (Lower Reservoir)	Name (Upper Reservoir)	Head (m)	Distance (km)	Head/Distance	Capacity (MW)	Storage (GWh)
Lake Roxburgh	Fruitlands	264	1.7	0.15	200	8.2
Lake Roxburgh	Speargrass Creek Lake	564	6.1	0.09	200	154
Moawhango	Koroteti Stream	195	2.8	0.07	200	21
Whakamaru	Pokuru Rd	243	4	0.06	200	21

The work undertaken by McQueen demonstrates the powerful ability computer modelling has in being able to identify the optimal locations of a new upper reservoir, based on an existing lower reservoir. The PHAT modelling described in McQueen (2019b) also estimated the construction cost and the cost for land inundation, including applying a cost impact for flooding special land types (e.g. wetlands).

Another potential PHES Type 2 scheme was identified using Lake Taupō as the lower reservoir during an unreported study undertaken by ECNZ in 1997. This scheme was not identified through any modelling exercise, but based on knowledge of the area. It involved using Lake Taupō as the bottom reservoir and then finding a location for a top reservoir in close proximity to the shoreline, preferably gaining advantage from natural features such as a river valley where a dam could be constructed for impoundment.

It was found that there were numerous locations on the western side of Lake Taupō between Kinloch and Kuratau where a head of around 150 m could be achieved. Alternatively, if a natural site were not available, an upper reservoir could be excavated (and lined) on one of the flatter (currently farmed or forested) areas above the lake.

Table 9 describes the parameters of a possible PHES using Lake Taupo. The size of the upper reservoir (and hence the storage) would ultimately be a trade-off between the cost of construction and a useful operational amount. A nominal 10 GWh has been assumed for the purposes of this report. The powerhouse would be on the shore of the lake, or an underground option could possibly be considered. It is noted that Lake Taupō is a highly utilised recreational amenity and has many environmental and landscape aspects along and adjacent to its shores. Consenting such a scheme is likely to be challenging.

This scheme was not progressed beyond 'conceptual' by ECNZ because there was not enough difference between peak and off-peak electricity prices for a commercially viable scheme at the time of the assessment.

Table 9 Parameters of the Lake Taupō (Type 2) option identified by ECNZ in 1997

Name (Lower Reservoir)	Name (Upper Reservoir)	Head (m)	Distance (km)	Head/Distance	Capacity (MW)	Storage (GWh)
Lake Taupo	Western Lake Taupo	150	2	0.075	200	10

One other hindrance to using Lake Taupō is that water is never spilled from this lake – all water from the lake has to pass through the Taupō Control Gates at the bridge over the Waikato River to the northwest of the Taupō town centre. With no spill this means there is no opportunity to save lost potential by pumping when water would otherwise be lost through spilling - which is the case for many other potential PHES sites, like those associated with Lake Roxburgh.

This means that taking water from Lake Taupō to store it for generation at some point in the future does not result in an overall increase in the generation potential of that water, which is realized when it flows through the hydro stations on the Waikato River. In fact, in an overall sense, there is a slight reduction given that pumping water up is less efficient than when generating.

There would be a benefit in the ability to change the timing of when that generation occurs, but given the storage potential is not significant (approximately 50 hours generation at 200MW) the Taupō scheme considered previously would not have addressed dry year risk. The other potential benefit would be to mitigate shoreline erosion/inundation by removing water from Lake Taupō during periods of extreme lake levels. However, the reduction in water level would only be a few centimetres and thus may not provide a significant benefit.

4.4.2.3. PHES Type 3

According to McQueen (2019a), Type 3 PHES (brownfield sites, often utilising old mining sites or irrigation schemes) are not typically identified through any modelling techniques, but through an understanding of the land topography in close proximity to identified lower reservoir lakes. McQueen (2019a) identified three sites – two based on irrigation schemes (Dairy Creek and Hakataramea) and one based on a gold mine (Macraes).

Table 10 Parameters of PHES Type 3 (closed loop) options identified through analysis of existing known opportunities (McQueen, 2019a).

Name (Lower Reservoir)	Name (Upper Reservoir)	Head (m)	Distance (km)	Head/Distance	Capacity (MW)	Storage (GWh)
Lake Dunstan	Dairy Creek	75	1.1	0.07	0.3	0.02
Lake Waitaki	Hakataramea	145	1	0.15	2	0.07
Macraes - lower	Macraes - upper	200	0.3	0.61		0.5
Lake Roxburgh	Irrigation pond	264	0.8	0.35	200	0.05

4.4.2.4. PHES Type 4

McQueen's method for identifying Type 4 sites was to modify the evolutionary algorithm used to identify the quasi-optimal Type 2 scheme so that it would identify the optimal locations for both the upper and lower reservoirs simultaneously. Due to the greater challenge of identifying both reservoirs, this method is best used on a relatively small area to reduce processing time and effort. McQueen (2109a) identified an area of the Raukawa Range, in Southern Hawkes Bay as the test case to demonstrate the performance of the algorithm.

McQueen first manually identified a pair of reservoirs by scanning the topographic maps of the area and picked two potential areas that constituted a "best guess". The evolutionary algorithm was then run across the entire map area selected to identify the quasi-optimal solution. The parameters of then best guess and quasi-optimal solution obtained through modelling are described in Table 11 and identified on Figure 4.

Table 11 Parameters of the Type 4 (closed loop) "Raukawa" option identified through 'best guess' and quasi-optimal modelling (McQueen, 2019a).

Name (Lower Reservoir)	Name (Upper Reservoir)	Head (m)	Distance (km)	Head/Distance	Capacity (MW)	Storage (GWh)
Raukawa - lower (best guess)	Raukawa - upper (best guess)	180	1.5	0.12	200	0.25
Raukawa - lower (quasi-optimal)	Raukawa - upper (quasi-optimal)	205	1.7	0.12	200	1.5

As can be seen in Table 11, the quasi-optimal modelling was able to identify a potential PHES site having a greater head and much larger storage capacity than that identified through the ‘best guess’ method of manually assessing the topography of the area of interest to determine suitable locations for upper and lower reservoirs.

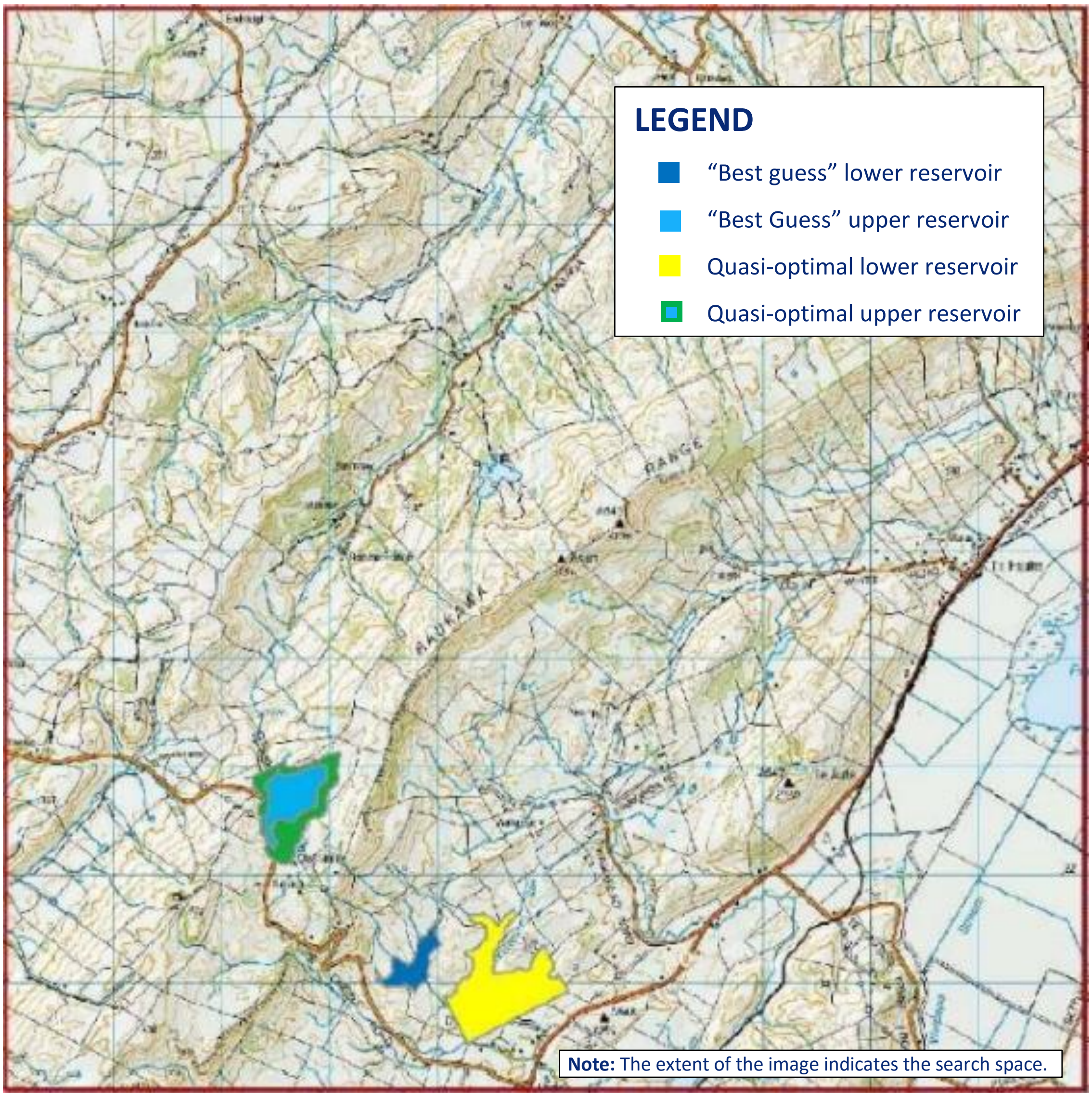

Figure 4 Results of particle swarm optimisation for Raukawa Range (McQueen, 2019a)

4.4.3. Summary

The amount of information on potential PHES opportunities in New Zealand is limited. This is perhaps not surprising given the relatively infrequent electricity market conditions in New Zealand that are typically required for PHES schemes to both exploit and mitigate. While the area around Lake Roxburgh has received the most attention through various studies and reports, especially the Lake Onslow scheme and to a lesser extent the Lake Hawea scheme, there hasn’t been a great deal of investigations into opportunities in other parts of New Zealand. The attention given to Lake Roxburgh is understandable as it provides a lower reservoir that receives a significant inflow fed by three of New Zealand’s large lakes (Wakatipu, Wanaka and Hawea). Additionally, and more importantly, it is surrounded by large areas of sparsely populated land at a significantly higher elevation. This presents opportunities for very large scale PHES schemes – something that could address New Zealand’s dry year risk. The Onslow scheme is by no means perfect though, and the distance between the upper and lower reservoirs is considerably further than what is considered desirable from a hydraulic efficiency perspective.

McQueen's recent studies (2019a and 2019b) are the most comprehensive sources of information on PHES schemes, other than those related to the very large 'Lake Onslow' scheme. However, the intent of McQueen's work was mainly to prove modelling techniques that could be used to identify potential PHES sites, as opposed to undertaking a detailed analysis to identify potential sites.

In theory, many existing operational assets could be used for PHES. However this would require conversions and modifications to the generating plant and hydraulic features (e.g. tailwater) and, as described previously, the occurrence of low prices in the electricity market are not reliable or dependable, meaning that opportunities for pumping would be infrequent. Similarly, such schemes devised around existing plant do not address dry year risk, due to the limitations of storage. Owners of existing assets have from time to time looked into such opportunities but the conclusion to date has been that they are not economic and have significant negative impacts on the operation of existing assets. In some cases, resource consent operating rules and other environmental factors would inhibit their consideration.

A list of potential PHES schemes have been identified in the course of preparing this report (Table 12). It is by no means a complete list of all potential opportunities, only those that have been identified and assessed by others to date. We have included all the sites identified and have not attempted to qualify their economic attractiveness or likelihood of being consented or constructed. We have, however, removed the Type 1 sites that McQueen (2019a) identified through GIS modelling but subsequently noted as having significant barriers to their construction. We have used the Head and Distance parameters from Majeed's thesis to describe the Lake Onslow scheme and have provided a range for Capacity and Storage based on the various options considered possible for this site.

Clearly there is a great deal of variance in the parameters of the potential PHES schemes that have been identified. The attractiveness of the options depends on what purpose the particular scheme would be trying to resolve. If the objective is to provide firming generation on a short duration, then there are a number of sites already identified that could be of interest. However, if the objective is to address dry year risk, then only one valid option has been identified to date – the Lake Onslow scheme – due to its significant storage capacity.

Table 12 Parameters of potential New Zealand PHES identified to date.

PHES Type	Name (Lower Reservoir)	Name (Upper Reservoir)	Date Reported	Reference	Head (m)	Distance (km)	Head/Distance	Capacity (MW)	Storage (GWh)
1	Lake Pukaki	Lake Tekapo	2018*	Barnett*	178	26	0.007		
1	Lake Roxburgh	Speargrass Creek	2019	McQueen	514	7.3	0.07	200	0.5
1	Lake Wanaka	Lake Hawea	2012	Bardsley	65	2	0.033	120	211
2	Lake Moawhango	Koroteti Stream	2019	McQueen	195	2.8	0.07	200	21
2	Lake Roxburgh	Lake Onslow	2006	Bardsley	615	24	0.026	1,000 - 1,300	4,000 - 12,000
2	Lake Roxburgh	Fruitlands	2019	McQueen	264	1.7	0.15	200	8.2
2	Lake Roxburgh	Speargrass Creek Lake	2019	McQueen	564	6.1	0.09	200	154
2	Lake Whakamaru	Pokuru Rd	2019	McQueen	243	4	0.06	200	21
2	Stewart Island - lower	Stewart Island - upper	2016	Mason	75	0.5	0.150		0.0033
2	Lake Taupo	Western Lake Taupo	1997	ECNZ	150	2	0.750	200	10
3	Lake Dunstan	Dairy Creek	2019	McQueen	75	1.1	0.07	0.3	0.02
3	Lake Roxburgh	Irrigation pond	2019	McQueen	264	0.8	0.35	200	0.05
3	Lake Waitaki	Hakataramea	2019	McQueen	145	1	0.15	2	0.07
3	Macraes - lower	Macraes - upper	2019	McQueen	200	0.3	0.61		0.5
4	Raukawa - lower	Raukawa - upper	2019	McQueen	205	1.7	0.12	200	1.5

*Although reference to the Lake Pukaki/Lake Tekapo PHES has been attributed to Barnett in 2018, clearly the concept was considered earlier and by others, as noted in Barnett (2018).

It is important to note that we have not attempted to make any assessment on the implications of the Tiwai Aluminium Smelter exit (which was announced 9 July 2020 during the preparation of this report) and what this means in regard to the dry year risk and the need for PHES. With the drop in demand (about 13% of New Zealand's total demand is consumed by the smelter) it is likely that this will bring forward the closure of baseload and mid-range plants like the Huntly Power Station and possibly also the Taranaki Combined Cycle station. Should this happen it will result in less thermal generation in New Zealand's generation mix, meaning a greater reliance on hydro generation and less 'back-up' thermal plant - potentially increasing the 'dry year' risk to New Zealand and the need for a solution like PHES.

We also have not attempted to comment on climate change and what the implications are hydro inflows and dry year risk. Modelling undertaken in some studies[35] suggest that inflows to the South Island hydro catchments will likely increase with the anticipated warming of the planet, and consequently, dry year risk (from a hydro generation perspective) could theoretically decrease. However, droughts are unlikely to ever cease being a risk given the nature of climatic patterns and extreme events.

In our opinion, a bespoke and in-depth PHES study is required to fully inform all potential PHES schemes in New Zealand. We believe analysis undertaken using a combination of GIS and modelling techniques such as those that have been developed successfully by McQueen would be the most sensible approach.

GIS analysis is an efficient way of assessing large quantities of geographical information. However, GIS analysis has its limitations and can easily miss valid opportunities or identify too many - as was the case in the Blakers et al (2017) study which identified 22,000 potential sites in Australia. Appropriate filtering needs to be integrated to avoid clearly undesirable areas from a land tenure perspective, resource perspective, areas too distant from existing transmission grid of suitable capacity, and avoidance of protected land or that afforded special status.

As such, a GIS analysis alone is not recommended. Any assessment should also include indicative construction cost estimates and economic analysis - including the benefits to the wider electricity system, to enable appropriate comparison and ranking of potential options. McQueen's models appeared to demonstrate the ability to estimate (at a high level) the potential construction costs of the sites identified – but modelling the economic implications on the operation of existing generation plant is a very complex undertaking and this would likely require a separate modelling exercise. If the objective of PHES in New Zealand is to address dry year risk, then clearly scale is an important factor. However, the required dry year risk cover may be best achieved through multiple attractive schemes located in different parts of New Zealand, as opposed to one very large scheme (i.e. the Lake Onslow scheme).

Following the identification of potential sites, it is also recommended that site visits are undertaken to better inform construction cost estimates, as well as high level environmental and planning assessments, in order to inform the likelihood of resource consent approval.

5. About the authors

The research and analysis for this report was undertaken by Steve Harding and Graeme Mills of Roaring 40s Wind Power Ltd (R40s) with some technical assistance and review by various industry experts. R40s was formed in 2018 to provide consultancy services to organisations wanting to identify, investigate and develop renewable energy projects. Our experience includes both small scale and grid connected projects and covers a wide range of project development aspects – site identification, land access negotiations, feasibility studies, resource modelling, project economic analysis, consent strategy and applications, consent hearings, stakeholder engagement, detail design studies and business case preparation.

Steve and Graeme have a significant amount of experience in hydropower investigations and operation, most of which was gained whilst working for the Electricity Corporation of New Zealand (ECNZ) and Works/Opus Consultancy in hydrology-related fields. In particular, Graeme was lead author of a number of studies that summarised the hydropower potential of New Zealand, including the identification and assessment of potential sites of new hydro generation whilst at ECNZ.

[35] Caruso et al (2017) and Meridian Energy (2019)

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