# Evaluating the potential for a multi-use seasonal pumped storage scheme in New Zealand’s South Island

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# Abstract

A simulation evaluation is presented of the seasonal operation a possible 1,300 MW pumped storage scheme in New Zealand. The simulations are with respect to a site in Central Otago, where the existing Lake Onslow is expanded to serve as the upper reservoir. The lower reservoir would be Lake Roxburgh on the Clutha River.

The simulations are based on permitting a large operating range (720 to 780 masl) for Lake Onslow, increasing New Zealand's hydro storage capacity from 4,000 GWh to 11,000 GWh. However, this range does not represent seasonal variation of a typical year. Other operating options are possible as well, including a smaller operating range or maintaining a raised lake Onslow at constant level as an energy reserve against dry years, avoiding the need for stand-by thermal stations.

In addition to providing a buffer against future dry periods, the simulations (based on past river flow records) indicate that active seasonal operation of Onslow pumped storage could allow more efficient use of the main South Island hydro lakes (Hawea, Tekapo, and Pukaki). Specifically, the possibility arises to maintain water levels of those lakes at their present mid-ranges. This essentially removes the active hydro storage role of the South Island scenic lakes, with lake outflows reverting to their natural seasonal regime of high flows in spring and summer and low flows in winter. In the simulations, the surplus power from the higher summer flows in the Clutha and Waitaki rivers is used for pumping water up to Lake Onslow, to be released later for winter power.

The simulations using past hydro lake inflows indicate that this mode of operation would significantly reduce spill losses, particularly at Waitaki power stations. Although hydro spill is intermittent, the net effect appears to be that spill reduction is sufficient to offset operating inefficiencies in pumped storage, with a small power surplus left over. In addition, reversion to higher summer lake outflows would result in a considerable increase in mean Waitaki River summer discharge, enabling additional river water diversions for irrigation developments.

Additional advantages of the pumped storage scheme are identified as:

- Reduced need for sending power from the North to South Islands during times of low South Island hydro inflows, reducing carbon dioxide emissions from North Island fossil fuel thermal stations.

- The new 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.

Taking all advantages into account, the scheme appears economically viable.

# Acknowledgements

Most of all, I thank you, God, for giving me the blessing, the strength, the opportunity and the endurance to complete this study.

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# List of Abbreviations

PHES: Pumped Hydroelectric Energy Storage.

Firm capacity: The amount of energy available for production or transmission which can be (and in many cases must be) guaranteed to be available at a given time. Firm energy refers to the actual energy guaranteed to be available.

OCGT: Open Cycle Gas Turbine.

LCOE: Levelised Cost of Electricity.

CCGT: Combined Cycle Gas Turbines.

Fault ride through: In electric power systems, low-voltage ride through (LVRT), or fault ride through (FRT), sometimes under-voltage ride through (UVRT), is the capability of electric generators to stay connected in short periods of lower electric network voltage (cf. voltage dip).

HVDC: A high-voltage, direct current (HVDC) electric power transmission system (also called a power super highway or an electrical super highway) uses direct current for the bulk transmission of electrical power, in contrast with the more common alternating current (AC) systems.

RSL: Relative Storage Level.

RIS: Reservoir induced seismicity.

# Chapter One: Introduction and motivation

## 1.1 Background

New Zealand's lakes are a valuable resource. Focal points for tourism, they attract visitors who appreciate their natural beauty, or who come to fish, swim or explore. They have long been important to Maori as a food resource and for their cultural associations. They have attracted people to live at their edges, creating iconic townships such as Queenstown.

The lakes are also used for hydro-electric generation, water storage for irrigation schemes and for flood control. There are now over 60 lakes and reservoirs managed for hydro-electric storage in New Zealand and about 60% of power generated is now from hydro sources, although the amount varies somewhat from year to year (Figure 1.1).

Figure 1.1 shows the annual generation in TWh and the proportion of total New Zealand generation from each of three major fuel types: hydro, fossil fuel and other renewable (mainly geothermal and wind). The share of hydro in total generation decreased from more than 71% for most of the early 1990s to less than 58% after 2005. This is because total hydro generation remained relatively consistent since 1992, when the last major hydroelectric power plant at Clyde was finished. All load development has been met by increments in fossil fuel generation and, to a lesser extent, from other renewables separated from hydro. The graphs also show that there can be economically significant shifts in partitioning between hydro and fossil fuel percentages (approximately five percent variation of total generation) between years with dry hydrological conditions (such as 2001 and 2003), and years with wet hydrological conditions (such as 2002 and 2004).

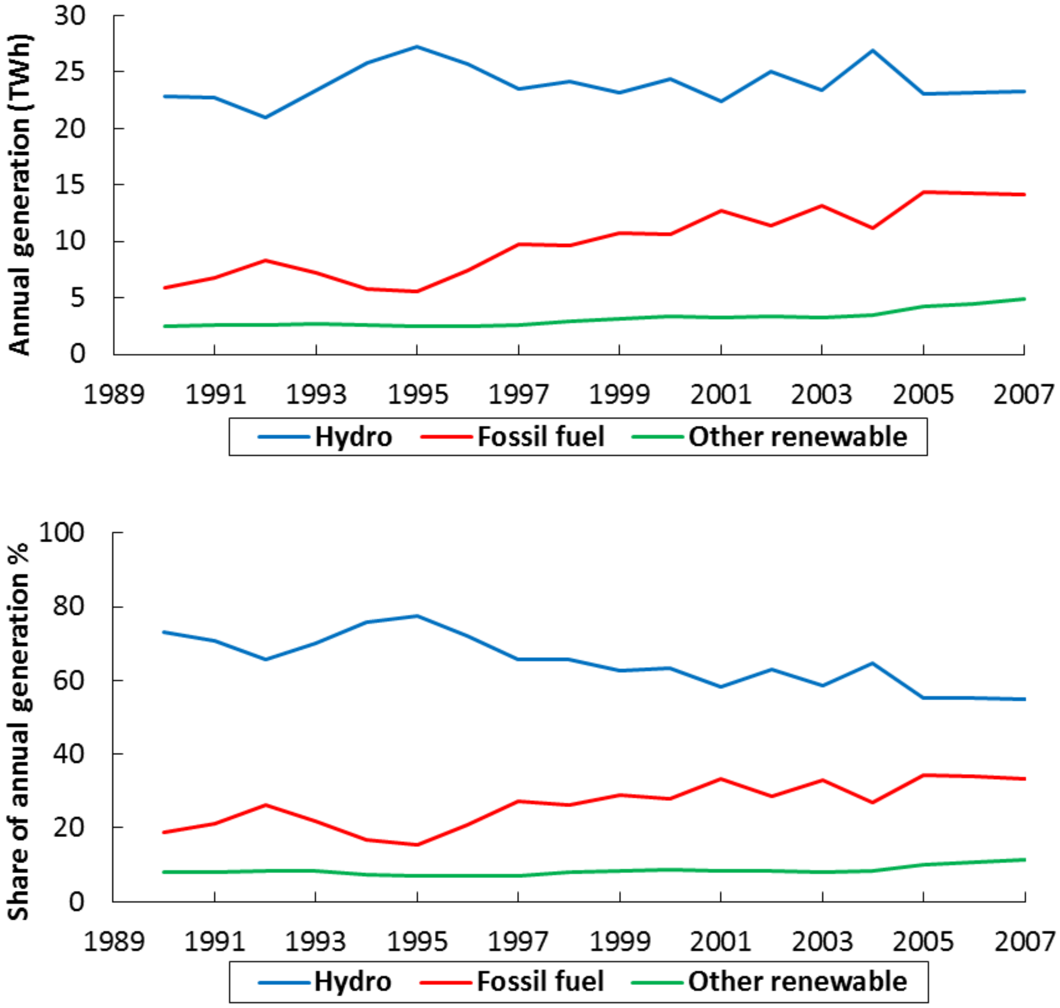

*Figure 1.1 Annual generation and percentage of share of annual generation by fuel type in New Zealand, 1990 – 2007 (adjusted) [1].*

This chapter first overviews current seasonal hydro power storage management in New Zealand, pointing out some of the issues arising with particular emphasis on South Island hydro storage management. A short section then follows on difficulties with meeting the national target of 90% renewable power generation with significant wind energy contribution. This chapter concludes with the thesis outline by chapters, with each chapter themed on some specific aspect of simulating a possible seasonal pumped storage scheme based in Onslow, Central Otago. Each chapter overviews different aspects of the how such a pumped storage scheme could provide multiple desirable outcomes leading to an economical and environmentally improved alternative scenario of seasonal hydro lake operation with wind power buffering toward the 90% renewable goal.

## 1.2 Current seasonal hydro power operations

The creation of the electricity market and the transfer of government-owned power stations to independent enterprises has resulted in a need for greater flexibility in hydro lake operational levels to meet peak power demands and the spot market. Manipulating water levels upward to maximise end-summer storage and then downward during peak winter electricity demand has altered the original natural seasonal regime of the main hydro storage lakes.

For example, Lake Pukaki water-level management has been enabled by raising the lake level by over 33 metres and then having a permitted seasonal operating range of 13.5 metres, much greater than the previous natural lake level fluctuations before control. Table 1-1 shows the operational water level range of the main New Zealand hydro storage lakes.

*Table 1-1 Operational water level range of selected New Zealand hydro lakes.*

| Lake | Permitted operational range (metres) |
|---|---|
| Tekapo | 9.1 |
| Pukaki | 13.5 |
| Hawea | 8.0 |
| Manapouri | 1.8 |
| Taupo | 2.6 |

There have been no recent major engineered increments in hydro storage capacity to match the increases in hydro generation capacity. Total hydro power storage capacity is presently only a little greater than 4,000 GWh, approximately two months of hydro power generation. The last significant storage increment was the raising of Lake Pukaki in 1977.

The current mode of operation for New Zealand’s South Island hydropower schemes is to hold back the high natural spring and summer inflows in lakes Pukaki, Tekapo, and Hawea. This stored water is later released through winter for power generation when national electricity demand is highest, which also corresponds to the time of year when inflows are lowest for these lakes.

This seasonal lake management is necessary to meet the winter power demands. However, there are some notable drawbacks of such power-dominated water use. In particular, the change to more reduced summer Waitaki River flows decreases the quantity of water that would be otherwise available for irrigation and recreational activities. The modification of the Waitaki seasonal flow regime is in fact one of the largest discharge changes imposed upon a New Zealand river, with lower Waitaki mean discharges for January reduced 400 $m^3s^{-1}$ from an original 600 $m^3s^{-1}$ (Figure 1.2).

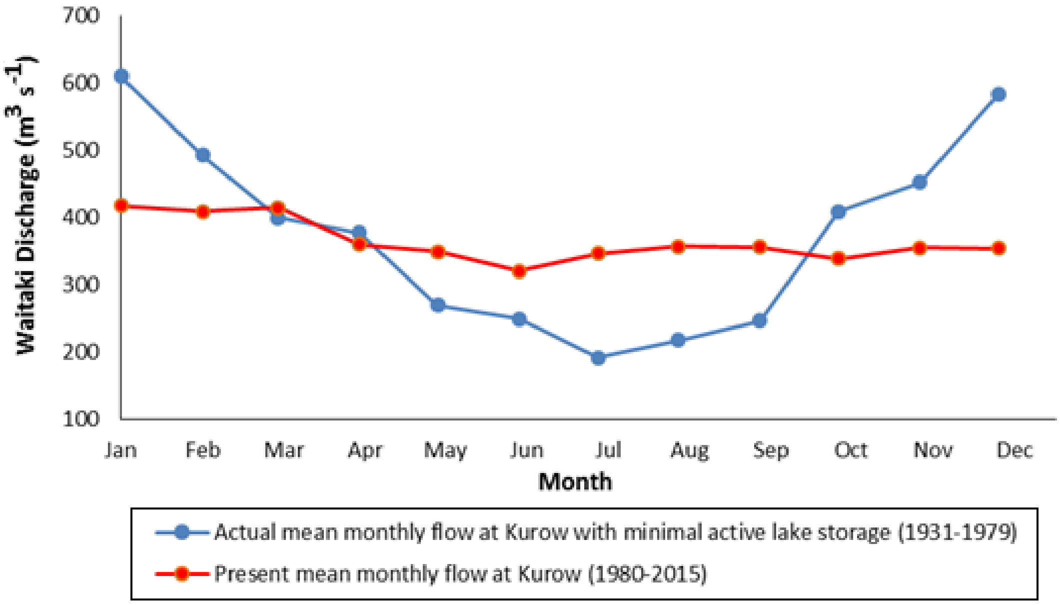

*Figure 1.2 Mean monthly Waitaki River discharge at Kurow with minimal active lake storage (1931-1979) compared to present mean monthly flow (1980-2015).*

The current importance of existing South Island hydro power lakes can sometimes result in water inefficiencies because deliberately high lake levels for summer storage create vulnerabilities for spill at downstream power stations in the event of major flood inflows into the lakes. Hydro dam spills are intermittent, but when spills do occur down a hydro station cascade there can be significant water wastage. With reference to a major spill from the Waitaki system during the summer of 2008-9, it was noted by a Meridian Energy spokesperson that *"it was proving difficult to keep up with inflows into the lakes. It was the first time in the 10 years of Meridian's existence that water had been spilled from the whole Waitaki system"[2].*

There is also an important environmental component because the increased seasonal fluctuation of lake water levels leads to shoreline erosion at some of our most scenic hydro storage lakes like Lakes Pukaki, Tekapo, and Hawea. These lakes have been formed in soft glacial tills that tend to undergo shoreline retreat as a consequence of the impact of the initial lake level raising and the subsequent sluicing effect of wind waves coupled with the enhanced seasonal water level cycle. Even Lake Taupo has some level of hydro impact with high or low lake levels providing recreational inconvenience at times, while possibly enhancing shoreline erosion.

An additional aspect is the issue of the viability of the present South Island hydro power operations with an uncertain climatic future. This is particularly relevant given government policy encouraging a dominance of renewable energy sources in the future while also placing a high value on security of power supply [3]. One aspect of the NZES report [4] concerning security is an expressed desire that when water is short, the New Zealand Government plans in the future to "maintain a secure electricity supply through an increased use of new renewable sources of electricity". That is, as opposed to fossil fuel-based generation as in the past [4]. However, this desirable outcome is presently unachievable because most alternative renewable energy resources are intermittent and cannot be dispatched to meet the demand of a power system.

The present seasonal operating mode is vulnerable even in the current hydro-climatic environment. Unlike some hydropower nations like Norway or Canada, there is no guarantee of year-to-year reliability of hydropower supply. This is because, unlike those countries, New Zealand has insufficient hydro lake storage capacity to last through the effect of occasional significant natural climatic variations leading to low lake inflows, as previously mentioned. For purposes of reference, "low" inflows or dry year have been defined as less than 85% of the long-term mean [5].

A number of low-inflow periods have occurred in New Zealand over the last decades, with low inflows to  hydro lakes in 1992, 2001, 2003, 2006, 2008, 2012, 2013, and 2017. Sometimes there have been resulting calls for power savings and restriction of power-intensive industry. For example, low storage levels and high prices caused temporary closure of a Tiwai Point aluminium potline in March 2006 (Figure 1.3). At this time, the hydro lakes were approaching the low levels of 1992 and the extremely cold June 2006 month might have precipitated a national electricity crisis had the southern hydro lakes not been fortuitously enhanced by high river inflows in April.

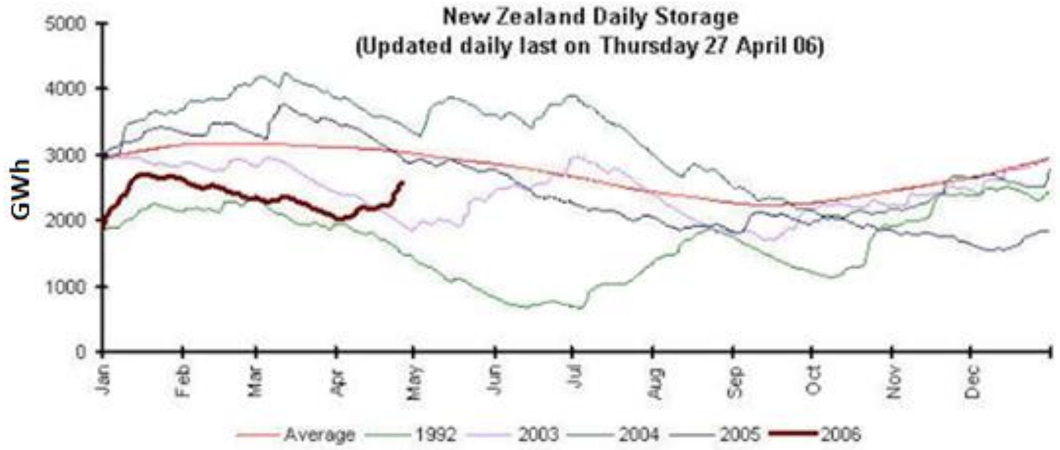

*Figure 1.3 Low storage in March 2006 caused temporary closure of a Tiwai Point aluminium potline.*

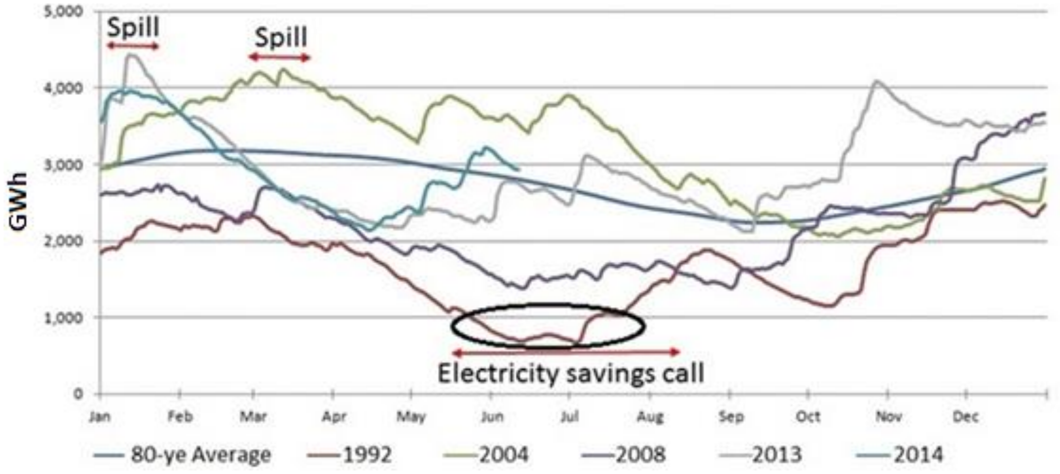

*Figure 1.4 National hydro storage levels showing the storage impact of the 1992 dry winter.*

Similarly, the 2008 dry winter (Figure 1.4) revealed the vulnerability of the South Island power supply to climatic variations. South Island power supply was then only maintained by significant north-south power transfers, which in fact was threatened for a time by an unstable pylon near Picton.

Low South Island inflows occurred also in the winter of 2017, when there were again significant north-south power transfers and high electricity market prices coupled with use of North Island thermal stations. Such power supply uncertainties going into the future could pose a risk to New Zealand's sustainable economic growth.

With limited storage capacity, even careful lake management will not be sufficient for maintaining long-term security of power supply. A factor here is the close proximity and resulting spatial correlation of inflows for the main South Island hydro lakes Tekapo, Pukaki, and Hawea. These three lakes represent about 62% of national storage capacity and their time-correlated inflows make them collectively vulnerable to local climatic variations that can then affect the nation as a whole through reduced hydro storage.

Storage variations in wet and dry years can in turn impact on wholesale electricity prices. In a market situation, prices increase in response to increase in demand and/or a shortage of supply. Consequently, there can be rapid price rises when hydro storage lakes are perceived to be trending down. This in turn results in additional carbon dioxide emissions from fossil fuel thermal power stations because the higher electricity prices makes generation economic.

Figure 1.5 shows how periods of down-trending storage levels can sometimes generate significant electricity price spikes. In addition to this purely economic aspect, it has also been suggested that some generators have used periods of low lake storage as a tool to artificially raise power prices [6].

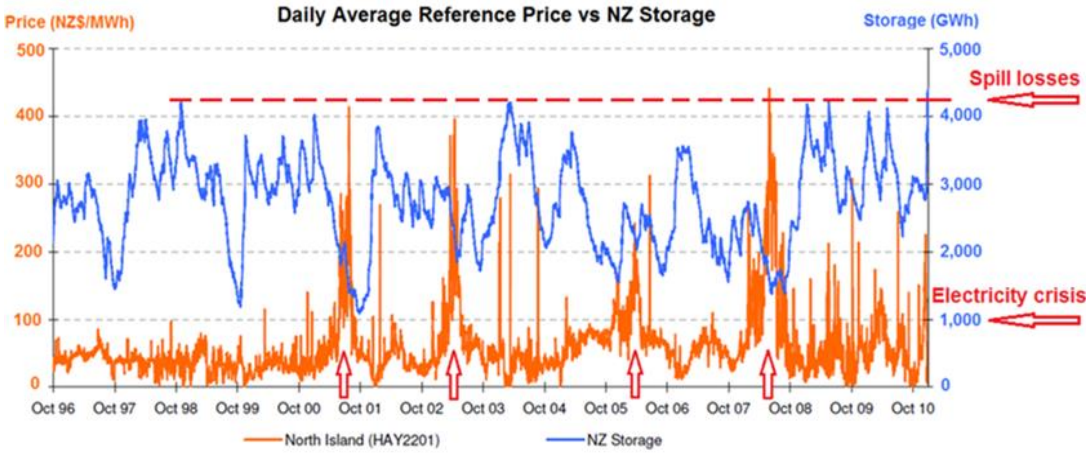

*Figure 1.5 Daily hydro-storage capacity and system prices, 1996-2010. Upward arrows indicate periods of high mean prices.*

Developing an ability to forecast South Island hydro lake seasonal inflows might be considered a means to aid seasonal lake level management. However, such forecasts such forecasts are liable to error and an incorrect forecast may prove damaging. This is illustrated in a NIWA forecast for the period of November 2010 - January 2011, stating that *"rainfall is likely to be near normal or below normal in the east of both islands and the southwest of the South Island"* [7]. At that time there was a downward trend in lake storages and Meridian Energy reduced the release of Waitaki Lakes water to maintain storage levels. As a result the electricity prices started to rise including 7 days in excess of NZ$ 150 / MWh. This was sufficiently high for initiation of thermal power generation, which included creating carbon dioxide emission from around 200 GWh of coal-fired power production.

Then, contrary to the climatic forecast, a period of heavy rain began in late December, resulting in a rapid increase in hydro storage and spill from the Waitaki hydro lakes due to insufficient available storage. The electricity prices decreased dramatically and the thermal power plants reduced to minor levels. Meridian Energy was unable to avoid spill from the Waitaki hydro system through January 2011. Likewise, lost generating opportunity from Clutha spill was 323 GWh in 2011, from Contact Energy power stations. The conclusion is that if the forecast had not been made, there might have been avoidance of high power prices, carbon dioxide emissions, and lost generating opportunity.

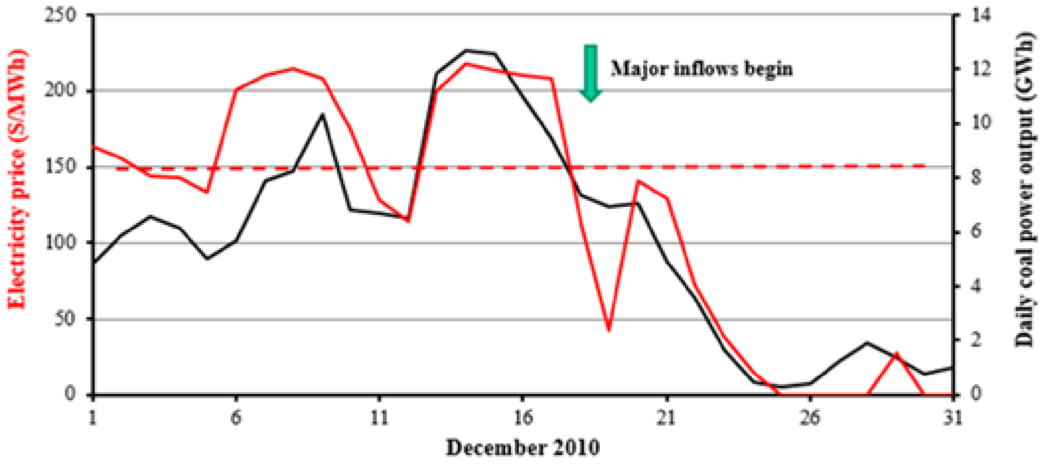

*Figure 1.6 December 2010: Market electricity price and coal-fired power output [8].*

## 1.3 Issues with the 90% renewable goal

The New Zealand government has set a target of 90% renewable power generation by 2025 [9], which will require considerable expansion of renewable electricity generation, with wind power playing a major role. However, the intermittent nature of wind means that there needs to be reserve generating capacity to meet the need to provide extra power to offset a sudden regional decrease in wind speed in the space of a few minutes. There is some suggestion that the New Zealand grid is already at capacity with respect to wind power.

## 1.4 A pumped storage alternative

A case is made in this thesis that the issues previously discussed could be largely offset by constructing a significant pumped storage scheme at Onslow, Central Otago. Each chapter will consider different facets of the topic, leading through to a conclusion that this large-scale pumped storage scheme could be both economic and of considerable net environmental benefit to New Zealand.

This thesis is organized into nine chapters and two appendices:

**Chapter Two:** *Pumped storage overview*. This chapter reviews pumped hydro energy storage generally and discusses the different types of pumped storage schemes, along with associated benefits and adverse effects. The chapter also describes cycle efficiency, energy and power in pumped storage systems and outlines the engineering issues for design and construction of a pumped storage system. A review of pumped storage worldwide is included, along with a case study of a seasonal pumped storage project in Switzerland. This chapter also presents previous economic studies relating to the Onslow scheme.

**Chapter Three:** *Onslow scheme proposed configuration*. This chapter delivers an overview, and discusses the design and role of the proposed Onslow pumped hydro energy storage scheme. A geological overview of the site and wider area is also presented, along with an evaluation of the hydraulic cycle efficiency of the proposed Onslow tunnel and an estimation of its optimum diameter. Specific roles for the Onslow pumped storage system are also considered.

**Chapter Four:** *Onslow simulation model*. An overview is provided of the current layout and operation of the Clutha, Waitaki, Manapouri and Waikato hydropower schemes and this chapter discusses how these were modelled in conjunction with the Onslow PHES to include and support wind energy developments. This chapter presents the results of modelled operation of the Onslow PHES, and gives examples of operation in wet and dry years.

***Chapter Five:*** *Wind power development in conjunction with Onslow pumped storage*. Background information is provided about New Zealand wind energy, and results are presented integrating the proposed Onslow PHES, both with and without wind energy development in the future.

***Chapter Six:*** *Waitaki Valley improvement from pumped storage: increased irrigation water*. This chapter provides background about irrigation in the Lower Waitaki region, consideringseasonal variations in flow before and after constructing the hydro dams, outlining the impacts of current operation. Possible Waitaki River water management in conjunction with the Onslow PHES is presented, together with modelling results.

**Chapter Seven:** *Onslow Scheme: environmental advantages and environmental impacts*. The local environmental impacts of the proposed Lake Onslow expansion are discussed. The wider environmental advantages of the simulated Onslow PHES are also discussed. In particular, reduced water level fluctuations in hydro lakes, reduced annual flow maxima in the Lower Waitaki, and the environmental value of emissions reductions. There is also a discussion of various hydrological changes arising from the new operation mode.

**Chapter Eight:** *Evaluation of the Onslow pumped hydro: kWh purchase and sales differential*. This chapter discusses aspects of the Onslow scheme operating in the current electricity market.

**Chapter Nine:** *Conclusions and recommendations*. This chapter outlines the key findings of the research and discusses their implications. Recommendations are made for future work related to the Onslow pumped hydro energy storage scheme that would prove useful if the proposed scheme was to be constructed.

**Appendix** One: *Operational possibility of Lakes Wakatipu and Wanaka with reduced water level variability*. Discusses the advantages of modifying natural lakes fluctuations to more mid-level frequencies.

**Appendix** Two: *Possibility of pumped storage between Lakes Hawea and Wanaka*. Overviews the special case of a possible small pumped storage scheme making use of the height differential Lakes Hawea and Wanaka.

# Chapter Two: Pumped storage overview

## 2.1 Introduction

There are many known ways to store energy for grid use, including compressed air, high-speed flywheels, pumped hydro, vehicle to grid, rail energy storage, solid electrochemical batteries, flow batteries, molten salt storage and thermal energy storage. Of all the energy storage technologies, only pumped hydro can be operated for large seasonal energy storage. With respect to efficiencies, pumped hydro, rail energy storage and compressed air can be operated for power output exceeding 100 MW with efficiency around 80%. Figure 2.1 shows a storage technology comparison [10]. Pumped hydro energy storage represents over 99% of energy storage capacity in the world in 2015 [11].

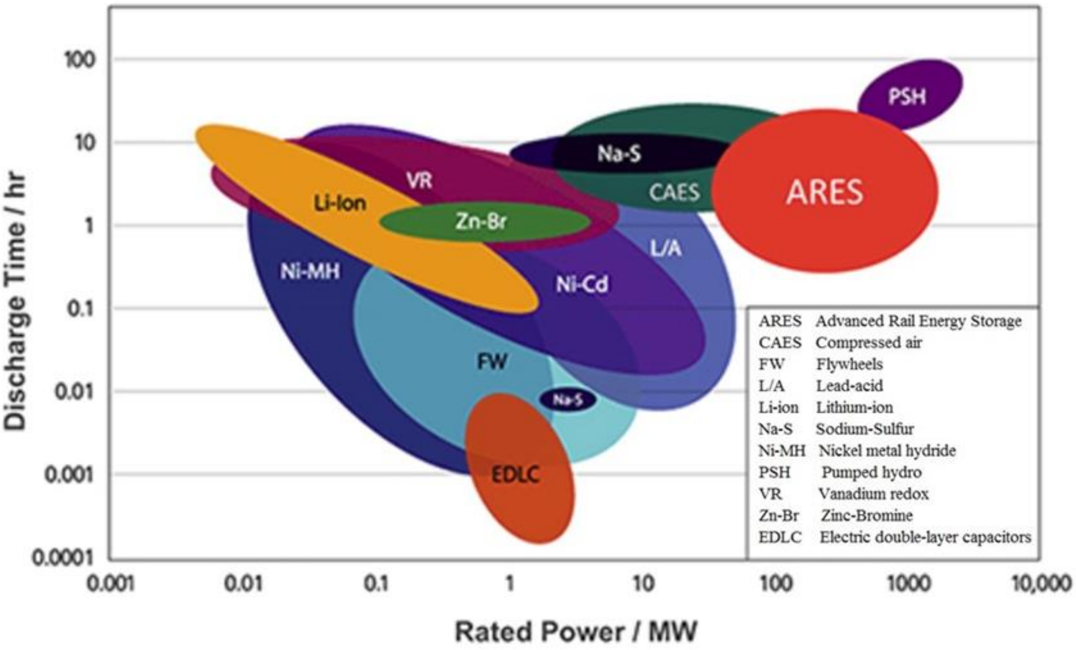

*Figure 2.1 Storage technology comparisons [10].*

Pumped hydroelectric energy storage (PHES) is a mature technology that has been deployed around the world for over a century. Examples of installed PHES systems as early as 1890 can be found in Italy and Switzerland. PHES does not generate net electricity in itself, being an energy storage mechanism. Rather, it uses electricity to pump water upwards to be stored in an upper reservoir, with the energy later released as required by running the water back through the pump under pressure. The pumps here operate in reverse as a generator. PHES systems are efficient, capable of reaching 80-85% round-trip efficiencies.

The fundamental principle of pumped hydro energy storage is to store electric energy in the form of hydraulic potential energy. Pumping typically takes place mainly during off-peak periods, when electricity demand is low and electricity prices are low. Generation takes place during peak periods, when electricity system demand is high. Pumping and generating usually follow a daily cycle, but weekly or, more rarely, seasonal cycling is also underaken with larger pumped-storage schemes [12].

Pumped storage hydro is cost-effective and efficient [13] and has a rapid-response reverse time of about 10 seconds [14]. PHES is the most economical of the storage methods for relatively large energy amounts. The schemes are typically characterised by long asset life (typically 50–100 years), but do have high capital cost. Operation and maintenance cost are typically low, around 1.5-2.5% of the capital costs per year [12, 15].

## 2.2 Overview of New Zealand electricity sector and market

Until 1987, New Zealand had a centrally run system of providers of generation, transmission, distribution, and retailing. The Fourth Labour Government corporatised the Electricity Division as a State Owned Enterprise in 1987, as the Electricity Corporation of New Zealand (ECNZ), which traded for a period as Electricorp. The Fourth National Government went further with the Energy Companies Act 1992, requiring EPBs and MEDs to become commercial companies in charge of distribution and retailing.

In 1994, ECNZ's transmission business was split off as Transpower. In 1996, ECNZ was split again, with a new separate generation business, Contact Energy, being formed. The Fourth National Government privatised Contact Energy in 1999. From 1 April 1999, the remainder of ECNZ was split again, with the major assets formed into three new state-owned enterprises (Mighty River Power (now Mercury), Genesis Energy, and Meridian Energy) and with the minor assets being sold off. At the same time, local power companies were required to separate distribution and retailing, with the retail component of the business sold off, mainly to generation companies.

The Electricity Authority (EA) was established in November 2010 as an independent Crown entity serving as the regulator of the electricity industry. The EA is tasked with governing the electricity market under the Electricity Industry Act 2010 (Act). The Act authorises the making of regulations and the Electricity Industry Participation Code 2010 (Code). The Code sets out the rules for the electricity sector. The Electricity Authority stated goal is to provide a competitive, reliable and efficient electricity industry for the long-term benefit of consumers and New Zealand.

New Zealand consumed about 38,800 GWh of electricity in 2017. A consumer's power bill is typically comprised of 32% generation, 27% distribution, 10.5% transmission, 13% retail, 13% GST, 3.5% metering, 0.5% market governance, 0.5% market services. Electricity is transported by overhead wires and underground cables to consumers within 39 networks. Most networks are owned by the 29 distribution companies. The largest distribution company, Vector, is listed on the stock exchange, but most are owned by trusts or local councils.

The power line that connects the North Island to the South Island HVDC carries electricity in both directions at 350 kV, but is mostly used to transport electricity from major hydroelectric generators in the South Island to the North Island. However, in periods of sustained low inflows into southern hydro catchments, this is often reversed, and power from North Island generators supplies consumers in the South Island. Transmission energy losses can be ~3% on average.

The Electricity Authority contracts out most of the services required to operate the retail and wholesale electricity markets. The spot and hedge markets are the major components of the wholesale electricity market. Prices on the spot market are calculated every half-hour and vary depending on supply and demand, and the location on the national grid. In addition to buying electricity directly from the spot market, retailers and large industrial users can also enter into financial contracts, often called hedges or hedge contracts, which smooth out some or all of the volatility in spot prices. For retailers and large industrial users, a hedge is a form of insurance against the financial harm of high electricity prices. Equally, some generators can sell their output via hedge contracts, insulating them against the risk of low spot prices.

Prices in the spot market rise and fall, as shown in Figure 2.2. The red line shows how prices in the hedge market are less volatile, but can change in response to views about what future spot prices are likely to be [16].

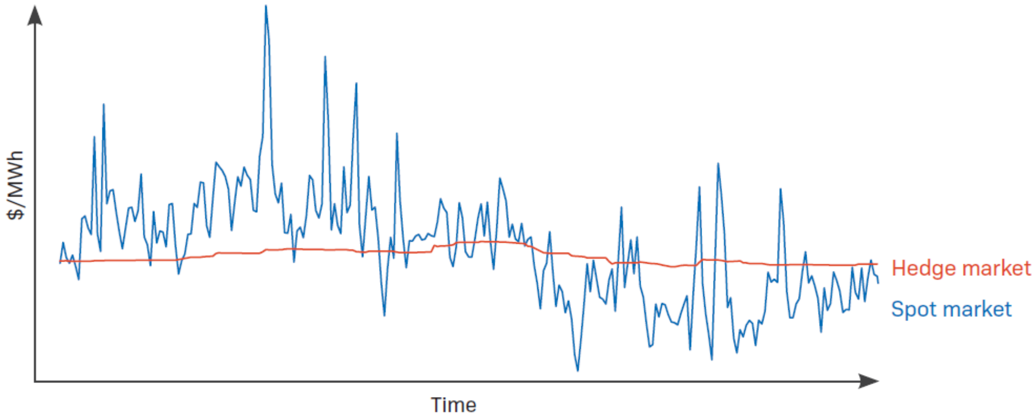

*Figure 2.2 The Hedge and spot market [16].*

## 2.3 Ancillary services

Managing an electricity system requires more than just scheduling generation. Additional support (ancillary) services ensure the New Zealand electricity system is stable and reliable. There are five types of ancillary services.

1. *Frequency keeping*: in New Zealand we operate a 50 Hz system. Managing the frequency is a technical way of measuring how well supply and demand is matched. Increasing and decreasing supply to keep frequency within a prescribed band keeps supply matched to changing demand.

2. *Instantaneous reserve*: to provide immediate backup electricity supply in the event of supply failure (eg, a generator fails or the HVDC stops working). This reserve is supplied by spare generation capacity and can also be supplied by interruptible load, which reduces demand if frequency falls unexpectedly.

3. *Over-frequency reserve*: to stop an unplanned rise in system frequency by reducing generation. This can be needed if a large load unexpectedly

disconnects from the system, especially the HVDC if it is transferring a lot of power.

4. *Voltage support*: to inject power into the system to boost voltage.
5. *Black start*: to restore operation in the event of a major power outage [16].

## 2.4 Definition and description of hydroelectric pumped storage

Pumped storage is a process for converting large quantities of electrical energy to potential energy by pumping water to an upper reservoir, where it can be stored indefinitely and then released to generate electrical power as required. An indefinite storage here carries the implication of no significant net water loss from the upper reservoir through evaporation or leakage. Storage is desirable, as the consumption of electricity is highly variable between day and night, between weekday and weekend, as well as among seasons [17].

As previously noted, water is pumped through a turbine from a lower reservoir (afterbay) to a higher reservoir (forebay) and the activity uses energy. When it is desirable to have that energy or water returned, the water is allowed to flow back through a turbine from the forebay to the afterbay and vice versa. Figure 2.3 and Figure 2.4 present simple line drawings of a PHES facility and different types of lining for the connecting tunnel.

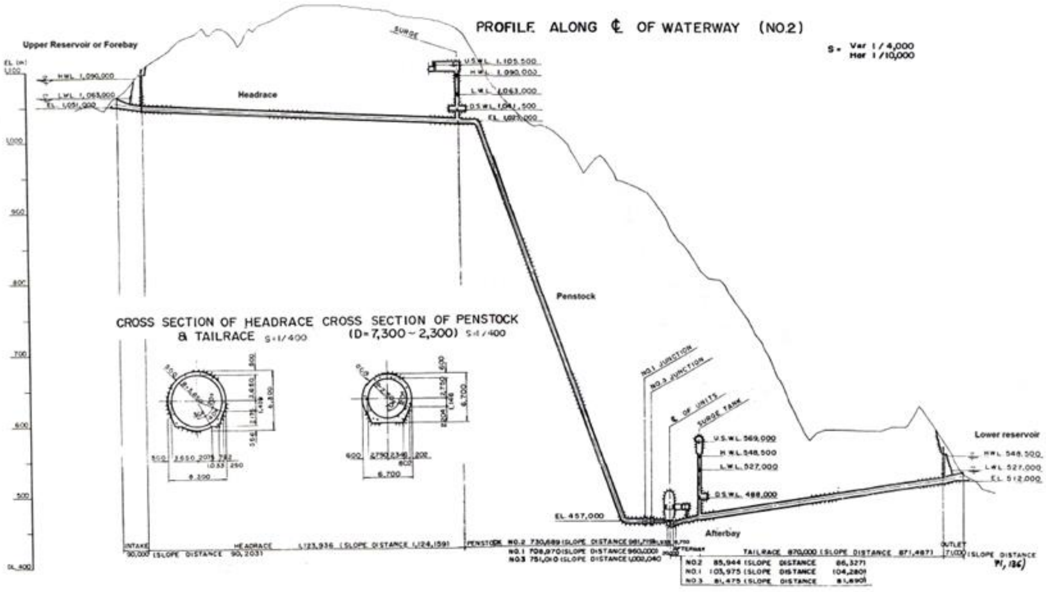

*Figure 2.3 Schematic drawing of PHES facility [18].*

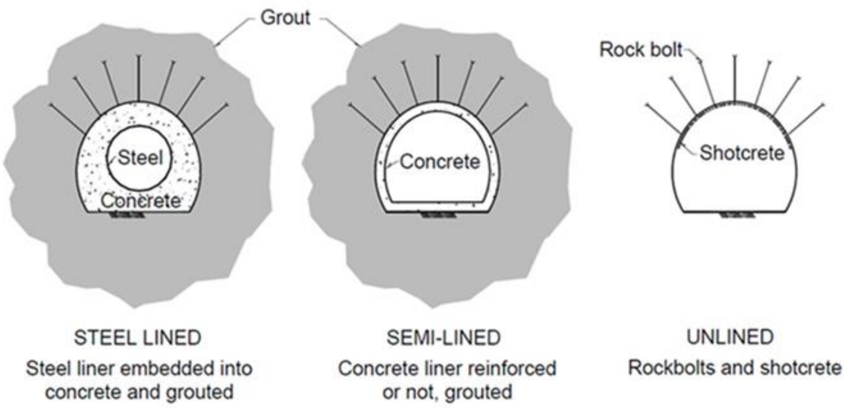

*Figure 2.4 Guidelines for preliminary design of unlined pressure tunnels [19].*

Pumped storage turbines can have either vertical or horizontal shaft arrangement. In the older plants, there were separate motor driven pumps and turbine driven generators. The improvement was the pump and turbine on the same shaft with the electrical elements. The latest design is to use a Francis turbine, which is just the reverse of centrifugal pump [20].

The capacity of power supply units has increased continuously to achieve optimum economics. For example, larger unit capacity machines are often designed in order to reduce the number of units at each plant. In addition, high-speed rating is an important factor for smaller volume machines. Figure 2.5 shows the history of motor-generators.

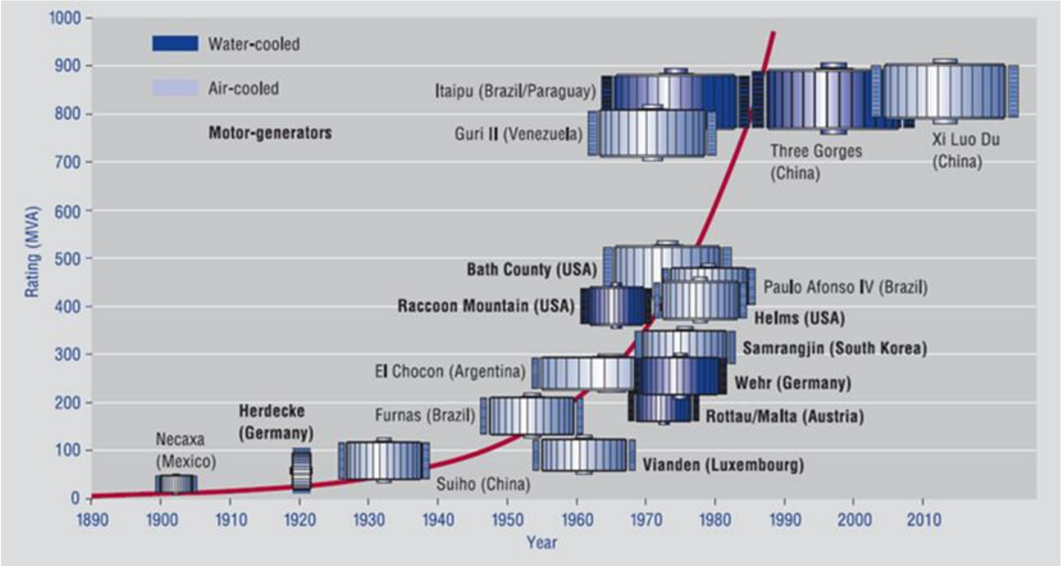

*Figure 2.5 History of generators and motor-generators [21].*

Pumped storage plants show the same useful characteristics as conventional hydroelectric plants. However, their design concepts and operation of the plant are very different. The position and arrangement of the facilities are flexible and site-dependent [22, 23].

In addition, a PHES can be part of a conventional storage hydroelectric project. This is the case of many new PHES developments in Europe, where a significant number of projects proposed are either extension to existing hydropower projects, or repowering of existing PHES systems. This is partly driven by a lack of economically attractive new sites there [12].

An important difference from a typical hydropower project is in the larger PHES power capacity ratings and pumping heads, and higher rotational speeds of turbines. These characteristics require that the hydraulic unit be set at some depth below the minimum tailwater level in order to avoid cavitation. To meet these requirements and based on geotechnical aspects, a massive concrete construction is needed to withstand the external water pressure and resist hydrostatic uplift. Therefore, an outdoor power transformation system became increasingly expensive [23].

In terms of environmental differences compared to a conventional hydropower project, there is a potential for increase in fish mortality, because of increased passage through the turbines. Where there was a prior existing major water body, it is desirable to keep fish away from intake structures. Although intake screens are drawing wider attention for use in preventing fish passage through turbines at conventional projects, fixed screens are difficult to use in pumped storage projects as they must also pass discharge water as well. Screens which could be raised during turbine/pump discharge might be more suitable than fixed ones, but they cause operating constraints if the mode of operation has to be changed suddenly [22]. In addition, there can be environmental impacts if new upper and/or lower reservoirs are created, inundating existing land.

## 2.5 Types of pumped storage systems

There are three principal categories of pumped storage projects:

1. *Pure projects* produce power only from water that has been previously pumped to an upper reservoir. Such schemes have minimal surface water inflow to the upper reservoir (< 5%) [24].

2. *Combined development*s utilize both pumped water and some natural stream-flow at elevation to produce power. A typical example is Cruachan in Britain. In some plants water is transferred to another hilltop upper reservoir to gain more energy storage. For example, the Reisach-Rabensleite project in Germany uses one upper basin and two power plants. In combined pumped storage schemes electricity can be generated without prior pumping [22].

   *Underground pure* or *combined pumped storage* are similar to conventional PHES except the lower reservoir is excavated underground [22]. An interesting project is the Summit PHES in the USA (1500 MW) which made us of an existing limestone mine at a depth of 670 m below ground level to provide (15 GWh) of energy storage [25].

### 2.5.1 Classification of pumped storage

There are two basic types of pumped storage schemes with reference to cycle frequency, the most common being short term pumped storage which is used to follow daily or weekly peak loads. The other, and less common type, is seasonal pumped storage, used for generation meet seasonal demand variations. Both types require specific design features in order to gain the most efficient use of the system.

- In a plant with a daily cycle, water is pumped up in the low demand period, generally from midnight to early morning, to generate power to meet the mid-morning and afternoon peak, an example is Cruachan in Great Britain.

- In plants utilising the weekly cycle, pumping is mainly during the weekend, taking advantage of the long off-peak period of 48 to 60 hours. In this case, the upper reservoir must have a larger storage capacity than plants working on daily cycle.

- In case of a plant using a seasonal cycle, the annual load curve is flattened by pumping water continuously for several days in extended low-demand times to be utilized for continuous power generation in the high demand seasons. Such a plant needs a suitable higher reservoir with large capacity to store water requirements for a few months. The available water in the lower lake must be sufficientfor this large quantity of water to be available available for pumping. An example of such a plant is Veytaux in Switzerland with storage capacity of 107.7 GWh and installed capacity 256 MW [11].

## 2.6 Technological advances in the PHES

Increased growth of pumped storage worldwide has stimulated major innovations in the development of high head, single, multi-stage, and pump turbine equipment along with site selection constraints. Some advanced equipment configuration and characteristics are outlined below.

### 2.6.1 Variable speed units

The use of variable speed units provides load ramping capability in the pumping mode and contributes to the versatility and effective use of pumped storage.

Introduction of variable speed units, starting from use in Japan in the early 1980's, contributes to higher pump-turbine efficiency and higher overall cycle efficiency. These units have added versatility to pumped storage projects and improved the performance of the projects in electric systems.

A variable speed unit has capability to vary the pump input power by adjusting speed within a specified range. Because of this characteristic, it is now possible to provide load regulation or automatic frequency control (AFC) during off-peak hours using a pumped storage project in the pumping mode [26].

Variable-speed units also allow operation at or near the optimum speed for a particular head and output, thus obtaining higher efficiency than possible with a single-speed unit. They are therefore becoming a state-of-the-art technology for optimised efficiency in turbine mode and for a wide range of power control in the pump mode.

Variable-speed units have many advantages including achieving higher generation efficiencies overhead ranges and allowing variable power consumption during pumping operation, suppression of power system fluctuations, smooth pump start up, and extension of the pump-turbine operating head range in the generating mode [26].

In New Zealand currency, variable speed pumping capability would add about 64 $NZ/kW to the cost of the power equipment [27]. Providing this capability for all the units of a station may therefore not be economically justifiable. In modern stations with variable speed units usually only two of four or two of six units incorporate variable speed.

### 2.6.2 Single-stage units

Single-stage units are used for heads up to 810 m, as in the Mount Hope project in New Jersey [26]. Two-set units (reversible turbine/pump and generator/motor) are usually 30% cheaper than three-set units (turbine, pump and generator/motor) and are now the usual solution rather than separate units. However, the drawback is that the pump starting regime is more complicated and the changeover time between generation and pumping is longer since the rotation of the turbine axis must be reversed [23].

*Table 2-1 Pumped-Storage Hydro Changeover Time, adapted from [23]*

| Mode Change | Changeover times in seconds | |
|---|---|---|
| | Three-set unit(s) | Two-set unit(s) |
| Standstill to full-load generation | 120 | 120 |
| Standstill to full-load pumping | 180 | 600 |
| Full-load generation to full-load pumping | 120 | 900 |
| Full-load pumping to full-load generation | 120 | 480 |

### 2.6.3 Multi-stage units

Multi-stage pump turbines were developed for situations of heads above the range of single-stage units. Such multi-stage systems units can extend the head values exceeding 1400 metres. However, they have lower efficiencies and longer changeover times than single-stage units [23]. A typical example is the Edolo Project in Italy, with a head of 1256 m. This project is equipped with eight reversible, five-stage, pump-turbine units [28]. Table 2-2 shows the pump turbine head limits for various types.

*Table 2-2 The pump turbine head limits for various types [29].*

| Type | Facility | Turbine Max Head (m) | Turbine Max Power (MW) | Pump Max Head (m) | Pump Max Power (MW) | Manufacturer |
|---|---|---|---|---|---|---|
| Single-stage reversible pump turbines | Ohira (Japan) | 512 | 256 | 545 | 269 | Hitachi, Toshiba |
| Multistage reversible pump turbines | Chiotas (Italy) | 1047 | 147 | 1069 | 160 | Hydroat, De paetto Escher Wyss |
| Tandem units with impulse turbine | Rottau (Austria) | 110 | 200 | 110 | 144 | Voith |
| Tandem units with Francis turbine | Hornburg (Germany) | 625 | 243 | 625 | 250 | Voith, Escher Wyss |

## 2.7 Cycle efficiency of a pumped storage plant

The process of pumping water up and releasing it back down to achieve the return of energy is not 100% efficient. Some of the electric energy used to pump the water up will not be recaptured as usable electric energy on water release. This efficiency loss is incurred as a result of rolling resistance and turbulence in the penstock and tail race, as well as efficiency losses in the motor generator and pump turbine. In addition, the water retains some kinetic energy as it flows into the tail race. Considering all of these losses, PHES have turnaround efficiencies ranging of 70 to 85%, dependent on design characteristics [29]. Table 2-3 shows PHES cycle efficiencies for plants constructed after the late 1970s.

The efficiency of a pumped storage project directly affects its operating costs, the higher the efficiency the lower the costs and it makes the pumped storage project more competitive with available thermal plants as one generates energy and one stores energy.

*Table 2-3 Pumped storage component operation efficiency.*

| Generating-Pumping Components | Low % | | High % | | By Jog P136 [30] |
|---|---|---|---|---|---|
| | Generating | Pumping | Generating | Pumping | |
| Water conductors | 97.4 | 97.6 | 98.5 | 98.5 | 97.0 |
| Pump turbine | 91.5 | 91.6 | 92.0 | 92.5 | 90.0 |
| Generator motor | 98.5 | 98.7 | 99.0 | 99.0 | 96.0 |
| Transformer | 99.5 | 99.5 | 99.7 | 99.8 | 98.0 |
| Subtotal | 87.3 | 87.8 | 89.4 | 90.0 | 82.1 |
| Operational | 98.0 | | 99.50 | | 99.0 |
| Total | 75.1% | | 80.1% | | 81.3% |

## 2.8 Energy and power in pumped storage

PHES facilities require two resources; elevation change and water and installed capacity. The potential energy in the upper reservoir at a given time can be determined from gravitational potential energy:

$PE=m.g.H$ …………….……. 2.1

Where; PE = potential energy; and H = hydraulic head height.

g= Gravitational acceleration.

The net potential energy excludes evaporation and seepage.

The power output is given by

$P=Q.H.\rho.g.\eta$ ……….…...….. 2.2

Where; P = generated output power. Q= flow discharge. H= operational efficiency. P=water density.

The head and the flow rate have an important relationship: if the head is larger, the water utilization can be minimized to reduce the total water volume required in the upper reservoir. As shown in Equation (2.2), to derive the power of a facility one must input the volumetric flow of water [31].

## 2.9 Pumped storage schemes worldwide

Pumped storage can provide a range of functions within an electricity grid. Interest in the technology is growing throughout the world but pumped storage is presently not utilised in New Zealand.

As of 2018, there are three big PHES in Australia with installed capacity of 2300 MW, two small with installed capacity of 330 MW and there are another two announced to construct with installed capacity of 550 MW [32].

Pumped storage is the most widely used electricity storage system in the world. Table 2-4 summarizes its significant development worldwide in recent years. At end-2015, global installed pumped storage generating capacity was about 145 GW, compared to 73 GW worldwide in 1990 [14]. A total of 33.7 GW of new installed hydropower capacity was commissioned in 2015, which included 2.5 GW of pumped storage [33].

*Table 2-4 PHES installed capacity development worldwide, in Gigawatt.*

| Country | Total Pumped Storage Capacity in Operation GW | Total Electric Installed Capacity GW | Pumped-storage as a Percentage of Total Capacity | Year of Data | Ref. |
|---|---|---|---|---|---|
| Japan | 24.6 | 239.9 | 10.2 | 2008 | [34] |
| USA | 21.9 | 994.8 | 2.2 | 2007 | [35] |
| Italy | 7.5 | 89.1 | 4.5 | 2008 | [12] |
| Germany | 6.5 | 125.0 | 3.9 | 2008 | [12] |
| Spain | 5.4 | 81.1 | 6.6 | 2006 | [12] |
| France | 4.3 | 115.5 | 3.7 | 2006 | [12] |
| Austria | 3.6 | 19.2 | 18.7 | 2006 | [12] |
| UK | 2.7 | 81.8 | 3.3 | 2006 | [12] |
| Australia | 2.3 | 49.0 | 4.7 | 2008 | [12] |
| Switzerland | 1.7 | 19.1 | 8.7 | 2006 | [12] |
| Norway | 1.5 | 31.0 | 4.8 | 2009 | [35] |
| Poland | 1.4 | 32.4 | 4.3 | 2006 | [12] |
| Belgium | 1.3 | 16.3 | 8.0 | 2006 | [12] |
| Czech | 1.15 | 17.5 | 6.6 | 2006 | [12] |
| Luxemburg | 1.1 | 1.6 | 67.2 | 2006 | [12] |
| Portugal | 1.0 | 14.5 | 7.3 | 2006 | [12] |

## 2.10 Potential benefits of pumped storage projects

Pumped storage is a technology that consumes more energy than it generates, so the question arises as to the point of building these types of power-consuming systems.

Firstly, pumped storage power plants have been incorporated into power systems for many years to optimize the operation of thermal based generation systems, recognizing the limited flexibility of nuclear and coal fired power stations on within-day time scales [36].

Because electricity cannot itself be stored in large quantities for later use, it must be produced on demand. Consequently, timing matters. Pumped storage facilities are valuable because they enable the producer to shift power production, to times when demand is high from times when demand is low.

For example, when there is a significant component of thermal generation and fluctuating through-day demand, utilities generally depend upon coal plants and nuclear plants to meet mean demand because coal and nuclear plants produce large amounts of power and work most efficiently when operated at a steady output for prolonged periods.

However, at night when demand is low these plants often produce surplus power which can then be used to "prime" the pumped storage facility. That is, surplus electricity powers the turbines acting as pumps, raising water from the lower reservoir to the upper. The water remains in the upper reservoir until it is needed later in the day when thermal plants cannot meet the total power demand. Water is then released from the upper reservoir and the turbines convert the potential energy back into electricity. For example, the 1,800 MW Tianhuangping pumped storage scheme in China helps to meet the daily cycle of power demand in the city of Shanghai. Figure 2.6 shows the operation of pumped storage during a typical week.

Depending on the situation, PHES may also be used to prevent flooding, to balance hydraulic loading, to maintain frequency and voltage, to avoid or reduce spill in hydro systems and to increase irrigation withdrawals [36, 37].

A particular application of PHES is to buffer fluctuating output of intermittent power sources. This application will gain importance in the future when combining with other renewable energy sources in order to guarantee the energy supply and the grid security [38]. For example, pumped storage can provide a practical solution to decrease variability from wind turbines by providing a means for storing excess energy and then quickly restoring that energy to the grid when the wind turbine output drops off or load demand is higher than the output can serve [39].

Pumped storage has evolved into a highly sophisticated electric system management resource with many functions that contribute to system reliability and quality of service provided. These functions include:

Peak-time energy: Provide the electric system with energy during peak hours, instead of using other generation sources such as gas turbines.

Load smoothing: Consume electricity during off-peak hours, dropping the difference between daily peak and daily off-peak capacity [26].

Ancillary services: Provide regulation and load following if outfitted with an automatic generation control system. It can also provide spinning and stand-by reserves, system frequency control, respond and correct for low frequency occurrences, and give quick response to rapid changes in load in case a large generator fails at short start-up time and low start-up costs [35]. For example, the pumped storage schemes at Dinorwig and Ffestiniog (UK) can offer 2 GW of power within 15 seconds [40].

Improvement of thermal system efficiency: Off-peak load of PHES generally results in less cycling of the thermal units and fewer stops and restarts of these units, thus improving their efficiency and reducing maintenance costs [26]. The PHES generally store water to supply peak load demands, so that fuel is saved at thermal plants [41].

Voltage regulation: Operate in condenser mode to generate or absorb reactive power for system voltage regulation.

Transmission system benefits: Provide reactive power and reserve capacity needed to permit more effective utilization of the transmission system.

Air quality Benefit: PHES projects have no emissions to the atmosphere and may contribute to air quality improvements, depending upon the source of power for the pumping energy. Generally, a pumped storage project provides for more efficient utilization of the thermal units and fewer stops and starts, thus contributing to overall reduced emissions [26]. Also, pumped storage facilities can enable countries to meet targets for reducing greenhouse gas emissions and build renewable energy capacity.

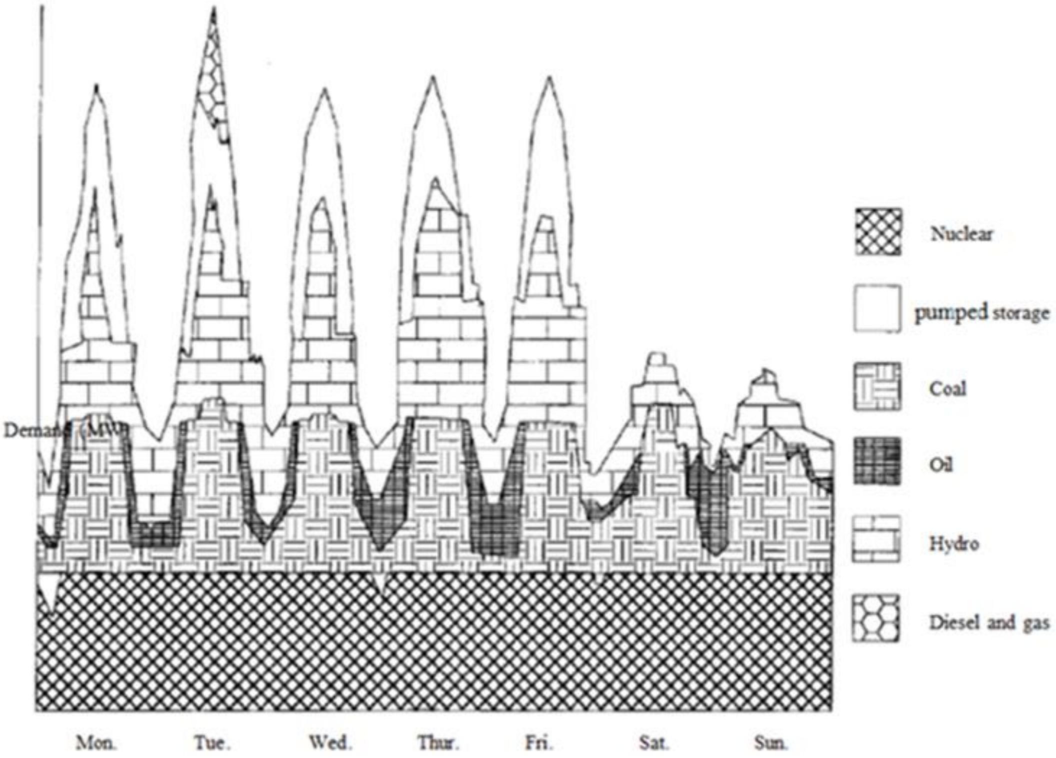

*Figure 2.6 Typical weekly load curve [20].*

## 2.11 Identification of possible PHES sites

Sites for PHES development are challenging to locate. The two basic requirements for a PHES facility are elevation change and being able to utilise or create upper and lower reservoirs. Head availability is traditionally provided by above-ground elevation change. In addition, the electricity grid near the site is essential for development [42].

More specifically, the main requirements for a good pumped storage site are:

- High head and shortest distance between upper and lower reservoirs, thereby reducing the volume of water to be pumped, reducing friction losses and thus keeping capital costs to a minimum.

- The larger the reservoirs, the smaller their water level fluctuation for a given power output.

- The site should be close to the electricity demand and to major electricity stations.

- Good rock conditions should be available for the underground power station, which is normally required. Good rock conditions are also desirable for tunnelling and shaft sinking.

## 2.12 Engineering issues for design and construction a pumped storage

In any given instance, the decision for an appropriate PHES system site is dictated by topographical, geographical, and environmental considerations, outlined below.

### 2.12.1 Topography

A significant PHES system requires considerable capital and nearly a decade to construct, so the appropriate placement of a site is crucial. In particular, developing or creating the reservoirs is possibly the most critical part of PHES site construction. In the United States, Germany, and the Ukraine, large rivers are often utilised as lower reservoirs, subject to constraints of water protection, irrigation, and wildlife impact [23]. Many PHES schemes incorporate existing lakes, often enlarged by dams, as upper and lower reservoirs. Most commonly, reservoirs are created by damming a river (Figure 2.7).

The difference in elevation of the paired reservoirs is also a critical factor, for it directly correlates to the energy output of the finished system. An agreed standard is that a 4:1 ratio should exist for the horizontal to vertical distance between the upper and lower reservoir. Of course, a lower ratio would be optimal.

There are several ways to acquire this elevation. In Ronkhausen Germany, a hilltop was levelled and then the extracted material used to form a dam to create an upper reservoir. Other feasible methods include using the ocean as a lower reservoir and elevated coast line as the base for an upper reservoir such as Yanbaru PHES in Japan. However, such sea-water system are disadvantaged due to cost of corrosion on mechanical parts as well as the risk of salt water leakage impacting the surrounding vegetation of the upper reservoir.

A new concept in development during the last ten years is underground PHES systems. With the lower reservoir surrounded by hard rock, the head height could be relatively unlimited and the system placed closer to areas with greater load demand. This concept is constrained by excavation and tunnelling costs, as well as the time and resources to discover suitable rock formations [23].

*Figure 2.7 Seneca Pumped hydro energy storage constructed in 1970, on Allegheny River, Pennsylvania USA, 435MW.*

### 2.12.2 Influence of geological structures in tunnel behavior

As the mechanisms of pressure tunnels are very complex and include several parameters and interactions, it is useful to start the analysis with the identification of the principal parameters based on a general classification which called the rock engineering system [43].

#### *2.12.2.1 Rock mass quality*

The rock mass quality is of vital importance to the design, construction and long term operation of all types of tunnels. It is generally responsible for structural stability problems encountered in tunnels. However, because of its intrinsic complexity, it requires considerable attention in order to characterize heterogeneity, anisotropy, non-linearity and identify associated uncertainties [44].

Rock mass includes discrete joint mechanisms and intact rock mechanisms into a global rock mass mechanism. Another characteristic such as chemical dissolution and mechanical properties are required for unlined tunnel design.

#### *2.12.2.2 Geological factors*

Rock mass mechanical properties are relevant in any civil engineering project and possible problems can be anticipated using empirical rock mass classifications, particularly the Q system [45] and the GSI [45]. Such classifications divide the rock mass into structural regions (rock mass partitioning or geomechanical zoning) that are assumed to have similar properties and behavior, with specific support and consolidation requirements. In order to achieve workable zoning, consistent mapping should be done along all proposed tunnel paths, describing all relevant features such as rock type, joint families, persistence, spacing, roughness and aperture, soluble seams or zones, etc. Support and consolidation requirements can then be examined.

A particularly important parameter associated with rock mass quality is the deformation characteristics of the rock. Rock mass deformability is difficult to model and expensive in-situ measurements are required to acquire knowledge of stiffness parameters, especially in the presence of pressurized water that will cause a coupling effect between the rock mass deformation and the rock mass porosity/permeability. Hoek, Brown and Diederichs present empirical rock mass deformation models [46, 47]. Brekke and Ripley reported that several tunnel failures have been associated with highly deformable geological structures [48].

Slope stability is also a major aspect of tunnel stability and requires a comprehensive structural analysis based on joint mapping and stereonets for basic pressure tunnel design. The preliminary identification of major structural features is also necessary for tunnel alignment and must be characterised and investigated separately because they could control the failure behavior of tunnel sections. These structures are commonly faults, shear zones, folds, geological contacts, dykes, beddings and joint sets.

## 2.13 Projects established in Schist rock

The presumed bearing capacity value of schist rock is 3000 kN/$m^2$ [49]. Some projects established in schist are summarized below to illustrate some of the structurally controlled factors in the design and construction of large underground excavations:

1. Morrow Point Dam, USA: The Morrow Point Power plant chamber is tunnelled into the canyon wall in the left abutment about 120 m below the ground surface. The installed capacity is 173 MW. The power penstocks consist of 4.2 m diameter steel lines in 5.5 m diameter tunnels.

- Rock types: Micaceous quartzite and mica schist intruded by granitic pegmatite veinlets.

- Geological structures: Bedding strikes nearly normal to the power plant alignment and dips westerly at 15°- 60°, averaging 35°. Three major joint sets comprise one dipping at 43° and the other two 80°- 82°. Two shear zones (faults) dipping at 23°: and 320° towards ESE and NE respectively pass through the power plant chamber. Both shear zones consist of fault gouge and fractured rock 0.3 to 1.5 m thick.

- Influence: 50 mm displacement in the downstream wall of the cavern was caused by the failure of a wedge formed by the two shear zones and joints. The volume of the wedge is approximately 19000 $m^3$ and the depth greater than 15 m. Longer rock supports were used to provide anchorages beyond the shear zones. A drainage tunnel with a line of vertical up-and-down drainage holes was driven behind the cavern wall to provide relief of joint-water pressure and access to anchorages of the post-tensioned tendons [50, 51].

2. Surge Chamber of the Waldeck II pumped Storage Plant, West Germany: The installed capacity is 440 MW.

    - Rock types: Alternating sequence of sand-banded dark schist-shale and fine to coarse greywacke.

    - Geological structures: A series of irregularly twisted fault zones ranging from 1.5 to 3 m thick, comprising rock, fragments and carbonate infilling, intersect the zone of arch action of the cavern roof. Three steeply dipping minor disturbances with rough and uneven surfaces infilled by carbonate run parallel or oblique' to the fault zones. The major one of the two joint sets runs parallel to the fault zones.

    - Influence: The New Austrian Tunneling Method [52] was adopted for the excavation. Prestressing anchors were used to prevent loosening of the rock structure and to back up friction in the pronounced slip planes. The support did not prevent rock mass movement, but it did positively maintain the structure of the rock mass and thus prevent any rock wedge from sliding into the opening [53].

3. Vianden Pumped Storage Scheme, Luxembourg: The installed capacity is 1296 MW.

    - Rock type: Devonian clay slate (schist).

    - Geological structures: A slight rolling folding structure with three discontinuity sets include bedding planes, schistosity and joints. Mylonite seams run parallel to discontinuities, generally 20-100 m spaced and ranging from a few millimetres to a few metres thick.

    - Influence: A three-dimensional rock mechanical model was developed, taking into consideration the orientations and spacing of the three discontinuity sets, to account for the anisotropic stress-strain behavior of rock mass. Based on this model rock mechanical analysis was carried out for planning and design of underground excavations [28].

Other projects have been established in schist. For example, the Grand Maison PHES Plant (1800 MW) constructed in the French Alps used tunnel-boring machines (TBM's) to bore a 7.7 km long tunnel, with 7.1 metre diameter. Rock types in the area consist of foliated schist and sandstone of medium to low strength and high permeability. The Tenzan pumped storage project in Japan and the Revin pumped storage plant in France have installed capacity of 1100 MW and 760 MW respectively. Their underground structures are located in very competent schist. The schist is relatively homogeneous and has good structural properties [47].

## 2.14 Economics

A successfully planned pumped storage project requires a sound economic analysis of a project that has been formulated and designed to provide its service reliably and at minimum cost [54]. Pumped storage gives no overall gain in electricity because the inevitable inefficiencies means electricity used in pumping exceeds the amount generated. However, the greater value of the peak-demand energy can make the trade-off worthwhile [55]. Furthermore, pumping the water up into storage when surplus energy is available and then expending it to generate power at other times gives economic benefit for PHES [56]. A PHES is built when it is believed to be the most economical means of providing a service to the electric system [45]. However, many electricity markets do not recognise true value of PHES because they do not recognise their contribution to reducing system costs.

Because the economic possibilities of any proposed pumped storage scheme are largely determined by the source of power for driving the pumps, seasonal schemes can be surprisingly attractive when low cost seasonal surplus power is available. Also, in a predominantly hydro system there will probably be some low head, ‘run of the river’ stations where water cannot at certain times be used or stored and can be truly regarded as surplus. Under such conditions of surplus hydro power, the incremental cost of supplying power for pumping will only be the relatively minor extra costs for operation and maintenance of the generating plant.

### 2.14.1 Energy prices - Capital cost for PHES and current trends

The costs of providing a reliable power supply are determined principally by the sum of the costs of constructing, maintaining and operating power plants to provide electrical service. Pumped storage plants usually have capital costs per kilowatt of capacity less than coal or nuclear units but greater than combustion turbines. Project costs for PHES are site specific with some mentioned costs varying between 1040–5200 $NZ/kW. The cost of establishing PHES in the US varies between 500 and 2,000 $NZ/kW. Capital costs depend on both the installed generating capacity and the energy storage capacity at any given site [57]. Table 2-5 shows the cost breakdown of the major components of four pumped illustrative pumped storage plants. The range of installed capacity cost is between 348 – 810 $NZ/kW. These power cost are cheaper than the cost of the projects listed in Table 2-5.

Table 2-6 gives capital costs of twenty PHES plants, together with cost per kW and GWh. The range of costs is wide, extending from $NZ 400 - 5976 per kW. This variation is due to many factors such as construction requirements, and topographical and geological conditions. The median and mean values are 1,536 and 1,710, respectively. The energy storage cost for the largest seasonal PHES plants vary between 0.22M and 9.96M $NZ/GWh. Most the PHES plants of the US, Japan, and China are used to cover the daily and weekly peak demand, with energy storage capacity less than 40 GWh. The capital cost of the Saurdal PHES station is equal to 1,733M $NZ. A study for evaluating the range of cost for 121 PHES plants in the world shows that the major cost was between 11.4 – 18.8 $NZ/MWh [58].

*Table 2-5 Breakdown costs of pumped storage plants [55].*

| PHES | Installed Capacity MW | Power cost $NZ/kW | Machinery % | Reservoir % | Waterways % | Powerhouse % | Road, land rights general overhead, Contingency etc. % |
|---|---|---|---|---|---|---|---|
| Revin | 760 | 348 | 40 | 27 | 15 | 8 | 10 |
| Muddy Run | 800 |  | 25 | 18 | 18 | 13 | 25 |
| Kneehills | 388 | 800 | 35 | 30 | 2 | 4 | 28 |
| Grande Cache | 436 | 810 | 28 | 19 | 25 | 4 | 23 |

*Table 2-6 Global PHES (Prices were adjusted to 2016 using the (LLC 2016) Calculator, then converted to $NZ.*

| Location | Plant Name | On-line Date | Tunnel length (m) | Hydraulic Head (m) | Power (MW) | Storage Capacity GWh | Plant Cost $NZ (M) | Power cost $NZ/KW | $NZ/GWh (M) | Ref. |
|---|---|---|---|---|---|---|---|---|---|---|
| NZ | Onslow |  | 23000 | 640 | 1300 | 12000 | 3000 | 2308 | 0.25 | [59] |
| Norway | Saurdal | 1985 | 10500 | 465 | 640 | 7760 | 1733 | 2707 | 0.22 | [60] |
| Switzerland | Nant-de- Drance | 2015 | 6000 | 390 | 620 | 1500 | 1281 | 2066 | 0.85 | [61] |
| Switzerland | Grande Dixence | 1998 | 20100 | 1883 | 2070 | 1400 | 2600 | 1256 | 1.86 | [62] |
| Austria | Kaunertal | 2014 |  |  | 1870 | 600 | 5976 | 3196 | 9.96 | [61] |
| Switzerland | Linth-Limmern | 2015 |  |  | 1000 | 460 | 2386 | 2386 | 5.19 | [26] |
| France | Grand Masion | 1984 | 9649 | 955 | 1800 | 244 | 2150 | 1194 | 8.80 | [63] |
| Ukraine | Dnister | 2010 | 2960 |  | 2268 | 240 | 971 | 428 | 4.04 | [63] |
| Switzerland | Grimsel 3 | 2014 |  | 560 | 660 | 210 | 985 | 1492 | 4.69 | [64] |
| U.S. | Helms | 1984 | 6036 | 520 | 1212 | 186 | 1104 | 911 | 6.00 | [63] |
| U.S. | Racoon Mt | 1979 |  |  | 1900 | 39.9 | 1094 | 576 | 27.4 | [63] |

| Location | Plant Name | On-line Date | Tunnel length (m) | Hydraulic Head (m) | Power (MW) | Storage Capacity GWh | Plant Cost $NZ (M) | Power cost $NZ/KW | $NZ/GWh (M) | Ref. |
|---|---|---|---|---|---|---|---|---|---|---|
| Japan | Kannagawa | 2005 | 6000 | 653 | 2820 | 33 | 6175 | 2190 | 187 | [63] |
| France | Montezic | 1982 | 1500 | 400 | 910 | 30 | 2170 | 2412 | 72 | [63] |
| U.S. | Bath County | 1985 | 2779 | 380 | 2700 | 30 | 4226 | 1565 | 142 | [42] |
| U.S. | Bad Creek | 1991 | 2901 | 370 | 1065 | 26 | 1320 | 1240 | 52 | [63] |
| U.S. | Ludington | 1973 | 408 | 110 | 1980 | 17 | 2030 | 1025 | 118 | [63] |
| U.S. | Blenheim | 1973 | 1187 |  | 1200 | 14 | 1316 | 1097 | 91 | [63] |
| Japan | Kazunogowa | 2001 |  | 714 | 1600 | 13 | 4983 | 3114 | 380 | [63] |
| China | Tianhuangping | 2001 |  | 590 | 1800 | 13 | 1683 | 935 | 129 | [63] |
| U.S. | Northfield Mt | 1973 | 1926 | 240 | 1080 | 11 | 4252 | 3937 | 394 | [63] |
| Taiwan | Mingtan | 1994 | 5000 | 380 | 1620 | 11 | 2489 | 1536 | 232 | [63] |

## 2.15 Challenges of pumped storage hydroelectricity

Although PHES will reduce surplus power and has many advantages in an electricity grid, creating new pumped storage facilities may pose challenges. By its nature of storing and passing a large volume of water, this volume requires an extensive upper reservoir, requiring purchase of the property or other compensation to the owner. Also, there may be mitigation for any environmental damages, such as reduced habitat quantity or quality, that may occur as a result of the any new reservoir [65]. As with any hydro system, A PHES system is also vulnerable to seasonal and long term climate changes such as years of low water flows [66].

### 2.15.1 Water inflow and outflow constraints

A PHES reservoir must maintain a minimum volume of water in the lower and upper reservoir to maintain pumping and generation operations and for environmental considerations [66].

On projects where water supply is critical, losses through evaporation and seepage can affect the available reservoir energy storage volume or PHES system efficiency. Evaporation losses depend on climatic conditions and vary with seasonal changes. On the other hand, seepage losses depend on the hydrogeological conditions of the reservoir site geologic formations and on the foundation treatment at the reservoir structures [67].

There is also a decline in reservoir water level from losses to groundwater through seepage. Asphalt or concrete seals have been developed to line reservoir floors to ensure that the system is sufficiently watertight, preventing water loss to groundwater. However, like any foundation, cracks and fissures occur and can be difficult to repair [23]. Since a PHES system uses water to store energy, it is important for operators to monitor, forecast, and model any losses.

As a part of water management at Dinorwig 1728 MW pumped storage power station, a mathematical model was constructed to increase understanding of the link between upstream catchment conditions, operational conditions/rules, excess water, and downstream catchment conditions, on a day-to-day basis. The model linked hydrology, hydraulics and power station operation, providing an increased understanding of water management at Dinorwig PHES station and assessing the commercial and environmental implications of different water management strategies [22, 54].

### 2.15.2 Environmental challenges

Any hydro-based development project will involve environmental considerations and preserving healthy aquatic environments is important [42]. The issues of major concern to PHES development in fact are the environmental and institutional/regulatory constraints [24].

When constructing a PHES, water protection interests and wildlife advocates are heavily involved in the development, and in some cases, the stalling of development, licensing, and relicensing of projects. Although these are real concerns and challenges, the focus here is in the challenges facing a PHES facility once in operation [23].

Whether or not to use existing reservoirs has been a common question asked during pumped storage project planning. Advantages and disadvantages of using existing reservoirs created for other purposes, such as water supply, conventional hydro or recreation, include:

Advantages

- Savings in construction cost.
- Minimum disruption of streamflow.
- Utilization of existing transmission routes.
- Minimum changes in land use.
- Reduction of adverse aesthetic impacts.
- Minimum effects on terrestrial habitats.

Disadvantages

- Adverse effects on boating and swimming.

- Potential bank erosion.
- Adverse aesthetic effects of water level fluctuations.
- Reduction of benthic organisms.
- Effects on temperature stratification.
- Adverse impacts on existing sport fishing.
- Impacts on fish habitats.

A summary of environmental issues resulting from pumped storage development indicates three main categories of impacts that must be analysed for both the construction and operation periods of a project. First are ecological impacts, including those described above for use of existing reservoirs. Other possible effects on aquatic and terrestrial species may result from spoil disposal from underground excavations, cutting of access roads, and dam construction. Since above-ground pumped storage plants have by nature been located in more remote, environmentally sensitive areas, the impacts may be particularly important.

Second, land use impacts such as flooding of agricultural land, reduction of forest productivity, and both positive and negative effects on recreation must be assessed. Third, cultural impacts such as those on historical and archaeological sites may be critical. The short- and long-term consequences of a project on the local economy must be considered.

In all assessments of the environmental effects of pumped storage, it is important to analyze the projected results of a project in comparison to other alternative actions that produce the same objectives [68].

The large-scale use of water resources is another characteristic common to pumped storage system. Thus, water quality and aquatic ecology impacts are potentially significant.

Pumped storage systems may produce significant beneficial or desirable environmental effects when compared to the alternatives. These could include:

- Supplying energy without air pollution, especially if pumping energy is supplied by a non-emitting base power source such as a nuclear plant.

- Reducing the rate of consumption of natural gas and oil resources, especially if pumping energy is supplied by a base power source such as a coal-fired plant.

- Providing a means to control both floods and droughts.

- Increasing fishery resources.

- Providing additional recreation and park facilities [24].

The potential environmental impacts of pumped storage systems can be summarized as following: flooding of large areas, alteration of the hydrology, changes to aquatic biology and fish, danger from possible failure of dams, and overhead high voltage transmission lines. However, the approval of such projects clearly indicates their benefits over the environmental impacts.

### 2.16 Modelling electricity prices in conjunction with PHES in Switzerland

Recently, the Swiss electricity supplier was maximising its profits generated by the PHES use of its eleven hydro-electric power plants with the software from the Aachen-based consulting firm, taking into account the electricity market rates and the inflows. Currently, new optimization solution software (BoFiT) has been integrated into the energy business processes (Figure 2.8).

The BoFiT introduction was preceded by a feasibility study on the hydrological optimisation of the pumped-hydro storage system of the Oberhasli power station. The software shows the ability to perform day-ahead planning as well as medium-term optimisation plans quickly and reliably based on solid data - for one year and for three years (at hourly rasters each). In addition, there were system services integrated into the optimisation, to allow the provision of primary, secondary as well as positive and negative tertiary control performances and their distribution to the different systems [69]. BoFiT Optimization is an instrument which maps a generation or trading portfolio into a mathematical model. Based on this model optimization tasks can be formulated and calculated for the various business processes. On the one hand, it allows investment planning, on the other hand, trading flexibilities can be optimized at short notice vis-à-vis current markets. Market channel optimization is possible, as is the evaluation of contracts or recalculation of portfolio performance. The model is created graphically, and no specialized mathematical knowledge is required. A basic model can be used for all business processes by creating variants [70].

Table 2-7 shows the typical power on Switzerland's grid with regard to daily and seasonal modulation, which shows the need for pumped storage hydro-plants to shift the energy of summer production to the winter months [62]. The size of PHES increased from 2.5% in 1995 to 9.7% in 2009, in the same way, the trend of establishing new PHES plants increased to triple in 2018, two of new projects have long tunnel (Figure 2.9). One of the seasonal operation PHES is Grimsel hydropower scheme with installed capacity of 600 MW and storage capacity 190 million m$^3$ [32].

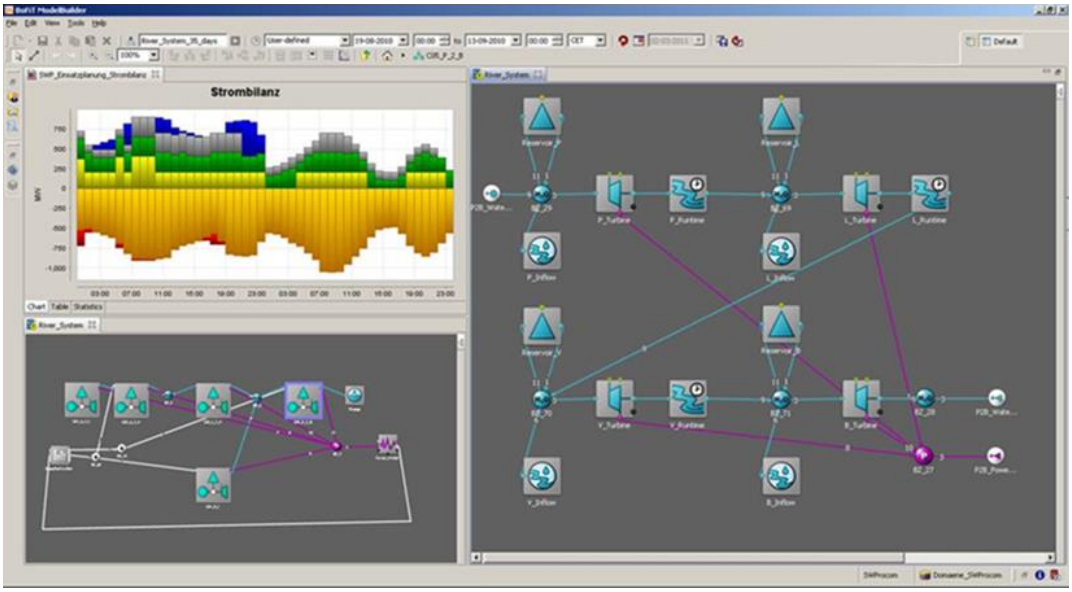

*Figure 2.8 Example of a graphic optimization model of hydrological system including PHES plant [69].*

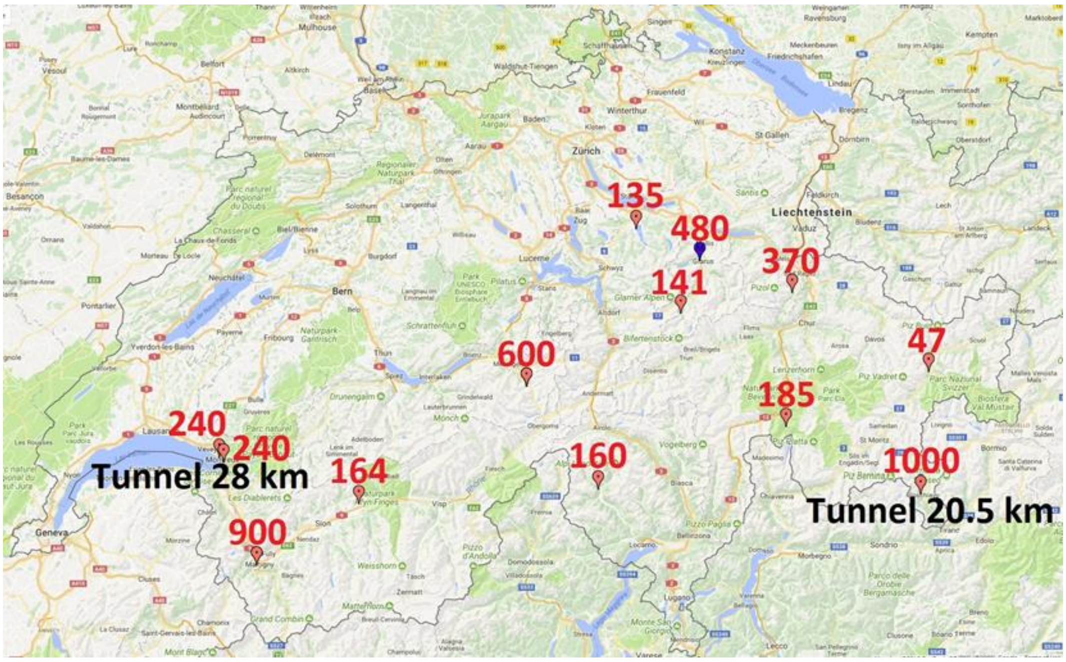

*Figure 2.9 Pump storage power-plants in MW in Switzerland. Existing total PHES in red color 4,662MW and under construction 765MW. (Data Collected from energystorageexchange.org, 2018)[32].*

*Table 2-7 Daily and seasonal changes in electric power demand and production on the Swiss grid [62].*

| GW, 1995 | Peak hours (6AM - 10PM) | | Low hours (10PM - 6AM) | |
|---|---|---|---|---|
| | Demand | Production | Demand | Production |
| Winter Oct-Apr | 7.5 | 9.5 | 6 | 4.5 |
| Summer May-Sep | 7 | 10.5 | 4.5 | 6 |

# Chapter Three: Onslow scheme proposed configuration

## 3.1 Introduction

As noted at the start of the thesis, the Onslow depression in Central Otago has possibilities for development as the upper reservoir of a large seasonal pumped storage scheme, with Lake Roxburgh as the lower reservoir.

This chapter presents a general overview of the study area, including site description, hydrology and geology, along with an evaluation of the hydraulic cycle efficiency of the proposed Onslow tunnel. Specific functions for the scheme are also discussed.

## 3.2 Previous studies about Onslow scheme

A possible large 1,300 MW seasonal pumped storage scheme between an expanded Lake Onslow-Manorburn linked to Lake Roxburgh was suggested by Bardsley and Bear. The scheme was found in that study to be viable in the sense of balancing local water and energy. However, a more complete analysis is required to determine whether the alternative scheme described in this thesis is feasible within the national economy [71, 72].

An economic study of the Onslow PHES, funded by the EC and performed by Parsons Brinkerhoff Associates Limited [73] stated that the Bardsley-Bear version of the scheme did not appear to be economically viable, costing approximately $NZ 2.75 billion at 75 percent efficiency and $NZ 50M per year for operation and maintenance. Another external study also suggested the economic infeasibility of the Bardsley-Bear Onslow PHES [74].

However, Contact Energy have noted that the figure cited by [73] for operation and maintenance expenses could be an extreme exaggeration as it is more than 5 times the OpEx cost for the entire Clutha Scheme. The Clutha Scheme has 3 dams, 2 power stations with a combined installed capacity of almost 2/3 of the Onslow project, and over 6 km of tunnels (M. Talor, pers. comm). A more likely OpEx figure would be $NZ 12M as a stand-alone plant, or $NZ 5M if operated as an additional part of the Clutha scheme. There are at least six plants operating globally that are more expensive per unit of installed power capacity than the specific proposed reduced Onslow scheme in the present thesis, and they still generate a profit (Figure 3.1).

The simulation models in the present study consider expanding only Lake, with an operating range extending to 780 masl to reduce the cost of dam construction. The current study will show that the preliminary cost estimate $NZ 2.77 billion could be reduced by almost $NZ 0.7 billion by expanding only Lake Onslow to the maximum height of 780 masl.

Also, the many multiple potential benefits of the Onslow scheme were not included in the EC report [73], such as Waitaki agricultural income, enabling wind power development, putting a price on present scenic lake shoreline destruction, reduced lake township flooding and reduced river flood peaks.

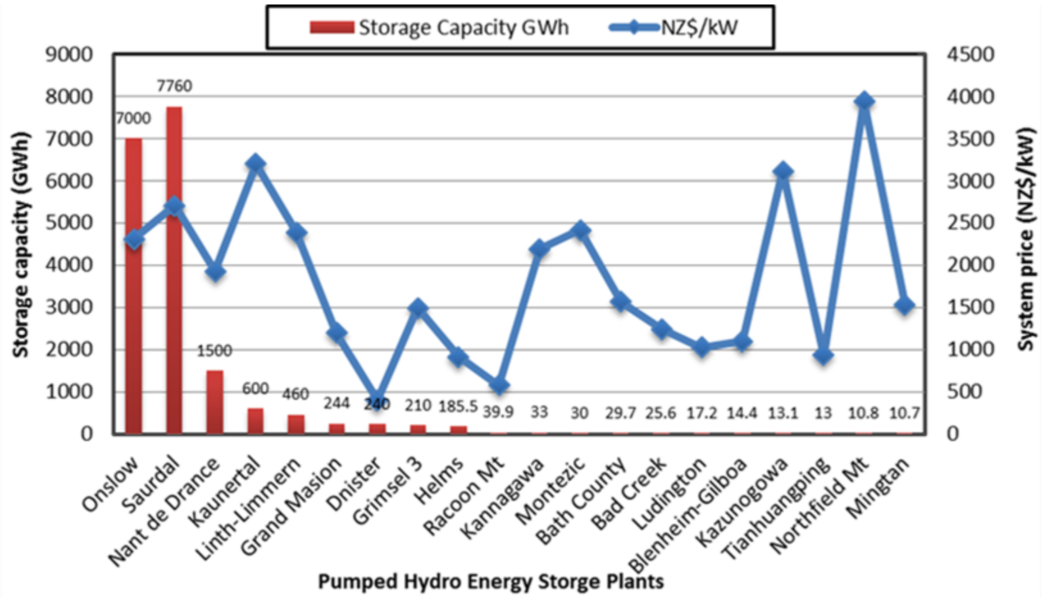

*Figure 3.1 Comparison of the project cost of pumped storage plants per installed capacity of 20 of the largest energy storage capacities in the world [75-77].*

The proposed Onslow tunnel is approximately 24 km, but is not be the longest hydro tunnel considered in New Zealand. The previously-proposed North Bank Tunnel Project (NBTP) by Meridian Energy would have taken water directly from an intake portal in the existing Lake Waitaki through an approximately 34 km tunnel in jointed greywacke before discharging back to the lower Waitaki River.

With reference to the Bardsley-Bear proposal, although New Zealand would gain advantages from the mitigation of dry-year price spikes, the commercial structure of the market at that time would probably not have been capable of supporting the scheme [78]. Pan Pac Limited suggested building the Lake Onslow PHES funded by an electricity flat levy [79].

Another study [80] discussed Manorburn-Onslow as a single proposal for PHES in New Zealand in terms of pumped hydro and utility-scale energy storage batteries for electricity storage and reserve generation in New Zealand. It showed that the Manorburn-Onslow pumped hydro is seen by most as prohibitively costly, based on the Parsons Brinkerhoff Associates Limited assessment (~NZ$ 3 billion), but is almost universally viewed as technically capable of providing renewables support and peak power adequacy [80].

Another two studies showed it is essential to construct a large seasonal pumped hydro energy scheme in New Zealand such as Onslow PHES in order to meet the targets for increasing renewable energy. The first study [81] addressed the issues of security of supply, energy spillage control and peaking option in a fully renewable electricity system for New Zealand, showing that peaking requirements were satisfied using 1550 MW of pumped hydro energy storage generation. The second study [82] focused on making the electricity system 100% renewable and switching 50% of the light vehicle fuel consumption to renewable energy by 2040. This study indicated that a 100% renewable electricity system in New Zealand is technically possible. The electric vehicle scenario would require a pumped hydro power plant to store some electricity to enable charging of electric vehicles.

The national advantage of the Onslow PHES is not merely spill reduction from NZ hydro power schemes: the real gains would be through (i) security of electricity supply; (ii) support to back up wind energy; (iii) environmental improvement of existing hydro lakes; (iv) reducing CO2 emissions by increasing renewable energy in support of the Onslow scheme; and (v) provision of Waitaki irrigation water, on which a levy can be collected.

Another suggestion could support the construction of the Onslow scheme by issuing a legislative recognition of the environmental value of our existing hydro lakes. That is, legislation would be passed so that after a given number of years in the future there would be a reduced limit on normal seasonal operating ranges for lakes Tekapo, Pukaki, Hawea, and Manapouri. This limit should move each lake closer to its previous natural lake level variation, rather than being a fixed number applied to all lakes.

The charging of the proposed scheme could occur during periods of high rates of renewable flows such as hydro and wind, and/or during off-peak times when the spot price is low although no guarantee of this with the present market. The energy could be subsequently discharged during periods of low renewable-based capacity, and/or when the price of electricity is high. Thus, the value of the electricity being used to charge the storage system must be small relative to the value of this energy when discharged and the difference must be greater than the added cost of storage.

### 3.3 Site description

Lake Onslow is a constructed reservoir lake, situated at the northwest end of the Lammerlaw Range, 22 km east of Lake Roxburgh and south of Alexandra in the Central Otago Region of Otago (Figure 3.2). The lake is set in open Otago tussock 695 masl

Lake Onslow was created in 1890 by the damming of the Teviot River and Dismal Swamp in an undeveloped high country catchment [83]. In 1982, an extended scheme was commissioned. This consisted of a new concrete dam, 14.6 metres high (Figure 3.3) which increased the lake area from 3.7 km$^2$ to 8.34 km$^2$ to store 46 million m$^3$. The total generating capacity of the current Onslow – Teviot River scheme is 12 MW [84, 85]. The lake is relatively shallow, with a maximum depth of 10 m.

The catchment has an area of 175 km$^2$ [85] of which 126 km$^2$ is used predominantly for grazing. However, in the last few years there has been some land use change in the lake’s immediate catchment from tussock to pasture [83]. Lake Onslow supports regionally important sports fisheries as it carries a large population of brown trout [86].

*Figure 3.2 View into existing Lake Onslow from an elevation of 780 masl.*

*Figure 3.3 Onslow Dam, photo taken in 2012.*

### 3.3.1 Water quality

As a water body's trophic state is largely determined by nutrient inputs from the surrounding catchment [87], there is the possibility that the trophic state of Lake Onslow may change with agricultural intensification. The lake can currently be classified as being in a eutrophic state.

The Trophic Level Index (TLI), which measures four parameters – water clarity, chlorophyll content, total phosphorus and total nitrogen – is used to give an overall picture of the health of New Zealand lakes. Each lake is assigned a number between 1 and 7; the lower the number, the better the water quality in the lake [83].

The TLI for Lake Onslow averaged level 3 (mesotrophic) for samples collected from 2008 to 2016. Mesotrophic means the lake has moderate levels of nutrients and algae. The TLI for Lake Dunstan was good, at level 2 (oligotrophic) for samples collected from 2004 to 2016 [83]. Therefore the proposed expanded Lake Onslow will have good water quality, reflecting Clutha water.

### 3.3.2 Hydrology

The mean annual flow of the Teviot River at Bridge Hut Road is 4.2 $m^3s^{-1}$ and the runoff is 540 mm/year based on normalised long-term mean flows 1930-1998. The annual runoff, plus an allowance of 700 mm/year for evaporation, indicates what the mean annual rainfall, averaged over each catchment area section in the Clutha catchment area, should be [88]. For example, based on the summation of the runoff and the evaporation the mean annual rainfall in the Onslow catchment should be about 1240 mm/year.

Losses through evaporation can affect the available reservoir energy storage volume or PHES system efficiency. Evaporation and evapotranspiration losses depend on climatic conditions and vary with seasonal changes.

There are no direct measurements available of evaporation or of input parameters such as saturated vapour pressure in the air and at the water surface, wind speed, air temperature and net radiation, to enable the use of empirical formulas for calculating Lake Onslow evaporation. Therefore, the evaporation rate used in this study was taken from another study estimating the evaporation rate at

Falls Dam. The evaporation rate at Falls Dam was estimated from available pan evaporation data near Lauder [89]. The Lauder site was operational between March 1982 and May 1986. In the study of evaporation rates at Falls Dam, the data from the Lauder pattern of evaporation rate showed it to be consistent with six other sites in the Otago area (Figure 3.4) [89].

Elevation is important as the higher the site, the lower the average annual temperature and consequently, the lower the annual evaporation [89]. Lake Onslow is situated at an elevation of 700 masl, which is higher than all the six measurement stations in the area. It is also some 130 m higher than the Falls Dam and 212 m higher than Tara Hills. Average annual temperatures and evaporation can therefore reasonably be expected to be less than in those locations. However, the estimated Falls Dam evaporation data as shown in Table 3-1 is used in this study although the total annual evaporation rate at Falls Dam is higher than the 700 mm/year for the Onslow catchment area, which was estimated in another study.

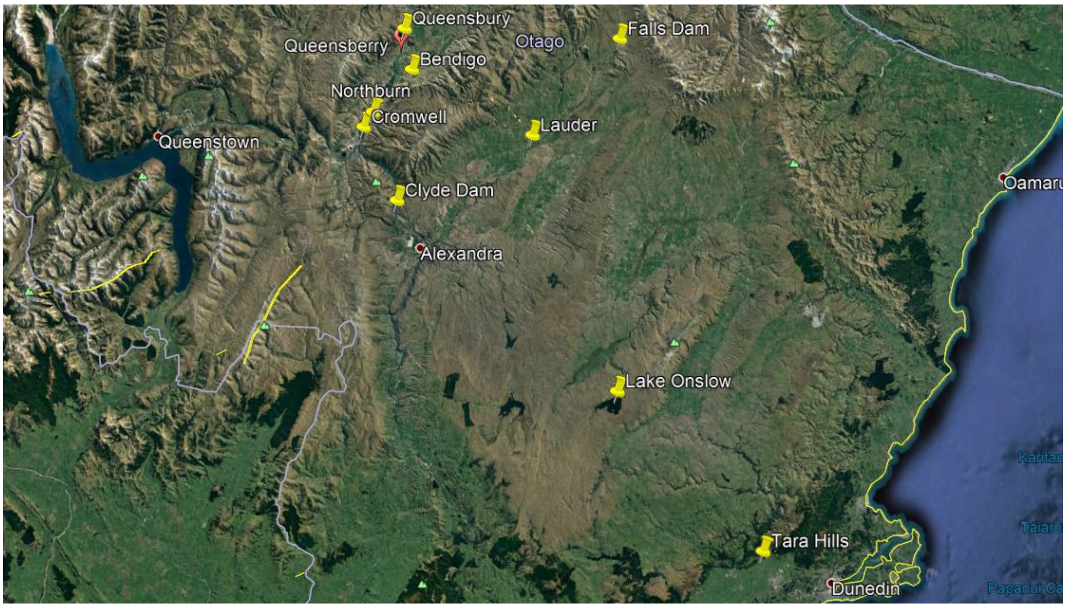

*Figure 3.4 The six stations for estimating evaporation rates in the Otago region. The locations of Lake Onslow and Falls Dam are included in the figure to show their proximity to the six stations.*

*Table 3-1 Monthly estimated evaporation data in mm at Falls Dam [89].*

| Jan | Fab | Mar | Apr | May | Jun | Jul | Aug | Sep | Oct | Nov | Dec | Total |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 141 | 113 | 79 | 46 | 23 | 10 | 10 | 25 | 48 | 84 | 113 | 133 | 825 |

Evapotranspiration is the loss of water by evaporation from the soil and via plant transpiration. It is dependent on meteorological conditions, as well as soil conditions. The average annual potential evapotranspiration deficit at Lake Onslow, using data collected from 1975-2015, estimated to be around 169 mm/year, is used in this study (Figure 3.5).

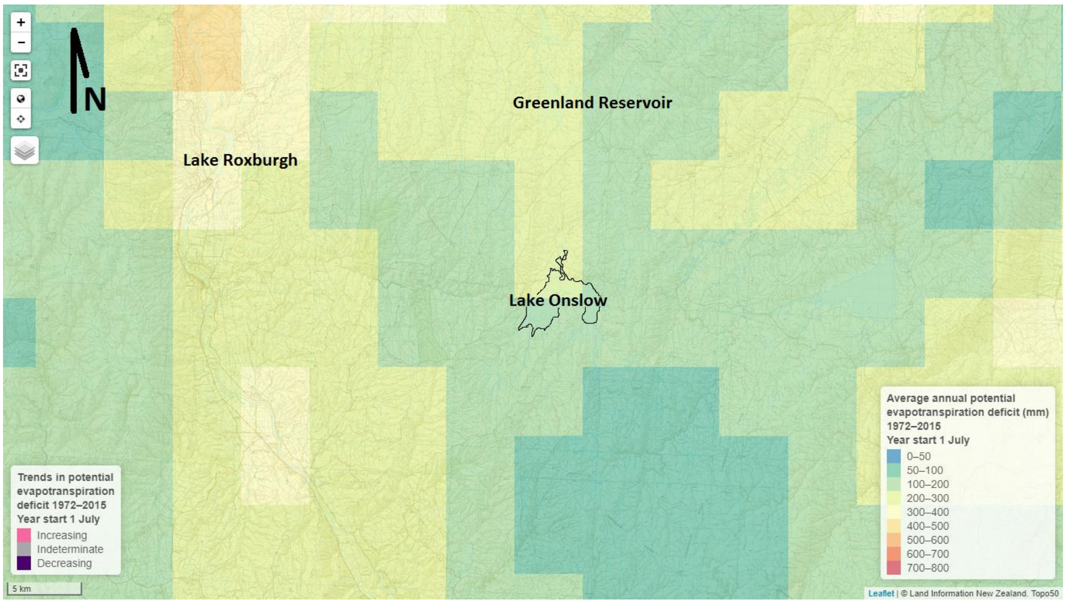

*Figure 3.5 The average annual potential evapotranspiration deficit in a part of Central Otago, 1972-2015 [90].*

The possible volume of water lost from the Onslow catchment area through evaporation and evapotranspiration was calculated, using Table 3-1 and the area of the expanded Lake Onslow, which depends on the lake level (Figure 3.11). The expanded area of Lake Onslow was taken from the results of the hypothetical operational Onslow PHES (See Figure 4.14). Figure 3.6 shows the calculated potential water loss due to evaporation and evapotranspiration during the simulated operation of the Onslow PHES 1998-2012. The total amount of water evaporated from the Onslow Catchment area during the operation of the Onslow PHES from 1998 to 2012 was calculated as 997,312,195 $m^3$, which is equivalent to 2.11 $m^3s^{-1}$. The total amount of water evaporated from the Onslow Catchment area without the operation of the Onslow PHES was 1.14 $m^3s^{-1}$. The estimated mean annual flow of the Teviot River at Bridge Hut Road during the operation of the PHES is 3.2 $m^3s^{-1}$, which would generate 17.5 MW if water was shifted to the possible Onslow PHES.

To sum up, there have been concerns that there will be net water loss from an expanded Lake Onslow. However, the simulated results of an operational Onslow PHES show that the natural inflows to the Onslow reservoir would be much higher than the losses due to evaporation from the catchment area and would produce energy by releasing it to the lower reservoir. But there may be some reduction in Teviot River flow.

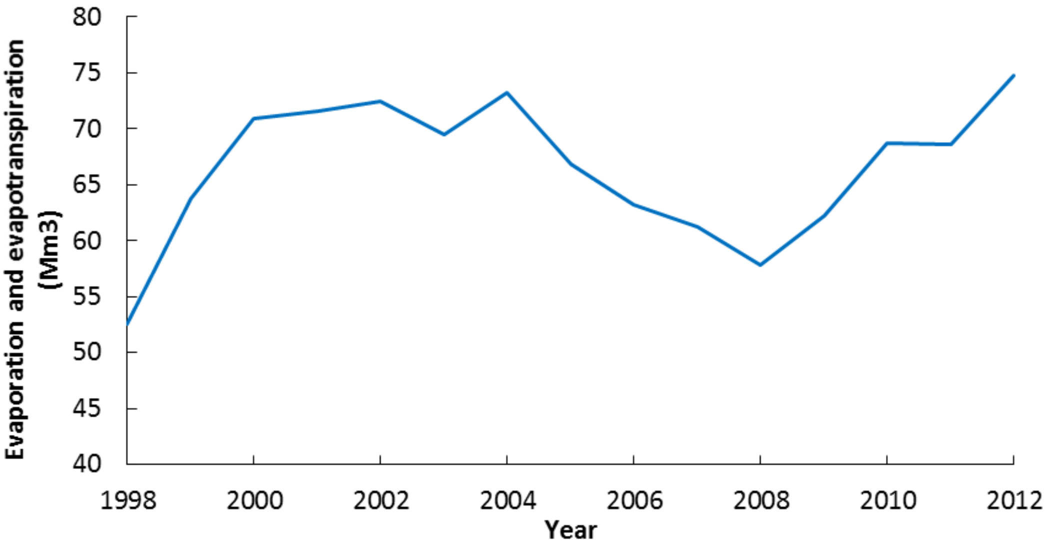

*Figure 3.6 Estimated evaporation losses for Onslow catchment area during the simulated operation of the Onslow PHES 1998-2012.*

### 3.3.3 The geology of the proposed PHES

The underlying bedrock in the area of the proposed project is metamorphic, mapped as the Otago Schist, which is part of a major metamorphic belt, the Haast Schist.

Two major types of Greenschist, (JeK) Biotite and Chlorite, are found in the area. The schist in the area of the proposed scheme falls within the Caples terrane with an absolute age of 220 to 275.6 million years. It can be described as well foliated psammitic and pelitic schist with incipient segregation; minor greenschist and metachert; quartz veins common; TZ3 [91].

Early Pleistocene gravel river deposits are found to the north of Lake Onslow. These have been described as moderately to strongly weathered, clayey sandy sandstone-schist gravel in isolated terrace remnants.

There are peat Holocene swamp deposits to the south of the lake, described as massive to bedded fibrous peat swamp deposits with interbedded sand, mud, and gravel. The gravel class is clastic sediment [91, 92].

Several faults are present within the area, and more investigation is needed to assess their activity. Figure 3.7 shows the proposed tunnel crossing two major faults.

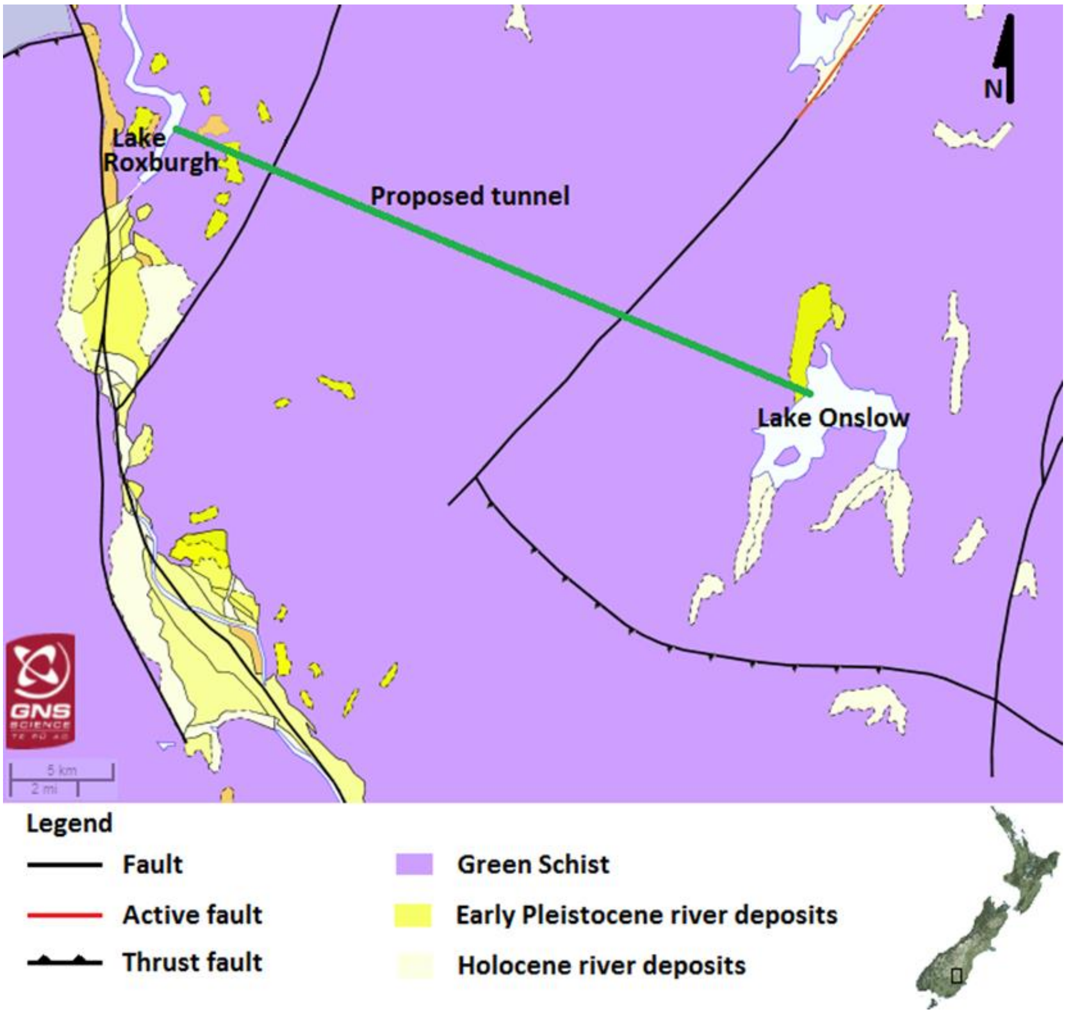

Figure 3.7 Geology surrounding the proposed scheme (based on Geology data GNS Science 2014) [91].

## 3.4 Possible Onslow pumped storage configurations

An upper reservoir located near Lake Roxburgh is well suited for the development of an elevated water storage area in an elongated schist rock basin where the artificial Lake Onslow is located. Water would be pumped up from Lake Roxburgh through a rock tunnel into an expanded Lake Onslow, serving as the upper reservoir (Figure 3.8). Water would be released back as required to generate electricity.

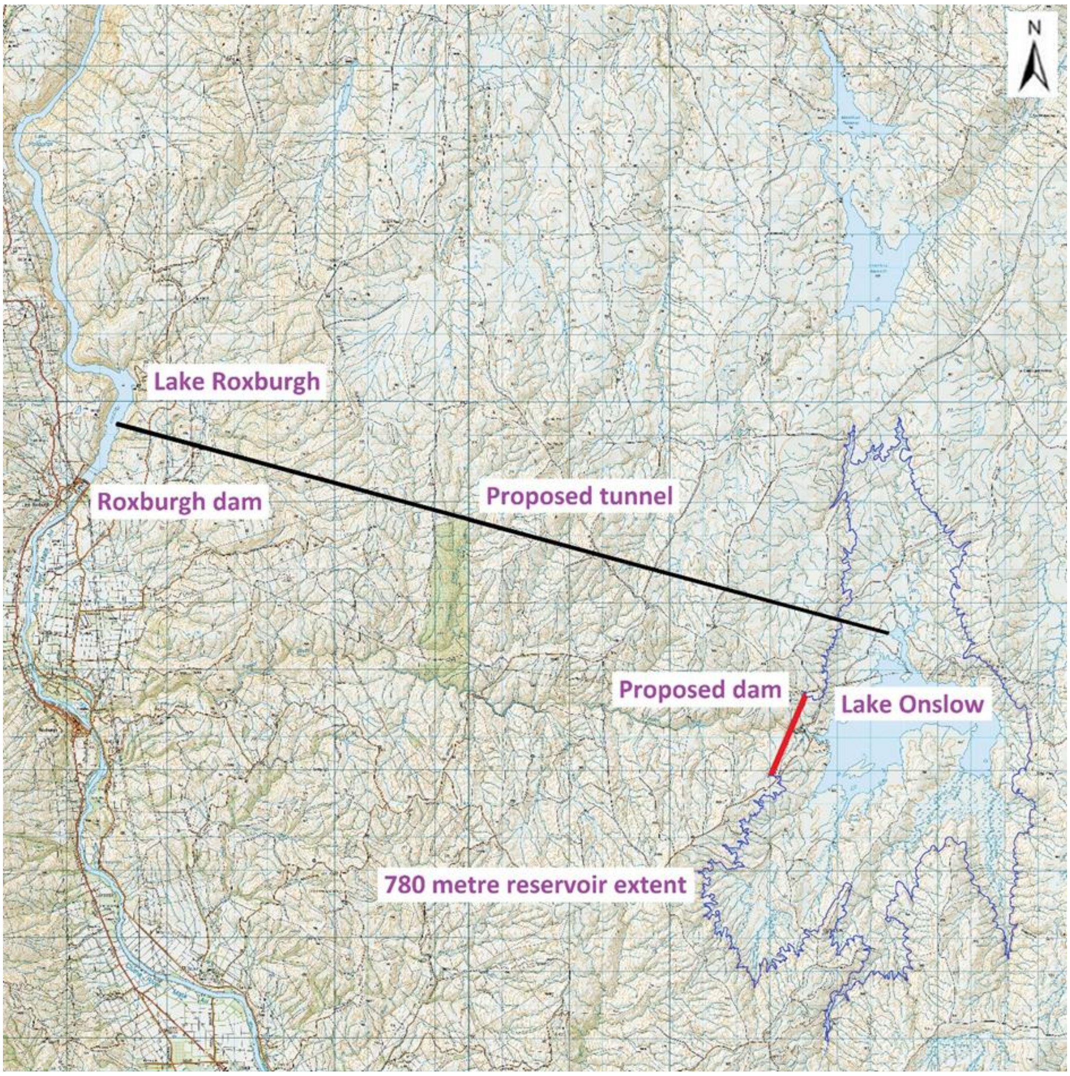

*Figure 3.8 Location and layout of the hypothetical Onslow PHES at the maximum extent of development of the upper reservoir 1:250,000 scale map.*

Bear suggested two possible configurations for the upper reservoir [72]:

1. Expanding both Onslow and Manorburn reservoirs

“The basic concept of the scheme is that the Onslow and Manorburn basins (both currently relatively small reservoirs) would be dammed and converted into large hydro lakes with an operating range of from 720 msal to between 760-800 msal. This would more than triple the current national energy storage capacity by way of an additional 12,000 GWh. The scheme includes an earth dam of 100 metres maximum in height and 3.8 km in length near the outlet of the present Onslow Reservoir, with a second dam of lesser height near the Manorburn Reservoir exit. These two dams would create an upper reservoir, which at maximum water level would have a surface area of 120 $km^2$ and provide 6.4 x $10^9$ $m^3$ of water storage.

There would need to be a cut or tunnel through the isthmus separating the two adjacent sub-basins shown in Figure 3.9.

2. Expanding Lake Onslow only with an operating range of 720 to 800 msal

“This reservoir will have a surface area of 82 km$^2$ at full elevation and correspond to maximum energy storage of 10,300 GWh“

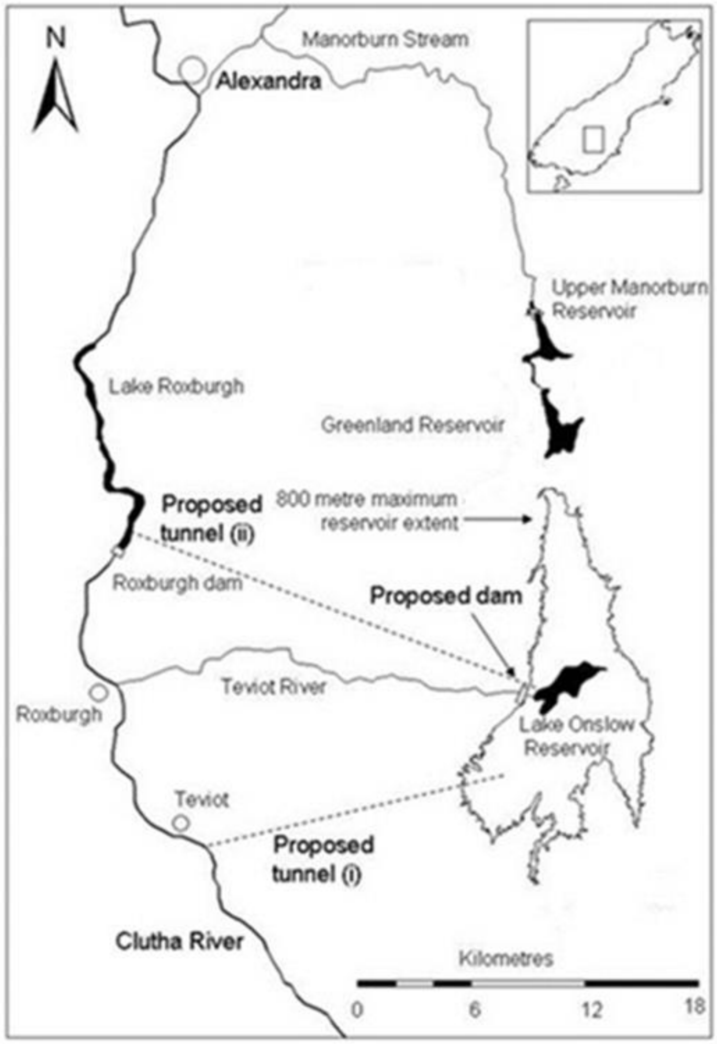

*Figure 3.9 Location and layout of the hypothetical Onslow PHES at 800 masl as the maximum extent of development of the upper reservoir [72].*

A smaller and more economical scheme is considered in this thesis study, using only an expanded Lake Onslow as the upper reservoir, with an operating range of 720 - 780 masl as shown in Figure 3.10. This is still a very large range compared with the permitted operational ranges of current hydro lakes in New Zealand. However, as will be noted later, this significant range could enable minimising the seasonal operating range of existing scenic hydro lakes, in addition to the primary Onslow role of giving power supply security.

The expanded Onslow reservoir in the proposed development would have a surface area of 74 km$^2$ at its maximum elevation of 780 masl. This is obviously still a major civil engineering scheme, with a maximum energy capacity of 7,000 GWh (Figure 3.11), compared to the current national hydro storage capacity of a little more than 4,000 GWh. A comparison between the proposed Onslow scheme and the Norwegian Saurdal PHES Scheme, which could be a model for New Zealand, is shown in Table 3-2.

There are multiple options for water release from Onslow, including a second tunnel to release water into the Clutha River below Lake Roxburgh in the event of constructing the possible Beaumont hydro power station. The present study considers just a single 24 km tunnel with Lake Roxburgh as the lower reservoir. This chapter describes the key design criteria.

*Table 3-2 Comparison between existing PHES in Norway and the proposed Onslow scheme.*

| PHES | Saurdal [93] | Onslow |
|---|---|---|
| Energy storage (GWh) | 7,760 | 7,000 |
| Reservoir level range (m) | 125 | 80 |
| Upper Reservoir area (km$^2$) | 82 | 74 |
| Tunnel Length (m) | 10.5 | 24 |

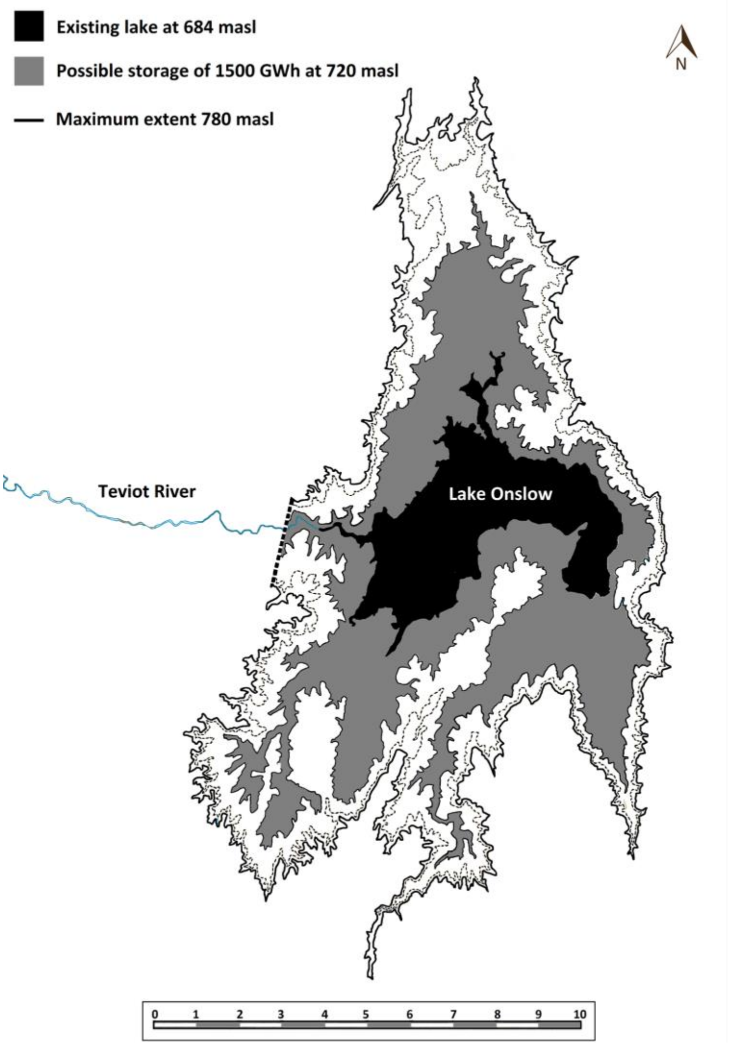

*Figure 3.10 The hypothetical Onslow basin at 780 masl as the maximum extent of development and 720 masl as the minimum operational level.*

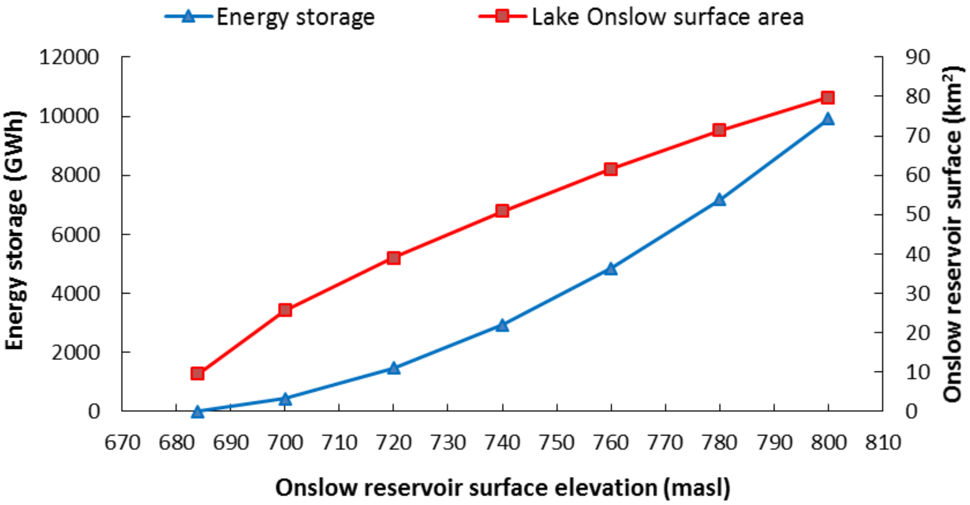

*Figure 3.11 Gravitational potential energy of the pumped storage reservoir in the Onslow depression, showing elevation/storage and elevation/area relationships.*

## 3.5 Evaluation of hydraulic cycle efficiency of the proposed Onslow tunnel

The maximum installed capacity of the simulated Onslow scheme is set at 1,300 MW, which is suggested by a previous study based on the Clutha upper and lower discharge bounds (900 $m^3s^{-1}$ and 300 $m^3s^{-1}$) and based on the results which was found the proposed pumped storage scheme to be hydrologically feasible, in terms of balancing water and energy, for stabilising hydropower output from the Waitaki and Clutha hydropower schemes, and for use as standby reserve [72]. The 1,300 MW installed capacity obtained from an average power hydro head of 615 m with a maximum generating discharge of 240 $m^3s^{-1}$ and a maximum pumping rate of 185 $m^3s^{-1}$. The simulated Onslow scheme includes waterway structural elements, the Onslow Dam and an underground station (Figure 3.12).

The civil engineering components of the 24 km Onslow tunnel include the tunnel itself, as well as the related components of tunnel intake and outlet, surge tank, power house, roading, and site establishment. The diameter of the tunnel is a major consideration as it directly affects the project budget and links to the sizes of the intake, outlet, and surge tank.

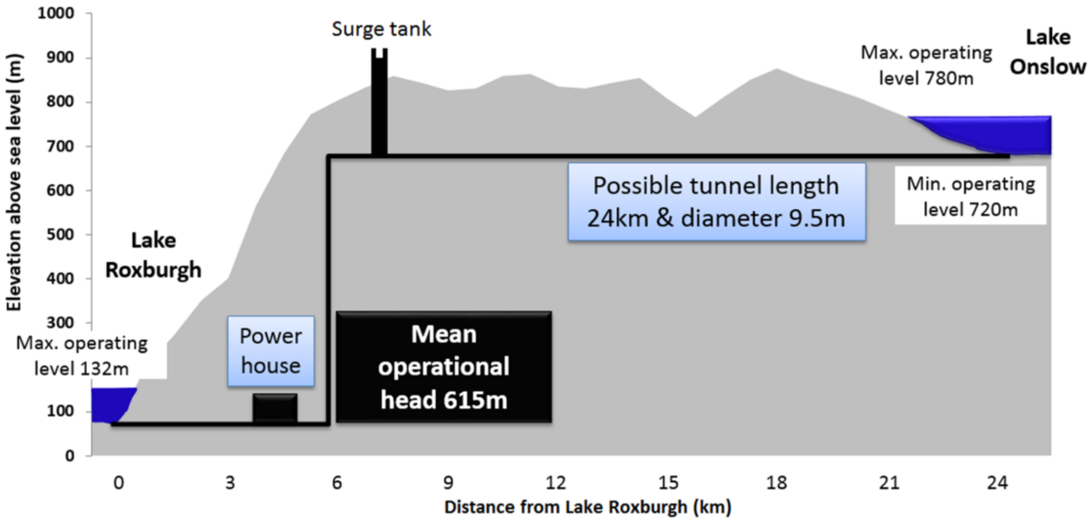

*Figure 3.12 Cross section of the simulated Onslow PHES.*

The processes of pumping water to elevation and later releasing it create losses as a result of hydraulic friction resistance and turbulence in the headworks, penstock, and tail race, with penstock friction loss representing the major loss component. Computer simulations of hydraulic head loss were carried out using standard packages [94] to estimate total head losses contributed by various components, using a range of different trial tunnel diameters and materials, for given pumping and discharge rates.

Two models were used to estimate the head loss due to frictional resistance and transitions or changes in tunnel direction: the Darcy-Weisbach formula [94, 95]. Figure 3.13 shows the calculation sequence for tunnel head loss and operational efficiency.

The benefit of a PHES plant can be maximized by minimizing the cost of civil works, water conduction systems, electro-mechanical equipment and the power evacuation system, which are directly related to the selection of optimum size / capacity of equipment. The selection of optimum diameter is achieved on the basis of friction losses, seepage losses, and cost of construction of the tunnel.

Following the process outlined in Figure 3.13, the method for selecting the optimum diameter of the Onslow tunnel is summarized as follows:

- Draw the layout of the tunnel according to minimum length in a long low-pressure tunnel option (Figure 3.12).
- Select the optimum diameter (D) of the tunnel for several factors (j) such as friction loss, seepage loss and construction cost including depreciation, interest, operation and maintenance. The construction cost items are the cost of excavation, lining and the cost of grouting.

$$Total\ Cost = \sum_{j=1}^{a} C_j(D) \tag{3.1}$$

Where D = Diameter of tunnel = f (Q, S, A)

S = tunnel gradient

Q = discharge ($m^3s^{-1}$)

A = area of the tunnel ($m^2$)

Cj = cost function for the *j*th items

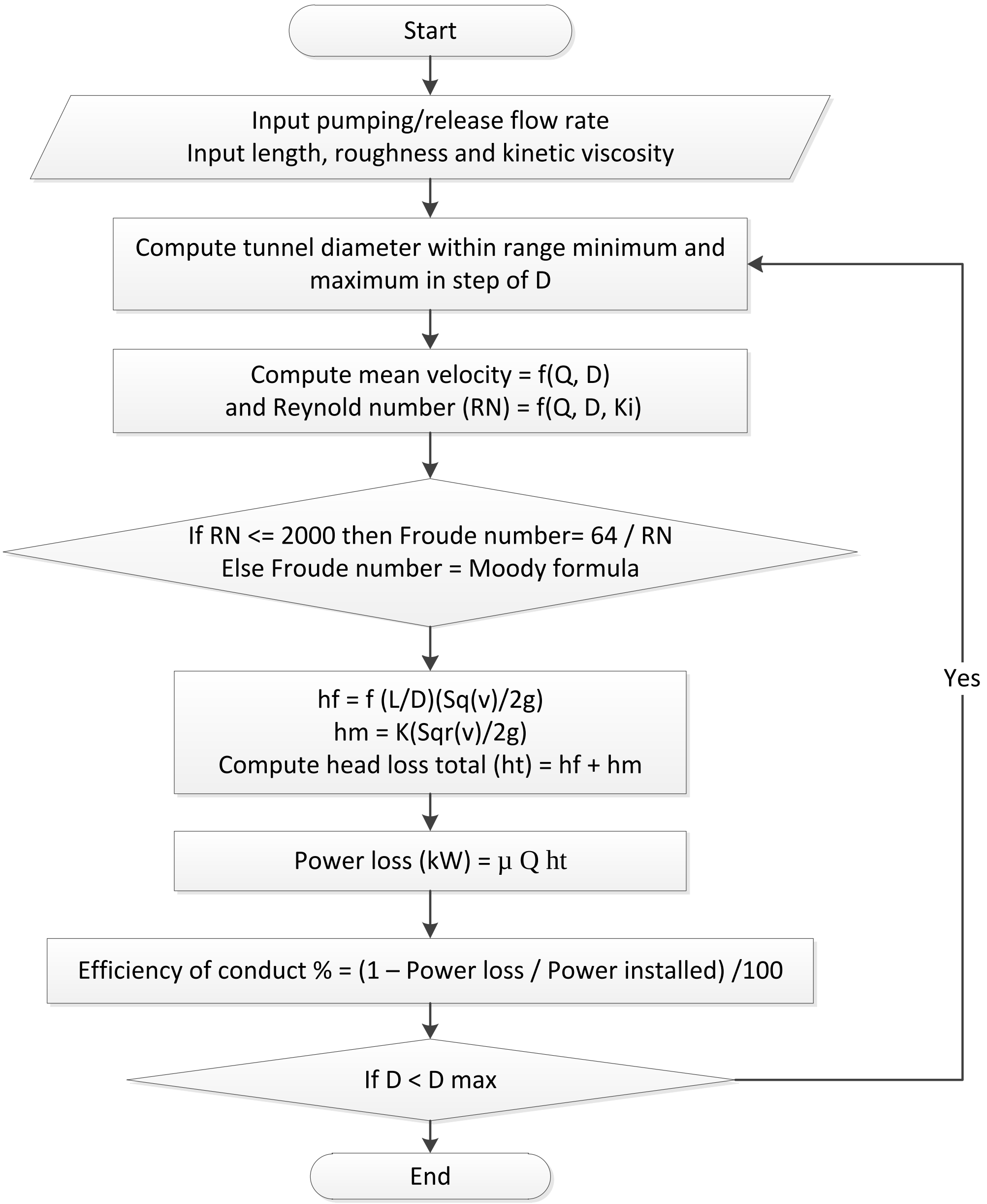

*Figure 3.13 System hydraulic head loss and parameter simulation diagram.*

- Optimisation solution can be solved for least cost per kWh by making:

$$\frac{dTotal\ Cost}{dD} = 0 \tag{3.2}$$

- Optimal Diameter (D) can be solved: $mD^N - D - K = 0$

The most economically efficient design can be obtained by making $\frac{dT}{dD} = 0$. The above procedure was applied and the output shows the optimum internal diameter is 7.5m. Adding an extra 0.5m for future development gives a total of 8.0m as shown in Figure 3.14. Parsons Brinckerhoff Associates Ltd considered a diameter of tunnel 8m in their primary estimation costing of the Onslow scheme. Figure 3.14 shows that the cost to construct a tunnel with a diameter of 8 metres is $NZ 14,276 per metre of tunnel length. This indicates that the cost to construct the tunnel will be $NZ 350M to 400M.

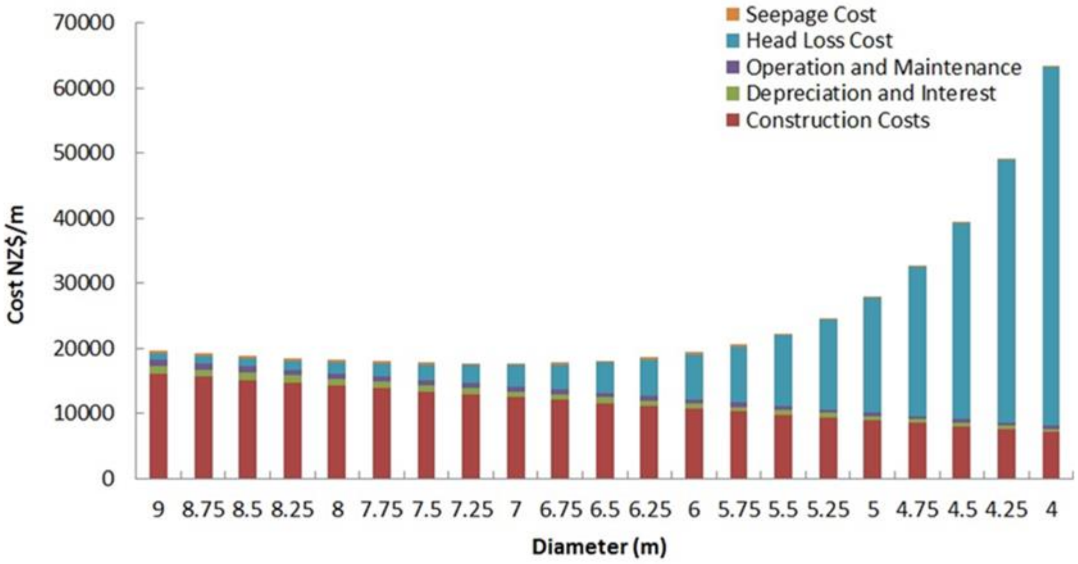

*Figure 3.14 Selection of optimum diameter of Onslow tunnel based on the costs of construction, headloss, seepage, operation and maintenance and depreciation and interest.*

Generally, tunnel constructions in the order of 8 metre diameters have thicknesses of precast concrete segments of 30 – 35 cm. Using 35 cm concrete with a strength of 50 Mpa, the volume of concrete required to construct the Onslow tunnel is estimated at 220,239 m$^3$. Adding 10% for wastage and various components gives a concrete lining cost of around $NZ 63M. The amount of steel required for the precast concrete is estimated at 160 kg/m$^3$ of concrete, meaning that the total steel requirement is 35,239 tons at a total cost of $NZ 39M. A typical cross sectional dimension of an underground power house is 50 m x 50 m x 40 m, which costs around $NZ 23M including materials.

Although steel has a lower head loss than precast concrete (Figure 3.15), the selection of the optimum diameter of the Onslow tunnel was based on the use of precast concrete as it offers advantages in terms of economics, strength, design flexibility, rapid installation, production controls, long life and durability in comparison with other materials. Therefore precast concrete was selected to construct a lined low pressure tunnel in schist rock. The maximum head loss due to friction in the Onslow tunnel is estimated to reach 2% for an 8 m diameter tunnel with a discharge of 210 $m^3s^{-1}$. In contrast, an unlined rock tunnel of 8 m diameter would lead to increased head losses amounting to approximately 10% of the operating efficiency. Figure 3.15 shows the operation efficiency head loss due to friction in different materials for tunnels of 8m diameter.

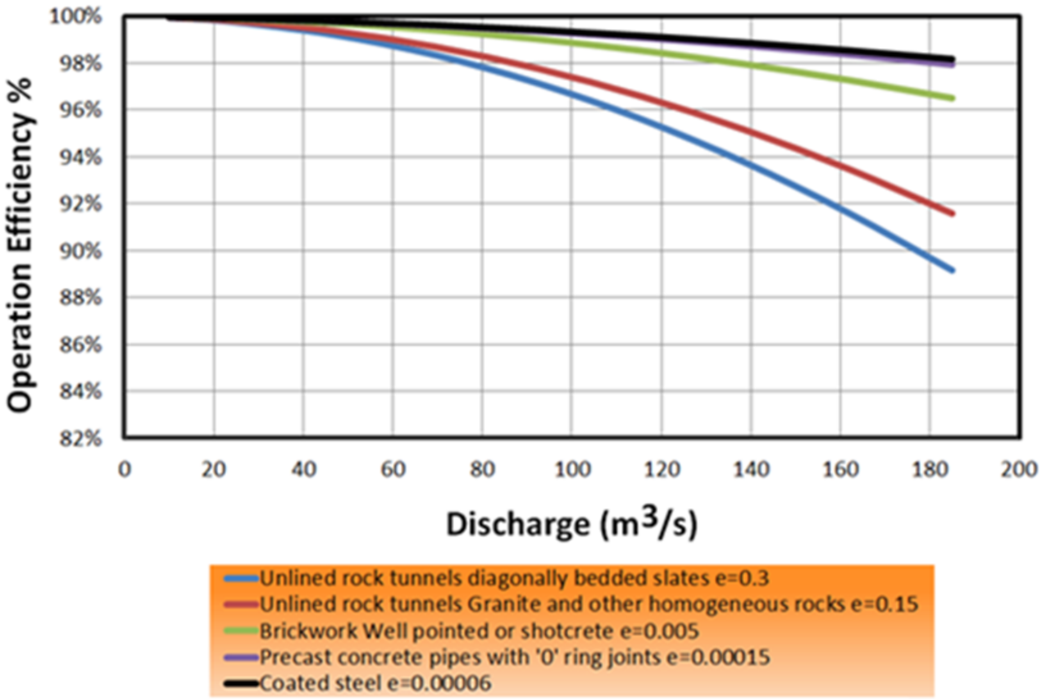

*Figure 3.15 Head loss operation efficiency vs discharge for different lining materials for Onslow scheme at 8m diameter.*

## 3.6 Specific roles for Onslow pumped storage

1) Seasonal hydro storage: - discussed later in this thesis.

2) Spinning Reserve: This is defined as electric power plant or generating capacity which is unloaded, synchronized, online and ready for immediate use in the event of a plant outage [96]. The Onslow pumped hydro storage scheme would be able to supply a full mix of reserve types. When operating in generation mode it would perform just like any other hydro generator. When pumping it would provide interruptible load, just like any other industrial load. When shut down it would be able to supply standby reserve.

3) Frequency ancillary services: New Zealand's electricity system is designed to run at 50 Hz and within very tight tolerances. The System Operator is

responsible for maintaining the quality of supply, which includes frequency, voltage and reserve. The normal frequency limits are 49.8 to 50.2 Hz and one station in each Island is assigned the role of frequency keeper to maintain this standard. The Onslow Scheme can contribute to keeping the frequency with the normal frequency limits.

Reserve is required to enable the electricity grid to maintain the system frequency when an unexpected contingent event occurs, e.g. a generator tripping.

4) Peaking capacity: Due to the anticipated high growth in peak demands and renewable energy, Onslow may be a feasible solution. The Onslow pumped storage plant can reduce fluctuations in power generation, because it can withdraw excess energy during the night, store it and later generate energy during periods of high demand. Looking at the type of demand during a typical week, it can be seen to vary in winter from about 3 GW to about 6 GW; this is a significant variance of about 3 GW. In summer it varies less than winter, from around 3 GW to 5 GW (a variance of 2 GW), as shown in Figure 3.16. To meet that demand using hydro power plants leads to high fluctuations in discharge downstream, and the use of combined cycle or steam power stations as backup is not very effective as they need stability and do not like following fluctuations. Pumped storage also reduces the use of OCGTs (Open Cycle Gas Turbines). The Onslow PHES could reduce the fluctuation on a daily basis by storing energy at night when the demand is low and producing it when demand is high. The dashed line represents the integration of the Onslow PHES into the grid.

A comparison of levelised cost of electricity (LCOE) for Norwegian pumped storage against OCGT and CCGT for providing peak power showed that pumped storage is a viable option if used more than 10% of the time. Another study in South Africa showed pumped storage can be the least cost supply option if the loading factor is higher than 10% (Figure 3.17) [97]. The loading factor of generation for the Onslow scheme was over 10% compared to OCGT. Therefore using the Onslow PHES would be more economical.

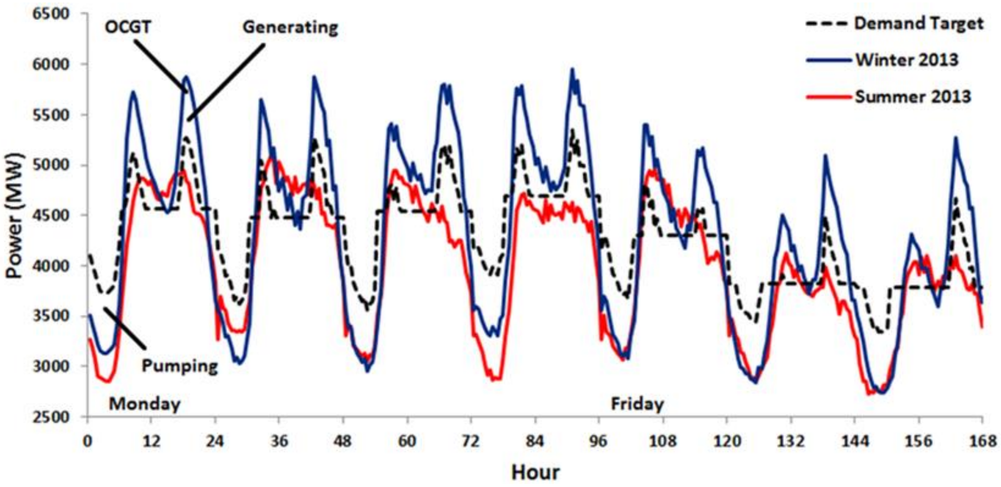

*Figure 3.16 Weekly load curve for summer and winter power use in New Zealand, with and without operating the proposed Onslow pumped storage in 2013.*

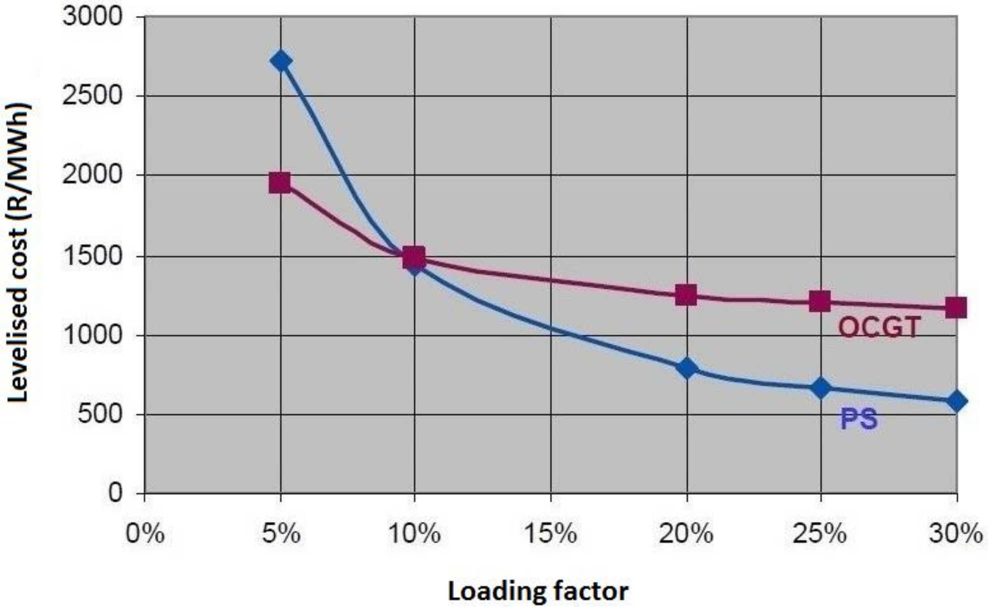

*Figure 3.17 Comparison between OCGT and pumped hydro energy storage plant in terms of loading factor and cost [97].*

The Onslow PHES would permit continuous operation of the base load plants: it allows much more stable operation of thermal power stations. Overall fuel consumption can be reduced.

- Synchronous condenser operation can be achieved via assistance with voltage control and improvement in the reactive power control.

- The Onslow PHES can provide a rapid response to national system load changes, such as during outages, giving it an advantage over thermal power. If there is a rapid change in the demand or a shortage of supply:

- Each generator in the Onslow PHES could go from standstill to full generation within 4 minutes. In the worst case, 400MW may be needed and that could be achieved in 15 minutes. This is similar to work done at the Ingula pumped storage scheme of 1332 MW installed capacity [97]. It estimated PHES idle to full generation taking less than 3 minutes with approximate load following 10MW per second [98].

- Although unlikely to be required, the cycle can change from pumping to full generation in 2 to 10 min and from generation to pumping in 5 to 20min [29]. It is estimated the PHES can switch from 100% generating to 100% pumping in less than 10 minutes [98]. In this way, it could effectively double the capacity to dispatch energy to the grid. So, every 1 MW of pumped hydro storage can support another 2 MW of renewable energy.

5) Further benefits of the proposed pumped storage scheme include smoothing of supply, reduced hydro spill, smoothing of spot prices and security of supply. Furthermore, hydro power, as with other renewable energy sources, is an environmentally responsible alternative to energy derived from fossil fuels as hydro generation does not produce carbon dioxide. Carbon dioxide emissions could be significantly reduced if the potential of renewable energy was fully exploited. By contributing to the reduction of greenhouse gases, the proposed pumped storage scheme would help New Zealand meet its commitments under the Paris agreement [99]. The proposed scheme may also be required to support wind power as wind approaches a 20% generation share in the future, to reduce the spillage of power.

The Onslow scheme gives options in fact for different operating modes. For example, an expanded Lake Onslow might be kept simply as a passive energy reserve, to be drawn down only in the event of dry years. Alternatively, in addition to a passive reserve, the lake could be used with minor water level fluctuation to buffer short-term wind power fluctuations and maintain frequency. Modelling in this thesis is based on the scheme being utilised to its fullest extent as part of on-going operation within the New Zealand electricity grid. The next chapter will describe a simulation model and its results, for the scheme operating in conjunction with the major South Island power schemes.

# Chapter Four: Onslow simulation model

## 4.1 Introduction

Pumped storage schemes typically serve to offset hourly variations in power demand in conjunction with constant-rate thermal power stations. Such systems have not been needed in New Zealand because its large hydro power component enables rapid changes in power output. However, pumped storage on a seasonal scale would be a definite advantage, if only because the move toward increased wind power is being constrained presently by limited hydro storage capacity. Another important factor is that climate change brings uncertainty over whether existing hydro storage capacity can maintain power through a dry year.

Furthermore, South Island power generation is presently wasteful of water. That is, potentially useful water is held back during spring and summer in the South Island hydro lakes to provide necessary additional winter power. For example, the mean January discharge in the lower Waitaki River is now 200 $m^3s^{-1}$ less than in pre-hydro times, meaning reduced water availability for summer irrigation and recreation. Another waste factor is that high South Island lake levels in summer can lead to water loss for all downstream users through hydro spill in the event of significant flood inflows to the lakes. There is also an environmental component because the current significant seasonal fluctuation of lake water levels leads to shoreline erosion in some of our most scenic hydro lakes such as Pukaki, Tekapo, and Hawea.

The proposed pumped storage scheme described in Chapter Three could operate so that South Island hydro lake inflows in spring and summer would no longer be held back for winter generation, but instead released downstream for power generation and other uses. The surplus power would be used to pump water into a high reservoir, thus shifting energy storage away from the hydro lakes. In winter, much of the power demand would then be contributed from pumped storage as water is shifted to a lower reservoir. It is therefore convenient, for the purposes of this thesis, to simulate the proposed Onslow PHES for multi-purpose use.

This chapter will provide an overview of the current layout and operation of the Waitaki, Clutha, Manapouri and Waikato hydropower schemes and will discuss how these were modelled when operated in conjunction with a multi-use Onslow pumped storage model.

## 4.2 Configuration of wind energy and hydro power schemes in the Onslow pumped storage model

A hydrological and economic simulation model was set up for the Onslow PHES operating within the present configuration of the national grid. The simulation model is constructed on the basis of a ‘national good’ philosophy – not competing power companies. Therefore, the power plants are being run as if following instructions from a central authority – as if the old ECNZ was in operation. The model is also constructed on the hypothesis that any Government, local authority, city council, or environmental agency may make a decision to reduce the operational level of hydro lakes to minimise an environmental impact, evaluate quantitive targets or support recreational activities at these lakes. The Onslow pumped storage would be able to absorb the excess energy from the grid or make up for deficits when required.

The model included sub-models of the Clutha, Waitaki, Manapouri, and Waikato hydropower stations, together with wind power contributions. The Clutha, Waitaki and Manapouri hydro power schemes were chosen on the basis of their proximity to the Onslow Scheme and their large installed capacity, economic and environmental aspects, while the Waikato scheme was chosen based on environmental aspects. The model was run in hindcast mode using historical hydro flows and records of electricity demand over the period 1998-2012. These data were obtained from the Hydrological Modelling Dataset (HMD), which contains hydrological information made available by the Electricity Authority. The dataset can be relied upon by modellers and analysts to test scenarios, provide commentary, and inform decision-making [93, 100-105]. The HMD consists of three main components:

1. Infrastructure and hydrological constraint attributes; this dataset records standing information about the capability of the main hydro schemes.
2. Flows; this time series provides inflows to reservoirs and flows at various existing or potential hydro generating sites.

3. Storage and spill; this time series indicates storage for the main hydro schemes.

The model was applied to evaluate the potential of future wind generation development throughout New Zealand, using a simplified model of the Clutha, Waitaki, Manapouri and Waikato hydropower schemes in conjunction with a seasonal pumped energy storage model for Onslow-Roxburgh. The model was also applied to address the benefits of providing dry-year energy back-up, and balancing and storing energy generated by renewable energy. The operation of the pumped hydro energy storage plant in the model was limited by a minimum elevation of 720 masl and a maximum elevation of 780 masl.

## 4.3 Model description

Simulations of seasonal pumped storage operation were carried out in Matlab to simulate dry year energy back-up, and balance and storage of energy generated by renewable energy sources. The model simulation was applied with half-hour time steps to the period 1998-2012, as if the scheme was operational over this period. The time range is helpful as it includes a wet year in 2000 and a dry year in 2006.

The model was operated primarily with a view to stabilizing the existing hydro lakes at specified levels, with most storage operation shifted to Onslow. Various advantages arising from that operational mode were quantified, including reducing water spill from hydro lakes and reducing hydro lake shoreline erosion.

The sub-model was to absorb wind power generation output by dispatching it to the electricity grid and using the excess energy by reducing water release from hydro power plants and engaging the pumped storage system. Pumped storage on a seasonal scale would be a definite advantage here, if only because the move toward increased wind power is being constrained presently by limited hydro storage capacity. This point will be discussed further in Chapter Five.

The priority in the model was to control the release of water from the Waitaki Scheme at Kurow to secure a supply of irrigation water from the Waitaki River for the existing 80,000 irrigated hectares of the lower Waitaki River catchment and gain from extra summer water in the Lower Waitaki River, which could enable a doubling of the current Lower Waitaki irrigated area. This point will be discussed further in Chapter Six.

The next priority was to absorb the power generation of individual hydro power plants that have small storage capacities, such as Clyde and Roxburgh in the Clutha scheme and hydro plants in the Waikato Scheme. The remaining hydro power plants, including Hawea, Pukaki, Tekapo, Manapouri and Taupo, were operated to hold specific levels in order to keep hydro spill to a minimum and to allow for extra water in summer in the Waitaki valley.

The lower and upper flow bounds of 300 $m^3s^{-1}$ and 900 $m^3s^{-1}$ applied in the model were set using statistics for the Clutha River based on different periods of record at Tuapeka Mouth and Teviot. There were chosen based on 90% exceedance flow and 10% exceedance flow. They were also chosen to secure water for maximum pumping and allow space at Lake Roxburgh for maximum release of water.

The existing hydro power stations were modelled together with pumped storage to match the power demand on the grid, as a way to store excess energy in the upper reservoir if power generated from the whole scheme is higher than demand or to generate power from the pumped storage if power generated from the whole scheme is below demand levels. Simulating power from hydro power plants is based on the volume of water in each lake. For example if Lake X has a higher percentage of storage than Lake Y, then the priority is to release water from Lake X. When reducing the release of water from any lake, the priority is for the lake with the lower percentage of storage.

The last priority for control of release from hydro lakes in the model was to manage the release of water from Lake Taupo, because there are inefficiencies in sending Waikato power south to Onslow storage and then later back to the North Island.

In the simulations, a quadratic relationship was used to calculate the volume of available water at Lake Onslow, as a function of lake level.

$$v = \left((28.25E - 5)L^2 - 0.36L + 113.06\right)x\ 10^9 \qquad (4.1)$$

where $v$ is volume of water at the Onslow reservoir in $m^3$, and $L$ is stored level in metres.

## 4.4 Description of existing power stations as simulated in the model

### 4.4.1 Waitaki Hydro component in the model

The Waitaki hydro power scheme includes eight hydro power plants (Figure 4.1). The catchment area of the Waitaki River is 9,700 $km^2$ at the Waitaki Dam and 12,000 $km^2$ at the coast. The majority of the catchment rainfall flows into Lakes Tekapo, Pukaki and Ohau, then into Lakes Benmore, Aviemore and Waitaki. These lakes are controlled by the following hydro dams, listed with the year in which power generation commenced: Tekapo (1951); Pukaki (1951 for Low Dam, 1979 for High Dam); Ohau (1979); Ruataniwha (1981); Benmore (1965); Aviemore (1968); and Waitaki (1935). Figure 4.1 also shows the stations of record data for inflows for reservoirs and flows at various existing which provided data to the HMD. The HMD also includes storage and spill. All these data were used as inputs in the model for the Waitaki Scheme.

For simplicity, power stations Tekapo A and B were simulated as a single station and as an approximation, three lakes – Aviemore, Benmore, and Waitaki – were considered as a single lake of combined surface area. Likewise Ohau A, B and C were combined into a single station and Benmore, Aviemore and Waitaki were considered as a single station. Because Lake Ohau has a low permitted storage capacity, the first priority in the model was to release water from it and keep it at a constant minimum level to reduce the risk of spill. The next priority was to keep Lakes Tekapo and Pukaki at their desired mid-range levels to reduce spill losses while also reverting to a more natural lake environment. The next priority was water release from Pukaki to the hydro canals, subject to not contributing to any spill at Benmore, Aviemore or Waitaki stations from high Ahuriri River flows.

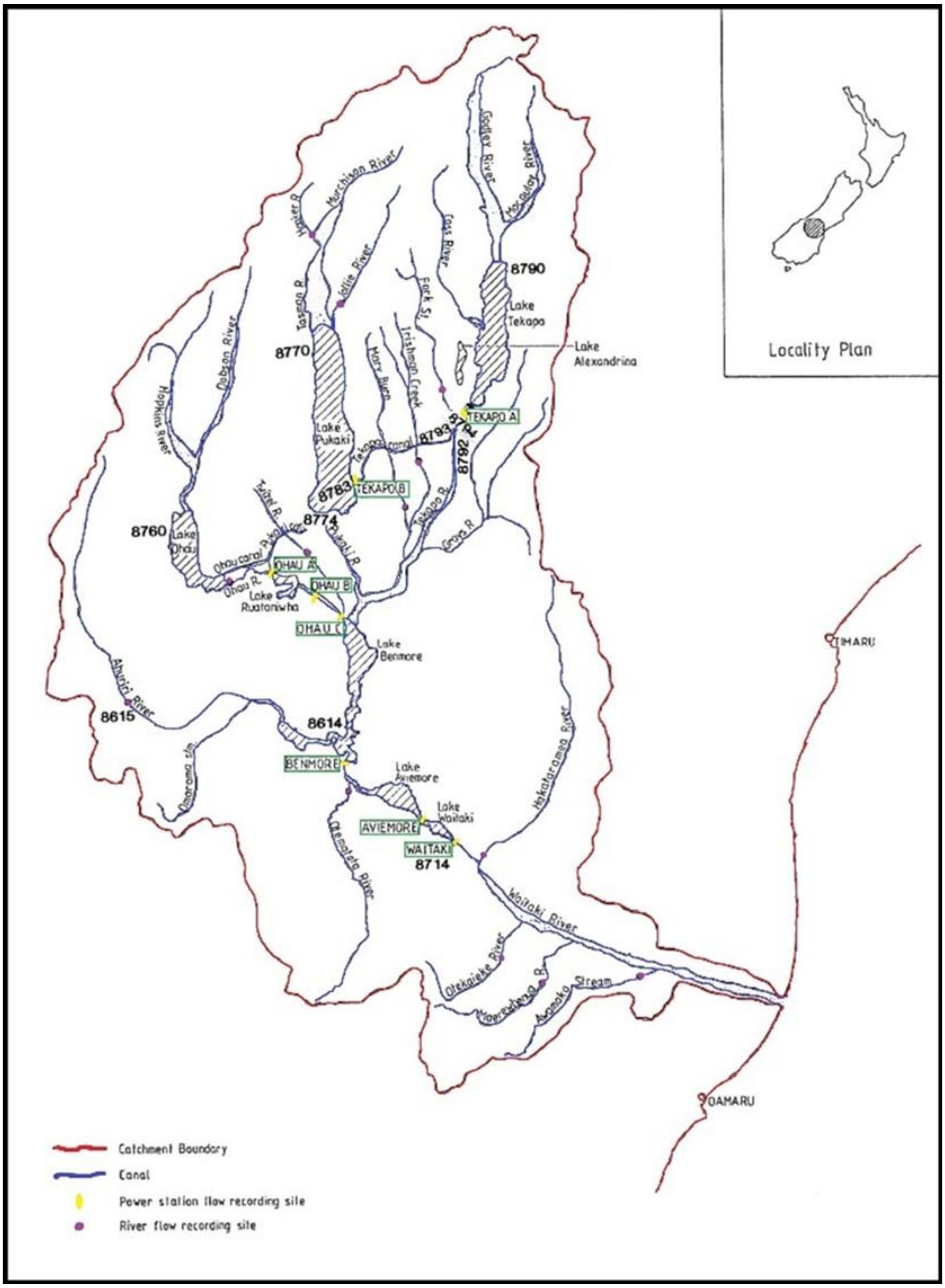

*Figure 4.1 Waitaki catchment and hydro power scheme [102].*

The essential structure of the Waitaki component of the model is shown in Figure 4.1 and a simplified flow diagram of the model operation is given in Figure 4.2. The model also includes an irrigation formulation for the Waitaki scheme to allow for extra summer water in the valley as illustrated in Chapter Six.

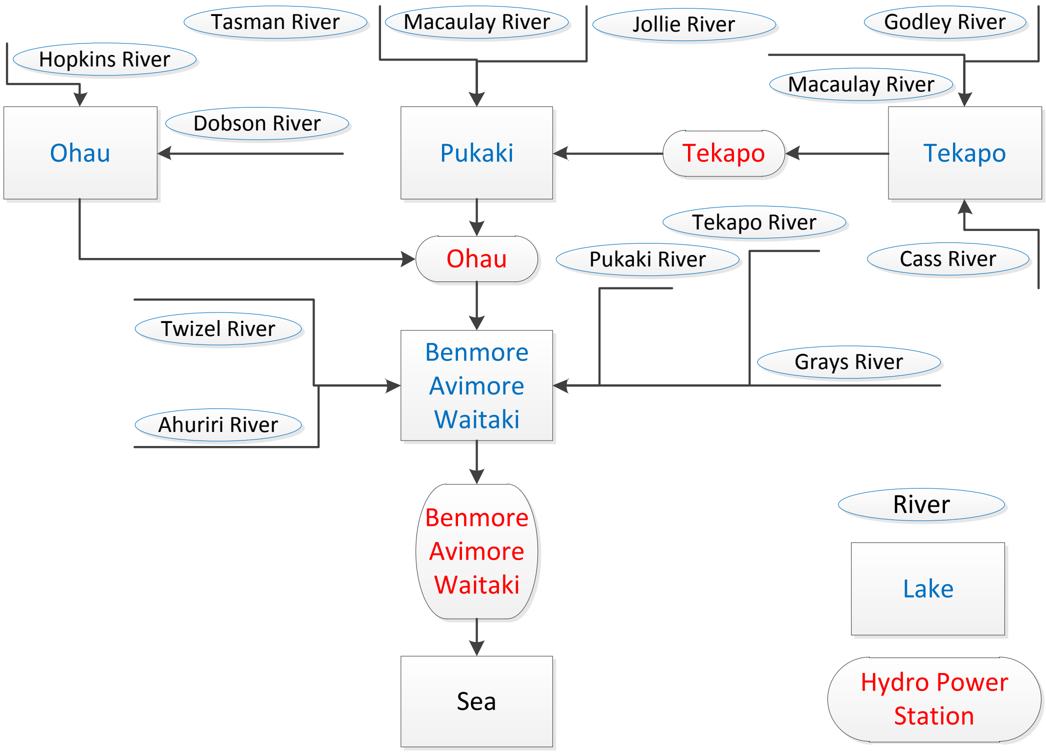

*Figure 4.2 The structure of the Waitaki component of the model.*

### 4.4.2 Clutha Hydro component in the model

The Clutha hydro scheme has two hydro power stations at the Clyde and Roxburgh dams, creating Lakes Dunstan and Roxburgh respectively. There are two large uncontrolled lakes in the upper catchment (Wanaka and Wakatipu) and also the controlled Lake Hawea. Actual data for inflow, flow, spill and lake levels used in the model were taken from the HMD. Figure 4.3 shows the site stations and their numbers in the HMD.

The Clutha model goal was to maintain Lake Hawea near its mid-range, subject to not contributing to any spill at Clyde and Roxburgh stations given the constraint of minimum and maximum discharges of 10 and 200 $m^3s^{-1}$ to the Hawea River. A simplified diagram of the Clutha part of the model is shown in Figure 4.4.

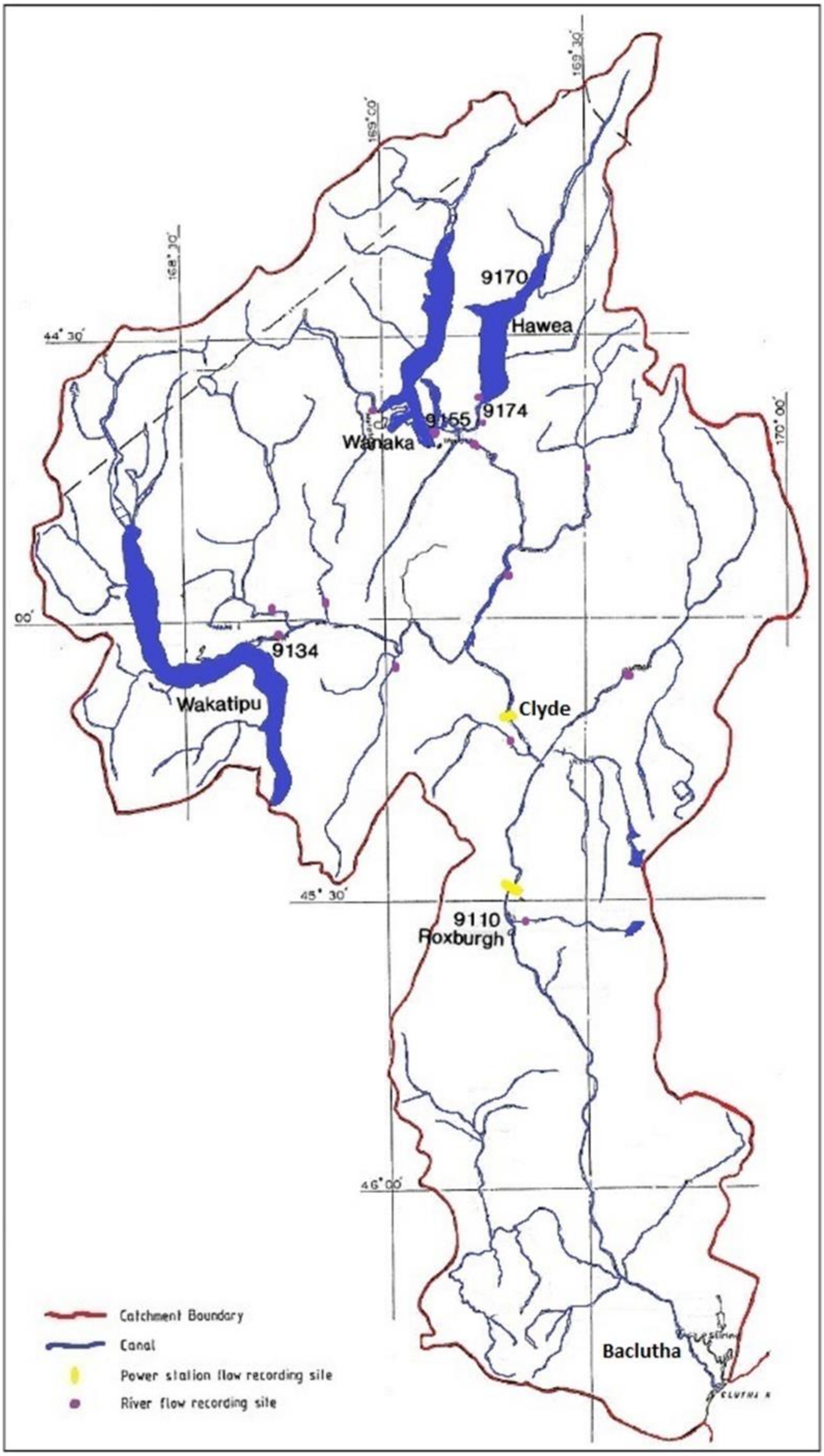

*Figure 4.3 Clutha catchment and hydro power scheme [102].*

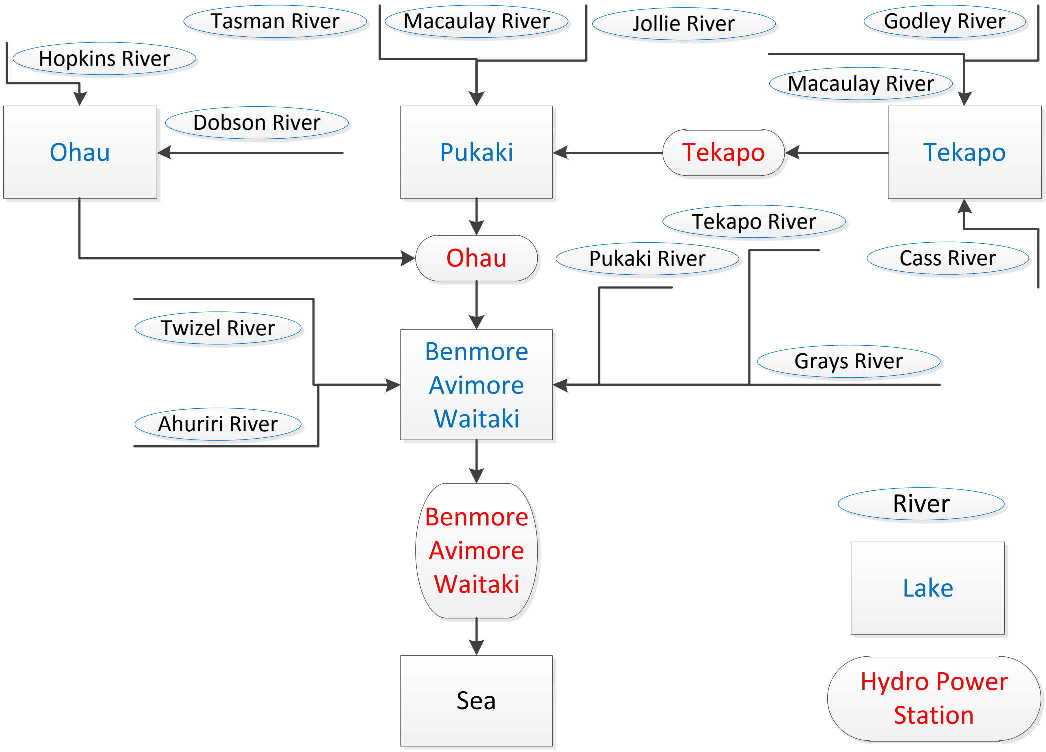

*Figure 4.4 Simplified diagram of the Clutha part of the model.*

### 4.4.3 Manapouri Hydro component in the model

The Manapouri Power Scheme consists of two lakes, Manapouri and Te Anau, and one hydro power station. The model goal was to maintain Lake Manapouri near its minimum permitted level to minimize spill and the inflow was modelled as the summation inflow for Lakes Manapouri and Te Anau. Operating ranges defined for Lake Manapouri are between 176.8 and 178.6 masl. The data of inflow, water spill, and lake level were collected from the HMD. Manapouri hydro power is contracted for the Tiwai point Aluminium Smelter supply.

### 4.4.4 Waikato Hydro component in the model

The Waikato scheme is located in the North Island. The components in the model are eight hydro stations: Aratiatia, Ohakuri, Atiamuri, Whakamaru, Maraetai, Waipapa, Arapuni and Karapiro, which were simulated independently as run-of-the-river hydro plants. The eight lakes behind the hydro power stations were considered in the model to have zero storage although in reality they do have some storage. The model goal was to maintain Lake Taupo near its mid-range level and the output was simulated to minimize hydro spill from downstream hydro stations, subject to not contributing to any spill at downstream hydro stations from the inflow of Ohakuri, Whakamaru, Maraetai, and Arapuni. A basic hydro analysis shows that to minimize hydro spill in the Waikato scheme, the maximum discharge from Lake Taupo in any run in the model is equal to the maximum output from Whakamaru hydro station minus the summed inflows of Lakes Aratiatia, Ohakuri, Atiamuri, and Whakamaru. For simplicity Maraetai 1 and Maraeti 2 are combined into a single station. The structure of the Waikato component of the model is shown in Figure 4.5.

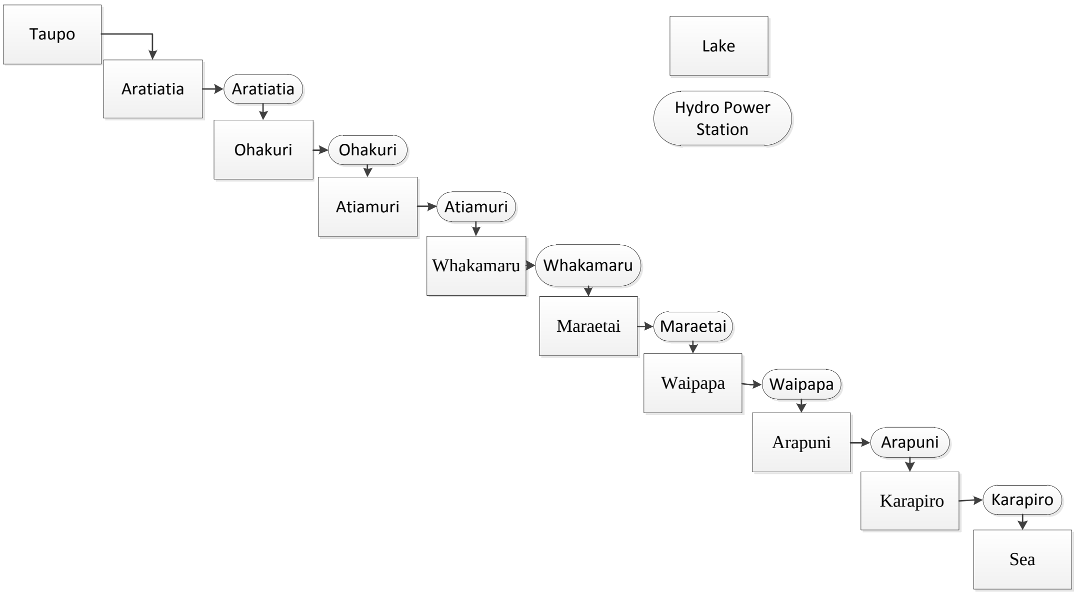

*Figure 4.5 The structure of the Waikato component of the model.*

## 4.5 Model operation of the Onslow pumped storage

A simplified model of the wind and hydropower schemes operating in conjunction with the Onslow pumped storage model is shown in Figure 4.6.

The first step in the model is to calculate the simulated output power in half-hour steps from the Clutha, Waitaki, Manapouri and Waikato hydro power schemes in order to meet the goal of each scheme, as discussed in the previous sections. It also includes irrigation formulations for the Lower Waitaki scheme, as will be discussed in Chapter Six. Historical records of electricity demand were used as the demand in the model, which were collected using the Gnash program [106]. The actual fluctuating wind energy was considered as output power per half hour in the model. However, the demand from the wind energy section of the model was considered as the annual average wind energy as a base reference in 2012. For example, with 50 MWh as a demand (average annual output) and actual output 90 MWh then the surplus energy would be 40 MWh. In this case would the Onslow PHES be able to absorb the 40 MWh? Development of wind energy on a year-by-year basis is discussed in Chapter Five.

The next step in the model calculates the outcomes (1) if the power generated from the whole scheme exceeds demand and the excess goes to pumped storage; and (2) if the power generated is less than demand and power is generated from pumped storage release.

Pumped storage operation is constrained by the following factors:

a) For the pumping phase, sufficient discharge must be present in the Clutha to supply water.

b) For the release phase, Clutha discharge must be low enough to accommodate the released water.

c) There must be sufficient storage capacity in the pumped storage lake to allow a given amount of pumping.

d) For a given power demand, there must be sufficient stored water to allow release.

e) After the pumping phase, if excess energy is found in the grid then the model must check if it is possible to reduce generation from the Clutha, Waitaki, Manapouri and Waikato hydro power schemes. The reduction in generation from hydro schemes is based on comparing the percentages of storage in the hydro power scheme. For example, if the percentage of storage in Lake Hawea is less than the percentage of storage in Lake Pukaki, then reduce release from Lake Hawea, and thus reduce generation by the Clutha hydro power scheme. Note that the flow time delay is ignored in the model.

f) After the generating phase, if there is insufficient energy in the grid then the model must check the possibility of increasing generation from the Clutha, Waitaki, Manapouri and Waikato hydro power schemes. The increase in generation from hydro schemes is based on comparing the percentages of storage in the hydro power schemes. For example, if the percentage of storage in Lake Hawea is less than the percentage of storage in Lake Pukaki, then increase release of water from Lake Pukaki to increase generation from the Waitaki hydro power scheme.

If any of the above conditions are violated then the program continues and meets the power demand/pumped storage requirements only to the extent possible.

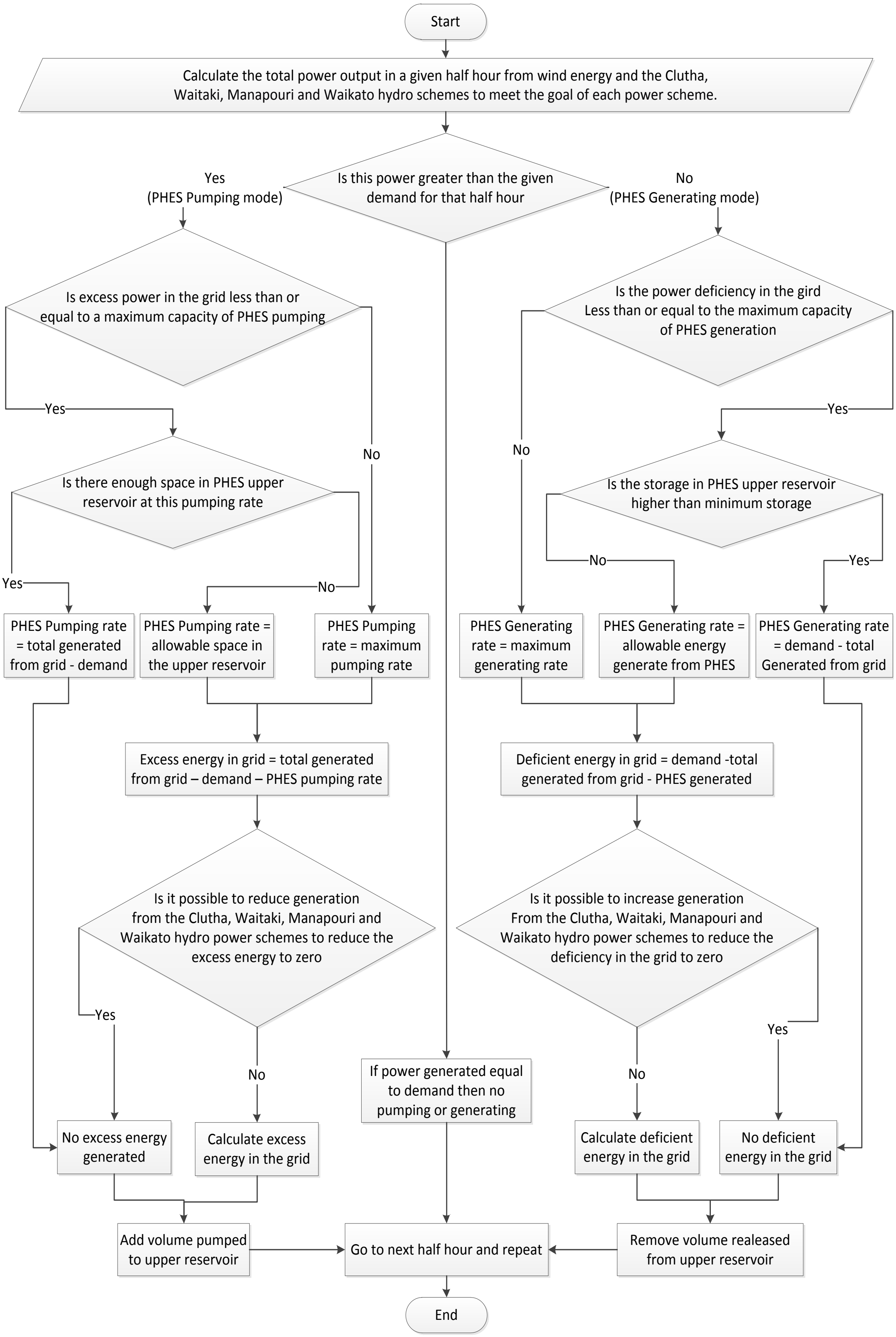

*Figure 4.6 Simplified flow diagram of the pumped hydro storage section of the model.*

## 4.6 Input data, parameters and scenarios

The power system in this chapter consists of a total hydroelectric installed capacity of 4809 MW (Manapouri 877 MW, Clutha 797 MW, Waitaki 2042, Waikato 1093 MW), pumped storage specified installed capacity of 1,300 MW and wind installed capacity starting at 610 MW and increasing in eight scenarios. The units used in the model were MW per half hour for energy and m$^3$ for water volumes.

The various power station specifications as used in the model are given in Table 4-1. The input data for inflow and model-generated outflows were compared to check water balances. The actual generation from hydro power plants in half an hour was used as the demand in the simulation, added to the yearly average of wind generation. The power plants were modelled with pumped storage serving to match the National power output demand from records. Transmission losses in the grid were ignored in the model and can be included in the future studies.

*Table 4-1 Power station specifications as modelled.*

| | Station | Capacity (MW) | Volume (m$^3$) | Conversion factor (W per half hour/m$^3$) |
|---|---|---|---|---|
| Clutha Scheme | Clyde | 464 | 25,200,000 | 142.44 |
| | Roxburgh | 334 | 10,324,800 | 107.66 |
| Waiaki Scheme | Tekapo A | 25.1 | 863,280,000 | 401.76 |
| | Tekapo B | 160.1 | | |
| | Ohau A | 264.2 | 2,465,840,000 | 382.2 |
| | Ohau B | 212.2 | | |
| | Ohau C | 212.2 | | |
| | Benmore | 540.4 | 80,000,000 | 400.7 |
| | Aviemore | 220 | | |
| | Waitaki | 105 | | |
| Waikato Scheme | Taupo | | 862,400,000 | |
| | Aratiatia | 78 | 717,120 | 75.07 |
| | Ohakuri | 112 | 13,504,320 | 70.17 |
| | Atiamuri | 84 | 2,877,120 | 46.63 |
| | Whakamaru | 100 | 10,549,440 | 83.39 |
| | Maraetai | 360 | 8,208,000 | 129.08 |
| | Waipapa | 55 | 1,105,920 | 36.65 |
| | Arapuni | 196.7 | 9,547,200 | 121.55 |
| | Karapiro | 100 | 13,936,320 | 72.32 |
| | Manapouri | 885 | 359,490,000 | 391.2 |

## 4.7 Simulation model of Onslow operation and results

As mentioned previously, the model, incorporating a hindcast simulation of the Onslow PHES, was operated with a simplified model of the Clutha, Waitaki, Manapouri and Waikato hydropower schemes. All water transfers and energy values were on 30-minute timesteps. The model was applied to the period 1998-2012, which was useful as it included wet and dry extremes and the 1999 flooding event. The mean daily power output, flow and lake level data were obtained for each of the hydropower schemes and inflow to each lake was calculated using a simple water balance.

There was a one-off power use of 1,623 GWh initially, to fill Lake Onslow from 695 to 720 masl, which is equivalent to a mean daily power output of 13.22 MW. This filling of Lake Onslow to level 720 masl would not represent energy consumption as it can be compensated for by the inflow to Lake Onslow (Section 3.3.2).

The results of applying the model are shown in Table 4-2. The simulation shows that almost 21,210 GWh of energy lost as spill could have been used and stored between 1998 and 2012. This is equivalent to a mean daily power output of 172.8 MW. This amount was gained through the model goal of always aiming for medium hydro lake levels, with the Onslow pumped storage system using surplus power during times of high lake inflows.

The total difference between the actual and simulated model is shown in Figure 4.7, Figure 4.8, Figure 4.9, Figure 4.10, and Figure 4.11, which illustrate the actual and simulated cumulative energy output from the Clutha, Waitaki, Manapouri, and Waikato hydro power schemes with the Onslow PHES in operation. The 172.8 MW can be separated into three parts as follows:

- A possible long-term mean power output of 35.47 MW.
- 6,412 GWh stored at the end of the simulation in the upper reservoir, which is equivalent to a mean power output of 52.24 MW or 45.24 MW after generation (generating loss 7 MW).

- 85.1 MW lost from operating the pumped storage plant (almost 75%). This increases to 92.1 MW after generating losses of 7 MW.

Total energy dispatched from the Waikato hydro power scheme to the Onslow PHES then sent back to the North Island was 10,283 GWh, which represents 17.7% of the total energy generated, while the total gain by reducing water spill was 1,760 GWh. If transmission losses are higher than 17.1%, power loss occurs from the Waikato scheme. Therefore, the power gained from reducing water spill in the Waikato scheme can compensate for the transmission loss. The 14.34 MW should be subtracted from the calculations.

The electricity market could be adjusted so Mercury has market priority whenever the lake goes above the target level, except for flood control. That way, there would be excess power in the South Island instead, which would go to Onslow, avoiding the North-South transmission loss.

The difference between actual and simulated total cumulative energy output is represented by the amount of spill, which is greatly reduced by operating the hydro power plants in conjunction with the Onslow pumped storage system in the model. Decreasing the amount of energy lost from spill means the efficiency of the Clutha, Waitaki, Manapouri, and Waikato hydro power schemes is increased. The cumulative energy generated with and without pumped storage 1998-2012 for the hydro power schemes is compiled in Table 4-2 and illustrated in Figure 4.7, Figure 4.8, Figure 4.9, Figure 4.10, and Figure 4.11.

*Table 4-2 Net energy gain in MW at Clutha, Waitaki, Manapouri and Waikato hydropower schemes, and the cumulative energy generated with and without pumped storage 1998 -2012.*

| | Clutha | Waitaki | Manapouri | Waikato | Total |
|---|---|---|---|---|---|
| Actual (TWh) | 50.97 | 108.02 | 65.34 | 56.85 | 281.18 |
| Model (TWh) | 55.13 | 120.62 | 68.03 | 58.61 | 302.39 |
| Difference (TWh) | 4.16 | 12.6 | 2.69 | 1.76 | 21.21 |
| Save (MW) | 33.9 | 102.67 | 21.92 | 14.34 | 172.83 |

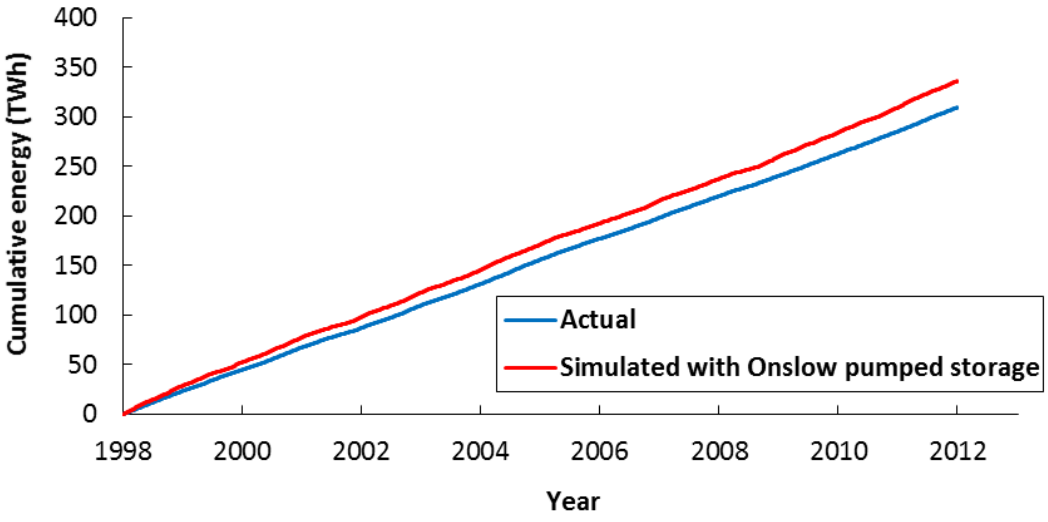

*Figure 4.7 Actual and simulated cumulative energy output from the Clutha, Waitaki, Manapouri, and Waikato hydro power schemes with pumped storage in operation. The difference is equivalent to 172.83 MW.*

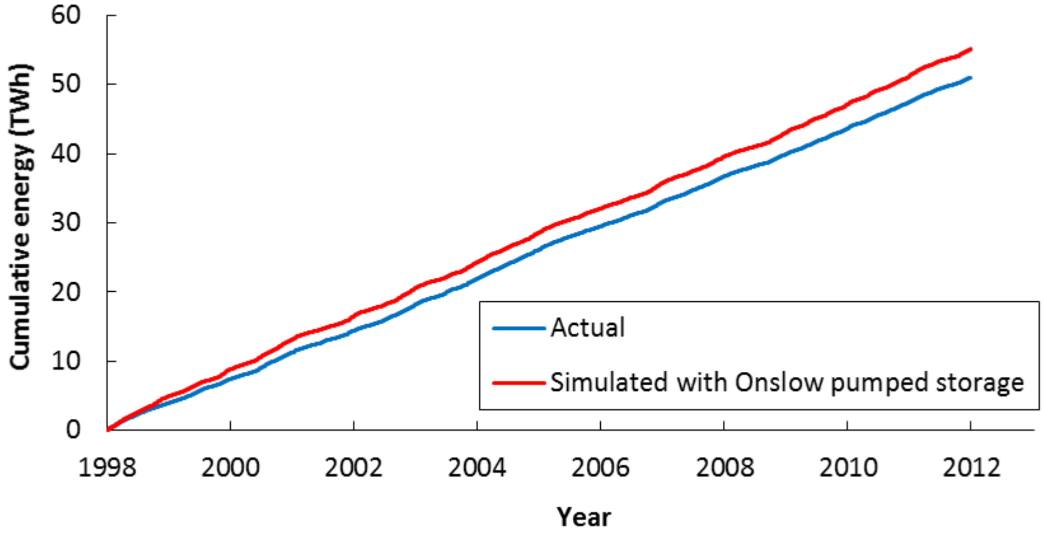

*Figure 4.8 Cumulative energy generated at Clutha hydropower scheme, with and without pumped storage, 1998-2012. The difference is equivalent to 33.9 MW.*

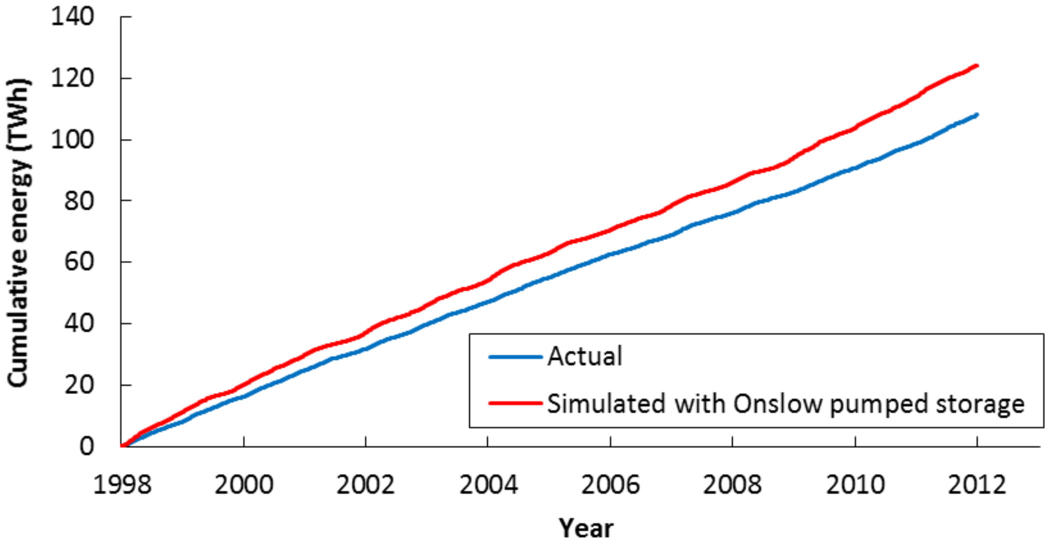

*Figure 4.9 Cumulative energy generated at Waitaki hydropower scheme, with and without pumped storage, 1998-2012. The difference is equivalent to 102.7 MW.*

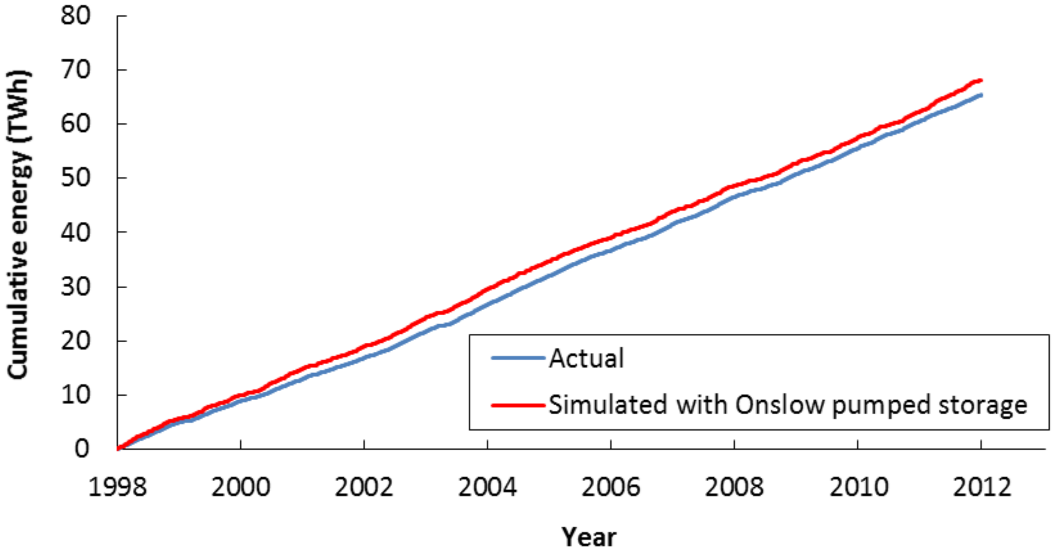

*Figure 4.10 Cumulative energy generated at Manapouri hydropower plant, with and without pumped storage, 1998-2012. The difference is equivalent to 21.9 MW.*

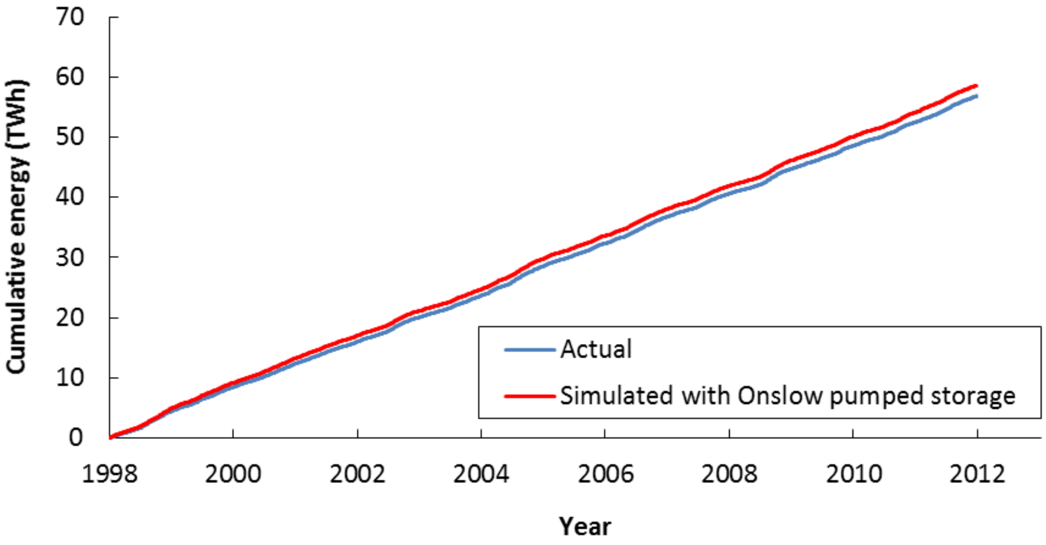

*Figure 4.11 Cumulative energy generated at Waikato hydropower scheme, with and without pumped storage, 1998-2012. The difference is equivalent to 14.34 MW. The power gain is minimal compared to another schemes. Note: it didn't incorporated transmission loss in the figure.*

The cumulative energy lost through spill at the Clutha and Waitaki hydropower schemes in reality and in pumped storage simulations 1998-2012 is illustrated in Figure 4.12 and Figure 4.13. The simulated Onslow pumped storage system saves these two schemes 16,760 GWh by reducing spill. This is equivalent to a mean daily power output of 136.57 MW. The spill loss from the Clutha hydropower scheme is higher than the Waitaki hydropower scheme in the pumped storage simulation model as flood outputs from Lake Wanaka and Lake Wakatipu cannot be controlled.

A similar scenario was applied in the simulation for the Waitaki scheme. Reducing the amount of energy lost from spill water increases the efficiency of hydropower schemes. The actual energy lost from spill was calculated using data from the HMD.

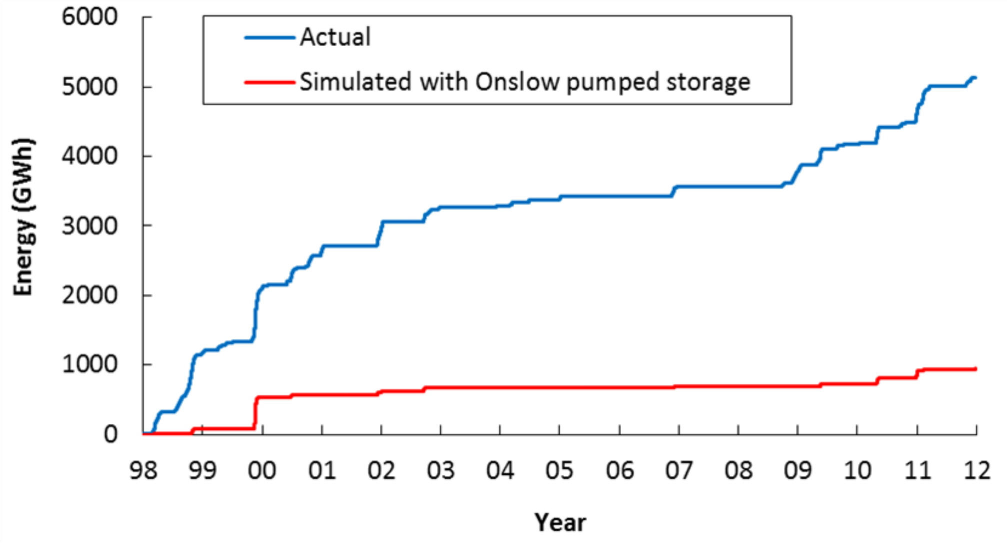

*Figure 4.12 Actual and simulated cumulative energy loss from spill at Clutha hydropower scheme. The difference is equivalent to 33.9 MW.*

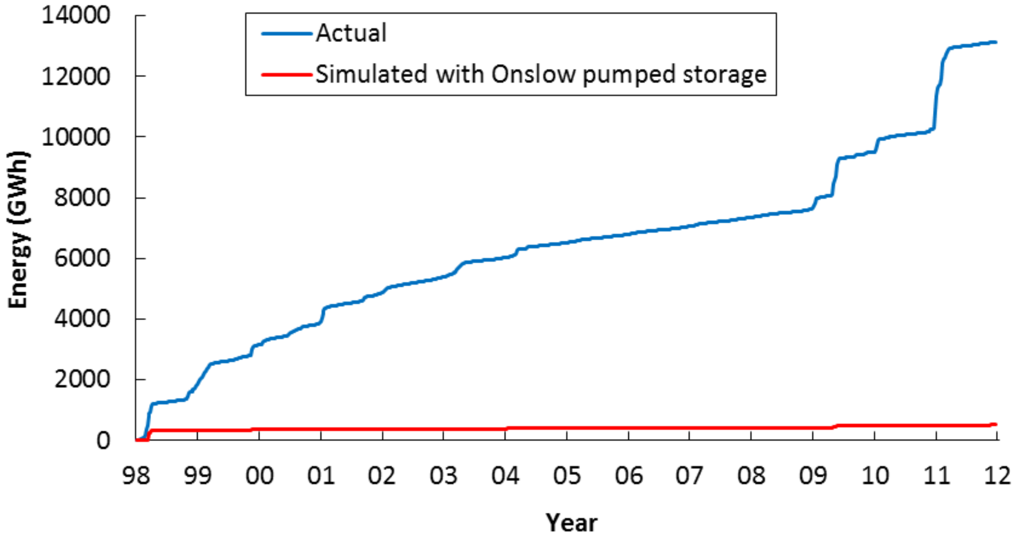

*Figure 4.13 Actual and simulated cumulative energy loss from spill at Waitaki hydropower scheme, equivalent 102.6 MW.*

## 4.8 Operation of Onslow pumped storage

Figure 4.14 shows the simulated water level of the Onslow storage reservoir for the recorded period. There is fluctuation in water levels in the upper reservoir every year as most pumping happens in summer, at a time of surplus power availability in the grid, and most generation occurs in winter when there is a high demand for electricity.

The simulation started with initial zero storage at 720 masl in 1998, then there was an increase in the level, especially in the wet years of 1998 and 2000, reaching

771 masl. Then there was an increase with a fluctuation to reach 777 masl in mid-2004. Then there is a downward trend in water levels over 5 years, including the dry years of 2006 and 2008, to reach a minimum operational level of 736 masl. The wet years 2009 and 2010 increased the level, reaching the maximum operational level of 779 masl in 2011. The fluctuation in water level over the 14 years suggests that a possible long-term mean output power source can sustain and support the electricity supply. The upward trend in operational level is due to the fact that overall gains in spill losses are enough to offset energy losses in pumping and generating and provide long-term mean power output as discussed in the previous section.

Figure 4.14 also shows the proposed Onslow pumped storage plant is an efficient system for dry year energy back-up and for balancing and storing the energy generated by other renewable energy sources. The main benefit of the Onslow scheme as a security power supply is the guarantee of year-to-year sustainability of hydro power output by providing sufficient storage capacity to buffer the effects of natural climatic variation. This can be seen in the dry years between 2004 and 2009, where additional electricity could have been generated.

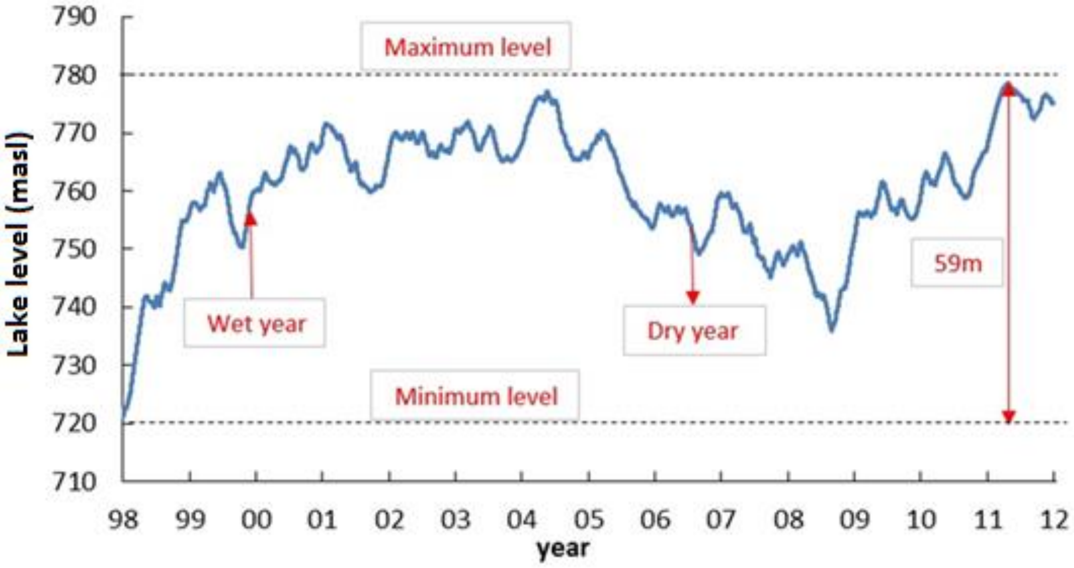

*Figure 4.14 Simulated Onslow water reservoir water level from 1998-2012. Starting point is zero storage at 720 masl.*

The percentage of volume of water pumped was 54% while the percentage of volume of water released was 46% during operation of the simulated Onslow pumped storage system (1998-2012).

Storing water in the upper reservoir for long periods for later use, as for example between 2000-2006 and 2009-2012, may reduce the benefit of the operation. However, it is there as a buffer if needed. The Saurdal PHES in Norway for example would also store water for long periods and still create a benefit. As discussed before the Onslow PHES will still:

1. Have the benefit of reducing water spill.
2. Reduce fluctuations in the hydro lakes and keep most of them near mid-range levels, which makes water more available for irrigation without pumping.
3. Support the development of wind energy and renewable energy as will be discussed in Chapter Five, thus reducing the emission of carbon dioxide.
4. Increase summer water availability for irrigation in the Lower Waitaki valley, as will be discussed in Chapter Six.
5. Regulate electricity, thus mimimising concerns about loss of income due to water storage. This means that an operator can buy electricity cheaply, have the water pumped to the upper reservoir, where it is stored for future use and electricity can then be sold at a large profit later when demand is high, as will be discussed in Chapter Eight. However, the way the market works, traders would jack up the price as soon as pumping started.
6. Reduce the transfer of North to South Island power, especially in winter, which creates environmental value as some North Island power supplies are derived from fossil fuels, so losses in transmission mean greater amounts of carbon dioxide emissions are produced. The transmission losses occurs in the HVDC Inter Island link of a 610 km long would be approximately 3.5% [107].
7. Reduce the risk of blackouts during peak demand periods and shortages during dry years.
8. Stabilise system voltage and frequency.

### 4.8.1 Pumped storage model results in wet year 1998

1998 can be characterised as a year of prolonged wet periods and floods. The simulated pumped storage reservoir therefore gained a large potential energy increment of 3,588 GWh, equivalent to increasing the level in the upper reservoir from 720 to 756.3 masl. In 1998, the simulated lake levels were lower than the recorded levels, which significantly reduced the water spill from the Clutha (1,095 GWh), Waitaki (1,829 GWh), Manapouri and Waikato hydro power schemes. The simulated Lake Hawea was higher than the mid-range due to high inflow, combined with reducing release to prevent spilling water at Clyde and Roxburgh stations as the Clutha scheme includes two uncontrolled large lakes. However, the dominant simulated Lake Hawea level was near mid-range for most of the operation period as shown in section 7.2.1. Lake Pukaki maintained its target level of 529 masl for 7 months and was below the actual level for most of the year.

Simulations showed a major reduction in lake level fluctuations at Lake Taupo and maintained its target level for the entire year. The modified operation of hydro power schemes in conjunction with Onslow PHES illustrates the national power saving from avoided water spill (Figure 4.15, Figure 4.16, Figure 4.17, Figure 4.18).

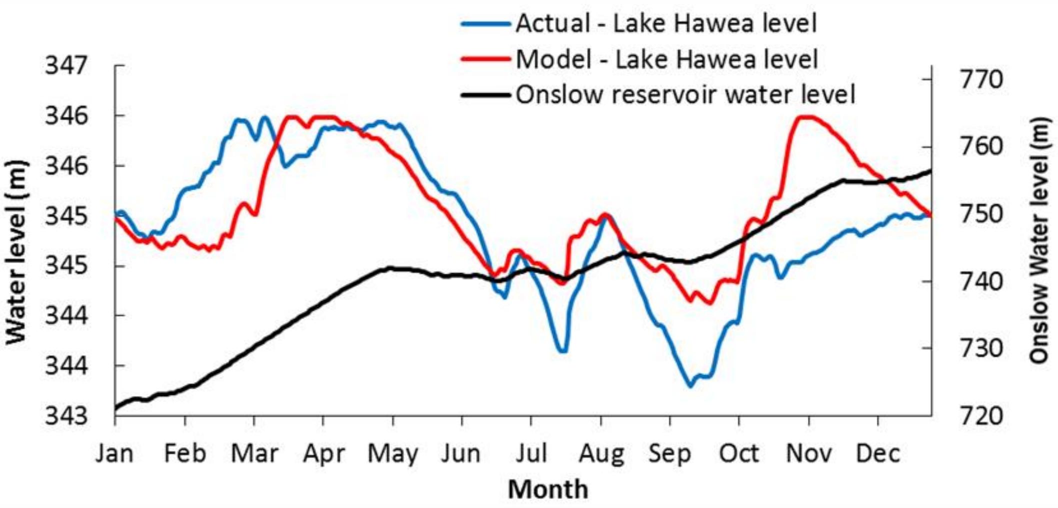

*Figure 4.15 Onslow water reservoir water level and Hawea water level: actual and modelled using pumped storage in wet year1998.*

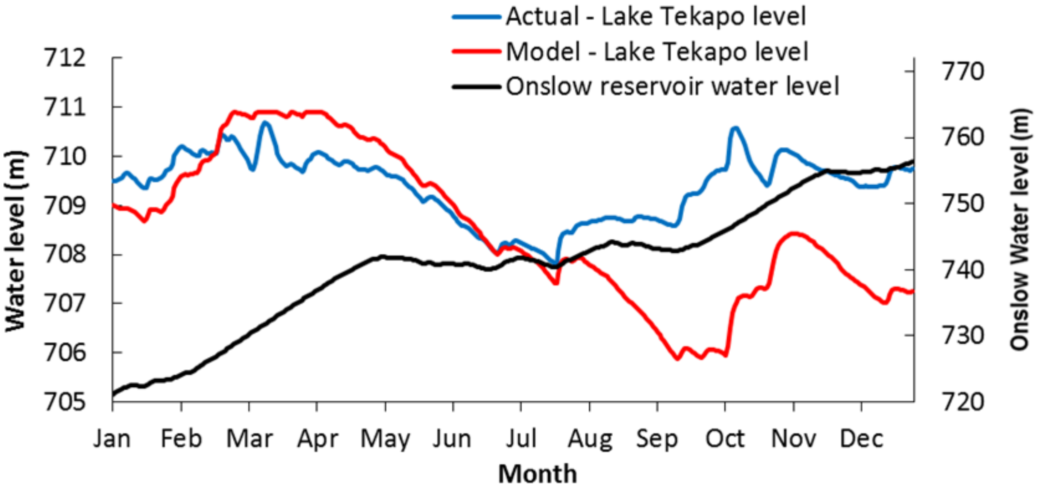

*Figure 4.16  Onslow water reservoir water level and Tekapo water level: actual and modelled using pumped storage in wet year1998.*

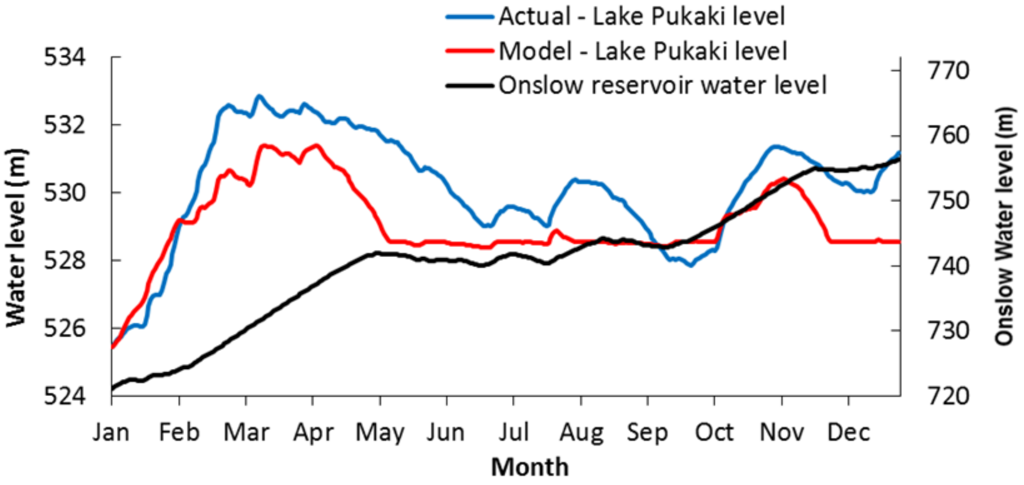

*Figure 4.17 Onslow water reservoir water level and Pukaki water level: actual and modelled using pumped storage in wet year1998.*

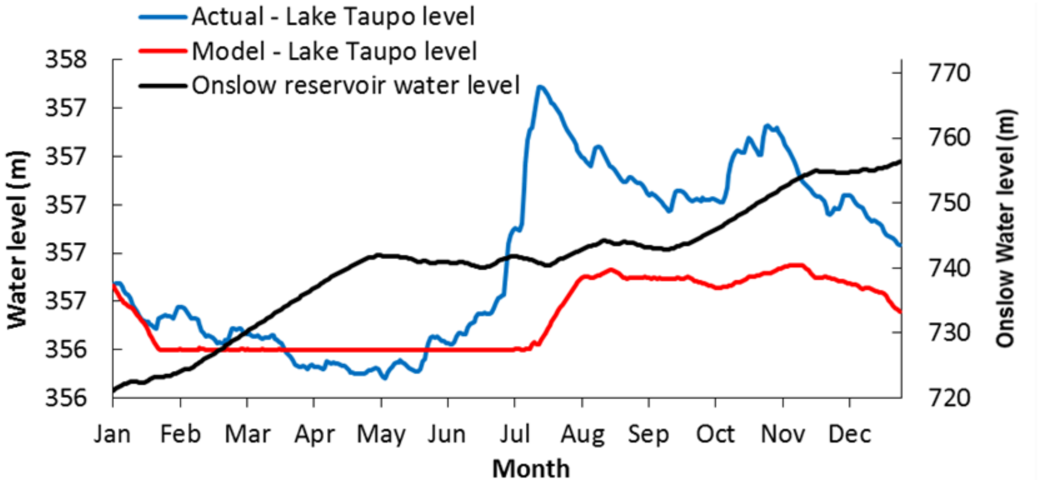

*Figure 4.18 Onslow water reservoir water level and Taupo water level: actual and modelled using pumped storage in wet year1998.*

### 4.8.2 Pumped storage model results in dry year 2001

The year 2001 can be characterised as a dry year. The Onslow hydropower output in 2001 was considerably increased using the model, to the extent that the effect of this dry year was effectively eliminated. As shown in Figure 4.19, Figure 4.20, Figure 4.21, Figure 4.22, generation from the Onslow scheme was carried out from February to October, making the level of the upper reservoir drop from 772 to 760 masl, which is equivalent to 1,827 GWh in order to compensate for the low inflows over the autumn to late winter period, maintain the levels in the hydro lakes near mid-range and maintain a stable hydropower output throughout the year. For example, the Onslow PHES simulation allowed Lake Hawea levels to be held near mid-range throughout the dry period of 2001 while power was maintained by pumped storage release (see Figure 4.19).

Lake Hawea maintained its mid-range level of 342 masl for around 8 months of the year, only increasing after a brief high inflow at the end of November, which caused a pause in pumped storage generation. However, actual release from Lake Hawea continued, to reach 339.3 masl. The same was observed for Lake Pukaki (Figure 4.21); the simulated Lake Pukaki was able to maintain its target level of 528 masl for the entire year. The actual level of the hydro lakes obviously illustrates how the national power crisis would have been averted in 2001 if the Onslow PHES had been in operation.

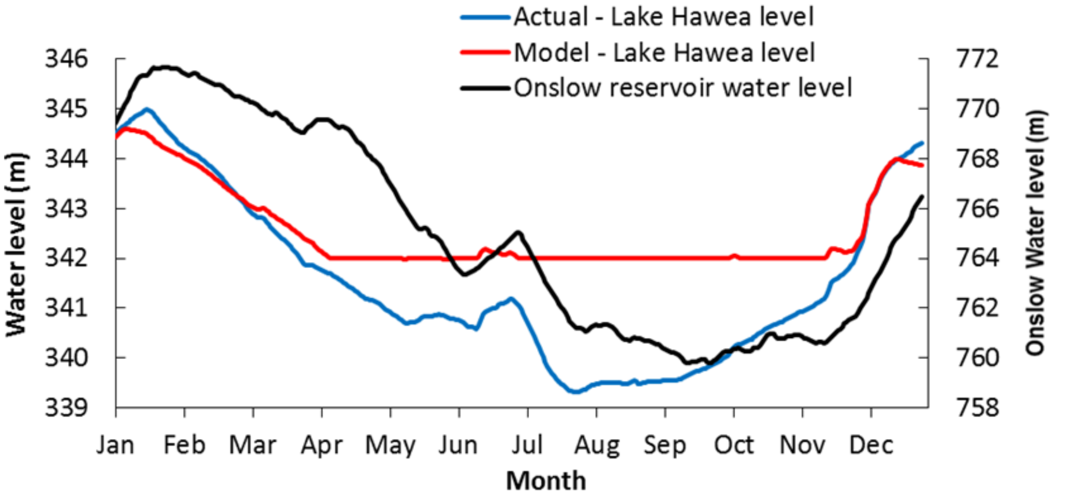

*Figure 4.19 Onslow water reservoir water level and Hawea water level: actual and modelled using pumped storage in dry year 2001.*

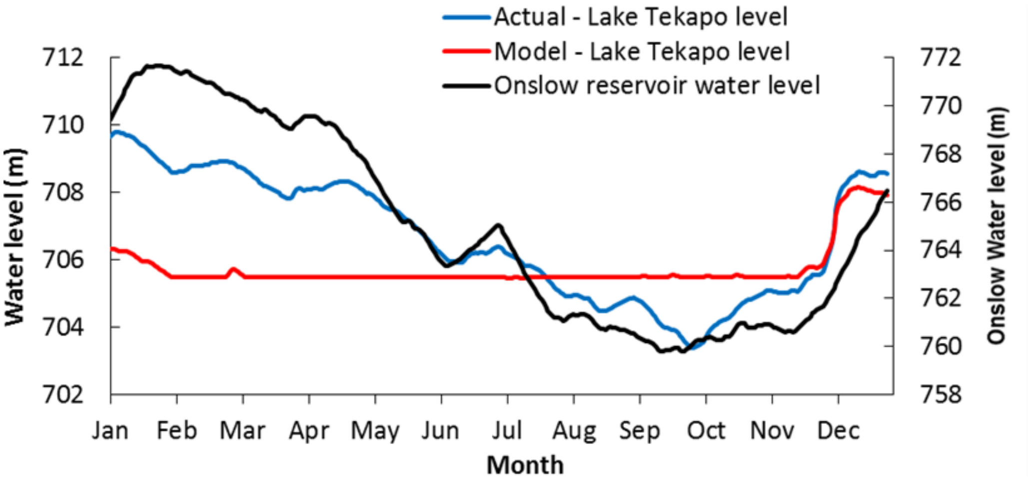

*Figure 4.20 Onslow water reservoir water level and Tekapo water level: actual and modelled using pumped storage in dry year 2001.*

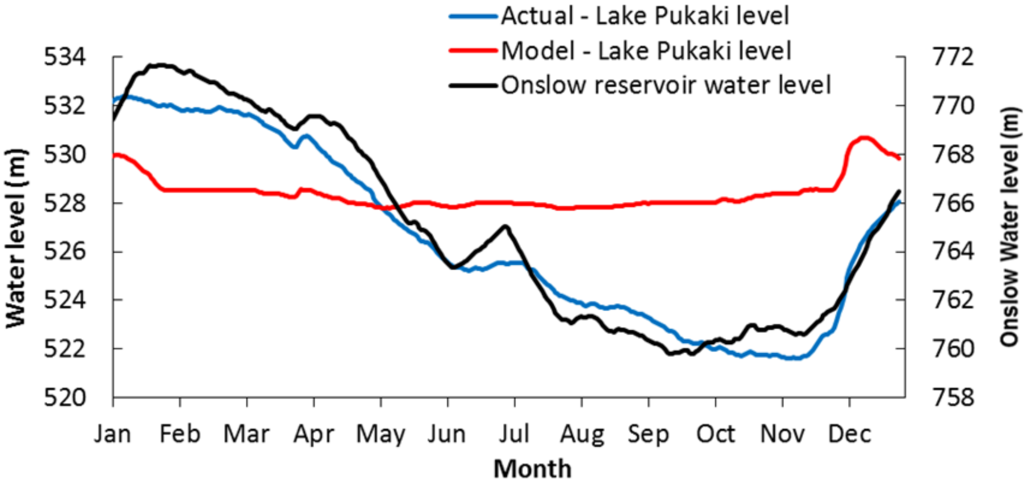

*Figure 4.21 Onslow water reservoir water level and Pukaki water level: actual and modelled using pumped storage in dry year 2001.*

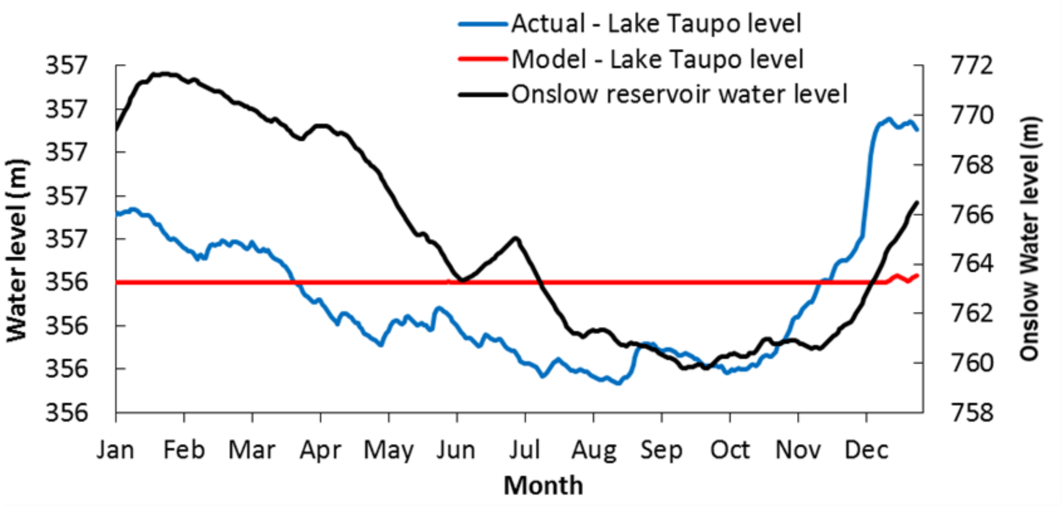

*Figure 4.22 Onslow water reservoir water level and Taupo water level: actual and modelled using pumped storage in dry year 2001.*

# Chapter Five: Wind power development in conjunction with Onslow pumped storage

## 5.1 Background

In 2011 some 75 countries worldwide had developed commercial wind power installations, as a result of which 41 GW of wind power came online, raising the total installed global capacity to 238,351 MW. The installed capacity continued to increase globally to reach 539,581 MW in 2017. Markets in such diverse locations as Morocco, India, Mexico and Canada range in the area of $US 0.03/kwh. Figure 5.1 shows the cumulative global wind generation capacity 2001 – 2017 in MW [108].

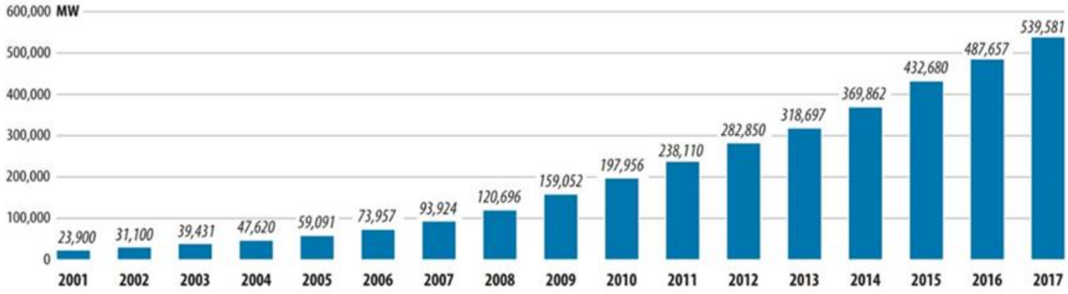

*Figure 5.1 Cumulative MW of global wind generation capacity 2001 – 2017 (Global Wind Energy Council, 2018) [108].*

Wind energy is abundant in New Zealand, which has one of the best wind resources in the world. In New Zealand, wind generation increased from 138 GWh in 2001 to 1,930 GWh in 2011, representing an average increase of 28% per year over that period. As of 2018, New Zealand has 19 operating wind farms with a combined installed capacity of 690 MW, accounting for 6% of total generation. The wind farms range in size from a single 100 kW turbine at Southbridge to 134 turbines with a total capacity of 161 MW at the Tararua Wind Farm [109]. Most existing wind generation is located in the Waikato, Manawatu and Wellington regions and Southland. Future growth areas (from 2018) include Northland, the Waikato west coast, South Taranaki, Hawkes Bay, Canterbury, Otago and Southland (Figure 5.2).

The current (2018) energy strategy of the New Zealand Government remains one of moving toward increased renewable generation, with a target of 90% of electricity coming from renewable sources by 2025. The present intention is the government will prepare a transition plan to achieve 100% renewable electricity generation, in a normal hydrological year, by 2035. NZ Wind Energy Association's vision is that wind power will account for around 20% of national electricity generation by 2035. New Zealand's wind energy resource is key to realizing the goal of 90% renewable energy by 2025. In 2011 renewable energy sources stood at approximately 77%. To help achieve the 90% renewable energy target, the Government legislated against any new fossil fuel-based generation for a 10 year period from 2008 [9]. However, several gas turbines have been commissioned since then.

*Figure 5.2 Wind power stations in New Zealand [9].*

Because of its intermittent nature at all timescales, wind power cannot be guaranteed to be available to make up electricity shortfalls in dry years. For example, a system of anticyclones may result in low hydro inflows while at the same time causing reduced wind power availability. However, the use of wind power in previous years may enable higher levels in hydro lakes going into a dry period, which might otherwise have resulted in increased carbon dioxide emissions from thermal stations.

Generation by hydro power plants decreased by 4% due to low hydro lake inflow in 2012, leading to an increase in generation by thermal power plants. Seasonally, however, wind power may not coincide well with the seasonal cycle of South Island hydro inflows because as a seasonal average, wind power generation tends to be highest in spring when South Island hydro lake inflows are also highest. In a high-inflow times this could result in the preferential use of wind power simply creating more spring hydro spill than otherwise would have been the case. At the other extreme, during winter, in situations of high power demand, direct use of wind power cannot be relied on and may be as low as 10% of installed capacity, compared to an average capacity factor of 35 - 40%. This increases the problems of dry year reserve.

There is presently (2018) a problem with further expansion of wind power in New Zealand, desirable though it may be deemed to be. The issue arises from the intermittent nature of wind power output on short timescales. Short-term wind speed changes cannot be predicted more than a few hours ahead at a given location, and the timing of any wind speed changes can be particularly difficult to predict. The nature of variability on hourly time scales is well illustrated in Figure 5.3, showing the daily variable wind generation over four sequential days (58MW capacity). Wind power is at a maximum in the springtime and a minimum during the autumn and early winter peak demand periods [110].

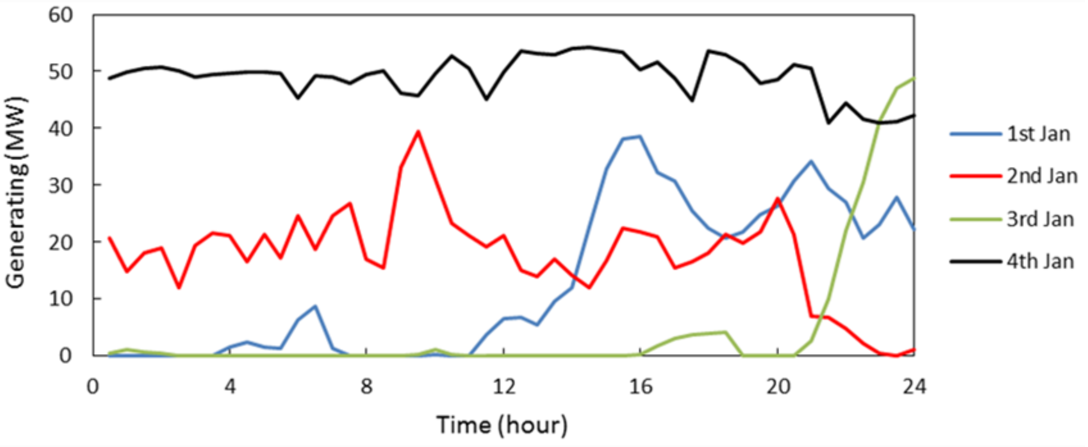

*Figure 5.3 Mean power output (MW) per half hour from White Hill wind farm (58 MW capacity) in Southland Region (1-4 January 2012).*

The impact of intermittent wind energy on the grid will have a constraining effect on future wind power development. In 2013, around 54.5% of the electricity in New Zealand was sourced from hydro generation, 24.8% from thermal generation, 14.5% was geothermal and only 4.8% was wind generation. However, as wind power installed capacity increases there is an increasing need for complementary energy availability if wind power output suddenly drops below the levels forecast a few hours prior. Using hydro power plants to balance short term wind energy availability means hydro will not be as readily available for other short-term reserve purposes [111].

A good local example of this constraining effect on wind power development is seen from Trustpower's Mahinerangi power stations in Otago, with synergies between hydro power capacity of 84 MW, wind power capacity of 36 MW and irrigation [112], as shown in Figure 5.4. The peak wind power generation times during the day tend to coincide with lower electricity prices because wind farm owners don't offer their generation into the market in five price bands. When the market closes, the system operator dispatches supply at least cost. Therefore, when wind generation is high, Trustpower reduces the release of water from Lake Mahinerangi to reduce hydro generation to keep the stored lake water for later use when there is low wind generation or high prices.

However, expansion of the system at Lake Mahinerangi is constrained because the lake has a limited storage capacity, with high inflow in summer months sometimes causing water spill losses due to high lake levels. There is a proposal

(2018) to increase the capacity of the Mahinerangi wind farm to 200 MW. However, this would mean there could would no longer be a good balance achieved between wind and hydro generation because of the relatively limited storage buffer at Lake Mahinerangi. There is also the issue of limited hydro generation capacity to buffer sudden short-term drops in wind speed. There might also be potential downstream impacts on irrigation due to the reduced water release resulting from high wind energy generation coinciding with low demand periods, as Lake Mahinerangi is an important water storage area for irrigation of the lowland and basins during the dry summer/autumn period [113]. This issue of storage buffer requirement on wind power development extends to the country as a whole.

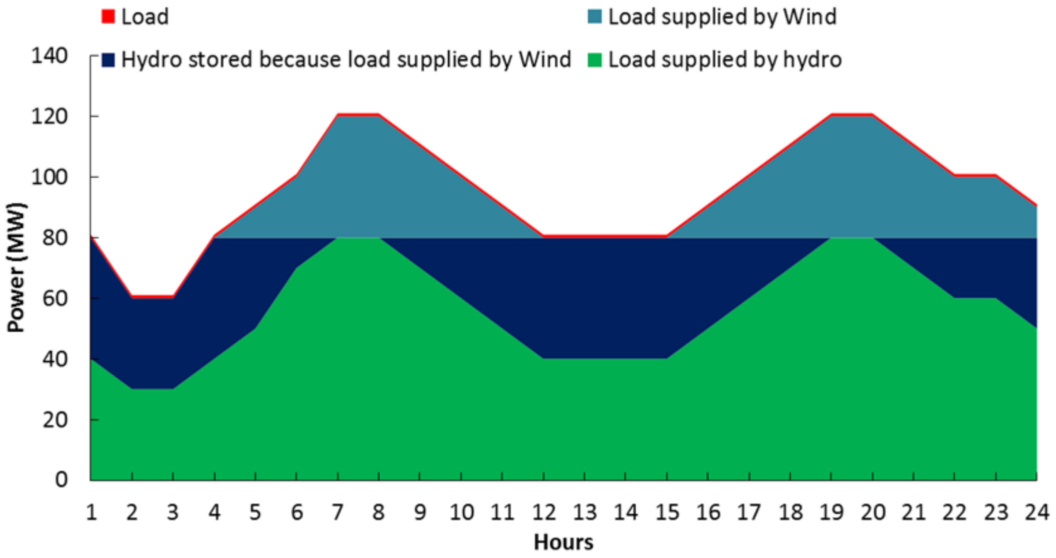

*Figure 5.4 Load component supplied by profile of 80 MW hydro capacity and 40 MW of Wind capacity for a typical day (adjusted) [112].*

There are also times when high wind energy production coincides with excess energy in the grid that cannot be supported by demand. This leads to a situation of wind energy loss by disconnecting from the grid to keep the frequency within an acceptable range. Likewise, there are times when very low wind energy production coincides with low hydro storage and low hydro generation. While the share of wind generation is 6% of the national power portfolio, this problem can be solved by increasing thermal power generation as a reserve. But increasing the wind energy share in the future to 20% adds a source of major fluctuations, increases the difficulties of keeping the frequency within an acceptable range, and poses economic challenges. There will also be a problem in securing the power supply unless thermal power is added as a reserve or a way is found of storing the wind energy that supports the frequency-maintenance requirements and can provide regulation reserves.

Another problem is that wind is variable in time and space and seldom correlates in time with the load profiles. These characteristics of variable renewable energy sources challenge the adequacy of a power system’s energy and power balance, and its voltage and frequency regulation [114].

Insufficient buffering for future wind energy development may cause stress on electrical components due to thermal cycling and ramping rates, stress on thermal gas turbine cores due to flame instability, and stress on hydro turbine runners due to cavitation. It also makes the operation of thermal power stations uneconomical during high wind generation as the thermal stations have to function at non-optimal operating efficiency. The effect of this situation is to increase the short-term volatility of wholesale electricity prices.

The impact of large amounts of new wind generation on the stability of any power system can be significant, especially if the wind generation is not equipped with Fault Ride Through (FRT) capability. If wind generators without FRT capability are widely used, a fault in the power system may cause voltage sags that can cause large amounts of wind generation to disconnect from the power system. The consequences include fast frequency drops, load shedding and voltage stability problems [115]. In the NZ electricity grid this would increase the amount of spinning reserve required.

In years where there is a dry spring and hydro inflows are low, New Zealand could be dependent on geothermal, wind energy and high use of thermal power plants to provide security of power supply and to maintain power supplies in the following winter. In this case there would be significant carbon dioxide output in dry years, in addition to considerable costs with minimal returns. The second option, creating new storage by raising existing lake levels, is no longer feasible in New Zealand because of environmental considerations.

Pumped storage schemes, as discussed in Chapter Two, are widely used as a potential solution for supporting a high share of variable renewable energy sources with a goal of also minimising economic and technical constraints. The pumped storage scheme at Onslow as previously described provides an alternative to allow for significant development of wind energy to reduce drawdown from hydro lakes. As noted earlier, it involves the construction of a seasonal (1,300 MW) pumped storage hydro at Onslow (Central Otago) with sufficiently large storage capacity to buffer the effects of a dry year as well as intermittent and unpredictable wind energy, and provide ancillary services.

## 5.2 Model formulation: integrating wind generation with the proposed Onslow pumped storage

The HVDC can transfer 1,200 MW between the North and South Island. It is therefore convenient, for the purposes of this chapter, to simulate the proposed pumped storage scheme in conjunction with wind power as generated throughout New Zealand. This section discusses the model used.

Wind power generation in 2012 was used in the model as the start year. The 2012 data was provided by the Electricity Authority and serves as a typical year. Figure 5.5 shows total generation due to wind energy in New Zealand in January 2012 and Figure 5.6 provides an example of the development of an installed capacity of 2,600 MW, which is double the installed capacity of the Onslow PHES. This example shows the minimum energy is below 600 MWh with an installed capacity of 2,600 MW. Average wind generation over a year was used as the demand as an input variable in the model, and the actual wind generation portfolio used a half-hour lead time to investigate the technical and economic feasibility of integrating wind power generation with the pumped storage scheme, and to check whether variations in wind power production would affect the other power production units.

Eight scenarios were created in the simulation model, showing an increase in installed capacity every year, starting with no increase in wind energy provision and progressively increasing by add 1%, 4%, 8%, 12%, 16%, 20%, and 24% every year for wind installed capacity. Figure 5.7 shows possible scenarios of developing installed capacity in MW of wind energy in the future in the eight scenarios applied in the model.

$$Generating\ Capacity\ (MW) = x + \ x\,y$$

Where, $x = Generating\ Capacity\ in\ 2012$

$y = increase\ in\ installed\ capacity\ every\ year$

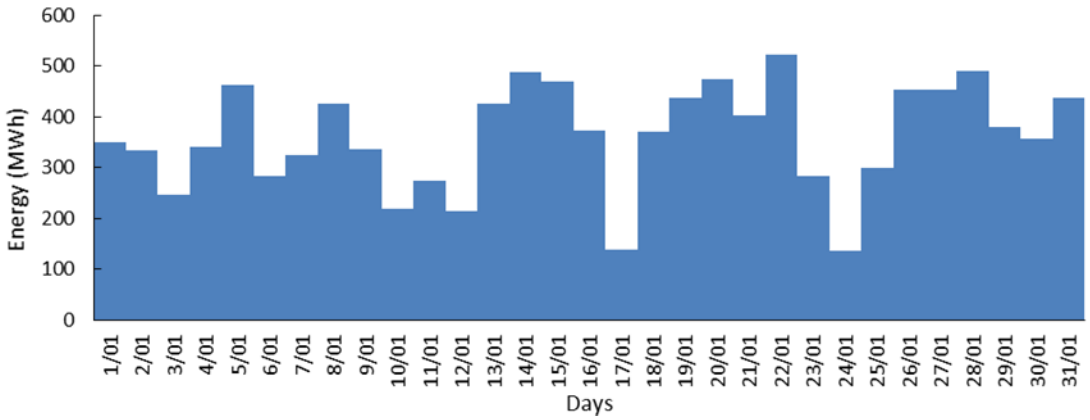

*Figure 5.5 Generated wind energy for installed capacity of 622MW in January 2012.*

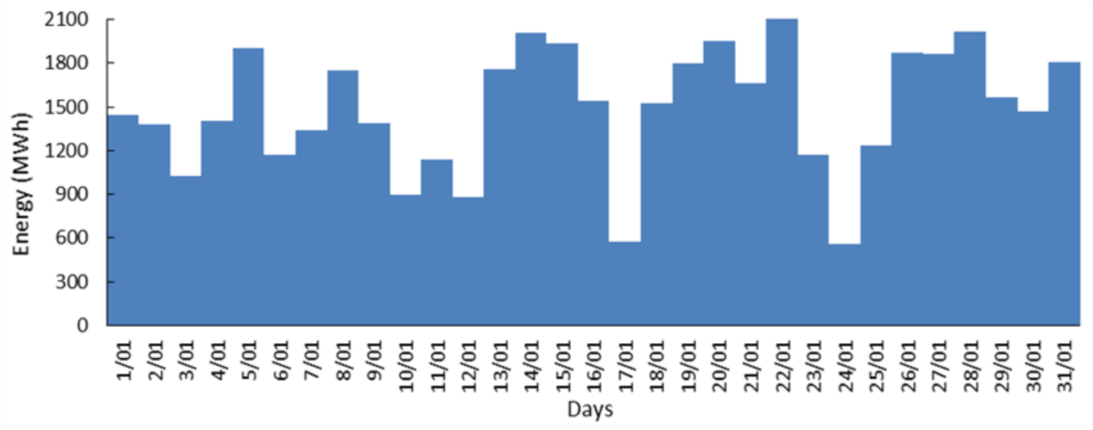

*Figure 5.6 Generated wind energy in the model for installed capacity of 2,600 MW in January.*

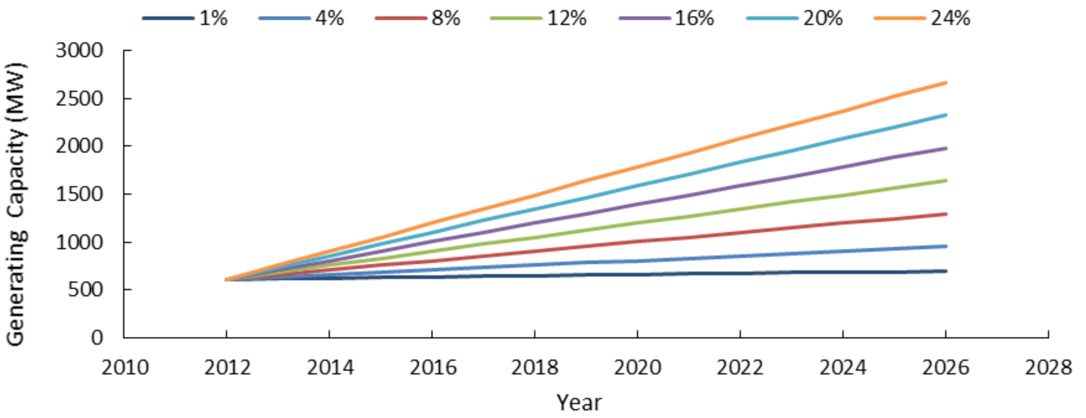

*Figure 5.7 Possible scenarios of developing installed capacity in MW of wind energy in the future in the eight scenarios applied in the model.*

## 5.3 Simulation model of Onslow operation and analysis of the results

As noted earlier, the computer simulation model of the Onslow PHES was operated with a simplified model of the Clutha, Waitaki, Manapouri, and Waikato hydro power schemes, with wind energy development. All water transfers and energy values are on a 30-minute timestep (trading period half-hourly data). As discussed in Chapter Four, the actual fluctuating wind energy was considered as output power per half hour in the model. However, the demand from the wind energy section of the model was considered as the annual average wind energy as a base reference in 2012. For example, taking 50 MWh as the demand (average annual output) and an actual output of 90 MWh then the surplus energy would be 40 MWh. In this case would the Onslow PHES be able to absorb the 40 MWh?

The simulation was performed using eight scenarios for wind energy generation capacity, to compare the benefits of integrating pumped storage in each case. The first scenario, with no increase in wind energy development, represented the lowest possible level of wind energy generation and the 24% increase assumed in this study is the maximum potential future development. All scenarios were conducted in conjunction with modified operation of hydro power schemes in half-hour simulation periods for 1998-2012.

### 5.3.1 Operation of the pumped hydro storage with and without wind energy development in the future.

The results of applying the model with and without wind energy development are shown in Table 5-1. The simulation with 24% wind energy development shows that almost 20,437 GWh, and without wind energy development 20,630 GWh per half hour could have been used and stored through avoided spill from 1998-2012. The total difference within the simulation periods is 193 GWh, which is equivalent to 1.415 MW.

*Table 5-1 Results of operating possible Onslow pumped storage for a range of wind energy senarios.*

| Wind energy development | 0 % | 1% | 8% | 16% | 24% |
|---|---|---|---|---|---|
| Mean daily power output through avoided spill throughout New Zealand in MW between 1998-2012 | 168 | 167.97 | 167.81 | 167.3 | 166.58 |
| Equivalent mean power output (MW) between 1998-2012 | 18.85 | 18.85 | 18.85 | 18.85 | 18.85 |
| Energy stored at upper reservoir GWh at the end of simulation | 6412 | 6382 | 6265 | 6052 | 5782 |
| Equivalent mean daily power output (MW) between 1998-2012 | 47 | 46.72 | 45.78 | 44.04 | 41.87 |
| Energy loss due to operation of pumped storage in TWh per half hour | 10.32 | 10.34 | 10.44 | 10.6 | 10.77 |
| Equivalent to power loss MW between 1998-2012 | 84.1 | 84.32 | 85.1 | 86.35 | 87.73 |
| Energy loss from wind energy GWh per half hour | 0 | 2.77 | 4.92 | 7.41 | 10 |
| Equivalent to power MW between 1998-2012 | 0 | 0.022 | 0.04 | 0.06 | 0.0814 |

The operation of the model with the zero wind energy development scenario shows that the Onslow pumped storage system could absorb all the extra wind energy with no wind energy development or compensate for any shortfall in the grid in the case of low wind energy availability. Similarly, there is a loss of 0.01% with a 24% development in wind energy every year. In other words, a pumped hydro energy storage of 1,300 MW can absorb all the excess energy dispatched to the grid with or without wind energy development. The simulation shows that every 1 MW of pumped storage can support another 2 MW of wind. The above results were compared with wind energy development in five scenarios, as shown in Table 5-1.

Figure 5.8 shows the operating level of the Onslow reservoir in two simulation scenarios: no increase in wind energy development and 24% increase every year from 1998-2012. The amount of water pumped and stored at the Onslow reservoir decreases proportionally with increases in wind integration levels. The two curves in Figure 5.8 illustrating the operation of the pumped storage scheme with and without wind energy development display the same trend during operation.

Sending more wind energy to the grid reduces avoided water spill in the hydro power plants, which reduces the level of the Onslow reservoir. However, the pumped storage scheme shows it can support the goal of increasing the use of intermittent energy sources such as wind power even when wind power approaches a 20% or more generation share in the future. This would also provide a grid buffer as it moves toward renewable energy with fluctuating power outputs.

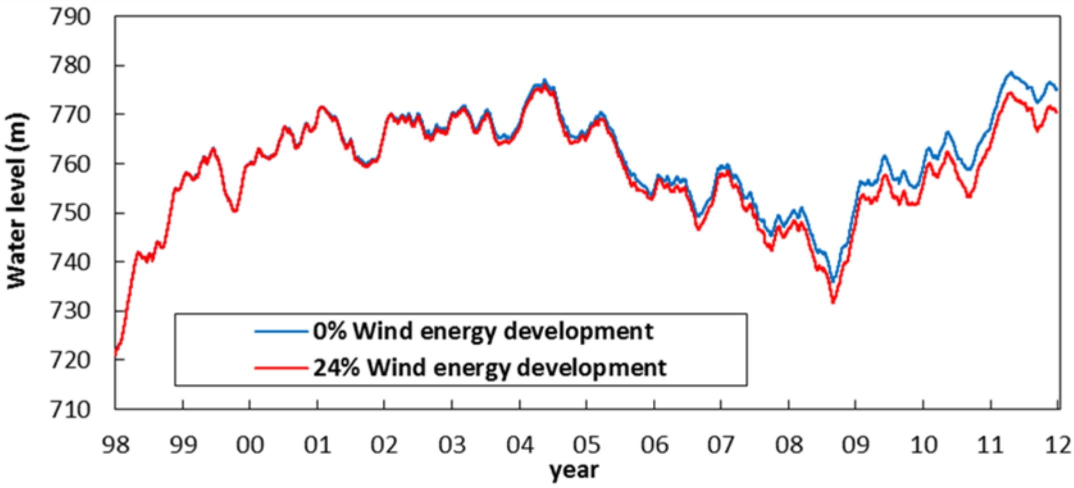

*Figure 5.8 Onslow water reservoir water level (1998-2012) in two scenarios: with no increase in wind energy development (blue line); and 24% increase every year (red line). Starting point is zero storage at 720 masl.*

# Chapter Six: Waitaki Valley improvement from pumped storage: increased irrigation water

## 6.1 Introduction

Irrigation began in the Waitaki Valley in the early twentieth century and has developed ever since. The generally temperate climate makes the area ideal for high-production agriculture, but a reliable supply of water is needed to maintain production levels, as the lower river catchment receives only around 500mm of rainfall annually. Irrigation is essential to the existing local economy, supporting a number of primary sector industries including horticulture, viticulture, arable farming, sheep and beef farming and dairying. A 2010 report by Lincoln University concluded that the Waitaki River is the most significant river for irrigation in Canterbury [116].

Competition for allocation is fierce and often litigious, and occurs between hydroelectric power schemes and irrigation, or between irrigators themselves. This has been in evidence on the Waitaki River where Meridian Energy Limited's Project Aqua hydroelectricity application and numerous irrigation applications prompted a Ministerial call-in, which was followed by special legislation requiring the promulgation of a water allocation plan [117].

The seasonal Onslow pumped hydro storage scheme offers a useful consequence of maintaining stable hydro lake levels so that more summer water is available in the Waitaki, which makes more irrigation a viable option.

The aim of the chapter is to demonstrate the value of extra Waitaki summer water, under the scenario of use to maximum possible extent.

## 6.2 Current irrigation in the Lower Waitaki

There are currently over 580 irrigators, with an irrigable area in the Waitaki valley of over 80,000 hectares across North Otago and South Canterbury, representing approximately 12% of the irrigated land in New Zealand. The irrigators within the catchment take water from the Lower Waitaki River, a number of tributaries, or from the complex groundwater system. The irrigators contribute approximately $NZ 550M per annum in gross income to the local and national economies, and represent a capital value of land and infrastructure in excess of $2.5 billion. Figure 6.1 shows the current irrigated area in the lower Waitaki scheme [118, 119].

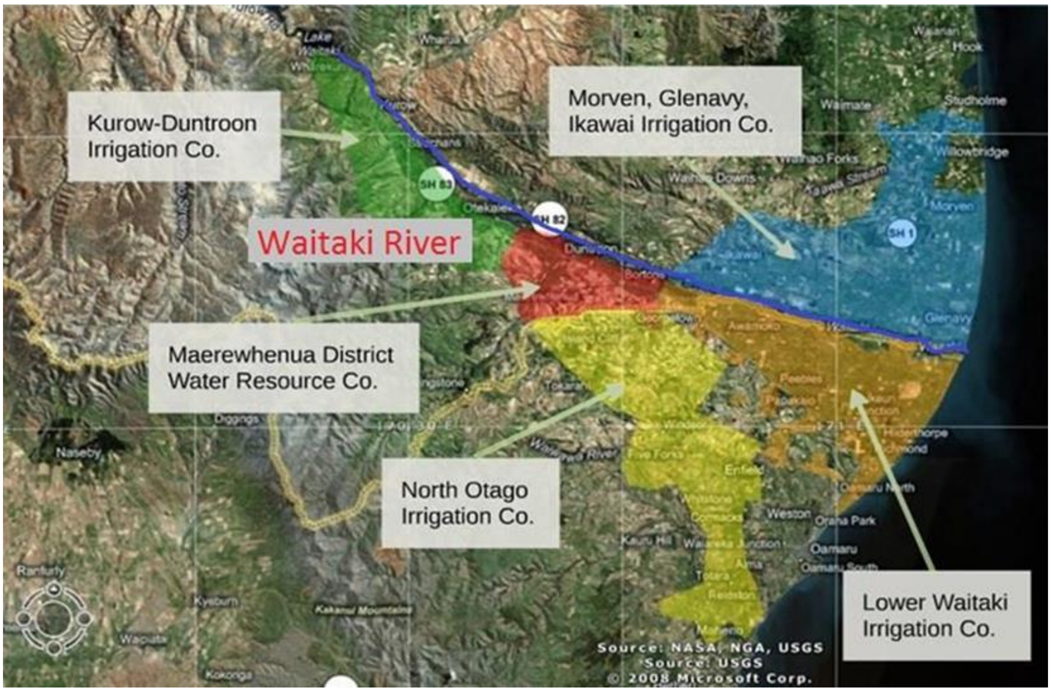

*Figure 6.1 Irrigated area in the Lower Waitaki scheme showing shareholders are the five irrigation schemes [120].*

The length of the Lower Waitaki River scheme is approximately 65km from the Waitaki Dam to the Pacific Ocean at Glenavy. Typically about 30% of the inflow to the upper Waitaki hydro lakes occurs in the summer months of December, January, and February, when power demand is lowest. Much of the water is, therefore, retained in controlled storage, particularly Lakes Tekapo and Pukaki, for generation later in the year when power demand increases and inflows are less. These two gated lakes represent around 41% of the total New Zealand hydro storage capacity.

Irrigation in the Lower Waitaki region is of importance to the national economy and security of irrigation supply is critical to ensure that optimum production levels can be reached. The current minimum flow as set out in the Waitaki Catchment Water Allocation Regional Plan is 150 $m^3s^{-1}$, to be measured at the Kurow recorder. Low summer flows (below 150 $m^3s^{-1}$) have a negative impact on production for farms in the lower Waitaki. It is assumed that 80 $m^3s^{-1}$ of the 150

$m^3s^{-1}$ is set aside for environmental requirements [121]. However, there is uncertainty about the ability to provide the minimum flow, which would equate to production losses.

## 6.3 Seasonal Variations in Waitaki flow before and after constructing the hydro dams: Impacts of current operation

The Waitaki River seasonal flow regime downstream of the Waitaki Dam at Kurow can be separated into two periods: firstly, the time of actual flow with minimal active lake storage control (1931-1979); and secondly, the present seasonal flow regime post-1979 (Figure 6.2). The mean flow (1931-1979) at Kurow was 376.8 $m^3s^{-1}$ and mean flow at Kurow after the construction of the hydro dams was 364.9 $m^3s^{-1}$ (1980-2015).

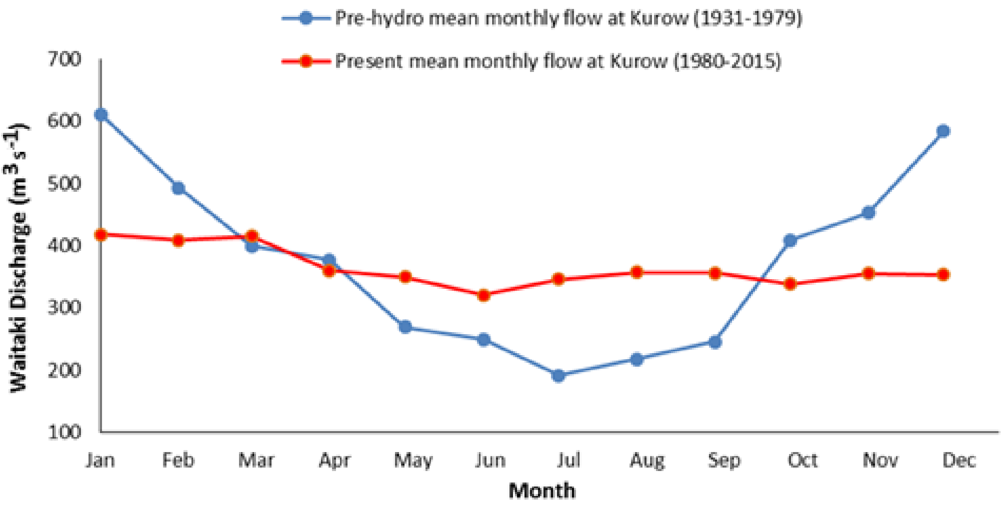

*Figure 6.2 Natural mean monthly flow at Kurow with minimal active lake storage (1931-1979) compared with mean monthly flow after construction of the hydro dams (1980-2015).*

At present the operating objective of Genesis Energy and Meridian Energy, which collectively operate the Waitaki scheme, is to store as much water as possible during the spring and summer months in the hydro lakes to last through the low winter inflow period and the associated higher demand for electricity. The operation of the hydro dams leads to a much flatter flow at Kurow. The natural seasonal Waitaki flow involves high average discharges in summer and low discharges in winter. The impacts of the operation, following construction of the hydro dams, in terms of water not available for irrigation and recreation at Kurow, are around 128 $m^3s^{-1}$ between October and February, as shown in Figure 6.2.

The current hydro operation has impact on the availability of water supply for irrigation and recreational activities. There is no allowance for efficient use of water, low support or provision for medium- to long-term investment certainty, and in otherwise drought-prone areas such as North Otago and South Canterbury it does not provide economic stability for the local community by improving outcomes in the social and economic areas of wellbeing.

Reliability of water supply is important not only from a farm economics standpoint. It also drives greater water use efficiency. Farmers who face unpredictable restrictions on the withdrawal of water due to low water flow in run-of-river schemes try to keep their soil moisture profile as high as they can because they are anxious that they may be restricted at any time. However, a "just-in-time" approach is more efficient, as water use is determined according to soil moisture deficit and plant growth requirements. This uses less water and reduces the risk of over-watering leading to wastage of water leaching through the soil, while also reducing the risk of contaminants entering the groundwater.

There was a plan, as stated in a Canterbury Regional Council document in April 2013, for providing an annual volumetric allocation of 150 million cubic metres of water per year, equivalent to 4.76 $m^3s^{-1}$, for agricultural and horticultural activities in the reach between the Waitaki Dam and Black Point [122]. However, it seems that this allocation had already been exceeded at the time the Plan was drafted, making even existing permits non-compliant with the Plan. It became clear that the intent of the Plan, to allow for future irrigation development from that part of the Waitaki River, was being frustrated as there was not enough annual volume to allow this to happen. Therefore there were concerns about future irrigation developments in the Lower Waitaki Scheme as these could negatively affect the current consent holders where irrigation reliability is already low, reducing irrigation reliability even further in an exponential manner [118].

The water wasted, in examples of hydro lake spill and unsuccessful management of operations as illustrated in section 1.1, would have been more useful for irrigation and recreational activities if it could have been released in summer.

## 6.4 New methodology for Waitaki River water management with Onslow pumped storage

This section focuses on formulations for water release for irrigation in the Waitaki scheme to gain from increased summer river discharge in the Lower Waitaki valley.

A model was developed for this section, which includes current water resource constraints issued in the Waitaki Catchment Water Allocation Regional Plan as discussed in 6.2 for releasing water for irrigation and recreational activities. The formulations for releasing water in the Lower Waitaki River for the current Waitaki scheme are used to secure a supply of irrigation water from the Lower Waitaki River for the existing 80,000 irrigated hectares of the lower Waitaki River catchment and would gain from extra summer water in the valley, which could enable a doubling of the current lower Waitaki irrigated area.

Figure 6.3 shows the current flow rates allocated to irrigation purposes for the Lower Waitaki River in the Allocation Plan, indicated as “a need for irrigation for current farms”. These flow rates must be provided above minimum flow as follows, in $m^3s^{-1}$: October to March, 80; April to September, 50; May to August, 20; and June and July, 10. The annual minimum flows downstream of the Waitaki station in $m^3s^{-1}$ in the model were set at 310 from October to March, 250 from April to September, 190 in May and 170 from June to August.

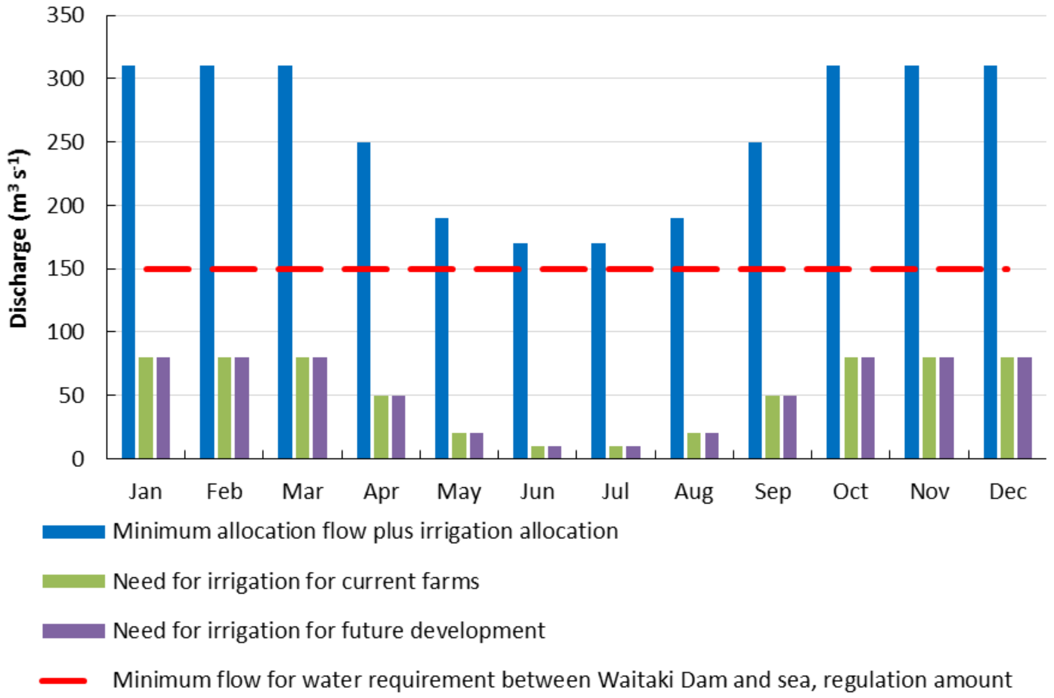

*Figure 6.3 Model formulation for releasing water for irrigation in the Waitaki valley to secure a water supply for the current 80,000 hectares and gain from extra water availability.*

## 6.5 Irrigation potential for the Lower Waitaki derived from Onslow pumped storage

Chapters Four and Five describe simulation models of the Onslow pumped hydro storage scheme, in conjunction with the modified operation of the Waitaki, Clutha, Manapouri and Waikato hydro power schemes and the inclusion of wind power. This section uses as input the modified discharge for the lower Waitaki River, as obtained from the model output from half-hourly time steps for the period 1998-2012.

The statistics for the model output (Table 6-1) show the expected matching of river actual and simulated mean discharges, so the model maintains water balance. The median flow in the simulated discharges was a little lower than the recorded flow because the operation of the model had the effect of shifting some higher discharges to 310 $m^3s^{-1}$. Median flow is the flow that is equalled or exceeded half the time over the period of analysis. Median flow differs from mean flow because discharge is not normally distributed.

The simulated flows show that the operation of the Onslow PHES as described earlier would have a significant effect on the Waitaki flow extremes at Kurow over the simulation period, with the maximum and minimum simulated values being 1,072.8 and 170 $m^3s^{-1}$, respectively, as compared with the corresponding actual discharges of 1,703 and 108.6 $m^3s^{-1}$. This in itself has implications for water availability because reduced maximum discharge reflects less water lost in flood events and instead held back in Lakes Pukaki and Tekapo.

*Table 6-1 Statistics for actual and simulated discharges for the Waitaki River at Kurow, 1998-2012 ($m^3s^{-1}$).*

| | Mean flow | Median flow | Minimum flow | Maximum flow |
|---|---|---|---|---|
| Actual | 350 | 334.2 | 108.6 | 1703.4 |
| Simulated | 349.6 | 314.2 | 170.0 | 1072.8 |

Figure 6.4 shows the comparison of average daily actual and simulated discharges for the Waitaki River at Kurow over the period of record.

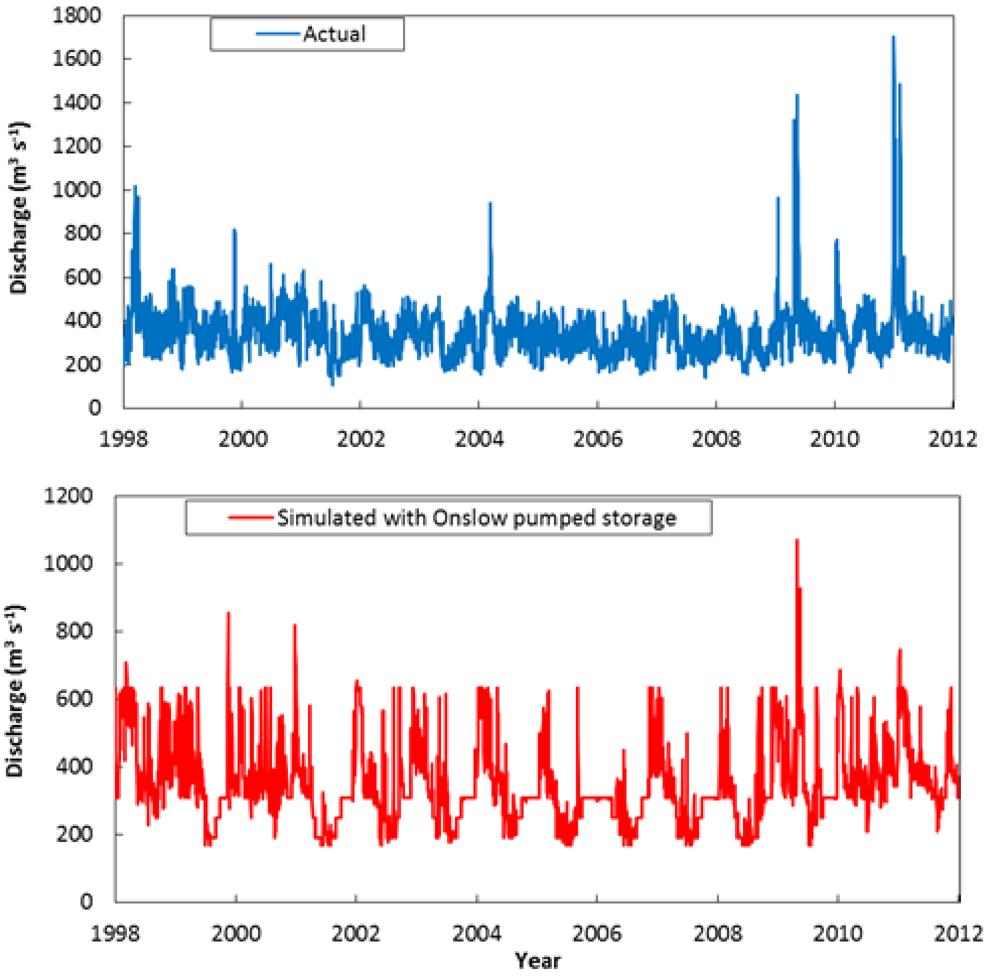

*Figure 6.4 Actual and simulated Waitaki average daily discharge at Kurow.*

A comparison of simulated flow with recorded flow at Kurow (1998-2012) between the months of October and March is shown Figure 6.5. The pumped storage simulations in conjunction with the formulations for water release for irrigation of the Waitaki scheme show a major gain in flow at Kurow between October and March, and the range of release of water from the Waitaki hydro power plant varying between 300 and 650 m$^3$s$^{-1}$. The simulated discharge remains between 300 and 325 m$^3$s$^{-1}$ 43% of the time. The effect of current actual operation of the hydro scheme is illustrated in the size of average fluctuations and spill as explained in the previous chapter.

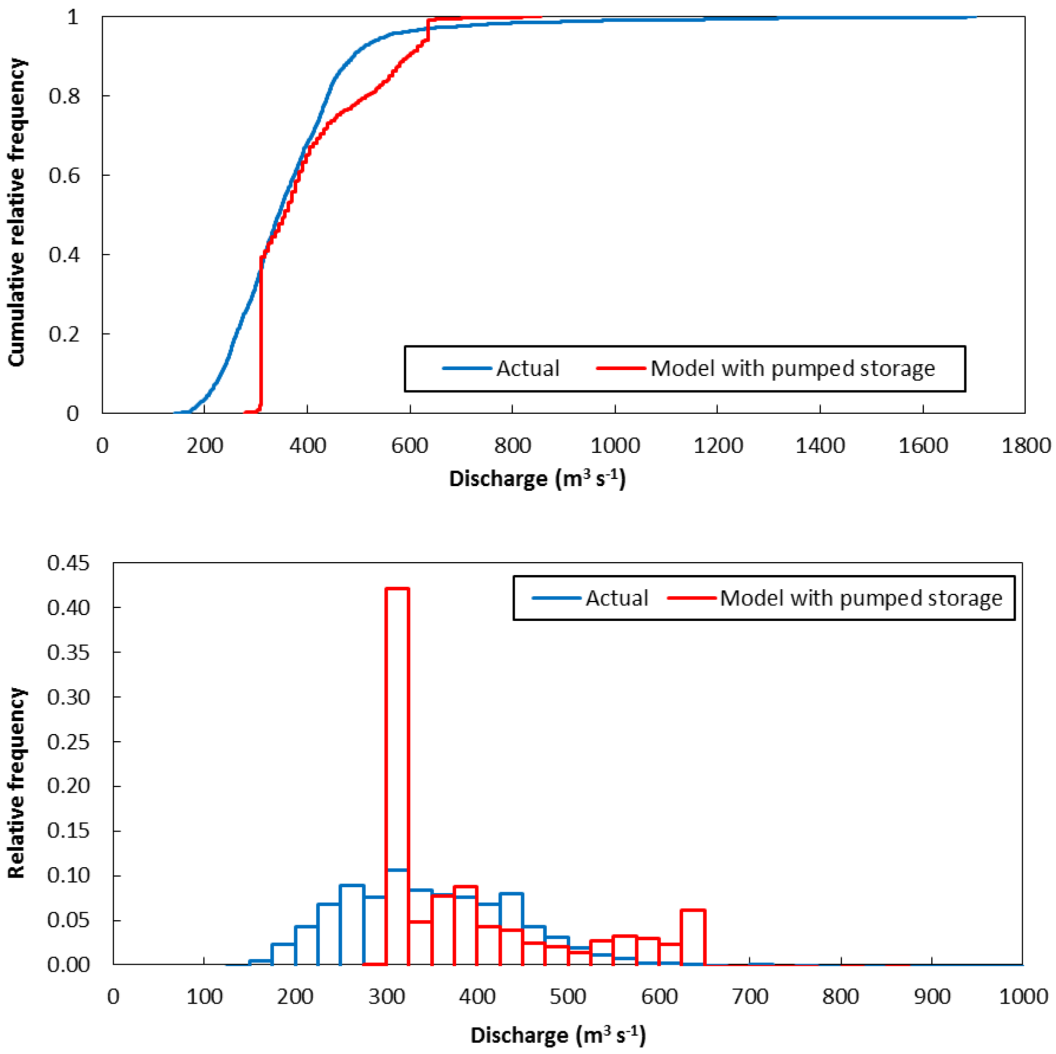

*Figure 6.5 Frequency distributions of mean daily discharge in m$^3$s$^{-1}$ at Kurow for October to March from 1998-2012 for recorded values and those simulated with pumped storage.*

One feature of South Island lake inflows is a high inflow in summer and low inflow in winter. Figure 6.6 shows that the mean daily simulated discharge at

Kurow is much greater than the boundary of the minimum flow plus irrigation allocation requirements and allows for possible future development. Figure 6.6 also shows that the mean monthly simulated discharge at Kurow is much higher than the actual discharge during spring and summer, especially in November, December and January, while it is lower during autumn and winter, especially in July, August and September.

This is because in the simulation, water was released from Lakes Tekapo and Pukaki to maintain stable lake levels and to match the demand for irrigation in the lower Waitaki scheme. It is also because in the model, during the low inflow months in autumn and winter, power was generated by the Onslow PHES, which allows more water to be retained in the Waitaki hydro lakes, causing the discharge at Kurow to be lower than the actual records. During the spring high inflow, the Waitaki hydro lakes would attain their base storage levels, allowing more water to be released from the system than that seen in the actual records, causing the simulated discharge at Kurow in spring and summer to be higher on average than the actual values.

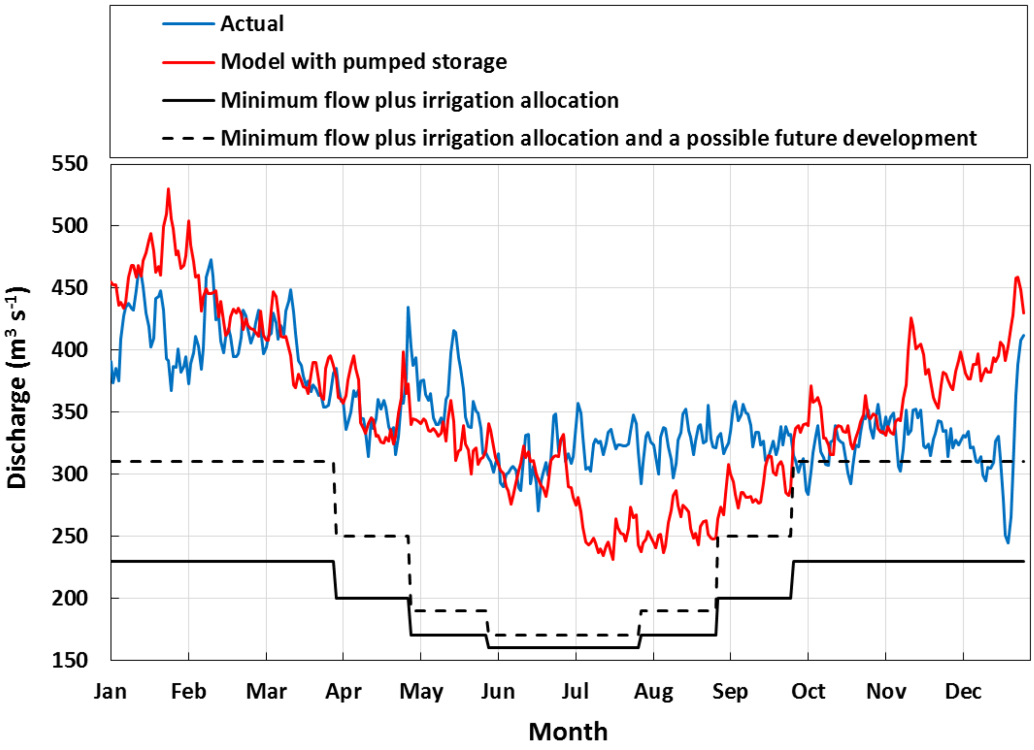

*Figure 6.6 Actual and simulated mean daily discharges for the Waitaki River at Kurow, where the record for each month is averaged over the period 1998-2012.*

The hydrographs in Figure 6.7 and Figure 6.8 show two independent examples comparing the actual flows and simulated flows involving the Onslow PHES, at Kurow in a wet year (2000) and a dry year (2006).

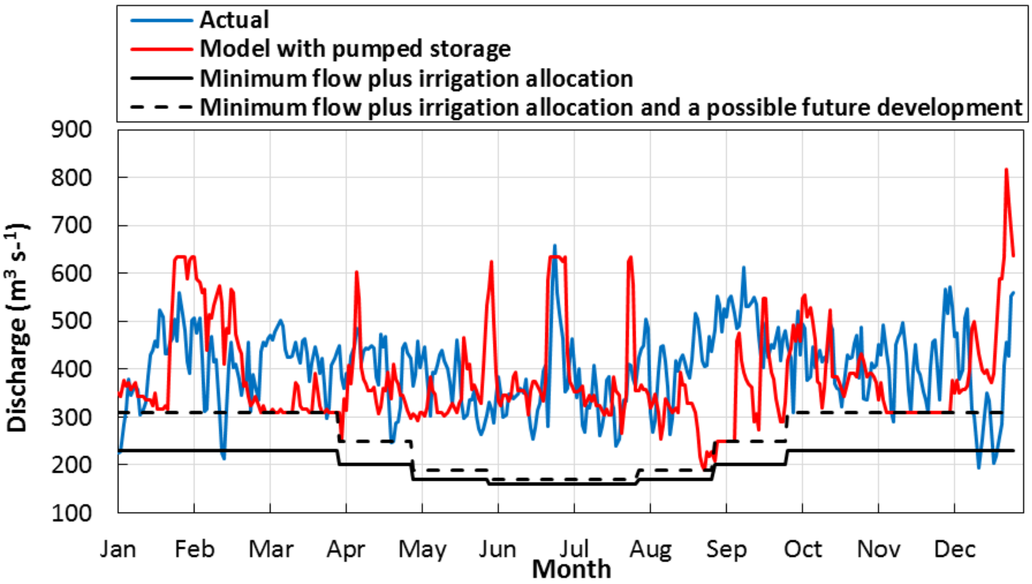

*Figure 6.7 Actual and simulated - Waitaki discharge at Kurow in a wet year (2000).*

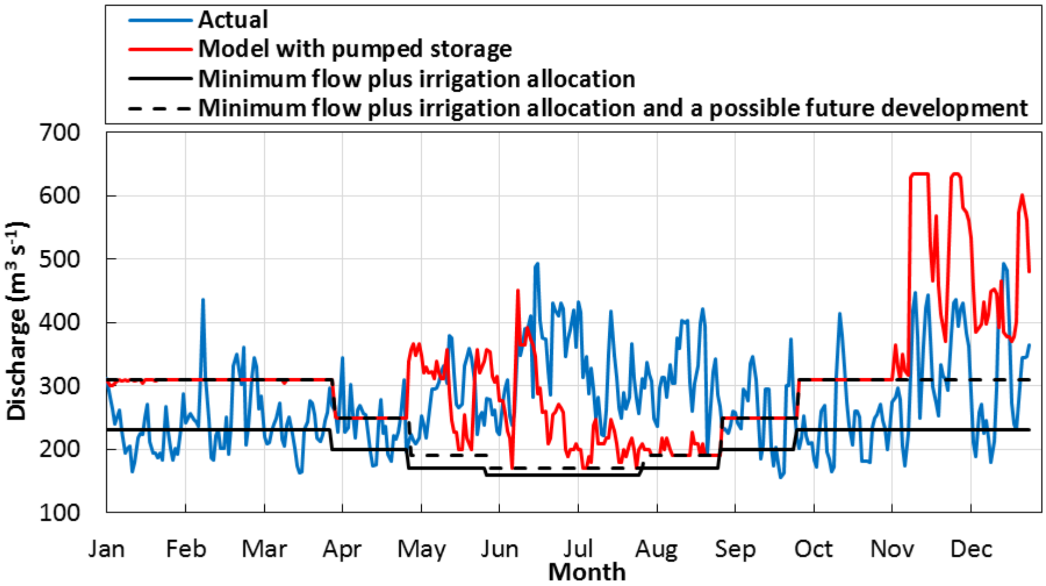

*Figure 6.8 Actual and simulated with pumped storage - Waitaki daily discharge at Kurow in a dry year (2006).*

Actual Waitaki River discharge at Kurow, as expected in a wetter year, was greater than the simulated inflow for much of the year, while the simulated flow was more frequently between 250 $m^3s^{-1}$ and 550 $m^3s^{-1}$ than the actual inflow

(Figure 6.9). The simulated flow in a dry year would meet the need for the current irrigated area and possible future needs.

Waitaki hydro power scheme water management, in conjunction with pumped storage, can make use of the natural high summer flows, because Onslow would take over the storage role, instead of storing as much water as possible during spring in the existing hydro lakes, Tekapo and Pukaki.

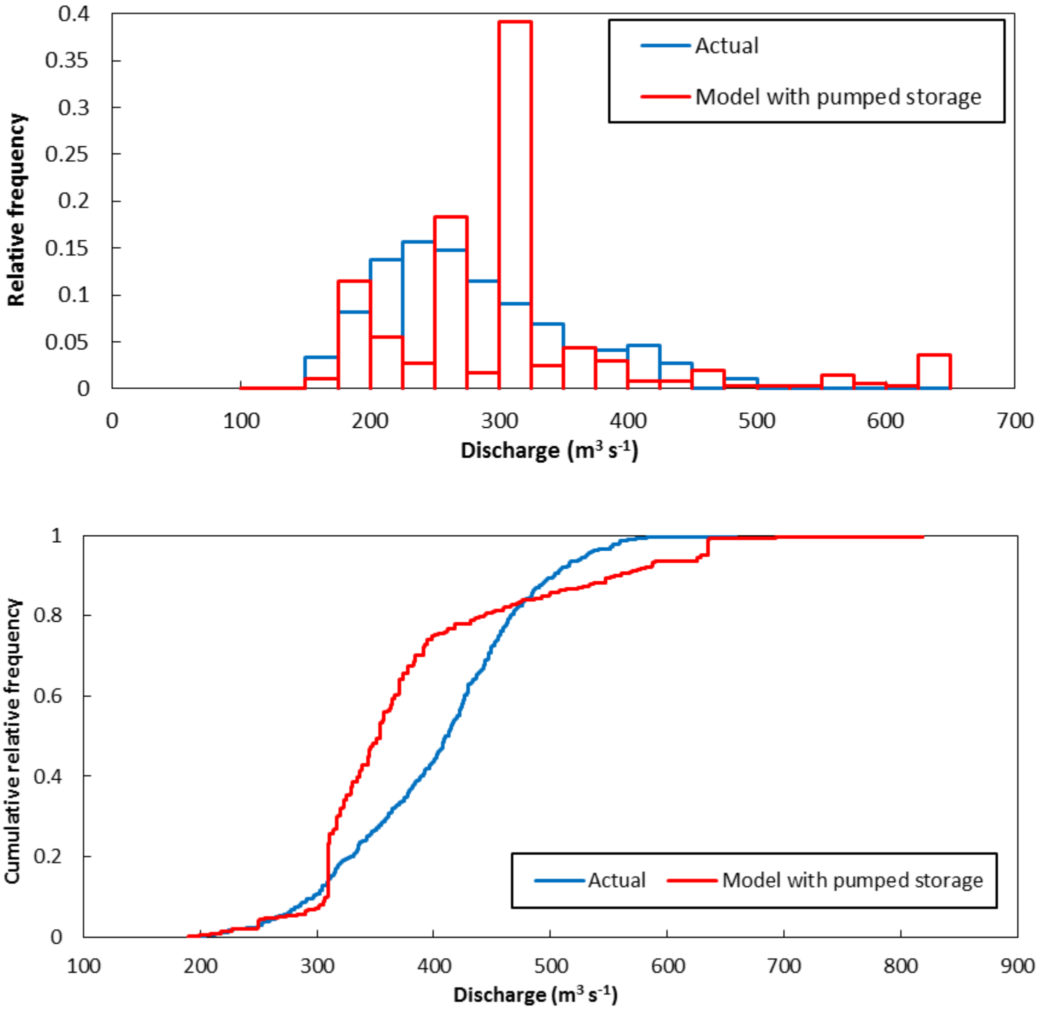

*Figure 6.9 Actual and simulated – Waitaki cumulative relative frequency discharge at Kurow in a wet year (2000).*

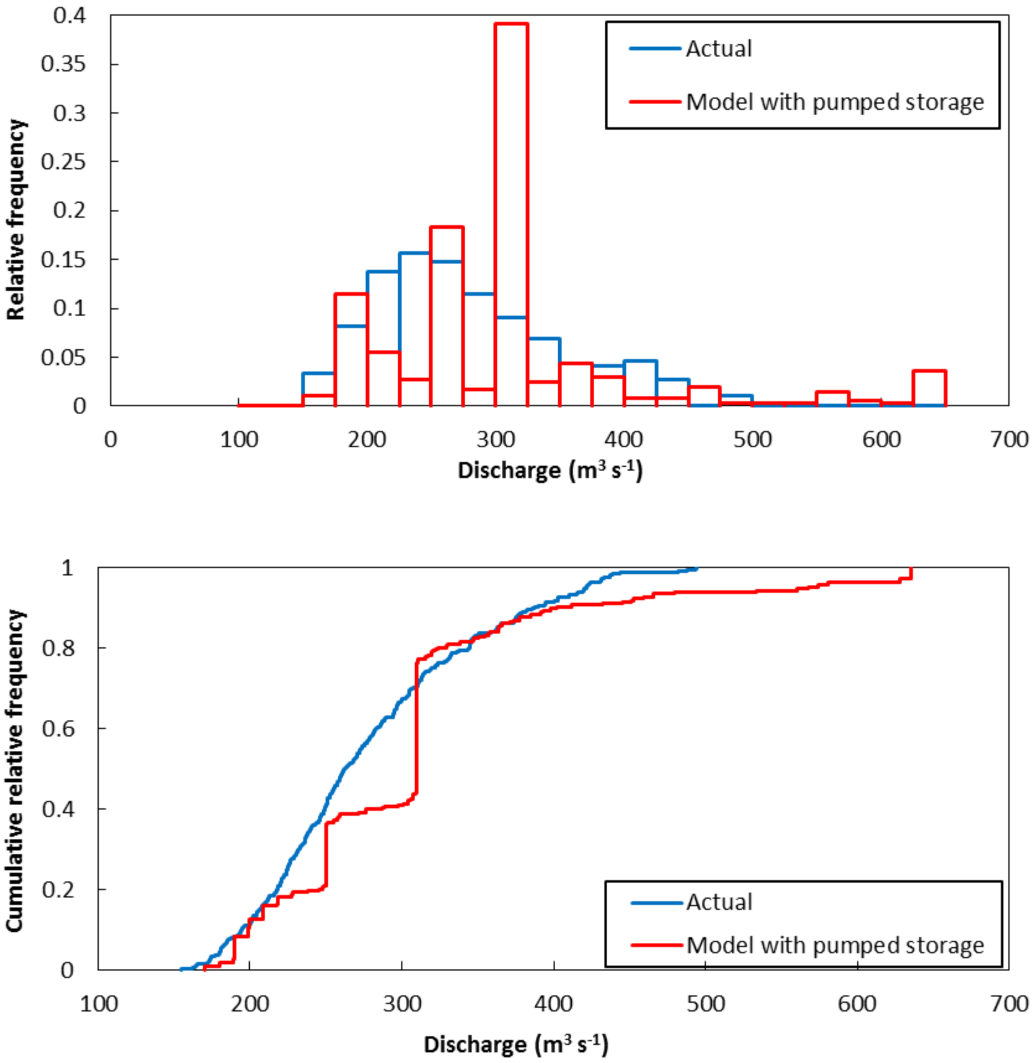

*Figure 6.10 Actual and simulated – Waitaki cumulative relative frequency discharge at Kurow in a dry year (2006).*

# Chapter Seven: Onslow Scheme: environmental advantages and environmental impacts

## 7.1 Environmental impacts of the proposed Lake Onslow expansion

Environmental impact is one of the primary factors influencing the consenting of new utilities and the re-consenting of existing plant. The proposed Onslow Scheme will inevitably have an impact on the local environment, specifically in terms of the wetland area surrounding the present Lake Onslow, which would be inundated following lake expansion and thus affect the habitat of threatened plant and animal species. The main visual impact of the scheme would arise from the large potential water level fluctuations (60 metres), with the new lake rising in area from 18 $km^2$ to 74 $km^2$ between minimum and maximum lake surface elevation. However, as was seen in the simulations, there is no suggestion of an annual 60-metre seasonal cycle of water level in an expanded lake Onslow.

The potential for a large operating range does give rise to the necessity for environmental policies in compensation for impacts, with some 62 $km^2$ of land lying within the large operating range. For example, permanent floating artificial wetlands could be constructed, which would simply rise and fall with Onslow water level fluctuations. Another possibility could be constructing low dams in the stream valleys within the proposed operating range. In this way when Onslow levels fall, the dams would appear above water and some valleys would then convert to a chain of lakes supplied by the local streams, to be inundated again sometime later when the water levels rise again. There will of course be other environmental impacts of an expanded and fluctuating Lake Onslow, including the possibility of dust generation, which would need to be considered in detail with mitigation as part of a consenting process.

Despite the large number of active faults in New Zealand, some regions are more prone to earthquakes than others. An iso-seismal map is used to determine the hazard for a particular location in the seismic design standard that engineers use. New Zealand’s construction standards divide the country into four earthquake risk zones. Structures in high-risk zones must be built to more stringent requirements than structures in low-risk zones. The proposed Onslow PHES sheme fall in zone 1 (low-risk zone).

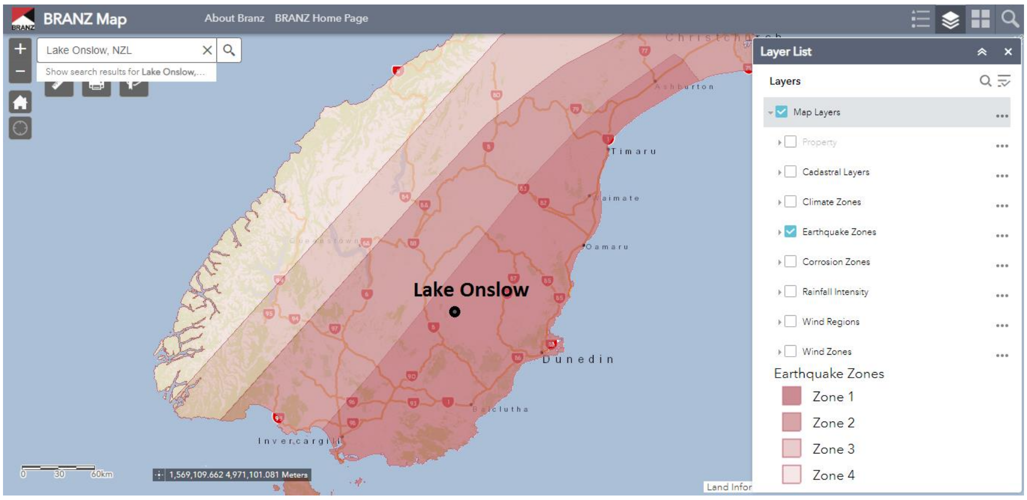

*Figure 7.1 Earthquake zones map [123].*

Reservoir induced seismicity (RIS) is usually associated with large reservoirs. It is definitely a concern for the Onslow storage reservoir, which has a maximum surface area of 74 km$^2$ and maximum active storage of 2.94 km$^3$. Based on Figure 7.2 the proposed Onslow PHES scheme has a 1.5 - 3.5 % probability of RIS as the storage reservoir is within the "medium" size range. However, this is based on limited international data and a site-specific evaluation would be required.

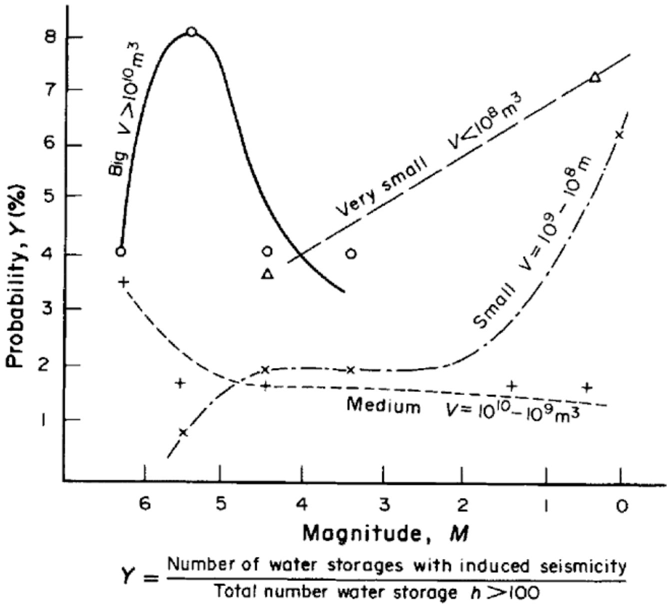

*Figure 7.2 Occurrence of RIS related to observed magnitude and reservoir volume [124].*

As was noted in the simulations, the Onslow scheme is not intended to operate as an isolated entity but would need to be part of an integrated system of national hydro lake management, perhaps extending as far north as Lake Taupo. For this reason, one collective environmental advantage of the Onslow scheme is that existing scenic lakes presently used for seasonal hydro storage could revert to a more natural scenario, with much reduced seasonal level changes. This and other environmental advantages are discussed further in this chapter.

The Lower Waitaki River is not only important for hydroelectricity and irrigation but is also  important to support recreation, angling, important Mahinga Kai sites and Tangata Whenua values more broadly, native flora and fauna, and some of New Zealand’s most iconic landscapes.

The aim of this chapter is to address the environmental benefits of running a hypothetical seasonal pumped storage facility at Onslow to operate in conjunction with modified operation of the Waikato, Waitaki, Clutha and Manapouri hydro power schemes.

## 7.2 Reduced water level fluctuations in hydro lakes

The main South Island lakes used for hydro storage (Pukaki, Tekapo and Hawea) operate on a seasonal storage regime of holding back the high spring and summer river inflows, followed by water release through winter to match the higher seasonal power demand. The hydro lakes have shorelines set in soft glacial till, which is easily eroded by wind waves during storm events when lake levels are high. Seasonal water level variation over several metres means that equilibrium lake beaches cannot be formed and there is net downslope transfer of sediment within the zone of seasonal fluctuation. This may lead to unstable sediment cliffs along the lake shore, with risk of collapse.

Lake-level fluctuations can lead to varied responses at the shore, from short-term adjustments to a quasi-equilibrium shoreline, to inducing a change in the long-term sediment budget of a shore. Significantly, erosion can – but will not always – result from either prolonged low or high lake levels. Storms when lake levels are low can move sediment from the active beach and nearshore to offshore and away from the influence of constructive wave action. Storms when lake levels are high can result in waves eroding the base of hillslopes, initiating slumping and shoreline retreat [125].

*Figure 7.3 Lake Pukaki at a low level of 524 masl in September 2005, showing big exposure of the shoreline and sediment transfer (Photograph supplied by Jackhynes, 2005).*

*Figure 7.4 Lake Pukaki at a low level of 525.4 masl, May 28, 2012, showing lack of stable natural beaches (Photograph supplied by Annette Teng, 2012).*

*Figure 7.5 Shoreline retreat at Lake Pukaki (supplied by Varvara Vetrova).*

*Figure 7.6 Lake Pukaki at a high level of 532 masl, February 2009.*

The seasonal cycle of hydro storage imposing a slow process of sluicing on shorelines provides a good example of exposure of the shoreline and sediment transfer at Lake Pukaki, as shown in Figure 7.3, Figure 7.4 and Figure 7.5. Figure 7.6 shows a more scenic view.

Converting natural lakes to hydro storage use in New Zealand typically involves first raising the lake level and then having seasonal water level variations of up to several metres, much greater than pre-hydro natural lake level variations. For example, Lake Pukaki's water level was raised by 33 m with a subsequent permitted seasonal operating range of 13.8 m.

Manipulating hydro lake levels upward to maximise summer storage and downward during winter peak seasonal electricity demand inevitably alters the previous natural pattern of lake level fluctuations. In the extreme case of Lake Hawea, hydro operation has produced a recorded 21.9 m of water level fluctuation compared with 2.86 m before controls, although in recent years fluctuations have been much smaller in order to mitigate adverse effects.

As noted in Chapter Four, the model simulations of the hydro lakes in conjunction with pumped storage were conducted on the basis of a desired goal of seeking to have the hydro lakes near stable mid-range levels as often as possible. Given a greater frequency of lake water levels being near their target levels, the hydro lake shorelines should then revert to a more natural appearance, with semi-permanent lake beaches along the target water level. In seeking to achieve target lake levels as one of the model goals, the simulation results are presented below for selected existing hydro lakes, illustrating how the Onslow PHES could reduce hydro lake level fluctuations.

Another environmental aspect of downstream rivers in hydro schemes is reduced flow, particularly illustrated by low summer flows in the Hawea River and the Waitaki River. Once South Island lakes were used for hydro storage (Pukaki, Tekapo, Hawea), water was retained in spring and summer when natural flows were high and released during winter when natural flows were low, resulting in a modified flow pattern that would tend to hide most hydrological droughts during winter, or make them appear worse during summer. It also increased the risk of flooding in summer months when both the hydro lake levels and inflows are high.

McGowan [126], studied dust issues at Lake Tekapo following long periods of low lake levels. The study also proposed that high lake levels may recharge deltaic surfaces around the lake with silt. Wind-blown dust particles can affect lakeside communities. He found that Tekapo Village can be exposed to dust from the exposed shores of Lake Pukaki (20 to 25 km to the west). He also found that dust storms were a frequent phenomenon during the Pleistocene. Contemporary dust storms are largely confined to the braided river systems, where there is abundant silt-sized material and winds are topographically reinforced.

He noted for Lake Tekapo that if the lake levels are not below 703.5 masl then areas of the deltaic surfaces may remain moist due to capillary rise of water. Similar problems have occurred with Lake Hawea and Hawea Township [126].

In summary, the current mode of operation of hydro lakes shows major level fluctuations over the course of a year, leading to seasonal shoreline erosion, and dust generation at low lake levels.

It is important, therefore, to minimise the draw-down of lake levels when seasonal wind events that may result in dust storms are likely [127]. If the Onslow PHES is constructed and operates to limit the Waitaki hydro lakes to near to mid-range levels then the risk of dust generation caused by low lake levels would be largely eliminated. Shifting the function of storage in hydro lakes to a seasonal pumped storage scheme could significantly reduce level fluctuations and improve the scenic attributes of the lakes.

### 7.2.1 Lake Hawea

#### Background

Hawea was originally a large natural lake (surface area 141 km$^2$), which was artificially raised for hydro storage purposes and irrigation in 1960, with a permitted outflow discharge range of 10 to 200 m$^3$s$^{-1}$. Figure 7.7 shows the recorded lake levels between 1930 and 2010 [128]. Pre-control, the natural mean lake level was about 327.6 masl, with water levels fluctuating between a winter minimum of around 327.3 masl and a summer maximum of 328.1 masl.

After water level control was introduced by constructing the earth dam at the Hawea outlet, the operating range was set at 18 m, with a mean lake level of 342.9 masl in the period 1960-1985. Three big lake level drawdowns were recorded in the dry years of 1964, 1976 and 1977, reaching a minimum lake level of 327.6 masl in the extreme dry year of 1976 (Figure 7.7).

In 1985, the free operating range was reduced from 18 m to 8 m, which reduced the fluctuations during the year and increased the level, as shown in Figure 7.7 for 1985-2011, with a consented minimum level of 338 masl and maximum control level of 346 masl.

The current operation of Lake Hawea by Contact Energy results in the lowest lake levels between July and October, when the demand for electricity is high. Thereafter the inflow into the lake is held back to provide storage for the next high electricity demand in winter, resulting in highest lake levels between February and June. The operation of the lake is opposite to a natural hydrological system, where outflow of water is lowest in autumn and highest in summer and spring.

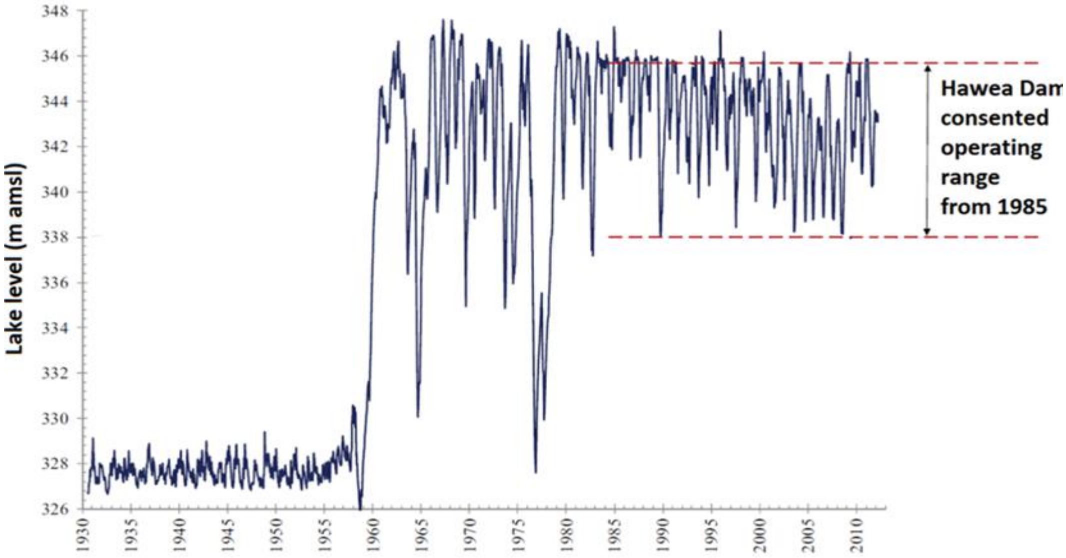

*Figure 7.7 Lake Hawea level records since 1930 [129].*

The flow of the Clutha River at Roxburgh prior to damming and raising of Lake Hawea in 1959 was completely natural. But once Lake Hawea was dammed, water was held back in spring and summer when natural flows were high and released during winter when natural flows were low, resulting in a modified flow pattern that would tend to hide most hydrological droughts during winter, and make them appear worse during summer [130].

### Simulation results (Hawea)

A comparison of the simulated lake levels with actual levels is shown in Figure 7.8 and Figure 7.9, indicating the possibility of converting Lake Hawea back to a natural lake hydrological system.

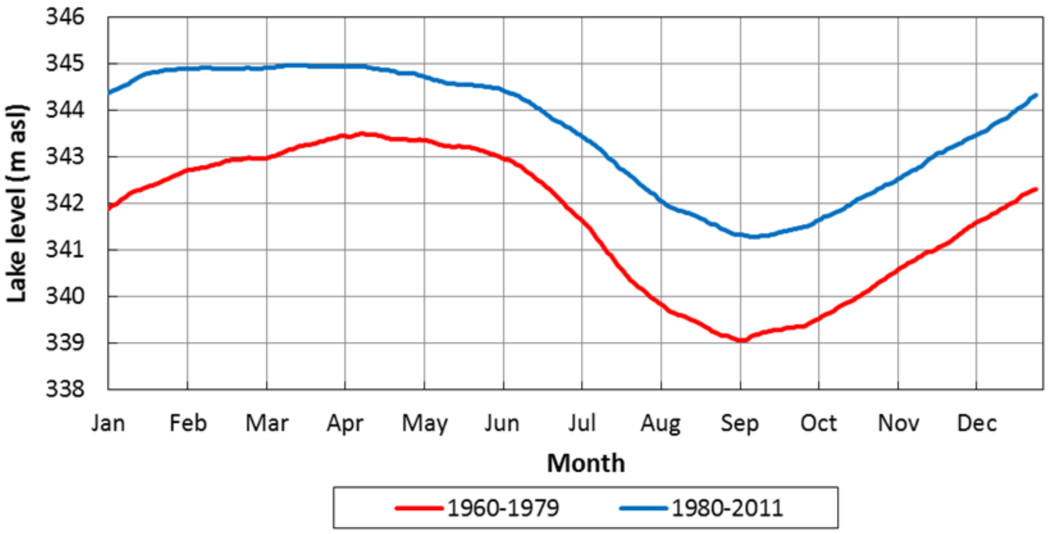

*Figure 7.8 Actual daily average Lake Hawea levels for the period of changing operational levels.*

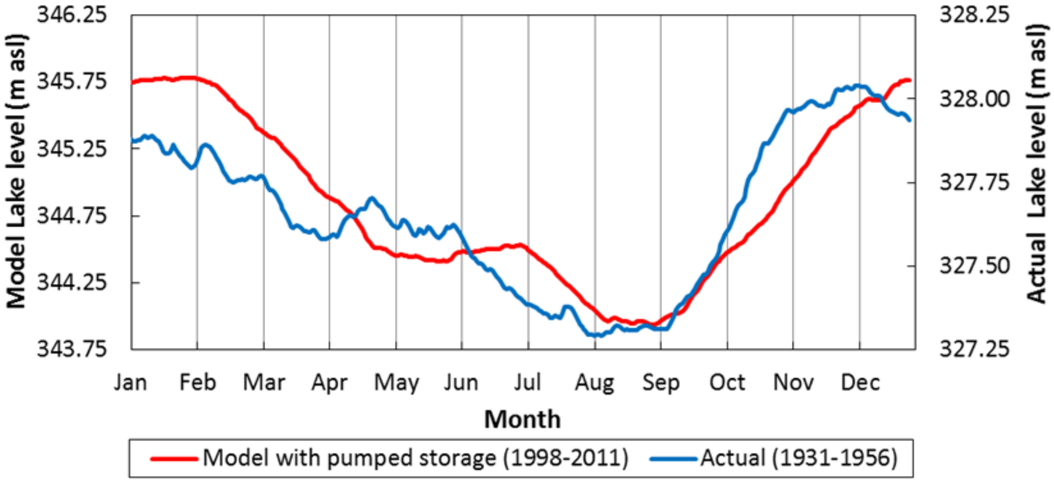

*Figure 7.9 Daily average Lake Hawea levels: actual lake level prior to constructing hydro dam and simulated with pumped storage.*

The simulation incorporating pumped storage shows considerable reduction in seasonal lake level variations (Figure 7.10). The high simulated levels in 1998 reflect high lake levels at the start of the simulation period, which take some time for the simulations to reduce to the target level. Figure 7.11 and Figure 7.12 show the simulated lake remains within a 1m range 42% of the time and most of the lake levels are above or near mid-range. There is a considerable reduction in water levels less than the target value, and the upper "tail" of the simulated lake levels is caused by holding back flood waters sometimes to avoid flood damage or hydro dam spill.

The simulation included wind energy with and without development, which had very minor (negligible) effects on the operating level.

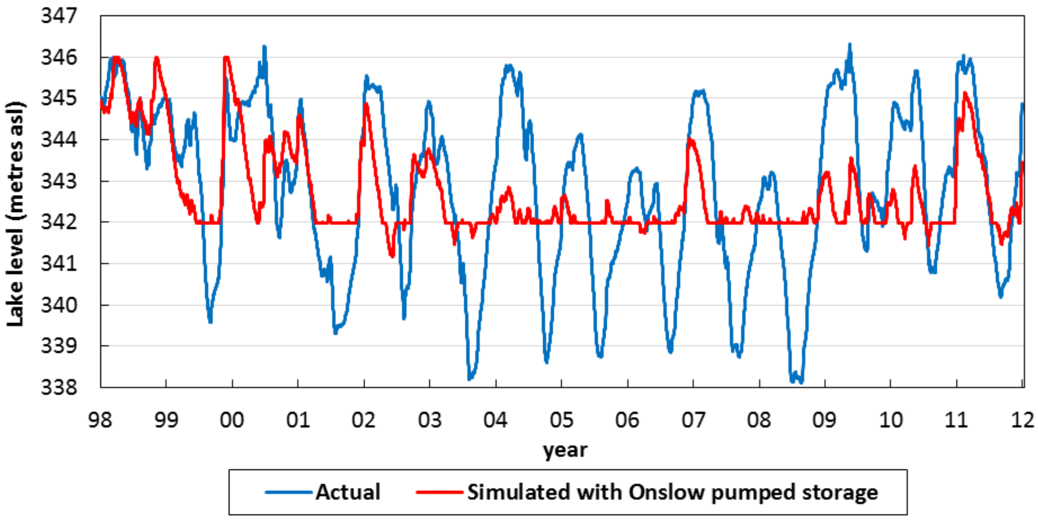

*Figure 7.10 Lake Hawea water levels 1998-2012 - actual water levels and as simulated with Onslow pumped storage in operation. In the simulations the Hawea target lake level was 342 masl.*

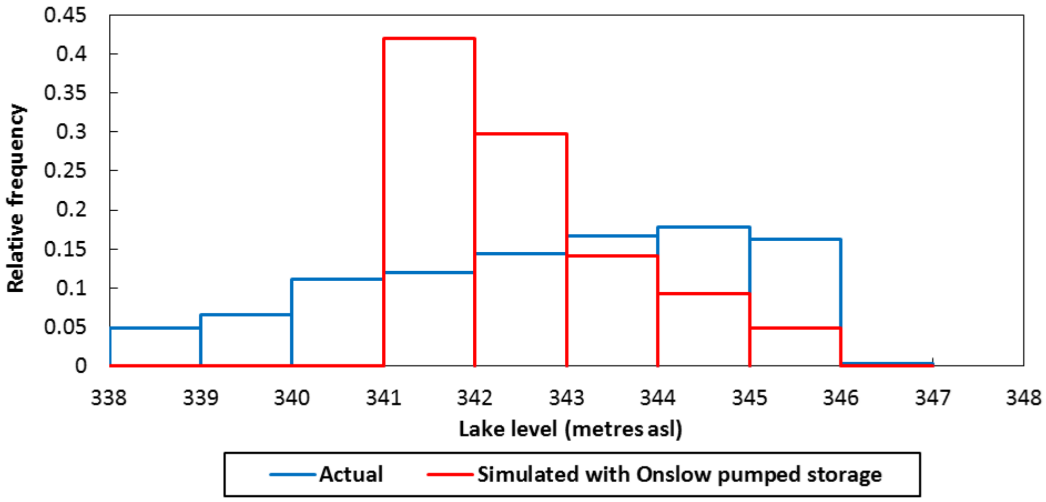

*Figure 7.11 Frequency histogram of Lake Hawea levels (masl) 1998-2012 – as recorded and simulated with Onslow pumped storage.*

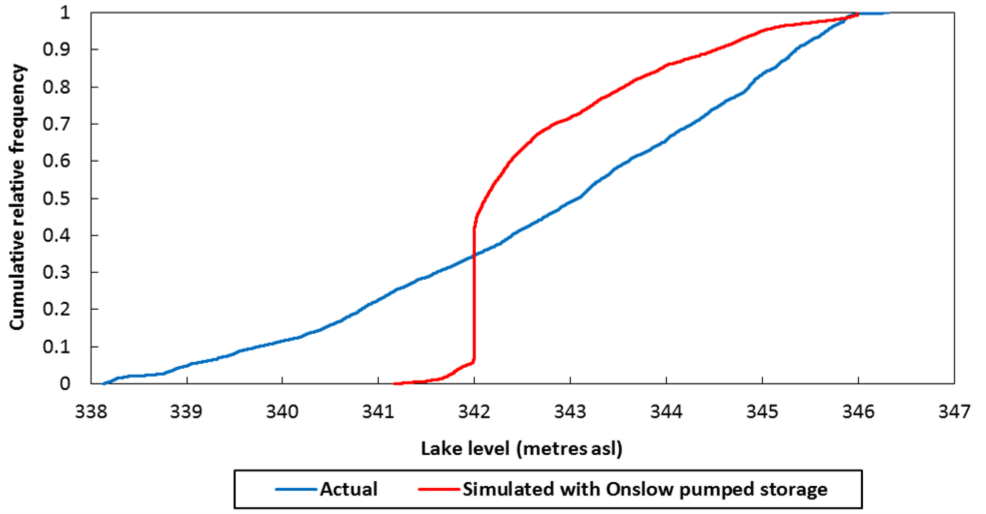

*Figure 7.12 Cumulative frequency distributions of Lake Hawea lake level fluctuations (masl) 1998-2012 - recorded and simulated with Onslow pumped storage.*

### 7.2.2 Lake Tekapo

The consented minimum control level for Lake Tekapo is 701.8 masl and the maximum control level is 710.9 masl. Comparisons of simulated lake levels against the recorded levels of Lake Tekapo are shown in Figure 7.13, which shows a great reduction in fluctuations in the simulated levels. The optimum simulated desired level in terms of lowest water spill was found to be 705.5 masl. The simulation included wind energy with and without development, which had very minor (negligible) effects on the operating level. The simulated lake level remains between 705-706 masl for 61.4% of the time (Figure 7.14, Figure 7.15).

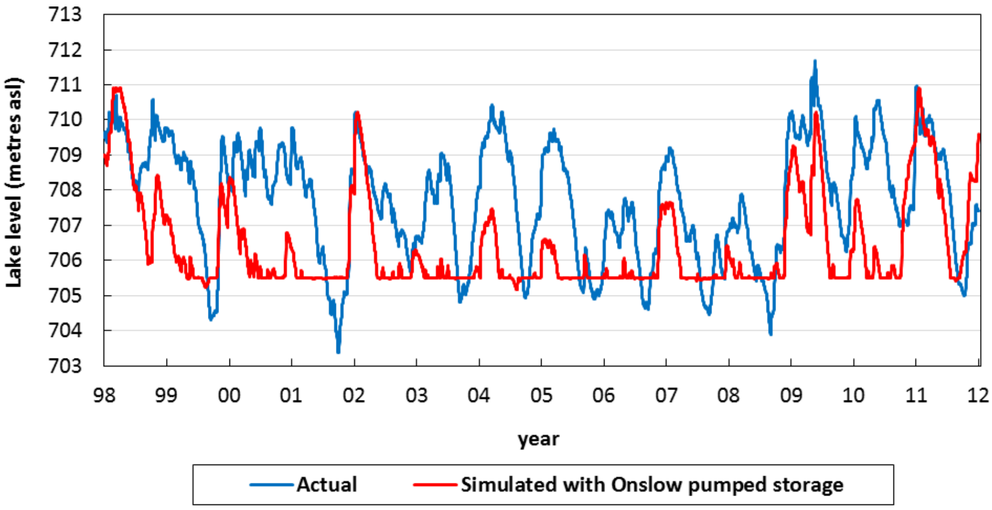

*Figure 7.13 Lake Tekapo water levels 1998-2012 - actual water levels and as simulated with Onslow pumped storage in operation. In the simulations the Tekapo target lake level was 705.5 masl.*

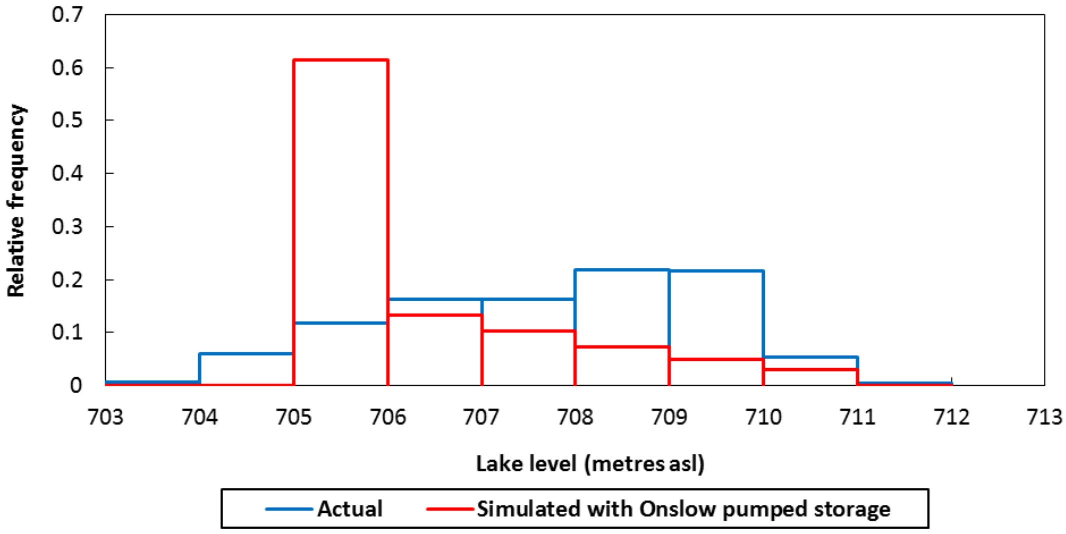

*Figure 7.14 Frequency histogram of Lake Tekapo levels (masl) 1998-2012 – as recorded and simulated with Onslow pumped storage.*

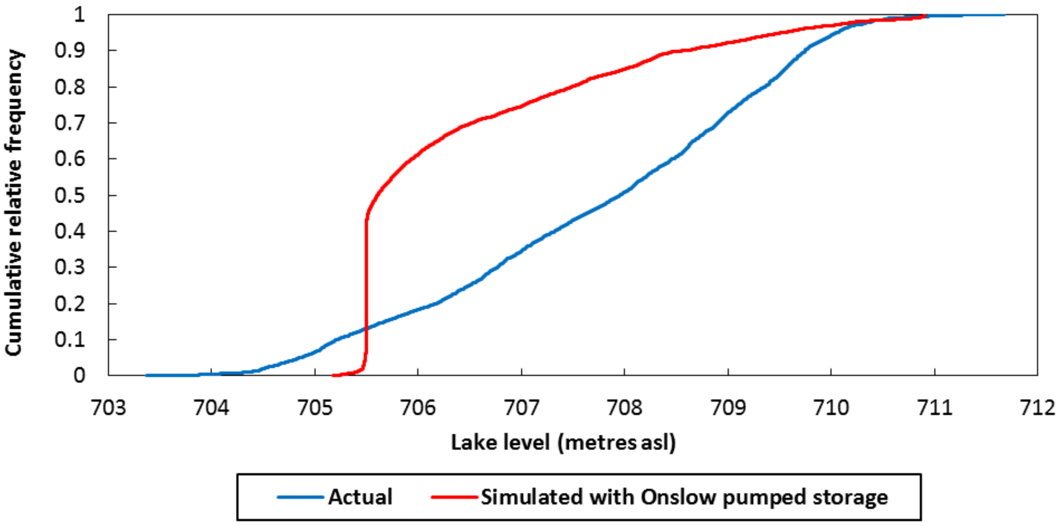

*Figure 7.15 Cumulative frequency distributions of Lake Tekapo lake level fluctuations (masl) 1998-2012 - recorded and simulated with Onslow pumped storage.*

### 7.2.3 Lake Pukaki

Lake Pukaki was first raised 9m in the 1950s and was further raised in 1976 by construction of a dam. This raised the level by a further 37m, with the new operating level being reached in 1979 (Figure 7.16). The lake is presently able to be operated over a range of 14.5 m with a minimum control level of 518.2 masl, an extreme minimum control lake level of 518.0 masl and a maximum of 532.5 masl in May-August and 532.0 masl in September-April being set as part of the 1990 consenting process [131].

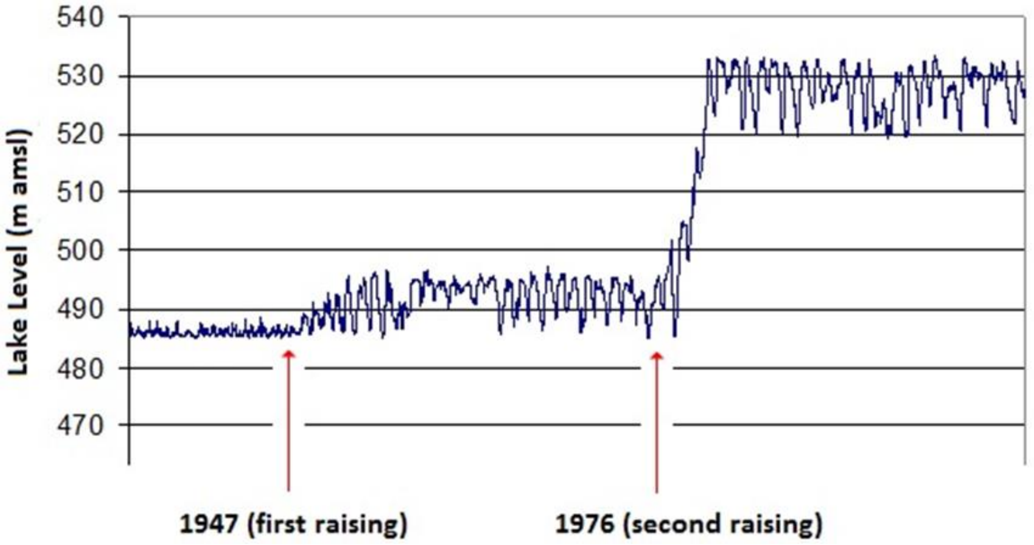

*Figure 7.16 Recorded Lake Pukaki Water levels 1925-2003.*

The operating range of Lake Pukaki is 518.2-532 masl. Comparisons of simulated lake levels against the recorded levels of Lake Pukaki are shown in Figure 7.17, which shows a major reduction in fluctuations in the simulated level. The optimum simulated desired level in terms of lowest water spill and highest hydro storage capacity was found to be 528.2 masl. The simulation included wind energy with and without development, which had very minor (negligible) effects on the simulated operating level. The simulated lake remains between 528-529 masl for 66% of the time.

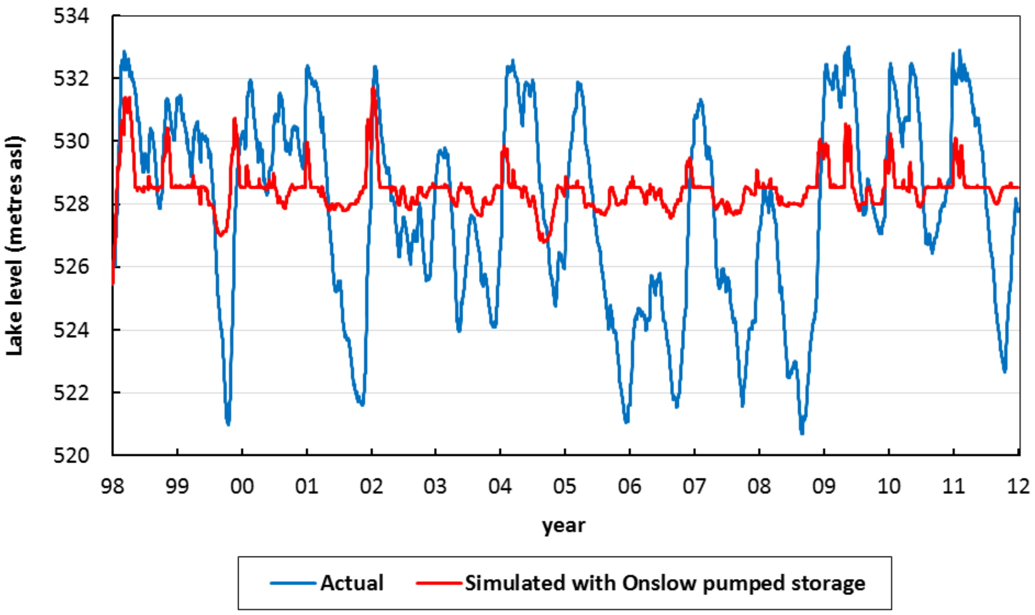

*Figure 7.17 Lake Pukaki water levels 1998-2012 - actual water levels and as simulated with Onslow pumped storage in operation. In the simulations the Pukaki target lake level was 528.2 masl.*

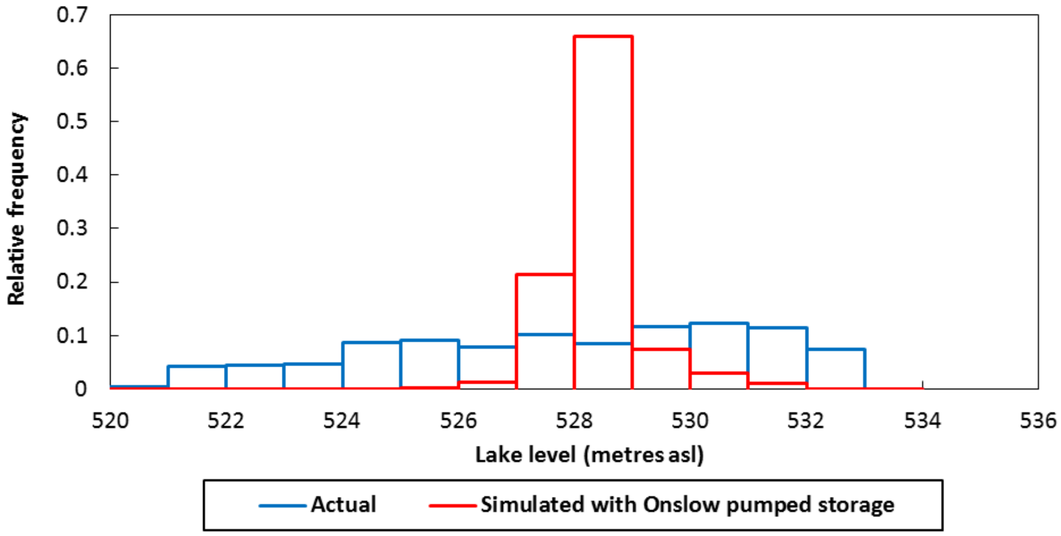

*Figure 7.18 Frequency histogram of Lake Pukaki levels (masl) 1998-2012 – as recorded and simulated with Onslow pumped storage.*

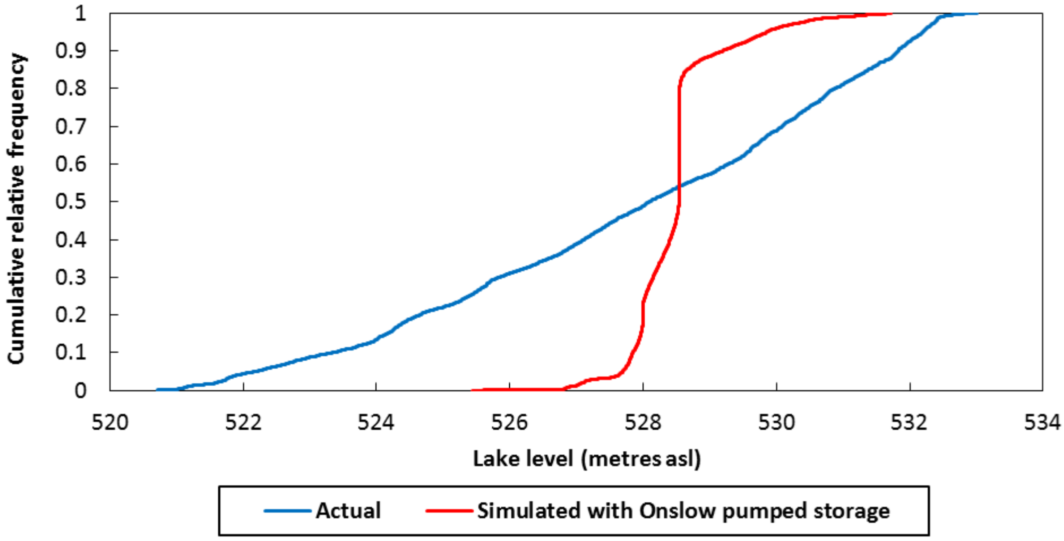

*Figure 7.19 Cumulative frequency distributions of Lake Pukaki lake level fluctuations (masl) 1998-2012 - recorded and simulated with Onslow pumped storage.*

### 7.2.4 Lake Manapouri

Lake Manapouri fluctuates because of natural variations in inflow, and a controlled outflow via the Manapouri Lake Control Structure, just downstream of the confluence of the Mararoa and Lower Waiau Rivers. The Manapouri Power Scheme has operated under Lake Operating Guidelines, developed by the Lakes Guardians, since 1977. These Guidelines were incorporated into the Manapouri-Te Anau Development Act 1963 in 1981.

The aim of the Lake Operating Guidelines is to protect the existing patterns, ecological stability, and recreational values of the lake's "vulnerable shorelines, and to optimise the energy output of the Manapouri power station". The Guidelines set limits on the frequency, duration, and return period for lake levels by describing low, main, and high ranges. The maximum and minimum control levels are 178.6 masl and 176.8 masl respectively [132].

Lake Manapouri is different to other lakes such as Hawea, Tekapo, Pukaki and Taupo because it's not a seasonal storage lake – the effect of Onslow PHES is to take away the high peaks and low points so it would look more aesthetically pleasing more often.

Comparisons of simulated lake levels against the recorded levels of Lake Manapouri are shown in Figure 7.20, which indicates a reduction in fluctuations in the simulated level. The optimum simulated level in terms of lowest water spillage was found to be 177.3 masl. The simulation included wind energy with and without development, which had very minor (negligible) effects on the simulated operating level. The simulated lake remains between 177-177.5 masl for 60% of the time and between 177.5-178 masl for 22.1% of the time (Figure 7.21) (Figure 7.22).

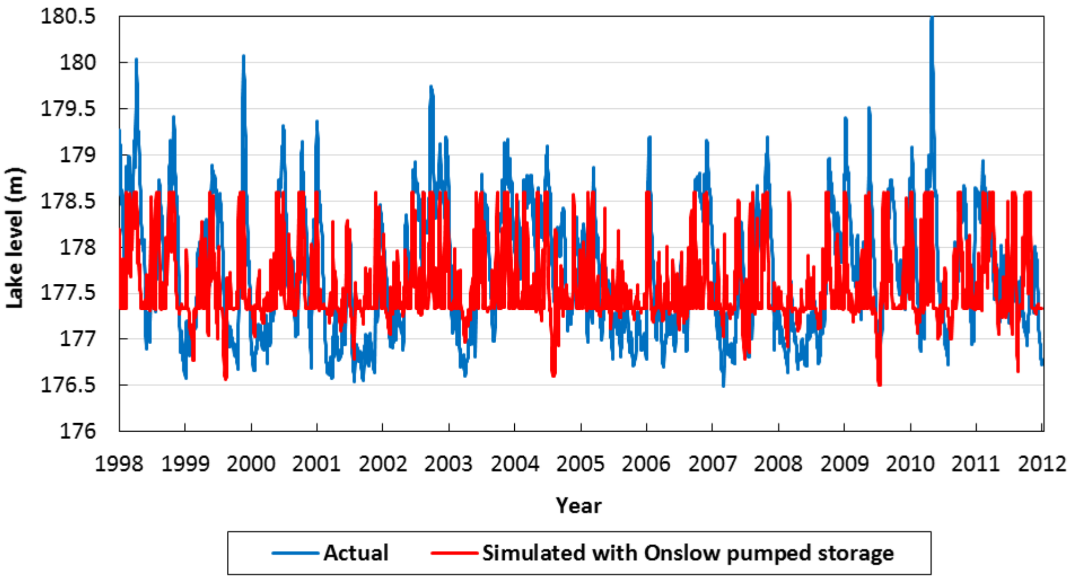

*Figure 7.20 Lake Manapouri water levels 1998-2012 - actual water levels and as simulated with Onslow pumped storage in operation. In the simulations the Hawea target lake level was 177.3 masl.*

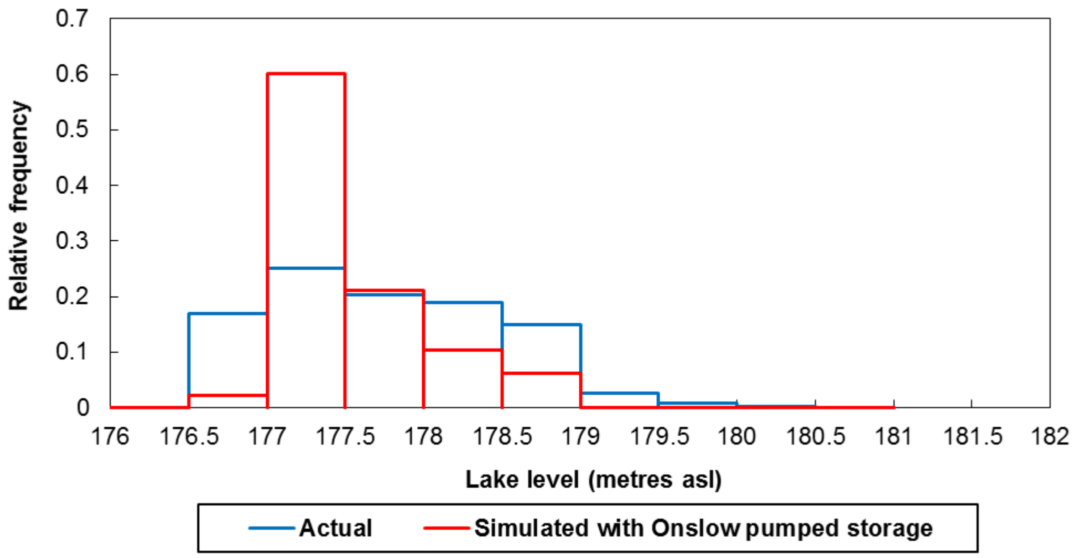

*Figure 7.21 Frequency histogram of Lake Manapouri levels (masl) 1998-2012 – as recorded and simulated with Onslow pumped storage.*

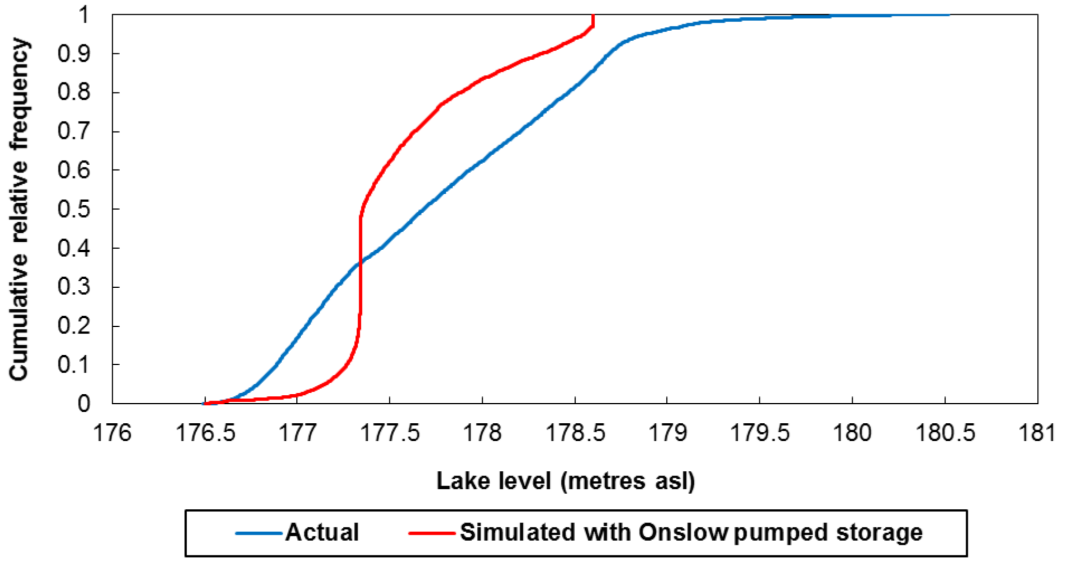

*Figure 7.22 Cumulative frequency distributions of Lake Manapouri lake level fluctuations (masl) 1998-2012 - recorded and simulated with Onslow pumped storage.*

### 7.2.5 Lake Taupo

Lake Taupo is the largest lake by area (622 km$^2$) in New Zealand. The processes and factors influencing erosion around the foreshore are complex and include both natural (e.g. geology, wind and waves, sediment inputs, tectonics) and human factors (development, structures, interruption of sediment supplies, control of lake levels, removal of vegetation, land use). The form of the lakeshore has naturally evolved over time as evidenced by significant historic landforms around the lake edge. Within the context of this natural change, human influences have more recently also had an increasing impact on the form of the lakeshore.

As areas around the lake have been developed there have been significant changes to the environment including land use changes within the catchment. These include development on the foreshore, structures such as groynes and ramps, increases in the volume of water entering the lake due to Tongariro Power Scheme diversions, dams installed on some of the inflowing rivers; and upgrade works to the outlet to allow the lake to be used more effectively for hydroelectric power generation in the Waikato hydroelectric scheme [133].

The geological map in Figure 7.23 identifies eleven different geologic formations occurring along the shoreline of Lake Taupo, three of which have low resistance to erosion such as alluvium and volcanic deposits. Soils in this area readily experience deep and accelerated erosion.

A study of Lake Taupo looked at future management of hazards associated with erosion of the shoreline and flooding of lakeside areas and key tributaries, showing that the recorded occurrences of very high wind events during times when the actual lake level was higher than natural levels indicate an increase in erosion risk. The record showed that controlled lake levels have been held higher than natural levels during summer months, which can coincide with high wind events, increasing erosion risk. It classified areas of the Taupo shoreline in terms of erosion hazard level into high, medium and low risk categories [133].

The operating range of Lake Taupo for the purpose of water storage for hydro electricity generation is 355.25-357.85 masl. Comparisons of simulated lake levels against the recorded levels of Lake Taupo are shown in Figure 7.24, which shows a great reduction in fluctuations in the simulated levels. The simulated desired level in terms of lowest water spill can be up to 356.8 masl. The simulated desired level is 356.4masl. The simulation included wind energy with and without development, which had very minor (negligible) effects on the simulated operating level. The simulated lake remains between 356.4-356.5 masl for 86.2% of the time. Reducing lake level fluctuations and reducing lake level are major factors in reducing the risk of erosion at Lake Taupo (Figure 7.25) (Figure 7.26).

*Figure 7.23 Lake Taupo erosion hazard summary map [133].*

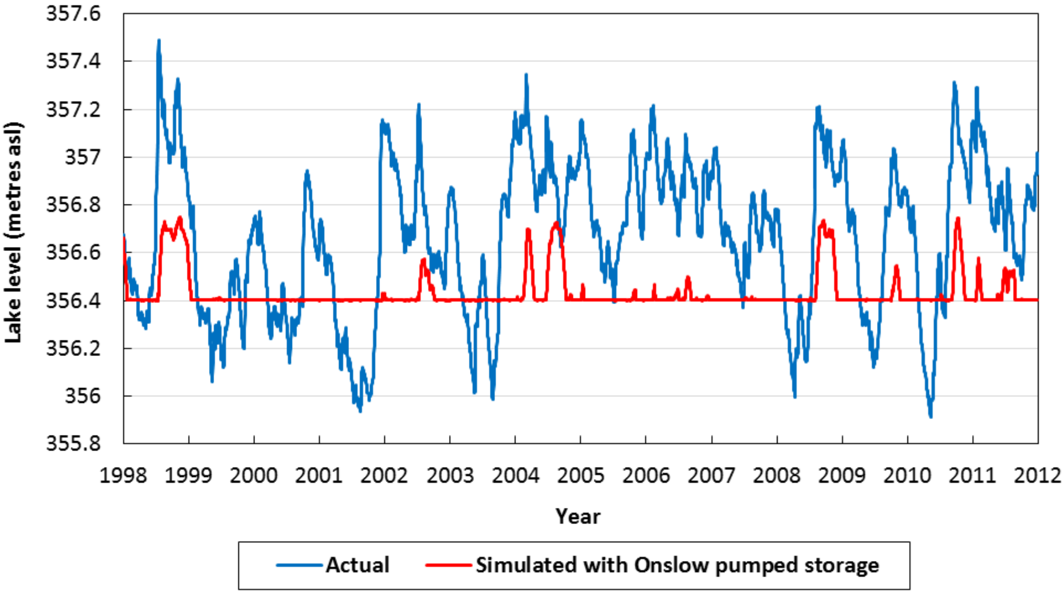

*Figure 7.24 Lake Taupo water levels 1998-2012 - actual water levels and as simulated with Onslow pumped storage in operation. In the simulations the Taupo target lake level was 356.4 masl.*

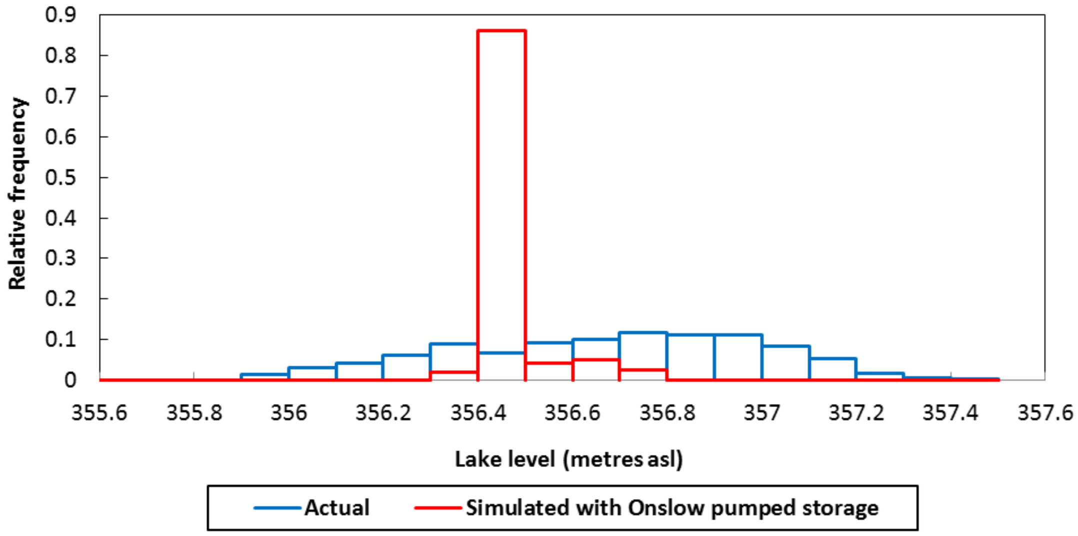

*Figure 7.25 Frequency histogram of Lake Taupo levels (masl) 1998-2012 – as recorded and simulated with Onslow pumped storage.*

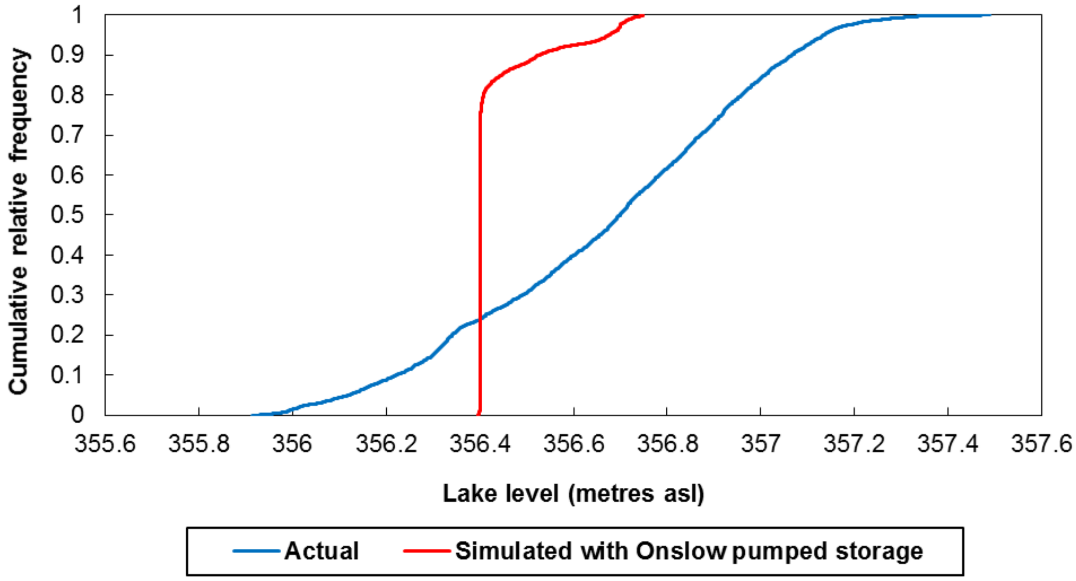

*Figure 7.26 Cumulative frequency distributions of Lake Taupo lake level fluctuations (masl) 1998-2012 - recorded and simulated with Onslow pumped storage.*

### 7.2.6 Lake Wakatipu

Lake Wakatipu is located in the southwest corner of the Otago Region, near its boundary with Southland. With a length of 80 km, it is New Zealand’s longest lake, and, at 291 km$^2$, it’s third largest. The lake is also very deep, its floor being as low as 100 m below sea level, giving it a depth of between 378-420 m. It is thus New Zealand's third deepest lake and is ranked 32nd deepest in the world. The lake receives perennial flow from the Dart River and drains via the Kawarau River, which flows out from the lake’s Frankton Arm, 8 km east of Queenstown.

Lake Wakatipu is presently an uncontrolled lake and is considered to be a natural lake. However, outflows from Lake Wakatipu are restrained by a concrete sill gated weir at a final level of 308.83 masl, which was commissioned in 1928, and by the hydraulic characteristics of the Kawarau River, including the delta of the Shotover River, which joins the Kawarau River 3 km downstream of the outlet (Figure 7.27). On rare occasions, outflow from the lake is reversed when a large flood occurs in the Kawarau catchment and the peak response of Lake Wakatipu lags that of the Shotover River by several days [134].

*Figure 7.27 Views of the Lake Wakatipu outlet weir at Kawarau Falls looking.*

Records show that Lake Wakatipu has exhibited large annual fluctuations in level. Most of the high levels happened during summer, caused by spillage from the Clutha hydro power scheme, while low levels in winter correspond to high electricity demand (Figure 7.28). Several large floods having occurred in the 1990s and significant floods are on record as occurred in 1878 and 1999 (Figure 7.29). Lake Wakatipu begins to flood some Queenstown streets through the stormwater system at a level of 311.3 masl.

This has happened on 20 separate occasions since 1878. There is a 13% chance of the lake exceeding this level in any given year. There is a 75% chance that the lake will exceed this level at least once during any 10-year period. Flood waters will reach the Steamer Wharf deck at a level of 311.6 masl. There is a 6% chance of the lake exceeding this level in any year. There is a 45% probability that the lake will exceed this level at least once during the next 10 years [134, 135].

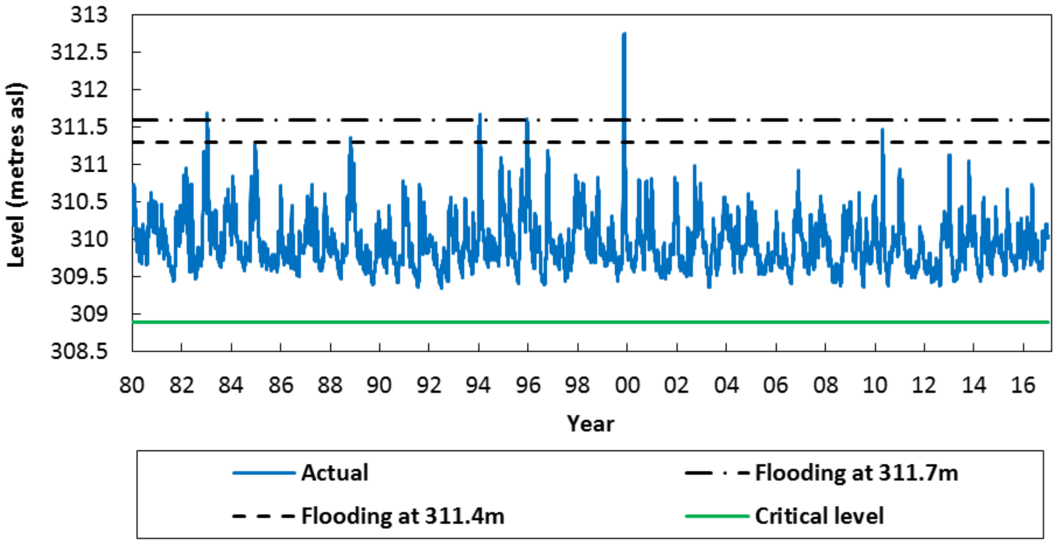

*Figure 7.28 Lake Wakatipu recorded natural levels 1980-2017.*

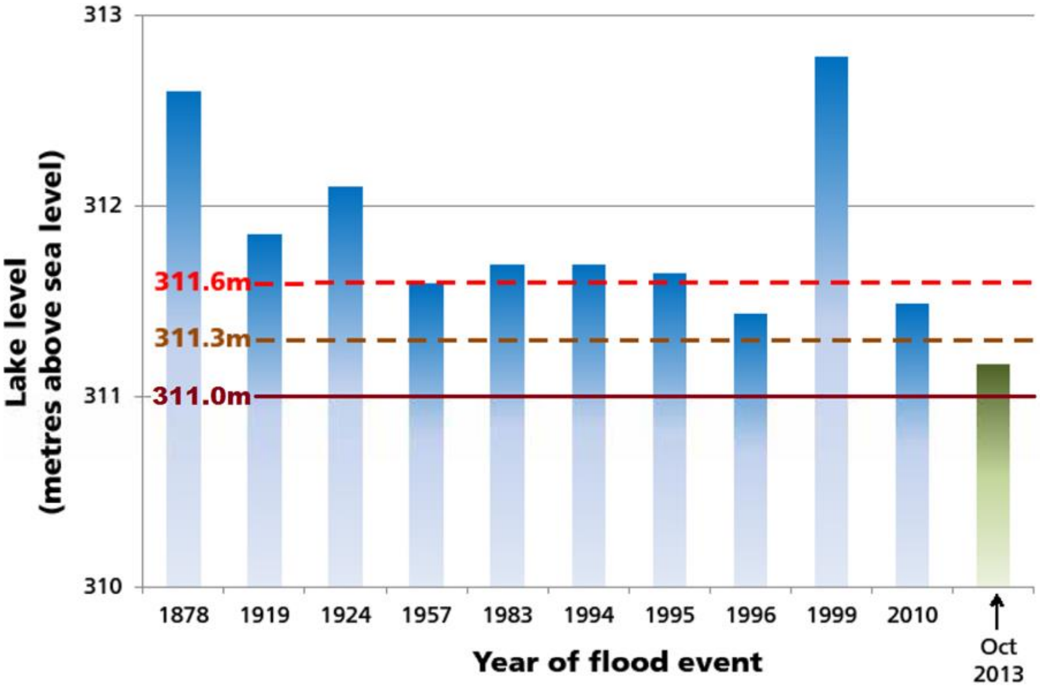

*Figure 7.29 The 10 highest lake levels since 1878 and the most recent flood event begin to inundate lower lying parts of Glenorchy Waterfront Reserve at a level of 311 masl, and Queenstown begins to flood through the stormwater system at a level of 311.3 masl [134, 135].*

To reduce the flood risk to Queenstown and other lakeshore locations, the Queenstown Lakes District Council applied for resource consents in 2003 to lower part of the sill of the outlet weir, which would deepen the channel upstream and downstream. The Council and its technical advisors considered that the proposed sill lowering and channel deepening would allow larger outflows under extreme flood conditions, thereby reducing peak flood levels. As part of a review of these flood mitigation proposals, the discharge rating for the outlet weir was re-evaluated using flow-gauging data collected since 1971. Webby evaluated the discharge rating for the modified lake outlet that takes account of the reverse flow phenomenon and the gradual drowning of the outlet weir leading to the occurrence of reverse flow. These formula were used in the model [136].

*Figure 7.30 High natural lake levels flood Queenstown, 1999 [137].*

Flooding from Lake Wakatipu occurs at times of high lake level associated with heavy rain on the Main Divide. Such storm events affect both the Shotover catchment and the main rivers such as the Dart and the Rees that flow into Lake Wakatipu. There is a timing difference in the impacts of these flows due to the routing or lag effect due to the storage in Lake Wakatipu. The interaction of sediment, lake levels and flows in the Shotover River, Lake Wakatipu and Kawarau Rivers is complex. There is a very flat grade in the Kawarau River between the outlet of Lake Wakatipu at Frankton and the Shotover confluence. Under heavy rainfall conditions when Lake Wakatipu is low at the start of a flood and the Shotover River is in high flow the Shotover River can flow back into Lake Wakatipu.

As the flow in the Shotover recedes, Lake Wakatipu continues to rise until the outflow exceeds the inflow. This may take one to two days. During a flood the Shotover moves a considerable amount of sediment and is on a steeper gradient than the Kawarau River. Until the flow in the Kawarau is more than about five times the Shotover River flow the sediment from the Shotover can infill and reduce the Kawarau channel capacity, but at Kawarau flows more than 5 times the Shotover flow the Kawarau River has sufficient energy to move this sediment faster than it arrives and the Kawarau channel will scour back to its more regular waterway area [138]. The major floods in Lake Wakatipu are often as a result of two or three storms where the time between events has not allowed either the Kawarau channel at the Shotover delta or Lake Wakatipu to return to their more normal conditions.

The simulation incorporating pumped storage shows considerable reduction in lake level variations above the target level (Figure 7.31). The 1999 severe flood event was the highest lake level on record since 1878, at 312.8m. The model runs indicate that the likelihood of flooding in Queenstown would be greatly reduced, to the extent that no flooding at 311.6 masl would have happened within the simulated period. Figure 7.31 shows three examples in reality and the simulated model of flooding events in 1994, 1995 and 1999. The highest level of Lake Wakatipu would have been reduced by the proposed tunnel scheme from 311.7 to 311.1 masl, 311.6 to 311.42 masl and from 312.8 to 311.6 masl, respectively.

The simulation results show that the proposed Wakatipu tunnel hydro power scheme will tend to move high lake levels toward the 310m target level. The effects of applying the operating rules to a 30 MW simulated tunnel hydro power scheme are shown in Figure 7.32 and Figure 7.33, indicating a much higher proportion of time now spent with Lake Wakatipu water levels within a narrow 25 cm target range below the target level. The simulated lake level remains between 309.5 and 309.75 masl 40.5% of the time and between 309.75 and 310 masl 27.7% of the time. Moving the lake below the target level will tend to increase recreational use and aesthetic appeal.

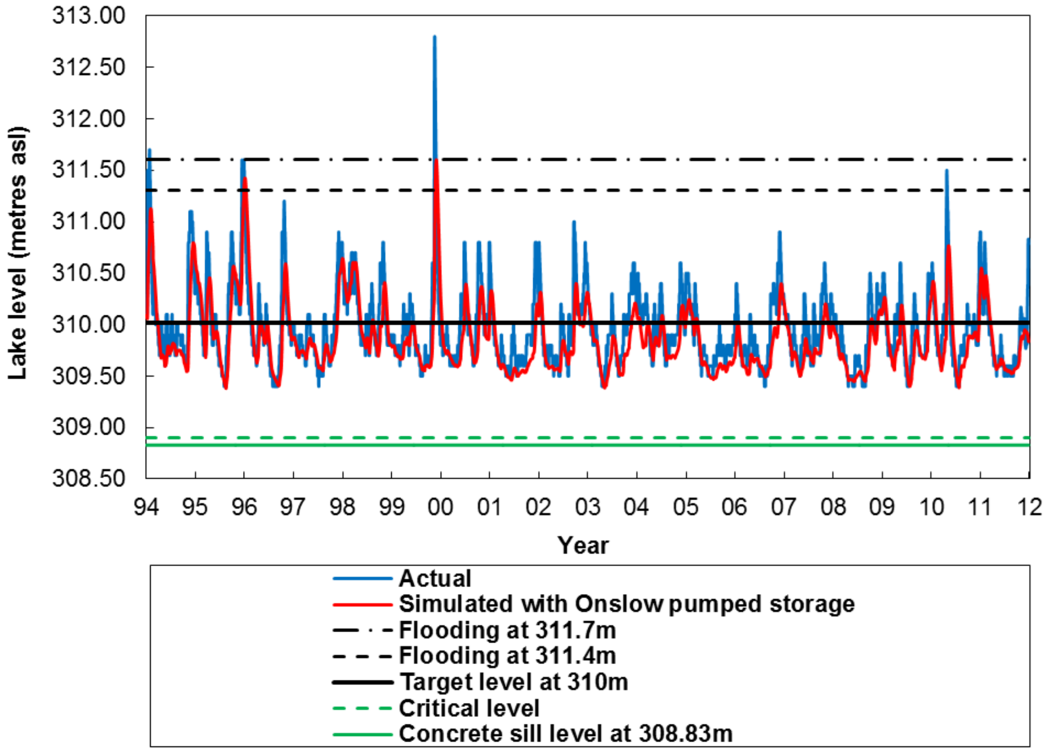

*Figure 7.31 Lake Wakatipu water levels 1994-2012 - actual water levels and as simulated with Onslow pumped storage in operation. In the simulations the Wakatipu target lake level was 310 masl.*

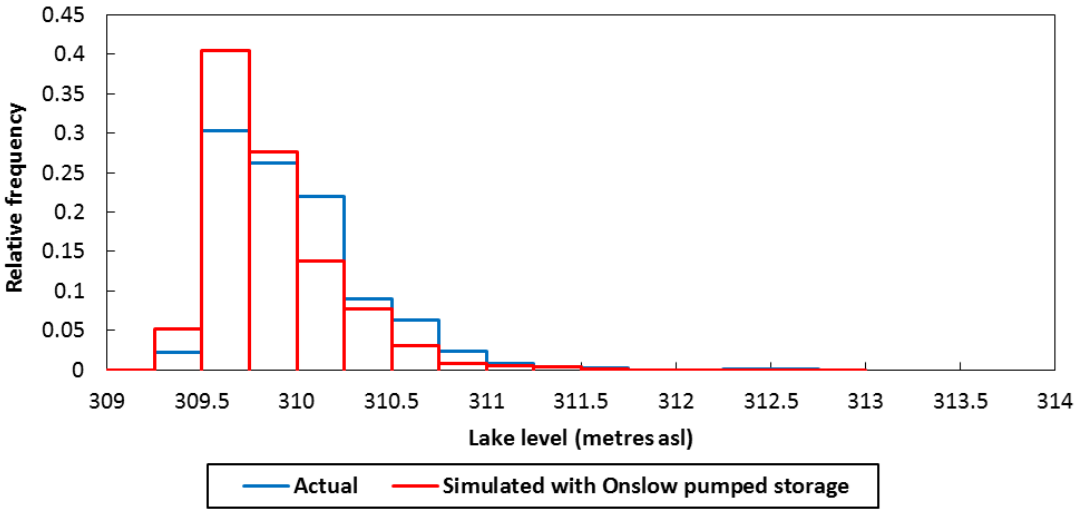

*Figure 7.32 Frequency histogram of Lake Wakatipu levels (masl) 1998-2012 – as recorded and simulated with Onslow pumped storage.*

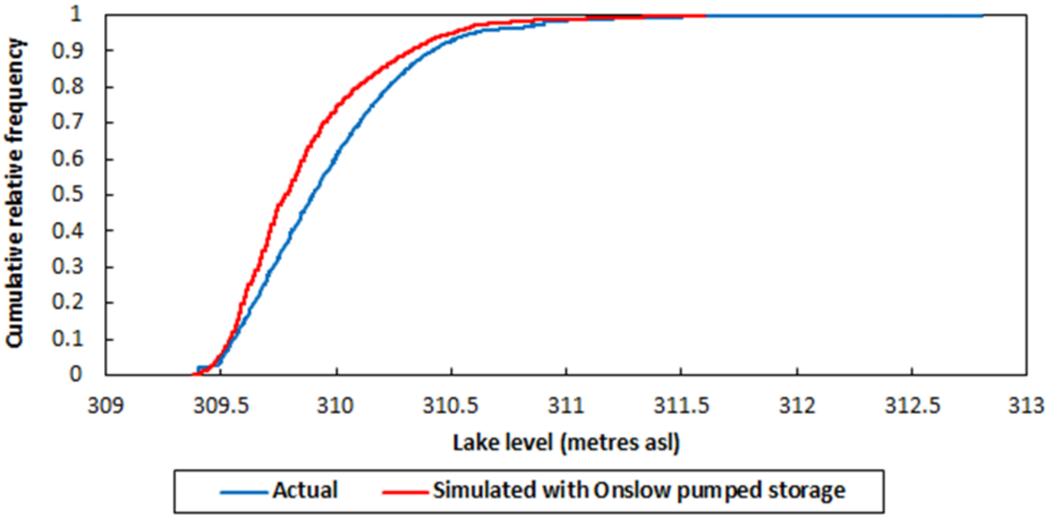

*Figure 7.33 Cumulative frequency distributions of Lake Hawea lake level fluctuations (masl) 1998-2012 - recorded and simulated with Onslow pumped storage.*

### 7.2.7 Lake Wanaka

The environmental advantages for the presently uncontrolled Lake Wanaka by integrating it with pumped storage scheme are described in Appendix Sections 2.7.6 and 2.7.7.

### 7.2.8 Induced hydrological changes

The simulation altered the flow of the Waitaki, Clutha and Waikato Rivers to some extent along with the pattern of lake level fluctuations at existing hydro lakes; Hawea, Tekapo, Pukaki, and Taupo. These induced hydrological changes were a result of Onslow PHES operation integrated with a more stable hydro lake scenario. The change in flow for two examples of the Waikato River and Waitaki River at Lower Waitaki will be discussed below while hydro lake level variation discussed in above sections.

### 7.2.9 Simulated Waikato River flow in the Onslow pumped storage model

The simulated Waikato River maximum flow was significantly reduced by 421 $m^3s^{-1}$ at Cambridge based on mean daily discharges between 1998-2012 (Figure 7.34). This was caused by the considerable amount of flood water volume held back in the lakes of the Waikato hydropower scheme.

Figure 7.34 shows the five highest flow discharges at Cambridge, some of which caused flooding events in 1998, 2004 and 2011. Extremely high flows were experienced between 9-20 July 1998. As a result, urban centres including Hamilton, Ngaruawahia, Huntly, and Mercer were inundated. Farms adjacent to the Waipa River, Whangamarino Wetland, and properties fringing Lakes Taupo and Waikare were also affected. Shoreline erosion at Lake Taupo was also produced by this event. The economic impact of the 1998 Waikato flood – was estimated at $NZ 25M [139].

Figure 7.35 compares the actual flow duration of the Waikato River at Cambridge (1998-2012) to the simulated flow duration. The simulated flow with Onslow PHES was higher than actual flow between range of 139 to 300 $m^3s^{-1}$ while lower than actual high flow of 300 $m^3s^{-1}$. The mean flow was reduced slightly from 238.3 in actual discharge to 232.8 $m^3s^{-1}$ in simulated discharge.

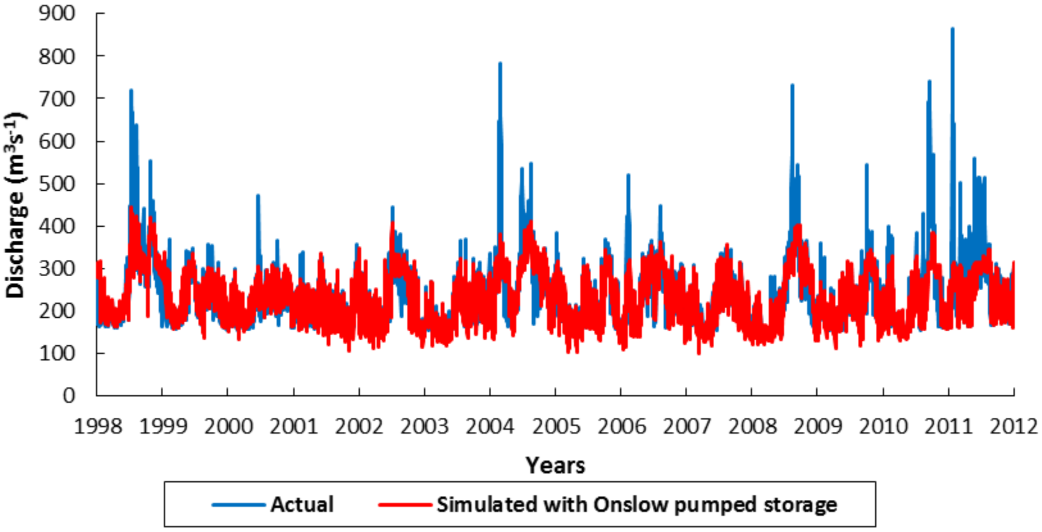

*Figure 7.34 Actual and simulated mean daily discharges for the Waikato River at Cambridge, 1998-2012.*

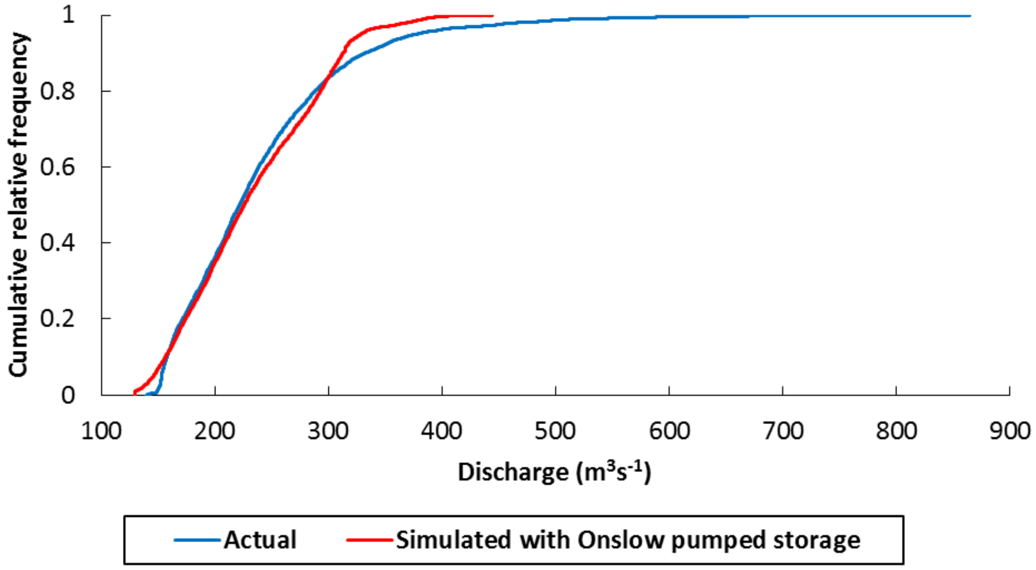

*Figure 7.35 Actual and simulated flow duration curves for the Clutha River at Teviot, based on daily averages (1998-2012).*

## 7.3 Simulated effect of Onslow Pumped Storage: reduced annual flow maxima in the Lower Waitaki

### 7.3.1 Lower Waitaki flood hydrology

The Lower Waitaki River is a braided river system with a mean flow of 360 $m^3s^{-1}$. The flood hydrology of Lower Waitaki River is dominated by the upper catchment and lakes which controlled by the hydro dams. The mean annual flood maxima at Kurow from 1980 to 2015 was 932 $m^3s^{-1}$ and from 1965 to 2015 was 947 $m^3s^{-1}$. The maximum flow recorded in a flooding event, in December 1995, was around 3,000 $m^3s^{-1}$, which had an estimated return period approaching 200 years according to Hicks, while largest tributary annual flood maxima event in March 1986 was around 2,058 $m^3s^{-1}$ [140].

A study by Hicks showed that mean annual flood maxima flows downstream of Waitaki Dam were significantly dampened by the hydro storage of Tekapo and Pukaki from 1,250 $m^3s^{-1}$ to 800 $m^3s^{-1}$ in one case and from 1,150 $m^3s^{-1}$ to 900 $m^3s^{-1}$ in other case. However, Waugh and Payne did not find any significant change in mean annual flood size in the 1927-2000 period (1,180 $m^3s^{-1}$) compared to the 1980-2000 period (1,200 $m^3s^{-1}$) [140].

The Waitaki River Hydrology Study, Lower Waitaki River geomorphology and sediment transport, and Lower Waitaki River control scheme Review have been well documented by Waugh and Payne, Hicks, Duncan, Shankar, Wild, Walsh, and Heslop I, Palmer G and Surman M [140-144]. In this section, the effect of configuring the Waitaki hydro power scheme with the Onslow PHES to reduce flooding frequency and flood maxima magnitudes were investigated.

### 7.3.2 Land use

The river has an “active bed” made up of a cleared fairway (600-800 m wide) and a vegetation buffer zone (heavy willow growth typically 50 to 500m wide on either side). Extending beyond the active bed are berm lands and floodplain areas bounded by terraces or hill toes. Farming activities have generally been confined to these floodplain areas, although in several locations these activities have extended into the landward margins of the active riverbed.

Intensive farming within the active bed is undesirable, because the removal of vegetation buffers increases flood and erosion risk to the adjoining floodplain and increases Scheme maintenance costs. While the developers might increase their farm productivity in the short term, the effects of increased erosion and flooding can offset these gains and often extend beyond individual boundaries to affect adjacent and downstream properties and public infrastructure.

For higher flows, flooding onto berm lands beyond the active bed is likely. Overflows are likely to seek out and follow old river channels that weave their way down the berm areas (swales). The greatest risk is not the flooding itself, but the possibility that the outflows will erode the land and occupy the swales to the extent that the old channel redevelops. The redeveloped channel can isolate sections of berm land, eventually reclaiming them into the active bed through the combined processes of erosion and deposition [140].

The Lower Waitaki River Control Scheme has considerable debt as a result of works undertaken in response to relatively small flood events in the Lower Waitaki River, including events since 2009.

### 7.3.3 Analysis of Lower Waitaki flood hydrology

This section uses actual records of stream flow and modelling to determine the expected discharge of a 100-year flood (a flood that has a 1% chance of being seen in any given year). Figure 7.36 shows the annual flow maxima for the Waitaki River at the Kurow measuring station. The plot shows the highest flow discharge for each year in time series for both the actual situation and modelled with the Onslow PHES scheme in operation. It is evident there has been a significant reduction in the magnitude of annual flow over the simulated period.

Although the peak annual discharges of the model were higher over 6 years than the actual, that is due to the maximum station throughput for Benmore, Avimore and Waitaki stations being 635 $m^3s^{-1}$ in the model. The recorded high flooding events between 2009-2012 can be reduced significantly, as shown on the model. In general, the recorded peak annual discharge is larger than that simulated in the model.

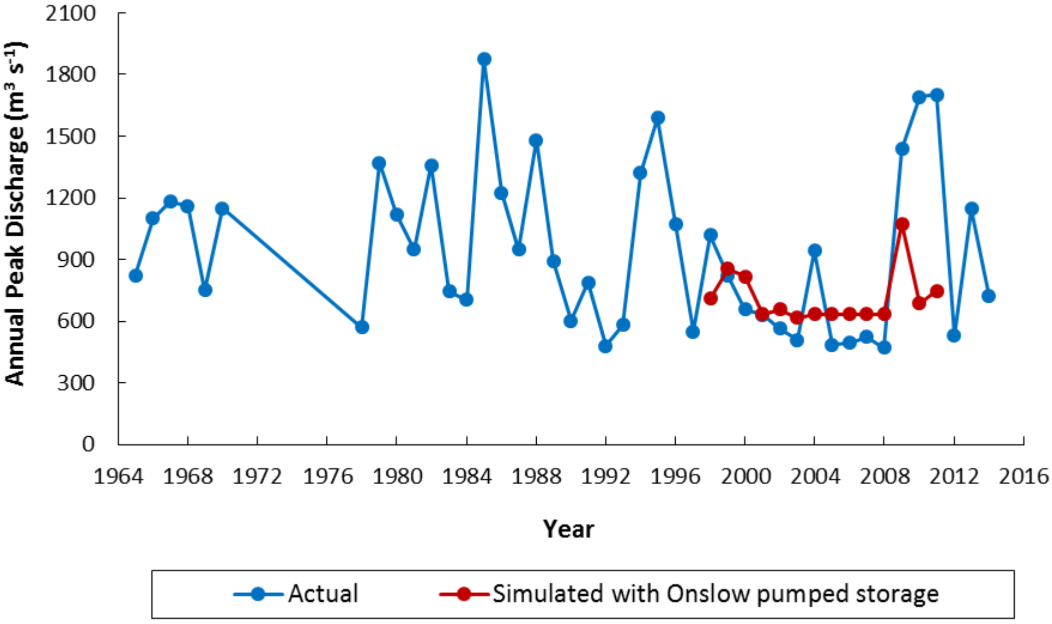

*Figure 7.36 Recorded and simulated peak annual discharge of Waitaki River at Kurow.*

This reflects the influence of modified operation with a pumped storage scheme to maintain water levels in the lakes near mid-range levels. This allows dams to hold back water during periods of high inflow, reducing the peak flow events. In other words, the simulations indicate that the operation of the Onslow scheme would reduce the size of flooding downstream from the Waitaki power station.

Because there is an obvious difference in the size of peak annual discharges in both the recorded data and the simulation with the Onslow PHES scheme, the frequency of annual flow maxima have obviously changed over the time period of record. It is possible to analyse the frequency of flooding for the recorded events and for the model and see how the probability of different sizes changes as a result of modified operation of the Waitaki River flow patterns.

The data for annual flood maxima is shown in Table 7-1 and Table 7-2. The recorded data set covers 43 years and the simulated model covers 14 years. The data for both recorded and simulated flood maxima were thus analysed to see how the probability of flood size changed as a result of modified operation of the Waitaki valley power scheme.

*Table 7-1 Recorded annual flood maxima of Waitaki River at Kurow.*

| Year | Actual | Year | Actual | Year | Actual | Year | Actual | Year | Actual |
|---|---|---|---|---|---|---|---|---|---|
| 1965 | 821.98 | 1981 | 948.65 | 1990 | 603.49 | 1999 | 820.43 | 2008 | 472.13 |
| 1966 | 1100.5 | 1982 | 1357.6 | 1991 | 788.95 | 2000 | 658.36 | 2009 | 1436.2 |
| 1967 | 1181.0 | 1983 | 745.17 | 1992 | 479.42 | 2001 | 629.89 | 2010 | 1691.69 |
| 1968 | 750.59 | 1984 | 704.03 | 1993 | 581.61 | 2002 | 565.30 | 2011 | 1703.4 |
| 1969 | 1150.7 | 1985 | 1872.9 | 1994 | 1320.5 | 2003 | 509.27 | 2012 | 529.47 |
| 1970 | 571.0 | 1986 | 1224.1 | 1995 | 1590.2 | 2004 | 941.98 | 2013 | 1146.30 |
| 1978 | 571.05 | 1987 | 947.71 | 1996 | 1073.9 | 2005 | 487.13 | 2014 | 721.13 |
| 1979 | 1369.8 | 1988 | 1482.1 | 1997 | 549.90 | 2006 | 493.77 | | |
| 1980 | 1120.6 | 1989 | 894.39 | 1998 | 1017.2 | 2007 | 523.00 | | |

*Table 7-2 Simulated annual flood maxima of Waitaki River at Kurow.*

| Year | Model | Year | Model |
|---|---|---|---|
| 1998 | 710.31 | 2005 | 635.00 |
| 1999 | 855.22 | 2006 | 635.00 |
| 2000 | 818.20 | 2007 | 635.00 |
| 2001 | 635.00 | 2008 | 635.00 |
| 2002 | 656.61 | 2009 | 1072.77 |
| 2003 | 615.63 | 2010 | 686.29 |
| 2004 | 635.00 | 2011 | 746.47 |

The best fit through the dataset of the recorded data shows $y = 428.76 \ln(x) + 536.69$ and for the model $y = 158.35 \ln(x) + 568.36$ as shown in Figure 7.37. Use of the flood frequency curve would assign a return period of 100 years to the recorded data at 2,511.2 m$^3$s$^{-1}$ and in the model at 1,297.5 m$^3$s$^{-1}$.

The maximum recorded peak flow was 1,872.9 m$^3$s$^{-1}$ in 1985 which had a return period of 44 years. The equivalent return period in the model produced a value of 1,167.5 m$^3$s$^{-1}$. Flood flows from the upper catchment are significantly reduced by Onslow-modified Waitaki River flows as shown in the flood events of 2009, 2010 and 2011.

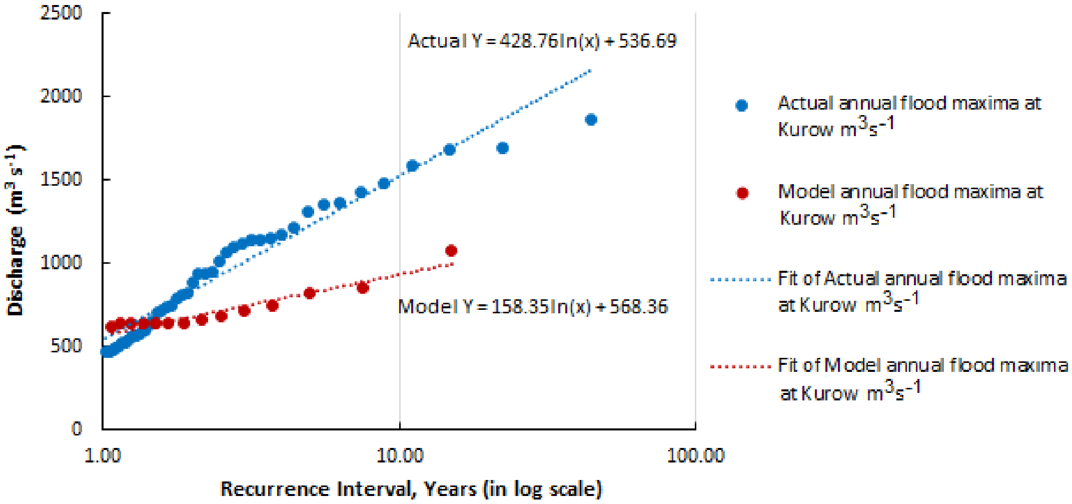

*Figure 7.37 Flood frequency distribution graphs for Waitaki at Kurow for the recorded data (1965-2015) and the model (1998-2012) based on daily mean flows recorded flows calculating.*

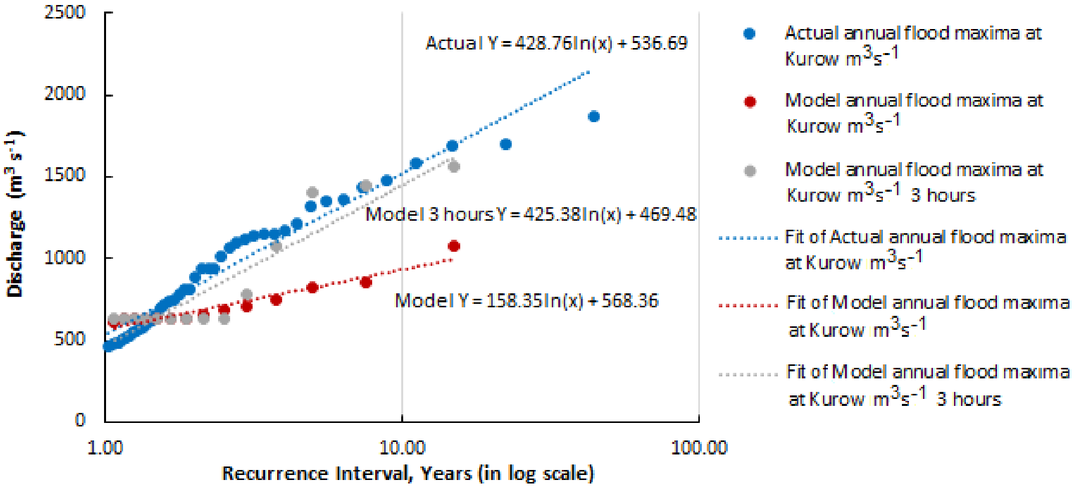

*Figure 7.38 Flood frequency distribution graphs for Waitaki at Kurow for the annual flood maxima for 3-hour mean discharges in the model (1998-2012). As described above the maximum release from the Waitaki dam was 635 m$^3$s$^{-1}$.*

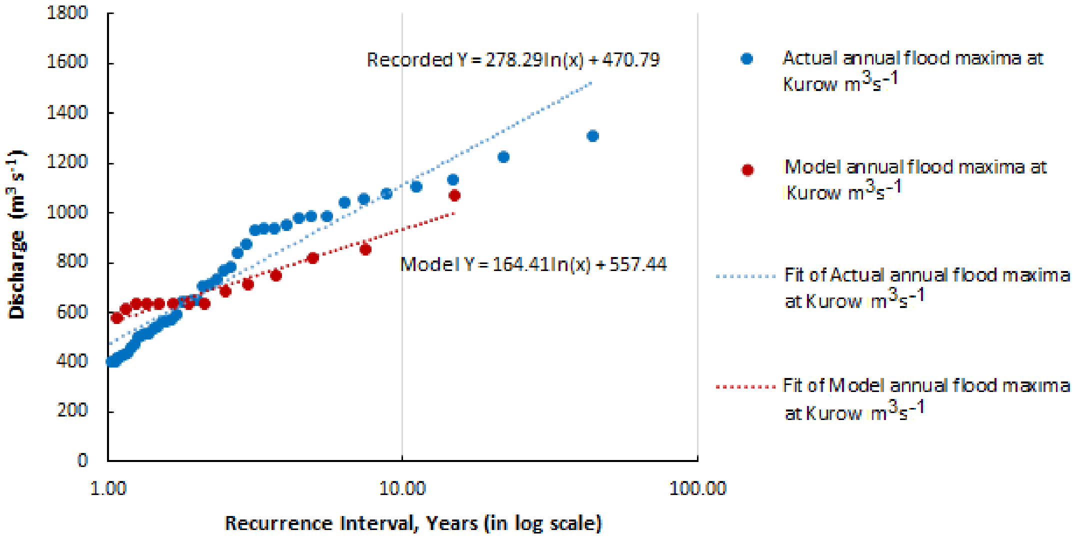

*Figure 7.39 Flood frequency distribution graphs for Waitaki at Kurow for the 7 days mean annual flood maxima for the recorded (1965 – 2015) and for model (1998-2012).*

Table 7-3, produced from Figure 7.37, Figure 7.38, and Figure 7.39, provides flood frequency information for the Waitaki River at Kurow for recorded flows from 1965-2014 and modelled flows for 1998 – 2012 for 3 hourly, 1 day and 7-day intervals. Annual maximum discharges are fitted using log curves. As Table 7-3 gives information on the size of flood peaks and durations that cause downstream flooding and erosion effects, it can provide meaningful information on the flooding and erosion potential of flood events.

For example, maximum 7-day mean flow damaging events occurred in May 2009, reaching 1,112.7 $m^3s^{-1}$, which is equivalent to approximately a 10-year return period. The second event was in January 2011, with 2 weeks exceeding 1,31 $m^3s^{-1}$, which is equivalent to a roughly 20-year return period. These events caused significant erosion and damage to riverbanks, and approximately five hectares of productive land was lost to the river after the event of 2011, as shown in Figure 7.40.

The simulation of flooding events using the model show a good mitigation of flooding compared to the recorded high discharges, as shown in Figure 7.37, Figure 7.38 and Figure 7.39. The peak was reduced from 1112.7 to 926.7 $m^3s^{-1}$ for the event of May 2009, which is equivalent to almost a 10-year return period in the model and 5 years in the recorded data, and from 1,313.3 to 717.4 $m^3s^{-1}$ in the event of January 2011, which is equivalent to almost the annual mean in the model and less than the annual mean in the recorded data. It seems evident therefore that Waiktaki flood events could be reduced significantly as a consequence of the Onslow PHES operation.

*Table 7-3 Estimated return period magnitudes ($m^3s^{-1}$) for the Waitaki River at Kurow, 1 day recorded (1966 - 2014), 1 day model (1998 -2012), 3 hourly recorded ( (1965 - 2000), 3 hourly model (1998 - 2012).*

| Averaging Interval | Return Period | | | | | | |
|---|---|---|---|---|---|---|---|
| | 5yr | 10yr | 20yr | 50yr | 100yr | 200yr | 1000yr |
| 3 hourly - Recorded | 1520 | 1800 | 2060 | 2410 | 2660 | 2920 | 3510 |
| 3 hourly - Model | 1154.1 | 1449 | 1743.8 | 2133.6 | 2428.4 | 2723.3 | 3408 |
| 1 day - Recorded | 1226.7 | 1524 | 1821 | 2214 | 2511.2 | 2808.4 | 3498.5 |
| 1 day - Model | 823 | 933 | 1042.7 | 1187.8 | 1297.6 | 1407.3 | 1662.2 |
| 7 days - Recorded | 918.7 | 1111.6 | 1304.5 | 1559.5 | 1752.4 | 1945.3 | 2393.2 |
| 7 days - Model | 822.1 | 936 | 1050 | 1200.6 | 1314.6 | 1428.6 | 1693.1 |

*Figure 7.40 South Bank of Waitaki River, near Duntroon, looking north-east, 10 March 2011, showing damage on riverbanks as shown by the red line. Approximately five hectares of productive land was lost to the River during the event. An intake and headrace structures were also destroyed during sustained high flows [145].*

## 7.4 Emissions reduction environmental value

Pumped hydro storage does not create $CO_2$, $SO_2$ and $NO_x$ emissions; however, the electricity it stores is not carbon dioxide-free, and it only redelivers this electricity with losses in round-trip efficiency [146]. Table 7-4 shows the emissions of CO2, SO2 and NOx per unit of power generated.

*Table 7-4 Emissions per unit of energy generated.*

| | kg $CO_2$/MWh | kg $SO_2$/MWh | kg $NO_x$/MWh |
|---|---|---|---|
| Coal | 960 | 6.08 | 0.82 |
| Oil | 708 | 5.1 | 1.36 - 14.98 |
| Natural gas | 468 | 0.0032 | 1.0 - 12.71 |

In New Zealand, the total installed capacity of thermal power plants in 2017 was around 1,966 MW, generating around 6,103 GWh per annum, which is equivalent to a total generating proportion of 15%. The fuels used were primarily 91.44% gas, 8.46% coal, and 0.086% oil. Using the database for calculation [147], the likely levels of emissions are shown in Table 7-5. This amount of greenhouse gas can be significantly reduced by integrating more renewable energy sources with the Onslow PHES.

*Table 7-5 Emissions example calculation in 2017.*

| | Ton $CO_2$ | Ton $SO_2$ | Ton $NO_x$ |
|---|---|---|---|
| Coal | 1,301,856 | 8,245 | 1,112 |
| Oil | 9,785 | 70 | 113 |
| Natural gas | 6,852,961 | 47 | 100,378 |
| Total | 8,164,602 | 8,362 | 101,603 |

The use of thermal power plants is one aspect of the NZ power supply that is vulnerable. The present electricity market causes price panics when the hydro storage lakes are perceived to be trending down, resulting in sometimes needless carbon dioxide emissions from the thermal power stations because of higher electricity prices, as noted earlier.

Buffering against climatic fluctuations could be met in principle with stand-by thermal power stations. There already is a small-scale version of that in the Contact Energy 155 MW diesel-powered Hawkes Bay Whirinaki power station, which generated during the 2017 dry South Island winter. However, a significant stand-by station would mean even more greenhouse emissions in dry years and in normal years the station would do nothing, despite requiring on-going maintenance.

# Chapter Eight: Evaluation of the Onslow pumped hydro: kWh purchase and sales differential

## 8.1 Introduction

Before 1996 the electricity market in New Zealand was administered by the government. Since then shares have been sold to various companies. It is known that during periods of peak demand and when electricity generation is limited, especially in dry years or situations where the wind energy drops off, the value of a kWh increases. In contrast, the price decreases during periods of high energy availability, especially in wet years. Therefore, under the current market structure the operator of the proposed Onslow PHES would buy electricity in wet years when the price is low in order to sell it in dry years when the price is high. Note that it can’t be assumed what would actually happen in the electricity market after integrating the Onslow PHES.

The aim of this chapter is to address purchase and selling power as part of the potential economic benefit of the Onslow scheme in two scenarios: where the size of storage at Onslow has no effect on electricity prices; and where the available storage changes electricity prices.

## 8.2 Simulation approach

A simulation model of the seasonal pumped storage plant in conjunction with the Clutha, Waitaki and Manapouri hydropower schemes, using historical hydro flows over the period 1998-2012, was run to address purchase and selling power as part of potential economic benefit of the Onslow scheme. The 1998-2012 period was chosen for the simulations because changes in the structure of the electricity market started around 1996. The simulation needed to input the electricity price half an hour ahead to bid for buying energy from the grid or to sell energy to the grid. The first scenario used the electricity prices set at Clyde station as a reference. In the second scenario, forecast prices were included.

The wholesale electricity market spot prices are affected by equilibrating demand and supply, which are affected by time, day and month of the year and the availability of fuel, such as the volume of water in the hydro lakes, inflow, wind and price of gas. New Zealand's wholesale electricity market is known to have a connection between spot prices and the level of storage, but there does not seem to be a connection between price and absolute storage level, as can be seen in Figure 8.1. High prices have been experienced regardless of whether the reservoirs were full or empty. These may also be driven by a high reserve requirement, or simply due to the system being capacity constrained. During a shortage the price is a trade-off between greed and guilt. Market power is exercised!

It is therefore hypothesized that the relationship between spot price and storage level is connected to Minimum Water Value (MWV). Calculating the MWV for a storage level does not depend solely on the total amount of water held. It also depends on the amount of water the producer would expect to have at that particular time in relation to their planned storage trajectory [148, 149].

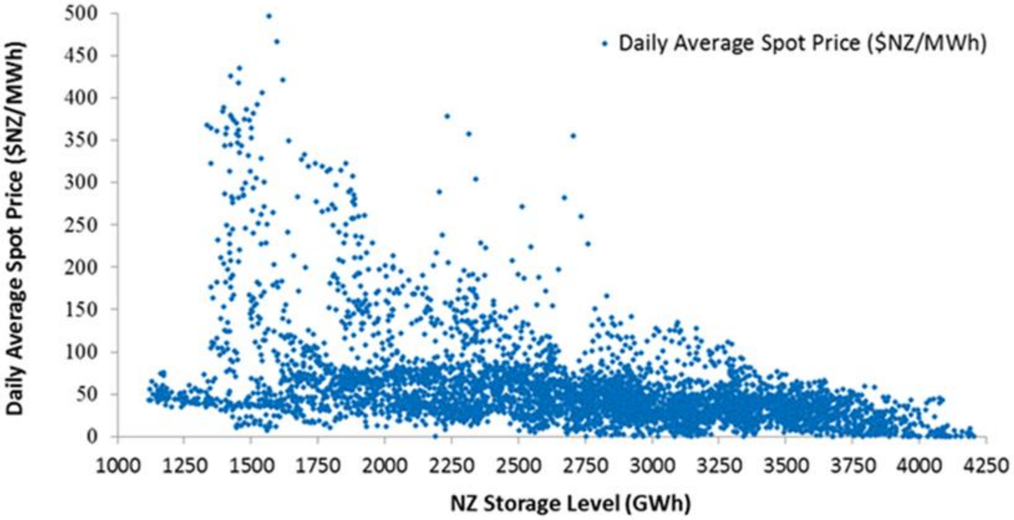

*Figure 8.1 Daily average spot prices versus national hydro storage, 1997-2010.*

The operator of the Waitaki system reservoirs, for example, could expect an average planned storage trajectory. This takes into account the yearly average patterns of load, generation and inflows. In the event of a storage level higher than the expected trajectory, a lower MWV would encourage generation up to the maximum of plant availability and thereby decrease the storage level and vice versa.

To determine the relative storage level, one has to compare the actual storage level with the lower bound or "danger zone". The MWV increases as the storage level gets closer to the danger zone. According to Tipping [149], using the tenth percentile of storage level best indicates a "danger zone" level, as well as being the most perceptive.

Once the lower envelope is known, the relationship of the envelope, actual storage level and price can be established. Calculating a net storage position, i.e. actual storage minus the lower envelope, provides the Relative Storage Level (RSL) for each day in the sample period. To calculate the RSL on a given day (t) therefore requires subtracting the actual storage level from the historic tenth percentile.

RSL(t) = Storage level (t) – Historic tenth percentile (d)

Where d is the day of the year corresponding to day t.

Electricity price, estimated = $-26.58 \times 10^{-9} (RSL)^3 + 11.28 \times 10^{-5} (RSL)^2 - 16.204 \times 10^{-2} (RSL) + 110.83$

When the RSL is high, prices are low, and when it decreases the price tends to increase. Thus, the time series for wholesale electricity spot prices was modelled for 1998-2012 as shown in Figure 8.2 and applied in the second scenario of the simulation model. It is evident from Figure 8.2 that for lower storage levels the "relationship" is poor and under-predicts when storage levels are low. The more important aspect is that it captures that high water levels are not associated with high prices.

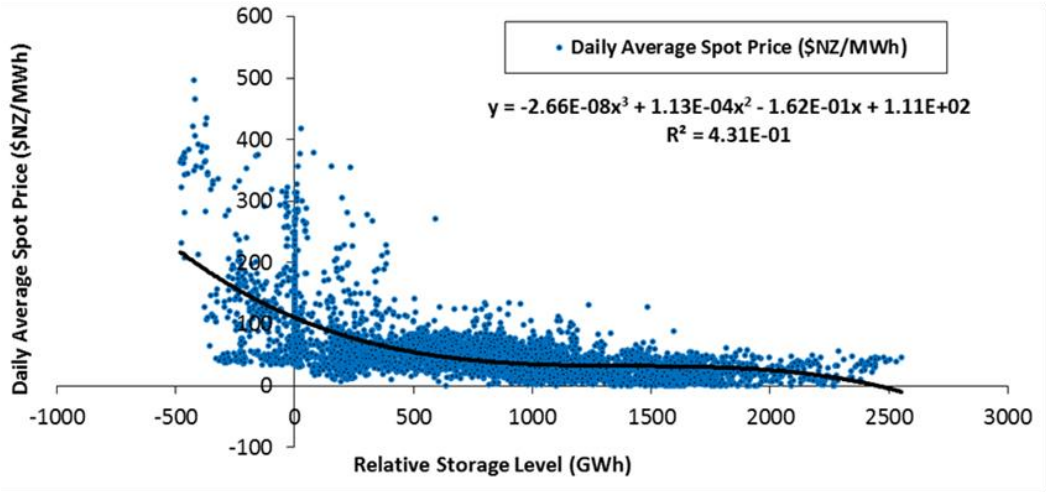

*Figure 8.2 The relationship between daily average price and relative storage level.*

The operation of the simulation model can be summarised as follows:

- Obtain the half-hourly power output records for Clutha, Waitaki and Manapouri power schemes over the period of interest (1998-2012) and consider them as demand in the grid in the model.

- The programme runs for the case of supply of electricity equal to demand (otherwise blackouts would be experienced). Therefore, the volume of water in the Lake Onslow reduces according to the need for extra energy in the grid or increases due to extra production of energy from the hydropower schemes.

- Forecast the electricity price for half an hour ahead by calculating the current total hydro storage volume of the Clutha, Waitaki, Manapouri, Taupo and Waikaremoana power schemes.

- Make a bid in the market for the pumped storage scheme. If the estimated electricity price falls below a certain point, such as $NZ/MWh 20, then pump water to the Onslow storage system equivalent to the possibility of generating energy from the power schemes (Clutha, Waitaki and Manapouri). In practice, this will require a small change to the market rules to allow for load, while pumping, to be dispatchable, just as generation is.

- If the estimated electricity price rises above a certain level, such as $NZ/MWh 60, then generate electricity by releasing water to the Lake Roxburgh equivalent to the possibility of reducing energy from the power schemes.

- If the estimated price falls between the prices indicating for pumping or generating, then no pumping or generating is carried out.

- For pumping or generating, have efficiency losses of 20%. For example, if energy pumping costs 20 $NZ/MWh and the energy is sold for 60 $NZ/MWh with an 80% round trip efficiency, the differential is 32 $NZ/MWh.

- The program tries to avoid a deficit of water in the lower reservoir, Lake Roxburgh, at all times.

Model parameters, which include:

1. Maximum pump/release rate;
2. Pumped storage efficiency; and
3. Maximum and minimum permitted discharge in the Clutha River must be varied according to the simulation scenario.

## 8.3 Verification and validation of simulation models

The simulation models were tested in terms of input and output of water quantity and energy production, checking that similar totals held.

Scenario 1 shows the simulated cumulative energy output in TWh for operating the pumped storage system in conjunction with the Clutha, Waitaki and Manapouri schemes. It produces values slightly lower than the recorded energy output due to the loss of energy in pumping and generating. However, it saves some energy by reducing spill at the Clutha, Waitaki and Manapouri schemes. In the second scenario, the actual energy is virtually the same as the simulated energy because there is less pumping and generating; the pumped storage could reduce the fluctuation of electricity market prices (Figure 8.3).

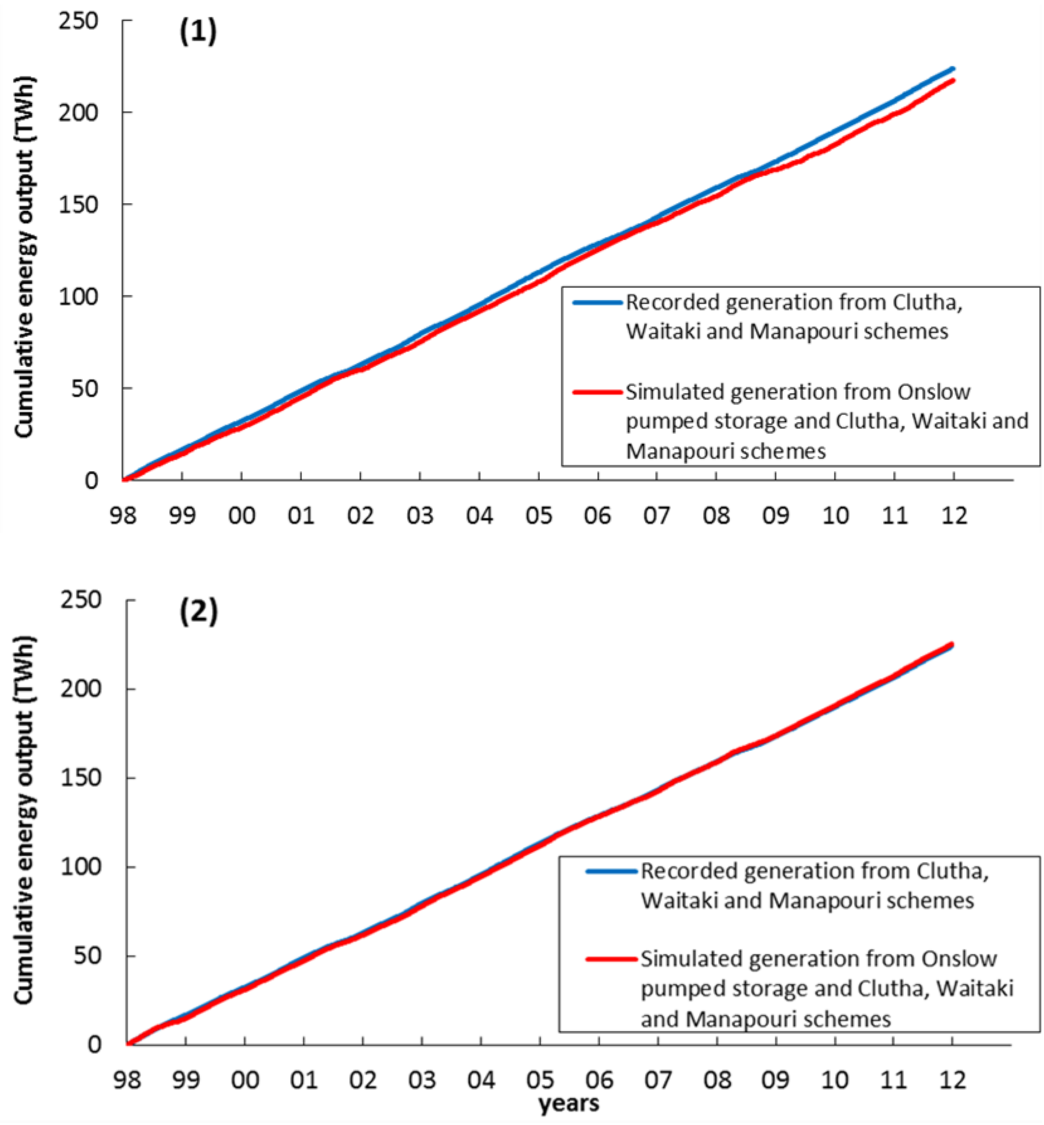

*Figure 8.3 Cumulative total output energy in the two scenarios of actual and simulated schemes including Onslow pumped storage and Clutha, Waitaki and Manapouri schemes, 1998-2012.*

## 8.4 Simulation results

Scenario 1: If the pumped hydro storage had been constructed in 1998 and had operated until 2012, it would have generated an income from purchase and sales differential of $NZ 1.8 billion. However, there is an initial cost to raise the water level in the upper reservoir to 740 masl. This cost has no effect on income from purchase and sales as the simulations end at the same 740 masl level. Scenario 2 would have generated around $NZ 220M and shows that pumped storage can reduce high prices in winter when the demand is high and increase them in summer when the demand is low, making prices more stable and leading to a lower income in a bidding market.

The major benefit of the scheme is that it could be used effectively during dry years such as 2001, 2003, 2006 and 2008. There was a noticeable increase in the simulated electricity prices during winter, especially during dry years. Scenario 2 shows that the volume of water in the upper reservoir gradually decreased due to a steady increase in electricity prices, with a reduction of fluctuation to between $NZ/MW 9 to 83.7 (Figure 8.5, Figure 8.6). Scenario 2 shows there is a loss due to reduction of the start level of 740 masl to end near 720 masl.

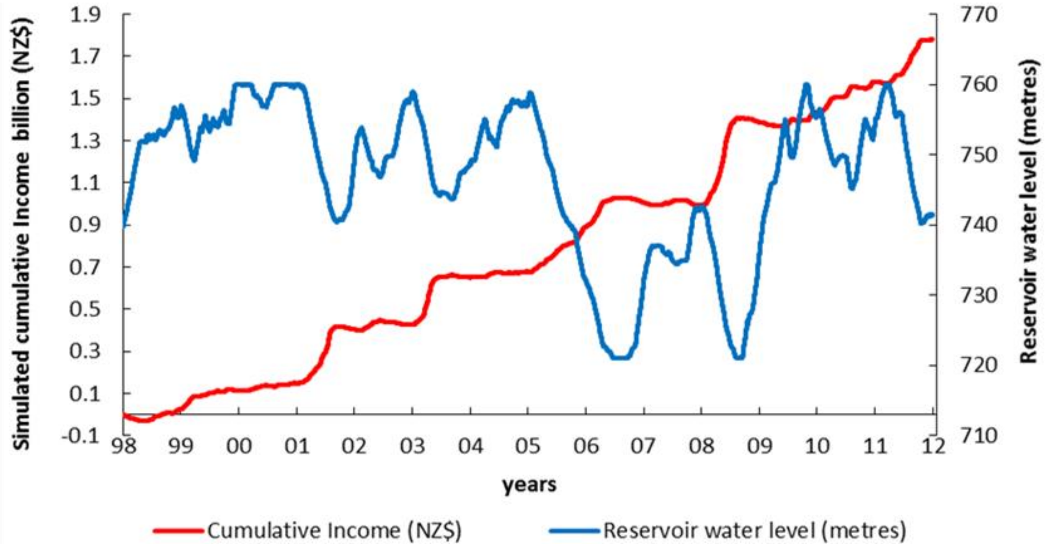

*Figure 8.4 Total cumulative income from operating the Onslow PHES and water level of extended Lake Onslow, 1998-2012 for the first scenario in the simulation model.*

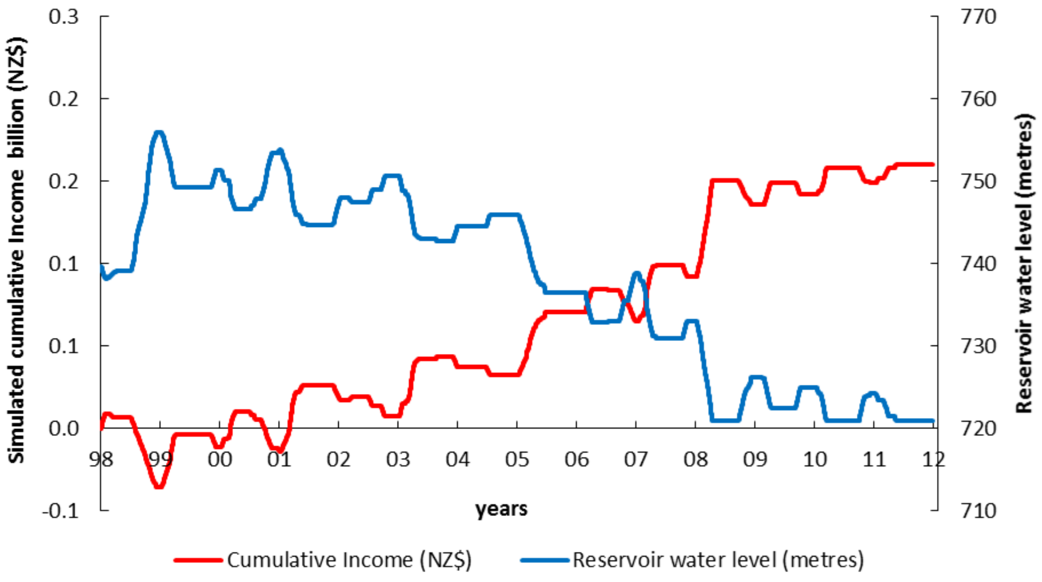

*Figure 8.5 Total cumulative income from operating the Onslow PHES and water level of extended Lake Onslow, 1998-2012 for the second scenario in the simulation model.*

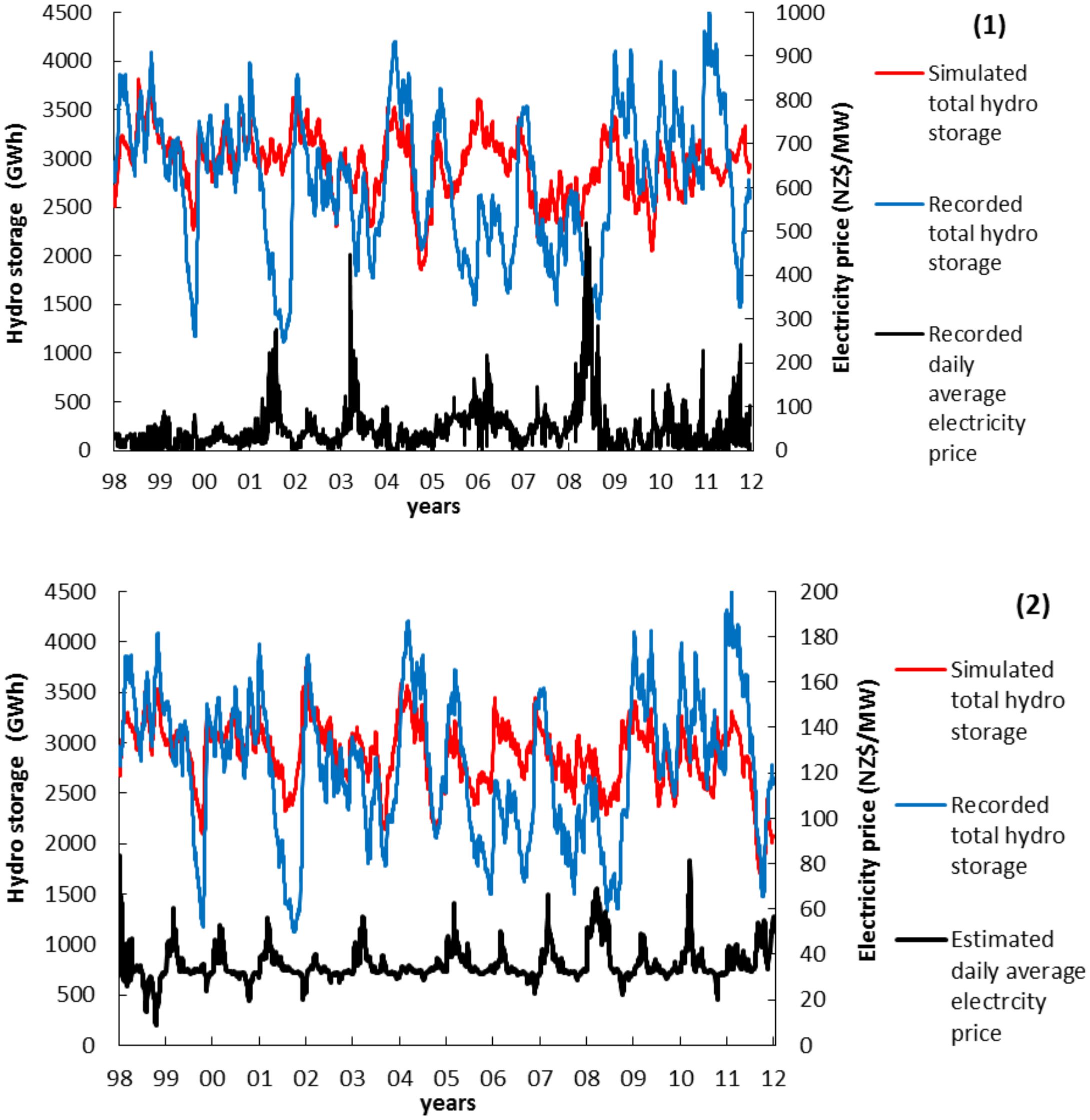

*Figure 8.6 Recorded and simulated hydro storage, and recorded and simulated system prices, 1998-2010. (1) refers to the first scenario in the simulation and (2) to the second. The simulation doesn't include Onslow storage.*

In scenario 1 (Figure 8.7 (1)), there is more pumping and generating due to high fluctuation in electricity prices, while scenario 2 (Figure 8.7 (2)) exhibits a low percentage of pumping/generating because the operation of the pumped storage system stabilises electricity prices.

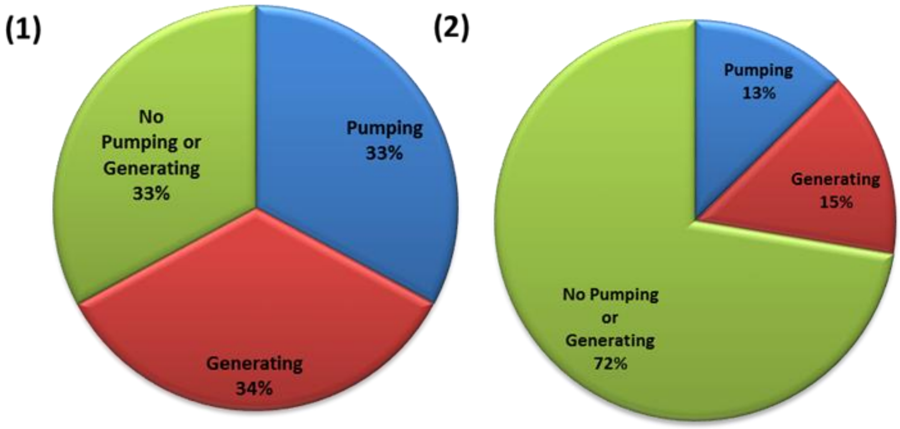

*Figure 8.7 Percentage of pumping, generating, and no pumping or generating (by time) from operating the Onslow pumped storage system from 1998 to 2012 for the two scenarios.*

## 8.5 Economic value of the Onslow pumped storage system as spinning reserve

Spinning reserve is electric power plant or generating capacity which is unloaded, synchronized, online and ready for immediate use in the event of plant outage. One economic value of operating the Onslow PHES 1,300 MW is increased security of electricity supply and spinning reserve. With respect to security of supply, New Zealand hydro water storage operation is strictly on a one-year cycle and does not have storage capacity to avoid hydro concerns if lake levels trend down significantly in autumn and winter. As uncertainty increases when levels fall, there is a fear of power blackouts, and inevitable price spikes occur in the electricity spot market. Such winter concerns and price spikes have been quite frequent since 2000, perhaps causing lost opportunities for overseas investment because we are perceived to have an insecure electricity supply.

With the Onslow PHES in operation as described, the national hydro-energy storage would fluctuate around a much higher mean value, perhaps 6000 GWh compared with the current low value of about 2700 GWh. With the extra energy buffer, price spikes and insecurity would largely vanish from the spot market and would give the nation a much better look to overseas investors.

In the long term it is considered that the costs of spinning reserve comprise:

a) Fixed costs associated with holding reserve generating capacity in the system to meet reserve requirements at peak. This cost is estimated to be $145/kW/yr based on the marginal source of generation capacity; and

b) Costs that arise from operating generation in a mode that allows reserve provision – estimated to be around $2/MW/h on average for the marginal source of reserves.

If pumped hydro storage were used to avoid spinning reserve costs, this would deliver savings to the market of approximately $NZ 50M per year.

## 8.6 Conclusion

In scenario 1, if a company were to develop the Onslow PHES, a benefit of approximately $NZ1.8 billion from kWh purchase and sales differential would be derived over 14 years by using pumping and generating, and added value is derived from a spinning reserve service.

In scenario 2, there is little fluctuation in the price of electricity, because pumped storage will change the volume of water behind the dam and thereby change the operation of the market. In this case, the consumers in three categories – industrial, domestic and commercial – gain certainty of electricity supply and diminished concerns about increasing electricity prices, as water is available in the upper reservoir.

The lake levels, now increased in winter due to pumped storage, take the role of generating in winter instead of the hydro power schemes and in this way make more water available for irrigating in spring. This applies especially in the Waitaki Valley, enabling greater agricultural income. In this scenario, the current lower price in summer can be increased and the higher price in winter can be decreased.

# Chapter Nine: Conclusions and recommendations

## 9.1 Conclusions

The proposed Onslow PHES was found to be hydrologically feasible and potentially provide multiple advantages in terms of managing water and energy systems, including buffering against climatic variations; increasing hydroelectric energy generation from the Waitaki, Clutha, Manapouri, and Waikato schemes; supporting wind energy developments; providing a standby reserve; providing increased irrigation water in the Lower Waitaki valley; stabilising wholesale prices; and reducing thermal power station greenhouse emissions.

A smaller possible pumped hydro energy storage scheme of 120 MW between Lakes Hawea and Wanaka was found to be hydrologically and economically feasible. If constructed, the operating rules of the proposed scheme would reduce Lake Wanaka’s shoreline flooding risk, by reducing the present extent of natural fluctuations.

### 9.1.1 Increasing hydropower output using seasonal Onslow pumped storage

By integrating the proposed Onslow PHES with the Waitaki, Clutha, Manapouri, and Waikato hydropower schemes, New Zealand's energy storage capacity was enhanced in modelling using historical records, reducing the effect of dry years/seasons over the period of record to almost zero as the hydropower output variation was consistent throughout the year.

The Onslow upper reservoir was set to have zero storage at (720 msal) at the start of the simulations (1 January, 1998). The level increased due to some wet years to reach 777 masl in mid-2004, which more than doubled the current maximum New Zealand hydro storage. The level then declined as a result of several dry years to reach 740msal in 2008, thereafter increasing again to 775 masl. The scheme could either operate on a seasonal cycle or act as a passive energy reserve to buffer existing hydro-power capacity against the effect of dry years.

Simulations indicate the Onslow scheme would operate in excess of 100% energy efficiency, providing a small net power gain, because of the extra power generated from existing hydro stations from reduced spill loss equivalent to 20,630 GWh over the simulation period.

A seasonal Onslow pumped hydro energy storage plant offers an alternative approach to the management of energy/water in the Waitaki, Clutha, Manapouri, and Waikato hydropower schemes. It would effectively replace the current approximately "run of the river" approach (for the Clutha) and the retention of water behind dams to meet high demands in winter (for the Waitaki) and would maintain the hydro lakes at mid-range stable levels. This level stability has the advantage of reduced hydro spill losses and reduced flood risk with respect to lake townships and both the Waitaki, and Clutha rivers by lowering maximum discharges. There would also be a return to more natural lake shorelines and the creation of equilibrium lake beaches for the main hydro lakes.

During years with prolonged wet periods and floods, the simulated pumped storage reservoir gained a large potential energy increment, while the simulated lake levels were lower than the recorded levels, which significantly reduced water spill from the Clutha, Waitaki, Manapouri and Waikato hydro power schemes.

During years with prolonged dry periods it was found that the simulated Onslow pumped storage release compensated for lower generation from the Clutha, Waitaki, Manapouri and Waikato hydro power schemes and maintained simulated lake levels near their target levels. This effectively eliminated the massive recorded lake level drawdowns, especially during dry winter periods. At the same time, the simulations indicate that low Clutha would be increased downstream of the Roxburgh dam.

The simulated operational range of the Onslow reservoir within the range of 720 to 780 masl provided an efficient standby reserve for the crises otherwise experienced in the dry years of 2001, 2003, 2006, and 2008.

To sum up, a seasonal-scale Onslow PHES has the potential to offer a potentially viable alternative to achieve the multiple aims of buffering against climatic variations; operating as a standby reserve; providing a small net power gain; maintaining the hydro lakes at mid-range; and reducing flood risk to lake townships and the Clutha, Waitaki, and Waikato rivers.

### 9.1.2 Support for intermittent energy supplies

The New Zealand government goal of moving toward increased renewables (mostly wind) means that the grid system is becoming increasingly vulnerable to intermittent effects as wind speeds rise and fall. Presently the national grid is at the limit of its operational stability with respect to further major wind power developments.

The simulations indicate that the Onslow scheme at 1,300 MW could absorb all the extra wind energy in the grid at a generation capacity of 622 MW in 2012 while there is a loss of 0.01% with a 2600 MW development in wind energy every year. With respect to buffering intermittent effects, every MW of pumped storage enables the construction of 2 MW of additional wind power. It seems inevitable therefore that New Zealand will require a considerable degree of pumped storage capacity if it is to meet its renewable energy goals.

### 9.1.3 Waitaki Valley improvement from pumped storage: increased irrigation water

A particular economic advantage of the Onslow scheme and the new seasonal water management regime is that the Waitaki River would be shifted back toward its pre-hydro seasonal pattern of high flows in summer and low flows in winter. This would result in a secure supply of irrigation water from the Waitaki River for the existing 80,000 irrigated hectares in the lower Waitaki River catchment, which presently yield some $NZ 550M per annum in gross income to the local and national economy. Also, and importantly, there would be approximately 80 $m^3s^{-1}$ of new Waitaki water available for the October-March period and 50 $m^3s^{-1}$ for the April-September period, which could enable a doubling of the current Waitaki irrigated area for commercial and recreational use.

### 9.1.4 Environmental advantages and environmental impacts

Shifting the main seasonal energy storage away from the soft glacial till scenic hydro lakes Tekapo, Pukaki and Hawea, which are susceptible to erosion with imposed seasonal storage cycles involving several metres of water level change, to the Onslow rock basin would be a highly desirable environmental development. Even Lake Taupo has some level of hydro impact with high or low lake levels, which cause recreational inconvenience at times, as well as a degree of shoreline erosion of unconsolidated deposits of pumice alluvium.

The reduction in lake level fluctuations and operating near mid-range, in the simulation model, would greatly enhance the aesthetic appearance of these hydro lakes by reducing visual impacts around the shoreline and improving the recreational benefits. Plant species would be able to grow further down in their local area, more beautiful natural stable beaches would be created, and the risk of dust generated by low lake levels would be eliminated.

Another environmental benefit of the Onslow scheme, as discussed previously, is that the lowering of their maximum flows considerably reduces the risk of flooding along the Waitaki, and Clutha.

A further benefit is that Lakes Wakatipu and Wanaka have potential to be controlled and operated in tandem with the Onslow PHES. This could be particularly significant for the Clutha scheme if management of the Lake Wakatipu and Wanaka water levels is permitted, in the sense of reducing natural lake level variations. As shown in the simulation model results (7.2.6 and 7.2.7), if engineering considerations permit, this would reduce the risk of flooding at Queenstown and Wanaka townships.

The main visual impact of the scheme would arise from the large potential water level fluctuations (60 metres), with the new lake developing in area from 18 km$^2$ to 74 km$^2$ between minimum and maximum lake surface elevation, although this was not a seasonal fluctuation range.

### 9.1.5 Economics

The total economic benefits of the Onslow PHES are the sum of the seasonal energy storage benefit, the dynamics of supply benefits, and multiple use benefits.

The seasonal energy storage benefit would result from a reduction in electricity supply and demand challenges at a national level. The present electricity market causes price panics when the hydro storage lakes are perceived to be trending down, most of time resulting in needless carbon dioxide emissions from the thermal power stations because of the higher electricity prices. The simulation results show the proposed scheme would be able to compensate for the lack of generation from hydro power plants for three consecutive dry years (in the case of full storage at the upper reservoir).

The dynamic benefits of the proposed Onslow PHES include smoothing of supply, smoothing of spot prices, improved spinning reserve and security of supply, resulting in less stress on and more efficient operation of geothermal and thermal power plants. The simulation results show that as a result of the purchase and sales differential using pumping and generating, a company would able to cover the cost the project's construction within 14 years in the event of the storage size in the upper reservoir not affecting the market's spot electricity price. An alternative scenario shows that pumped storage can reduce high prices in winter when the demand is high and increase them in summer when the demand is low, making prices more stable.

Multiple use potential benefits of the Onslow scheme include efficient resource use by managing energy/water, thus increasing the potential Waitaki agricultural income; enabling wind power development; putting a price on present scenic lake shoreline destruction; and reducing lake township flooding and river flood peaks.

## 9.2 Recommendations for future work

Suggestions to expand the research perspectives of this thesis include:

- An economic investigation in detail, taking into account all aspects including the electricity market.
- An environmental and social impact investigation into the impact on wetland ecology, aquatic ecosystems and water quality for both the Onslow and Wanaka-Hawea PHES schemes.
- Encouraging policy makers and electricity authorities to include beneficiaries from the proposal Onslow PHES, such as Waitaki Irrigators Collective Ltd, Irrigation New Zealand, and the New Zealand wind Energy Association, to

invest in the exploration of large-scale Onslow PHES capability and collaborate with possible investors.

- Extend the operation of the simulation model to include the dry year of 2017 and to include the Waikaremoana hydro power scheme.
- A primary geotechnical site investigation and assessment of the potential and magnitude of earthquake loading on the upper reservoir structures is required.
- An investigation into further developments within the Clutha and Waitaki hydropower schemes, to incorporate into the Onslow PHES a number of other possible hydro power plants such as Luggate 90 MW, Queensberry 180 MW, Beaumont 190 MW, Tuapeka 340 MW and the North Bank Tunnel Project 260 MW.
- Investigations of smaller schemes such as a possible Neck scheme between Lakes Hawea and Wanaka and a possible Fraser PHES near Dunstan, 8km tunnel, with 358 m operational head (542 to 184 msal).

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# Appendices

# Appendix One: Operational possibility of Lakes Wakatipu and Wanaka with reduced water level variability.

## 1.1 Introduction

This chapter focuses on an investigation into further potential developments within the Clutha hydropower scheme. Focus is on the natural Lakes Wanaka and Wakatipu. It would not be acceptable economically or environmentally to seek to “control” these lakes in the traditional storage mode of raising lake levels coupled with increased water level fluctuations through the year.

However, with suitable engineering at their outlets the lakes might be managed in conjunction with Onslow pumped storage so as to optimize water levels toward the mid-range point of present natural water level fluctuations. This would reduce the lake flood risk at Wanaka and Queenstown and also reduce spill losses at the Clyde and Roxburgh stations.

The simulation model of the Onslow pumped hydro energy storage scheme was operated in conjunction with a model of the Clutha hydropower stations in which Lake Wakatipu is controlled by an existing concrete sill gated weir across the outlet and a tunnel between Lake Wakatipu and Kawarau River and Lake Wanaka is controlled by the Neck PHES.

This chapter provides an overview of the layout and operation of the proposed tunnel, and discusses how the proposed tunnel and Neck schemes were modelled when operated within the Onslow pumped storage model.

## 1.2 Characteristics of the Study Area

This section provides a brief description of the physical environment of the proposed tunnel between Lake Wakatipu and the Kawarau River (Figure 1.1). The distance between the entrance and exit of the proposed tunnel is 10.6 km, with about 28 metres (310 to 282 masl) water level difference, making a hydro power generation plant potentially operative here. More information about the characteristics of the study area is provided in section (7.2.6).

*Figure 1.1 Proposed Wakatipu-Kawarau tunnel location showing topographic elevation profile.*

The underlying bedrock in the area of the proposed Wakatipu-Kawarau tunnel is metamorphic, mapped as Otago Schist. It can described as schistose volcaniclastic sandstone, siltstone, mudstone and conglomerate with included volcanics and limestone; with minor quartzite, metachert and serpentinite on the Lake Wakatipu side. On the Kawarau River side it can be described as Pelitic and subordinate psammitic schist, including areas and bands of greenschist or amphibolite, and minor marble, metachert and serpentinised ultramafics. Late Quaternary alluvium and colluvium surrounds the Kawarau River. Inactive accurate thrust faults cross the proposed tunnel [91].

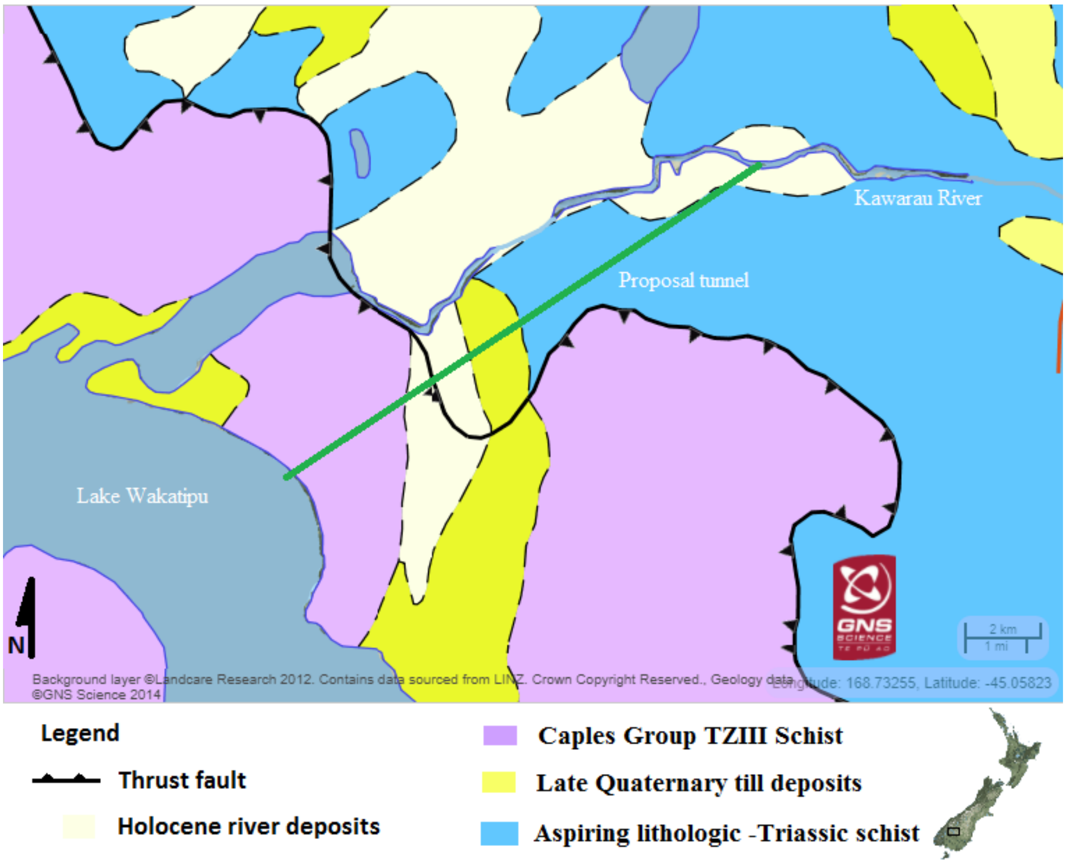

*Figure 1.2 Geology surrounding the proposed Wakatipu-Kawarau tunnel (based on Geology data GNS Science 2014) [91].*

## 1.3 Description of Model and Layout Structure

Another simulation of a large seasonal pumped storage operation was built in Matlab to operate with the Clutha hydro power scheme with the additional goals of maintaining Lake Hawea at or near its mid-range of 342 masl to allow for Lakes Wakatipu and Wanaka to be controlled over the period 1994-2012. A tunnel between Lake Wakatipu and the Kawarau River, with a length of 10.6 km, would allow a potential hydro power plant and reduce the potential for flooding near the shoreline of Lake Wakatipu, in towns such as Queenstown. The potential pumped hydro storage between Lakes Wanaka and Hawea can control Lake Wanaka in the model.

If power from the whole scheme is generated beyond demand, the excess goes to the Onslow PHES. If the power generated is less than demand then excess power is generated via release from the Onslow PHES. Pumped storage operation is constrained by the following factors:

a) For the pumping phase, sufficient discharge must be present in the Clutha to supply water.

b) For the release phase, Clutha discharge must be low enough to accommodate the released water.

c) There must be sufficient storage capacity in the pumped storage lake to allow a given amount of pumping.

d) For a given power demand, there must be sufficient stored water to allow release.

If any of the above conditions are violated then the programme continues and meets the power demand/pumped storage requirements only to the extent possible.

All water transfers and energy values are on a 1-day time-step, with volume in cubic metres, discharge in cubic metres per day (mean daily discharge), and energy in MW-day. Lakes Dunstan and Roxburgh are defined in the model to have zero storage.

Webby evaluated a discharge rating for the modified lake Wakatipu outlet that takes account of the reverse flow phenomenon and the gradual drowning of the outlet weir, leading to the occurrence of reverse flow. These formulae were used in the model [136].

The first priority in the model was to release water from Lake Wakatipu if it rises above the target level of 310 masl.

The next priority was to operate the Wanaka-Hawea pumped storage in order to reduce the Wanaka shoreline flooding risk and reduce the present extent of natural fluctuations; reduce the operating range of Lake Hawea; and generate energy from the inflow of Lake Hawea by releasing to Lake Wanaka while maintaining a minimum discharge of 10 $m^3s^{-1}$ in the Hawea River.

The last step was to operate the Onslow PHES to pump water into the upper reservoir in the event of extra power in the grid, or release water into the lower reservoir to meet the demand in the grid. All the operation rules were subject to not contributing to any spill at Clyde and Roxburgh hydro power stations.

The target level for Lake Wakatipu was 309.4 masl and for Lake Wanaka 277.8 masl. Lake Wakatipu’s minimum storage level is 308.83m based on the level of the concrete sill, so that Queenstown Bay remains navigable for the tourist steamer *Earnslaw*. The proposed Wakatipu tunnel maximum discharge capacity model applied different ranges to investigate the optimum capacity at which no flooding occurred at Queenstown. Figure 1.3 provides the flow diagram for the Clutha component of the model, showing the operational sequence.

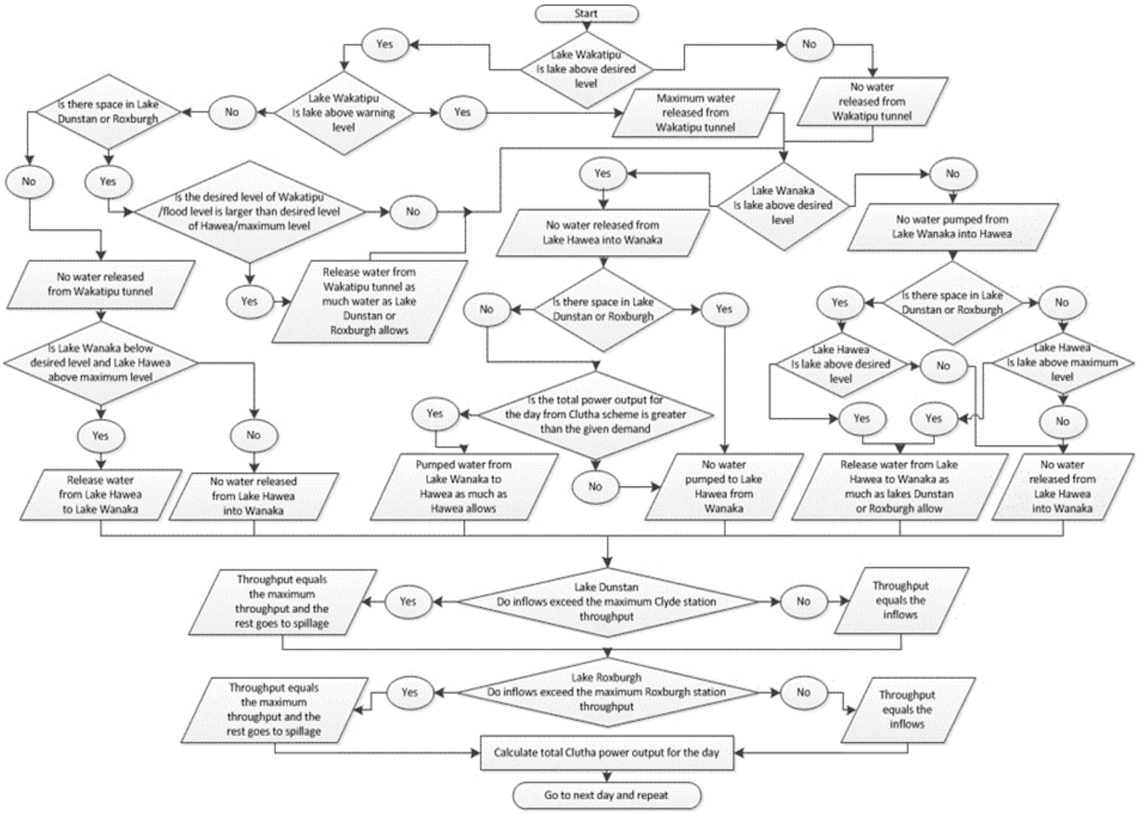

*Figure 1.3 Flow diagram of the Clutha component of the model, showing the operational sequence.*

## 1.4 Model verification and calibration

A comparison of total inflows to the Clutha hydropower scheme for recorded and simulated discharges is shown in Table 1-1. A simple water balance method was used to ensure that the total volume of water passing through the hydropower plants in the simulation was similar to the actual volume.

*Table 1-1 Water balance for the Clutha hydropower scheme 1994-2012.*

| Inflow volumes to scheme ($m^3$) | Recorded inflows | Simulated inflows |
|---|---|---|
| Lake Hawea outflow | $3.58 \times 10^{10}$ | $3.56 \times 10^{10}$ |
| Kawerau flow below confluence | $1.22 \times 10^{11}$ | $1.22 \times 10^{11}$ |
| Lake Wanaka outflow | $1.16 \times 10^{11}$ | $1.16 \times 10^{11}$ |
| Estimated Lake Dunstan tributaries | $2.34 \times 10^{10}$ | $2.34 \times 10^{10}$ |
| Estimated Lake Roxburgh tributaries | $7.39 \times 10^{9}$ | $7.39 \times 10^{9}$ |
| Total inflow volume | $3.0466 \times 10^{11}$ | $3.0461 \times 10^{11}$ |

The total inflow volume to the Clutha hydropower scheme at Teviot in the simulation was very similar to the actual record, confirming that the model was working correctly to the extent of maintaining the total volume of water passing through the scheme.

In order to calibrate the Clutha component of the model, the annual energy output from the model was required to match the actual annual energy output over the period 1994-2011, using inflows as recorded.

To begin with, the recorded power conversion factors for the Clyde and Roxburgh hydropower plants were calculated (Figure 1.4 and Figure 1.5). Then the conversion factor for each station was used in the model in the case of low-spill years. Once the fitted curve of simulated power output from each station in the model and the actual power generated resembled the 1:1 line (Figure 1.6), the conversion factor for each station was fixed within the model.

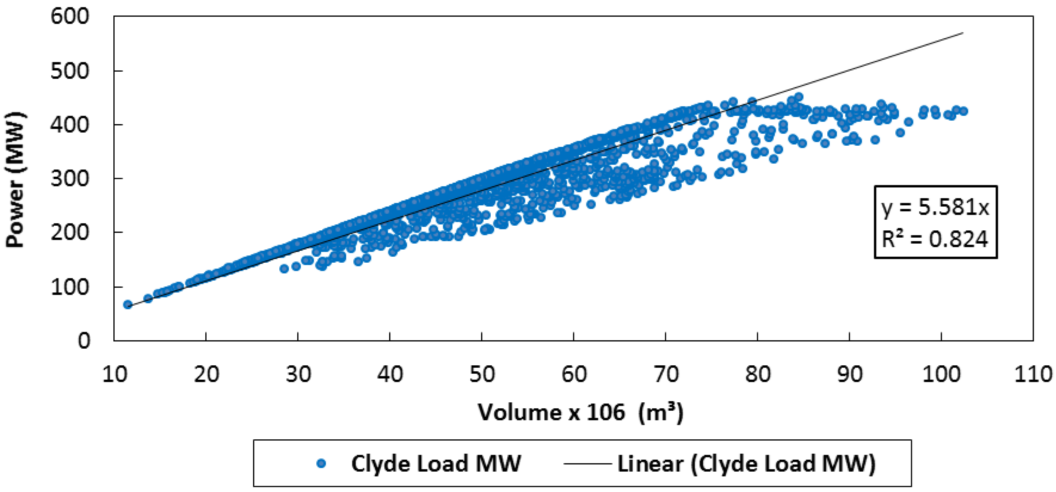

*Figure 1.4 Conversion factor for generation at the Clyde station.*

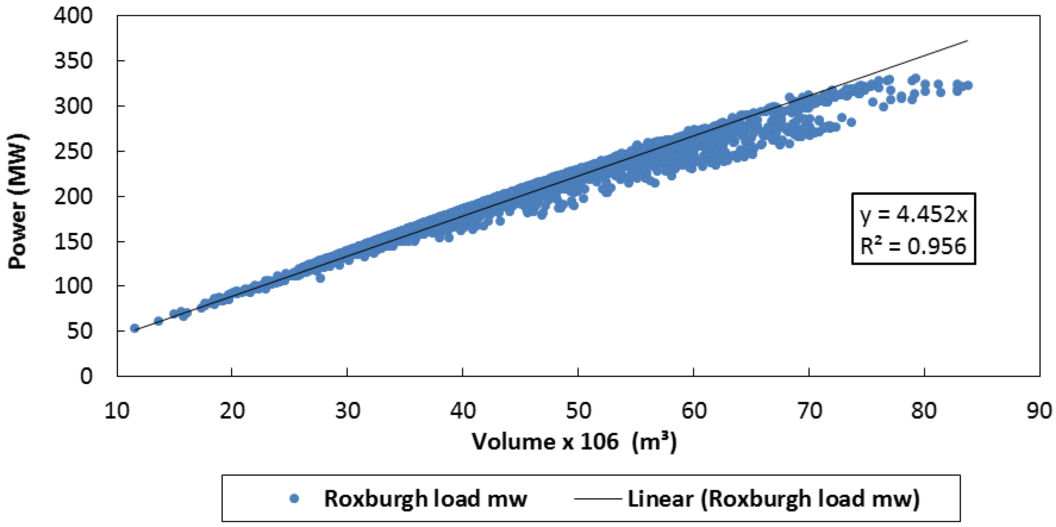

*Figure 1.5 Conversion factor for generation at the Roxburgh station.*

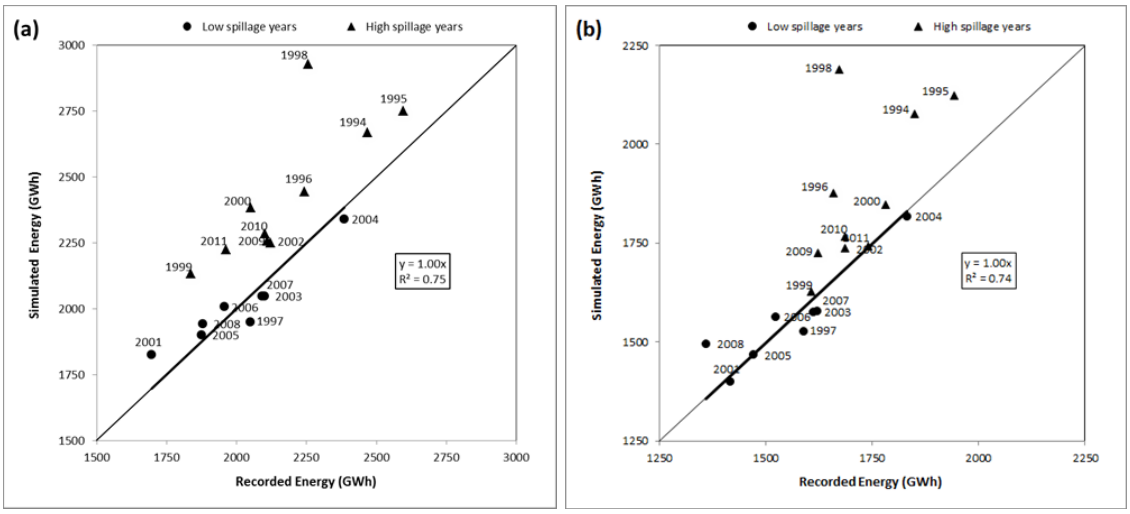

*Figure 1.6 Actual annual energy generated against annual simulated generation for 1994-2012 for a) the Clyde station and b) the Roxburgh station.*

For checking purposes, the model power output from each station resembled the actual power generated over a certain time frame and with the same throughput discharge.

The energy generation from the Clyde and Roxburgh stations (Figure 1.7) displays a good fit to the 1:1 line during low spillage years, and a reasonable fit to the 1:1 line during high spillage years, confirming the model to be an acceptable representation of reality at the level required as a component in the pumped storage model.

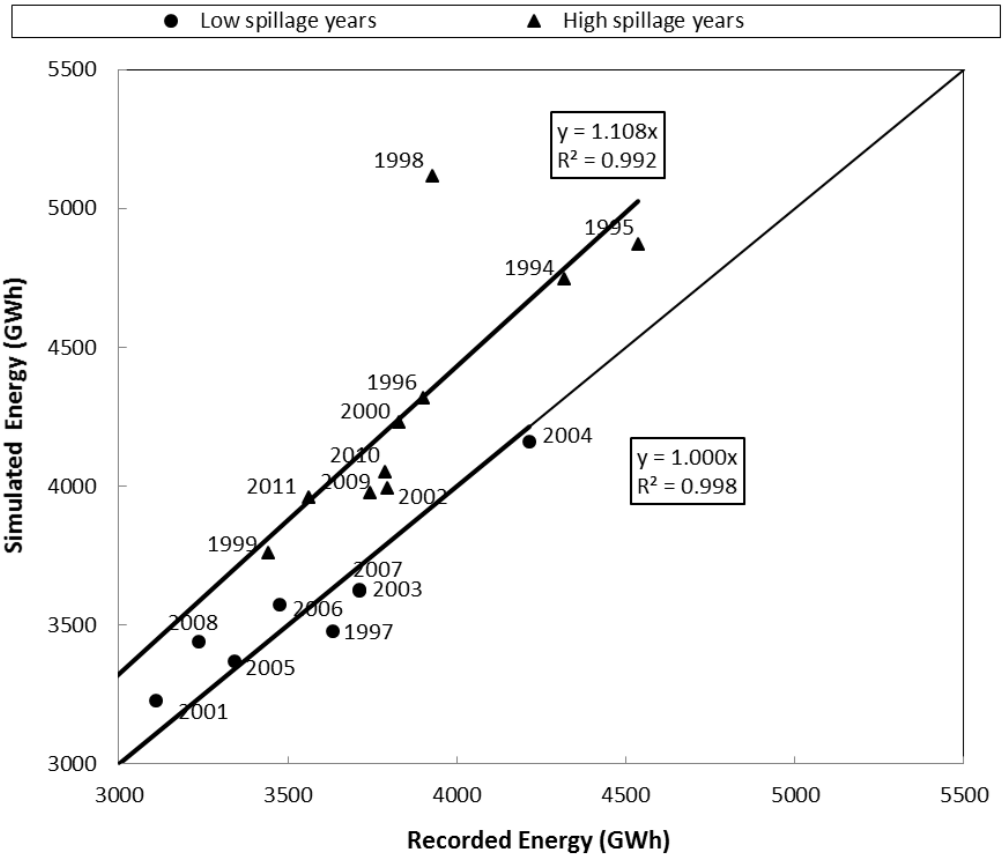

*Figure 1.7 Output generation from the Clutha scheme: actual annual energy against annual model energy, during low and high spillage years.*

## 1.5 Simulation results

The simulation results show that the proposed Wakatipu tunnel maximum release capacity of 120 m$^3$s$^{-1}$ with a diameter of 5.5 m avoided lake flooding at Queenstown over the simulation period. The release capacity of 120 m$^3$s$^{-1}$ can generate an electrical capacity of 28.5 MW with a hydro head of 28 m. The Onslow pumped storage simulation, by potentially controlling Lake Wanaka and Lake Wakatipu, saves approximately 5100 GWh by reducing spill, as illustrated in Figure 1.8. This is equivalent to a mean power output of 32.4 MW. The rest of the simulation results are explained in section 7.2.6.

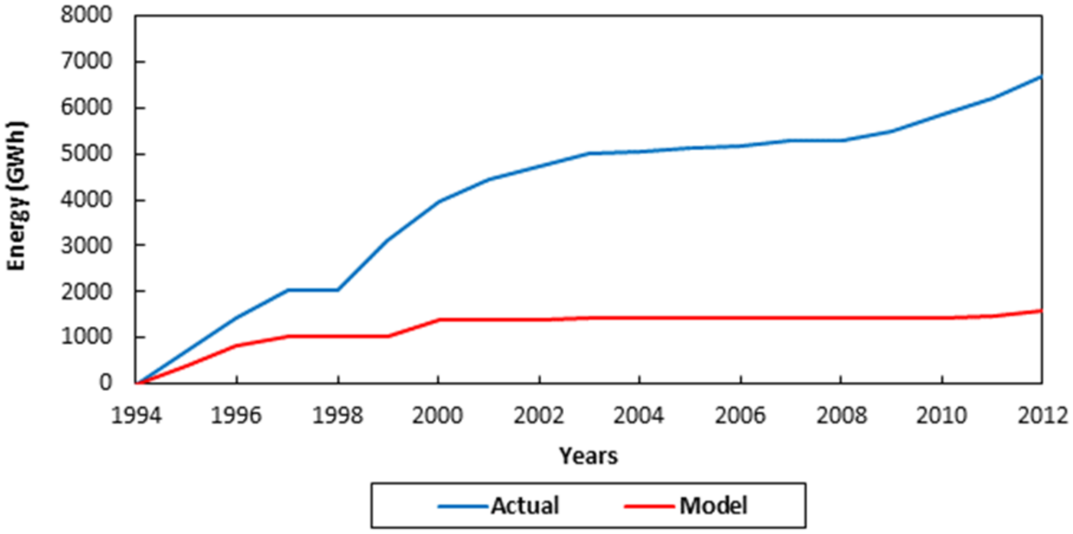

*Figure 1.8 Actual and simulated cumulative energy loss from spill at the Clutha hydropower scheme, 32.4 MW, where Lake Wanaka and Lake Wakatipu are controlled.*

# Appendix Two: Possibility of pumped storage between Lakes Hawea and Wanaka.

## 2.1 Introduction

The theme of this thesis is with respect to a large multi-purpose pumped storage plant based around an expanded Lake Onslow. However, the narrow "Neck" between Lakes Hawea and Wanaka in Central Otago has long been considered as a potential pumped storage location and could also operate in a multi-use way, so is included in this Appendix for the sake of completeness. Smaller pumped storage schemes of this type may become more common as a variety of new designs become available, in addition to changing economic factors, the availability of low-cost off-peak energy, more intermittent energy integration into the national electricity grid and the increasing importance of a number of environmental factors.

The Neck was considered as a hydro-electric resource in the 1904 "Hay Report". However, it was regarded as too remote and there were environmental concerns to be considered seriously at the time [150].

The horizontal distance between the two lakes at the Neck is just 2 km. Coupled with about 64.5 metres difference in lake water levels, this gives pumped storage potential in conjunction with some net power generation. Lake Hawea would serve as the upper reservoir and is presently controlled as Contact Energy's main hydro storage. On the other hand, Lake Wanaka experiences natural water level variation and is under protection by Act of Parliament against any deliberate modification of lake levels. The current conservation order would therefore need to be modified to Wanaka to allow pumped storage utilising the two lakes.

A possible coupled hydro and pumped storage scheme between Lake Wanaka and Lake Hawea is discussed in this chapter. This hypothetical scheme would increase the benefit of the Lake Hawea storage. The main advantages of the scheme are that it would create a new power scheme to reduce power spill losses at the Roxburgh and Clyde stations and provide a spinning reserve service. It would also make the irrigation costs within the Hawea irrigation scheme negligible, reduce lake level fluctuations in both Lakes Wanaka and Hawea, as well as reducing both flooding and low lake levels in Lake Wanaka.

## 2.2 Characteristics of Study Area

This section provides a brief description of the physical environment of the Neck scheme and the basins of Lakes Hawea and Wanaka (Figure 2.1 and Figure 2.2).

*Figure 2.1 Topographical map showing the Neck land between Lake Hawea and Lake Wanaka [151].*

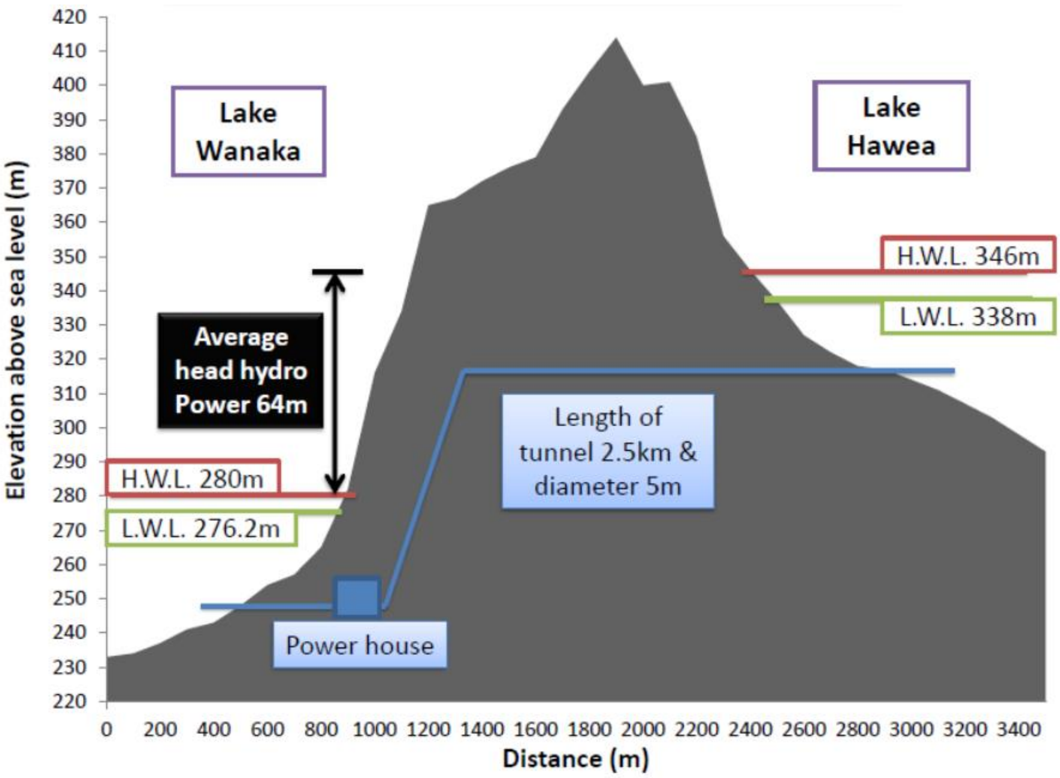

*Figure 2.2 Cross-section of the proposed Neck PHES, showing the maximum and minimum operating levels of Lake Hawea and the range of natural lake levels in Lake Wanaka.*

### 2.2.1 Location

The Neck, a rocky ridge, is the closest point between Lakes Hawea (upper reservoir) and Wanaka (lower reservoir) and could be the location for the possible pumped hydro energy scheme. It is located between 169 00E – 169 20E and 44 20S – 44 40S as shown in Figure 2.3.

### 2.2.2 Description of area

Lake Hawea has an area of 141 km$^2$. It is 35 km long, and its surface has a mean altitude of 348 metres. In 1958 the lake was raised artificially by 18 m to store more water and allow increased hydroelectric power generation at Roxburgh power station and later at Clyde power station. It provides water storage for both Roxburgh and Clyde power stations. Both stations are otherwise dependent on the natural flow of the Clutha and Kawarau rivers. Lake Hawea lies in a glacial valley formed during the last ice age, and is fed by the Hunter River. Nearby Lake Wanaka lies in a parallel glacial valley to the west. The population of Hawea township is about 1,500.

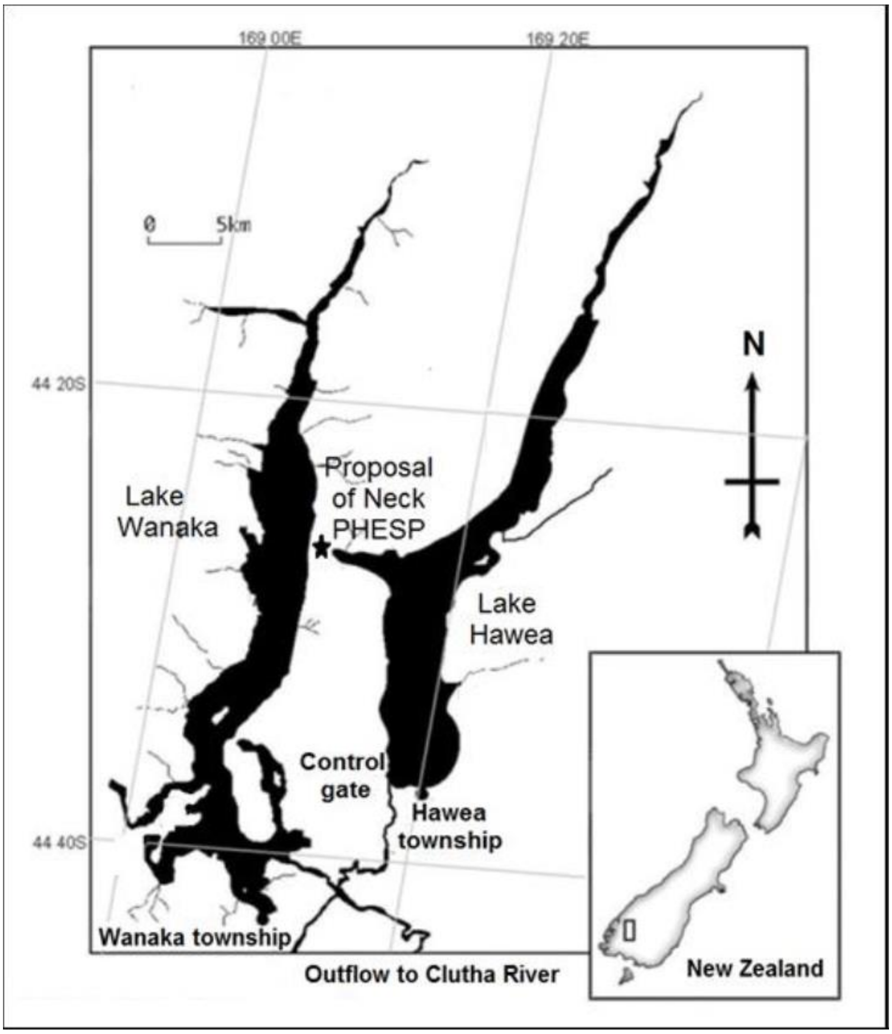

*Figure 2.3 Location of proposed Wanaka - Hawea pumped hydro energy storage.*

Lake Wanaka covers an area of 192 km$^2$ at an altitude of 280 masl. It lies roughly along a north-south axis and is 42 kilometres long. The township of Wanaka is located at the southern end of the lake, not far from the Hawea River outflow of the lake, linking to the Clutha River. Developments in and around Wanaka have doubled over the last 10 years and are continuing to grow. Development has forced parts of the town onto the hills that surround the central business district, which is located on the flat, flood-prone land south of Lake Wanaka. Wanaka township has a permanent population of around 7000.

The land at the Neck is mainly used for sheep and some beef farming, as well as having tourist attraction. The lakes themselves are used for aquatic activities, such as fishing and water skiing.

*Figure 2.4 Lake Wanaka & Lake Hawea*

*Figure 2.5 Map of highway to The Neck.*

### 2.2.3 Geomorphology

The land at the Neck is on the catchment boundary between Hawea and Wanaka. The major factors contributing to the appearance and character of the land are the geology and basement schist rock; the action of ice; and the use of the land. The small knoll constituting the Neck area is described as a distinctive ice-sculptured lumpy landform.

The Hawea-Wanaka basin has rugged steep mountain slopes with fans of prominent land along the edge of both lakes and small areas of alluvial flat near the mouth of the Craig Burn and at Dinner Flat.

The topography of the surrounding site is hilly, with the highest peak at an altitude of 490 masl and very steep on the Lake Wanaka side, with a more gentle slope on the Lake Hawea side. The contours at the Neck are all between 300 and 500 masl.

### 2.2.4 Geology and seismic hazard

The underlying bedrock in the area between Lake Hawea and Wanaka is metamorphic, mapped as the Otago Schist (Figure 2.6), which is part of the major Rakaia Terrane, the Haast Schist. The Otago Schist Belt has been traditionally interpreted as a major feature of the New Zealand Geosyncline, which formed during the Rangitata Orogeny.

The textural schist found at Lake Hawea in the Rakaia Terrane can be described as semi-schist with strong planar foliation, dipping steeply to the right. In contrast, the schist found at the Lake Wanaka site can be described as schist with flattened veins and irregular foliation. The Rakaia Terrane schist found within the area of the possible scheme is described as prominently planar-foliated; psammitic and pelitic schist; rare green schist, metachert; strained meta conglomerate and marble, well foliated, slightly segregated schist. Near the Neck at Wanaka and Hawea there is undifferentiated till and associated outwash gravel greywacke from valley glaciers. The Neck is mainly composed of schistose to non-schistose quartzofeldspathic sandstone (greywacke) (Yt) interbedded with mudstone (argillite) (Tt) as it moves from a well foliated and slightly segregated schist (III) to a foliated semi-schist (IIB) through the Neck (see Figure 2.7 Figure 2.8) [91, 92]. The Fold type across Neck antiform overturned schistosit accurate.

The schist basement rock is still being actively folded, faulted and eroded in response to regional compression and strain distributed across the mid to lower South Island. Much of the fault activity and uplift in the area has occurred over the past 5 million years. There is no major fault in the region of the possible scheme, but the Gardona Active Fault lies across Lake Hawea, approximately 10.8 km away from the Neck PHES. It is capable of generating large earthquakes of magnitude (MW) 6.7–7.0 with a slip rate of 0.38 mm/yr and a 5100 years recurrence interval [152].

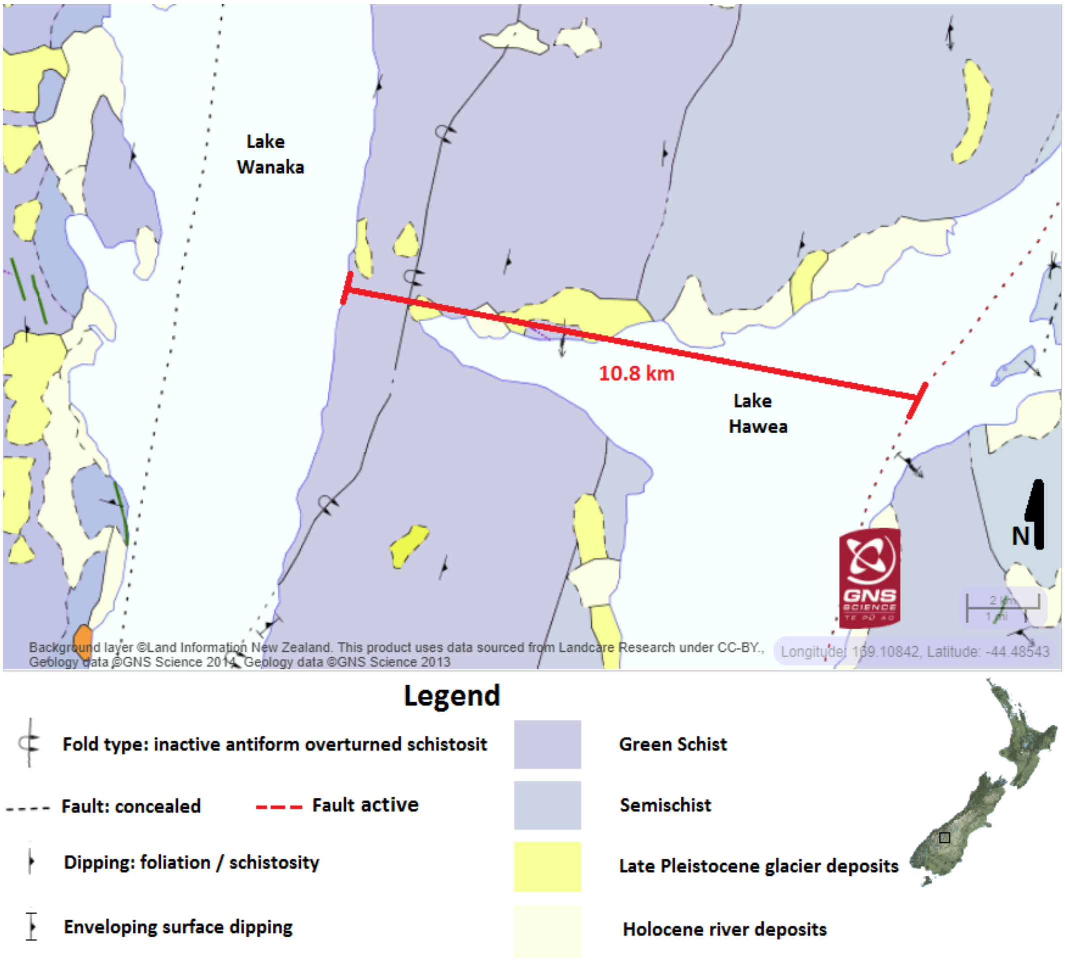

*Figure 2.6 Geology of the Wanaka-Hawea region, showing distance between the active fault and the Neck PHES (based on mapping by GNS, 2014) [91, 92].*

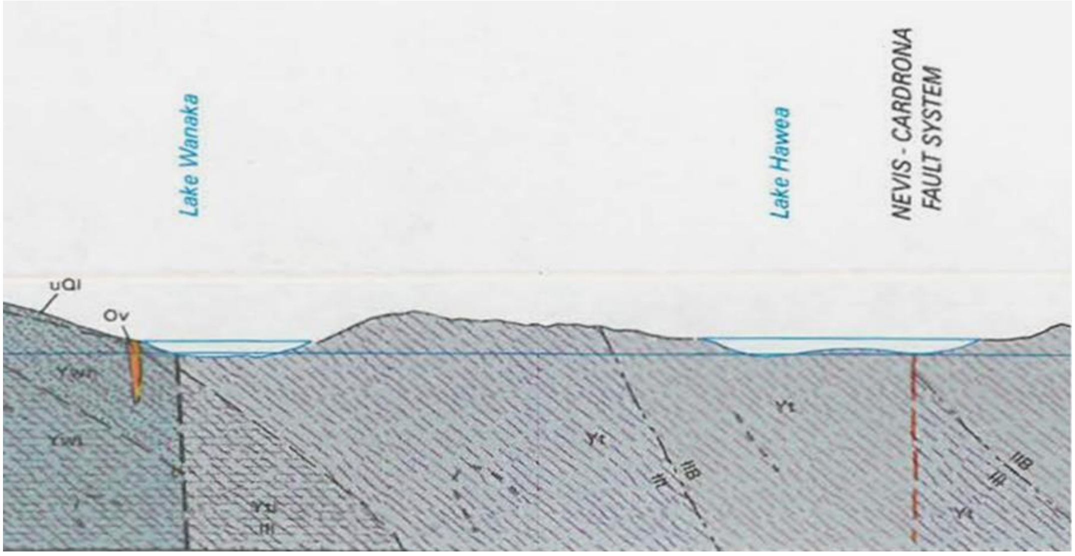

*Figure 2.7 Geology cross section for Lale Wanaka and Lake Hawea [92].*

*Figure 2.8 Q2t represents the deposits of till and outwash [92].*

## 2.3 The current state of Lakes Wanaka and Hawea

Lake Wanaka is a natural lake, with most inflow from the Makarora and Matukituki Rivers. It has no control structure as it is protected under the Lake Wanaka Preservation Act 1973, which prohibits any form of control of the lake. The Clutha River discharges from the lake.

Fluctuations in lake level from 1994 to 2012 are shown in Figure 2.9. The minimum Wanaka lake level is 276.23 masl, the first warning level is 279.4 masl and the flooding level is 280 masl, which begins to flow over Ardmore Street in Wanaka township.

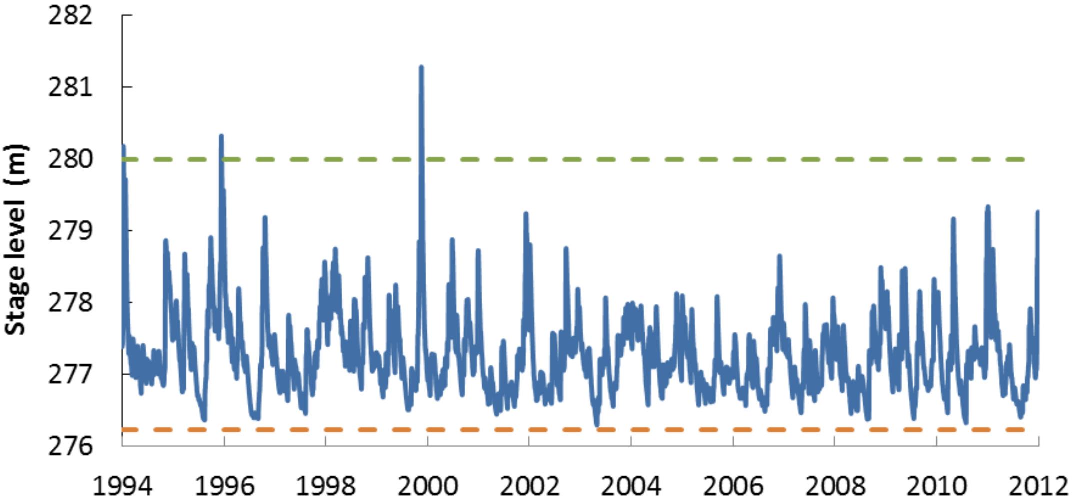

*Figure 2.9 Lake Wanaka recorded natural level.*

Flooding of Lake Wanaka is a natural process, occurring when more water is flowing into the lake than flows out, and when there is insufficient time for levels to drop between heavy rainfall events. The highest lake flood level events and durations on record in Lake Wanaka since 1984 are shown in Figure 2.10. Waves and surges can cause the lake to be even higher. The nature of the damage caused will vary depending on the length of time properties remain underwater, and may include waterlogging, the accumulation of sediment, and damage due to breaking waves and debris [153]. This impacts both the local economy and tourism.

The consented minimum lake level for Hawea is 338 masl. However, this can be lowered to 336 masl when the Electricity Authority determines that reserve generation should be used. The spilling level is 346 masl. Management of Lake Hawea is discussed in section 7.2.1. A case will be made that a PHES plant between Lake Wanaka and Hawea could be a way to more efficiently manage both lakes and reduce the fluctuations and flooding risk in Lake Wanaka.

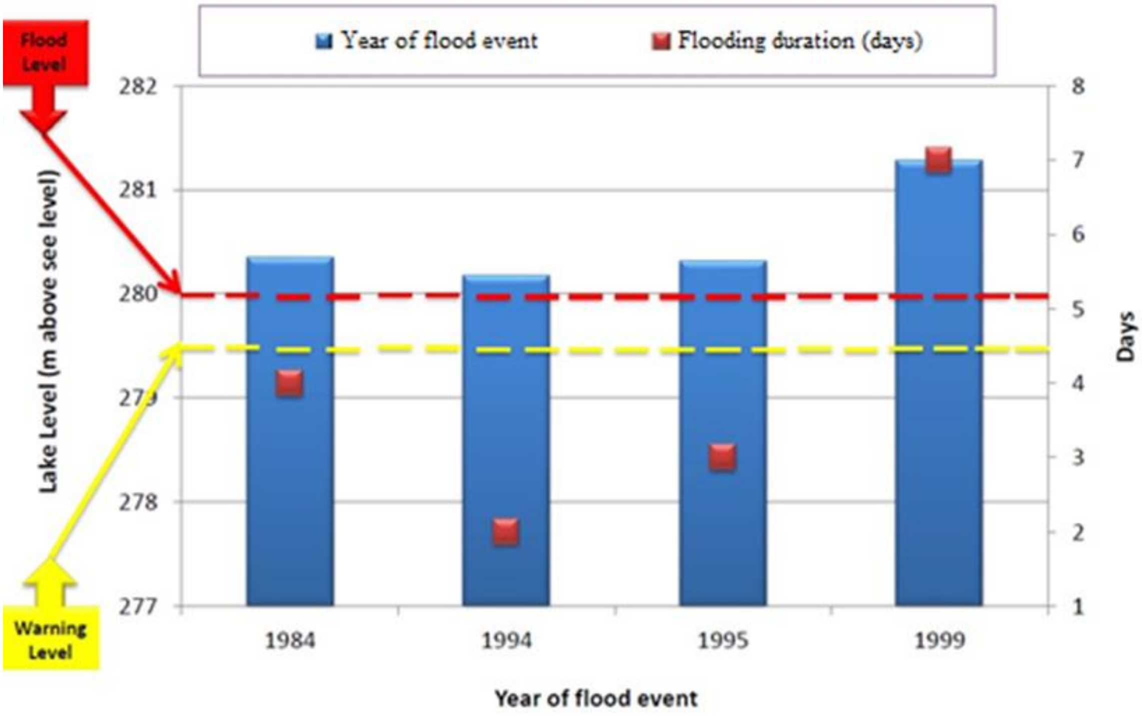

*Figure 2.10 The highest flood events on record in Lake Wanaka since 1984.*

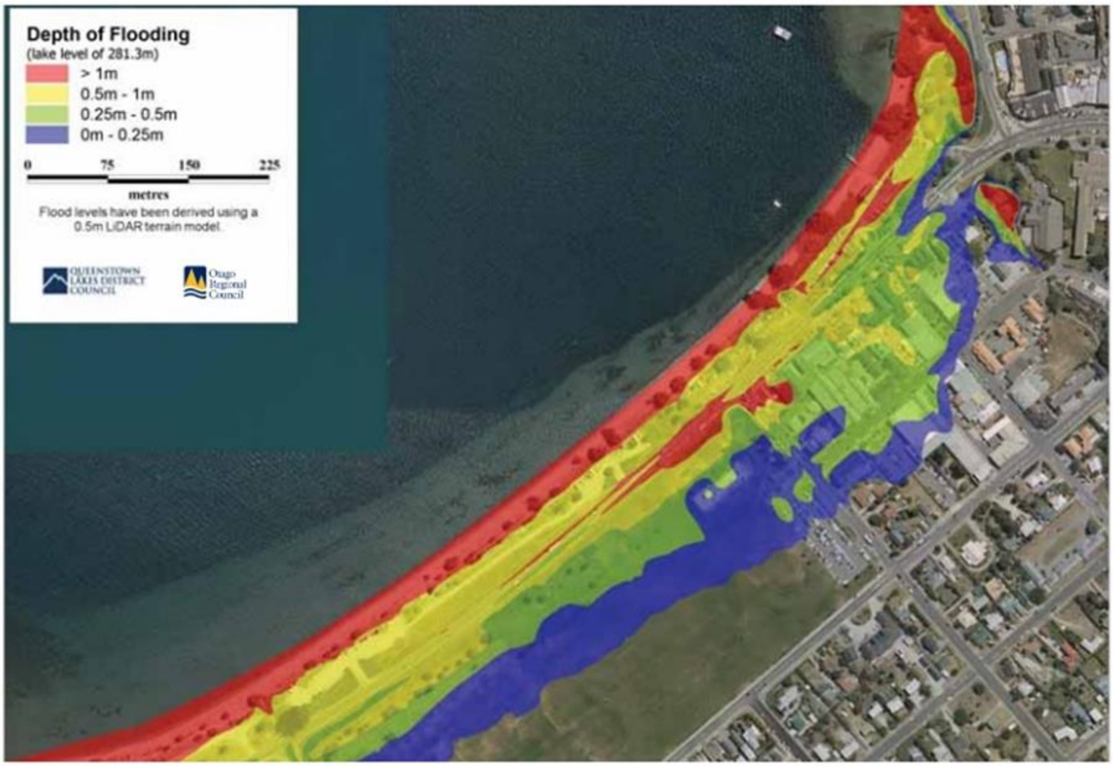

*Figure 2.11 Depth of flooding in the Wanaka CBD at a water level of 281.3 masl [153].*

## 2.4 Configuration of the possible Neck Pumped Storage simulation model

This model study investigated the benefits of building a combined hydro-power station and pumped storage system by transferring water between Lakes Wanaka and Hawea via a short tunnel.

The computer simulation model of the Neck pumped storage scheme was operated using a simplified model of the Clutha hydropower schemes. All water transfers and energy values were on a 30 minute timestep (trading period half-hourly data). The model was applied to the period 1998-2012, which was useful as this period included wet and dry extremes and the 1999 flooding event. The mean daily power output, flow and lake level data were obtained for the Clutha hydropower schemes and inflow to each lake was calculated using a simple water balance.

A constraint of the model's operation (written as Matlab code) was to avoid adding to the natural lake level fluctuation of Lake Wanaka. This means that at times the station would operate in reverse, pumping water up into Lake Hawea. The proposal offers many benefits, which will be discussed later.

The model also seeks to optimise the economic value of the Neck pumped storage scheme. The operating rules of the proposed scheme would be to reduce the Wanaka shoreline flooding risk and reduce the present extent of natural fluctuations. Part of the operation would involve the net release of water to Lake Wanaka from Hawea, with the model indicating a power gain of about 30 MW.

Importantly, the model indicates that the time spent above the 280m high lake level would be reduced from 16% to zero in the simulations, indicating a significant reduction in high water risk to Wanaka township. A case could therefore be argued for a change in the Lake Wanaka Preservation Act in terms of both the local and national good.

The operating rules in the model of the proposed scheme were to reduce power spill losses at Clyde and Roxburgh hydro power stations by controlling flow from Lake Wanaka; reduce the Wanaka shoreline flooding risk and reduce the present extent of natural fluctuations; reduce the operating range of Lake Hawea, and generate energy from the inflow of Lake Hawea by releasing to Lake Wanaka while maintaining a minimum discharge of 10 m$^3$s$^{-1}$ in the Hawea River. The operating rules of the proposed scheme were to gain economic value by diverting water to Lake Wanaka, buying electricity at a low price and selling at a high price, reducing power station spill losses, evaluating the Neck scheme as a source of spinning reserve, and reducing the cost of pumping water from Lake Hawea to the Hawea irrigation scheme. A simplified flow diagram of the components of the model in the Clutha scheme is shown in Figure 2.12.

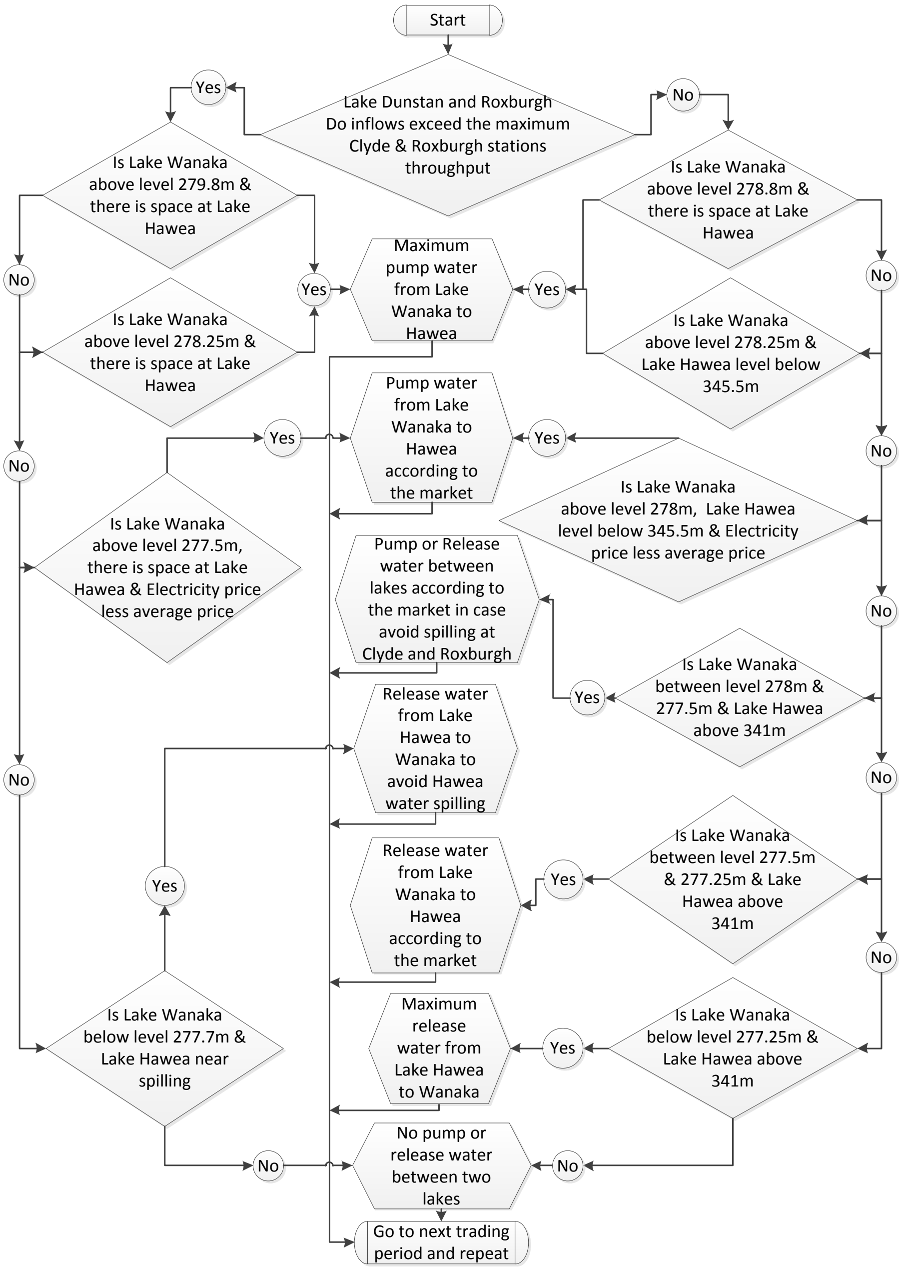

*Figure 2.12 Simplified flow diagram of the proposed Neck PHES scheme to integrate with Clutha scheme in the model.*

The Neck pumped storage operation model is constrained by the following defined parameters:

a) For the pumping phase (from Lake Wanaka to Hawea), the minimum inflow in the Clutha River must be higher than 300 $m^3s^{-1}$ and for the release phase, the maximum total permitted discharge to the Clutha River is 900 $m^3s^{-1}$.

b) There must be sufficient storage capacity in Lake Hawea to allow a given amount of pumping. The maximum simulated level of Lake Hawea for the pumping phase is 345 masl, except for emergency situations.

c) The minimum flow in the Hawea River is maintained at 10 $m^3s^{-1}$ in the model to meet environmental requirements.

d) For the purposes of the Hawea Irrigation Scheme, the minimum level of Lake Hawea in summer is 342.5 masl.

e) The operating rules for controlling Lake Wanaka were divided into 5 bands as follows:

    1) If Wanaka is above 278.25 masl the Neck must pump as efficiently as possible.

    2) Between 278.00 and 278.25 masl, the Neck may pump as required by market conditions, but may not generate.

    3) Between 277.50 and 278.00 masl, the neck may pump or generate as required by market conditions.

    4) Between 277.25 and 277.50 masl, the neck may generate as required by market conditions, but may not pump.

5) Below 277.25 masl, the Neck must generate as efficiently as possible.

f) All the pumping from Wanaka to Hawea is subject to not contributing to any spill from Lake Hawea.

g) All the release from Wanaka and Hawea to the hydro system is subject to not contributing to any spillage at the Clyde and Roxburgh stations.

## 2.5 Optimum rate of pumping and generating for Neck scheme

The optimum pumping/release rates of water between lakes Wanaka and Hawea were examined in this study based on the concept of the minimum risk of flooding in Wanaka town, while ensuring the maintenance of a mid-range level in Lake Hawea and achieving the lowest energy losses at the Clyde and Roxburgh stations. The simulation model was run in different scenarios with target levels in Lake Hawea of between 340 and 342 masl and pumping rates between 70 and 250 $m^3s^{-1}$. The output results are presented in Figure 2.13, showing an optimum pumping rate of about 170 $m^3s^{-1}$.

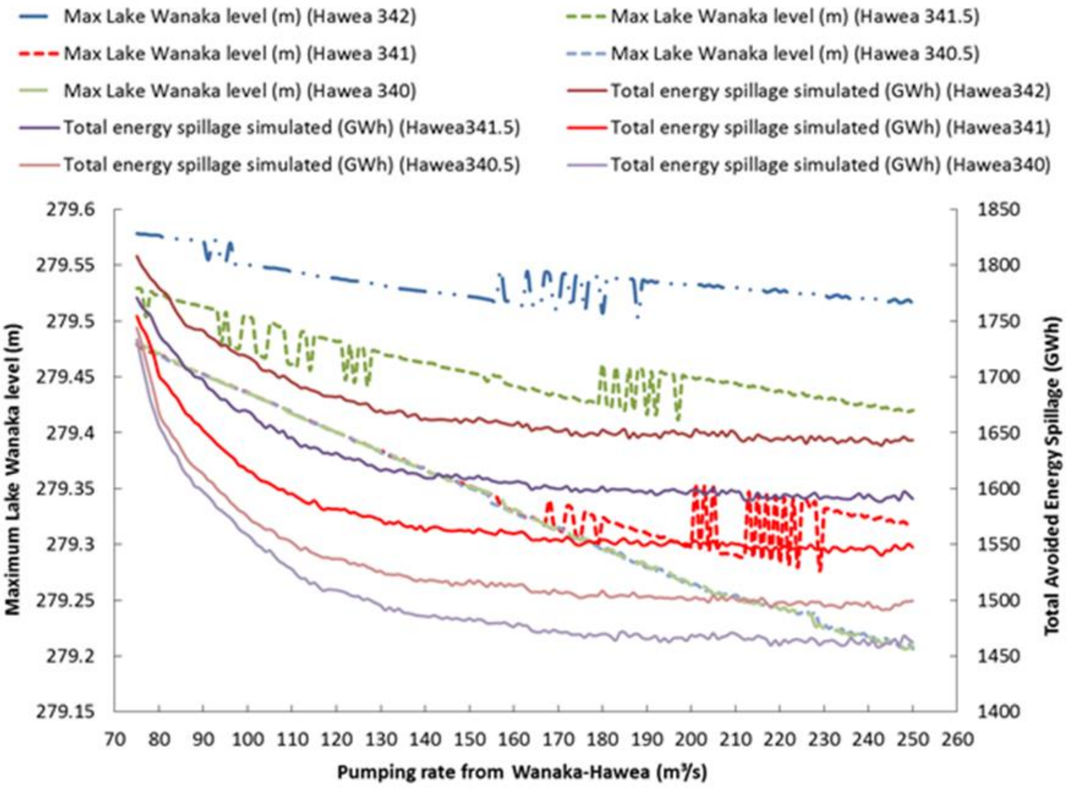

*Figure 2.13 Optimum pumping rate from Lake Wanaka to Lake Hawea.*

The installed capacity of the Neck scheme can be calculated from the formula [22] below, giving 120MW. This could operate as 3 pumps/turbines of 40MW at a pumping and generating efficiency of 84.64%, derived from 90% pumping efficiency and 90% generating efficiency.

$$P_P = \frac{0.00981\ Q_P\ H}{E_p}$$

where:

$P_p$ = capacity when pumping (MW),

$Q_p$ = discharge pumping (m$^3$s$^{-1}$), set at 176 m$^3$s$^{-1}$,

$H$ = gross average head (m), set at 64.5 m,

$E_P$ = efficiency when pumping, set at 90%,

The water released to generate 120 MW can be calculated from the formula below, giving 210.75 m$^3$s$^{-1}$.

$$Q_g = \frac{0.00981\ P_g}{H\ E_g}$$

$P_g$ = capacity when generating (MW), set at 120MW,

$Q_g$ = discharge generating (m$^3$s$^{-1}$),

$H$ = gross average head (m), set at 64.5m,

$E_g$ = efficiency when generating, set at 90%

The capacity of the Neck scheme could be designed to be larger than 120 MW by integrating it with a renewable energy source such as wind energy, as every 1 MW of pumped storage can support another 2 MW of wind generation.

## 2.6 Selection of pipe diameter size

The Neck project includes waterway structural elements such as intakes, tunnels, shafts, penstocks, and surge tanks. The tunnel length in the Neck scheme is around 2.5 km. The tunnel diameter has the main influence on the project budget as the size of the inlet, outlet, and surge tank depend on the diameter of the tunnel. The optimum installed capacity of the Neck scheme would be 120 MW, derived from an average head of 64.5 m with a maximum generating discharge of 210.75

$m^3s^{-1}$ and a maximum pumping discharge of 176 $m^3s^{-1}$ as shown in Figure 2.14. The civil engineering aspects of the Neck scheme include the structures of the tunnel, intake/outlet, surge tank, power house, roading, and site establishment.

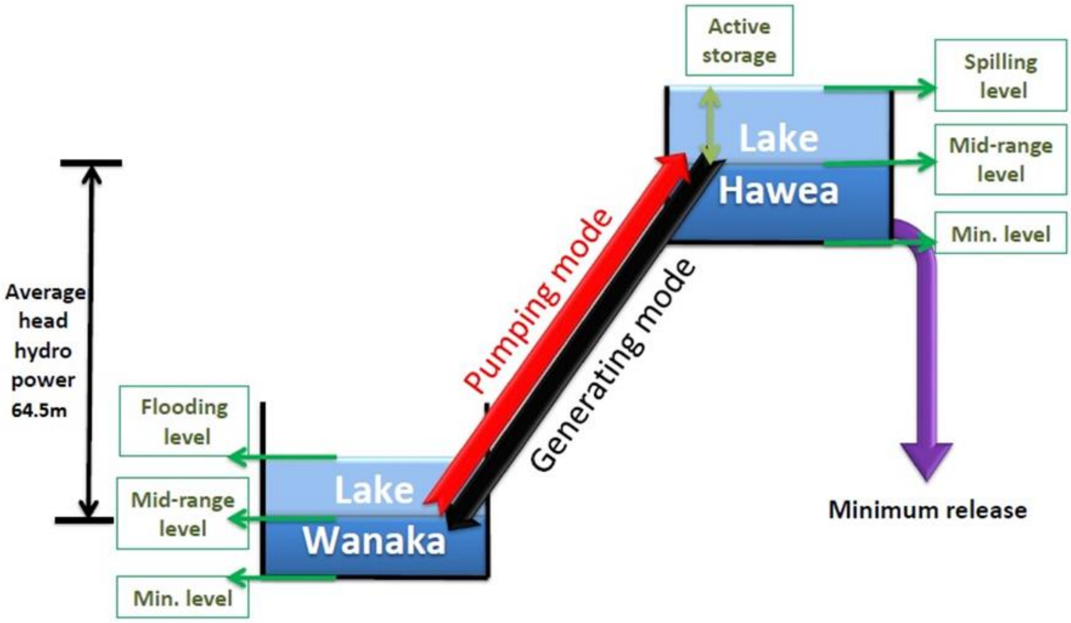

*Figure 2.14 Schematic diagram of Neck scheme.*

This section is focused on the scheme’s operating cycle efficiency. The process of pumping water to an elevation and releasing it incurs losses as a result of rolling resistance and turbulence in the headworks, penstock and tail race, with penstock friction being the major loss component.

A methodology for finding the optimum diameter of tunnels for hydro generating stations on the basis of economic analysis was presented by Sharma in 2000 [95] and developed, then applied to the possible Neck pumped storage scheme. The benefits of pumped hydro storage can be maximized by minimizing the civil project costs, including the water conductor system, electro-mechanical equipment and power evacuation system, which are directly related to the selection of the optimum capacity of equipment. The selection of an optimum tunnel diameter is based on friction losses along the tunnel in the system between the upper and lower reservoirs at a total power head of 64.5m, the cost of construction of the tunnel, seepage losses, the cost of operation and maintenance of the scheme, and depreciation and interest.

It is essential to find the most economic diameter of the tunnel; by changing the dimensions or slope of the tunnel, the cost and benefits for the whole project will alter significantly. The mathematical model determines Z, which is the minimum cost:

$$Min\,Z = \sum_{j=1}^{n} C_j(D)$$

Where:

D = Diameter of the tunnel, which is a function of (Q. S. A)

Q = Discharge ($m^3s^{-1}$)

S = Tunnel gradient

A = Area of tunnel

$C_j$ = Cost function for jth item

The unit used is cost is per kWh. A formula is used to calculate head loss due to friction per meter of length of the tunnel.

$$H = \frac{Q^2\,N^2}{\left(\frac{\pi D^2}{4}\right)^2\,\left(\frac{D}{4}\right)^{4/3}}$$

H = Head loss due to friction

N = Rugosity coefficient

Annual energy loss due to friction in the tunnel (L) = 9.8 Qi H η T

η = Efficiency of electromechanical equipment in the power house

T = Operating hours per year

Substituting the values for T and H from the above equations

L = $6.157\,x\,10^5\ Q^3\,N^2\,\eta\,D^{-16/3}\,Et$

Darcy's Equation for jointed schist rock is used to calculate seepage loss. Seepage loss is directly affected by the increase in diameter/area of the tunnel; therefore it must be considered in evaluating the economic diameter/area of the tunnel.

$$q_i = \frac{k\ \Delta h\ A}{d}$$

k = Coefficient of permeability

$q_i$ = leakage across concrete lining ($m^3s^{-1}$)

Δh = (hi - he), where hi is the internal and he is the external hydraulic head

d = thickness of concrete lining

Annual energy loss due to seepage = $8.585\ x\ 10^4\ h\ \eta\ \frac{k\ hi\ \pi\ D}{d}\ \ Et$

A survey of 25 projects worldwide in terms of tunnel construction cost for diameters ranging from 3.5 to 10m, as shown in Table 2-1, was used to estimate the cost of the Neck tunnel (Cc). The cost included excavation, lining, grouting, contingencies (C) and supervision (S) charges. Depreciation and interest, and operation and maintenance are calculated in the project cost. The total annual cost

$$T = Cc(1+C)(1+S)\left[\frac{i(1+i)^n}{(1+i)^n-1}\right] + Cc(1+C)(1+S)O +$$
$$6.16x\ 10^5\ \eta\ Q^3\ N^2\ \eta\ D^{-16/3}\ Et + 8.58\ x\ 10^4\ \ h\ \eta\ \frac{k\ hi\ \pi\ D}{d}\ \ Et$$

Minimum cost can be obtained by making $\frac{dT}{dD} = 0$. The application shows the optimum diameter is 5m, with the addition of an extra 0.5m for future development to give a total of 5.5m. The price for establishing the tunnel is 9710 $NZ per metre and the total cost is $NZ 24M, as shown in Figure 2.15.

The thickness of the precast concrete segments of 5m diameter tunnels varies between 20cm and 30cm. Taking 30cm of 50Mpa, the volume of concrete required to construct the Neck tunnel would be 12,246m$^3$. Adding 10% waste and allowing for components produces a total costing of around $NZ 5M. A typical cross sectional dimension of an underground power house is 30m x 30m x 15m, costing around $NZ 20M including the materials. The total costs of construction are estimated at $NZ 50M.

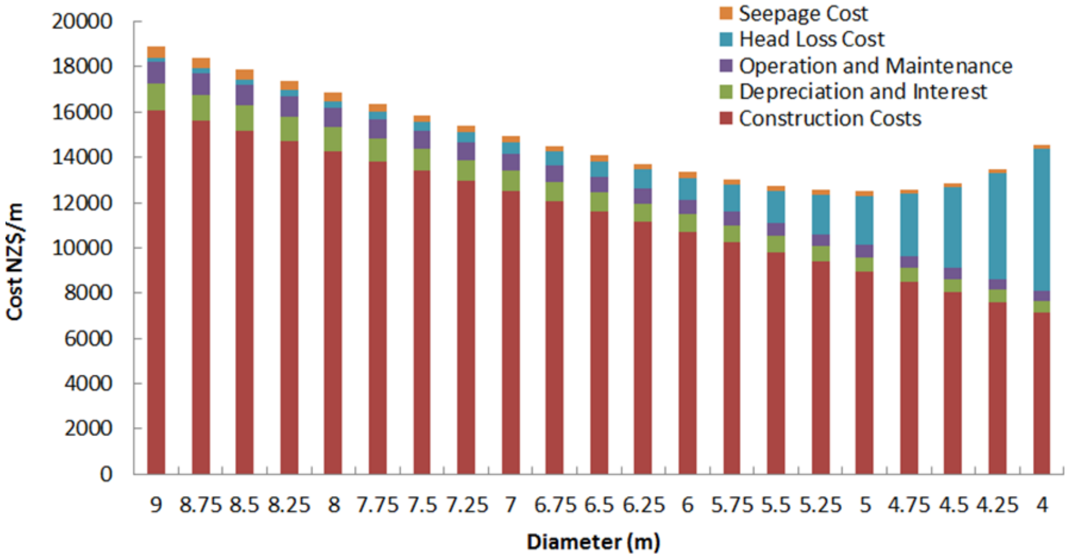

*Figure 2.15 Cost analysis (Optimum Pipe Diameter Graph).*

*Table 2-1 Tunnels data survey .*

| Year | Country | Type | Length (m) | Rock Type | Rock Support | Project Cost $NZ as 2014 in Million. | Diameter (m) | Cost per meter $NZ |
|---|---|---|---|---|---|---|---|---|
| 1997-2000 | New Zealand | CBD | 6450 | Sandstone, siltstone | Precast lining | 62 | 3.56 | 9612.4 |
| 2010 | PANAMA | HYDROPOWER | 13039 | Lahar | 25 cm thick precast concrete | 129 | 3.92 | 9953.6 |
| NA | Italy | Hydroelectric | 10000 | Micaschist- granodiorite | 20cm Precast concrete segment | 24 | 4.04 | 2439.9 |
| 2008 | ITALY | HEADRACE TUNNEL | 9154 | Gneiss, mica schists, marbles and lime schists, dolomitic segments | Tunnel lining with steel ribs | 62 | 4.2 | 6791.7 |
| 2008 | CHILE | TUNEL | 7650 | Monzonite quartz, tourmalinic breccia " Andesite, porphyry " Monzonite quartz, | 1st phase lining by fixing of bolts and metallic panels | 18 | 4.5 | 2337.0 |
| NA |  | HYDROPOWER | 11900 | Limestones, Verrucano formations, schists | NA | 29.5 | 4.77 | 2480.9 |
| 2003-2005 | ITALY | TUNNEL | 8509 | Sandston, marl & limestone | 20 cm Precast segment | 42 | 4.88 | 5389.1 |
| 1996-2000 | Philippines | Sewerage | 1,3000 | Conglomerate, basalt | Precast segment | 85 | 4.88 | 6534.2 |
| 2000-2001 | ITALY | DIVERSION | 7080 | Gneiss | 20cm Precast segment | 36 | 4.88 | 5154.0 |

| Year | Country | Type | Length (m) | Rock Type | Rock Support | Project Cost $NZ as 2014 in Million. | Diameter (m) | Cost per meter $NZ |
|---|---|---|---|---|---|---|---|---|
| NA | VIETNAM | HYDROPOWER | 7800 | Sandstone, , rhyolite | 30 cm thick precast concrete | 12 | 5.48 | 1561.3 |
| 2010 | India | HYDROPOWER | 14630 | Basalt, andesite, granite/granodiorite | 30cm Concrete segment | 64 | 6.1 | 4376.4 |
| 1993-1995 | CHINA | DIVERSION | 21000 | Limestone, dolomite, Loess | 25cm Precast segment | 115.5 | 6.12 | 5499.7 |
| 2003-2005 | Costarica | HYDROPOWER | 7900 | Lahar, andesites and tuff | 20cm Precast segment | 68 | 6.18 | 8604.5 |
| NA | GREECE | METRO | 9600 | Clay, sandy clay, sand | 30 cm thick precast concrete | 165.5 | 6.19 | 17237.2 |
| NA |  | Railway | 10400 | NA | NA | 94.3 | 6.3 | 9067.9 |
| 2008 | ITALY | Railway | 10150 | granites, granodiorites | 20cm Precast concrete segments | 149.7 | 6.3 | 14753.7 |
| 1998-2000 | Slovenia | HYDROPOWER | 10000 | Limestone | 20cm Precast segment | 95.3 | 6.98 | 9531.5 |
| NA |  | HYDROPOWER | 26000 | Basalt, rhyolite, trachyte, dolerite | 25cm precast concrete segments | 65.1 | 6.98 | 2503.4 |
| 2004 | ECUADOR | HYDROPOWER | 9700 | Granite, gneiss and schists | 20 cm precast concrete segments | 20.8 | 7.05 | 2147.1 |
| 2008 | Hong Kong | Drainage Tunnel | 5100 | Volcanic tuffs and granodiorites | 25 cm precast concrete | 173.7 | 7.27 | 34053.5 |
| 2002-2004 | Italy | Subway | 2358 | Cemented sand and gravel deposit | 30cm Precast segment | 92.4 | 7.77 | 39183.7 |

| | | | | | | | | |
|---|---|---|---|---|---|---|---|---|
| 2000-2002 | ITALY | Railway | 2710 | Limestone | 35cm Precast segment | 42.3 | 8.03 | 15593.2 |
| Year | Country | Type | Length (m) | Rock Type | Rock Support | Project Cost $NZ as 2014 in Million. | Diameter (m) | Cost per meter $NZ |
| NA | ETHIOPIA | Hydroelectric | 16130 | Basalt, tuff Lacustrine deposits and pyroclastic rock | 30 cm thick precast concrete | 85.4 | 8.1 | 5292.9 |
| 1999 | | HYDROELECTRIC | 1500 | Limestone | NA | 5.1 | 9.2 | 3421.0 |
| 2002-2005 | SPAIN | Tunnel | 7000 | Limestone, Sandstone | NA | 251.4 | 10 | 35922.3 |

## 2.7 Potential benefits of the Neck pumped storage scheme

This section focuses on analyzing the potential economic, environmental and ancillary services benefits of the Neck scheme.

### 2.7.1 Economic value of the Neck scheme as a new renewable power source

As discussed in the last section about shifting the release of the Lake Hawea inflow to Lake Wanaka (Figure 2.16), the net outflow of Lake Hawea would decline from normal to minimum release of 10 $m^3s^{-1}$ at the Hawea River. The output results of the simulation model for 1998-2012 showed the mean net power gain would be 30 MW, which would be generated by releasing water via the net water flow from Lake Hawea to Lake Wanaka and the mean annual income from generating electricity would be $NZ 36.4M as shown in Figure 2.17.

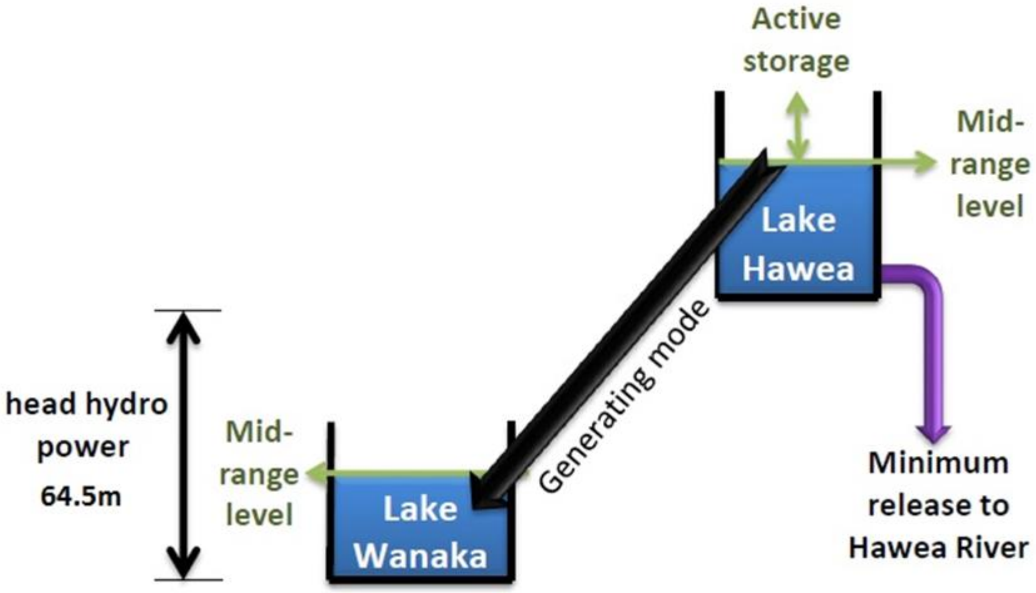

*Figure 2.16 Schematic diagram of the Neck scheme as a new hydro power station.*

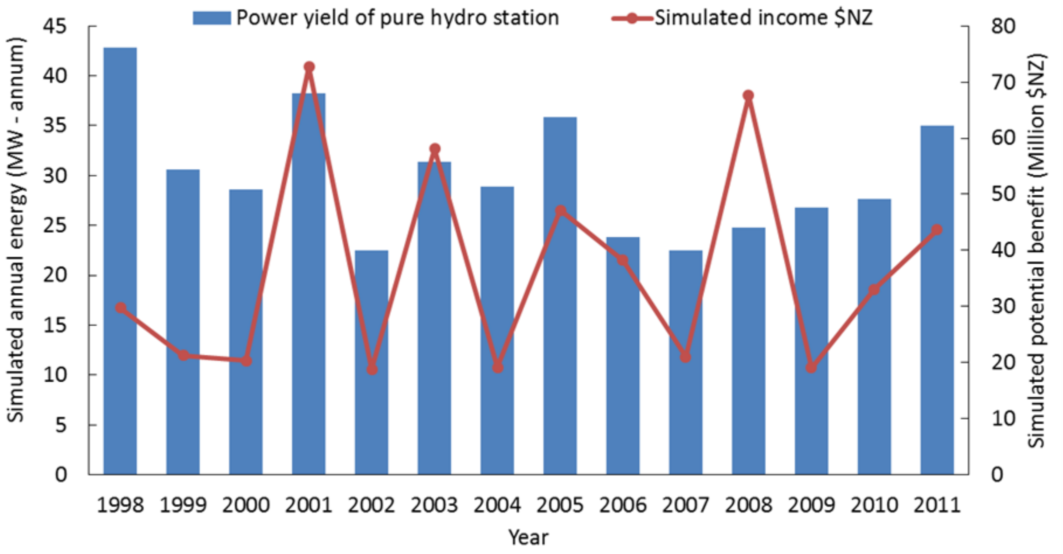

*Figure 2.17 Simulated power yield and benefit 1998-2011 for a pure hydro station operation.*

### 2.7.2 Economic value of the Neck scheme as a pumped hydro energy storage plant

In Lake Wanaka, natural high water levels tend to coincide with lower electricity prices, as shown in Figure 2.18. This is because the same rains what increase the Wanaka lake level will also raise the storage level in the South Island generally. Thus the Wanaka lake level can be reduced by pumping water into lake Hawea at low electricity prices and later generating at high electricity prices when the Wanaka lake level is low, to increase the level. The output results of the simulation model showed the Neck pumped storage system will tend to move the lake levels toward the mean levels, as shown in Figure 2.19. Shifting from low time prices to high time prices will not only create a benefit for the operator of the Neck scheme but will also increase the profit for the operators at the Clyde and Roxbugh stations by reducing high inflows into Lake Dunstan and Lake Roxburgh.

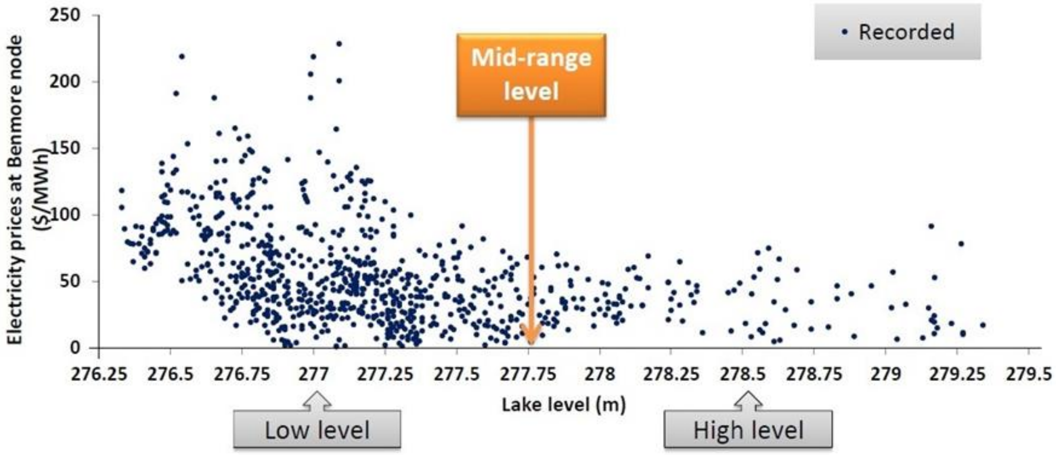

*Figure 2.18 Lake Wanaka high water levels tend to coincide with lower electricity prices.*

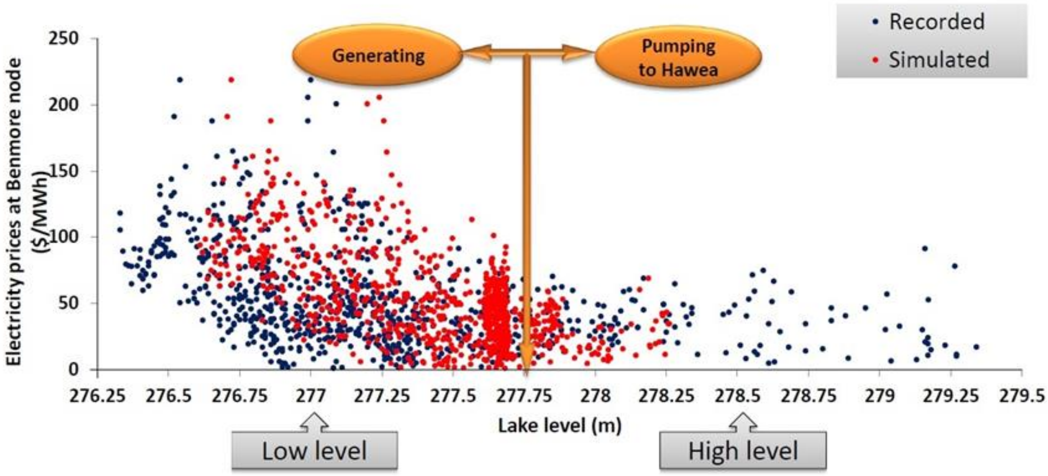

*Figure 2.19 The level of Lake Wanaka related to recorded and simulated electricity prices.*

The pattern of intraday prices for each half-hour between 1998-2012 at the Clyde station was analysed as a reference for either pumping or generating at the Neck scheme. Figure 2.20 shows the pattern of mean prices during a day in two patterns: Monday to Friday and during the weekend. The absolute value of the difference between the minimum and maximum priced half-hours was used in the simulation model to make the decision about either pumping or generating to create an economic benefit for the operator. Many scenarios were run in the model to investigate maximum possible income. The best time to pump water from Lake Wanaka to Lake Hawea from Monday to Friday appears to be between 1am and 5am and during the weekend between 3am and 5:30 am. For generating, the best times from Monday to Friday are 7am to 10:30 am and 6pm to 7pm and during the weekend from 10 am to 10:30 am and 5:30 pm to 8:30 pm.

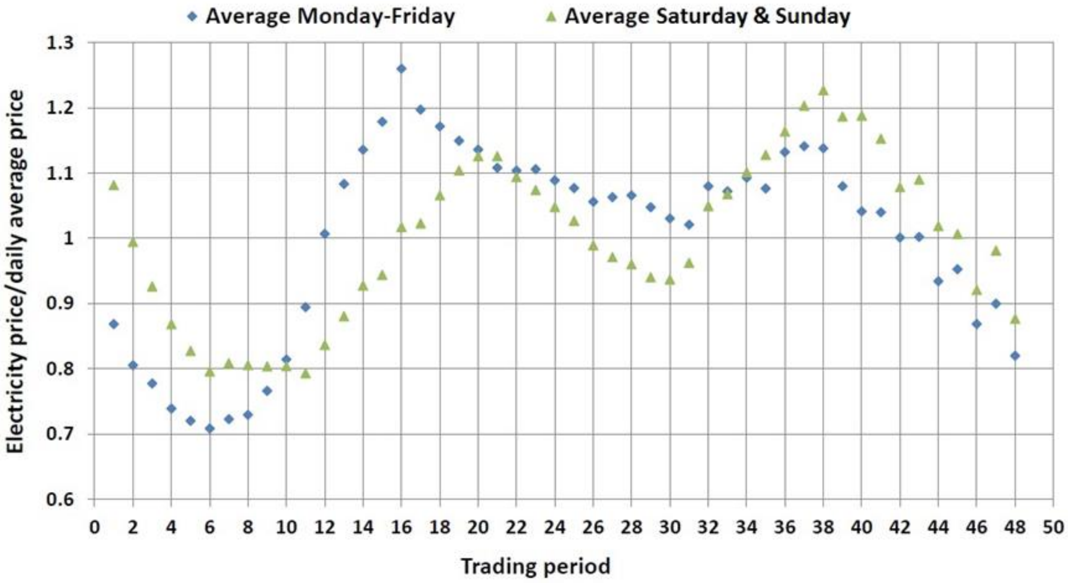

*Figure 2.20 Intraday variation in generation half-hourly prices divided by daily average price from 1998-2012 at Clyde Station.*

The simulation model was developed to maximize economic profit by pumping and generating, with consideration given to improving the environment. The output results show the cumulative income that would have been achieved from operating the Neck scheme as a pure hydro station from 1998-2012 was $NZ 509M; on average $NZ 36M per year. The cumulative income earned by operating the Neck scheme as a PHES and generating power by releasing water from Lake Hawea showed profit improvements of 54.73%, totalling $NZ 930M; on average $NZ 66M per year as shown in Figure 2.21. This amount was determined assuming a generating total of 25,500 GWh between 1998-201, equivalent to a mean daily power output of 52 MW, and a pumping total of 16,200 GWh, equivalent to a mean daily power output of 33 MW as shown in Figure 2.22. The difference between generating and pumping is a mean daily power output of 19 MW and the mean daily power efficiency loss would be 8.5 MW.

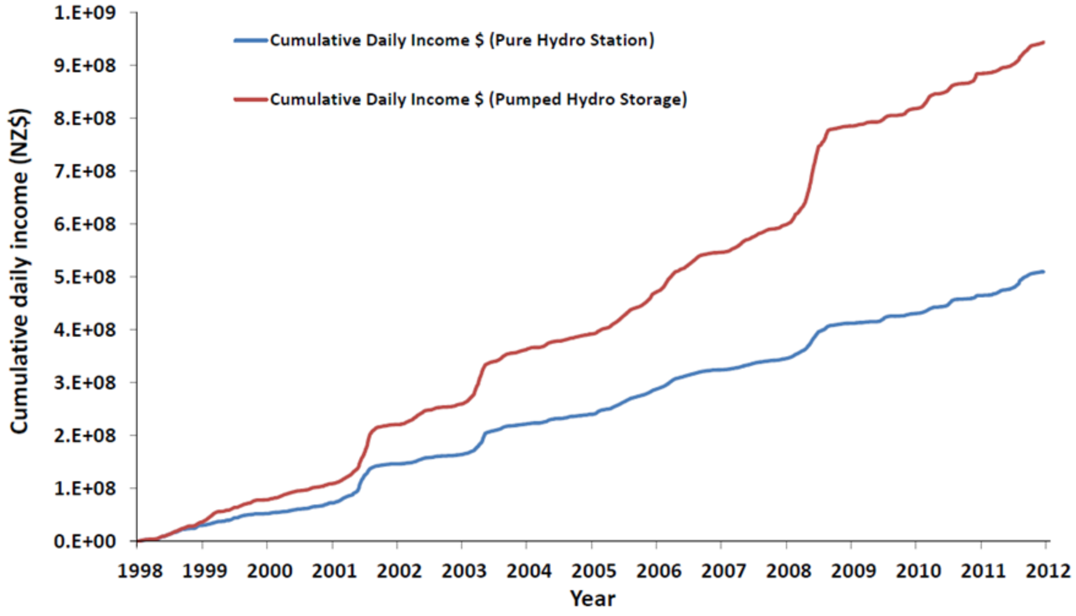

*Figure 2.21 Cumulative income for the Neck scheme for both pumped storage and operation as a pure hydro station.*

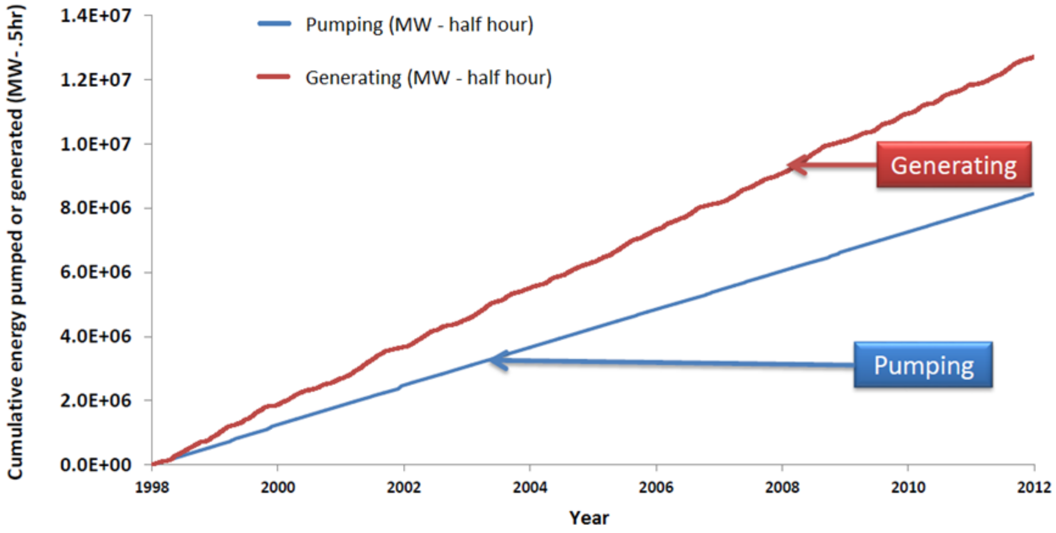

*Figure 2.22 Production from the potential Neck scheme as a conventional power plant and as a pumped storage scheme.*

### 2.7.3 Economic value of the Neck scheme by reducing power loss from spill at the Clutha hydro power stations

The model indicates the amount of water spill from the Clyde and Roxburgh stations would be reduced considerably by the Neck pumped storage simulation model, through the model goal of pumping water during times of high inflows into Lake Wanaka. The model shows that almost 3.7 TWh of energy could have been stored through avoided spillage from 1998-2012. This is equivalent to a mean daily power output of 30.6 MW. This means the efficiency of the Clutha hydropower scheme would be increased. Figure 2.23 compares the cumulative energy lost through spillage at the Clyde and Roxburgh hydropower stations in reality and in the Neck pumped storage model from 1998-2012.

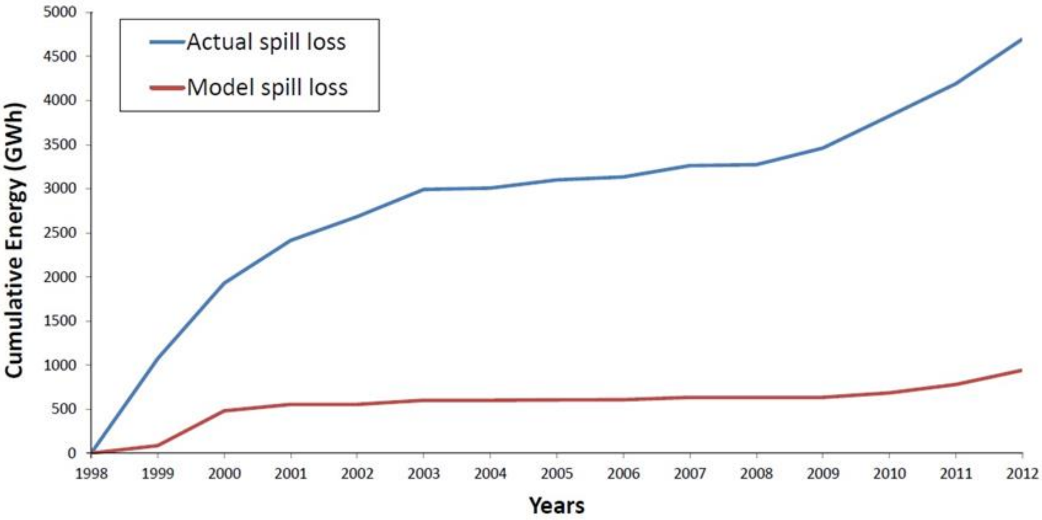

*Figure 2.23 Cumulative energy loss from spillage from Clyde and Roxburgh dams: actual and with the Neck pumped storage scheme.*

### 2.7.4 Economic value of the Neck scheme as spinning reserve

Spinning reserves are defined as electric power plant or generating capacity that is unloaded, synchronized, online and ready for immediate use in the event of a plant outage.

The volume of available water below mid-range level (Lake Hawea) is 553 x 106 $m^3$. Figure 2.24 shows the number of days of spinning reserve from Lake Hawea with a plant outage.

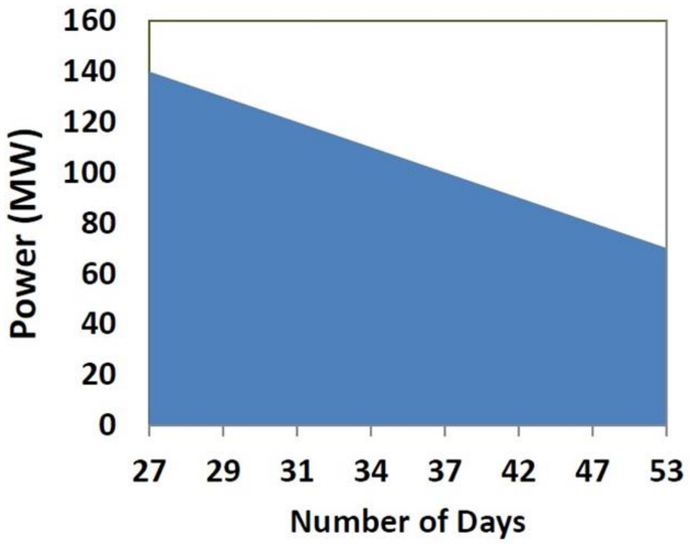

*Figure 2.24 Possibility of spinning reserve from Lake Hawea with a plant outage.*

### 2.7.5 Economic value of Neck scheme from Hawea Irrigation Scheme

The goal of the Neck Pumped Hydro Energy storage scheme model as related to Lake Hawea is to maintain the lake level above 342.5 masl between 15 September and 30 April. However, this level was interrupted due to high electricity demands in 2002 and 2008.

The water used for irrigation from the HIS (Hawea Irrigation Scheme) covers 35km of races and services approximately 1017ha. Contact Energy supplies water to the HIS under a supply agreement. The current policy and constraints regarding Lake Hawea allow it to be used for irrigation: if the lake level is above 342.5 masl then the irrigation is gravity fed by a siphon system which has negligible running costs. If the lake level is below 342.5 m then HIS has to pump water for irrigation. The cost of pumping for a supply of 1000 l/s is approximately $NZ 1000/day. These pumps are run when the lake level is low during the irrigation season (15th Sept-30th April). Figure 2.26 shows the actual days of pumping for the HIS (1998-2012). The proposed Neck scheme would have made the irrigation cost in the Hawea irrigation scheme very low instead of costing an average of $NZ 64,000/annum.

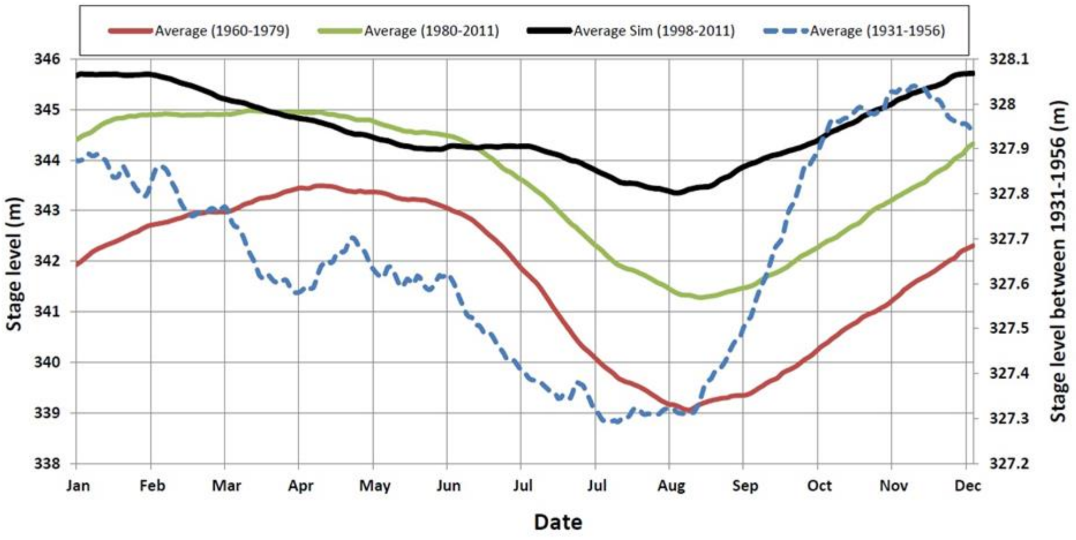

*Figure 2.25 Simulated and recorded average level of Lake Hawea since 1931 for uncontrolled and controlled operation.*

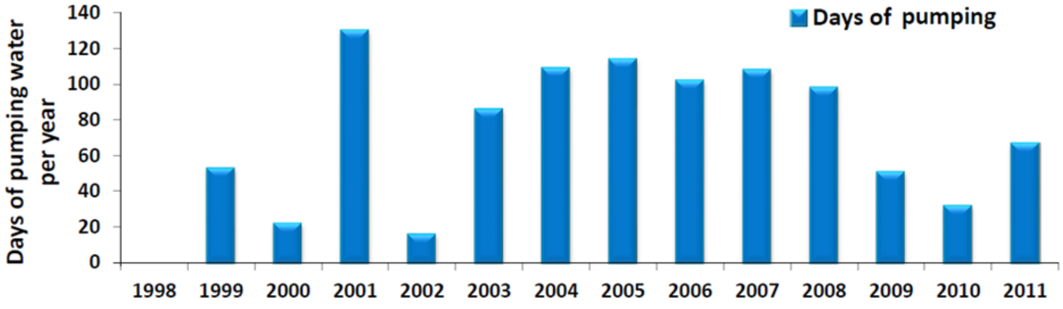

*Figure 2.26 Actual days of pumping for the Hawea irrigation scheme (1998-2012)*

### 2.7.6 Economic advantage of the Neck scheme by reducing the flooding risk at Wanaka Township

The model runs indicate that the likelihood of flooding in Wanaka would be greatly reduced, to the extent that no flooding would have happened within the simulation period (Figure 2.27). Figure 2.28 shows two examples in reality and the simulated model of flooding events in 1995 and 1999. The highest level of Lake Wanaka would have been reduced by the proposed Neck scheme from 281.3 to 279.65 masl and from 280.4 to 279.1 masl, respectively. The duration of water levels being above mid-range is almost the same in both events. The 1999 flood caused severe damage to the communities of Lake Wakatipu and Wanaka, with the closure of lakefront businesses for up to 3 weeks, resulting in $NZ 56M in lost revenue and damage to commercial premises in Queenstown alone [154]. The delay of the peak event of flooding is about 24 hours.

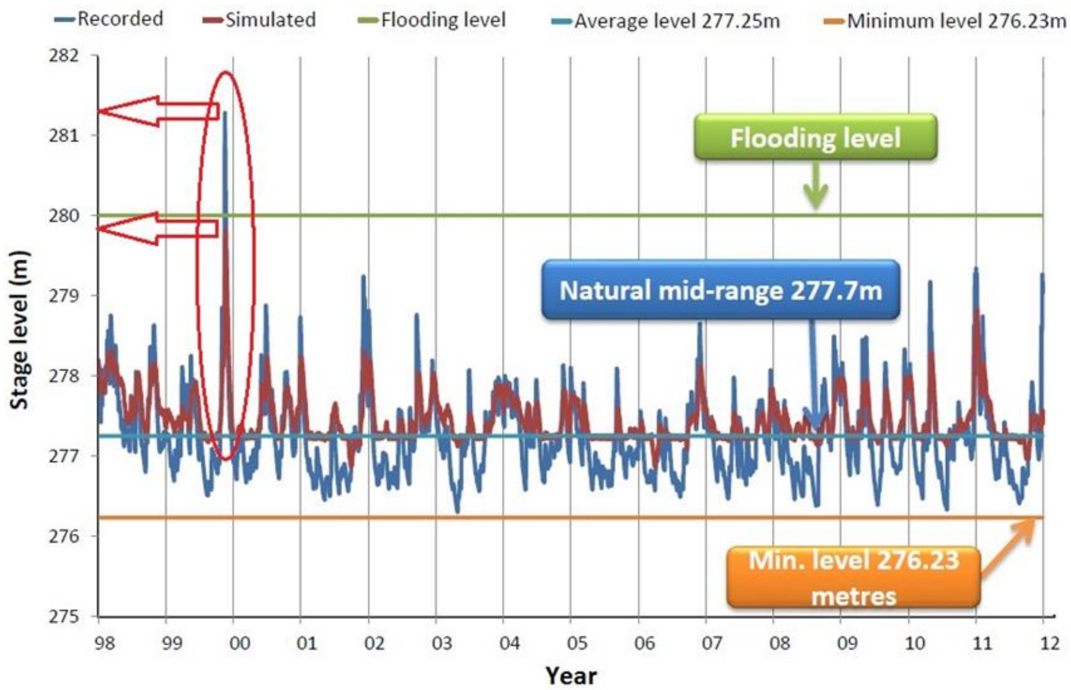

*Figure 2.27 The recorded and simulated fluctuations in level of Lake Wanaka (Lower reservoir) from 1998-2012.*

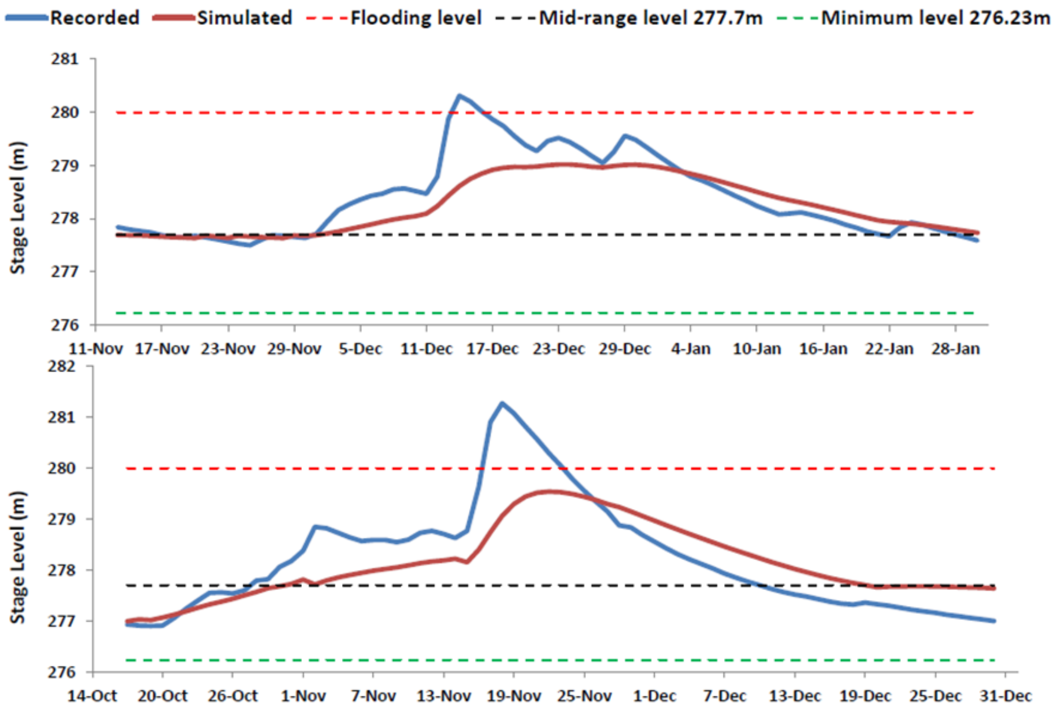

*Figure 2.28 Recorded and simulated levels of Lake Wanaka during the December 1995 (upper graph) and November 1999 (lower graph) flood events.*

### 2.7.7 Environmental advantage of the Neck scheme in reducing the Lake Wanaka level range (lower reservoir)

The simulation results show that the proposed Neck scheme would tend to move lake levels toward the mid-range level, with a major reduction in level fluctuations and reductions in lake bed exposure during dry seasons. The effects of applying the operating rules to a 120 MW simulated Neck scheme are shown in Figure 2.29, indicating a much higher proportion of time now spent with Lake Wanaka water levels within a narrow 25 cm target range near the mid-range of present natural fluctuations. The simulated lake level remains between 277.25m and 277.5m 50% of the time and between 277.5m and 277.75m 20% of the time. Moving the lake to the mid-range level will tend to increase recreational use and aesthetic appeal.

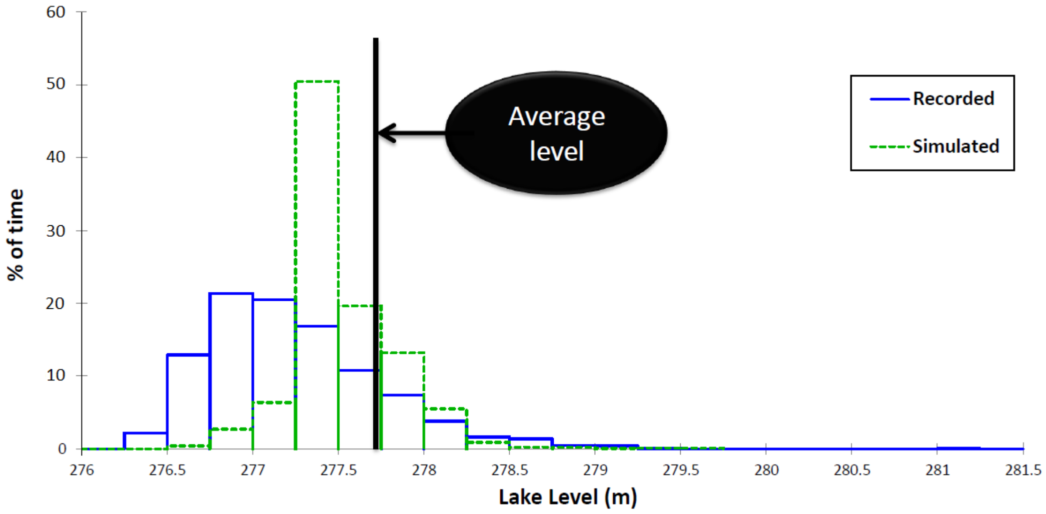

*Figure 2.29 Frequency distributions of Lake Wanaka lake level fluctuations (masl) for 1998-2012 as recorded and simulated with the Neck pumped storage scheme.*

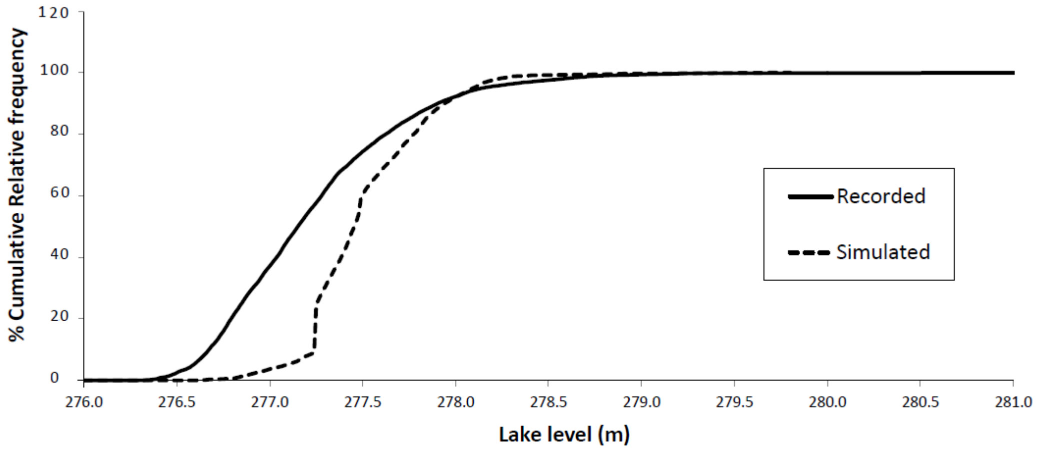

*Figure 2.30 Cumulative frequency of Lake Wanaka lake level fluctuations (masl) for 1998-2012 as recorded and simulated with the Neck pumped storage scheme.*

### 2.7.8 Environmental advantages of reducing the seasonal operating range of Lake Hawea (upper reservoir)

The pumped storage simulation model shows a major reduction in variations in lake level; 87% of the time the simulated lake level is above or near mid-range, compared with 65% of the time in the recorded levels. In addition, the simulated lake remains within a 1m range between 344m and 345m for 26.5% of the time compared to 16% of time in the recorded levels. The Neck scheme would therefore be able to reduce the extent of shoreline fluctuations in Lake Hawea.

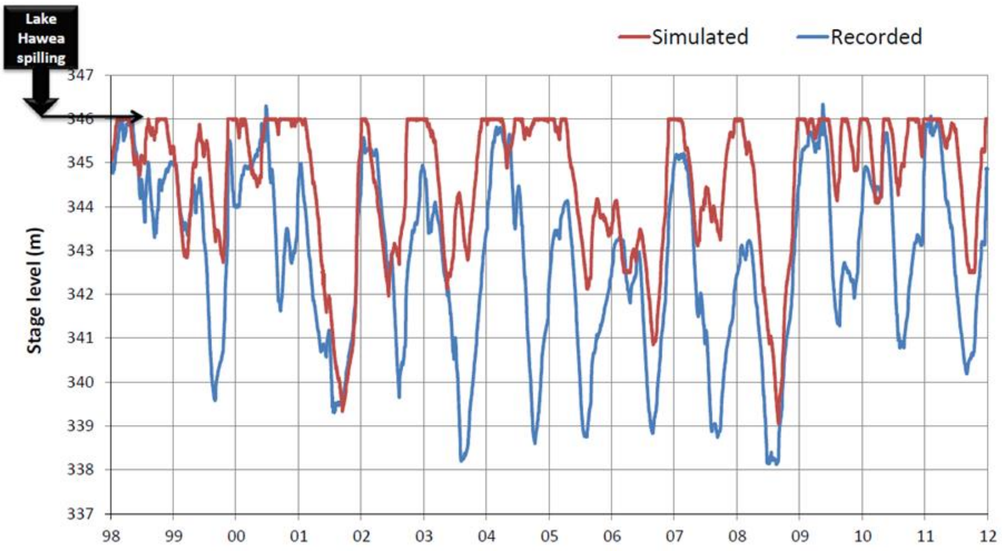

*Figure 2.31 The recorded and simulated level of Lake Hawea (Upper reservoir) from 1998-2012.*

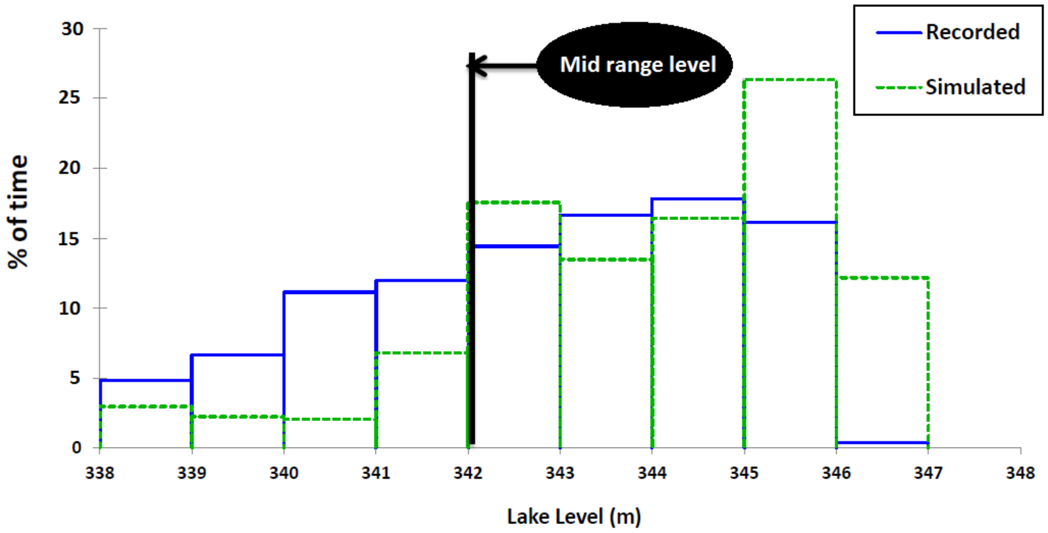

*Figure 2.32 Frequency distributions of Lake Hawea level fluctuations (masl) from 1998-2012 for recorded levels and the simulated Neck pumped storage scheme.*

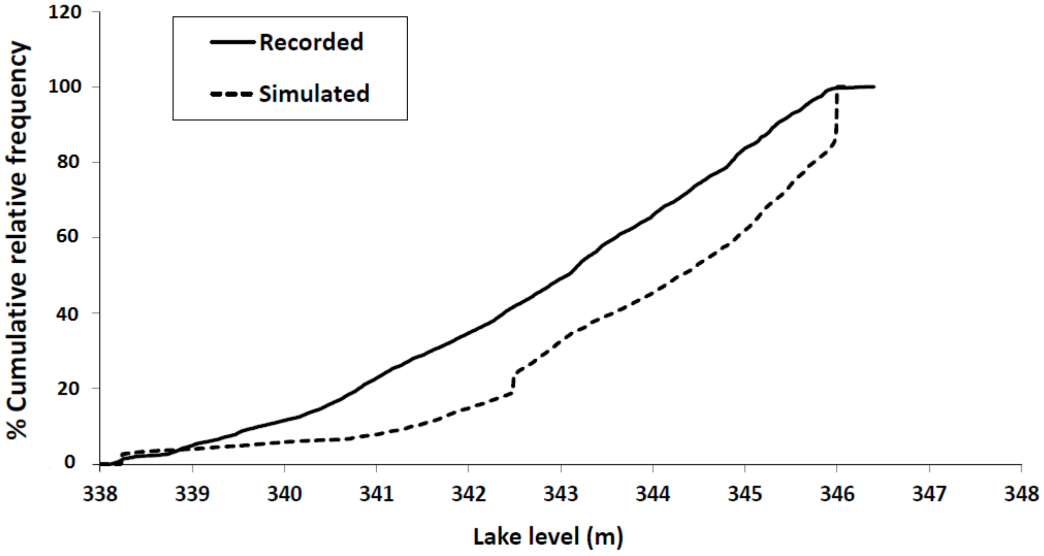

*Figure 2.33 Cumulative relative frequency of Lake Hawea lake levels.*

## 2.8 Lake Wanaka Preservation Act 1973

Currently Lake Wanaka is protected by the 1973 Wanaka Preservation Act, which prohibits any form of control of the lake.

The purposes of this Act are:

a) to prevent the water in the body of the lake from being impounded or controlled by, or, as far as possible, obstructed by, any works except in an emergency;

b) to prevent the natural rate of flow of lake water between the outlet of the lake which forms the source of the Clutha River and the confluence of that river and the Cardrona River from being varied or controlled by any works except in an emergency;

c) to preserve, as far as possible, the water levels of the lake and its shoreline in their natural state; and

d) to maintain and, as far as possible, to improve the quality of water in the lake.

## 2.9 Summary

The distance between the two lakes at the Neck is just 2 km with about 64 metres water level difference, making pumped storage potentially operative here in conjunction with some net power generation. The Hawea upper reservoir is controlled as Contact Energy's main hydro storage, while Lake Wanaka has natural water level variation and is under protection by act of parliament against any deliberate level modification.

The operation rules of the proposed scheme would in fact be to reduce Wanaka shoreline flooding risk and reduce the present extent of natural fluctuations. Part of the operation would be net release of water to Lake Wanaka from Hawea, giving a power gain of about 30 MW.

The effect of applying the operating rules to a 120 MW simulated Neck scheme indicate a much higher proportion of Wanaka water level time spent within a narrow 25 cm target range near the mid-range of present natural fluctuation. Importantly, the time spent above the 280 masl high lake level is reduced from 16% to zero in the simulations, indicating significant reduction in high water risk to Wanaka township. The Neck PHES simulation would save approximately 30.6 MW by reducing spill at both Clyde and Roxburgh hydro power stations. A case could therefore be argued for a change in the Lake Wanaka Preservation Act in terms of both the local and national good.