The value of network-coordinated water heating in the Upper South Island

25 March 2026

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Executive Summary

Since 2009, eight Upper South Island electricity distributors have coordinated their use of hot water load management in an effort to deliver benefits for consumers in their region.

Together, the group has been able to deliver significant value for consumers by reducing peak demand over the three major transmission lines that carry power from the Waitaki Valley up to Canterbury, Marlborough, Tasman and West Coast consumers.

Transitioning to next-generation load management

Increasingly, traditional ripple-controlled hot water management will operate alongside next-generation management of hot water and electric vehicle charging.

Preventing a regretful short-lived need for major transmission investment through this transition will require investment to sustain ripple control in the interim, and to implement a next-generation commercial model that continues to deliver network benefits while expanding scope for retailers and other providers to manage energy costs and deliver end user services.

New and existing mechanisms, including non-transmission solutions funding and the new emergency reserve scheme, provide potential routes for Transpower to work with the Upper South Island group to manage this transition.

Benefit of historical load control

The group's actions have helped to push back the need for Transpower to invest in new capacity, delivering on the order of $11 million of cost savings each year since 2021. These savings continue, with the deferred transmission investment now planned for 2028.

The link between deferred investment and reduced transmission charges is complex, and complicated further by changes to Transpower's pricing methodology from 2023.

Prior to 2023, we estimate the group was reducing the share of transmission costs recovered from Upper South Island consumers by around $10 million per year.

Since 2023, Upper South Island consumers are instead benefiting more directly from the deferred investment, and this will continue until 2028 regardless of whether load control continues.

Past actions of the group have also locked in the benefit for Upper South Island consumers of paying for a reduced share of Transpower's 'residual' costs. This saves consumers on the order of $2 million per year. This will continue regardless of whether load control continues, but the value will gradually decline over coming decades.

Benefit of current and future load control

In the lead up to 2028, load control helps to keep demand within current transmission capacity limits.

Beyond 2028, Transpower expects that further investment may be needed through the 2030s and 2040s. If load control were to reduce, these dates would come forward. With continued load control, the group could deliver benefits beyond 2028 on the order of $10 million per year.

At present, the group only controls load on days when it will help manage network capacity.

If load control were also carried out on all winter, spring and autumn days it would reduce the cost of water heating on the order of $2 million per year.

In addition, load control would tend to make peak prices lower for all consumers – in the Upper South Island and across New Zealand. Accounting for offsetting increase in off-peak prices, we estimate this would deliver on the order of $3 million in benefits for upper South Island consumers and $20 million nationwide.

Due to evolving load profiles and generation, the nationwide benefit would climb to around $30 million per year by the mid-2030s. This benefit could be delivered with next generation load management, if the right commercial model for access network and retail benefits is in place.

The group could also offer its resources into instantaneous reserves markets. This would earn on the order of $2 million per year, though this figure is likely to decline over time as more batteries come online.

These figures are summarised in the table below.

Consumer savings (USI region) $ million, 2025 dollars	**Past**	**Future**
Transmission costs (deferred investment)	11	10
Transmission interconnection charge (RCPD, until 2023)	10	-
Transmission residual charge (from 2023)	2	3
Additional untapped:		
Lower cost heating	-	2
Lower energy prices	-	3
Instantaneous reserves	-	2

Contents

1 Introduction

This report assesses the benefits of coordinated hot water control by the Upper South Island (USI) Load Management Group (USI LMG or LMG).

The LMG is a group of eight electricity distributors who co-fund and work with a regional load management controller operated by Orion. The LMG coordinates use of ‘ripple’ systems that turn off hot water cylinders temporarily to shift their demand away from network peaks.

The LMG engaged Concept to prepare this report, which has benefited from access to LMG datasets and engagement with LMG members.

The report considers historical and prospective benefits to electricity consumers on LMG member networks. We have considered benefits across:

- deferred transmission investment and reduced charges
- reduced wholesale electricity purchase costs
- ancillary services
- other potential value streams.

The report does not assess additional benefits LMG members (and their customers) may realise from reducing investment needs, or supporting operations, in their own distribution networks.

In addition to quantifying benefits (where possible) we provide context on conceptual issues and comment on implications for the transition to next-generation technical and commercial platforms for managing hot water and electric vehicle loads.

The report begins with a background covering:

- the types of benefits that hot water management can deliver
- a timeline of key events relevant to the LMG
- discussion of transitioning to new load management systems.

The body of the report then steps through our assessment of transmission, generation, stability and operational, and other (non-monetised) benefits.

2 Background

New Zealand distributors have a long history of remotely managing hot water cylinders to reduce peak electricity demand.

This has made sense because:

- uncontrolled cylinders contribute to peak demand (kW), which has historically occurred on winter mornings and evenings in most New Zealand networks
- networks are sized to meet peak demand, so reducing peaks enables more efficient, lower-cost networks
- peak demand is also a driver of generation costs (alongside overall energy demand in kWh)
- hot water cylinders store energy, so they can (up to a point) be interrupted without impact – i.e., without running out of hot water
- managed cylinders provide a better level of service, and more effective peak management, than simple timer-operated cylinders.

The technical platform for hot water control has typically involved:

- dedicated hot water circuits in homes (and some businesses)
- a ripple receiver that can turn the hot water circuit off and on
- separate metering of the hot water circuit[1]
- ripple injection plant within distribution networks that can signal ripple receivers (via the power lines)
- a distributor-owned system for controlling the ripple injection plant
- an ability to control 'blocks' of demand on separate ripple channels.

Ripple control is a relatively simple, reliable, cost-effective control technology that does not rely on digital communication or control systems at each end point.

2.1 USI load management group

The Upper South Island Load Management Group (USI LMG or LMG) is a collaboration between eight upper South Island electricity distribution businesses (EDBs) to jointly fund and work with a regional load management centre operated from Orion's network control room in Christchurch.

The eight USI LMG members are (in alphabetical order):

- Alpine Energy
- Buller Electricity
- Electricity Ashburton
- Marlborough Lines
- Mainpower
- Orion
- Network Tasman
- Westpower

The LMG members link to centralised load management hardware and software that monitors load and load management activities, setting limits for each distributor to use in their own load management systems with the aim of limiting aggregate USI peak demand – that is the peak demand of the USI region as a whole.[2]

The LMG started as a two-year trial project in winter 2009, co-funded by Transpower and the LMG members. Establishment costs for the LMG were on the order of $1.6m, with Transpower contributing approximately

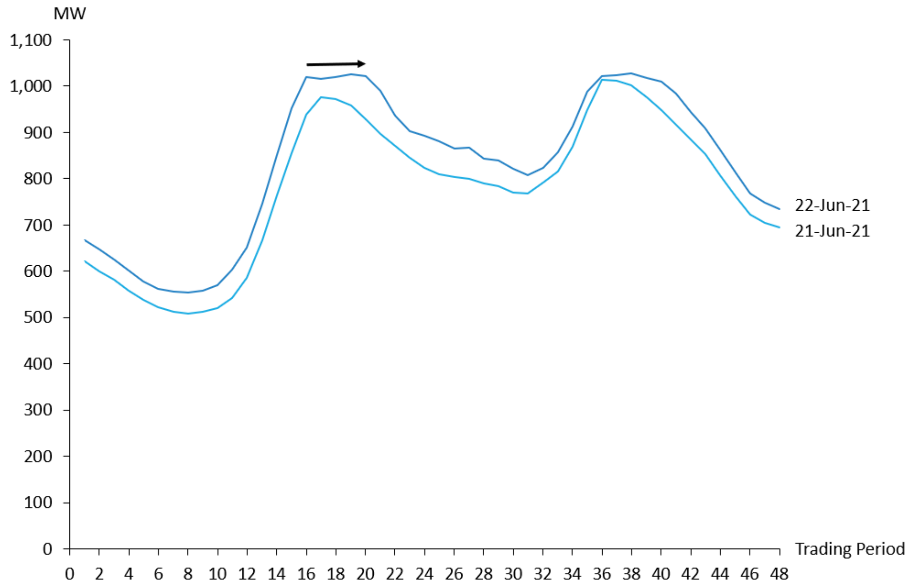
1 Some distributors do not separately meter hot water demand and use 'inclusive' tariffs that reflect an estimate of hot water as a share of total demand.
2 Demand at each grid connection typically peaks at a different time, and there is some generation capacity within the region. As such, managing to the regional peak is different from managing to individual distribution network peaks.

$560k. Ongoing operating costs are on the order of $200k per year, recovered from members in proportion to each network's connection count.

Transpower's contribution to establishment costs reflected its recognition that the LMG may help defer the need for Transpower to upgrade USI grid capacity.

Since its inception, the LMG has reduced aggregate winter peak demand across its members' networks by an estimated 65 to 90 MW. This in turn reduces peak demand in the USI region by around 7% to 9%. However, we understand from engaging with the USI LMG that maximum load shed capability could be as high as 140 MW.

Figure 2.1: Example of 'flattened' USI morning demand peak (22 June 2021)



2.2 Types of benefits

We have assessed a range of benefits delivered by the LMG to date, and the outlook for further benefits.

LMG benefits are linked to the ability of hot water control to help manage the cost or quality of electricity supply. Generally, hot water control can:

- shift the timing of energy demand (kWh) within a day
- temporarily (for several hours) reduce demand at short notice (within seconds or minutes)
- control the rate at which demand is restored.

This makes hot water control valuable for a range of network capacity, generation capacity, system stability and operational management uses.

Additionally, the LMG's ability to coordinate across eight distributors is unique, delivering benefits by virtue of:

- scale – aggregating a greater capacity (MW) of load control
- regional coordination – managing loading into the USI as a whole, rather than individual networks or sub-regions.

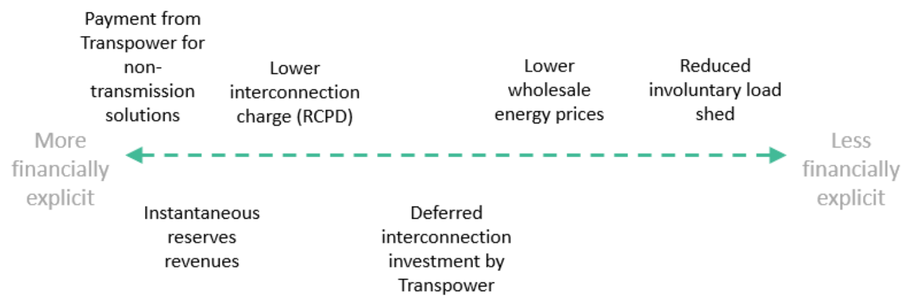
This report does not consider distribution network and grid connection capacity[3] – the focus of the LMG is on benefits of coordination across distribution networks, whereas within-network benefits depend on each member's independent load management.

Figure 2.2: Types of benefits from LMG

	Description	USI LMG opportunities
Transmission capacity	Capacity to transfer power through grid to meet demand	• Defer grid investment • Reduce transmission charges • Provide non-transmission solutions • Reduce nodal price separation
Generation capacity	Capacity to produce enough power to meet demand	• Shift heating to cheaper times • Reduce peak energy prices
Stability resources	Ability to maintain a stable power system frequency and voltage	• Supply instantaneous reserves
Operational management	Ability to manage planned and unplanned transmission outages, incl. grid emergencies	• Avert load shedding • Extend outage windows

More generally, we observe that benefits cover a wide spectrum in terms of how readily they can be quantified and expressed in monetary terms.

Figure 2.3: Explicitness of benefits



At the financially explicit end of the spectrum are cash payments (or credits) received by the LMG members directly, such as:

- payment from Transpower for supplying a 'non-transmission solution'
- revenues from providing instantaneous reserves.

The other end of the spectrum contributes to averting involuntary load shedding. This is clearly beneficial, but difficult to observe and even more difficult to value.

Intermediate examples include:

- supporting a later sequencing of grid investments than would otherwise have occurred (ie, transmission deferral)
- shifting how interconnection costs are recovered under the former Transmission Pricing Methodology (TPM)
- shifting water heating to lower-cost times of the day and reducing electricity prices at peak periods.

[3] A grid connection is the substation assets and any spur lines owned by Transpower that tie a distribution network (or generator) to the wider interconnected grid.

2.2.1 Transmission network capacity

Transpower recovers transmission investment and operating costs from its customers, which include distributors. Distributors in turn pass the transmission costs allocated to them on to retailers along with their own network costs. Retailers bundle network costs with energy and other costs (such as metering) in the prices they charge end consumers.

The LMG members are therefore directly exposed to transmission charges, which in turn reflect Transpower's investments.

There is some complexity to the way Transpower is required to allocate its costs to its customers, and the pricing methodology it uses for this has changed over the last few years.

As such, we have assessed the transmission network capacity benefits of the LMG by examining a mix of:

- historical impact on investments and charges
- impact on current charges
- prospective impact on investment and charges
- potential for collaborating on non-transmission solutions.

In addition to the above cost-recovery, the economic cost of transmission capacity constraints is signalled through the nodal prices used for wholesale electricity purchases.[4]

Accordingly, we have also considered 'location factors', which are a measure of the difference in price between two nodes. This provides an indicator of transmission loss and constraint costs.

Refer Sections 3, 4 and 5 for more information.

2.2.2 Generation capacity

Across New Zealand, generation output must match demand at all times. The cost of meeting demand is determined in real time and reflected in wholesale electricity spot prices at each node.

Generally, wholesale prices are highest when one or more of the following applies:

- demand is high, such that higher-cost generation capacity is needed to balance the system
- generation is tight, generally due to low fuel (including hydro storage) or plant unavailability
- transmission constraints are restricting the ability to import low-cost generation.

This means generation costs can be assessed by looking at historical wholesale prices, and Concept's internal forecast of future prices.

Distributors are not exposed to wholesale prices, but energy costs make up a large share of their customers' electricity bills. The LMG's actions can reduce energy costs for their customers (and energy consumers across New Zealand).

Refer to Section 6 for more information.

The Electricity Authority is currently working with the System Operator and wider industry to develop an Emergency Reserve Scheme (ERS). The ERS aims to provide an additional tool for the System Operator to use to help manage critical supply shortfalls over short periods of time. ERS suppliers are remunerated, though it is not clear whether the LMG will be able to participate.

[4] As the grid approaches its limits, the loss and constraint components of nodal prices in an importing region increase.

2.2.3 Power system stability

In addition to dispatching enough generation to meet demand, the System Operator procures several ancillary services to help keep the electricity system in balance.

Of these, hot water control can be used to provide 'instantaneous reserves' services – ie, a backup resource that is armed and ready to deliver load reductions if there is an unexpected loss of a generation unit or transmission circuit.

Refer Section 7 for more information.

2.2.4 Operational management

The USI LMG has used its capabilities cooperatively with Transpower to support planned and unplanned transmission outages, including during grid emergencies. The LMG provides Transpower with access to USI-wide capability and point of contact.

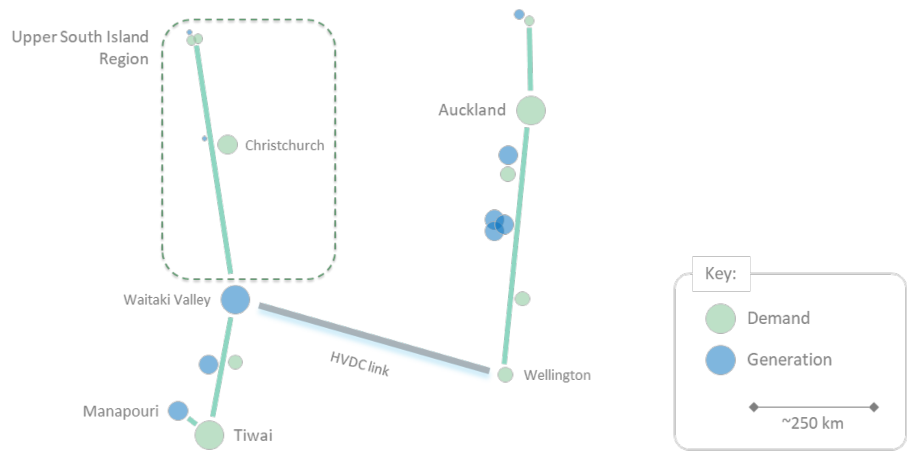
For planned outages, this assists with efficient scheduling and can help avoid placing load on reduced security. For unplanned outages, it can help to avoid involuntary load shedding or facilitate quicker restoration.

We have not attempted to value these benefits because it is difficult to quantify both the nature and the value (in monetary terms) of such benefits.

2.3 The USI region

In power system terms, the Upper South Island region is the part of the grid north of the Waitaki Valley.

Figure 2.4: Stylised representation of NZ power system



The Waitaki Valley is a major generation centre and is connected directly to the Wellington region via a high-voltage direct current (HVDC) link.

The USI region:

- consistently imports power from the south
- transports energy over relatively long distances to demand centres, without any major generation along the way[5]
- has had significant summer demand growth due to irrigation
- is becoming a key region for large-scale solar developments.

2.4 Timeline of key events

The USI LMG was formed in 2009 and has now operated for more than 15 years.

Key events prior to and since the LMG establishment have included:

[5] The largest (semi) flexible generating plants in the USI region are relatively small hydro schemes each under 50 MW in capacity – such as Coleridge, Cobb and Highbank.

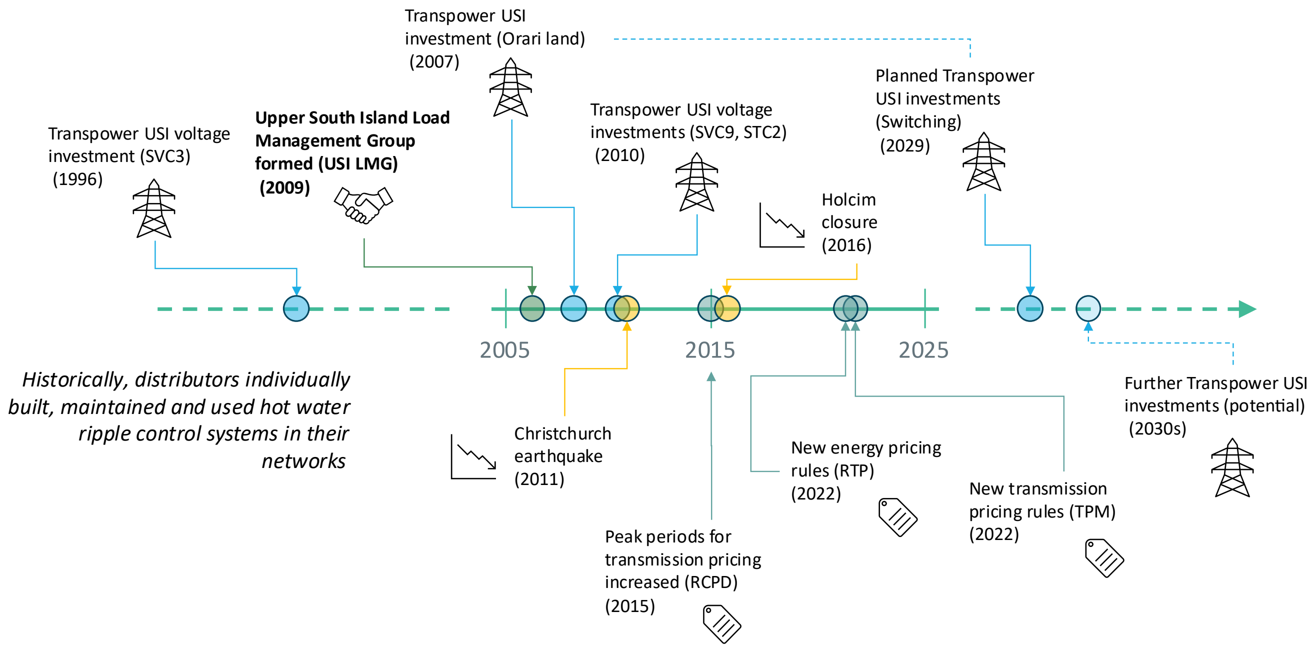
- a sequence of mid-scale transmission investments to address winter voltage constraints in 1996, 2007 and 2010
- significant demand shocks in 2011 (Christchurch earthquake) and 2016 (closure of Holcim cement factory in Westport)
- changes to transmission pricing in 2015 and 2022, and to wholesale electricity pricing in 2022.[6]

The changes to transmission pricing were:

- an operational review (which concluded in 2015) that increased the number of peak periods used to allocate interconnection charges from 12 to 100 for the USI region for charges from April 2017. This meant more load management operations (100+) were needed to achieve the same charge reduction
- a full reform that revamped the approach to recovering interconnection costs. The reform applied to charges from April 2023 but altered the load management payoff from September 2021.[7]

Transpower is planning further upgrades this decade and anticipates the potential need for further investment from the 2030s.

Figure 2.5: Timeline of key events



2.5 Future of residential load management

For a typical household in New Zealand, water heating makes up around 27% of energy demand.

Without load control, water heating contributes at least 0.5 kW to the amount of network capacity required per household.[8] With load control, capacity per household can be reduced by around 20%.

[6] The wholesale market moved to 'real time pricing' in 2022, which can improve the payoff from load management by using the same prices for dispatch and settlement. Previously, settlement used final prices that were often lower than dispatch prices.

[7] A decision on the new methodology was not confirmed until April 2022 but had a retrospective impact on any load management from September 2021 to March 2022.

[8] Concept estimates water heating contributes 0.36 kW per household nationwide at peak. Since half a million houses have gas-fired water heating, this is equivalent to 0.5 kW per electric household. Smaller populations of connections tend to have higher 'after-diversity' demand figures, so 0.5 kW is a reasonable lower-bound.

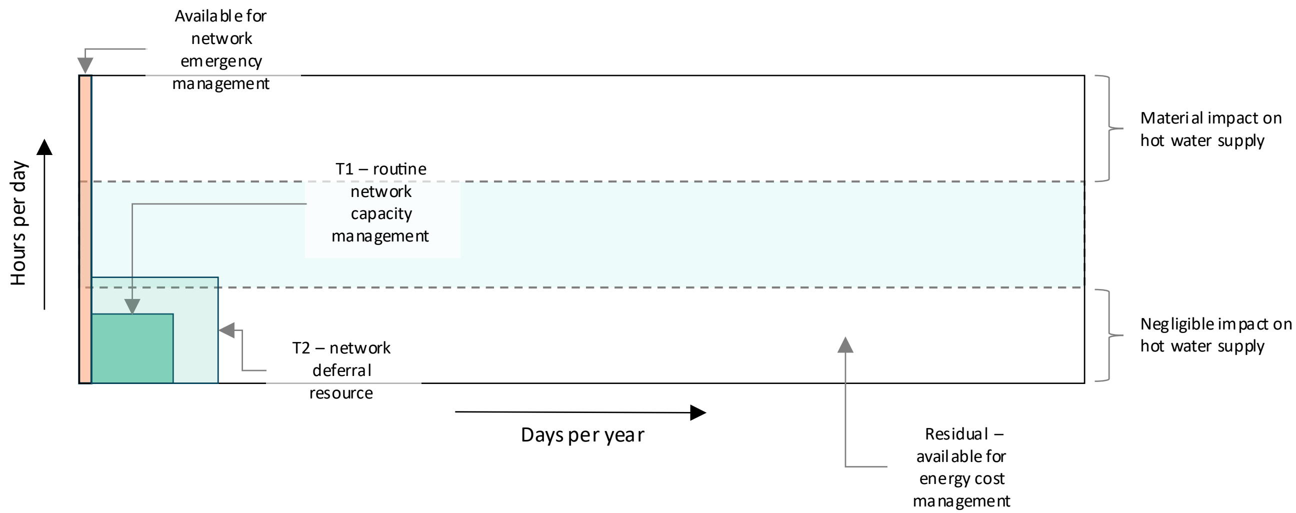
Design capacities for smaller collections of households (eg, within an individual distribution network) would be higher than these national-level figures. For example, we understand that on Orion's network, water heating contributes around 0.8 kW to after-diversity peak demand per household.

Hot water has been uniquely able to deliver load management benefits because it is a large load and hot water cylinders can store heat for when it's needed (so heating can be timed some time before or after hot water usage).

Looking ahead, there are some key technological changes that will shift the picture for residential load management:

- electric vehicles (EV) will become another large, controllable household load. As with hot water cylinders, the timing of EV charging can usually be shifted without any material user impact[9]
- new control technologies are available that do not use the distribution network (ie, ripple control) for communications. These can provide a technical platform for next-generation hot water control (NG-HWC) and EV control. Implementing these control technologies entails new costs, but they can cover both hot water and EV charging and allow finer-grained control (house-by-house) and two-way communication (to verify operation), capabilities that electricity retailers, aggregators and energy services providers are likely to find valuable[10]
- as the share of electricity supplied from intermittent renewable technologies (solar and wind) grows, there will be increasing value in controlling demand at times of low generation (ie, outside of peak demand periods)
- advanced meters (and better back-office data and billing systems) are improving the ability for retailers to track demand and purchase energy based on the actual time-profile of demand from their customers.[11]

Figure 2.7 – Commercial model for next-generation hot water load control



Put together, this means the future of residential load management is likely to involve:

- ripple control operating alongside other load management platforms operated by or for electricity retailers[12]

9 A car travelling 30 km during the day can recharge from a household power point in less than 4 hours overnight, which is around half the typical overnight off-peak window.
10 For example, fine-grained control means a retailer can flex load from its own customers without competing retailers 'free-riding' and can offer customers individual control (eg, to temporarily opt-out if they have guests using extra hot water).
11 The Electricity Authority is also phasing out the option for retailers to use estimated demand profiles for connections with advanced meters installed.
12 In the sense that some properties may have ripple and next-generation control operating together, and in the sense that networks are likely to end up with some properties responding only to ripple control and others responding only to various next-generation control platforms.

- management of both hot water and EV charging – with both eventually being equally important
- load management with more granular visibility and targeting, including two-way communication to confirm operation.

Alongside adapting to these technological changes, distributors will need to evolve new commercial models if they wish to access next generation load management for distribution network purposes.

The current commercial model typically involves:

- network ownership and control of the technology platform
- network standards that drive initial installation of ripple receivers
- 'type of use' tariffs that incentivise participation.[13]

Figure 2.6 helps illustrate how a commercial model for distributors to access NG-HWC provided by others could operate:

- a distributor may make emergency access a mandatory requirement. This would not normally be used, but when it is it may be called on to a degree that would impact hot water availability
- a distributor may then specify a 'tranche' of control (eg, X days per year) that would enable them to manage network capacity investment in much the same way as the USI LMG (or individual distributors) do today. If a property with NG-HWC opts into providing that level of service to the distributor, then the property can access a discounted type-of-use tariff. This is illustrated as box T1 on the diagram
- this leaves a residual capability (days per year and hours per day) that may be used for managing wholesale energy prices (or for any other purpose). The smaller the distributor makes T1, the larger the residual capability and the more likely NG-HWC operators are to opt into the type-of-use tariff
- additionally, a distributor may offer to pay for extended access to hot water control in a targeted area to help defer a specific network upgrade. This is illustrated at T2 on the diagram.

Alongside this approach to allocating resource, distributor would need to:

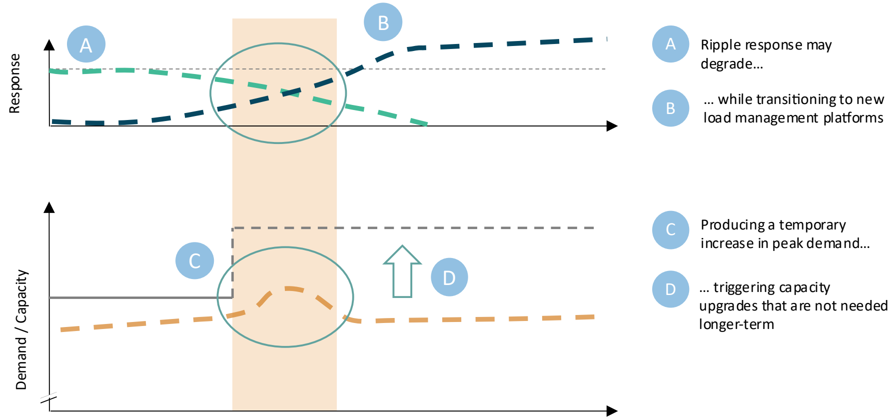
- establish processes for validating whether a given NG-HWC platform can be eligible for tariffs (eg, specifying control protocols and performance requirements for load control systems)
- determining any other NG-HWC provider requirements, such as reporting, assurance and network standards compliance

In time, this technology platform and commercial model have the potential to expand the value of load management – delivering routine distribution network and generation cost reduction and providing a large pool of flexible resource to target more acute needs.

As the transition from ripple-only to NG-HWC progresses, it will be important to manage the risk that a deteriorating level of response from existing platforms during the transition could trigger a short-lived need for permanent capacity expansions.

[13] Traditionally referred to as 'controlled' or 'inclusive' tariffs. They offer discounted lines charges in return for permitting remote management.

Figure 2.8: Risk of regretful investment through transition



The potential for regretful capacity investment applies across distribution networks, transmission and generation capacity. In the USI context, the LMG has a unique role in optimising distribution and transmission deferral. There is no reason this cannot continue through the transition to a mix of legacy and next generation hot water and EV control platforms.

2.6 Effective transition

Successful transition to next-generation load management is likely to require:

- efforts to sustain ripple control capability until next-generation technology is providing enough response to avoid regretful network investment, not just within individual distribution networks but the USI as a whole to support efficient investment by Transpower
- work to develop the next-generation commercial platforms to ensure new technology platforms are able (and incentivised) to deliver distribution *and* transmission network benefits alongside energy benefits.

Sustaining ripple control capability involves some mix of:

- continued operation of the LMG
- potentially, renewal of injection plant
- work to test and sustain ripple response – including testing and replacing receivers
- continuing training and awareness efforts directed at electricians, including solar installers.[14]

Without this activity, the baseline scenario is that ripple response degrades over time as the population of reliably controllable hot water cylinders declines.

At the same time, properties are shifting to next-generation control platforms that may not opt into network load control unless suitable commercial platforms are developed. Developing next generation commercial platforms is likely to involve some mix of:

- tariff design and implementation
- updated network agreements with suitable load management protocols
- defining the 'T1' tranche reserved for network load management
- business processes for approving platform providers and monitoring their performance.

In short, continuation of current levels of load control should not be taken for granted or built into baseline demand forecasts.

[14] It is common for electricians to shift hot water off ripple-controlled circuits, including when installing new solar systems. This can erode the available capability over time.

3 Transmission – historical

The USI region on the high voltage transmission grid comprises all the South Island north of Timaru and Tekapo.

The USI is supplied by four 220 kV circuits that connect Christchurch (and beyond) to generation in the Waitaki Valley as shown in Figure 3.1:

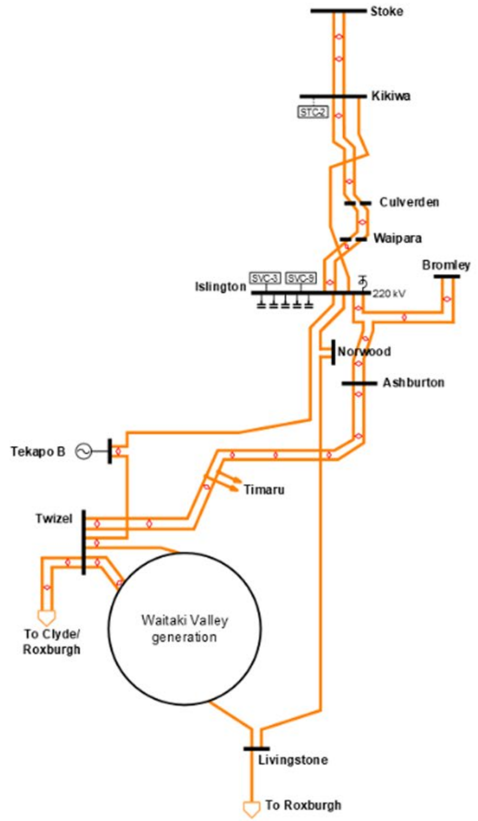
- a single circuit line from Twizel to Islington
- a single circuit line from Livingstone to Islington
- a double circuit line from Twizel to Islington and Bromley.

Demand in the USI region significantly exceeds local generation capacity, making the region dependent on power imported from the lower South Island (LSI).

This is seen in the wholesale market spot price 'location factor' between Benmore (the key LSI market reference node) and market nodes in the USI shown in Figure 3.2.

A location factor is the ratio of the average spot price at one node relative to another over a chosen period. For example, the Benmore-Islington (BEN-ISL) location factor represents the ISL price divided by the BEN price. A location factor above 1 would indicate that the ISL price is above that of BEN on average. This normally means power is flowing from

Figure 3.1: USI transmission system

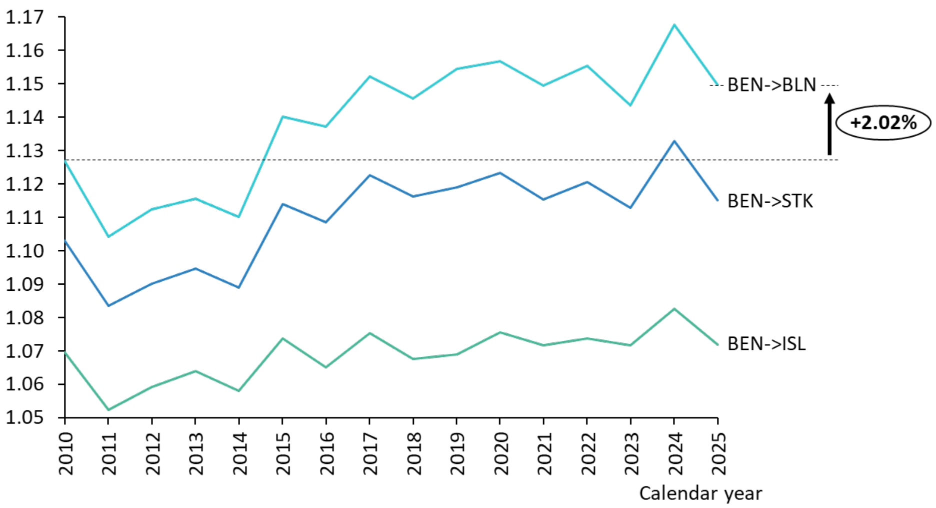


BEN to ISL, and the higher price at ISL reflects the impact of transmission losses and constraints.

Figure 3.2 shows that BEN to USI location factors have gradually increased through time, reflecting increasing energy imports as demand has grown.

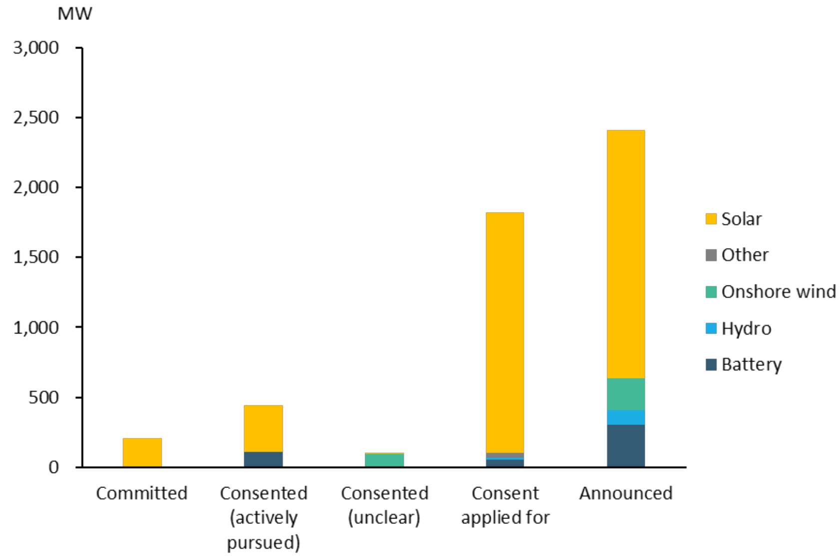
There was a pronounced dip in location factors in the early 2010s, when the Pike River mining disaster and the Christchurch earthquakes dampened demand.

Figure 3.2: Wholesale market spot price location factor annual averages from Benmore to Blenheim, Stoke and Islington nodes



Although there is considerable potential for new renewable generation in the region (mainly solar power, and some wind farms and grid-scale battery storage), few projects have been committed for development, as shown in Figure 3.3.

Figure 3.3: Pipeline of generation and storage projects in USI



Given this grid topology, the USI transmission grid has been affected by two main issues – one relating to summer demand and the other relating to winter demand:

- thermal capacity – line ratings are lowest in summer (when lines sag in the summer heat) and demand has been growing, including due to irrigation
- voltage stability – high winter demand challenges voltage stability in the upper South Island due to low levels of local generation and long distances to Waitaki Valley generation.[15]

Transpower has been closely monitoring summer thermal and winter voltage constraints and has made several 'tactical' voltage investments.

[15] Voltage falls away with distance from generation (or other voltage sources).

In its roles as system operator, Transpower also maintains a permanent voltage stability constraint that limits flow into the USI region to 1,330 MW.

3.1 Historical transmission investments

The transmission lines supplying the USI are part of the 'core grid', which means Transpower must adopt a 'N-1' planning standard – ie, supply must be robust to an unplanned outage in any single asset.[16]

3.1.1 Prior to the USI LMG

Around the time the USI LMG was formed, Transpower addressed voltage stability concerns by installing:

- a static VAR compensator (SVC) at Islington in 1996 (known as SVC3)
- a larger SVC at Islington (SVC9) and a shunt capacitor bank in 2010
- a Static Synchronous Compensator (STATCOM) at Kikiwa in 2010 (known as STC2).

In 2007, Transpower also made a strategic land purchase in Orari to help create an option to establish a new switching station that would connect nearby USI circuits. The switching station would provide redundant pathways for power flows, reducing the severity of voltage disturbances and enhancing power system reliability and resilience.

3.1.2 Since the USI LMG was established

In 2012, Transpower forecast a need for additional work to bolster USI voltage support by the winter of 2014.

The need was highly uncertain given the impact of Christchurch earthquakes and the Pike River coal mining disaster, offset by strongly growing (but summer-weighted) irrigation loads.

Transpower prepared a two-stage development plan:

- Stage 1 – fit a new bus coupler at Islington to address near term voltage stability risks and decommission end-of-life voltage stability equipment[17]
- Stage 2 – a more significant investment, potentially including a new transmission line between the Waitaki Valley and Christchurch.

In June 2012, Transpower submitted its USI Stage 1 proposal to the Commerce Commission for approval, which was granted in February 2013.

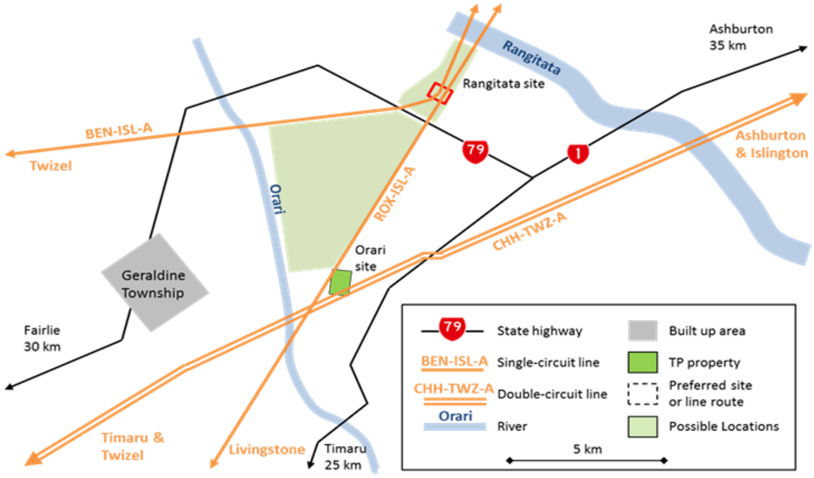
Transpower proceeded with a new bus coupler at Islington, 10 load monitoring units, protection work, and engineering studies.

Transpower then amended its proposal in 2014, and this was approved in 2015. The amended proposal added preparatory work for Stage 2, including investigating switching station options, and acquiring property rights and designations.

[16] Including any circuit, substation bus section, interconnecting transformer, shunt capacitor, HVDC pole or generator.

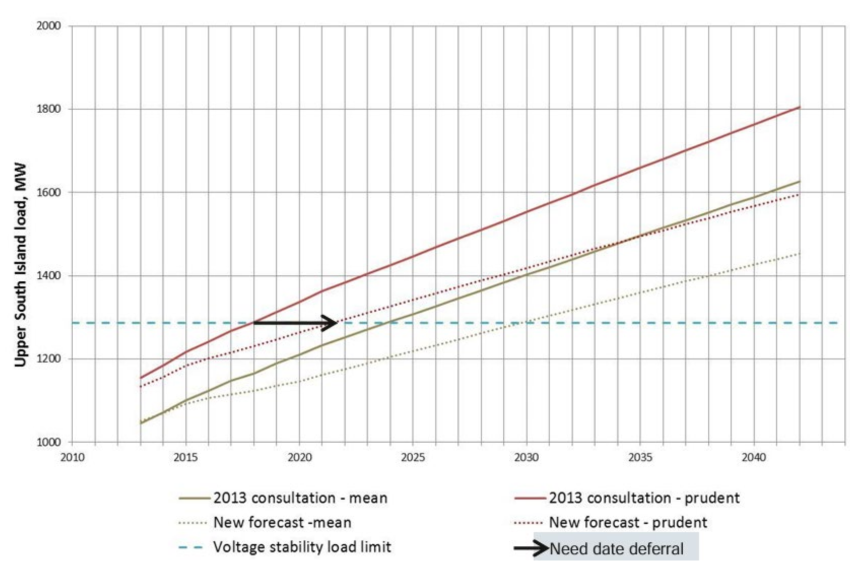
[17] In 2013, the Commerce Commission approved up to $5m for the bus coupler, installation of ten load monitoring units at substations in the Upper South Island and preliminary work for subsequent investments.

Figure 3.4: Potential Orari and Rangitata switching station locations



Transpower put further preparatory work for Stage 2 on hold, because its revised forecasts indicated the need date had receded beyond 2020, as shown in Figure 3.5.

Figure 3.5: Transpower's change in USI prudent peak demand[18] forecast in 2013 justifying Stage 2 deferral[19]

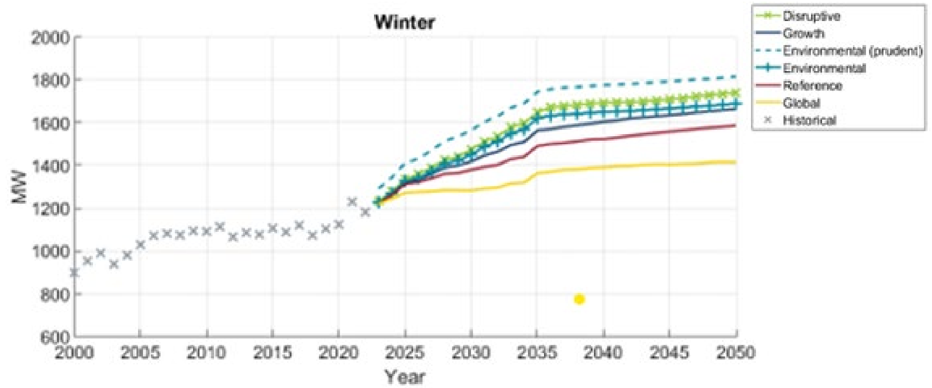


As shown in Figure 3.6, USI peak demand growth remained subdued throughout the 2010s, allowing Transpower to push out its assessed need date at each review.

18 For planning, Transpower uses a 'prudent' forecast of peak demand that has only a 10 percent chance of being exceeded. This is consistent with a view that the disruption associated with adding capacity too late would be more costly than the direct cost of adding capacity too early.

19 Transpower, Upper South Island Stage 2 Information Paper, page 6.

Figure 3.6: USI historic winter peak demand with Transpower's 2025 forecasts[20]



Alongside these investments for winter voltage stability, Transpower has been monitoring the need date for summer thermal capacity, which is influenced by growth in irrigation demand. The combination of load growth, and tactical investments to improve voltage stability, has seen the need dates for both investment drivers converge over time, as summarised in Table 3.1.

[20] Transpower, Upper South Island Major Capex Proposal Stage 1: Need, Demand and Generation Scenarios, August 2025, pg15 (image manipulated to include legend)

Table 3.1: Summary of USI voltage and transmission constraint need dates

Source	Voltage needs (winter)	Thermal need (summer)	Notes
2012 USI reliability proposal	2014		Urgent dynamic reactive power support need
2014 Annual Planning Report	~2020	Later than 2020	Voltage flagged as first binding issue for USI demand
2017 TPR (Transmission Planning Report)	2022	2030	Based on 2013 studies; outage sensitivities noted
2020 TPR	2027	2028	Deferral due to lower demand forecasts
2021 TPR	2030	2032	Need dates further extended due to softer load growth
2022 TPR	2026	2026[21]	Forecasts revised upward; Orari need date pulled forward.
2023 TPR	2027	2028	
2025 TPR	2028	2029	

3.1.3 Within-region investments

Over the past 15 years, regional transmission constraints within the USI have remained limited and have been generally manageable within the existing grid footprint.

Peak demand growth has been modest overall, and the regional grid has remained broadly adequate without major new regional projects. Where investment has occurred, it has typically been customer-led, incremental, or renewal-driven. Transpower's annual forecasts have consistently projected demand to grow within a similar band for several years, meaning grid planning has been identifying and monitoring the same risks over a prolonged period. Note that these peak demand forecasts are for 'prudent' peak demand, with a 10% chance of exceedance, equivalent to a P90 forecast. The forecasts are therefore inherently conservative in comparison to a midpoint (P50) estimate, since the consequences of not being able to meet load growth by underestimating demand are significant.

The LMG will have contributed to low peak demand-growth, helping to keep demand within voltage and thermal constraints. This will likely have reduced the need for and urgency of transmission investment.

West Coast

Peak demand on the West Coast has declined over time, particularly because of the closures of the Pike River mine (2012) and Holcim cement plant (2016). In 2012, Transpower completed the West Coast Grid Upgrade – a reliability- and voltage-driven project designed to improve security of supply to Greymouth and surrounding areas. These works incidentally increased transfer capacity into the region—though improving redundancy and voltage performance were the primary drivers of the project. While Transpower has been monitoring some more localised constraints, there has been minimal investment since those upgrades.

21 Under the "System Condition 1" scenario, which tests the impact of extremely low generation in the Upper South Island during a summer peak load period.

Nelson–Marlborough

Peak demand here has remained broadly flat. Capacity issues have been addressed through transformer upgrades at the time of replacement or customer-led investment. For example, Golden Bay constraints were resolved by renewing an existing transformer and customer investment in a further one at Tākaka. Voltage issues have been managed via the 2010 Kikiwa STATCOM investment and other incremental reactive support investments.

Canterbury (incl. South Canterbury)

Canterbury has seen some significant demand changes. The earthquakes have altered load flows around Christchurch and Islington, and rapid irrigation growth in Mid- and South Canterbury has created strong summer daytime loads stressing parts of the 110 kV network. Summertime constraints around Timaru have driven some of the largest investments Transpower has made in the last 15 years. Even so, Transpower's investments in Canterbury have generally been incremental rather than transformational – reconfiguring bus sections, upgrading transformers during renewals, refining protection schemes, and deploying shunt reactors or special protection schemes.

3.1.4 Value of historical deferrals

From the above, it is clear that Transpower has been close to committing to major investments to serve the USI region for some time. It has been able to avoid major investment due to a combination of:

- tactical investments that have provided relatively low-cost improvements to winter voltage stability limits
- demand shocks and subdued growth, which have kept demand below 'prudent' planning forecasts
- USI load management, which has flattened winter peak loadings on the three major transmission lines serving the USI region.

This has enabled major investment to be pushed back from the early to the late 2020s. In 2023, Transpower provided a 'notice of intention' to prepare an investment proposal for further USI investment. In late 2025, the Commerce Commission published a draft decision to approve the first stage of that further investment.[22]

The cost of the approved (in draft) investment is estimated as $193mi (in 2025 dollars) and Transpower is targeting completion in 2029 (switching stations) and 2030 (thermal upgrades and capacitors). Due to construction lead times, this is one year later than Transpower's projected 'prudent' need date.

The investments will address both summer (thermal) and winter (voltage) constraints for some time, but Transpower is anticipating further investment may be required from as early as 2033.

[22] This is different from the earlier 'stage one' and could be thought of as 'stage 2a' in terms of Transpower's earlier planning and regulatory processes.

Figure 3.7: Late 2020 investment – draft approval amounts

MCA component	Amount ($m 2025 unless otherwise stated)
Switching station at Orari	41.4
Switching station at Rangitata	29.8
Switching stations line turn-in connections	31.9
Thermal upgrade of the Norwood–Rangitata circuit to 90°C and Orari–Rangitata circuit to 100°C	50.1
2 x 75 Mvar shunt capacitor banks at Orari 220 kV	11.4
Automatic over-voltage shunt capacitor and shunt capacitor switching scheme	1.0
Investigation cost	1.5
P50 estimate of cost	167.0
Inflation related cost[135]	12.2 ($m nominal)
Interest During Construction (IDC)[136]	13.9 ($m nominal)
MCA (sum of P50 cost, inflation related cost and IDC)[137]	**193.0 ($m nominal)**

It is fair to expect that without the efforts of the USI LMG to manage peaks since 2009, Transpower would have been compelled to commit to this $193m investment before now.

In 2014, Transpower was projecting a six-year lead-in to the voltage need date. This contracted to five years by 2017, before extending out to nine years by 2021 and pulling back sharply to four years in 2023 – at which time Transpower issued its notice of intention.

If peak demand had been higher, Transpower would likely have committed to investment around 2017 with a target commissioning date of around 2021.[23]

Each year of deferral for a $193m project saves consumers around $11m.[24]

As this investment is now planned for 2028, the USI LMG's past actions have likely contributed to around seven years of saving around $11m per year.

3.2 Historical transmission charges

The deferral value identified above relates to the total revenue Transpower would have recovered from its customers each year. Prior to 2023, Transpower allocated its target revenue to customers using three types of charges:

- **HVDC** – used to recover the cost of the inter-Island link from South Island generators (ie, not paid by distributors)
- **connection** – used to recover the cost of connection spurs from the customers using each spur
- **interconnection** – used to recover the balance of Transpower's costs from offtake customers (including distributors).

Distributors can potentially reduce their connection charges by managing demand if they share a connection spur with another customer (eg, a generator). However, the connection pool is comparatively small, and this opportunity is relatively limited. As such, we have focussed on interconnection charges.

23 At this time, reducing the forecast lead-in by only one year (due to higher peak demand) would likely have prompted Transpower to commit given the four-year lead time from notice of intention to commissioned assets.

24 Based on a 39-year asset life and 5% financing rate, which translates into a capital recovery factor of around 6% per year.

Interconnection charges were Transpower's largest revenue pool and would have been used to recover any USI investments. Interconnection charges allocated costs based on each customer's contribution to peak demand in one of four pricing regions – ie, their regional coincident peak demand (RCPD).[25]

Under this arrangement:

- offtake customers (including distributors) could reduce their charges by reducing their demand during the relevant regional peak demand periods (ie, by reducing their RCPD)
- in the first instance, reducing RCPD reduces a customer's share of a fixed pool of costs. In other words, managing RCPD shifts costs to other offtake customers
- additionally, reducing RCPD may contribute to deferring transmission investment. Where this is the case, it will reduce costs for all customers (by limiting the growth of the interconnection pool).

Since the USI is a regional spur that imports energy from the rest of the grid, there was a reasonably good link between managing USI RCPD and helping defer investment – at least in terms of effect, if not in the strength of the signal.

We have used historical data to estimate the savings the USI LMG was able to achieve from 2019 to 2022 by reducing its members' contributions to USI RCPD.

To do this we have:

- used Orion's estimates of what uncontrolled load would have been for the relevant 100 half hours for each year
- scaled up the figures for Orion to estimate uncontrolled load across all USI LMG members for those periods
- compared the above with actual (controlled) demand figures
- compared the controlled and estimated uncontrolled demand figures to estimate the reduction in measured USI RCPD
- assuming RCPD values for the other four regions are unchanged, determined the reduction in interconnection charge for USI LMG members due to load control.

There are two effects to account for in this analysis:

1. if RCPD were higher in the USI region then the interconnection rate ($ per MW of RCPD) would be slightly lower[26]
2. the reduced interconnection rate would be multiplied by larger RCPD values for each USI LMG member.

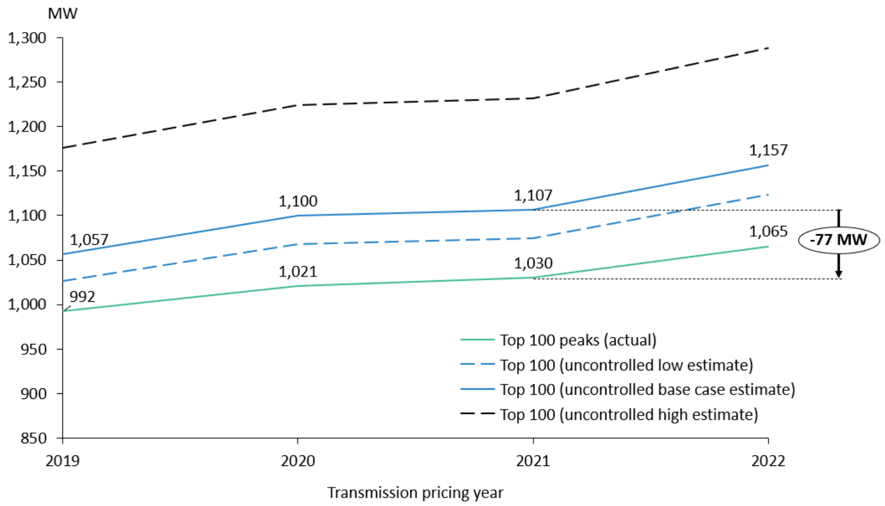
The net result is that USI LMG members would pay more without load control and all other transmission customers would pay less.

Our findings are summarised in Figure 3.8 and Figure 3.9 and Table 3.2 below.

[25] Demand is measured during a 'capacity measurement period' or CMP. CMPs begin on 1 September in year X-2 and finish on 31 August in year X-1 for transmission prices set from 1 April in pricing year X. The CMP ending Augst 2016 was the last to use 12 peaks for the USI region. From September 2017 RCPD for all regions was measured on the top 100 peaks.

[26] The interconnection rate is Transpower's target revenue for the year divided by the sum of all RCPD measures. If RCPD is higher than the rate is lower (ie, target revenue is spread across a larger RCPD total).

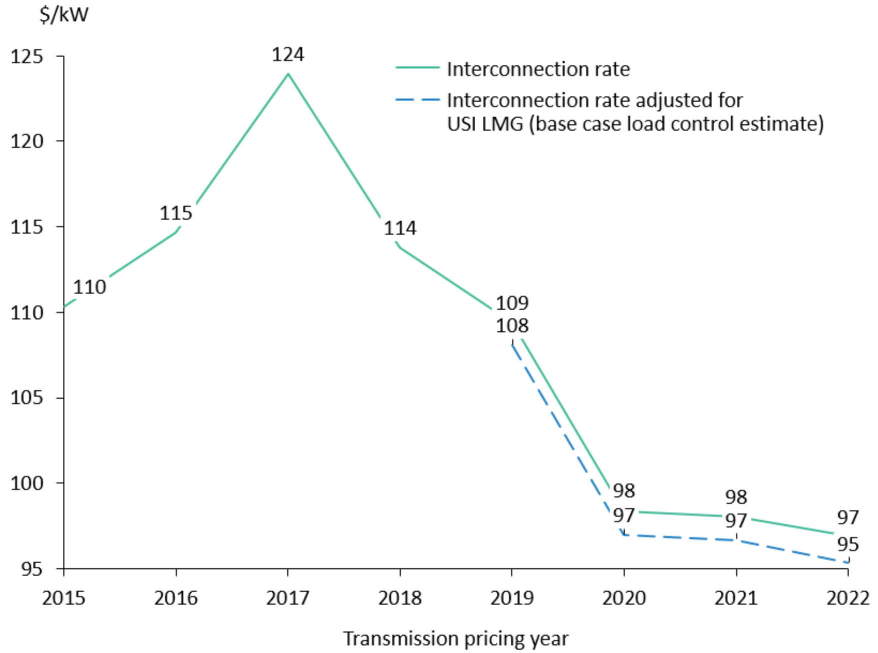
Figure 3.8: Estimated RCPD reductions due to USI LMG control



First, we see that (based on our base case estimate of uncontrolled load) the USI LMG has delivered around 65 MW to 90 MW in annual RCPD reductions.

The interconnection rate varied over time (with changes in Transpower's target revenue and in RCPD measures) and we have estimated how it would have been reduced if USI RCPD were higher.

Figure 3.9: Transpower interconnection rates



Putting these two inputs together, we estimate average savings from 2019 to 2022 ranging from $9m to $10m per year in 2025-dollar terms. For years from 2015 to 2018 we do not have USI data, so have scaled the 2019 figure for the published interconnection rate.

Table 3.2: Interconnection charge savings estimates

Pricing year (starting 1 April)	Savings ($m, nominal)	Savings ($m, 2025 dollars)
2015	7.0	9.4
2016	8.1	10.7
2017	8.5	11.0
2018	9.1	11.7
2019	7.0	8.8
2020	7.7	9.5
2021	7.4	9.0
2022	8.7	9.8
Average	-	10.0

For the period from 2015 to 2022, the average reduction in transmission costs allocated to USI LMG members was $10m per year in 2025-dollar terms.

3.3 Summary (historical transmission)

We have estimated the value of two historical transmission-related value streams. These are related but not additive:

1. deferral benefit – for each of the seven years from 2021 until 2027, the LMG has plausibly contributed to deferring transmission investment with an annualised cost of around $11m. This represents an economic benefit that will have reduced transmission charges for consumers nationwide
2. charge reduction – up until the TPM changed in 2023, the LMG members were able to reduce their share of transmission charges by around $10m each year. These actions align with delivering the economic benefit, though the savings and the benefit do not match year-to-year (or in aggregate).

4 Transmission – current

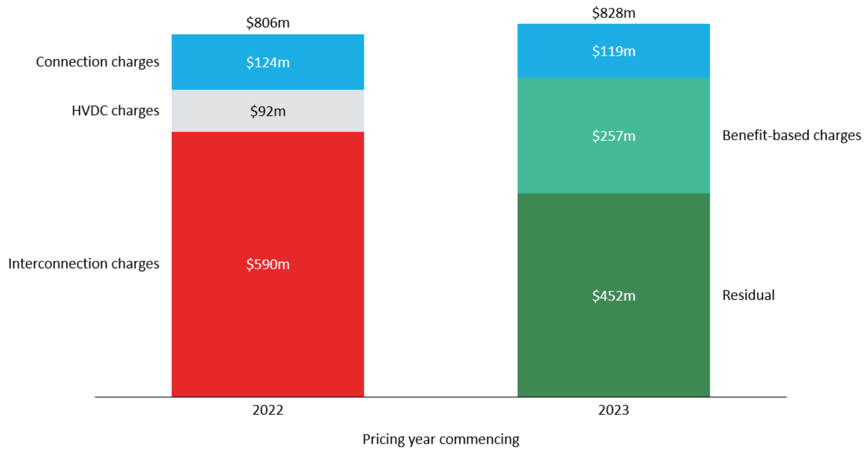
4.1 Current charges

Since April 2023, interconnection (and HVDC) charges have been replaced with two new types of charges:

- benefit-based charges (BBCs) – used to recover the cost of each investment from the parties assessed as being most likely to benefit from the investment (eg, from improved reliability, lower energy prices or, for generators, increased revenue)
- residual charges – used to recover remaining (residual) costs.

Figure 4.1 shows how Transpower's revenue recovery shifted with the introduction of the new pricing methodology.

Figure 4.1: HVDC and interconnection have been replaced with benefit-based and residual charges



Note that:

- connection charges are largely unchanged
- the BBC pool will grow over time, and the residual pool will decline – ie, as Transpower invests in grid asset renewals and additions.

4.1.1 Benefit-based charges

There are three types of BBCs:

- Appendix A – seven investments made before the new TPM came into effect. Customer allocations for these projects were determined through bespoke analysis at that time
- large investments – any post-2019 investment with a commissioned value of $30m or more is allocated using a 'standard method' assessment of who is expected to benefit
- smaller investments – smaller investments (which collectively are worth $100s of millions each year) are allocated using pre-determined 'simple method' allocators that are refreshed every five years.

Appendix A investments

The seven transmission projects with allocators determined prior to the new TPM are:

- Bunnythorpe-Haywards conductor replacement project
- HVDC investments before 2019
- Lower South Island reliability project
- Lower South Island renewables project
- North Island Grid Upgrade
- Upper North Island Dynamic Reactive Support Investment
- Wairakei Ring (C line) upgrade

The 'covered cost' for these projects was $206m for the 2023 pricing year, or just under 25% of Transpower's total revenue. USI LMG members pay around 7% of the Appendix A BBI charges ($15m in 2023).

The Appendix A allocations were based on market modelling using generation, demand and price data from July 2014 to June 2018.[27] As such, the actions of the USI LMG through that period are likely to have reduced members' allocations, and hence the charges paid today (and into the future) for those investments.

The market modelling is complex and detailed, so we have not attempted to reproduce it to test the impact of USI load control. However, as the current allocation is $15m and USI load control reduces peak demand on the order of 7%, the value is likely to be significantly less than $1m per year (and will decline each year as Appendix A assets depreciate).

[27] See Appendix A of TPM decision paper.

Standard method BBC (high value investments)

Larger post-2019 investments are allocated using bespoke forward-looking analysis carried out prior to each investment, known as the 'standard method.' For every transmission investment with an expected cost of more than $30m, a model is run with factual (ie, a world with the investment) and counterfactual scenarios (a world without the investment).

For 'resiliency' investments, the focus for benefits estimation is on reduced likelihood of interruption.

For 'economic' investments, the focus is on beneficial changes in wholesale market revenue (for generators) and energy purchase costs (for load).

Comparing scenarios with and without the transmission asset allows Transpower to estimate how much consumers and producers upstream and downstream of the investment are likely to benefit – eg, from lower risk of curtailment, from lower peak energy prices, or from lower energy prices at other times (eg, in dry conditions).

'Intra-regional' allocators are then determined based on each customer's share of upstream and downstream injection or offtake. Allocators may be based on coincident peak demand or mean demand, depending on the nature of the benefits delivered by the project. In either case, allocators are based on demand measured over the five years preceding the analysis.

Once determined, allocators are fixed for the life of the assets, unless specified reopener events occur (such as the exit of a customer).

Overall:

- the value of standard method BBCs remains low, at less than $12m nationwide in 2025[28]
- the share paid by USI consumers is lower again, and we do not think the LMG actions will have materially altered the share allocated to LMG members (noting allocated investments to date have been weighted toward energy benefits and Upper North Island reliability).

Simple method (lower value investments)

The cost of lower value investments is recovered using allocators that are fixed and updated each five years.[29]

Most of Transpower's investment is a high-volume of lower-value projects and programmes, so the portion of Transpower's costs allocated using the simple method has been growing rapidly – from $48m in 2023 to $90m in 2025.

Table 4.1summarises the relationship between measurement periods and allocations.

Table 4.1: Interconnection charge savings estimates

Investments in years…	…are allocated based on grid flows measured in years…
April 2022 to March 2027	September 2016 to August 2021
April 2028 to March 2033	September 2021 to August 2026

Transpower's simple method investments to date have been allocated based on grid flows measured in the five years to August 2021. Costs are allocated:

- between regions based on flows
- between customers within each region based on mean demand.

28 See Transmission pricing rates table April 2026.pdf
29 Updated allocators are then assigned to new investments. Each investment retains the allocators in force at the time the investment was made.

The LMG's actions impact how much power flows into the USI region, but do not change the direction of flows. Likewise, they do not materially alter mean demand. As such, we do not think the LMG actions will have had a material impact on its member's shares of the $90m (and growing) simple BBC pool.

4.1.2 Residual charge

Residual charges recover the balance of Transpower's costs – ie, those not collected through connection or benefit-based charges.

In 2023, the residual pool made up more than half of Transpower's total revenue. As more assets transfer into the benefit-based pool each year, the residual pool is shrinking (as a share of Transpower's revenue).

Residual charges were initially set for all existing transmission customers based on their anytime peak demand (across all their connection locations) averaged over the four years from July 2014. This provides a 'baseline' for allocation, and the baselines are updated annual based on lagged measures of gross energy consumption. The baseline is referred to as a customer's AMDR.[30]

The LMG's actions will have impacted baseline measures but will not alter the effect of the annual adjustments. As such:

- load control from 2014 to 2018 will have produced a lower baseline for the LMG members
- this will produce an enduring benefit, regardless of whether the LMG continues to manage peak demand
- the benefit will gradually decline as the residual pool shrinks.[31]

The historical data available to us (beginning calendar year 2018) only allows us to analyse part of the final baseline year and only provides full 'with and without' information for Orion's network. However, it indicates the LMG's actions would likely have reduced anytime maximum demand for the USI region as a whole in that year by many tens of MWs.

AMDR reflects each individual distribution customer's peak demand, so a single half hour of high local demand at a time outside of the regional peak would undo any benefit from the USI LMG (for that distributor).

The residual charge started at $53/kW in 2023 and stepped up as a reset of Transpower's allowable return has flowed into pricing. From 2026, the rate is $77/kW.[32]

In recognition that individual anytime peaks would have been less impacted by USI LMG than regional coincident peaks (averaged over 100 periods), we think it is prudent to assume the LMG may have reduced the sum of its members' baseline AMDRs by around 40 MW.

Table 4.2 summarises estimated savings for each year for which Transpower has published residual rates.

Table 4.2: Estimated residual charge savings (assuming 40 MW reduction in AMDR baseline values)

Pricing year (starting 1 April)	Savings ($m, nominal)	Savings ($m, 2025 dollars)
2023	2.1	2.3
2024	2.2	2.2
2025	2.5	2.5
2026	3.1	3.0

30 This is to distinguish the baseline from AMDC, which is the annual anytime maximum demand at a connection location used for determining connection charges.
31 A customer's share of the residual pool may increase over time if gross energy demand is increasing on their network, but the benefit of a lower baseline persists.
32 Transpower's allowable return stepped up from 4.57% to 7.1% in 2025 and will reset again (up or down) in 2030 to reflect the cost of capital at that time. The 2025 step-up has in the near-term obscured the long-term trend of a shrinking residual pool.

4.2 Summary (current transmission)

The main way in which the LMG's actions have likely impacted its current charges is by reducing the baselines used for allocating residual charges.

This benefit will endure independently of any further action but will decline over decades as Transpower's residual pool shrinks. We estimate this is currently saving the LMG members on the order of $2.5m per year.

5 Transmission – prospective

This section discusses three key investment programmes:

- committed major upgrades
- potential further major upgrades
- smaller regional investments.

5.1 Committed major upgrades

Transpower has draft approval to invest up to $193m to upgrade supply into the USI over the next few years. This investment can essentially be treated as committed, so its timing cannot realistically be deferred further by the USI LMG.

Based on its 'prudent' demand forecast, Transpower forecasts a need date of 2027 for the first stage of the work but expects to complete and commission the related work in 2028.

The prudent forecast is a deliberately pessimistic (high growth) forecast intended to ensure prudently conservative planning. As such, it is likely that 2028 will prove to be acceptable timing.

However, the prudent forecast does assume continued operation of the LMG at its current level. This means that:

- if the LMG were to cease operation, this would increase risk in the lead-up to commissioning Transpower's upgrades
- the ability for the LMG to deliver larger load reductions could be valuable if demand growth trends high or if Transpower experiences delays commissioning the upgrades.

In addition, until the upgrades are commissioned there is heightened risk associated with loss of ripple control resource. The biggest potential drivers of resource loss are:

- electricians disabling ripple control relays, as is relatively common when installing rooftop solar
- failure to execute a commercial platform to access next-generation hot water and electric vehicle control.

5.2 Potential further major upgrades

Transpower anticipates that, as demand grows, there will be a need for further major upgrades in the 2030s and 2040s to increase capacity into the USI region.

Table 5.1 summarises the forecast cost and sequencing of the potential investments, and associated deferral values. The overall value of the further investment is similar to the planned late 2020s investments.

Table 5.1: Deferral value associated with further major upgrades (2025-dollar terms)

Component	Year	Cost $m	Deferral value (individual) $m	Deferral value (cumulative) $m
Thermal upgrade Opihi-Twizel	2033	17.0	0.9	0.9
STATCOM Ashburton	2033	67.2	3.7	4.7
Thermal upgrade Rangitata-Tekapo B	2035	25.3	1.4	6.1
Shunt capacitor - Ashburton	2035	11.8	0.7	6.7
Thermal upgrade Ashburton-Orari	2043	19.2	1.1	7.8
STATCOM-Orari	2046	62.1	3.4	11.3
Total		202.6		

This indicates that:

- from 2033, actions that defer investment could be worth $5m or more for each year of deferral
- from 2046, if all investments were still being deferred, the value could have climbed to around $11m for each year of deferral.

Transpower's forecasts assume that the LMG will continue to operate and continue to deliver similar levels of response as today.

We do not think this is a sound assumption, unless distributers develop and execute suitable commercial platforms for accessing next generation load control. In particular:

- the installed base of ripple-controlled appliances is likely to have declined markedly by the mid-2030s as ripple relays are either bypassed or displaced by next-generation load control
- absent suitable commercial mechanisms, next generation load control will predominantly target nodal price signals
- as renewable penetration increases, the correlation between high nodal prices and peak demand will decline (see analysis at Figure 6.1)
- in any event, price separation tends to arrive too late to influence the timing of transmission investments given their long lead times. This can be seen in the relatively benign movement in location factors ahead of Transpower committing to the late 2020s investments (as per Figure 3.2)
- retailers are not incentivised to defer benefit-based transmission charges, as these are allocated in a competitively neutral way across retail books at a given location.

In terms of prospective benefits, this means that:

- a poorly managed transition to next-generation load control could bring forward the 2030s investments, at a cost of more than $5m per year
- a well-managed transition could potentially avoid this cost and sustain deferral benefits into the early 2040s.

Under the current TPM, these costs and benefits would predominantly fall on consumers (via their distributors) in the USI region (ie, the expected beneficiaries).

5.3 Within-region investments

Transpower's 2025 Transmission Planning Report indicates that future regional investment will remain largely incremental. Planned or potential works include:

- transformer upgrades at the time of renewal at Islington, Bromley, Studholme, Kikiwa, and Dobson
- continued reactive-power and voltage-control investments across Nelson–Marlborough and the West Coast, including small shunt devices and mid-life refurbishment of the Kikiwa STATCOM
- thermal and substation upgrades being considered in Timaru to maintain security of supply given growing irrigation demand in South Canterbury
- potential reactive support and protection improvements around Hokitika
- post-contingent demand-management schemes to manage planned outages in Canterbury.

These are generally low-regret incremental developments involving tactical upgrades as lifecycle investments arise, plus use of operational tools to incrementally sustain or enhance security. As such there are not material deferral opportunities associated with these plans.

In addition to these Transpower-led investments, there are a number of potential customer-led projects in the planning horizon. These include possible new grid exit points (GXPs) at Brightwater (Tasman) and Orari (South Canterbury) that would allow distributors to relocate load and improve flexibility.

Transpower is also signalling the potential for two larger regional investments:

- North Canterbury / Waimakariri interconnection: A proposed 220/66 kV substation north of Christchurch, near Waipara or the Waimakariri River, to strengthen supply and reduce reliance on Islington by 2032. The driver is gradual demand redistribution north of the city, which is eroding system security under n-1 conditions
- Nelson-Tasman reliability improvements via upgrades at Stoke: Transpower is considering installing a second 220/110 kV transformer and a new bus-section circuit breaker at Stoke to strengthen supply security and improve operational flexibility for the Nelson–Tasman area. The additional transformer would provide n-1 redundancy and support increasing load in the region, while the bus-section breaker would allow greater isolation during maintenance or faults.

These upgrades are driven by load growth from greenfield residential development, in which new demand emerges in concentrated locations.

The rate at which greenfield residential growth translates into a need for transmission investment will depend on the extent to which new dwellings participate in network load control – both for hot water and electric vehicle charging. This in turn will depend on how successfully distributors:

- develop and execute commercial models for accessing next generation load management, and
- in the interim, continue to successfully implement recruitment into ripple-based load management.

5.4 NTS mechanism

In its draft decision on the late 2020s investments, the Commission indicates that it intends to approve $7m of funding for developing and implementing 'non-transmission solutions' – that is, initiatives that defer the need to invest in transmission assets.

In the early 2010s, Transpower similarly had non-transmission solution funding that it used for a demand response investigation and development programme. This included dedicated staff within Transpower, a demand response platform and trial purchases of demand response from various types of end users. Conclusions from this work included that procuring demand response was generally (at the time) more costly than implementing special protection schemes or other tactical improvements to the transmission system.

In contrast, Transpower has proposed a more transactional approach for its current round of NTS funding. It plans to run two rounds of tenders aimed at procuring sufficient response to enable at least one year of deferral.

This may risk repeating a common failing, which is that the time it takes to develop and 'prove up' response capability within a given network is not compatible with a procurement approach that attempts to transact with high confidence at a point in time.

Given hot water control is the largest and most dependable source of demand response, there is also a risk that any successful response would rely on large-scale displacement of ripple control with next-generation control.

In our view, there would be merit in Transpower adopting a hybrid approach to its current NTS funding that includes:

- a development programme focussed on working with the LMG and its members to support successful transition to next generation load control. This could include work to sustain ripple control in the interim, while helping develop and execute a commercial model for next generation hot water and electric vehicle control
- within the context of the commercial model, trialling access to T2 network deferral response (see Figure 2.6).

This approach would help safeguard the level of response Transpower has assumed into its planning, while developing the framework for extended access to key load management resource (ie, hot water and electric vehicle charging).

6 Generation

6.1 Introduction

Hot-water load management can help reduce the cost of energy by shifting electricity use away from periods when generation is tight and towards times when it is more abundant. This can:

- reduce reliance on higher-cost thermal generation
- reduce fuel use and emissions
- defer the need for additional peak generation capacity
- reduce wholesale spot prices, including at nodes serving the USI region.

These effects show up directly in wholesale prices, which are highest when generation is tight.

The LMG's ripple-control actions reduce demand during some of these higher-priced periods. This can have two effects:

- direct wholesale cost savings for the controlled hot-water load, as heating is shifted from high price periods to lower price periods
- broader price effects, whereby lowering peak demand reduces wholesale prices for all load during those periods (with some offset from increased prices when heating is turned back on).

At present, these benefits are not monetised (or targeted) by the LMG. Instead:

- they accrue automatically to retailers, through lower wholesale purchase costs; and
- may flow on to consumers, depending on tariff structures and retail pass-through.

Because ripple control targets network peaks, any overlap with high-price periods occurs incidentally, rather than through targeting wholesale-market value.

Looking ahead, the wholesale-market value of flexible demand is expected to grow as supply becomes more variable with increasing wind and solar generation. Retailers are already developing next-generation load-management platforms that seek to capture this value more directly by timing control actions to coincide with high-price intervals. These trends present both opportunities and complications for the LMG.

The sections below discuss historical wholesale market value, estimate prospective value, and consider how opportunities to recognise and monetise this value may change over time.

6.2 Historical benefit

We have not estimated generation savings from historical load control because Orion has prepared preliminary analysis of this already.

According to Orion:

> "Orion ran simulations of hot water ripple control using EA's vSPD model to produce conservative, high-level estimates of the potential value of using Orion/USI's existing control capability to reduce systemic wholesale electricity costs. The simulations applied a flat 40 MW reduction in demand at Islington across six months in 2024/25 (August 2024, and January, February, May, June and July 2025) to capture a range of market conditions. Note that as this exercise was intended to give a high-level value estimate, it excludes modelling of the hot water ripple control turning back on.
>
> The 40 MW figure was chosen as a conservative estimate of controllable load available to the USI at any given time. Orion considers 40 MW to be conservative, as the USI's available hot water load at peak is currently estimated to be 140 MW. To reflect a realistic operating scenario, days where network shed exceeded 0% were excluded from the simulation, on the basis that control would be prioritised for distribution and transmission peak

management. Given the unusually extreme market conditions in August 2024, results were produced both including and excluding that month.

From these simulations, the top 10% of trading periods (890 in total) were selected based on a value metric defined as nodal spot price multiplied by systemic demand. Using this metric, the estimated value of control at Islington as the pricing node was $128m, or $110m when excluding August 2024. Using Otahuhu as the pricing node, the corresponding values were $104m, or $91m excluding August 2024. These results indicate that even under conservative assumptions, existing ripple control capability has the potential to deliver material reductions in wholesale system costs, particularly during high-value trading periods."

We note that this analysis is, in effect, testing how much could have been saved had hot water control been extended to operate on more days (rather than quantifying what was actually saved as a byproduct of network load management).

Overall, we consider Orion's approach is useful and agree that vSPD is a robust and appropriate tool for assessing the impacts of changes in demand on wholesale price outcomes.

We understand Orion may develop and refines its analysis, in which case we:

- agree a 40 MW reduction is a reasonable (and likely conservative) assumption for controllable load on days where ripple control is not used for network purposes
- recommend extending the timeframe analysed, noting the system was unusually tight and had elevated prices over the analysis period
- note that the analysis assumes perfect foresight in targeting high-value periods. This is likely optimistic given operational realities
- recommend adding turn-on effects as another important extension. These cannot be assumed to be negligible at times when energy supply is tight (ie, when hydro lakes or thermal fuel supplies are low)
- recommend also estimating the value of incidental wholesale benefits on days when ripple control was used for network purposes (ie, by adding back the controlled load).

6.3 Prospective benefit

We have used two analytical tools to estimate future energy cost savings that the LMG could deliver:

- Concept's proprietary forecasts of future wholesale prices. These are based on simulating the expansion and future operation of the power system and include hourly prices across dozens of weather scenarios for each forecast year[33]
- linear regressions estimating the price impact of various levels of demand reduction (or increase). The regressions are based on analysis of our forecast prices, so reflect our view of how the power system will evolve over time.

Using these tools, we have estimated the value from load management associated with:

- the direct benefit of shifting water heating from higher to lower priced periods (ie, reducing the cost of water heating)
- the additional benefit that arises from altering prices (by removing and adding demand) for all consumption.

We have repeated each analysis for the forecast state of the power system in 2028 and 2035.

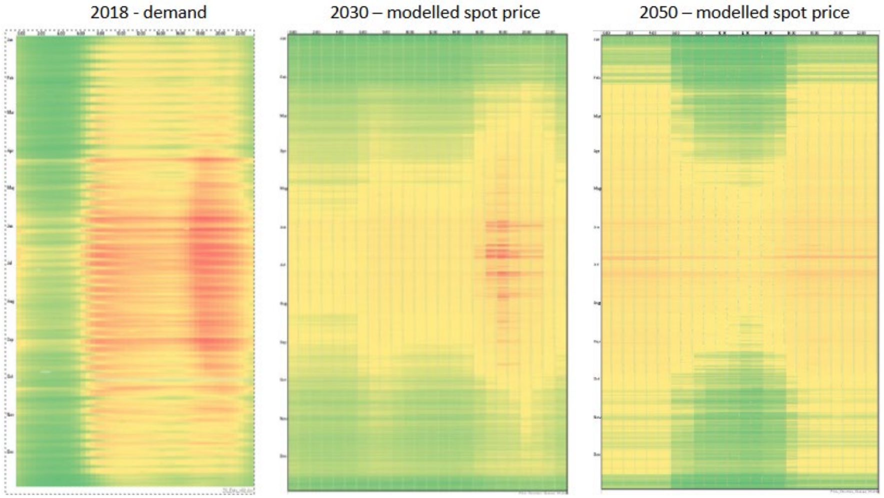
Three key changes in the power system between 2028 and 2035 are:

[33] We simulate 43 'weather years', which are combinations of temperature, sunshine, wind and precipitation. These have a major impact on prices in New Zealand's highly renewables-based power system.

- a significant increase in electric vehicle charging demand. This is assumed to be weighted toward evenings[34]
- further significant increases in wind and solar as a share of total generation. This reduces the share of controllable generation (such as hydro)
- increases in stationary batteries. These smooth out much (but not all) of the within-day variation in wind and solar production.

Figure 6.1 helps visualise how this impacts the timing of high price periods (within days and across the seasons).

Figure 6.1: Colour plots of spot prices by time of day (horizontal) and time of year (vertical) in 2018 (actual) and modelled years



Note that in this visualisation:

- relatively high-priced periods are shown in red, and relatively low-priced periods are shown in green
- colour relativities apply within each plot only (not between plots)
- prices are an average across all weather years.

The visualisations show:

- currently, prices are consistently low overnight, moderate during the day, and highest in mornings and evenings. Prices are highest in winter and shoulder months
- by the 2030s, prices are more consistently lower during summer months (when solar production is high) and peak prices are increasingly concentrated in a small proportion of winter evening peaks
- by the 2050s, high prices have become less centred on evening peaks and occur at any time (day or night) in the winter.

This represents a growing disconnect between peak demand (which remains centred on cold winter nights) and peak prices that occur when renewable production is low.

6.3.1 Direct benefit (cheaper heating)

Table 6.1 summarises estimates of the direct benefit of shifting water heating from higher to lower priced periods. It includes estimates for 2028 and 2035, for winter, summer and shoulder months, and for three levels of load shifting.

[34] We assume that, in the 2030s, around one-third of electric vehicle demand is load managed.

Table 6.1: Estimated direct impact on water heating costs (unit cost)

$/MWh (2025 dollars)		Morning			Evening		
Load shifted		**50 MW**	**100 MW**	**140 MW**	**50 MW**	**100 MW**	**140 MW**
2028	**Winter**	52	48	46	82	76	71
	Shoulder	39	36	34	8	4	1
	Summer	12	9	7	-15	-19	-22
2035	**Winter**	73	69	66	162	150	141
	Shoulder	49	47	45	20	15	10
	Summer	23	20	18	-20	-23	-25

Note that our analysis:

- provides results that are the average across all the simulated weather years – from cold to warm, wet to dry, etc
- uses forecasts that do not attempt to simulate within-island location factors (that is, the effect of future transmission constraints on regional prices). If USI transmission capacity were severely constrained, then we would expect this to increase the available value
- assumes a simple regime of deferring one hour of morning (from 8am) and evening (from 6pm) heating by four-hours (to midday and late evening).

Some observations from this analysis are that:

- load management is most valuable in winter months and shoulder months, and may actually increase the cost of water heating (on average) in summer evenings[35]
- the cost saving per unit of heating declines with larger control volumes. This is because a larger volume of deferred heating has a larger impact on off peak price levels.

Table 6.2 summarises annual savings for our base case scenario, in which 80 MW of load is managed across the LMG.

Table 6.2: Estimated direct savings in water heating costs (annual saving from shifting 80 MW twice daily)

Year	**Season**	**Value ($m, 2025 dollars)**
2028	Winter	1.0
	Shoulder	0.6
	Total	**1.6**
2035	Winter	1.7
	Shoulder	1.0
	Total	**2.6**

Note that this analysis assumes load is managed every day for three winter months and six shoulder months. The estimated direct saving per year (ie, from lower heating costs) is $1.6m in 2028, increasing to $2.6m by 2035.

35 Drivers for this outcome include that the through-day demand profile is comparatively flat in summer and that summer evening prices will increasingly be suppressed by high solar output. A positive outcome could be achieved by controlling mornings only, or by more actively managing the timing of reductions and restoration.

6.3.2 Indirect benefit (lower prices)

In addition to directly reducing the cost of water heating (by shifting heating to cheaper off-peak periods), load management can impact the prices paid for electricity consumption.

Load shifting reduces prices in the load reduction period and increases them in the load restoration period. If demand in the reduction period is higher than demand in the restoration period, then this produces a net reduction in electricity purchase costs.

Absent severe transmission constraints, nodal prices move together nationwide such that reducing demand in the Upper South Island will tend to reduce prices everywhere.

Table 6.3 summarises annual savings for our base case scenario.

Table 6.3: Estimated indirect savings (annual saving from shifting 80 MW twice daily)

$m (2025 dollars)	Region	
Year	**Upper South Island**	**All of New Zealand**
2028	3	21
2035	4	30

Note that the regression-based analysis used for these estimates is a relatively simple approach that does not fully account for how the power system may respond to repeated load management of this nature (for example, by building less peaking generation or batteries).

Nonetheless, the analysis indicates that the potential consumer benefits are large at more than $20m per year from 2028 (across all New Zealand electricity consumers).

6.4 Commercial model for generation benefits

The LMG coordinates load management for network purposes. This incidentally delivers direct energy cost benefits for USI consumers, and indirect energy cost benefits for all consumers (including in the USI region).

As such, the LMG is currently delivering only a fraction of the consumer benefit that could be delivered if the resource were used more extensively.

Unlike transmission costs, energy costs do not flow through distribution businesses – they are a direct input cost for retailers alongside network costs.

In theory, this means that retailers should be incentivised to procure (or deliver) load management directly. This would reduce a retailer’s input costs, allowing it to increase its margin (or simply stay competitive with other retailers).

However, ripple control is a ‘broadcast’ technology that cannot be used to target an individual retailer’s customers. This means a retailer paying for ripple control would be paying to reduce both its own input costs and the input costs of its competitors. In other words, there is a ‘free rider’ problem that removes the incentive for retailer to procure ripple-based load management.

This problem does not exist for next-generation load management, which can target individual properties – ie, retailers will be incentivised to use next generation load management.[36]

[36] There is still a free-riding dynamic for the indirect benefits of load management (ie, price effects) but these are incidental to the direct benefits (ie, cheaper water heating).

This creates a dynamic where energy cost benefits are unlikely to be delivered from ripple unless distributors opt to target them.

6.5 Emergency Reserve Scheme

The Electricity Authority is currently developing a new Emergency Reserve Scheme (ERS) in consultation with the System Operator and wider industry.

The scheme is intended to give the System Operator access to additional supply or demand response during rare, high-impact events where the power system risks running short of generation. ERS would allow the System Operator to contract for response that can be delivered at short notice to help avoid involuntary load shedding.

The Authority's decision paper describes 'the use of EDB controllable load' as a 'business-as-usual' mechanism that would be fully deployed before calling on emergency reserves – in other words, the intent appears to be to exclude the resources controlled by the LMG from the emergency reserve scheme.[37]

In our view, excluding all distributor controllable load may be misplaced. As with transmission capacity planning, it is appropriate to recognise that distributor controllable load is not a fixed or enduring resource that should be treated as built into baseline assumptions. Instead, the ERS could play a role alongside the USI NTS in:

- supporting investment to sustain response from ripple-controlled properties, including through awareness and education initiatives for electricians and solar installers
- developing the commercial model and technical integrations that support a transition to next generation load management without transitory loss of response volumes
- obtaining access to residual capability (beyond a distributor's own emergency and T1 needs) for ERS deployment.

[37] See 'activation' in Table 1 of Emergency reserve scheme decision paper. We note that it is not entirely clear this signalled intent has been carried through in the wording of the Code amendment.

7 Stability and operations

In its role as System Operator, Transpower procures various ‘ancillary services’ that work alongside the wholesale market to keep the power system stable.

The instantaneous reserve ancillary service is used to procure standby generation and load control resources and can be supplied by ripple controlled hot water.[38]

7.1 Instantaneous reserve ancillary service

Instantaneous reserve is supply that is available at very short notice to support the electricity system in the event of an unexpected outage of the largest supply resource in a given island.

Instantaneous reserve is divided into two classes: Fast Instantaneous Reserve (FIR), which must respond within one or six seconds (depending on the provider’s installation) of a frequency drop and hold output (or reduced demand) for up to one minute, and Sustained Instantaneous Reserve (SIR), which must respond within one minute and last for up to fifteen minutes while slower-acting generation adjusts. A single resource can often provide both classes if it can act quickly and sustain that action for the required period.

Instantaneous reserve is often provided by hydro or thermal generation that can ramp up generation very quickly. However, it is also well suited to load that can be switched off quickly such as ripple-controlled hot water. In principle, aggregated ripple-controlled load could deliver both FIR and SIR by switching off in response to a frequency event and remaining off until the system stabilises. There is no minimum size threshold for providing instantaneous reserves.

Instantaneous reserve receives an availability payment (in $/MWh) to be on standby. If it is called on, it also receives the wholesale price for any generation provided (or avoids the wholesale price for any load reduction).

The System Operator monitors providers of instantaneous reserve to ensure they comply with their obligations when called on and penalties can apply for non-compliance.

Historically, reserve prices have been much lower than wholesale energy prices – typically a few dollars per MWh compared with hundreds per MWh for energy. This reflects that the frequency of events is low and the cost of being available is relatively small.

Reserve prices tend to be lower in the South Island, because the required quantity is lower and can readily be supplied by low-cost hydro. However, during tight supply conditions (such as very cold winter evenings) reserve prices can rise sharply and, at times, equal energy prices. This volatility reflects the co-optimisation of reserves and energy in the market: when capacity is scarce, the opportunity cost of being held back for reserves increases.

Looking ahead, battery energy-storage systems (BESS) could become the dominant providers of instantaneous reserve – though we are not currently aware of any specific investments being considered in the South Island.[39]

Batteries can respond almost instantaneously and have very low marginal costs at times, making them well suited to providing the service. As more battery capacity is added, potential earning from providing instantaneous reserves is likely to decline.

[38] Ripple control is not suited to providing other ancillary services (black start, over-frequency reserve and voltage support).

[39] Some South Island solar farm developments are considering battery storage, but we are not aware of any standalone battery developments in the South Island. Note also that reserves can be provided into the South Island from the North Island via the HVDC link. Thus, North Island BESS investments could also compete for South Island reserves.

7.1.1 Potential revenues from instantaneous reserves

The amount of FIR and SIR procured depends on the size of the risk setter in each island – that is, the largest single source of energy. In the South Island this is usually one of the 120 MW hydro unit at Manapouri. However, if hydro lakes are low then south flow from the HVDC link can become the risk setter. Figure 7.1 shows recent IR volumes.

Figure 7.1: Distribution of SI FIR and SIR procurement from 2019 to 2024

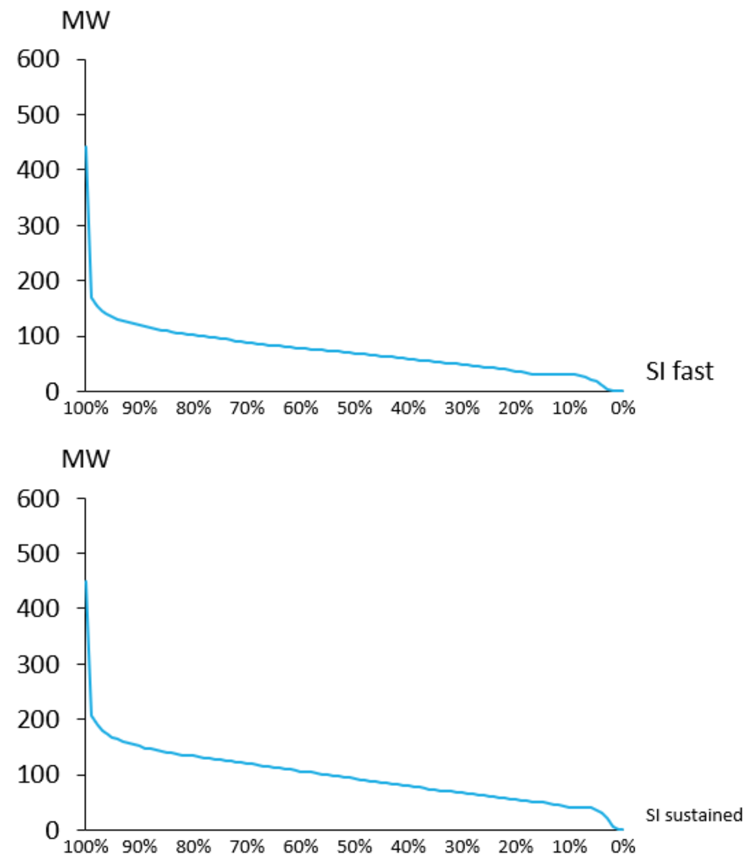


Figure 7.2 shows how the hydro operators Meridian and Genesis are the main suppliers of South Island IR.

Figure 7.2: Indicative cumulative reserves provision totals for 2023 and 2024 in the South Island

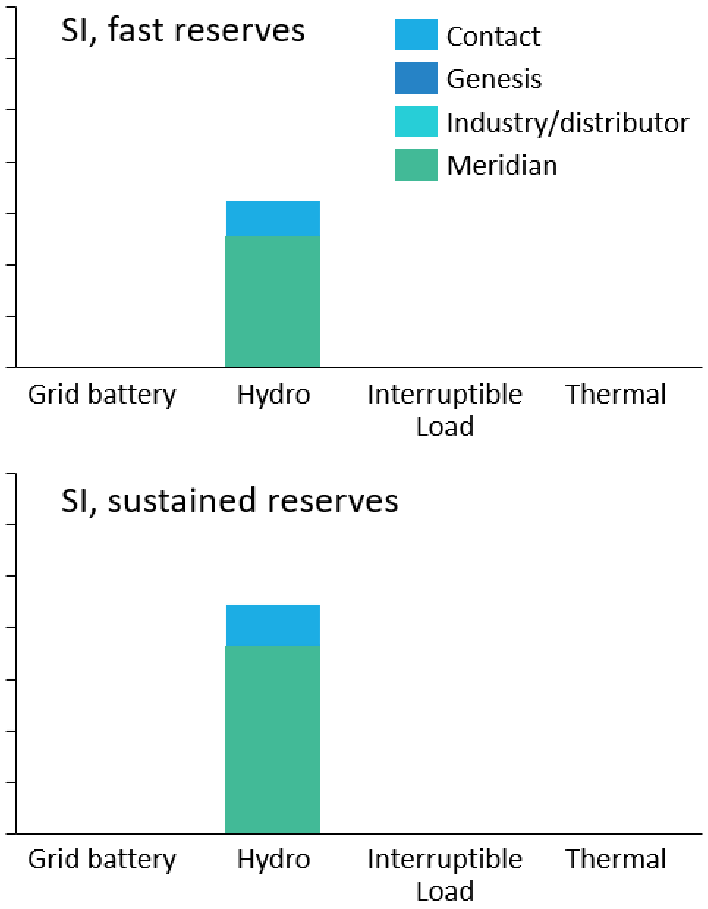


Figure 7.3 shows how this contrasts with North Island reservices, where interruptible load – including from ripple-controlled hot water – is a major supplier.

Figure 7.3: Indicative cumulative reserves provision totals for 2023 and 2024 in the North Island

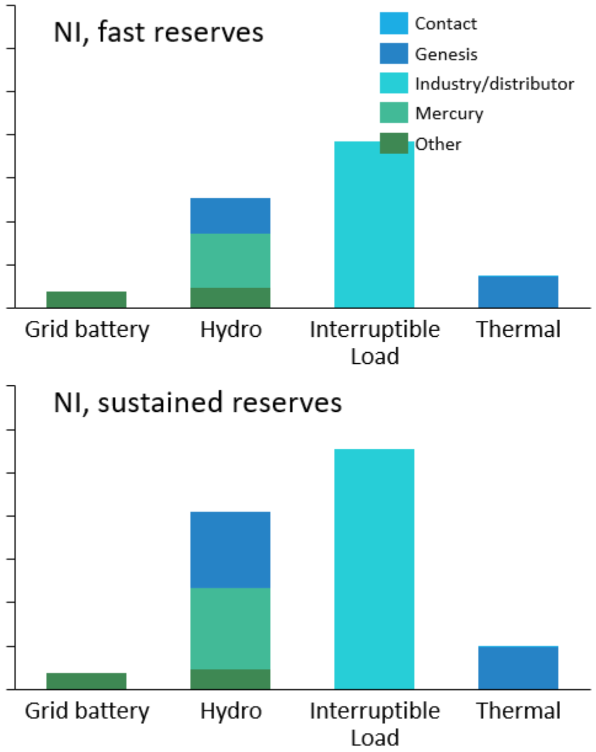
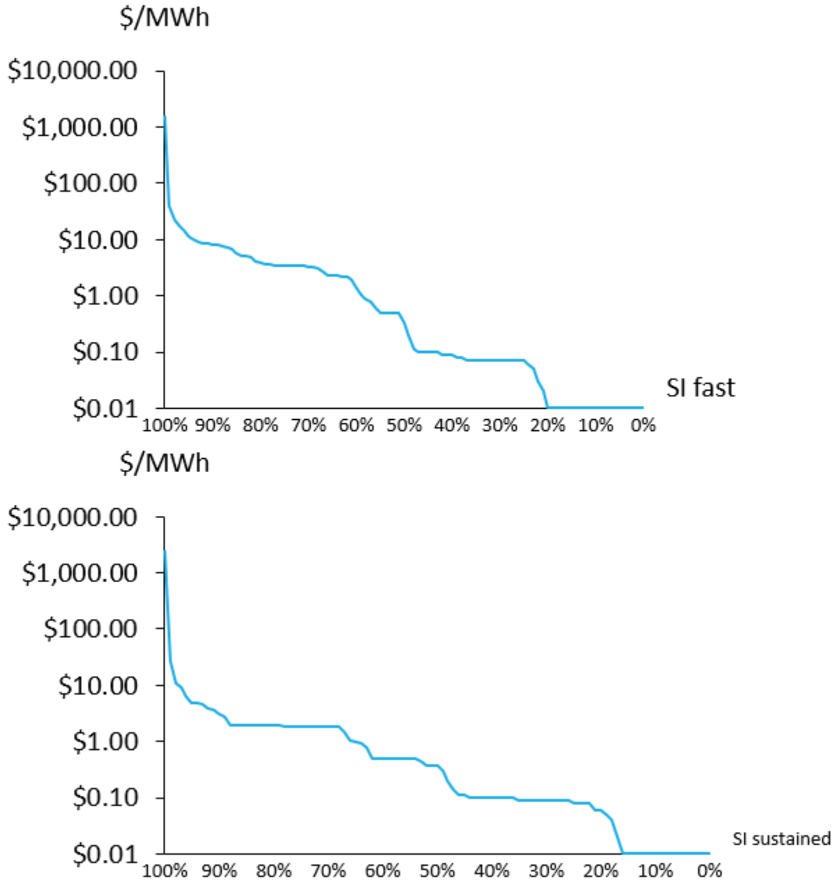


Figure 7.4 shows a historical distribution of South Island IR prices (with a logarithmic scale for the vertical axes). IR prices are usually low but can approach the energy price when supply is tight.

Figure 7.4: Half hourly trading period reserves price percentiles, covering the period from 2019 to 2024



Based on reserves prices from 2019 to 2024, offering a fixed quantity of reserves for 24 hours each day would have earned an average of $62,000 per MW per year (ranging from a low of $36k to a high or $88k).

If the LMG were able to offer 40 MW of IR, this would have earned around $2.5m per year on average.[40]

We note that:

- if the USI LMG were to start offering IR this would come with administrative and compliance costs
- the value of IR is likely to decline year on year as battery capacity is added to the New Zealand power system.

[40] At peak, the LMG may have access to around 140 MW of resource and be controlling around 80 MW, making a 40 MW IR offer potentially feasible. Off peak, the LMG would have less resource but would not be controlling for network purposes.