Line Pricing Methodology

AS AT 1 APRIL 2026

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GLOSSARY

AMP is Asset Management Plan.

Contract Capacity is the capacity of a customer used for billing purposes. It is formalised by way of agreement and control can be by way of the ICP fusing or the Anytime Maximum Demand.

Customer refers to the person or body that is responsible for an electrical installation that is connected to OtagoNet's electricity network.

Distributed Generation or embedded generation is electricity generation that is connected directly to a distribution network.

Diversity Factor is the factor applied to a load or customer demand to allow for the use of electricity at different times. In theory, the sum of the customer Maximum Demands after the Diversity Factors have been applied should equal the Maximum Demand measured at the GXP.

ENA is Electricity Networks Aotearoa.

Grid Exit Point (GXP) means the Grid Exit Point and is the connection point between the Transpower grid and OJVs network.

Group Customers include most customers with a Contract Capacity up to 100 kVA.

Individual Customers are in most cases commercial or industrial customers that have a Contract Capacity equal to or in excess of 150kVA.

Installation Control Point (ICP) is the point of connection between the OJV network and the Retailer's customer.

LRMC is Long-Run Marginal Cost.

Retailers are the companies that generate and/or buy electricity and then sell this service to end use customers utilising the local electricity network.

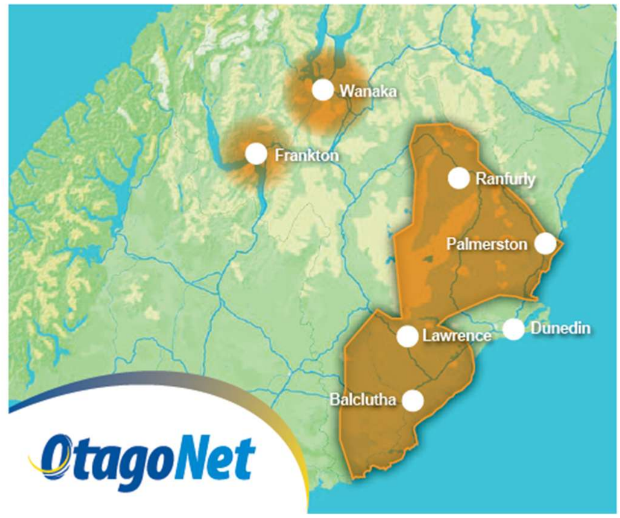
The Code is the Electricity Industry Participation Code 2010, which is the set of rules created and administered by the Electricity Authority.

Time of Use (TOU) refers to meters that are capable of providing Anytime and Maximum Demand readings and Peak, Shoulder and Night Period Energy readings for billing purposes.

Transpower is the State-Owned Enterprise that owns the transmission network and delivers electricity to Electricity Distribution Businesses (EDBs).

SUMMARY

OtagoNet Joint Venture (OJV) owns the electricity lines network that conveys electricity to much of rural Otago, areas of Frankton and parts of Wanaka and Cromwell, supplying approximately 20,361 customers.



Our Pricing Methodology Disclosure describes how we determine our annual revenue target based on our costs of operating and maintaining the OJV network. It also describes how we determine the prices in a way that recovers costs across a diverse range of connection types, and the pricing structures we use to signal information about the cost of using the network during peak periods.

Our customers and pricing groups

Through the 4,392 kilometres of lines, OJV's rural network delivers electricity to 15,676 homes and businesses and has the lowest density (customers per kilometre of line) of any electricity network in New Zealand. OJV's Lakeland network consists of 49 kilometres of underground cable supplying a mix of 5,406 commercial and residential customers in the Frankton and Wanaka areas.

Large consumers within OJV's rural network area include sheep, beef and dairy farming, extensive meat and dairy processing, forestry and timber processing and gold mining.

We set our pricing separately for the OJV and Lakeland networks and use three main customer pricing groups: Residential, General, and Individual. Individual customers are typically commercial or industrial customers that have a contract capacity at or above 150 kVA and have connection-specific pricing.

For residential and general customers, our pricing differs according to the fusing and size of the connection (measured in capacity) and whether the connection is in the Otago region or in the Lakeland network area. Connections that choose to have their hot water heating controlled receive lower charges – this reflects that we can shift some hot water heating load away from congested periods and avoid or defer costly capital upgrades. For Residential and General connections in the Otago region we use a pricing structure that applies separate usage charges for Peak, Shoulder and Off-peak time periods. In the Lakeland area, we apply a seasonal usage charge that reflects that the network is winter peaking. For General connections in the Lakeland area, we apply a Control Period Demand (CPD) charge instead of kWh charges.

Where we fit in the electricity industry

Generation

Electricity is generated using a variety of resources – water, geothermal, gas, wind, coal, and solar.

Transmission

Transpower owns and operates the high voltage transmission system that transports electricity from generators to local distribution networks.

Distribution

High voltage electricity is stepped down at substations, then **OJV** distributes it safely to local residential and business consumers using our network of poles, lines, and underground cables. **PowerNet** manages our network for us.

Retail

Your retailer measures how much power you use and sends you your power bill. Some of what you pay your retailer comes to us to cover the cost of investing in and maintaining a reliable network.

Customers

Our customers are households and businesses in the lower south eastern part of the South Island (the Otago Region, excluding Dunedin, Mosgiel and Port Chalmers) and a rapidly growing network in the Central Otago region (the Lakeland network), who use the electricity provided to power their home or business.

What our pricing covers

OtagoNet's network prices are charged to retailers and include the costs of electricity distribution and transmission.

Our network is managed by PowerNet

OJV has a Network Management Agreement with PowerNet. Through this agreement, PowerNet manages our network and carries out all corporate functions of our business. PowerNet invoices retailers on OJV's behalf.

PowerNet is an electricity network management company. It was established in 1994 to achieve scale benefits through integrated network management across the Southern region's Electricity Distribution Businesses (EDBs).

PowerNet provides services to over 79,000 customers through more than 14,300 circuit kilometres and manages the fourth-largest suite of EDB assets in New Zealand. With its head office in Invercargill, the company has over 300 staff based at depots across Southland and Otago

Our target revenue and pricing reflect costs of developing and maintain the OtagoNet network

Our annual revenue is regulated by the Commerce Commission under the Default Price-Quality Path (DPP).

The methodology used by the Commission to set a cap on our annual revenue (allowable revenue) is based on our expected costs, which include:

- the costs of operating and maintaining the network (direct network costs),
- business support costs (indirect network costs),
- the costs of connecting to and using the national transmission network,
- tax, and
- capital-related costs (depreciation and the cost of capital) associated with assets.

Our allowable revenue also includes adjustments for incentives and penalties that relate to reliability targets and cost targets.

Our revenue requirement for the 12 months from 1 April 2026 is $53.8 million, which is an increase of 16.4% from the previous year. This includes a 22.2% increase in transmission charges and a 15.1% increase in distribution charges.

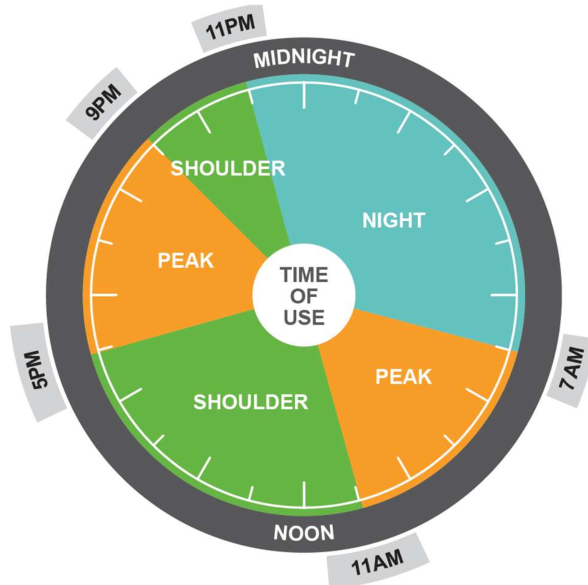
Before setting lines charges, we remove capital contribution revenue – that is, revenue from new or upgraded connections that provides a direct contribution to costs of required network augmentation.

Recovering costs across customers

We allocate costs across the customer groups according to their network use characteristics, including capacity, demand during peak periods (kVA), electricity use during peak times (kWh), and total electricity use. The cost allocation process gives an annual cost for each of the individually priced connections, which is recovered through a monthly charge and a usage charge. For residential and general connections, we converted the allocated cost into daily fixed charges and usage charges per kWh that vary according to the time of day, and for General customers in the Lakeland region we determine the CPD charge.

In line with requirements by the Electricity Authority, we carry out a check to ensure that our pricing does not result in a cross-subsidy. This analysis shows that the revenue from each customer group covers the costs directly associated with serving that group (avoidable costs) but that the revenue does not exceed the standalone costs.

Signalling the busy times on our network



For the Otago region we use a Time-of-Use (TOU) pricing structure, where the price of electricity usage is higher during times when there is most likely to be congestion on the network, and lower (or zero) at times when there is plenty of capacity. Pricing in this way sends a signal to transfer load outside of congestion periods and incentivises use of the network at times when there is no incremental cost for us to deliver the additional energy.

As a result, this type of pricing can defer or avoid the need to make costly investments in network capacity upgrade, benefiting all consumers in the longer term.

To date, few consumers have received these pricing signals because only some retailers have incorporated TOU into their retail pricing. As a broader range of retailers offer TOU retail prices, we will observe how consumers respond and what that means for network peaks and future investment.

For the Lakeland region, our price signals refers that the strong winter peak. Rather than time-of-day pricing, we provide the price signal through seasonal usage charges for residential customers and a demand charge that is based on periods when our network is at its peak use.

Key changes made to the previous methodology

The changes made to the previous year's methodology are:

- Phase out of Low-User Fixed Charges (LFC) – In line with regulation changes, OJV has continued to phase out LFC charges to support the move towards more cost-reflective pricing. RY27 is the fifth year of a five-year phase out of the regulations and results in fixed charges for residential consumers increasing, from $0.75 per day to $0.90 per day from 1 April 2026.
- Implementation of a rebate for distributed generation exported into the network by residential and general customers with a supply capacity of up to 45kVA
- Introduction of a new pricing region within the Lakeland Network area.
- Introduction of a new pricing category code 3 to identify commercial customers with a connection capacity of greater than 45kVA.
- Time of Use price differentials between the peak and shoulder prices are strengthened to encourage the use of off-peak energy.
- Revision of our capital contributions policy, in line with regulatory requirements.

1. INTRODUCTION

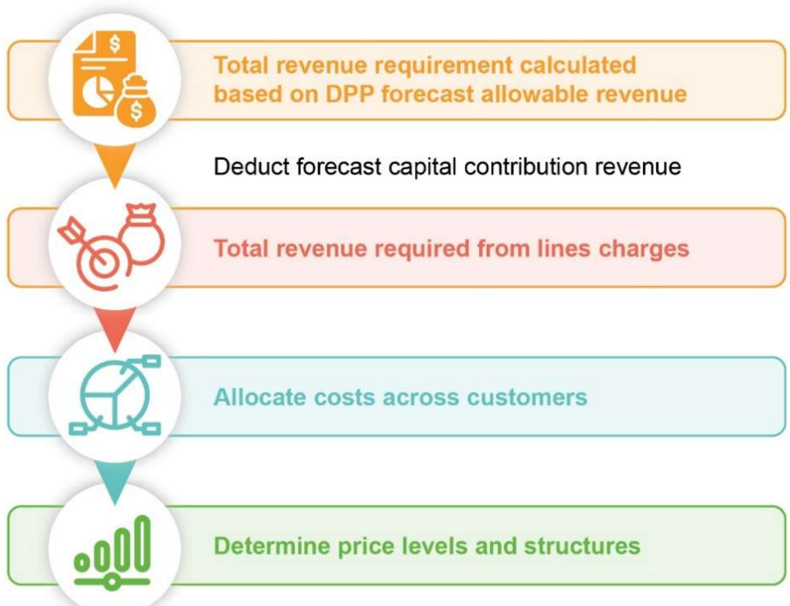
OJV owns the electricity distribution network in the lower south eastern part of the South Island (the Otago Region) and a rapidly growing network in the Central Otago region (the Lakeland network).

OJV's joint venture owners are Pylon Limited and Last Tango Limited which are subsidiaries of The Power Company Limited (TPCL). OJV does not employ any staff and has outsourced its management of the electricity network distribution business to PowerNet Limited (PowerNet) which also manages the electricity networks owned by Electricity Invercargill Limited (EIL) and TPCL.

OJV faces a number of regulatory requirements relevant to pricing that are administered by either the Commerce Commission (the Commission) or the Electricity Authority (the Authority). OJV's total revenue is regulated under the Commission's Default Price-Quality Path Determination 2025 (DPP Determination). In addition, the Commission's Information Disclosure Determination requires OJV to disclose a pricing methodology each year. The purpose of this document is to comply with the disclosure requirements by describing the methodology OJV uses to reflect the costs of providing delivery services to the different consumer groups supplied on the network. This document also assesses how our pricing compares with the Authority's Distribution Pricing Principles.

OJV sets its total revenue requirement to comply with the Commerce Commission's DPP Determination. We then deduct the capital contribution revenue that we expect to receive from new and upgraded connections to determine the total revenue required from lines charges. The next step is to allocate the revenue requirement across customers and customer groups, before determining the pricing structures and price levels that will apply to each customer group.

Figure 1 OJV's process for setting prices



The following sections explain how we implement this process. We first provide contextual information about OJV's network **(section 2)**, then present an overview of our prices and how they are set (**section 3).** We discuss our pricing strategy **(section 4).** This is followed by a more detailed discussion of how overall target revenue is determined, how that revenue is allocated to customer groups, and the methodology used to convert the revenue requirement into prices **(sections 5 to 7)**. We then assess our pricing against the Authority's Distribution Pricing Principles **(section 10) and**

discuss our pricing for non-standard contracts (section 8). Finally, we describe charges for generators connected to OJV's network **(section 9)**.

2. CONTEXTUAL INFORMATION ABOUT OJV

2.1 OJV's Network

The rural Otago area of the OJV network covers 14,000 square kilometres and stretches from Owaka in the south through to Shag Point in the north and Lawrence in the west but excludes Dunedin city, Mosgiel and Port Chalmers. The topography of the terrain covered by the Otago region varies from rolling farmland and coastal bush covered hills to high altitude relatively arid plains. Corresponding variations in climate occur between onshore coastal winds to areas of freezing temperatures and heavy snow.

The Lakeland Region is a rapidly growing network in the Frankton area of Queenstown, Wanaka and Cromwell. Lakeland is supplied by the Transpower Frankton GXP and has one 23 MW zone substation and Network Supply Points (NSPs) from the Aurora network in Wanaka and Cromwell.

Electricity is delivered to OJV from Transpower's national grid through four GXPs located at Naseby, Halfway Bush, Balclutha and Frankton. The OJV distribution network also receives electricity from three Distributed Generators via stations located at Paerau (hydro), Falls Dam (hydro) and Mount Stuart (wind).

OJV does not buy and sell electricity; it delivers electricity to its customers on behalf of the electricity Retailers. Accordingly, OJV charges the Retailers at a wholesale level for this service, which includes Transpower's charges. The Retailers then pass on these charges to OJV's customers as part of their retail electricity charges.

2.2 Upcoming investment in network capacity

As at end March 2025, the value of OJV's network assets in its Regulatory Asset Base was $298M.

Over the next three years, OJV anticipates investing $101.1 million in the network, of which the majority relates to asset replacements $64.9 million and consumer connections in the Lakeland region $15.9M.

As explained in the Asset Management Plan (AMP), assets that are at or approaching the point of triggering upgrades due to capacity requirements are:

- Sub-transmission lines, some of which are undersized for current capacity.
- Some distribution lines and LV lines.
- Rapid urbanisation in the Frankton and Wakatipu basin means that the Transpower's GXP transformer and the 110 kV supply lines that serve the areas are in need of upgrades.

2.3 Uptake of evolving technologies

Several technologies have the potential to change the way customers use and generate electricity. Pricing has a role to play in providing efficient signals about the economic costs of using electricity networks. In that context, we provide a summary of existing and expected uptake of a number of these technologies: solar (Photovoltaic; PV) with and without battery storage as well as electric vehicles.

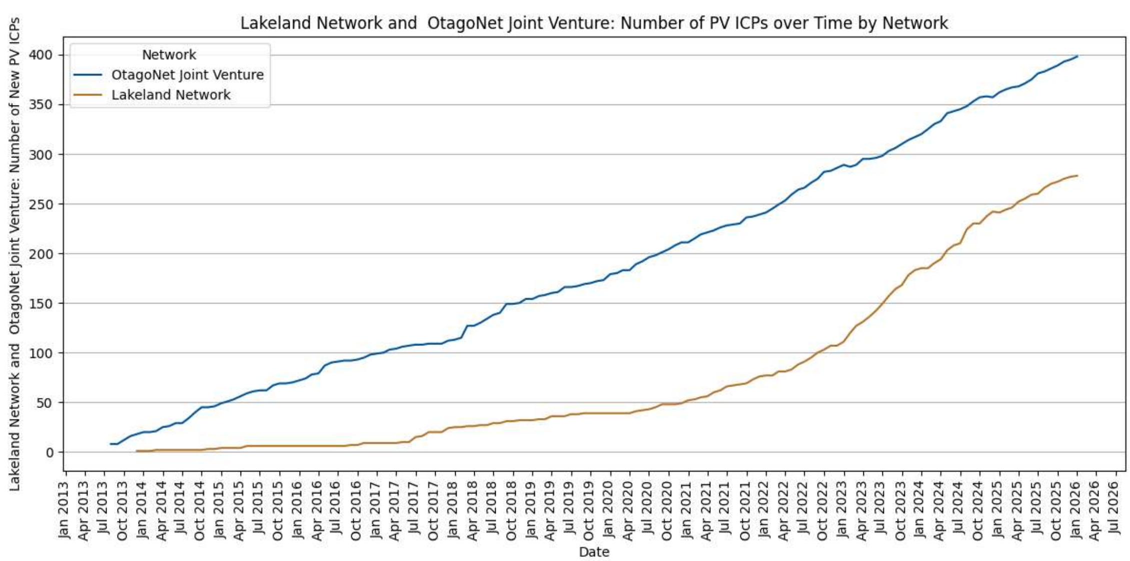
2.3.1 The uptake of solar (Photovoltaic) is significantly below the national rate

Solar Connections without Battery

Over the past 12 years, there are growing numbers of solar (Photovoltaic) connections without battery across the Lakeland Network (LLN) and OtagoNet Joint Venture (OJV) networks (see Figure 1). This is also similarly reflected in the uptake rates over time, with only Lakeland Network (LLN) seeming to plateau around mid-2024 (see Figure 2). The national uptake rate was still relatively lower than the 5.00% rate in the top ten highest uptake EDB areas[1] with the highest being Top Energy at 7.01%. As of January 2026, the uptakes of solar in OJV was still below the national rate of 2.80% while LLN at 4.45% is almost doubled the national rate and sits within the top 10 EDBs.

Solar installations are likely to reduce total energy consumption within the AMP planning period. While energy consumption levels do not tend to affect network planning, which focuses on providing capacity for peak demand periods, it does affect price levels, to the extent that some component of price is set based on energy consumption (kWh). This is relevant to the development of our forward pricing strategy.

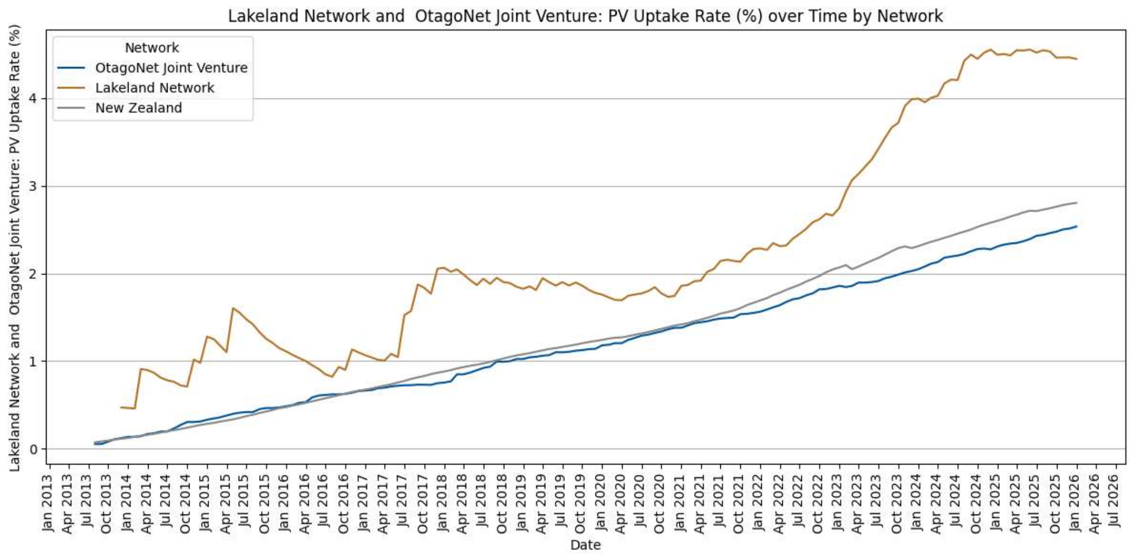
Figure 1 Monthly solar without battery connections (ICPs) over time



Source: Electricity Authority EMI Installed distributed generation trends

[1] Top ten EDB areas include Top Energy, MainPower NZ, Network Tasman, Marlborough Lines, Counties Power, Nelson Electricity, Waipa Networks, Lakeland Network, Northpower, and Electra.

Figure 2 Monthly solar without battery uptake rate (%) over time



Source: Electricity Authority EMI Installed distributed generation trends

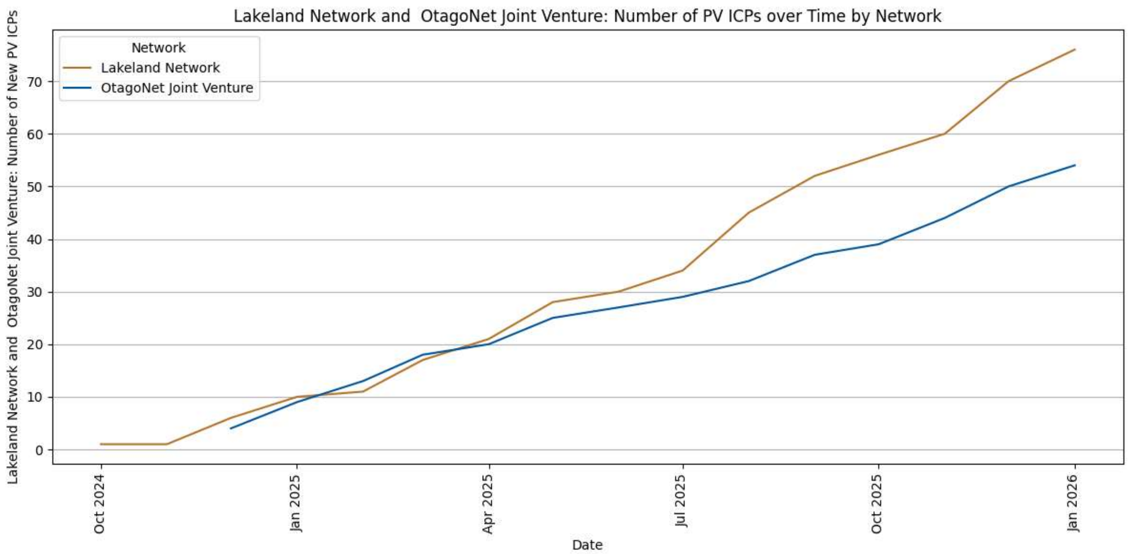
Solar Connections with Battery

While the majority of new DGs is from solar connections, LLN and OJV networks' peak is historically on winter evenings, and coupling solar generation with battery energy storage could change this dynamic. In New Zealand this technology started to be adopted around late 2023. Within LLN and OJV the adoption began a year later around late 2024 but has gained a rapid interest as reflected by the relatively steep uptake rates, especially in LLN (see Figures 3 and 4). As of January 2025, LLN has a rapidly increasing uptake rate at 1.22% of all its ICPs with 76 connections, which is higher than the national rate of 0.65%. The uptake rates of OJV still sits at 0.34% with 54 connections.

At present, the adoption of this technology is still at an early stage and the impact on the network is relatively insignificant. The major barrier for this slow adoption is likely the high upfront cost and long payback period, which is a concern given the rising cost of living. Many customers are also uncertain about the immediate benefits of batteries, despite the potential long-term savings. Any impact these devices have, nonetheless, is likely to be beneficial in terms of network constraints, as they act to reduce rather than increase the peak demand on network assets. To encourage adoption, future pricing should aim to reward customers where batteries benefit the network as well as to focus on educating customers about the long-term financial and environmental advantages.

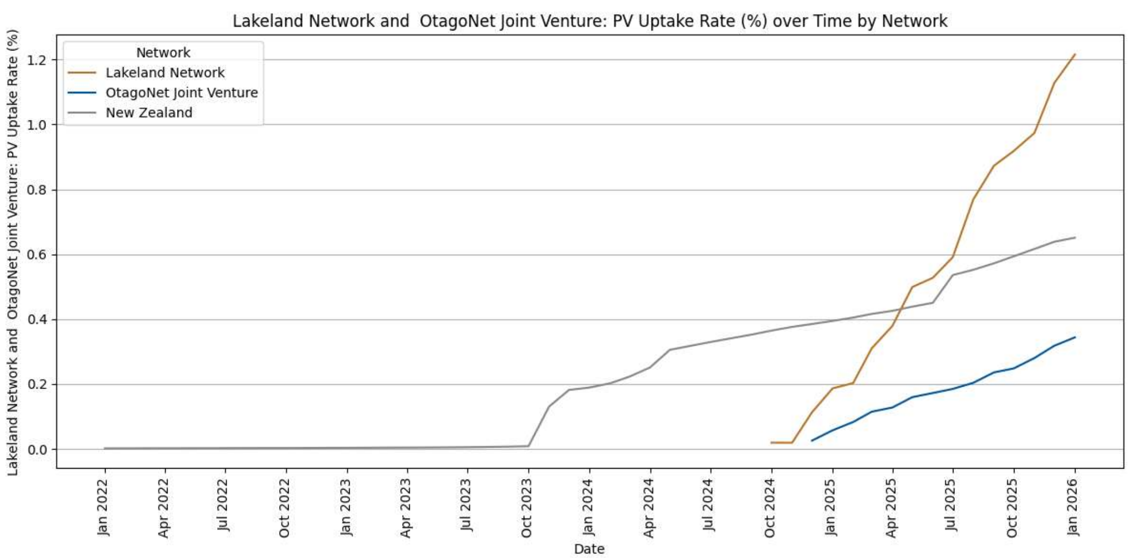
Having a battery storage gives customers some control over their demand without impacting their consumption and could make it possible for customers to go "off grid" with a sufficiently sized generation source. However, there is an uncertainty in this area around the viability of alternative battery chemistries and the timing of their introduction; the regulatory environment and the extent to which electricity distribution businesses will be able to utilise storage services; and future pricing structures and the level of responsiveness of the public to load-driven pricing signals.

Figure 3 Monthly solar with battery connections (ICPs) over time



Source: Electricity Authority EMI Installed distributed generation trends

Figure 4 Monthly solar with battery uptake rate (%) over time



2.3.2 Electric Vehicles

With rising fuel costs, increasing concerns about global warming, and the impact of carbon emissions, we expect electric vehicle adoption in New Zealand to continue growing each year, despite the end of the Clean Car rebate. In fact, there have been a consistent growth in the number of electric vehicles[2] (EVs) across the LLN and OJV networks but still below the national rate (Figure 5). As of January, the

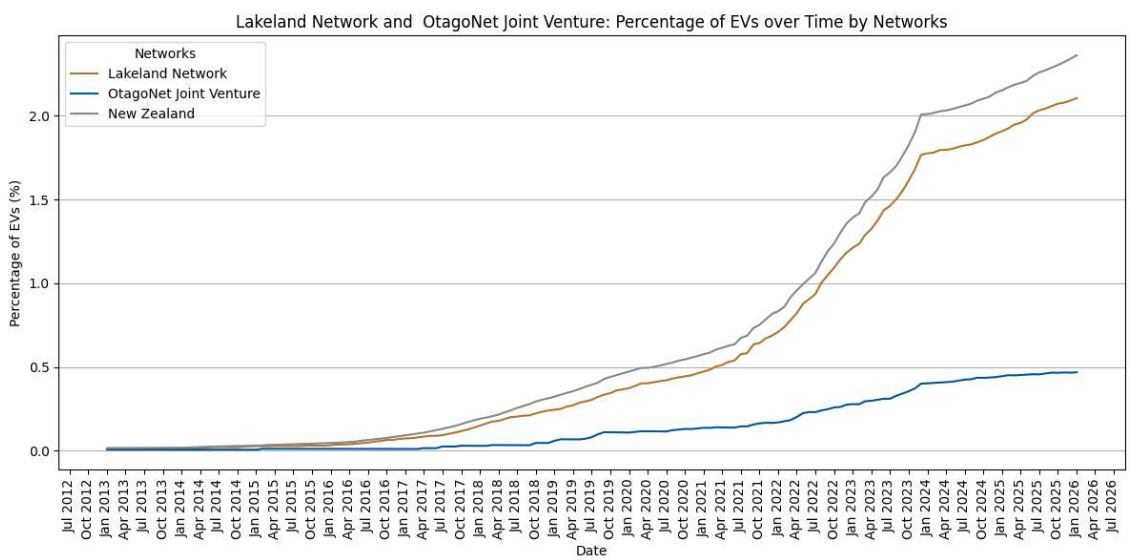
[2] The definition of EV vehicles follows that of NZTA which includes vehicles with BEV, PHEV, range extended motive powers. Here all vehicle types and classes are included.

percentage of EVs compared with the entire vehicle fleet (<3% in both networks) is small (see Table 1).

EVs have the potential to have large impacts on network demand with sufficient adoption. Prices are an important means for signaling peak periods and enabling customers to choose whether to charge off-peak or pay a premium and charge during peak periods. If customers choose not to charge off-peak in response to price signals, EV charging may increase peak demand, triggering greater investment. This effect will be greatest on the suburban LV network in built-up urban and semi-urban areas as the upstream MV network generally has sufficient capacity to allow for the forecast increases in load from EVs.

Having pricing structures in place before EV uptake reaches widespread levels will enable a degree of customer education before load shifting is needed from a network capacity perspective. It will also allow networks to understand the effectiveness of price signals in managing EV loads before load capacity is reached. Reducing peak load would also reduce the average marginal carbon intensity (AMCI) in the grid.

Figure 5 Monthly percentage of registered EVs over time



Source: NZTA's Motor Vehicle Register open data as of January 2026

Table 1 EV uptakes across networks as of January 2026

	OJV[3]	LLN[4]
Percentage of registered EVs (%)	0.47%	2.11%

2.4 The Power Company Ltd and PowerNet Limited Structure

PowerNet Limited (PowerNet) is an electricity distribution network management company 100% owned by TPCL's subsidiaries Pylon Limited and Last Tango Limited and is contracted to manage the network assets of OJV in accordance with a Management Agreement (Agreement).

The Agreement includes provision for PowerNet to act as manager on behalf of OJV to collect revenue from line and metering charges to retailers or end consumers, pay transmission costs, incur maintenance expenditure and to pass the net amount through to OJV each month. PowerNet charges a management fee that covers its overheads for operating the line and metering businesses for OJV.

[3] EV Registrations in the Clutha District Territorial Authority as a proxy.
[4] EV Registrations in the Queenstown-Lakes District and Central Otago District Territorial Authority as a proxy.

3. OJV CONSUMER GROUPS AND PRICING OVERVIEW

OJV's prices are used to charge electricity retailers for the cost of its local electricity distribution network, pass-through costs (such as industry levies) and the costs associated with national grid transmission. Electricity retailers determine how to package these charges together with the energy, metering and other retail costs when setting the retail prices that appear in consumers' power accounts.

OJV uses "GXP billing" for its residential and general connections in the rural Otago areas. This means that consumption charges are based on electricity volumes injected into OJV's network at the Transpower grid exit points. Quantities are determined by the wholesale electricity market reconciliation process, which is itself governed by the Electricity Industry Participation Code (the Code). This method saves on administration costs, which are ultimately transferred back into the prices. In the Lakeland network area, "ICP billing" is used, which means that billing to retailers is based on the usage at individual customer connection points

3.1 Consumer load groups used for pricing

OJV defines two broad types of consumers for pricing purposes: Residential & General consumers; and Individual Consumers. The prices for Individual customers are connection specific.

3.1.1 Residential and General customers (domestic, small commercial, farms etc.) - Otago Region

The Residential and General Customer category includes most customers with a Contract Capacity up to 150 kVA and is divided into different segments.

OJV charges a fixed charge per ICP and a variable charge based on the energy metered at the GXP. Quantities attributed to each retailer are determined by the wholesale electricity market reconciliation process with adjustments for major customer quantities.

Residential Installations

Residential customers are connected at a voltage of 400V, and the connection is for the purpose of supplying electricity to premises that are used or intended for occupation principally as a place of residence. For all residential customers the supply capacity is rated at 10kVA.

In accordance with the legislation a low fixed charge option is available for permanent residential customers. OJV retained a standard domestic line charge so larger families would not be unnecessarily penalised by a higher variable energy component.

The Low Fixed Charge option is thus available for residential customers incorporating a fixed charge per day and peak, shoulder and nighttime rates for energy used in those periods. From 1 April 2022 the Low fixed Charge Tariff Option is being phased out over a 5-year period by the Government. The phase out allows distributors to increase the daily fixed charge by an additional 15 cents per day for each of the 5 years, and when it reaches 90 cents per day in 5-years' time it will be removed altogether. This year is the fifth and final year of the phase out, OJV has therefore increased the daily fixed charge to 90 cents per day for Low fixed Charge option customers in the Otago region.

General Customers

These connections are connected to the 400V system, generally with a fuse capacity of less than 150kVA, and are not a residential customer.

The size of the general connection is determined by the size of the service fuse or the rating of the distribution transformer. The supply capacity can be measured by demand half hour metering or portable logging equipment to measure the maximum average electrical demand over any half hour period. If the customer has contracted for a larger capacity due to predicted growth this will be the contract capacity. The minimum capacity is 10kVA.

These customers are charged at an annual fixed rate per kVA of their supply capacity and two variable charges based on their daytime and night time energy usage.

Unmetered Loads up to 1 kVA

These are commercial connections of less than 1kVA capacity and are connected to the 400V system. Due to the small load on these connections, they are not required to be metered.

There is an annual fixed charge per year and the daytime and nighttime energy is calculated by the retailer.

Streetlights

Street lighting connections are used for the illumination of roadway and pedestrian areas, they are connected to separate circuits and controlled between the hours of dusk to dawn.

There is an annual fixed charge per lamp watt per year and daytime and nighttime energy rates.

This customer category has been withdrawn and is no longer available, all customers previously on this tariff are now on the individual customer's category and an individual line charge has been calculated for each one.

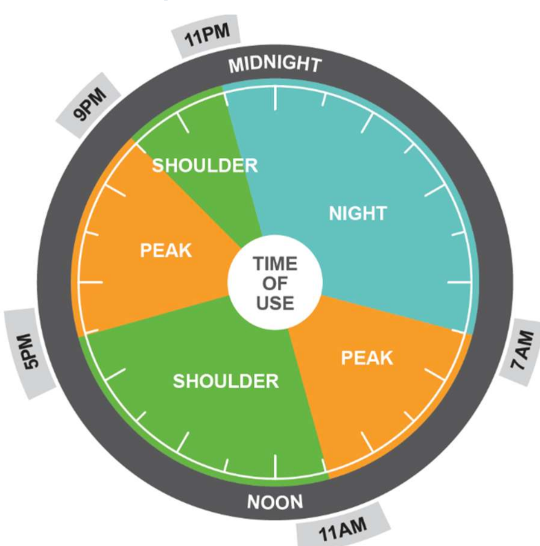
Time of use pricing

Time of Use (TOU) pricing for Residential and General Customers consists of three time periods, which are:

- **Peak** period: 7am to 11am and 5pm to 9pm,
- **Shoulder** period: 11am to 5pm and 9pm to 11pm, and
- **Night** period 11pm to 7am.

The time-bands shown for peak, shoulder, and night were selected based upon the times that peaks occur on our network. We will continue to review peak times at our individual GXPs and zone substations to ensure the time bands are appropriate and will make changes if required.

Figure 2: TOU time periods



TOU pricing provides an incentive for consumers to shift energy usage out of peak periods, which can avoid or defer costly network upgrades. New uses of electricity such as solar generation, batteries, electrification and charging EVs are increasing the scope for network pricing to influence investment, and cost-shifting outcomes mean that it will be even more important to have meaningful peak pricing signals. Ensuring that the supporting price structures, such as TOU, are in place before EV uptake is widespread will mean that pricing will be up and running and effective when it is needed, allowing time for consumer education and for networks to understand consumer preferences and price responsiveness.

The price differential between the peak and shoulder price can be increased over time if network constraints become greater or we have EV clustering on the network.

3.1.2 Residential and General Customers (domestic, small commercial, farms etc.) - Lakeland Region

The Group Customer category includes most customers with a Contract Capacity up to 276 kVA and is divided into different segments.

Residential Installations – Lakeland Region

A "Standard Residential" connection is one where the connection capacity is set according to the size of the network fuse provided for the short-circuit protection of consumers' mains. The default for a Standard Residential connection is a single phase 63-amp fuse providing a connection capacity of up to 15kVA.

A "low capacity" option is available and is set by a single phase 32-amp fuse providing a connection capacity of up to 8kVA.

In order to be eligible for Standard Residential pricing, premises must comply with the definition of "home" given in the Electricity (Low Fixed Charge Option for Domestic Consumers) Regulations 2004. A residential consumer's "home" is their principal place of residence and, for the avoidance of doubt, excludes holiday homes. Also excluded are:

a) penal institutions.

b) hospitals, homes or other institutions for care of sick, aged or disabled.

c) police barracks, cells and lockups.

d) armed forces barracks.

e) hostel, dormitory or similar accommodation.

f) premises occupied by a club for provision of temporary accommodation.

g) hotels, motels, boarding houses; and

h) camping grounds, motor camps or marinas.

OJV charges the Retailers in the Lakeland region on an ICP metered billing basis for standard residential customers (i.e. price codes LD15, LD15E, LM15, LM15E, LD08 and LD08E) costs are recovered through:

- fixed charges (per ICP); and
- kWh charges (based on periodic consumption).

This price structure for residential consumers is not the preferred recovery mechanism but has been used in order to comply with Government Policy as to the level of fixed charges (as per the Electricity (Low Fixed Charge Tariff Option for Domestic Consumers) Regulations 2004). These regulations required domestic consumers using up to 9,000 kWh per annum to have, as an option, the fixed portion of their line charges limited to 90 cents per day. This has been applied to the recovery mechanism used for costs in these load groups.

This price structure nonetheless signals some of the peak demand cost drivers for these smaller domestic consumers, with the main weakness being that actual capacity costs are not recovered from consumers that use low kWh volumes.

Two components of line charges are used. The components are as follows:

Fixed Component

The fixed component has been increased to 90 cents/day from 1 April 2026, which is in line with the 5-year phase out of the Electricity (Low Fixed Charge Tariff Option for Domestic Consumers) Regulations 2004 which took effect from 1 April 2022.

Variable Components

The variable components are defined by the existing metering arrangements. Most domestic connections have two meters – one to record general purpose consumption and one to record controlled water heating (minimum 16 hours service) consumption.

General Connections (Non-Domestic Connections and Non-Standard Residential Connections including street lighting) – Lakeland Region

Two components of line charges are used. The components are as follows:

Fixed Charge

This charge recovers costs that are incurred on a connection basis and includes.

Assessed Capacity

LV Metered Connections

This charge recovers costs associated with the distribution system local to each connection point, i.e. LV lines and cables, distribution substations, and HV lines and cables. The use of these assets is more directly related to the capacity of the individual connections.

The basis for the annual Assessed Capacity is the minimum fuse size, mains size or standard distribution transformer size required to supply the maximum anytime power demand. Normally this will be the minimum fuse size for capacity up to 276 kVA.

HV Metered Connections

This charge recovers costs associated with the distribution system local to each connection point, i.e. HV lines and cables. The use of these assets is more directly related to the capacity of the individual connections.

The basis for the annual Assessed Capacity of HV metered connections, excluding residential secondary networks which are assessed on the basis of installed distribution transformer capacity, is the lesser of the installed distribution transformer capacity (kVA) and minimum standard transformer capacity greater than 1.18 times the average of the 12 highest anytime power demands (kVA). The factor of 1.18 is used so that the average ratio of maximum anytime power demand (kVA) to Assessed Capacity (kVA) for HV metered connections is the same as for LV metered connections.

Control Period Demand Charge

This charge recovers costs associated with zone substations and Sub-transmission lines and cables, which are sized for system peak loads.

The basis for the Control Period Demand (CPD kW) is the energy used at the installation when OJV is managing demand. This energy usage will accumulate and at the end of the Control Period the accumulated energy is divided by the duration of the Control Period to obtain average power demand. If a consumer commences during the year a negotiated Control Period Demand will apply until a full winter is completed.

The Control Period Demand for each installation is set at 1 December to the average of CPD kW (Previous Winter) and chargeable CPD kW (at 1 December the previous year). The Control Period is likely to occur on cold winter days, anytime between 0700 hours and 2200 hours, and to last typically for two to three hours (but could last for up to ten hours on occasions) and is most likely to occur on approximately 20 to 50 days during the May to September period with most activity during June, July and August. Control periods will be signaled via ripple control and consumers may use this signal, via clean relay contacts, to operate a warning device to directly control deferrable load or to start up a standby generator, whichever is the most convenient.

Where it is not presently economic to install Control Period Demand metering for connections, then any charges that would normally be recovered via a Control Period Demand charge will be recovered via an Effective Control Period Demand charge based upon kWh consumption at the installation during winter days (0700 hours - 2300 hours). This will be based upon the four months consumption reported by electricity retailers for the period May to August. Energy consumed by defined night loads is discounted by 100%. A list of discount rates for kWh usage on controlled rate registers is set out in Appendix 2.

The Effective Control Period Demand for each installation is set at 1 April to the average of CPD kW (Previous Winter) and chargeable CPD kW (at 1 April previous year). Thus, a strong economic signal exists for consumers to accept controlled loads. By signaling the impact of network coincident demand in this way, OJV is able to defer the need for investment in more capacity, which is a very expensive alternative. Consumers do not have to respond every time the signal is sent. Many will respond only when it suits, however the rewards for responding are substantial.

3.1.3 Individual Consumers (larger commercial, industrial)

In most cases these customers have a Contract Capacity equal to or in excess of 150kVA, but smaller customers may be included if the customer believes there may be economic advantages such as a more favorable load profile than the corresponding Residential and General Customer class.

Line charges for this category are individually calculated and applied. They are based on meter readings that more accurately reflect the load profile of the customer.

It is considered that there is a higher probability that customers in this category may be able to respond individually to pricing signals, both at the time of connection and subsequently on a dynamic basis through varying their load profiles. They may also be more able to compare security of supply options and costs and then select their individual network configuration in considering the price/quality tradeoffs.

Due to their size, these customers have a higher impact on the network design and operation and therefore their geographical location in the network is taken into account when calculating their individual line charges. This also provides a signal for future investment and through the correct pricing discourages network by-pass.

Individually calculated or estimated loss factors are also applied to these customers. The application of these loss factors enables reconciliation of measured and calculated demands and energy across the network.

- Individual factors considered in cost allocations to individual line charge customers include:
- Connections having dedicated transformers.
- Low percentage use of the low voltage network
- Low diversity as capacity and demand increases
- Customer owned transformers.
- Additional security and back supplies, n-1.
- Higher importance on network maintenance.

These customers have Half-Hour Metering (HHM). Customers with Half-Hour meters have line charges based on more precise load profiles, as meter readings for every half hour of the year are available.

These customers, through the Half-Hour metering, have individual profiles, which are used to calculate the line charges.

Metering of these customers includes kVA demand measurement which provides the seasonal Maximum Demand, the Anytime Peak Demand and in the case of Half-Hour metered customers the Coincident grid Maximum Demand.

The meter readings are also used in the calculation of line charges and to determine the Contract Capacity. For these customers, the Contract Capacity is based on the standard transformer size immediately above their Anytime Peak Demand or, alternatively, as per the original contract if growth is predicted and the network has been designed and built to supply the increased level.

Another advantage for a new Individual Customer is that some of the costs of connecting the customer to the network and any related network extension can be incorporated into the line charges in accordance with the terms of OJV’s Capacity Guarantee Agreement.

Irrigation Customers

Irrigation customers are a subgroup of the Individual Customers. An Irrigation customer’s installation is used solely for pumping water commercially for irrigating farmland.

Irrigation operations vary from other customers insofar they all tend to operate at the same time, their demands are flat for extended periods, but the operation is spasmodic depending on weather conditions.

Embedded Networks

An “Embedded network” is an electricity distribution network that is owned by someone other than OJV and is connected to OJV’s network via a registered network supply point (NSP). The Embedded network must be metered with a compliant Half-Hour meter at the NSP. Due to the uncertain nature of electricity consumption in both irrigation customers and embedded networks this subgroup of customers will have their line charges calculated in the same way as Individual Customers, but the total line charge will be recovered by an annual fixed charge only.

Otago Power Limited Legacy Customers

Some arrangements with customers in place were inherited from Otago Power Limited. As these contracts expire they are being replaced with the methods described above.

4. PRICING STRATEGY

Given that OJV's pricing to Individual Customers is highly cost-reflective and service-based, the focus of our pricing strategy has primarily been on pricing for Residential and General customers.

The mandatory TOU pricing that applies to Residential and General consumers was introduced by OJV in 2022 as the first stage in moving to more cost-reflective network pricing. Over time as more consumers face TOU price signals through retailer pricing, we will observe how this impacts electricity use, which will help us to refine our pricing.

OJV's costs including Transpower charges are largely fixed. To reflect this cost structure, our strategy has been to increase the proportion of overall revenue that is recovered through daily capacity charges, From 1 April 2026 we continue this strategy and pass through the majority of the price increases through an increase to the prices of the capacity charges. Half hour metered individually assessed line charge customers who previously had their annual line charge recovered 50% through the fixed charge and 50% through the variable charge have now increased to 60% fixed charge and 40% through the variable line charge.

4.1 Time of Use (TOU) Pricing

OJV's consumption pricing previously consisted of a price for Day (7am to 11pm) energy use and zero for Night (11pm to 7am) energy use. This pricing sent a strong signal for customers to shift consumption into the night period, but it did not signal times during the day when the network is at peak loading or times when there is there is spare capacity in the network. It made no difference, if for example people with EVs charged their cars at 5pm, which is a network peak time, or at 2pm, which is a network off-peak time. This lack of signal could force the network to invest in expensive upgrades and pushing the price of line charges higher for everyone.

OJV has completed significant work on examining alternative cost reflective pricing options.

We evaluated five different cost reflective pricing options on the following criteria:

1. Economic Efficiency
2. Actionable and Simple
3. Supports retail Competition
4. Durable and Flexibility
5. Stable/Predictable

The combination of installed capacity and TOU was superior to all other options under the evaluation process. From 1 April 2022 this combination was the start of our cost reflective pricing journey as we look to provide customers with better pricing signals and a choice of when and how much they pay for their line charges, which is efficient and fair for the long-term benefit to all our customers.

4.2 TOU implementation

PowerNet engaged in work streams to enable TOU pricing including billing system changes, engagement with retailers seeking support and feedback on best practice to implementing a change to TOU and how the necessary data is provided and preparing TOU pricing models along with comprehensive customer impact analysis. We also introduced new loss codes to identify low user energy at a GXP level to aid the analysis.

4.3 Customer impact analysis

When selecting the combination of capacity and TOU as our preferred pricing option, we examined the impact on consumers in detail. The change in consumers' lines charges as a result of TOU will depend on usage profiles, but generally TOU implementation will have the least bill impact of available price reform options, while still providing valuable pricing signals.

OJV completed extensive impact analysis of a shift to installed capacity and TOU pricing. The analysis involved modelling over 52% of the residential and general customers on The Power Company Limited network who had more than 12 months' worth of half hourly smart meter data and using OJV line charge prices. Each ICP was overlaid with a NZ deprivation level index rating which was derived by the University of Otago using NZ census data to enable us to evaluate the impact at a socioeconomic level.

The analysis showed that the change to TOU pricing would have very little impact on total charges for residential consumers, regardless of whether the consumer is a standard or low user. The analysis also shows that consumers in the most deprived deciles would face less impact on their charges than customers in the least deprived deciles.

4.4 Refining TOU price signals by observing consumer responses

While OJV implemented TOU for network prices charged to retailers, there was little use of TOU pricing by retailers in the prices that they charge customers. The Electricity Authority has issued a decision requiring all retailers to offer a TOU pricing option to their customers. Going forward, we will be observing and monitoring the impacts of TOU pricing and customer response as more consumers are exposed to TOU signals in retail prices, which will help us to refine our TOU pricing.

4.5 Understanding forward-looking costs of peak usage

The nature of electricity network costs is that they are largely fixed – consumer electricity usage does not change our existing costs. However, the timing of customer usage can affect future investments. In particular, increases in consumer use of electricity at the times when the network is most heavily congested (typically winter mornings and evenings) can trigger network upgrades to accommodate higher network demand. Conversely, electricity use at times when network load is at its lowest, such as overnight, does not drive additional future cost.

In an effort to better inform our TOU pricing, we have prepared a model of the forward-looking costs associated with electricity consumption at peak times – the Long-Run Marginal Cost (LRMC). We describe details of this modelling exercise in section 10.1.2. We expect to continue to refine this estimate and to draw on it when setting TOU prices.

4.6 Installed Capacity pricing and the LFC phase-out

Given that a significant proportion of OJV's costs are essentially fixed, it would not be efficient for all costs to be recovered through charges that relate to energy usage. As a result, a portion of our costs are recovered from daily fixed charges. OJV's daily charges vary according to a connection's capacity (installed capacity) and availability of controlled load.

This year 56% of OJV's total line charge revenue is from fixed (capacity) charges. With the 5-year phase out of the Low Fixed Charges and the fact that the majority of costs are fixed, OJV will look to continue to increase the share of total revenue from fixed charges over time.

Customers with at least 25% of their total energy consumption on a controlled load or energy used during the night period qualify for the "off-peak" fixed charge price, which is up to 35% reduction on the "peak" price. This price incentive is fixed for customers and does not vary according to monthly consumption; it provides a strong signal and a tool for OJV to control the load on the network during congestion periods therefore helping to avoid network upgrades and price increases.

5. REVENUE REQUIREMENT

OJV is subject to the Commerce Commission's Default Price-Quality Path regulation that sets an annual revenue cap (allowable revenue). Net Allowable Revenue is calculated based on various building block inputs including network operating expenditure (opex), non-network opex, a return of capital employed (depreciation), a return on capital employed (based on asset values and the WACC) and regulatory tax. Forecast pass-through costs and recoverable costs are added to the Net Allowable Revenue to determine the Total Allowable Revenue for the year. Table 1 below shows the calculation of Total Allowable Revenue. Table 2 and Table 3 provide the details of the forecast pass-through costs and recoverable costs.

Table 1 Allowable revenue

Forecast allowable revenue RY27 ($000)	
Forecast net allowable revenue	39,758
Forecast pass through costs	11,026
Forecast recoverable costs	2,937
Total allowable revenue	**53,721**

Table 2 Pass-through costs

Forecast Pass-through Costs RY27 ($000)	
Rates on system fixed assets	237
Commerce Act levies	182
Electricity Authority levies	131
Utilities Disputes levies	15
Transpower transmission charges	9,957
New investment contract charges	505
Total forecast pass-through costs	**11,026**

Table 3 Recoverable costs

Forecast Recoverable Costs RY27 ($000)	
IRIS incentive adjustment	(552)
Wash-up draw down amount	3,569
Quality incentive adjustment	(120)
Fire and emergency NZ levies	40
Innovation project allowance	-
Total forecast recoverable costs	**2,937**

In accordance with the DPP requirement that forecast revenue should not exceed allowable revenue, OJV's total target revenue for 2026/27 is set at $53.8 million, increasing from $46.2 million the previous year. Below is a summary of target revenue for both transmission costs and distribution price components broken down by the two customer group categories and disaggregated into the Otago Region and the Lakeland Region for the 2026-27 year.

Table 4 Target revenue

Otago Region Year 2026-27	Residential and General	Individual	Total
Distribution	$28,158,074	$2,964,525	$31,122,599
Transmission	$3,095,898	$5,742,092	$8,837,990
Pass-through costs	$569,022	$4,092	$573,114
Recoverable costs & Washup draw down amount	$2,607,876	$328,988	$2,936,864
Total	**$31,494,006**	**$9,039,697**	**$40,533,703**
Lakeland Region Year 2026-27	Residential and General	**Individual**	**Total**
Distribution	$10,783,936	$811,545	$11,595,481
Transmission	$1,058,679	$565,141	$1,623,820
Pass-through costs	$30,709	$77	$30,786
Total	**$11,873,324**	**$1,376,763**	**$13,250,087**

6. COST ALLOCATION

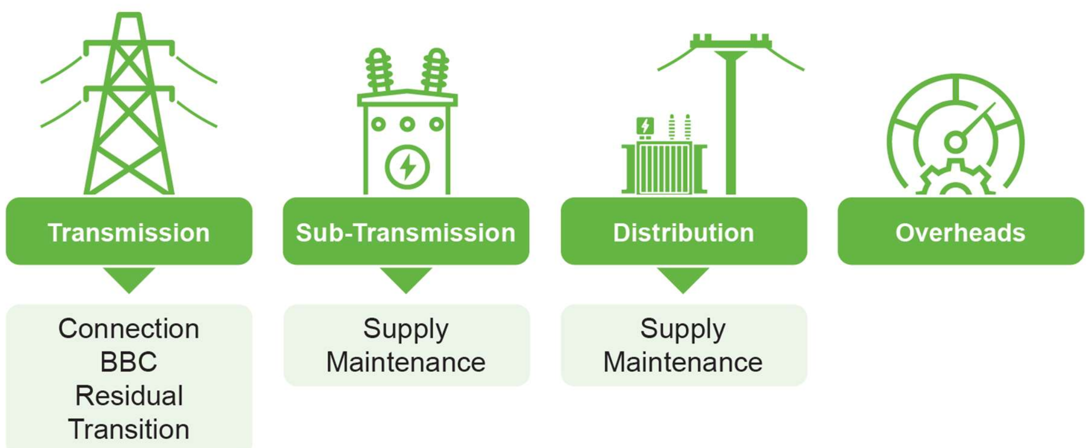
The costs used to calculate the revenue requirement are allocated between the relevant consumers and consumer groups. In carrying out this allocation, the objective is to reflect the share of the costs in a robust and equitable manner. Each consumer or consumer group's share of the use of the assets and costs is calculated to reflect their respective use.

6.1 Methodology and allocators

We allocate costs separately for categories and sub-categories of network asset groups and other costs:

- **Transmission charges** are what we pay to Transpower for access to and use of the national grid.
- **Sub-transmission costs** relate to the 66kV and 33kV network and the zone substation costs.
- **Distribution costs** relate to 11kV and 400V line and cables as well as distribution substations and transformers.
- **Overhead costs** are other costs associated with operating our distribution network business that cannot be allocated directly to either capital or maintenance.

Figure 3 Cost categories and sub-categories



The costs of the sub-transmission and distribution components of the line charges are split into two categories:

- Supply, which is the depreciation of the network assets, other ownership costs and the cost of capital required to fund the assets. As the company is owned by a consumer trust, the required gross return is presently comparatively low as most of the consumer shareholders receive an implicit benefit in the way of reduced line charges.
- Maintenance, which is based on the Maintenance Works Program for the current year.

Management costs for capital and maintenance work are allocated to Supply and Maintenance respectively.

6.1.1 Our allocators are selected to reflect cost-drivers

The allocators we use are based on seven profile parameters relating to the customer group, or the Individual customer.

We use a measure of demand to allocate sub-transmission costs and Transpower's connection charges, as this is a key driver of costs. Similarly, for distribution costs we allocate using a measure of consumer's installed capacity. However, our methodology also takes into account the duration that the customer impacts on the peak loading hours of the network. We do this by allocating some of the transmission, sub-transmission and distribution costs based on the amount of electricity that consumers use during peak times and during winter days. In effect, this reduces the charges for a customer who incurs just one-half hour peak for the whole peak period or is only impacting on the peak hours for part of the peak period and increases the charges for those customers who are impacting regularly on the peak periods.

Measures of network use for cost allocation

Capacity

1. The Contract Capacity kVA (kW) of the installation

Peak Demand

2. The Peak demand kVA. (kW) (0700-1100 hours and 1700-2200 hours, each weekday during sub-transmission peak months of individual grid exit points)
3. For Individual customers only, Coincident Peak demand with Transpower's individual GXP residual charge peak times.

Amount of electricity used

4. The Peak energy MWh. (0700-1100 hours and 1700-2200 hours, each weekday during sub-transmission peak months)
5. The Winter Day energy MWh. (0700-2300 hours, May to September inclusive)
6. The Summer Day energy MWh. (0700-2300 hours, October to April inclusive)
7. The Total energy for the 12-month period MWh.

The following table provides a summary of the customer profile measures, with further details provided in **Error! Reference source not found.**.

6.1.2 We apply diversity factors to peak demands and contract capacities

For the purposes of cost allocations, we apply diversity factors to the peak demand and contract capacity measures.

The Diversity Factor that we apply to the measured Maximum Demand of each customer varies reflecting the assessed contribution of the different sized customers on the required capacity of the GXP and the OJV network. This is known as the After Diversity Maximum Demand (ADMD).

Larger customers have lower Diversity Factors as there are a smaller number of these customers and their impact on the GXP Peak Demand will be greater.

Measurements of diversity across domestic customers have been recorded for years using MDI's (Maximum Demand Indicators) at the local distribution transformers. The ADMD for domestic customers typically varies from 1kVA up to 10kVA depending on the size, age and location of the houses. An average of about 3kVA or a Diversity Factor of 20% has been used reflecting the increase in the number of heat pumps over the past few years.

For the OJV network these Diversity Factors for different sized customers are shown in the following table.

Table 5 Diversity factors

Maximum Demand	Diversity Factor
Over 750kVA	95%
Over 105kVA and up to 750kVA	45% to 95%
Over 5kVA and up to 105kVA	17% to 45%
Unmetered Supplies up to 1kVA	100%
Streetlights	85%

The Diversity Factors are applied proportionately on an incremental basis between 5 and 750KVA.

As there is no documented methodology for the Group Customers the Diversity Factors are not used as the line charges are based on a rate per kVA of installed capacity.

6.2 Transmission Charges

Transmission charges reflect the Transpower grid asset management charges faced by OJV based on the four grid exit points of supply: Naseby, Halfway Bush, Balclutha and Frankton.

Transpower's charges have four components: connection charges, Benefit Based Charges, Residual Charge and a Transitional Cap. The following discussion explains how we allocate each of these charges across consumers and consumer groups.

6.2.1 We allocate Transpower's connection charges using a mix of peak demand and energy usage

The Transpower connection cost allocation is based on the Transpower local assets utilised to provide the supply and includes Transpower new investment charges. As the Connection Charges are to recover the costs of the local assets at each of the GXPs including any upgrades through a Transpower Works Agreement (TWA), the allocation of these charges is mainly based on the ADMD of each customer. It is believed that this parameter is the most practical method of reflecting each customer's contribution to the requirement for Transpower's local GXP investment.

The 2026/27 charges for each GXP, as well as the projected peak demands and energy delivered through each GXP are shown in the following table.

Table 5 Connection Charges and Profiles

GXP	Annual Connection Charges	GXP Peak kW Demand	Annual MWh
Balclutha	$1,351,735	29,452	180,937

Halfway Bush	$89,922	6,246	33,354
Naseby	$946,094	31,822	227,287
Total or Average - Otago Region	$2,387,750	67,520	441,578
Frankton – Lakeland Region	$949,691	18,104	63,062

Ideally the allocations of connection charges should apply to all customers supplied from the specific GXP, in the case of the Otago region we apply the average rate to all existing customers. The reasons for this are as follows:

- The large differences in rates,
- The location of existing customers is historical, and some customers would be unduly penalised,
- The predominant load in the area (Oceana Gold's McRae's mine) has a relatively short predicted life at which time a GXP could be phased out.
- The allocation of the Connection Charges is ideally based on the coincident demand for each customer during the period when the GXP peak demand occurs. For customers with half hour metering this is the case.
- For non–half hour metered residential and general customers this half hour period cannot be predicted accurately, and customers are unable to respond to dynamic real time pricing signals, the ADMD is used.

The resulting allocation of the Connection Charges is in the following table.

Table 6 GXP Profiles

Customer Group	GXP Peak Demand $/kVA	ADMD $/kVA
Half hour metered Individual Otago region	35.36	
Residential and General Otago region		18.36
Half hour metered Individual Lakeland region	52.46	
Residential and General Lakeland region		20.98

The sub-transmission and distribution loss factors are applied to meter readings so that meter readings can be reconciled across the network and with the GXP meter readings.

Loss factors are applied to the GXP rates to produce the equivalent customer rates.

The total Connection Charges revenue from the Individual Customers is to be $1,726,805 or 52% of the total Transpower Connection Charges.

6.2.2 We allocate the Transpower Benefit Based Charge (BBC) using total energy consumption

The costs of new and some historic interconnection investments (the BBIs) are allocated by Transpower according to the beneficiaries of those investments through the BBC. BBIs include investments in new interconnection assets or interconnection transmission alternatives and the replacement or refurbishment of existing ones. The cost recovered through the BBCs is referred to as the BBI's "covered cost" and includes capital components (return of and on capital expenditure) and an allocation of Transpower's total operating costs (including overheads).

Transpower allocates each BBI's covered cost between transmission customers broadly in proportion to the positive net private benefit (NPB) each customer is expected to derive from the BBI. That is, the BBC paid to Transpower by a transmission customer must reflect the positive NPB that customer is expected to receive from the BBI (if any) relative to all other customers.

The NPB of each BBI is derived by historic load flow analysis (MWh). As a result, OJV allocates BBCs on an annual energy consumption basis.

To calculate the BBC allocation to Individual Customers, we divide the BBC for each GXP by the annual total energy consumption of the GXP, to provide a $/MWh rate for each GXP. Each Individual consumer's total annual energy consumption (MWh) is then multiplied by the rate for the relevant GXP to calculate the annual BBC. The total benefit-based charges for each point of supply and the allocation rate for Individual customers are contained in the following table.

Table 7 BBC allocation rates for Individual Customers

Point of Supply	Total Benefit Based Charges	Allocation rate (per MWh)
Balclutha	$600,161	$3.32
Halfway Bush	$87,175	$2.61
Naseby	$443,759	$1.95
Frankton – Lakeland Region	**$67,796**	$1.08

The remaining BBC charges (net of the amount allocated to the Individual customers) are allocated to Residential and General customers. After the revenue from the Individual customers has been subtracted from the total the remaining BBC to be allocated to Residential and General customers equates to $2.73 per MWh for the Otago region and $1.26 per MWh for the Lakeland region.

6.2.3 We allocate Residual Charges using measures of demand

Residual Charges recover Transpower's remaining revenue that is not recovered through other transmission charges. Residual Charges are paid by Transpower load customers only, in proportion to their historic (or, for new load customers, estimated) maximum gross demand. Gross load excludes contributions from batteries when charging or discharging other than their storage losses.

The initial (baseline) allocations of residual charges are in proportion to Transpower customers' maximum gross demand (kW) at the grid exit point averaged across the four financial years (FYs) from FY 2014/15 to FY 2017/18, i.e., the period 1 July 2014 to 30 June 2018. For a Transpower load customer that did not exist on 1 July 2014, including a new load customer, Transpower estimates maximum gross demand based on the customer's assets and the assets connected to them being fully operational.

Load customers' initial allocations are adjusted annually based on changes in their lagged average gross energy usage (kWh) over the period of four financial years commencing eight financial years ago, e.g., for PY 2026/27 the relevant period is from FY 2018/19 to FY 2021/22.

The annual Residual charge for OJV by GXP are described in the following table.

Table 8 Total Residual charges paid by OJV by GXP

GXP	Residual Charge
Balclutha	$2,352,632
Halfway Bush	$555,709
Naseby	$2,407,331
Frankton	$606,006

For Individual customers the allocation of the Residual Charge is calculated using the same method that Transpower uses to allocate the residual charge to OJV (based on average gross demand and lagged average energy usage). For Individual customers that were not active during the baseline allocations or who are new customers, the initial average gross demand and lagged average energy will be estimated as if it was fully operational during the baseline period. The estimate is based on similar-sized businesses' average gross demand. The estimates may be adjusted following the recording of actual demand levels through half-hour metered data. OJV may alter an individual customers' average gross demand and lagged average energy should a major repurpose of the ICP occur.

For Residential and General groups, the total amount of residual charge allocated to the Individual customers is deducted from the total network residual charge, the result is the amount to be allocated to all the residential and general groups. This resultant amount is then divided by the total peak demand of the Residential and General customer groups to calculate a $/kW rate. Each Residential and General load group's average after-diversity maximum demand is then multiplied by the $/kW rate to calculate the annual allocation to each ICP in the load group. The annual allocation amount is then multiplied by the number of ICPs in the load group to calculate the residual amount allocated to the load group.

The allocation rates are in the following table.

Table 9 Residual charge allocation rates

	Per kVA Average Gross Demand
Individual customers, per kVA Average Gross Demand	$77.42
Residential and General Customers, per kVA After Diversity Maximum Demand	
Otago region	$39.10
Lakeland region	$10.55

8.1.4 Transitional Cap

The Transitional Cap applies to distributors and grid-connected consumers' BBCs for the seven historic (pre-July 2019) BBIs and residual charges, and caps those charges relative to the distributors or grid-connected consumer's interconnection and HVDC charges for PY 2019/20. This is not a cap on total transmission charges. The cap is funded by distributors.

The Transitional cap is allocated to customers based on their share of the overall Benefit Based and Residual Charges. The annual transitional cap for each GXP is shown in the following table.

Table 10 Annual Transitional Cap for OJV by GXP

GXP	Transition Cap charge
Balclutha	$1,594
Halfway Bush	$343
Naseby	$1,535
Frankton	$327

For Individual customers the sum of the annual BBC and RC are divided by the sum of the total GXP's BBC and RC, this percentage is then multiplied by the annual Transitional Cap amount for the GXP to calculate the annual Transitional Cap charge.

For the Residential and General customers, once the total amount of Transitional Cap allocated to the individual customers is deducted from the total network Transitional Cap charge, the result is the amount to be allocated to all the residential and general customers. The sum of the annual BBC and residual charge for each load group customer is divided by the sum of the total benefit-based charge and residual charge for the network. This percentage is then multiplied by the annual Transitional Cap amount for the network to calculate the annual Transitional Cap charge for each customer. The annual allocation amount is then multiplied by the number of ICPs in the load group to calculate the residual amount for the load group.

8.2 Sub-transmission cost allocation

6.2.4 Supply costs

To allocate supply costs, we disaggregate the sub-transmission network into its constituent components including every line and every zone substation. These components are then categorised, i.e. 66,000 and 33,000V, indoor and outdoor, size, number of transformers, circuit breakers, length of line etc.

Values for each of these sub-transmission network components are based on the replacement value costs. These values were then amended by the ratio of the overall replacement cost to the asset value of the network. The appropriate share of the supply charge was allocated to each zone substation on this basis.

The share of the sub-transmission lines by each zone substation was determined using the electrical circuit superposition theorem and by calculating load flows through the interconnected mesh network.

The total annual revenue required from the sub-transmission lines assets by the owners is $3,292,889 in the Otago region and $1,540,541 in the Lakeland region.

This annual revenue requirement was then allocated to the zone substations according to the load flow calculations outlined above.

The modern equivalent replacement value of the zone substations is the basis of the annual costs attributed to these assets. The total annual revenue required from these assets is $3,402,652 for Otago and $4,313,516 for Lakeland.

6.2.5 Maintenance costs

The sub-transmission lines maintenance budget of $389,129 in Otago and $69,116 in Lakeland is allocated across the line segments based on the length of each line segment. These maintenance figures are then allocated across the zone substations in accordance with the load flow methodology referred to above. The zone substation maintenance budget of $1,102,532 for Otago and $215,987 for Lakeland is allocated across the zone substations based on a weighting proportional to the relative size of the substation.

6.2.6 Total sub-transmission costs

The total sub-transmission costs allocated to each zone substation are shown in the following table. Three zone substations either have none or a minimal number of customers supplied directly from them, and their main purpose is as part of the sub-transmission network configuration.

Table 11 Total annual sub-transmission costs for each zone substation

Zone Substation	Total Annual Cost per Zone Substation
Charlotte	$208,748
Clarks	$222,814
Clinton	$267,175
Clydevale	$276,405
Deepdell	$100,461
Elderlee St	$395,610
Falls Dam	$75,470
Finegand	$153,634
Glenore	$109,681
Golden Point	$143,097
Greenfields	$253,481
Hindon	$292,585
Hyde	$127,117
Kaitangata	$176,373
Lawrence	$620,562
Macrae's Mine	$265,658
Mahinerangi	$164,069
Merton	$370,653
Middlemarch	$302,098
Milburn	$312,145
North Balclutha	$146,196
Oturehua	$89,465
Owaka	$296,484
Pereau	$259,068
Pereau Hydro	$606,239
Palmerston	$307,118
Patearoa	$165,677
Port Molyneux	$142,008
PPCS	$134,864
Pukeawa	$91,718
Ranfurly	$185,113
Stirling	$141,338
Waihola	$198,307
Waipiata	$119,516
Waitati	$328,277
Wedderburn	$137,291
Totals	$8,186,515
Remarkables	$6,139,159

6.2.7 Sub-transmission Charges for Individual Customers

For the Individual Customers, the sub-transmission component of the line charges is based on the ADMD of the customer.

Similar to the transmission charges, to mitigate against one off occurrence and provide a better reflection of the impact of the customer load on the sub-transmission costs, the pricing methodology also takes into account the duration that the load of the customer impacts on the peak loading hours of the network. This is achieved by allocating some of the sub-transmission costs to the Peak, Shoulder and Low Period Energy volumes.

This in effect reduces the charges for a customer that incurs just one half hour peak for the whole peak period or is only impacting on the peak hours for part of the peak period and increases the charges for those customers that have a higher potential impact on the peaks.

The annual cost of each zone substation is then allocated across the maximum demand, Peak, Shoulder and Low Period volumes of energy as follows:

- Peak Demand 35%
- Peak Period Energy 25%
- Shoulder Period Energy 30%
- Low Period Energy 10%

The sub-transmission cost allocation rates relating to each zone substation are shown in the following table Individual Customers.

Table 12 Sub-transmission cost allocation rate for Individual customers

Sub-transmission Profile Rates				
Zone Substation	**Subtrans $ per kVA**	**Subtrans $ per Peak MWh**	**Subtrans $ per Shoulder MWh**	**Subtrans $ per Low MWh**
Charlotte	$14	$17	$6	$4
Clarks	$364	$349	$119	$72
Clinton	$43	$49	$17	$10
Clydevale	$25	$40	$12	$7
Deepdell	$352	$290	$99	$60
Elderlee St	$31	$36	$11	$8
Falls Dam	$20	$15	$5	$2
Finegand	$46	$65	$20	$13
Glenore	$55	$84	$28	$17
Golden Point	$17	$358	$86	$216
Greenfields	$39.57	$46.19	$8.83	$5.13
Hindon	$512	$731	$250	$151
Hyde	$64	$104	$21	$12
Kaitangata	$43	$44	$14	$9
Lawrence	$175	$185	$59	$36
Macraes Mine	$3.30	$3	$1	$0
Mahinerangi	$1,436	$1,358	$447	$261
Merton	$49	$51	$15	$10
Middlemarch	$117	$176	$63	$37
Milburn	$50	$77	$23	$22
North Balclutha	$20	$21	$7	$4
Oturehua	$157	$231	$79	$48
Owaka	$74	$78	$27	$16
Paerau	$278	$627	$214	$130
Palmerston	$49	$53	$17	$10
Patearoa	$26	$49	$18	$11
Port Molyneux	$83	$86	$27	$16
PPCS	$7	$11	$3	$1
Pukeawa	$67	$169	$51	$40
Ranfurly 33kV	$26	$25	$8	$5
Stirling	$12	$30	$4	$2

Waihola	$50	$70	$24	$14
Waipiata	$21	$44	$14	$9
Waitati	$61	$76	$26	$16
Wedderburn	$281	$318	$115	$80
Remarkables	$57	$61	$12	$7

The ADMD, the Peak, Shoulder and Low Period Energy of each Individual Customer are then adjusted by the respective loss factors to determine the Individual Customer's sub-transmission annual charge.

6.2.8 Sub-transmission cost allocation rates for Group customers

After the revenue from the Individual customers has been subtracted from the total sub-transmission costs, the remaining costs are recovered from Residential and General customers. The resulting cost allocations are displayed in the table below.

Table 13 Sub-transmission cost allocation rates for group customers

	Otago	Lakeland
Individual Customers	$2,388,726	$479,812
Residential and General	$5,798,476	$5,659,347
Total	$8,187,202	$6,139,159

The significant difference in the share of the transmission and sub-transmission costs between the two main categories, Individual and Residential and General Customers is due to one major customer.

The 66kV sub-transmission line and zone substation supplying this customer have minimal capital and maintenance costs incorporated in the line charges as the capital costs were paid by the customer under a separate agreement and the owner is invoiced directly for all maintenance carried out on the 66kV line and zone substation.

The size of this customer also has a major impact on the allocation of OJV's pass through of Transpower's transmission charges.

6.3 Distribution cost allocation

The distribution costs are the annual capital and operating costs of the 11kV, 400V networks, distribution substations and transformers.

The distribution component of the line charges is split into two subcomponents, the annual costs of the lines and/or cables that are connected to the customer and secondly the annual costs of the local distribution substation or transformer.

6.3.1 Cost of distribution lines/cables

An annual capital and maintenance cost per urban and rural km of line is calculated and used to determine the location costs of the Individual Customers.

The table below shows the annual costs of the distribution lines. The cost per km of urban lines is higher than the rural lines, reflecting the closer spacing of poles, the larger conductor sizes and the inclusion of the 400-volt lines. The rural lines tend to have longer spans, lighter conductors, minimal amount of 400-volt lines and utilise SWER (Single Wire Earth Return) technology which reduces the cost per km.

For Individual Customers the location of the customer is taken into consideration in determining the former's share of the distribution line charge component.

The location is determined by measuring the radial distance from the nearest zone substation to the customer or local distribution transformer from which the customer is supplied. Any natural structures that would prohibit a cost effective supply are bypassed effectively increasing the radial distance.

The maximum demand of the Individual Customer is then compared to the maximum load on the 11kV distribution line ("feeder") supplying the customer and area. This ratio is then used to calculate the Individual Customer's share of the feeder.

The annual distribution line charge for the Individual Customer is its share, based on the above ratio, of the annual cost of the length of line supplying the customer.

Table 14 Annual distribution line costs

Annual Distribution Line Costs	Otago	Lakeland
Distribution Line Urban annual costs	$1,685,335	$3,852,266
Line Length Urban km (11kV)	120km	90km
Cost per km of urban line (11kV and 400V)	$14,044	$2.36/kVA/km
Distribution Line Rural annual costs	$15,167,901	
Line Length Rural km (11kV)	3000km	
Cost per km of rural line (11kV and 400V)	$5,056	

In calculating the distribution maintenance charges an allowance is made for the fact that customers above 150kVA have less use of the 400V network than smaller customers, i.e. they often have their own local transformer or exclusive supply cables from a transformer. The line portion of the distribution charges is multiplied by a factor of 70%.

For the Residential and General Customers, the remaining distribution Line costs are allocated on an average basis using the same methodology as described above for the sub-transmission charges.

6.3.2 Distribution transformer costs

Annual capital and maintenance costs have been calculated for the distribution transformers dependent on their size.

The table below shows the number and capacity of distribution transformers owned by OJV and connected to the network.

The annual cost per transformer is dependent on its size or kVA rating so the capital cost has two subcomponents, one being a fixed cost per transformer (22.5%) and the other cost (67.5%) based on the kVA capacity.

The total annual capital cost to be recovered is $3,073,363 in the Otago region and $1,027,028 in the Lakeland region. The distribution transformers maintenance costs to be recovered in the Otago region are $324,274 and $115,423 for Lakeland.

For Individual Customers the transformer costs are charged on an individual basis depending on transformer size and use i.e. whether it is for the exclusive use of the customer or it also supplies other customers.

Table 15: Distribution Transformer Cost and Capacity

Description	Capacity	Number	Total Capacity	Annual Cost per Transformer
Transformer 15kVA	15	2839	42,585	$592.01
Transformer 30kVA	30	588	17,640	$711.75
Transformer 50kVA	50	364	18,200	$871.40
Transformer 75kVA	75	31	2,325	$1,070.97
Transformer 100kVA	100	121	12,100	$1,383.82
Transformer 150kVA	150	0	0	$1,782.96
Transformer 200kVA	200	99	19,800	$2,182.10
Transformer 300kVA	300	72	21,600	$2,980.38
Transformer 500kVA	500	48	24,000	$4,576.93
Transformer 750kVA	750	12	9,000	$6,572.62
Transformer 1,000kVA	1,000	6	6,000	$8,568.31
Transformer 1,250kVA	1,250	0	0	$10,564.00
Transformer 1,500kVA	1,500	0	0	$12,599.69
Total		**4,180**	**173,250**	

6.4 Overhead cost allocation

Overhead cost allocation rates reflect those costs that cannot be allocated directly to either capital or maintenance. These costs can include Executive Management, Directors Fees, System Control, and Miscellaneous overheads such as buildings. These costs are allocated equally over the total customer base.

The cost allocation rate per customer is $165.64 per year in the Otago region and $81.66 in the Lakeland region.

6.5 Loss Constraint Excess Payment

Loss Constraint Excess Payments are credits rebated by Transpower as a result of money received from the Clearing Manager for the Wholesale Electricity Market and are excluded from the Transmission Charges. The payments are allocated each month to the retailers on the basis of total energy consumption for the month in which the rebate applied.

6.6 Summary of target revenue and pricing changes

The total target revenue of $53.8 million for 2026/27 compares with $46.2 million the previous year. The following table provides a summary of revenue across both years for transmission distribution price components, broken down by the two customer group categories.

Table 16 Target revenue comparison with last year

Otago Region	Residential & General customers	Individual customers	Total
2026-27 Revenue			
Distribution	$28,398,108	$3,297,605	$31,695,713
Transmission	$3,095,898	$5,742,092	$8,837,990
Total	$31,494,006	$9,039,697	$40,533,703
Previous year			
Distribution	$25,064,672	$3,351,997	$28,416,669
Transmission	$2,602,645	$4,948,947	$7,551,592
Total	$27,667,317	$8,300,944	$35,968,261
Lakeland	**Residential & General customers**	**Individual customers**	**Total**
2026-27 Revenue			
Distribution	$10,814,645	$811,622	$11,626,267
Transmission	$1,058,679	$565,141	$1,623,820
Total	$11,873,324	$1,376,763	$13,250,087
Previous year			
Distribution	$8,543,873	$663,674	$9,207,547
Transmission	$630,656	$381,536	$1,012,192
Total	$9,174,529	$1,045,210	$10,219,739

The changes in revenues are based on changes to our costs and our allocation of these costs to the customer groups. Other factors that impact on the allocation of costs relate to changes in quantities and individual customers profile changes as well as contractual changes.

Distribution revenue changes reflect changes in operation and maintenance costs and capital investment requirements.

The pricing schedules are contained in Appendix B.

7. SETTING PRICES

After having set the target revenue and determining the revenue to be determined from each customer group, we then determine each price that appears in the OJV pricing schedules. The following discussion describes how we set pricing, having regard to economic principles, network cost drivers and consumer impacts.

7.1 Residential and General Customers

As was described in section 3, our pricing for Residential and General customers in the Otago Region includes a daily capacity charge and TOU usage pricing, where the price per kWh varies across Peak, Shoulder and Night periods. For the Lakeland region for residential customers the price per kWh is seasonal and for General connections we apply a CPD charge. To set prices for each group, we need to decide what the optimal prices are for network use during each of these periods and then set the prices for capacity charges to recover the remainder of the target revenue. As part of this calculation, we also need to forecast usage volumes for the coming year. The following sections discuss how we set prices and the resulting prices for Residential and General customers are presented in **Error! Reference source not found.**.

7.1.1 The balance between fixed and variable charges

Strictly applying economic principles tells us that the off-peak price should be set at or close to zero, with peak price set at the forward-looking cost of upgrading the network to serve additional demand. As discussed in section 10.1.2, we estimate the Long Run Marginal Cost (LRMC) in the Otago region of our peak TOU times to be $0.0369 per kWh. Our peak TOU price for 2026/27 in the Otago region is higher than this at $0.14388 per kWh. However, if we were to reduce this price to be closer to the LRMC-based price, then we would need to significantly increase the daily capacity charges.

While forward-looking LRMC estimates form an input into our decision-making, we also account for customer impacts in making pricing decisions. This year daily capacity charges increased to reflect an increase in transmission and distribution costs. As was discussed in section 4, our current strategy is to rebalance our fixed and variable charges over time so that fixed charges account for 60% of revenue.

7.1.2 Recovery of Transpower Charges

Transpower's charges, which follow the Transmission Pricing Methodology (TPM), are fixed in nature and not intended to influence customer network use decisions. As a result, OJV recovers Transpower charges through fixed (capacity) charges where possible.

For half-hour metered Individual customers, we recover the residual, benefit based and transitional cap charges through fixed daily charges and the connection charge through variable line charges.

Currently the recovery of total line charges is on a 60/40 split between fixed and variable charges, OJV's strategy is to recover more line charge revenue through the fixed daily charge. This will be achieved by increasing the fixed charge percentage each year to allow all of the Transpower charges to be recovered through the fixed daily charge over time.

7.1.3 Forecasting usage when setting prices

We forecast consumption for combined residential and general customers including the low user consumption based on the last three years consumption. The low user forecast quantity is then deducted from the combined averaged consumption to establish the forecast quantities for the remaining residential and general customer groups.

7.2 Individual Customers

The total line charge allocation for Individual customers is converted into fixed charges and variable charges. The fixed/variable split is approximately 60:40. With more costs, in particular Transpower costs, being of a fixed nature OJV will be increasing the fixed charge percentage split of the total line charge.

For the Individual line charge installations with half hour metering the total line charge is multiplied by 0.6 to establish the fixed charge per annum. The variable charge is calculated as the remaining charge divided by the number of Day kWh in the customer energy profile to give a variable charge in cents per Day kWh.

Individual line charge customers have their line charges reviewed each year in line with the line pricing methodology. Actual day energy volumes recorded from December 2024 to November 2025, are used as the forecast quantity for the 2026 - 2027 forecast period.

7.3 Customer Consultation

Where significant changes in pricing structure are considered, OJV consults with retailers and customer groups. The changes to pricing that took effect on 1 April 2022 involved significant changes, OJV consulted with retailers on the change to Time-of-Use pricing and the likely impact to customers.

Even in the absence of significant pricing change, OJV seeks the views of consumers as part of the asset management process and has reflected these views in the published AMP. This included a face to face survey with key clients including expectations on price and current service

1. A bulk phone survey of current customers including expectations on price and quality
2. Consultation meetings at various locations throughout the network
3. Individual consumers are consulted as they consider supply upgrades or new connections to the network.

The views are considered in preparation of the AMP.

Quality in the form of security of supply (n versus n-1), capacity (equipment loadings) both impact on the cost of supply and subsequently prices charged. Price is able to be varied through different payment options (such as capital contributions, line charges and new investment agreements) which are discussed with large individual consumers as they consider supply upgrades or new connections to the network.

8. NON-STANDARD CONTRACTS

OJV has a standard methodology for the determination of line charges for large customers, these line charges are charged to the customer via an interposed basis with the energy retailer.

In rare cases, the standard methodology may not fully recover the return and operating costs of the large capital expenditure required in supplying these customers. These customers may also have enhanced security arrangements. In the situations where customers have significant capital contributions, and new investment agreements, robust commercial contracts incorporating prudential requirements are prudent to mitigate the risk of these assets being stranded. These contracts can also assist in avoiding uneconomic by-pass of the network when negotiating commercial arrangements and encourage growth within the network.

OJV contracts directly with three ICP's for the line services provided to their large industrial sites. This is essentially because the value of the OJV-owned assets dedicated to the supply of these sites is significant (in the millions of dollars) and one customer has a limited operational life.

The manner in which the charges were set in these contracts reflect the term of the agreement, the incremental costs involved in supplying these customers, the customer owned assets, any additional maintenance costs and the use of upstream network assets consistent with the pricing methodology and pricing principles.

8.1 Line Services Interruptions

Customers on non-standard contracts can contract to have an N-1 security arrangement, this is where the customer has an alternative supply to their site from the substation should their normal supply route be interrupted, this can be an automatic or manual change over process. Should customers choose to have the additional security of supply, their line charges will reflect the additional cost.

Customers on non-standard contracts who have standard security arrangements are subject to the same restoration arrangements as customers on standard contracts.

8.2 Target revenue from ICP's on Non-standard contracts

The total target revenue from ICP's on Non-standard Contracts for the 2026/2027 year is $4.063M.

9. DISTRIBUTED GENERATION

OJV's line pricing methodology and Part 6 of the Electricity Industry Participation Code 2010 applies to Distributed Generation connected to the electricity network for varying capacities.

In certain situations, it will be possible to connect Distributed Generation to the network downstream of the meter at a low capacity without modifications to the electricity network, in which case a standard offtake Line Charge will be required to be paid to OJV.

In other situations, there may be incremental costs incurred by OJV due to investigation and network modifications required. As with all customers seeking connection to the OJV electricity network where incremental costs are incurred an upfront capital contribution may be required to be paid.

For large capacity Distributed Generation options may exist to meet incremental costs either through payment of an upfront capital contribution and /or entering into a New Investment Agreement and / or Delivery Services Agreement with appropriate prudential security. A normal line charge will also apply according to the installation connection capacity of the Distributed Generators off take.

9.1 Financial Transactions with Distributed Generators

An application fee based on the capacity of connection is payable by the party making application to connect Distributed Generation to the network.

Financial transactions that can occur when Distributed Generation is connected to OJV's electricity network are:

Transaction Types	Capacity
Normal off take Line Charge (paid by the Distributed Generator to OJV)	All capacities
Capital Contribution (paid by the Distributed Generator to OJV)	All capacities where incremental costs are incurred by the network
New Investment Agreement charge (paid by the Distributed Generator to OJV)	For capacities > 500kW
Recovery of Benefit Based Transmission Charges (paid by the Distributed Generator to OJV)	Where the Distributed Generation is injected into the Transmission Network

9.2 Capital Contributions

Capital Contributions are calculated in accordance with the published Capital Contribution policy.

9.3 New Investment Agreement and / or Delivery Services Agreement Charges

New Investment Agreement and / or Delivery Services Agreement charges are negotiated with each customer and depend on factors including length of contract, asset lives, sunk costs, recoverable costs, maintenance costs, return on investment and prudential security provided.

9.4 Benefit Based Transmission Charges

Benefit Based Transmission Charges are recovered from Distributed Generators based on their share of the injected energy into the Transmission Network at the grid exit point they inject into.

9.5 Energy Reporting

Where distributed generation is connected to the distributor's network, kWh being exported onto the distributor's network must be submitted to the distributor.

The format the data is submitted must match the format of the ICPs other submitted data, e.g. either EIEP1 or EIEP3 format.

For clarity, export onto the distributor's network, and consumption off the distributor's network, are to be reported separately under the relevant price options (i.e. they should not be netted off).

9.6 Distributed Generation Injection Rebate

In accordance with new requirements in the Electricity Industry Participation Code, OtagoNet has introduced a distributed generation injection negative variable price. The new negative injection price is only available to all residential and general connections with a connected load capacity of 45kVA and below with an export capacity of less than 45kW that inject energy into the network during the distributed generation peak times, with volumes submitted in the half hour format (HHR) with a network approved application.

To identify ineligible commercial customers with a connection capacity of greater than 45kVA in the Otago region a new commercial tariff code 3 has been established from 1 April 2026, all customers in this capacity level will be migrated from the current commercial tariff code 2.

As per the Authority's Negative Charge Guidance for Distributors (Guidance), we have taken a three-step approach to setting prices, using the long run marginal price (LRMC) to base the negative charge based on a similar LRMC methodology as in section 10 below. The final negative charge for peak injection for the pricing year beginning 1 April 2026 is -$0.0506 per kWh with a 50% adjustment factor applied in the Otago region and -$0.0773 per kWh with a 70% adjustment factor.

Step 1: Determine the pricing window for the negative charge.

The peak time periods for the negative charge aligns with our top 100 peak times recorded for each of the network regions, being 7am to 10.00am and 5.00pm to 7pm during certain months for the Otago region and 7am to 10am and 5pm to 9pm in the Lakeland region for the winter months of May to September inclusive due to the high winter heating load.

The Otago region network has a diverse range of connected load, from rural dairy and irrigation, winter domestic heating to large processing loads this results in the network peaking at different times throughout the year and not the standard winter period. For the negative charge, the pricing window is the months of (May, August, October to December and February to March). This is because:

- For the negative charge for peak injection, as per the guidance, the goal is to determine the periods when demand on our network is at its greatest and when additional demand is likely to drive future network investment. Our network peaks occur during the identified months and times and our future network investment is driven by the growth in our peak demand, therefore we believe narrowing the pricing window for the negative charge to these months only is appropriate, which aligns with the Guidance's principles.

Step 2: Calculate the LRMC for Distributed Generation during Network Peak Times

- For the pricing year beginning 1 April 2026, our peak LRMC for Distributed Generation Injection is -$0.1012 in the Otago region and -$0.2577 in the Lakeland region before the adjustment factors are applied. We calculated this using the ENA LRMC template model with the best estimate we had of forecast capex at the time of setting prices*. The ENA model uses an Average Incremental Cost methodology.

Step 3: Determine an appropriate adjustment factor.

As allowed under subclause (1)(c) in Part 12A.7 of the Code, we have adopted a 50% adjustment factor to negative charges in the Otago region and 70% in the Lakeland region. This scales the negative charge down to reflect the specific risks and characteristics of injection with regard to transaction costs, consumer impacts, uptake incentives, and network stability, which are outlined below. At the outset, as suggested by the Authority in the guidance, we have been prudent to begin with a relatively high adjustment factor (and therefore lower negative charge), and will fine-tune it over time as better data and consumer feedback become available. In the Guidance, the Authority mentioned that Australian distributors use a range of adjustment factors ranging from around 10% to over 70%. To align with the prudent approach, we therefore have adopted 50% and 70% factor - the higher end of the adjustment factor range as a starting point. The Lakeland region is one of the highest growth areas in the country, with distributed generation also having a higher uptake, to allow us to assess the impact of this on the network we have initially allocated a higher adjustment factor.

Transaction costs

This consideration has prompted us to adopt a simple and broad approach, rather than a granular locational pricing approach, because:

- ICPs with distributed generation on our network is a very small portion with only around 806 ICPs – less than 3.6% of the total ICPs.
- Our estimate of total negative charge is likely to be less than $20k per year for all eligible ICPs.
- With such low penetration of ICPs with DG and low negative charge amount, changes to systems and processes (such as billing system upgrade) to facilitate granular pricing would outweigh the benefit itself.

Consumer impacts

This consideration has prompted us to adopt a conservative approach initially at setting the negative charge, because:

- As suggested by the Authority in the guidance, to avoid price shock, this means setting a negative charge at a relatively conservative rate initially, which increases over time, rather than setting it too high and discovering it needs to be lowered. This allows distributors to test and learn while sufficient visibility into our LV network is not available.
- Starting conservatively will also minimise the risks where the benefits from peak injection do not eventuate and same network investments are still required, leading to existing load customer cross-subsidising the negative charges.

Uptake incentives

This consideration also relates to us adopting a simple and broad approach. By not having a granular and complex set up, it facilitates retailers to pass them through efficiently.

*We note that as the AMP was in draft form at the time that we set the injection price, the forecast capex and demand that we used to calculate the LRMC may differ from what appears in the finalised version of the AMP

Network stability

Injection at the wrong time/place may not only provide no network benefits but may incur additional network costs by causing localised export congestion or voltage issues. This is also one of the reasons why we have adopted a conservative approach to avoid a sudden spike in generation leading to congestion. As we learn and gather more data throughout this journey, it will allow us finetune the negative charge amount to drive the best outcome for both the consumers and the network.
To further manage this risk:

- From a pricing perspective, additional costs caused by excess injection can be recovered under our export charge as incremental costs to distributed generation customers under Part 6 of the Code.
- From a technical perspective, setting appropriate export limit and smart meter data availability will also help us monitor and address potential congestion issues.

9.7 The form and the time periods in which it applies

As a result of the consultation with the retailers, new pricing component codes will be created for retailers to be able to submit injection volume for peak, shoulder and off-peak time band, and negative charges will apply accordingly.

10. PRICING PRINCIPLES ASSESSMENT

The Authority revised its distribution pricing principles in 2019 and provided clarification of how the principles should be applied in practice. The pricing principles are as follows:

The 2019 Distribution Pricing Principles

(a) Prices are to signal the economic costs of service provision, including by:

(i) being subsidy free (equal to or greater than avoidable costs, and less than or equal to standalone costs).

(ii) reflecting the impacts of network use on economic costs.

(iii) reflecting differences in network service provided to (or by) consumers; and

(iv) encouraging efficient network alternatives.

(b) Where prices that signal economic costs would under-recover target revenues, the shortfall should be made up by prices that least distort network use.

(c) Prices should be responsive to the requirements and circumstances of end users by allowing negotiation to:

(i) reflect the economic value of services; and

(ii) enable price/quality trade-offs.

(d) Development of prices should be transparent and have regard to transaction costs, consumer impacts, and uptake incentives.

We have considered each of these principles in developing our line prices.

10.1 Prices are to signal the economic costs of service provision

10.1.1 By being subsidy-free (equal to or greater than avoidable costs, and less than or equal to standalone costs)

OJVs cost of supply model allocates costs to Individual customers based on their geographical location and taking into account their share of the actual assets employed to supply them. The remaining group customers (Residential and General) have the resulting costs allocated to them on an averaged basis once the Individual customers' costs have been deducted from the total costs. It is not easy to accurately establish the stand-alone costs for most customers supplied by a common service via a meshed network. However, we can conclude that stand alone costs would be higher than average costs for those customers given the scale efficiencies in supplying them from a meshed network. OJV believes that the cost allocators used in the model are a representation of the underlying cost drivers of the business and therefore is subsidy free.

As a further check on existence of subsidies between consumer groups, we provide a calculation of avoidable and standalone costs based on a methodology that uses the readily available and audited data published in our information disclosures, rather than a methodology that involves remodelling the network. The methodology is assumption-driven but nevertheless provides comfort for each of our three load groups (Residential, General, Individual) and also for large industrials that have dedicated assets, our target revenue lies between avoidable and standalone costs. The following tables and chart set out the results of this analysis.

Table 17 Avoidable costs by load group

	OJV Residential	OJV General	OJV Individual	LNL Residential	LNL General	LNL Individual
Avoidable opex ($000)	$2,105	$1,744	$1,529	$719	$322	$204
Transmission ($000)	$1,707	$1,389	$5,742	$911	$148	$565
Avoidable cost ($000)	$3,812	$3,133	$7,271	$1,630	$470	$769
Revenue ($000)	$17,335	$14,159	$9,039	$9,590	$2,283	$1,377
Revenue > Avoidable cost?	Yes	Yes	Yes	Yes	Yes	Yes

Table 18 Standalone costs by load group

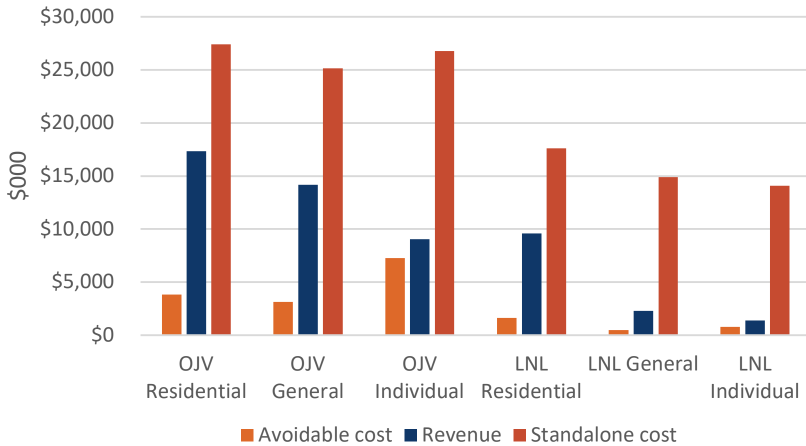
	OJV Residential	OJV General	OJV Individual	LNL Residential	LNL General	LNL Individual
Depreciation	$6,427	$5,976	$5,736	$4,831	$4,387	$4,255
Return on capital (pre-tax)	$13,897	$12,756	$12,148	$9,859	$8,735	$8,401
Opex	$5,385	$5,024	$3,169	$2,032	$1,634	$860
Transmission	$1,707	$1,389	$5,742	$911	$148	$565
Total standalone costs	$27,417	$25,146	$26,794	$17,633	$14,904	$14,081
Revenue	$17,335	$14,159	$9,039	$9,590	$2,283	$1,377
Revenue < Standalone costs	Yes	Yes	Yes	Yes	Yes	Yes

When carrying out this analysis, we estimated avoidable costs by first identifying which types of assets could be abandoned if each consumer groups was no longer be supplied. We then used data published in our regulatory Information Disclosures to estimate the avoidable costs associated with abandoning those assets.

To estimate the standalone asset costs for each customer load group, we:

- Identified which asset classes most resemble common assets, where the value of the assets needed to serve an individual customer load group are similar to value of assets needed to serve all customer load groups. Then we identified the RAB value of those assets, by asset class for each customer load group
- For asset classes that are more attributable to individual load groups (rather than being common to the supply of multiple customer groups), we allocated the RAB value to each customer load group
- We then calculated, for each customer load group, the depreciation and return on capital for common assets and for allocated attributable assets to estimate the standalone asset costs.

Figure 4 Subsidy-free test



Although OJV's pricing methodology attempts to minimise cross subsidisation between the larger individual consumers and between consumer load groups, it is possible that there is some degree of cross subsidisation between urban and rural consumers within the same consumer group.

New connections to the network pay a capital contribution if the expected revenue from the line charge does not cover the capital recovery cost required, this ensures that new connections are not subsidised and that total revenue from the new customer is not less than the expected incremental costs.

10.1.2 Reflecting the impacts of network use on economic costs

The introduction of Peak, Shoulder and Night energy component of line charges to residential and general customers in the Otago also provides a strong signal to consumers to utilise spare network capacity at Shoulder or Night time's thus reducing capital investment in the network. A time-of-use pricing structure assists in deferring network upgrades. The move to TOU pricing has served to refine and improve the signals of the previous day/night structure. Looking to the future, and the potential for developments such as EVs, to bring network assets closer to capacity limits, a forward-looking approach to having structures in place and understanding/developing the responsiveness of customers to signals before they need to be relied upon has been implemented.

For the Lakeland network, pricing for residential connections signals that winter is the season during which peak loadings are highest and provides reduced rates for controlled load. General connections to the Lakeland network are provided with peak control period demand pricing signals. These types of peak signals (kWh and demand) assist in deferring distribution and transmission network investments where network loadings are approaching capacity.

As we look to further develop our pricing, we need to have a greater understanding of our economic cost of supply. To do this, we have estimated our Long-Run Marginal Cost of supply (LRMC), and this will help with setting the time of use prices in the future. LRMC provides a measure of the forward-looking economic cost of network use and enables us to move towards price signals about the costs that will be incurred in future as a result of network use – that is, if peak usage increases, how much additional cost will be incurred by the network?

There are several methodologies that can be used to estimate the economic cost of incremental network use. We have used the Average Incremental Cost methodology (AIC) developed by Link Economics for the ENA, which unitises forecast network costs that are demand-driven by incremental demand. We applied this methodology because it:

- uses information that is already prepared for network management and disclosure purposes, rather than requiring network models of hypothetical changes in demand.
- is the most widely adopted and well-established method used in Australia, where AIC has been used for a number of years to set price levels, and this provides precedent on calculation and application to pricing.

However, we note that this methodology can provide volatile results because network investment is typically lumpy.

To estimate the LRMC using the Average Incremental Cost (AIC) methodology, we divide the Present Value (PV) of annualised incremental capex and opex by the PV of incremental demand. To do this, we:

- Sourced capex from OJV's system growth capex forecasts. We then used a WACC estimate with a 40-year assumption on asset lives to calculate annualised incremental capex.
- Included incremental opex by applying an opex factor to system growth capex. The opex factor was calculated using previous opex as a % of RAB (adjusted for average asset life) to estimate incremental opex as a percentage of incremental capex.

For simplicity, we calculated an average LRMC across all customer load groups (i.e., rather than calculating disaggregated estimates). Our resulting estimate of LRMC per kW was $108. Given our TOU definitions, this translates to a LRMC of $0.0369 for the Otago region.[5]

The LRMC-based kWh prices imply fixed charges that are substantially higher than OJV's existing fixed charges. These results support the continued rebalancing of prices to increase the proportion of revenue earned through fixed charges.

In practice, daily fixed charges are constrained by affordability considerations, an EDB's need to maintain social license, and the Low Fixed Charge Regulations.

Daily fixed charges can be suppressed by increasing kWh charges above LRMC levels. Exactly how this is done is a judgement call. OJV has a low night charge which, in the context of growing EV uptake is likely a key focus. In other words, it is arguably more important to keep prices closer to the LRMC rate for off-peak periods than it is for peak and shoulder (as OJV has done).

We continue to refine our LRMC modelling and note that one issue for further consideration is the treatment of replacement capex. Our LRMC analysis has focussed on system growth capex, but this approach could potentially understate the true LRMC. Arguably some replacement capex could be included as replacement may include some degree of capacity increase to cater to future growth.

With regard to charges for individual customers, total allocations are determined annually through a method which incorporates allocation of a portion of charges through peak demand measures. This is because the most significant cost driver that influences investment requirements in the network is the combined peak demand of all consumers in an area. OJV designs and constructs its network to meet this peak load. This ensures that charges signal the impact of additional demand on future investment costs. The use of a more sophisticated charging arrangement for individual customers reflects that they typically have greater capacity to manage and respond to demand-driven charges than smaller customers.

[5] LRMC price per kWh = (Probability of system peak x LRMC/kW/year)/(number of hours per year in TOU period)

OJV's peak times are outlined in the methodology and have encouraged individual customers to employ demand response actions such as turning on alternative generation or load shifting during these times to reduce their peak demands.

Customers are encouraged to use energy at shoulder or night times through the use of night store heaters, heating the hot water or using their appliances such as clothes driers, washing machines etc. during these periods. The customer is then financially rewarded, as the consumption attracts lower variable line charge prices. The "whole house TOU tariff" can reward consumers financially through prudent management of their power requirements.

10.1.3 Encouraging efficient network alternatives

The locational specific pricing that is incorporated into Individual Customer charges assists in providing signals on the cost of network provision in particular locations that can then be compared against network alternatives to encourage efficient decision-making by consumers.

Signalling when the network is likely to be at its busiest or when capacity is available also provides signals on when network alternatives can aid in meeting peak loads or in smoothing peaks through load shifting. TOU pricing assists with this – for example, by encouraging EV charging overnight. However, it is envisaged that TOU pricing will allow more accurate signalling of network busy times than the broad day/night periods that were previously in use. For individual customers, charges reflect demand during peak periods which would encourage efficient decision-making on customer investment in and use of network alternatives.

10.2 Where prices that signal economic costs would under-recover target revenues, the shortfall should be made up by prices that least distort network use

OJV uses capacity charges to recover costs that are not recovered through peak demand charges (Individual Customer) or TOU kWh charges (Residential and General) charges. These types of charges would have less distortionary impacts in recovering sunk costs than kWh or demand charges would, but arguably fairer than a single fixed charge for each and every ICPs. However, there are limitations on the proportion of costs that can be recovered through capacity or daily charges as a result of the Low Fixed Charge Regulations, as well as fairness considerations. OJV is continuing to follow the transition path in the LFC Regulations for increasing fixed charges to low users.

Another interpretation of prices that least distort network use is Ramsey pricing, where those consumers with inelastic demand face higher charges as their consumption is least likely to be distorted as a result. However, this principle is difficult to apply as price elasticity information is difficult to obtain, and it is likely the price elasticities will be different within each load group.

10.3 Prices should be responsive to the requirements and circumstances of end users by allowing negotiation to: (i) reflect the economic value of services; and (ii) enable price/quality trade-offs

As is discussed in section 8, in some cases non-standard prices and contracts are appropriate. This may be the case where, for example, a customer has enhanced security arrangements. In situations where customers have significant capital contributions or new investment agreements, robust commercial contracts incorporating prudential requirements are prudent to mitigate the risk of these assets being stranded. These contracts can also assist in avoiding uneconomic by-pass of the network when negotiating commercial arrangements and encourage growth within the network. OJV's individual pricing for large customers and individual account management to industrial and large commercial customers addresses the risk of bypass by negotiating arrangements that, as closely as is practical, reflect the network costs incurred by each individual consumer.

OJV's pricing model for large individual consumers ensures that the price is cost reflective and takes into consideration a distance factor from the customer's premises to the local zone substation, thus relating their line charges to the assets used for their supply. The closer to the zone substation the lower the distribution cost component. This component also allows for the shared use of those assets.

The pricing model allows customers to own their own distribution transformers passing on the savings made by ownership.

Each zone substation has individual costs allocated to it based on the substation assets and the share of the use of the sub-transmission network as determined by load flow analysis. These individual zone substation costs are allocated to the individual consumers based on their respective load profiles and share of the use of the zone substation.

The use of individual capacity and demands also ensures that the price is cost reflective. By these processes, OJV discourages uneconomic bypass of its network and allows negotiation to tailor its services to the specific needs of the consumer.

During the consultation process with consumers, particularly the larger individual consumers, and often when they are extending or requiring a new supply, price/quality trade-offs are discussed and offered, these often in the form of offering the customer an (n-1) supply. Consumers who choose this level of supply will have the extra costs reflected in their individual line charge.

Each year OJV conducts a customer survey of 400 residential and commercial customers. Customers are asked if they would pay an extra $10 per month in their line charge to reduce the number of outages they experienced each year, 82% stated no to this question.

10.4 Development of prices should be transparent and have regard to transaction costs, consumer impacts, and uptake incentives.

OJV's price structure for customers over 150kVA has been in place since 2002. The change to TOU variable pricing and to tariff options in response to customer demand or legislative requirements such as the Electricity (Low Fixed Charge Tariff Option for Domestic Consumers) Regulations 2004.

Price levels for Individual Customers each year are based on the previous year's performance and projections for the current year following discussions with the owner when required.

More efficient use of electricity by these customers may be reflected at the time in the variable charges but will primarily be effective as the basis for calculating reduced line charges (in real terms) for the following year.

Once the line charges have been established by the methodology, the tariff structure is straight forward, limited to a fixed daily charge and variable consumption tariff for the majority of the larger customers.

The Electricity (Low Fixed Charge Tariff Option for Domestic Consumers) Regulations 2004 requiring a low fixed charge option for each domestic tariff has increased the number of options.

The issue is a compromise between simplicity and equitability of pricing. Three parameters influence the cost, the location of the premises to be supplied (governs the assets used), the load to be supplied (governs the size of assets used) and the time the load is supplied (governs the diversity and hence size and share of the assets used).

OJV's line charge methodology has endeavoured to incorporate these aspects and then apply in the most equitable but simple way practicable.

OJV uses "GXP billing" for its residential and general connections in the Otago network (i.e., excluding Lakeland). This is where variable consumption charges are based on electricity volumes injected into the network at the Transpower grid exit points. Quantities are determined by the wholesale electricity market reconciliation process, which is itself governed by an Industry Participation Code. This method saves on administration costs, which are transferred back into the pricing.

OJV also recognizes that "ICP pricing and billing" can send stronger price signals to customers but does constrain tariff innovation by the Retailers. The change to further breakdown of the GXP energy volumes into "peak" and "shoulder" rates or "congestion" and "non congestion" periods, will sharpen the signal to the retailers and end use consumers.

OJV's pricing from 1 April 2022 does incorporate structural changes and as a result, consumer impacts of the change in price levels have been predicted with through analysis.

APPENDIX A COMMERCE COMMISSION INFORMATION DISCLOSURE REQUIREMENTS

In the table below, we describe the relevant sections of this methodology where we demonstrate compliance with the key sections of the Commission's information disclosure requirements.

IDD Section	Requirement	Key sections of methodology demonstrating compliance
2.4.1	Every EDB must publicly disclose, before the start of each disclosure year, a pricing methodology which:	
2.4.1 (1)	Describes the methodology, in accordance with clause 2.4.3, used to calculate the prices payable or to be payable;	Sections 3 to 7
2.4.1 (2)	Describes any changes in prices and target revenues;	Section 6.6
2.4.1 (3)	Explains, in accordance with clause 2.4.5, the approach taken with respect to pricing in non-standard contracts and distributed generation (if any);	Sections 8 and 9
2.4.1 (4)	Explains whether, and if so how, the EDB has sought the views of consumers, including their expectations in terms of price and quality, and reflected those views in calculating the prices payable or to be payable. If the EDB has not sought the views of consumers, the reasons for not doing so must be disclosed.	Section 7.3
2.4.2	Any change in the pricing methodology or adoption of a different pricing methodology, must be publicly disclosed at least 20 working days before prices determined in accordance with the change or the different pricing methodology take effect.	Compliant
2.4.3	Every disclosure under clause 2.4.1 must-	
2.4.3 (1)	Include sufficient information and commentary to enable interested persons to understand how prices were set for each consumer group, including the assumptions and statistics used to determine prices for each consumer group;	Sections 6 and 7
2.4.3 (2)	Demonstrate the extent to which the pricing methodology is consistent with the pricing principles and explain the reasons for any inconsistency between the pricing methodology and the pricing principles;	Section 10
2.4.3 (3)	State the target revenue expected to be collected for the disclosure year to which the pricing methodology applies;	Section 5
2.4.3 (4)	Where applicable, identify the key components of target revenue required to cover the costs and return on investment associated with the EDB's provision of electricity lines services. Disclosure must include the numerical value of each of the components;	Section 5
2.4.3 (5) (a), (b)	State the consumer groups for whom prices have been set, and describe- (a) the rationale for grouping consumers in this way; (b) the method and the criteria used by the EDB to allocate consumers to each of the consumer groups;	Sections 3 and 6
2.4.3 (6)	If prices have changed from prices disclosed for the immediately preceding disclosure year, explain the reasons for changes, and quantify the difference in respect of each of those reasons;	Section **Error! Reference source not found.**
2.4.3 (7)	Where applicable, describe the method used by the EDB to allocate the target revenue among consumer groups, including the numerical values of the target revenue allocated to each consumer group, and the rationale for allocating it in this way;	Section 6
2.4.3 (8)	State the proportion of target revenue (if applicable) that is collected through each price component as publicly disclosed under clause 2.4.18.	Section 6
2.4.4	Every disclosure under clause 2.4.1 must, if the EDB has a pricing strategy-	

2.4.4 (1-3)	(1) Explain the pricing strategy for the next 5 disclosure years (or as close to 5 years as the pricing strategy allows), including the current disclosure year for which prices are set. (2) Explain how and why prices for each consumer group are expected to change as a result of the pricing strategy. (3) If the pricing strategy has changed from the preceding disclosure year, identify the changes and explain the reasons for the changes.	Section 4
2.4.5	Every disclosure under clause 2.4.1 must-	
2.4.5 (1)	Describe the approach to setting prices for non-standard contracts, including- (a) the extent of non-standard contract use, including the number of ICPs represented by non-standard contracts and the value of target revenue expected to be collected from consumers subject to nonstandard contracts. (b) how the EDB determines whether to use a non-standard contract, including any criteria used. (c) any specific criteria or methodology used for determining prices for consumers subject to non-standard contracts and the extent to which these criteria or that methodology is consistent with the pricing principles;	Section 8
2.4.5 (2)	Describe the EDB's obligations and responsibilities (if any) to consumers subject to non-standard contracts in the event that the supply of electricity lines services to the consumer is interrupted. This description must explain- (a) the extent of the differences in the relevant terms between standard contracts and non-standard contracts. (b) any implications of this approach for determining prices for consumers subject to non-standard contracts;	Section 8
2.4.5 (3)	Describe the EDB's approach to developing prices for electricity distribution services provided to consumers that own distributed generation, including any payments made by the EDB to the owner of any distributed generation, and including the- (a) prices; and (b) value, structure and rationale for any payments to the owner of the distributed generation.	Section 9

APPENDIX B SCHEDULE OF PRICES

OTPO - OtagoNet Joint Venture Delivery Price Schedule for Residential & General Connections						
Residential and General Connections	Code	No of ICPs	Charges Effective from:	Transpower Fixed Price $per kVA of supply capacity	Distribution Price $per kVA of supply capacity	Total Fixed Price $per kVA of supply capacity
Delivery Prices effective from 1 April 2026 **Fixed Prices**						
Residential Standard - Fixed Price	1A	1755	1-Apr-26	0.041144	0.224490	0.265634
Residential Standard - Fixed Price	1B	4773	1-Apr-26	0.041144	0.224490	0.265634
				Transpower Fixed Price $per Day	Distribution Price $per Day	Total Fixed Price $per Day
Residential Low Fixed Charge - Fixed Price	7	3906	1-Apr-26	0.375600	0.524378	0.9000
Residential Low Fixed Charge - Fixed Price	8	1394	1-Apr-26	0.375600	0.524378	0.9000
General Connection Group - Fixed Price per kVA of supply capacity 45kVA and below	2	2924	1-Apr-26	0.068469	0.197165	0.265634
General Connection Group - Fixed Price per kVA of supply capacity 46kVA and above	3	2924	1-Apr-26	0.068469	0.197165	0.265634
				Transpower Fixed Price $ per annum	Distribution Price $ per annum	Total Fixed Price $ per annum
Unmetered Loads up to 1 kVA - Fixed Charge per connection	5	77	1-Apr-25	72.4777	256.36230	328.84
				Transpower Fixed Price $ per lamp watt per annum	Distribution Price $ per lamp watt per annum	Total Fixed Price $ per lamp watt per annum
Streetlights Fixed Price per lamp watt per annum	6	9	1-Apr-26	0.050630	0.145840	0.196470
Variable Volume Prices **Peak**				Transpower Variable Price $ per Day kWh	Distribution Price $ per Day kWh	Total Variable Price $ per Day kWh
Variable Volume prices for codes 1A,1B, 2,3, 5, 6 metered at the GXP			1-Apr-26	-	0.143880	0.143880
Variable Volume prices for codes 7 & 8 metered at the ICP			1-Apr-26	-	0.249670	0.249670
Shoulder				Transpower Variable Price $ per Day kWh	Distribution Price $ per Day kWh	Total Variable Price $ per Day kWh

Variable Volume prices for codes 1A,1B, 2,3, 5, 6 metered at the GXP			1-Apr-26		0.118999	0.118999
Variable Volume prices for codes 7 & 8 metered at the ICP			1-Apr-26		0.226138	0.226138
Night				Transpower Variable Price $ per Night kWh	Distribution Price $ per Night kWh	Total Variable Price $ per Night kWh
Variable Volume prices for codes 1A,1B, 2,3, 5, 6 metered at the GXP			1-Apr-26		0.02280	0.02280
Variable Volume prices for codes 7 & 8 metered at the ICP			1-Apr-26	$	0.02724	0.027240
Distributed Generation Injection Variable Price				**Transpower Variable Price**	**Eligible Months:** May, August, October, November, December, February, March	**Non-Eligible Months:** April, June, July, September, January
				$ per Peak kWh	**$ per Peak kWh**	**$ per Peak kWh**
Variable Volume Peak Injection Period price at the GXP Peak*			1-Apr-26		-0.05060	
Variable Volume Peak Injection Period price at the GXP Off-Peak*			1-Apr-26			

LLNW - OtagoNet Joint Venture - Lakeland FKN0331 NSP Price Schedule Prices Effective from 1 April 2026						
Standard Residential Connections				**$ Per Day**		
Fixed Charges	**Capacity**	**Description**	**Code**	**Distribution**	**Transpower**	**Total**
	15 kVA	Single phase 63 amp	LD15	$0.3662	$0.5338	$0.9000
	15 kVA	Three phase 20A MCB	LM15	$0.3662	$0.5338	$0.9000
	8 kVA	Single Phase 32A MCB	LD08	$0.2605	$0.1859	$0.4464
Variable Charges			**Code**	**(cents / kWh)**		
	Uncontrolled 24hr	Summer	LD24S	15.55	0.00	15.55
	Uncontrolled 24hr	Winter	LD24W	23.40	0.00	23.40
	Controlled 20	20 Hour Supply	LD20C	9.47	0.00	9.47
	Controlled 16	16 Hour Supply	LD16C	7.74	0.00	7.74
	Night Boost 5	13 Hour Supply	LD13C	7.80	0.00	7.80
	Night Boost 3	11 Hour Supply	LD11C	4.49	0.00	4.49
	Night Only	8 Hour Supply	LD08C	1.96	0.00	1.96
	*Distributed Generation Injection					
	Distributed Generation	Peak Injection	LDDG24IP	-7.7300	0.00	-7.7300
	Distributed Generation	Off-Peak Injection	LDDG24IQ	0.00	0.00	0.00

General Connections

Capacity	**Description**	**Code**		**Distribution**	**Transpower**	**Total**
				$ per Day		
1 kVA	Single Phase 5A MCB+	LS001	Fixed Charges	$1.0325	$0.0198	$1.0523
2 kVA	Single Phase 63 amps++	LS002		$2.0486	$0.0341	$2.0827
8 kVA	Single Phase 32A MCB	LS008		$1.0859	$0.1124	$1.1983
15 kVA	Single Phase 63 amps	LS015		$1.5721	$0.4964	$2.0685
23 kVA	Single Phase 100 amps	LS023		$1.9947	$0.6159	$2.6106
28 kVA	Two Phase	LT028		$2.5207	$0.6370	$3.1577
15 kVA	Three Phase 20A MCB	LT015		$1.4908	$0.5777	$2.0685
24kVA	Three Phase 32A MCB	LT024		$2.1042	$0.6159	$2.7201
41 kVA	Three Phase 63 amps	LT041		$3.8859	$0.6942	$4.5801
69 kVA	Three Phase 100 amps	LT069		$6.4282	$1.2153	$7.6435
103 kVA	Three Phase 150 amps	LT103		$9.4972	$1.8665	$11.3637
138 kVA	Three Phase 200 amps	LT138		$13.1603	$2.0330	$15.1933
172 kVA	Three Phase 250 amps	LT172		$36.4862	$4.4081	$40.8943
207 kVA	Three Phase 300 amps	LT207		$43.7482	$5.0983	$48.8465
276 kVA	Three Phase 400 amps	LT276		$55.0136	$5.9648	$60.9784

Capacity	Description	Code		$ Per Day Distribution $/kW	Transpower $/kW	Total $/kW
1 kVA	Single Phase 5A MCB+	LS001	Control Period Demand	$0.00000	$0.00000	$0.00000
2 kVA	Single Phase 63 amps++	LS002		$0.00000	$0.00000	$0.00000
8 kVA	Single Phase 32A MCB	LS008		$0.95363	$0.00000	$0.95363
15 kVA	Single Phase 63 amps	LS015		$0.95363	$0.00000	$0.95363
23 kVA	Single Phase 100 amps	LS023		$1.03948	$0.00000	$1.03948
28 kVA	Two Phase	LT028		$1.03948	$0.00000	$1.03948
15 kVA	Three Phase 20A MCB	LT015		$0.95363	$0.00000	$0.95363
24kVA	Three Phase 32A MCB	LT024		$1.03948	$0.00000	$1.03948
41 kVA	Three Phase 63 amps	LT041		$1.03948	$0.00000	$1.03948
69 kVA	Three Phase 100 amps	LT069		$1.03948	$0.00000	$1.03948
103 kVA	Three Phase 150 amps	LT103		$1.03948	$0.00000	$1.03948
138 kVA	Three Phase 200 amps	LT138		$1.03948	$0.00000	$1.03948
172 kVA	Three Phase 250 amps	LT172		$0.70535	$0.00000	$0.70535
207 kVA	Three Phase 300 amps	LT207		$0.70535	$0.00000	$0.70535
276 kVA	Three Phase 400 amps	LT276		$0.70535	$0.00000	$0.70535
Variable Charges			**Code**	**(cents / kWh)**		
	Uncontrolled 24hr	24 Hour Supply	LN24G	0.00	0.00	0.00
	Controlled 20	20 Hour Supply	LN20C	0.00	0.00	0.00
	Controlled 16	16 Hour Supply	LN16C	0.00	0.00	0.00
	Night Boost 5	13 Hour Supply	LN13C	0.00	0.00	0.00
	Night Boost 3	11 Hour Supply	LN11C	0.00	0.00	0.00
	Night Only	8 Hour Supply	LN08C	0.00	0.00	0.00
	***Distributed Generation Injection**			0.00	0.00	0.00
	Distributed Generation	**Peak Injection****	**LNDG24IP**	-7.7300	0.00	-7.7300
	Distributed Generation	**Off-Peak Injection**	**LNDG24IQ**	0.0000	0.00	0.0000
	Distributed Generation	**Peak Injection** Not Eligible**	**LNLDG24IP**	0.0000	0.00	0.0000
	Distributed Generation	**Off-Peak Injection Not Eligible**	**LNLDG24IQ**	0.0000	0.00	0.0000

Residential definition - a residential consumer is where the consumer's metered point of connection to the network is for the purposes of supplying a home (the principal place of residence of the consumer), not normally used for any business activity and not used as a holiday home.

Control Period Demand (CPD) - each general connection ICP greater than 2kVA will have an individually assessed kW demand level calculated each year. The annually assessed CPD level will be effective from 1 April each year.

***Distributed Generation Injection Variable Price**

The volume prices apply to distributed generation injected into the distribution network during **peak periods by DG connections approved by the network. Distributed Generation Export Variable Price applies to all residential and general connections of 41kVA and below with an export capacity of less than 45kW and volumes submitted in the half hour format (HHR)

****DG Peak Periods -**

Peak periods for distributed generation injection are May to September, 7am to 10am and 5pm to 9pm

Summer/Winter

Winter - 1 May to 30 September

Summer - 1 October to 30 April

Losses

400V	Loss Code LLNW02	Loss Factors	Loss Code LLNWNL	Loss Factors
	Winter Day	1.067	**Winter Day**	1.0000
	Winter Night	1.067	**Winter Night**	1.0000
	Summer Day	1.067	**Summer Day**	1.0000
	Summer Night	1.067	**Summer Night**	1.0000

Notes

\+ Unmetered connection

++ Unmetered Builders Temporary Supply must have 20A MCB fitted to switch board.

LLNW - OtagoNet Joint Venture – Lakeland, All NSP's Except FKN0331 NSP Price Schedule

Prices Effective from 1 April 2026

Standard Residential Connections

Fixed Charges	Capacity	Description	Code	Distribution ($ Per Day)	Transpower ($ Per Day)	Total ($ Per Day)
	15 kVA	Single phase 63 amp	LD15	$0.9000	$0.0000	$0.9000
	15 kVA	Three phase 20A MCB	LM15	$0.9000	$0.0000	$0.9000
	8 kVA	Single Phase 32A MCB	LD08	$0.4464	$0.0000	$0.4464

Variable Charges			Code	Distribution (cents / kWh)	Transpower (cents / kWh)	Total (cents / kWh)
	Uncontrolled 24hr	Summer	LD24S	15.55	0.00	15.55
	Uncontrolled 24hr	Winter	LD24W	23.40	0.00	23.40
	Controlled 20	20 Hour Supply	LD20C	9.47	0.00	9.47
	Controlled 16	16 Hour Supply	LD16C	7.74	0.00	7.74
	Night Boost 5	13 Hour Supply	LD13C	7.80	0.00	7.80
	Night Boost 3	11 Hour Supply	LD11C	4.49	0.00	4.49
	Night Only	8 Hour Supply	LD08C	1.96	0.00	1.96
	*Distributed Generation Injection					
	Distributed Generation	Peak Injection	LDDG24IP	-7.7300	0.00	-7.7300
	Distributed Generation	Off-Peak Injection	LDDG24IQ	0.00	0.00	0.00

General Connections

Capacity	Description	Code		Distribution ($ per Day)	Transpower ($ per Day)	Total ($ per Day)
1 kVA	Single Phase 5A MCB+	LS001	Fixed Charges	$1.0523	$0.0000	$1.0523
2 kVA	Single Phase 63 amps++	LS002	Fixed Charges	$2.0827	$0.0000	$2.0827
8 kVA	Single Phase 32A MCB	LS008	Fixed Charges	$1.1983	$0.0000	$1.1983
15 kVA	Single Phase 63 amps	LS015	Fixed Charges	$2.0685	$0.0000	$2.0685
23 kVA	Single Phase 100 amps	LS023	Fixed Charges	$2.6106	$0.0000	$2.6106
28 kVA	Two Phase	LT028	Fixed Charges	$3.1577	$0.0000	$3.1577
15 kVA	Three Phase 20A MCB	LT015	Fixed Charges	$2.0685	$0.0000	$2.0685
24kVA	Three Phase 32A MCB	LT024	Fixed Charges	$2.7201	$0.0000	$2.7201
41 kVA	Three Phase 63 amps	LT041	Fixed Charges	$4.5801	$0.0000	$4.5801
69 kVA	Three Phase 100 amps	LT069	Fixed Charges	$7.6435	$0.0000	$7.6435
103 kVA	Three Phase 150 amps	LT103	Fixed Charges	$11.3637	$0.0000	$11.3637
138 kVA	Three Phase 200 amps	LT138	Fixed Charges	$15.1933	$0.0000	$15.1933
172 kVA	Three Phase 250 amps	LT172	Fixed Charges	$40.8943	$0.0000	$40.8943
207 kVA	Three Phase 300 amps	LT207	Fixed Charges	$48.8465	$0.0000	$48.8465
276 kVA	Three Phase 400 amps	LT276	Fixed Charges	$60.9784	$0.0000	$60.9784

Capacity	Description	Code		Distribution $/kW ($ Per Day)	Transpower $/kW ($ Per Day)	Total $/kW ($ Per Day)
1 kVA	Single Phase 5A MCB+	LS001	Control Period Demand	$0.00000	$0.00000	$0.00000
2 kVA	Single Phase 63 amps++	LS002	Control Period Demand	$0.00000	$0.00000	$0.00000
8 kVA	Single Phase 32A MCB	LS008	Control Period Demand	$0.95363	$0.00000	$0.95363

15 kVA	Single Phase 63 amps	LS015		$0.95363	$0.00000	$0.95363
23 kVA	Single Phase 100 amps	LS023		$1.03948	$0.00000	$1.03948
28 kVA	Two Phase	LT028		$1.03948	$0.00000	$1.03948
15 kVA	Three Phase 20A MCB	LT015		$0.95363	$0.00000	$0.95363
24kVA	Three Phase 32A MCB	LT024		$1.03948	$0.00000	$1.03948
41 kVA	Three Phase 63 amps	LT041		$1.03948	$0.00000	$1.03948
69 kVA	Three Phase 100 amps	LT069		$1.03948	$0.00000	$1.03948
103 kVA	Three Phase 150 amps	LT103		$1.03948	$0.00000	$1.03948
138 kVA	Three Phase 200 amps	LT138		$1.03948	$0.00000	$1.03948
172 kVA	Three Phase 250 amps	LT172		$0.70535	$0.00000	$0.70535
207 kVA	Three Phase 300 amps	LT207		$0.70535	$0.00000	$0.70535
276 kVA	Three Phase 400 amps	LT276		$0.70535	$0.00000	$0.70535
Variable Charges			**Code**	**(cents / kWh)**		
	Uncontrolled 24hr	24 Hour Supply	LN24G	0.00	0.00	0.00
	Controlled 20	20 Hour Supply	LN20C	0.00	0.00	0.00
	Controlled 16	16 Hour Supply	LN16C	0.00	0.00	0.00
	Night Boost 5	13 Hour Supply	LN13C	0.00	0.00	0.00
	Night Boost 3	11 Hour Supply	LN11C	0.00	0.00	0.00
	Night Only	8 Hour Supply	LN08C	0.00	0.00	0.00
	***Distributed Generation Injection**			0.00	0.00	0.00
	Distributed Generation	**Peak Injection****	**LNDG24IP**	-7.7300	0.00	-7.7300
	Distributed Generation	**Off-Peak Injection**	**LNDG24IQ**	0.0000	0.00	0.0000
	Distributed Generation	**Peak Injection** Not Eligible**	**LNLDG24IP**	0.0000	0.00	0.0000
	Distributed Generation	**Off-Peak Injection Not Eligible**	**LNLDG24IQ**	0.0000	0.00	0.0000

Residential definition - a residential consumer is where the consumer's metered point of connection to the network is for the purposes of supplying a home (the principal place of residence of the consumer), not normally used for any business activity and not used as a holiday home.

Control Period Demand (CPD) - each general connection ICP greater than 2kVA will have an individually assessed kW demand level calculated each year. The annually assessed CPD level will be effective from 1 April each year.

***Distributed Generation Injection Variable Price**

The volume prices apply to distributed generation injected into the distribution network during **peak periods by DG connections approved by the network. Distributed Generation Export Variable Price applies to all residential and general connections of 41kVA and below with an export capacity of less than 45kW and volumes submitted in the half hour format (HHR)

****DG Peak Periods -**

Peak periods for distributed generation injection are May to September, 7am to 10am and 5pm to 9pm

Summer/Winter

Winter - 1 May to 30 September

Summer - 1 October to 30 April

Losses

400V

Loss Code LLNW02	Loss Factors	Loss Code LLNWNL	Loss Factors
Winter Day	1.067	Winter Day	1.0000
Winter Night	1.067	Winter Night	1.0000
Summer Day	1.067	Summer Day	1.0000
Summer Night	1.067	Summer Night	1.0000

Notes

+ Unmetered connection

++ Unmetered Builders Temporary Supply must have 20A MCB fitted to switch board.

APPENDIX C CPD KW DISCOUNT

The table below lists the discount rate to be applied to the winter kWh for each register prior to the calculation of the assessed CPD kW for each ICP. The network tariff codes contained in the table are those to be supplied for variable consumption reporting in retailer EIEP1 files submitted to OJV.

Register Contents	Network Tariff Code		CPD kW Discount
	Standard Domestic	Non-Standard Domestic	
UN24	S24S	S24SND	Nil
UN24	S24W	S24WND	Nil
CN20	S20C	S20CND	25%
CN16	S16C	S16CND	50%
CN13	S13C	S13CND	60%
CN11	S11C	S11CND	75%
CN8	S08C	S08CND	100%