LINE PRICING METHODOLOGY

OtagoNet Joint Venture (OJV) Electricity Network

For prices applicable from 1 April 2024

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GLOSSARY OF TERMS

After Diversity Maximum Demand (ADMD) is the customer's Maximum Demand after it has been adjusted by the Diversity Factor.

Anytime Maximum Demand (AMD) is the Maximum Demand of the customer measured at the customer's installation during any half hour period during the year.

Contract Capacity is the capacity of a customer used for billing purposes. It is formalized 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 OJV'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.

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

Group Customers include most customers with a Contract Capacity up to 150 kVA.

Half Hour Metering (HHM) describes the metering equipment that is capable of measuring electricity consumption on a half hour basis and when the half hour readings are used for billing purposes.

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.

Maximum Demand (MD) of a customer is the maximum demand of the customer that occurs throughout the specified Peak Period Energy time periods for each GXP or if that measurement is not available, it is based on the Contract Capacity.

Optimised Depreciated Replacement Cost (ODRC) relates to the network assets and is the current depreciated value of all the network assets based on an efficient network design using modern equivalent assets.

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

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).

1 INTRODUCTION

This document explains the reasoning and calculations used in establishing OJV line charges which are payable by the Electricity Retailers (Retailers) and the revenue from which is required to operate and maintain the OJV electricity network.

Regulation requires OJV to:

a. limit its line charge increases while maintaining the quality of supply; and
b. disclose specific business information including this Line Pricing Methodology document.

In compliance with these regulations, OJV is issuing this document, which outlines the methodology it uses in establishing its line charges from 1 April 2024. This document also assesses OJV's pricing against the Electricity Authority's (the Authority) Distribution Pricing Principles.

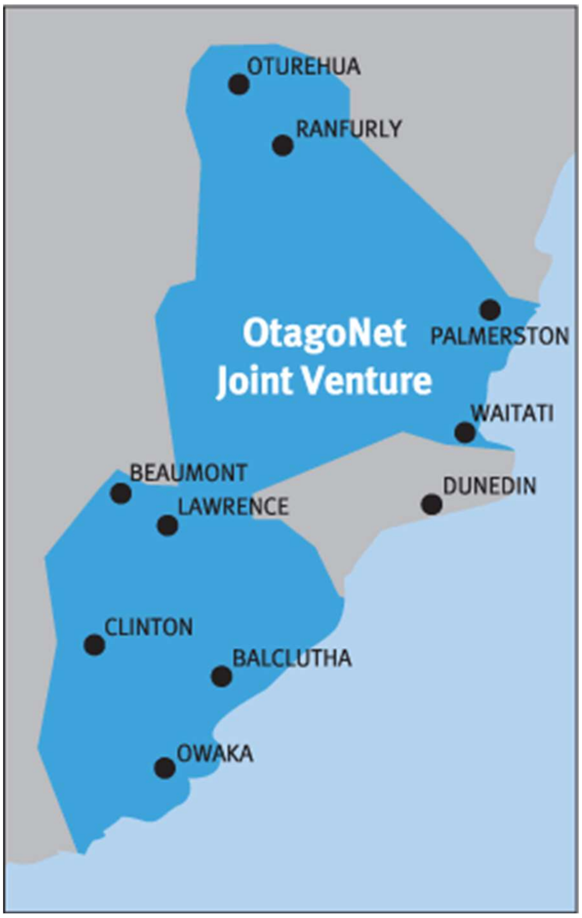
In addition to the Authority's Pricing Principles, the Commerce Commission (the Commission) continues to have regulatory jurisdiction for pricing methodology disclosure as per section 53C (2) (c) of the Act. These requirements are set out in Clauses 2.4.1 to 2.4.5 of the Electricity Information Disclosure Determination 2012 (ID Determination), published by the Commission in October 2012. Compliance with the ID Determination is outlined in Section 12. Assessment against the Authority's Pricing Principles is discussed in Section 11.

Changes made to the previous methodology include:

- An increase to Transpower's charges under their new pricing methodology (section 8).
- Further Implementation of OJV's pricing strategy of increasing the recovery of revenue through fixed charges including increasing the recovery of the individually assessed line charge customers to be 60% fixed and 40% variable from the previous 50%/50%.
- OJV is increasing the price differential between the "peak" and "shoulder" periods of the variable line charges to encourage more usage in the shoulder and night periods.
- Continuation of the phase out of the low user fixed charge price option.
- Calculation and discussion of long run marginal cost.

2 CONTEXTUAL INFORMATION ABOUT OJV

2.1 The OJV network



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).

The Otago area 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. Through the 4,392 kilometres of lines, the Otago network delivers electricity to 15,633 homes and businesses and has the lowest density (customers per kilometre of line) of any electricity network in New Zealand. 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. The network consists of 19 kilometres of underground cable supplying a mix of 4,619 commercial and residential customers. 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.

Large consumers within OJV's network area include sheep, beef and dairy farming, extensive meat and dairy processing, forestry and timber processing and gold mining. Most of the large and small towns in the service area are rural service towns, except for Frankton which is a tourism service town.

OJV's joint venture owners are Electricity Invercargill Limited (EIL), and 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 EIL and TPCL.

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 Network investment

As at end March 2022, the value of OJV's network assets in its Regulatory Asset Base was $240.5m. Over the next five years, OJV anticipates investing $61.8 million in the network, of which the majority relates to asset replacements $30.970 million.

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

- The Patearoa substation (and potential the Gimmerburn substation), due for replacement and upgrade, depending on the extent of irrigation growth
- Subtransmission 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 100 kV supply lines that serve the areas are in need of upgrades.

As is noted in the AMP, load control is utilised by OJV to manage:

- GXP load when maximum demand reaches the capacity of that GXP.
- Load on feeders during temporary arrangements to manage constraints.

2.3 Uptake of evolving technology

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, electric vehicles and battery storage.

Solar (Photovoltaic) connections

As of February 2023, OJV had 320 solar connections to its network, equivalent to 2.05% of all OJV ICPs. This rate is below the national average of 3.07%, and significantly below the rate of 6.65%, which is the average of the top ten highest uptake EDB areas. There is slight acceleration in uptake on OJV's network: the average number of new solar connections per month over the 12 months to January 2024 was 2.9, as compared with 4.1 and 2.5 for the prior two preceding 12-month periods.

OJV explores the potential for growth in solar uptake and impact on the network in the company's Asset Management Plan (AMP). According to the results of our annual customer engagement survey, 47% of respondents within the OJV network are contemplating the purchase and installation of solar panels[1]. This closely aligns with the figures for all PowerNet-managed networks, where 51% of survey participants expressed similar interest. Nationally, 56% of respondents are considering investing in solar panels. This indicates a notable increase from the 39% reported in the 2022 survey across all

[1] *Note: Considering purchasing it includes all those who intend to purchase within the next year, within the next 3 years, within the next 5 years, within the next 10 years, or more than 10 years from now.

PowerNet-managed networks, underscoring a growing perception among customers that solar photovoltaic systems are a valuable investment.

The main barriers to adoption related to economic reasons where projected payback period was a large influence on the purchase intention. Other considerations that may limit solar uptake are property ownerships and energy cost reduction options such as home insulation and electric vehicles now receiving increasing attention and better returns.

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.

Electric vehicles

There are approximately 109 electric vehicles registered in the OJV area[2]. With the increase in the cost of fuel, and despite the discontinuation of the Clean Car rebate, we expect electric vehicle adoption to grow year on year. According to the results of our annual customer engagement survey, 40% of respondents within the OJV network are contemplating the purchase of an electric vehicle[3]. This closely aligns with the figures for all PowerNet-managed networks, where 44% of survey participants expressed similar interest. Nationally, 63% of respondents are considering investing in electric vehicles. This is a notable increase from the 36% reported in the 2022 survey across all PowerNet-managed networks, underscoring a growing belief among customers that electric vehicles are a valuable investment.

As OJV explains in the AMP, EVs have the potential to have large impacts on network demand with sufficient adoption. Prices are an important means for signalling 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 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 the network reaches load capacity.

Energy storage

As OJV explains in the AMP, the majority of new DG is from solar PV, while OJV's network peak is historically on winter evenings. Coupling solar PV generation with energy storage could change this dynamic, but at present rates the storage capacity provided is immaterial.

[2] EV Registrations in the Clutha District Territorial Authority
[3] *Note: Considering purchasing it includes all those who intend to purchase within the next year, within the next 3 years, within the next 5 years, within the next 10 years, or more than 10 years from now.

According to the results of our annual customer engagement survey, 36% of respondents within the OJV network are contemplating the purchase of a battery energy storage system (BESS)[4]. This closely aligns with the figures for all PowerNet-managed networks, where 42% of survey participants expressed similar interest. Nationally, 45% of respondents are considering investing in a BESS. This is a notable increase from the 33% reported in the 2022 survey across all PowerNet-managed networks, underscoring a growing belief among customers that BESSs are a valuable investment.

Storage gives customers some control over their demand without changing their consumption and could make it possible for customers to go “off-grid” with a sufficiently sized generation source. However, there is significant 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 promote/utilise/market storage services; and future pricing structures and the level of responsiveness of the public to load-driven pricing signals.

Under the status quo this technology is not economic except in exceptional circumstances, and it is not expected that there will be major developments in this area for the next five years. If any such developments occur in the second half of the planning period, it is expected that they will take several years to have an impact at the network level, during which time OJV can respond in a focused manner. Any impact these devices have is likely to be beneficial in terms of network constraints, as they act to reduce rather than increase the peak demand on network assets.

2.4 The Power Company Ltd and PowerNet Limited Structure

PowerNet Limited (PowerNet) is an incorporated joint venture owned by The Power Company Limited (TPCL) and Electricity Invercargill Limited (EIL) 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.

[4] *Note: Considering purchasing it includes all those who intend to purchase within the next year, within the next 3 years, within the next 5 years, within the next 10 years, or more than 10 years from now.

3 OVERVIEW OF OJV'S PRICING

The pricing methodology, described in this document, is designed to provide adequate revenue to recover OJV's costs including its cost of capital and depreciation.

Delivering electricity to the many customers around Otago requires a network of connected fixed assets, the investment in which is required to earn an economic return for the asset owners.

The required revenue is paid by the customers through the Retailers, and it is important that the line charges paid by each customer are equitable and recover the capital, operation and maintenance costs of the network assets employed in the supply of electricity to the customer.

The line charges pricing structure seeks to allocate OJV's costs equitably across its customers and reflect the economic costs of delivering its services.

OJV also seeks to comply with all relevant regulations and guidelines with respect to the principles behind this methodology adopted in determining its line charges. The 2010 Electricity Authority's distribution Pricing Principles are shown in Section 11.

3.1 Signalling Economic Costs

OJV's pricing methodology is designed to ensure customers are paying the economic cost of the services provided by OJV. Basing the pricing and new connection fees on the Long Run Average Incremental Cost (LRAIC) of investment in the network ensures that future investments in the network are economically efficient and that the correct pricing signals are seen and accepted by the customers. The methodology results in line charges that are subsidy free insofar that they are based on and will be more than the LRAIC.

Values used in allocating the capital costs are based on the replacement values of the network assets. These replacement values are then adjusted by the ratio of the overall replacement cost to the ODRC of the network.

This means that all the network assets used in the calculation to supply a customer do not take into account the actual depreciated value of the specific assets but reflect the overall depreciated value of the network assets. All customers will then contribute to the renewal of the network based on the relative replacement value of the assets used to supply the customer.

OJV's pricing structures are designed to drive improved utilisation of network assets by sending strong signals to encourage long-term behavioural changes such as increased shoulder and night-time usage.

3.2 Practical Considerations

Consideration was given to determining line charges for customers based on the cost of supply, being the locational based depreciated value of the actual assets used to supply customers. This approach was discounted on the basis it would be difficult to administer and could lead to issues surrounding asset renewals and because it is not practical to single out capacities below 150kVA for location based pricing.

The methodology while resulting in cross subsidisation between locations such as urban and rural groups results in robust stable line charges that recognises that consumers share the benefits of greater utilisation of shared assets.

The methodology involves offering strong price signals based on peak, off peak, day and night rates using fixed charges by capacity and variable charges for consumption and are easily understood. The prices are offered to all Retailers and provide a level playing field and the opportunity for retail competition.

The methodology maintains a balance between equitability of pricing for the customers and minimising transaction costs for the Retailers.

3.3 Return on Investment

OJV is owned by two joint venture parties who expect an appropriate commercial return from their investment.

These expectations are tempered by the Commissions Input Methodology Determinations based on the Commissions interpretations of Part 4 of the Acts DPP regime. This broadly restricts OJV to earning a substandard regulated return on its investment of 4.57% for the regulatory control period ended 31 March 2025. Annual increases in regulated revenue are restricted to a calculation based on the CPI.

3.4 Equitability

Equitability is an important criterion in allocating existing network costs and signalling additional demand. This is countered by practicality and OJV has sought to establish a sensible and acceptable balance in the interests of its customers without oversimplifying a complex reconciliation of several parameters that need to be taken into account in determining the cost of supplying electricity. These parameters include the power and energy used, the time it is used, the location it is used, and the electricity network assets used to deliver the electricity to the location.

In pursuit of an optimal position, OJV has sought to split its customer base. The main split identifies those customers who are able to respond to pricing signals and where it is practical to allocate network assets to their supply as one group and another group, which is the majority of customers, where these considerations would be impractical.

3.5 Regulatory Constraints on Pricing Methodologies

The principle regulatory requirements that OJV operates within are the DPP set by the Commission under the Act, the Electricity Authority's 2010 Guidelines and the ID Determination promulgated by the Commission in October 2012.

However, there are specific regulations and requirements that also influence OJV's line pricing methodology that exist contrary to these principle regulatory requirements that include:

- Low Fixed Charge Regulations that require we offer low fixed charge options that benefits consumers with annual consumption below 9,000kWh
- Rural and Non-Rural Pricing – changes to pricing differentials are restricted under section 113 of the Electricity Industry Act that ties price increases to rural customer to those of urban customers, which results in an EDB subsidising one group of customers. The subsidisation is

offset somewhat by the provision of a different service level to urban customers due to a greater security level of electricity supply.

- The regulations for Distributed Generation which prevent charging for the use of assets shared with other groups of consumers effectively allowing free entry to the network apart from charging for incremental costs.

3.6 Overview of the Methodology

OJV's costs are predominantly based on its investment in fixed assets and hence are mainly fixed in the short term subject to any major natural events such as an earthquake.

The methodology divides the network assets for costing and charging purposes into two specific network asset groups, the subtransmission and distribution network assets. This separation facilitates investigations into alternative options to transmission extensions and the substitution of network expansion by other alternatives such as Distributed Generation or demand side management applications.

Ideally, the line charges should also be a predominantly fixed charge in the short term reflecting OJV's investment. Traditionally most metering and billing is based on the energy used by the customer that does not necessarily reflect OJV's costs in providing line services.

For the larger commercial and industrial customers new metering is enabling OJV to more accurately reflect its costs in its line charges.

Line charges for the larger commercial and industrial customers are adjusted annually to reflect the performance of the individual customer from the previous year. Agreements can be reached with the customers on forward projections to counter aberrations or growth.

For most of the larger customers there is also a variable monthly component dependent on the volume of electricity used. This mechanism, described later, is intended to share some of the risk between OJV and its customers.

3.7 Consumer Consultation

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

OJV seeks the views of consumers as part of the Asset Management Process (AMP) and has reflected these views in section 1.6.5 of the published AMP.

The views were obtained via the following methods:

1. A bulk phone survey of current customers including expectations on price and quality
2. A face to face survey of with key clients including expectations on price and current service
3. Consultation meetings at various locations throughout the network

4. 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.

The Default Price Quality Path (DPQP) established regime has a tenuous link between price and quality. Costs and subsequently quality cannot be reduced by OJV without increasing the risk of a quality breach and should OJV increase its operating costs to improve quality these cannot be recovered through increased prices due to operating expenditure building block allowances being set based on historic costs by the Commission when calculating the DPQP price resets.

4 PRICING STRATEGY

Given that OJV's pricing to Individual Customers is highly cost reflective and service based, the focus of the pricing strategy has primarily been on the structure of pricing for residential and general customers and to recover more of the overall revenue through fixed charges.

On 1 April 2022 OJV introduced mandatory Time of Use (TOU) pricing for all residential and general customers in the Otago region, as the first stage to more cost reflective pricing.

OJV's costs including Transpower charges are increasingly becoming fixed, OJV's strategy is to ensure that these fixed costs are passed onto customers and that a larger proportion of OJV's overall revenue is recovered through the fixed daily charges. From 1 April 2024 we continue this strategy and pass through the majority of the price increases through an increase to the prices of the fixed charges. Half hour metered individually assessed line charge customers who currently have their annual line charge recovered 50% through the fixed charge and 50% through the variable charge will have this increased to 60% fixed charge and 40% through the variable line charge.

In line with the pricing strategy and the advantage of TOU variable charges we have increased the price differential between the "Peak" and "Shoulder" prices to encourage the use of shoulder and night pricing. The night price will remain unchanged.

4.1 Time of Use (TOU) Pricing

OJV's variable pricing previously consisted of a variable price for Day (7am to 11pm) energy and Night (11pm to 7am) energy. This pricing sent a strong signal for customers to shift consumption into the night period, it did not however 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 EV charged their cars at 5pm, network peak time or at 2pm, 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 started, 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 price implementation.

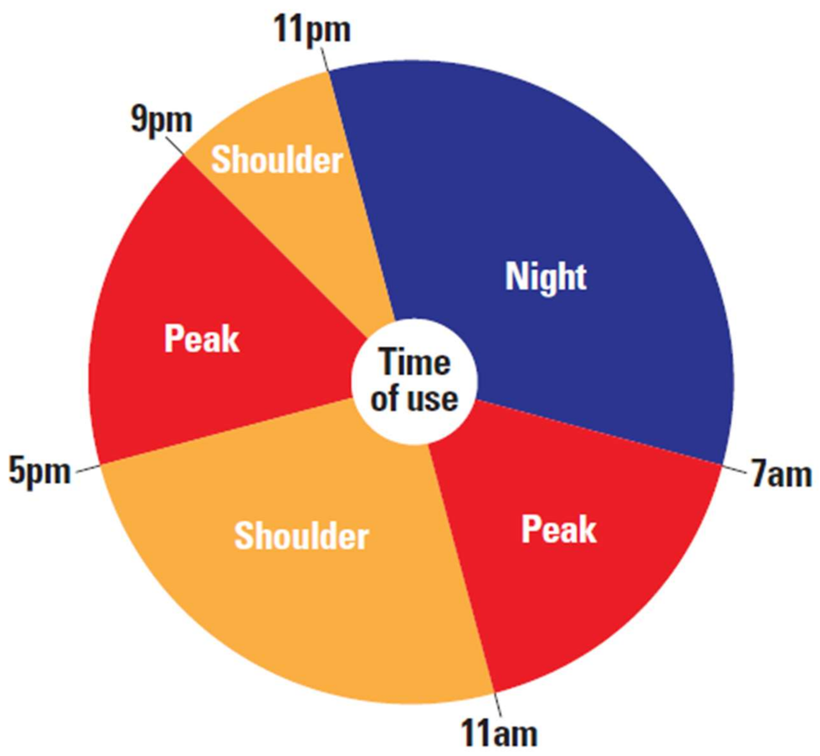
PowerNet engaged in work streams to enable TOU pricing including billing system changes; engagement with retailers seeking support and feedback on best practice to implementing a change to TOU and how the necessary data will be provided; and preparing TOU pricing models along with comprehensive customer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

As a result of all the previous work a combination of installed capacity and TOU pricing for residential and general consumers was implemented from 1 April 2022.

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 time-bands shown in the graph below for peak, shoulder, and night were selected based upon the times that peaks occur on our network. We will continually review peak times at our individual GXP's and zone substations to ensure the time bands are appropriate and will make changes if required.

Graph: OJV TOU time periods



The price differential between the peak and shoulder price will initially be marginal but as network constraints become greater or we have EV clustering on the network, we will use the price differential as a tool to send stronger signals to customers to shift load out of the peak periods and therefore avoiding or deferring expensive network upgrades.

4.3 Installed Capacity (Charges)

As 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).

This year 55% of OJV's total line charge revenue is from fixed 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 increase the share of total revenue from fixed charges over time. This year line charge price increase is being recovered through increased fixed charges only in line with OJV's overall strategy

4.4 Customer Impact Analysis

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.

OJV has completed extensive impact analysis of a shift to installed capacity and TOU pricing. OJV does not own or have access to any smart meter data on the network. 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 shows that the change to TOU pricing has 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 face less impact on their charges than customers in the least deprived deciles.

This is summarized in the below table:

OJV Average Annual Bill Impact by Changing to TOU Pricing Option with Deprivation Level & Customer Group					
OJV: Fixed + TOU: YEAR ONE Avg Annual Bill Impact by Price Category and Depreviation Band	ICP Sample No.	Avg Annual Energy Useage kWh	Avg Annual Line Charge	Avg Change to Annual Line Charge	
Residential				%	$
Standard Residential	**8,793**	**9,490**	**$1,560**	**0.11%**	**$1.77**
Standard Residential decile 10 - 8 (Most Deprived)	1,523	8,806	$1,494	0.03%	$0.50
Standard Residential decile 7- 4 (Middle NZ)	4,063	9,121	$1,520	0.13%	$2.01
Standard Residential decile 3-1 (Advantaged)	3,207	10,281	$1,642	0.13%	$2.07
Standard Domestic Decile 10	100	8,446	$1,448	0.07%	$0.99
Standard Domestic Decile 1	1,062	11,265	$1,747	0.11%	$1.86
Low User	**5,868**	**6,021**	**$1,084**	**-0.06%**	**-$0.62**
Low User decile 10 - 8 (Most Deprived)	1,657	5,679	$1,019	-0.05%	-$0.48
Low User decile 7- 4 (Middle NZ)	2,698	6,038	$1,086	-0.05%	-$0.53
Low User decile 3-1 (Advantaged)	1,513	6,366	$1,150	-0.08%	-$0.92
Low User Decile 10	135	5,672	$1,022	-0.11%	-$1.15
Low User Decile 1	440	6,538	$1,188	-0.13%	-$1.50
Commercial					
General 8kVA	594	4,373	$1,040	0.01%	$0.05
General 15kVA	214	7,273	$1,645	-0.12%	-$1.91
General 20kVA	1,034	7,324	$1,943	-0.02%	-$0.39
General 30kVA	1,195	13,533	$3,185	-0.08%	-$2.58
General 50kVA	779	76,063	$10,721	-0.09%	-$9.72
General 75kVA	110	86,297	$13,391	-0.27%	-$36.58
General 100kVA	6	181,459	$23,861	0.03%	$5.99
Dairy Byre	624	92,565	$12,252	-0.02%	-$1.94
Woolsheds	304	3,139	$1,561	-0.01%	-$0.23
Farm pumps	362	7,596	$1,774	0.05%	$0.90

4.5 Economic Cost Estimates

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 developed a methodology to estimate Long-run marginal cost of supply (LRMC), and this will help with setting the time of use prices in the future and could also assist to calculate our subsidy-free consumer range.

- Long Run Marginal Cost (LRMC) provides a measure of the forward-looking economic cost of network use. It can be used to formulate price signals about the costs that will be incurred in future as a result of network use.
- For example, 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), 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, particularly for small networks this methodology can provide volatile results as investment is lumpy.

LRMC Methodology

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 2023 opex as a % of RAB (adjusted for average asset life) to estimate incremental opex as a % of incremental capex.

1. Identify upcoming network capital expenditure that is demand-driven

2. Annualise the capex (i.e., calculate the annual cost of capital and depreciation)

3. Add extra opex that would be incurred in maintaining the new assets

4. Unitise the costs using forecast demand to calculate LRMC/kW/year

5. Use the LRMC estimate to calculate peak $/kWh and implications for other rates

For simplicity, we calculated an average LRMC across all customer load groups (i.e., rather than calculating disaggregated estimates).

Estimates of LRMC per kW

	OJV	LNL
DPP3 WACC (5.88% pre-tax)	$53.00	$102.17
IM decision – estimate for Mar 23 WACC (9.08% Pre-tax)	$72.72	$138.24

- These estimates are significantly affected by choice of WACC, which is used to annualise capital cost.
- We calculated LRMC using two different WACC options:

(1) the DPP3 WACC (4.23% post-tax, adjusted for tax is 5.88% pre-tax)

(2) the WACC estimated by the Commerce Commission in its Cost of Capital topic paper, which accounts for the December 2023 changes to the IMs (6.54% post-tax, adjusted for tax is 9.08% pre-tax).

- Option 1 produces estimates that are consistent with the current revenue cap.
- Option 2 provides a more likely view of the forward-looking economic cost (ie, the interest rates used for DPP3 were an anomaly and unlikely to be a good indicator of future rates).

LRMC-based TOU kWh Prices

A key output of the LRMC analysis is the LRMC-based peak price of 2.37 c/kWh for OJV region and 3.76 c/kWh for the LNL region. Although the LNL has significant forecast system growth capex, the pricing periods are broader (have more hours per annum) than for the other network.

Otago Region	**Probability of System Peak (assumptions)**	**Number of hours per annum**	**LRMC price *(FY2025 std res price for comparison)***
Peak	95%	2,920	$0.0237 *($0.11279)*
Shoulder	5%	2,920	$0.0012 *($0.09941)*
Off-peak	0%	2,920	$0.0000 *($0.02280)*

Lakeland Region	**Probability of System Peak (assumptions)**	**Number of hours per annum**	**LRMC price *(FY2025 std res price for comparison)***
Winter	100%	3,672	$0.0376 *($0.1739)*
Summer	0%	5,088	$0.0000 *($0.1156)*
Controlled 16	10%	8,760	$0.0016 *($0.05520)*

The above results use the forward-looking pre-tax WACC of 9.08%.

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

Constraints on daily charges increase peak, shoulder, or off-peak rates, or a combination

The fixed daily charge recovers the residual revenue (ie, the difference between the revenue earned from the kWh prices and the target revenue for the customer group).

The LRMC-based kWh prices imply fixed charges that are substantially higher than OJV's existing fixed charges – around $0.25c/kVA. These results support the continued rebalancing of prices to increase the proportion of revenue earned through fixed charges, as the networks have done for the FY2025 year.

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 off-peak 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).

Topics for further consideration

- Treatment of replacement capex – This analysis has focussed on system growth capex. Arguable some replacement capex could be included as replacement may include some degree of capacity increase to cater to future growth.
- The LRMC estimates have focussed only on signalling the economic costs of distribution. Following the TPM revisions, Transpower's pricing to EDBs no longer contains congestion signals to pass on. However, a refinement to the LRMC estimates is to consider signalling congestion at GXPs – that is, where OJV expects that a GXP will need to be upgraded due to growing demand, those costs can be signalled in LRMC prices. Due to this exclusion from the current LRMC calculations, the estimates presented above likely understate the true economic cost of peak usage.
- Individually priced customers - The LRMC cost per kW can be used to inform the peak demand component of individual customer pricing.

5 CUSTOMER INSTALLATION CATEGORIES

Installation categories are determined by OJV based on the level of service received by the customer and reflect groupings with distinct demand profiles and associated asset requirements.

There are two overarching customer categories used for calculating line charges.

The two categories are “Individual Customers” and “Residential and General Customers”.

The main distinguishing factor between the two categories is the size of the customer and the type of metering. These two factors relate to the impact of the customer on the network design and operation and secondly the cost of the metering relative to the line charges and the potential benefits the customer could obtain from network configuration and more accurate data.

5.1 Individual Customers (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 sub group 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.

5.2 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 the Retailers on a GXP metered billing basis; there is 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 and General Customers – Otago Region

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 second year of the phase out, OJV has therefore increased the daily fixed charge to 45 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 day time 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.

Maximum Demand Customers – Withdrawn in 2015

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.

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 lock-ups.
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, LM15 and LD08) 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 15 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 60 cents/day from 1 April 2024, 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:

1. 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 subtransmission 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.

6 CUSTOMER ATTRIBUTES

Consideration was then given to the parameters to be taken into account in determining the line charge methodology. The capital invested in the network has to provide sufficient assets to meet the customers' requirements at any time during the year.

The customers' requirements will generally be in terms of meeting a specific customer load or demand and providing a specified quality of supply with respect to both reliability or security and voltage. Meeting these requirements is at a cost and whenever possible trade-offs are discussed or negotiated with new customers. At this stage, and when increased capacities are required, options considered and discussed will include demand side management and local generation.

To enable these options to be considered it is necessary to be able to analyse the various parameters that affect the required network investment and how these are related to the customer attributes.

These parameters and attributes have been considered at length and condensed down to the following list. All the attributes can be identified individually and their impact on the costs and subsequent line charges quantified. This can give customers a degree of choice when planning a new connection or increased capacity.

A reduction in the attributes to be factored into the line charges would increase the risk of cross-subsidisation between different customers. Further segmentation would create excessive complexity for minimal gain in accuracy. OJV continues to refine some of the arbitrary factors as more information becomes available.

The recovery of the OJV costs through the line charges takes into account the following customer attributes:

6.1 The geographical location of the customer

The location of a customer's connection will determine the size and length of cables or lines required to supply electricity to it. Considering this parameter can reduce cross subsidisation and provide pricing signals based on assets used.

The location is based on the radial distance from the zone substation from which the customer is normally supplied. The radial distance is used as it puts all Individual Customers on the same basis and eliminates variations in line routes and lengths due to historical or other reticulation issues. Natural barriers are taken into consideration when determining the radial distance.

A special factor may be applied to this radial distance if, for instance, the zone substation is not located at the optimum location relative to the current load centre due to historical reasons which no longer exist. A zone substation may have been located adjacent to an obsolete industrial site and it is not economic to relocate it closer to its current load centre, which might be a township.

The Individual Customer's share of the use of the "virtual line" will also be assessed based on the capacities or demands of other customers in that area that would be connected to that "virtual line".

6.2 The size of the customer's installation

This is known as the "Contract Capacity" kVA of the customer and is determined by either the size

a) of the Installation Control Point (ICP) protective device, or
b) as agreed, and then measured by the metering as the "Anytime Maximum Demand" (AMD) which is the maximum power used by the customer in any 30 minute period during the year.

The size of the customer will determine the size and type of cables, lines and transformers required to supply electricity to it.

In the calculations this Contract Capacity is adjusted by a Diversity Factor (explained below) which allows for the net contribution of the customer to the investment required in network assets taking into account the varying demands of multiple customers sharing the use of those network assets at the time of the local distribution network maximum demand.

6.3 The power used by the customer in specified 30-minute periods when the network is delivering the maximum power

This is known as the "Maximum Demand" in kVA and is the maximum power used by the customer in any half hour between 0700 to 1100 hours and 1700 to 2100 hours each weekday between May to September inclusive for customers supplied from the GXPs at Half Way Bush, Balclutha and Frankton and during the same hours between December to April for customers supplied from the GXP at Naseby.

The times when the network is delivering its maximum power from the Halfway Bush, Balclutha and Frankton GXP's occur during the winter months. The peak demand times during this period occur in the morning and evening when coincident domestic and commercial use is at its highest. The use of ripple control tends to flatten out the actual peak demands so the periods when the maximum demands occur extend to the two four-hour periods each day.

On the Naseby GXP, the Maximum Demand daily times are the same but due to the increased power use by dairy farms and irrigation equipment the periods when the network is delivering its maximum power occur during the summer months.

The Maximum Demand of the customer, as opposed to the Contract Capacity is the more appropriate input to be used for measuring the contribution of the customer to both the investment in the subtransmission network and to Transpower's transmission charges. Many customers' installations can be oversized, or the Anytime Maximum Demands may be outside the periods when the maximum power is being delivered through the network.

6.4 The quantity of energy used by the customer at specific times

a) The "Peak Period Energy" (kWh) is the energy used between 0700 to1100 hours and 1700 to 2100 hours, each weekday between May and September inclusive for Installations supplied from Half Way Bush, Balclutha and Frankton and during the same hours between December and April for customers supplied from Naseby.
b) The "Night Period Energy" (kWh) is the night time energy used between 2300 to 0700 hours each day.
c) The "Shoulder Period Energy" (kWh) is the energy used at all other times.

The investment in the network and transmission network has to enable the maximum power to be delivered through the respective network assets. The energy used by a customer during the periods when the network is delivering its maximum power will also reflect the customer's use of or contribution to the requirement for those assets. The combination of the customer's Maximum Demand and the Peak Period Energy will reflect the customer's share of the network investment and provide a strong pricing signal to the customer.

Conversely, the Night Period Energy contribution to the line charges is insignificant in comparison and encourages customers to shift load into the night-time period to better utilise the network assets and defer capital expenditure.

The contribution of the Shoulder Period Energy is the middle step between the times the network is close to or at its constraint limits and the times of low utilisation when significant spare capacity is available.

These three time zones for electricity consumption represent a balance between complexity and simplicity and better reflect the dynamic impact of a customer on the network costs.

The energy used is a measured quantity (kWh) at all metered connections. For the larger customers the measurement of energy can be recorded every half hour (HHM) or during specific periods (TOU) metering. Other smaller customer metering may be Day/Night or be customised for the Retailers' tariffs.

6.5 The "Coincident Grid Maximum Demand" is also used for those customers with HHM

This is the average of the customer's half hour demands occurring during the periods when Transpower's grid exit peaks occur.

This input permits a more accurate determination of a customer's contribution to the grid exit point maximum demand.

6.6 Diversity Factor

The Diversity Factor applied 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
Table 7-A.

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%

Table 6-A Diversity Factors

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.

6.7 Loss factors

The loss factor is the factor that is applied to demand and energy measurements taken at the customer's connection point to compensate for the losses in conveying the electricity across the network. In theory the sum of all the customer connection point measurements after the loss factors have been applied should equal the meter measurement at the zone substation or GXP.

Subtransmission and distribution network loss factors have been allocated to all the Individual Customers. The distribution loss factor includes an iron loss provision and a factor based on the radial distance from the zone substation. The subtransmission loss factors are based on calculated losses between the GXP's and the outgoing 11kV feeders at the zone substation.

The application of the loss factors to the Individual Customer meter readings provides a more accurate basis for allocating the costs between Individual and the Group Customers.

7 ELECTRICITY NETWORK ASSETS AND COSTS

Revenue Requirement for the Year Ended 31 March 2025

The following table lists the revenue allowances as per the Commission's Electricity Distribution Services Default Price-Quality Path Determination 2020.

The Determination is based on a variety of Input Methodologies that determines the inputs into the calculation of the Weighted Average Cost of Capital (WACC) used in the Commissions price reset calculations.

The inputs have concernedly resulted in lower price reset outcomes. The inputs include out of date market risk premiums and narrow time bands for calculations of interest costs used in the WACC calculation and in the reset calculation use of inflation assumptions from a party with a vested interest in a mid-range inflation outcome.

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.

The use of inputs that are more current and independent results in a higher Allowable Revenue outcome than that calculated by the Commission as outlined in the table below.

Forecast allowable revenue RY25	
Term	Value ($000)
Forecast net allowable revenue	**27,898**
Forecast pass through costs	388
Forecast recoverable costs	6,650
Opening wash-up account balance	2,264
Total	**37,200**

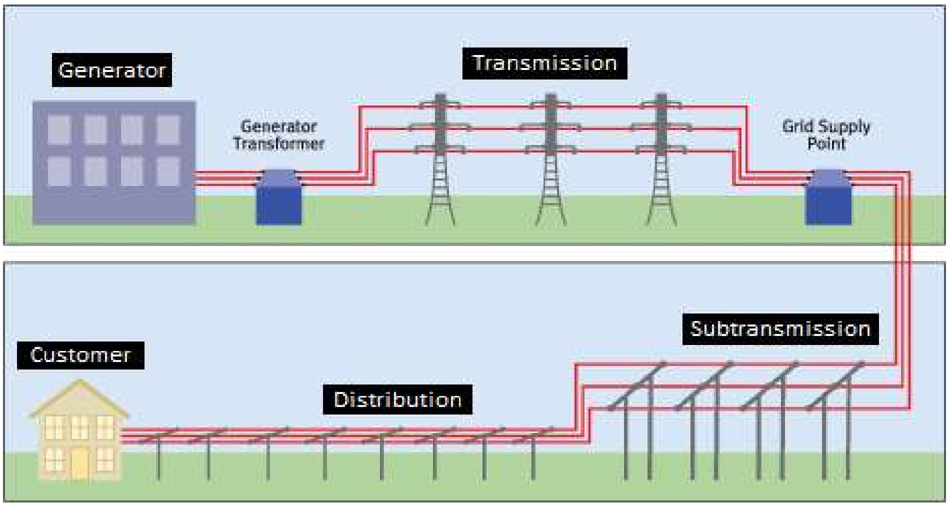
Pass-through costs are made up of:

Forecast Pass-through Costs RY25	
Forecast pass-through costs	**$000**
Rates on system fixed assets	191
Commerce Act levies	99
Electricity Authority levies	86
Utilities Disputes levies	12
Total forecast pass-through costs	**388**

Recoverable costs are made up of:

Forecast Recoverable Costs RY24	
Forecast recoverable costs	$000
IRIS incentive adjustment	(320)
Capex wash-up adjustment	(242)
Transpower transmission charges	7,195
New investment contract charges	107
Distributed generation allowance	0
Quality incentive adjustment	(120)
Fire and emergency NZ levies	30
Innovation project allowance	-
Total forecast recoverable costs	**6,650**

The OJV electricity network supplying the customers has distinctive categories of assets, outlined in the diagram below. The costs attributable from each of these assets can be individually identified to aid an equitable and more accurate allocation of costs.



The first part of the system is the Transpower grid **Transmission network** owned by Transpower and operating at 220kV or 110kV) which delivers electricity from the many generation stations around New Zealand to the connection points to the OJV network at Naseby, Half Way Bush and Balclutha. These connection points are known as Grid Exit Points (GXP).

The second part of the network is the **subtransmission network** which delivers the electricity "in bulk" to various townships, industries and areas around Otago. These lines transmit the electricity at either 66,000 or 33,000 volts and the lines are terminated at zone substations. These zone substations are typically just outside townships such as Owaka, Lawrence and Waitati.

The third part of the network is the **distribution network** which delivers the electricity to the distribution substations and then through the lines to the customers in homes and businesses. The lines to the distribution substations transmit electricity at 22,000 or 11,000 volts and the lines from the distribution substations to premises operate at 400 and 230 volts.

All the above segments make up the electricity network and their individual costs are recovered in accordance with the methodology described in this document.

The subtransmission network and distribution network costs are split into a "capital" component and a "maintenance" component reflecting the capital and maintenance costs respectively.

The "capital" component is based on the cost of capital and depreciation of the network assets and other ownership costs. This is not the net return on investment but the gross return before expenses and tax.

The "maintenance" component values are based on the equivalent values in the OJV business plan for the current year.

Network management costs which are directly associated with maintenance work are allocated to maintenance and added pro rata to the other direct field costs relating to the various groups of assets.

The network management costs that are not allocated to maintenance are allocated to administration.

Each customer's share of the use of the above assets and costs is then calculated. This is either on an individual customer basis or, in the case of the smaller Installations, on a group basis.

The objective is to reflect the share of the costs in a robust and equitable manner and the line charges to be structured so that the network investment and line charges are responsive to the individual customers' or customer groups' behaviour or pattern of usage.

8 COST ALLOCATION

8.1 Transmission Cost Allocation

Principles

Transpower’s charges are based on recovering the costs of its necessary investment in the grid and the GXP’s that is required to meet the maximum power delivered through them.

1 April 2024 is the second year of Transpower’s new pricing methodology. The new methodology replaces the old interconnection charges with three new charges, a Benefit Based Charge, Residual Charge and a Transitional Cap, the pass through of these charges and the connection charge is outlined below.

With the introduction of the new Transpower pricing methodology, there is no longer any Transpower charges that can be avoided through the connection or running of distributed generation embedded in the network, the Electricity Authority has removed the requirement on distributors to make these payments to generators from the regulations. Therefore, the transmission charges no longer include the equivalent costs of the embedded generation supplied by the Southern Generation point of supply at Mt Stuart wind generation, Pioneer Energy’s Falls Dam and Manawa Energy’s Hydro generation at Paerua.

The component of Transpower’s charges to recover its investment and operation costs of the four GXPs located at Naseby, Halfway Bush, Balclutha and Frankton is called the Connection Charge.

The Connection Charges incurred by OJV reflect Transpower’s investment and operating costs which in turn reflect the maximum power conveyed through the GXP. OJV has purchased the connection assets of the Palmerston GXP and the 110,000V lines which run from Halfway Bush GXP in Dunedin to Palmerston, from Transpower.

The second component of Transpower’s charges is to recover Transpower’s investment and operation of the main grid. They are known as the Benefit Based Charges and the Residual Charge.

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 from 1 April 2023 will be allocated each month to the retailers on the basis of total energy consumption for the month in which the rebate applied.

8.1.1. Connection 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.

Projected peak demands on each individual GXP and energy delivered through these GXP's for 2024/25 with the charges are shown in Table 8-A.

GXP	Annual Connection Charges	GXP Peak kW Demand	Annual MWh
Balclutha	$1,012,654	27,192	174,820
Half Way Bush	$69,712	4,286	33,742
Naseby	$708,134	30,894	222,820
Total or Average - Otago Region	**$1,790,501**	**62,372**	**431,382**
Frankton – Lakeland Region	**$425,794**	**14,818**	**46,940**

Table 8-A GXP Connection Charges and Profiles

The Connection Charge is based on the annual costs of the GXP.

The GXP peak demand is the maximum load on each individual GXP occurring during the twelve-month period.

Although ideally the rate per kW of GXP peak demand should apply to all customers supplied from the specific GXP, in the case of the Otago region it was decided to apply the average rate to all existing customers.

The reasons for this are as follows:

a. The large differences in rates,
b. The location of existing customers is historical, and some customers would be unduly penalised,
c. 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 allocation of the Connection Charges is thus as follows:

Customer Group	GXP Peak Demand $/kVA	ADMD $/kVA
Half hour metered Individual Otago Region	28.71	
Residential and General Otago Region		14.89
Half hour metered Individual Lakeland Regio Lakeland	28.73	
Residential and General Lakeland Region		11.49

Table 8-B GXP Profiles

The subtransmission 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 in Table 9-A and Table 9-B to produce the equivalent customer rates.

The total Connection Charges revenue from the Individual Customers is to be $1,404,114 or 63% of the total Transpower Connection Charges.

8.1.2. Benefit Based Charges (BBC)

The costs of new and some historic interconnection investments (the BBIs) will be allocated 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 for a BBI is referred to as the BBI's "covered cost" and includes the BBI's capital components (return of and on capital expenditure) and an allocation of Transpower's total operating costs (including overheads).

A BBI's covered cost is allocated between 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 by a 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) it is therefore proposed to allocate BBCs on an annual energy consumption basis.

The total befit based charges for each point of supply are:

GXP	Annual Benefit Based Charges
Balclutha	$497,634
Half Way Bush	$76,477
Naseby	$402,512
Frankton – Lakeland Region	**$60,692**

Table 8-C

The Benefit Based Charges are applied to customers on the basis of the following allocation:

Individual Customers:

The individual GXP BBC is divided by the annual total energy consumption of the GXP, to provide a $MWh rate for each GXP. Each individual customer's total annual energy consumption (MWh) is then be multiplied by the GXP rate supplying it to calculate the annual BBC. For individual customers this equates to the following charges:

Point of Supply	Per Total Annual MWh
Balclutha	$285
Halfway Bush	$2.27
Naseby	$1.81
Frankton	$1.29

Table 8-D

Residential and General customers:

The total amount of BBC's allocated to the individual customers will be deducted from the total network BBC's, the result is the amount to be allocated to all the residential and general customers. The residential and general customers BBC's amount is then divided by the total annual consumption of the residential and general customers to arrive at a $/MWh rate. Each residential and general customer load group's average annual consumption (MWh) is then multiplied by the $/MWh rate to calculate the annual allocation to each ICP in load group, the annual allocation amount is then multiplied by the number of ICP's in the load group to calculate the BBC to the load group.

After the revenue from the individual customers has been subtracted from the total the remaining residential and general customer charges are as follows:

	Per Total MWh
Otago Region	$2.46
Lakeland Region	$0.82

Table 8-E

8.1.3 Residual Charge

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 2024/25 the relevant period is from FY 2016/17 to FY 2019/20.

The annual Residual charge for OJV by GXP are:

Balclutha	$1,623,814
Halfway Bush	$383,303
Naseby	$1,691,477
Frankton	$346,290

For individual customers the allocation of the Residual Charge is calculated in the same method as Transpower allocates the residual charge to OJV as described above to determine an average gross demand and lagged average energy usage. For individual customers that were not active during the baseline allocations or are new customers the initial average gross demand and lagged average energy will be estimated as if it was fully operation during the baseline period. The estimate will be 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 individual customers this equates to the following charge:

	Per kVA Average Gross Demand
All Points of Supply	$54.54

Table 8-F

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 load group, the annual allocation amount is then multiplied by the number of ICP's in the load group to calculate the residual amount to the load group.

After the revenue from the individual customers has been subtracted from the total the remaining residential and general group customer charges are:

Table 8-G

	Per kVA After Diversity Maximum Demand
Otago Region All Points of Supply	$32.45
Lakeland Region All Points of Supply	$5.75

The total Residual Charges revenue from the Individual Customers is projected to be $2,618,843 or 65% of the total Residual Charges.

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 OJV by GXP is:

Balclutha	$1,728
Halfway Bush	$375
Naseby	$1,706
Frankton	$332

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 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 ICP's in the load group to calculate the residual amount for the load group.

8.1.5 Recovery of Transpower Charges

The new Transpower pricing methodology charges are fixed in nature and not intended to influence customer network use decisions, therefore Transpower charges will be recovered through fixed charges where possible.

For residential and general customers, the total Transpower charges are recovered through the fixed daily charge,

The Transpower amount of the fixed daily charge for the residential and general customer groups is outlined in the table below:

Residential and General Connections Otago Region	Transpower Fixed Price
	$/kVA/Day of
	supply capacity
Residential Standard - Fixed Price per kVA of Supply Capacity	$0.028653
General Connection Group - Fixed Price per kVA of Supply Capacity	$0.046323
	Transpower Fixed Price
	$per Day
Fixed Prices per Day	
Residential Low Fixed Charge - Fixed Price	$0.25360
Unmetered Loads up to 1 kVA - Fixed Charge per connection	$0.162187
	Tranpower Fixed Price
Streetlights	**$ per 100 lamp watt per day**
Street Lights Fixed Price per 100 lamp watt	$0.03427

Table 8-H

Half hour metered individual customers in the Otago region recover the residual, benefit based and transitional cap charges through the fixed daily charges and the connection charge through the variable line charge.

Currently the recovery of total line charge is on a 50/50 split between fixed and variable charges, this year we increase this to 60% fixed charges and 40% 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, this will allow all of the Transpower charges to be recovered through the fixed daily charge over time.

In the Lakeland region the line charge is fully recovered through the fixed daily charge which incorporates the Transpower component.

8.2 Subtransmission Cost Allocation

The subtransmission component of the line charges is based on the costs of the zone substation from which the customer is supplied.

The costs associated with the zone substations include their respective share of the costs of the 66,000 and 33,000 volt subtransmission lines connected directly or indirectly to the zone substation.

Each zone substation's respective share of the subtransmission line costs is determined using the "superposition" theorem to calculate the load flows through the network. The load flow analysis then enables the costs of each section of the subtransmission network to be allocated to one or more zone substations.

Replacement modern equivalent installed costs of the subtransmission lines and zone substations are the basis of the annual costs attributed to the assets.

The total annual revenue required from the subtransmission lines assets by the owners is $2,676,734 the Otago region and $898,867 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 are the basis of the annual costs attributed to these assets. The total annual revenue required from these assets by the owners is $2,379,319 for Otago and $2,362,690 for Lakeland.

The subtransmission lines maintenance budget of $332,168 in Otago and $104,802 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 $941,142 for Otago and $282,947 for Lakeland is allocated across the zone substations based on a weighting proportional to the relative size of the substation.

Table 8-I shows the annual costs of the subtransmission lines and zone substations allocated to each zone substation.

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 subtransmission network configuration.

Zone Substation	Total Annual Cost per Zone Substation
Charlotte	$154,186
Clarks	$174,289
Clinton	$208,803
Clydevale	$215,387
Deepdell	$75,890
Elderlee St	$303,835
Falls Dam	$60,688
Finegand	$115,383
Glenore	$83,651
Golden Point	$118,224
Greenfields	$195,349
Hindon	$230,556
Hyde	$96,136
Kaitangata	$135,294
Lawrence	$492,625
Macraes Mine	$189,160
Mahinerangi	$129,647
Merton	$287,361
Middlemarch	$235,869
Milburn	$237,376
North Balclutha	$108,328
Oturehua	$68,131
Owaka	$230,773
Paerau	$206,235
Paerau Hydro	$474,948
Palmerston	$236,215
Patearoa	$128,969
Port Molyneux	$107,922
PPCS	$108,291
Pukeawa	$69,465
Ranfurly	$136,085
Stirling	$105,665
Waihola	$153,240
Waipiata	$90,377
Waitati	$258,167
Wedderburn	$106,282
Totals	**$6,628,802**
Remarkables	**$3,649,306**

Table 8-I Subtransmission Annual Costs

For the Individual Customers, the subtransmission 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 subtransmission 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 subtransmission 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 shown below with the rates shown in

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

Table 8-J:

	Subtransmission Profile Rates			
Zone Substation	**Subtrans $ per kVA**	**Subtrans $ per Peak mWh**	**Subtrans $ per Shoulder mWh**	**Subtrans $ per Low mWh**
Charlotte	$10	$10	$4	$3
Clarks	$222	$187	$74	$46
Clinton	$35	$38	$11	$9
Clydevale	$21	$50	$11	$9
Deepdell	$139	$306	$89	$73
Elderlee St	$25	$23	$9	$7
Falls Dam	$16	$12	$4	$2
Finegand	$35	$38	$13	$10
Glenore	$38	$54	$16	$13
Golden Point	$12	$296	$71	$178
Greenfields	$30.94	$40.70	$7.75	$4.47
Hindon	$427	$469	$135	$83
Hyde	$44	$63	$18	$11
Kaitangata	$38	$36	$12	$8
Lawrence	$141	$126	$47	$34

		Subtransmission Profile Rates		
Zone Substation	Subtrans $ per kVA	Subtrans $ per Peak mWh	Subtrans $ per Shoulder mWh	Subtrans $ per Low mWh
Macraes Mine	$2.76	$3	$1	$0
Mahinerangi	$1,134	$1,073	$354	$206
Merton	$40	$42	$12	$9
Middlemarch	$101	$126	$41	$29
Milburn	$30	$59	$18	$17
North Balclutha	$14	$13	$5	$3
Oturehua	$179	$187	$65	$43
Owaka	$54	$54	$18	$14
Paerau	$237	$419	$198	$110
Palmerston	$14	$78,607	$25,903	$15,103
Patearoa	$35	$39	$11	$9
Port Molyneux	$24	$32	$15	$9
PPCS	$58	$67	$22	$16
Pukeawa	$6	$9	$2	$1
Ranfurly 33kV	$51	$128	$38	$30
Stirling	$9	$21	$3	$2
Waihola	$47	$44	$19	$14
Waipiata	$20	$34	$14	$9
Waitati	$57	$77	$22	$17
Wedderburn	$218	$246	$89	$62
Remarkables	$46	$55	$9	$5

Table 8-K Subtransmission Profile Rates

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 subtransmission annual charge.

After the subtransmission costs have been allocated to the Individual Customers the remaining costs are then allocated across the Group Customers

The respective subtransmission revenues from the Individual and Residential and General Customers are as follows:

	Otago	Lakeland
Individual Customers	$1,859,507	$312,987
Residential and General	$4,469,855	$3,336,319
Total	$6,329362	3,649,306

Table 8-L

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

The 66kV subtransmission 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.

As stated in Section 8, the size of this customer has a major impact on the allocation of OJV's pass through of Transpower's transmission charges.

8.3 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.

8.3.1 Distribution Line Charge Component

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.

Table 8-F 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.

Annual Distribution Line Costs	Otago	Lakeland
Distribution Line Urban annual costs	$871,636	$1,767,804
Line Length Urban km (11kV)	120km	45km
Cost per km of urban line (11kV and 400V)	$7,264	$3.02/kVA/km
Distribution Line Rural annual costs	$10,995,871	
Line Length Rural km (11kV)	3000km	
Cost per km of rural line (11kV and 400V)	$3,665	

Table 8-MD Annual Distribution Line Costs

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 subtransmission charges.

8.3.2 Distribution Transformer Component

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

Table 8-G 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 $1,993,196 in the Otago region and $538,566 in the Lakeland region. The distribution transformers maintenance costs to be recovered in the Otago region are $276,807 and $87,565 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.

Distribution Transformers and Capacity				
Description	Capacity	Number	Total Capacity	Annual Cost per Transformer
Transformer 15kVA	15	2839	42,585	$409.76
Transformer 30kVA	30	588	17,640	$472.53
Transformer 50kVA	50	364	18,200	$556.21
Transformer 75kVA	75	31	2,325	$660.82
Transformer 100kVA	100	121	12,100	$862.14
Transformer 150kVA	150	0	0	$1,071.36
Transformer 200kVA	200	99	19,800	$1,280.58
Transformer 300kVA	300	72	21,600	$1,699.02
Transformer 500kVA	500	48	24,000	$2,535.90
Transformer 750kVA	750	12	9,000	$3,582.00
Transformer 1,000kVA	1,000	6	6,000	$4,628.10
Transformer 1,250kVA	1,250	0	0	$5,674.21
Transformer 1,500kVA	1,500	0	0	$6,720.31
Total		**4,180**	**173,250**	

Table 8-NE Distribution Transformers

8.4 Overhead Cost Allocation

Overhead cost is those costs, which cannot be allocated directly to either capital or maintenance.

These costs include the following:

(a) Executive Management
(b) Directors Fees
(c) System Control
(d) Miscellaneous overheads, e.g., buildings, etc.

The annual OJV overhead costs are allocated equally across all customers.

The charge per customer is $160.92 per year in the Otago region and $87.01 in the Lakeland region.

8.5 Pass-through costs

Pass-through costs are costs relating to rates on network fixed assets charged to OJV by local authorities and industry levies imposed by the Commerce Act, the Authority and the Utilities Disputes Scheme and the Pass-Through Balance from the previous year.

The total estimated Pass-through costs for 2024 -25 are $400,647 in the Otago region and $17,710 in the Lakeland region

Pass-through costs are recovered by $26.00 per ICP in the Otago region and $3.65 per ICP in the Lakeland region.

8.6 Recoverable Costs & Wash-up Amount

Recoverable costs and Wash-up Amount recover 5 components.

1. IRIS incentive adjustment – an additional recoverable cost has been allocated to OJV due to the amount of opex and capex completed over the previous regulatory control period. For the 2024-25-year OJV will under recover $320,247.

2. Quality Incentive Scheme – an adjustment either positive or negative is allocated to OJV based on the previous years' performance against the networks target SAIDIs and SAFIs, for the 2024-25 year this adjustment is -$120,520.

3. Capex wash-up – is a recoverable cost has been allocated to OJV due to the amount of capex completed, for the 2024-25 year this adjustment is -$241,651.

4. Fire Emergency New Zealand is a new recoverable cost introduced by the Commission to allow future increases and decreases to be shared with customers. For the 2024 -25 year the allowance is $29,538

5. Wash-up Amount is the difference between OJV's actual allowable revenue for the period 2022-23 minus the actual revenue for the period 2022-23. The wash-up amount is $2,264,341.

The total recoverable costs and Wash-up Amount, amounts to $1,611,461 this is allocated to the customer groups on the same methodology basis as the supply costs of the subtransmission and Distribution costs outlined in section 7.2 above.

8.7 Target Revenue Requirement Summary

Below is a summary of our projected revenue for both Transmission costs, Distribution price components and Pass-through and recoverable costs broken down by the two customer group categories for the 2024 -25 year. We also outline the change in revenue compared with the previous year:

Otago Region Year 2024-25	Group Customers	Individual	Total
Distribution	$19,077,100	$2,227,767	$21,304,867
Transmission	$2,112,180	$4,357,348	$6,469,528
Pass-through costs	$397,735	$2,912	$400,647
Recoverable costs & Washup Amount	$1,395,601	$185,692	$1,581,293
Total	**$22,982,616**	**$6,773,719**	**$29,756,335**
Lakeland Region Year 2024-25			
Distribution	$5,966,199	$490,150	$6,456,349
Transmission	$520,120	$312,987	$833,107
Pass-through costs	$17,663	$47	$17,710
Total	**$6,503,982**	**$803,184**	**$7,307,166**

Otago Region Year 2023-24	Group Customers	Individual	Total
Distribution	$20,027,110	$2,355,871	$22,382,981
Transmission	$2,081,431	$4,470,615	$6,552,046
Pass-through costs	$880,512	$6,333	$886,845
Recoverable costs	-$1,555,288	-$204,777	-$1,760,065
Total	**$21,433,765**	**$6,628,042**	**$28,061,807**
Lakeland Region Year 2023-24			
Distribution	$4,443,934	$448,047	$4,891,981
Transmission	$423,279	$306,061	$729,340
Pass-through costs	$14,421	$44	$14,465
Total	**$4,881,634**	**$754,152**	**$5,635,786**

2024-25 is the fifth year of the five-year reset period under the Commission's Default Price-Quality Path. Under this regulation, OJV is allowed to increase its distribution charges by CPI. Other factors that impact on the allocation of costs relate to changes to chargeable quantities and individual customers profile changes along with contractual changes.

Transmission changes relate increases to Transpower's charges following the previous years introduction of Transpower's new line pricing methodology which resulted in an overall reduction in transmission charges to OJV.

Application of the line charges:

The line charges paid to OJV by the Retailers are based on a fixed charge per ICP and a rate per kWh of Peak time Energy, Shoulder time energy and a rate per kWh of Night Energy as measured at the GXP's for the Otago region and at the customers ICP in the Lakeland region.

This will be the second year OJV is implementing it's pricing strategy to recover more revenue from the fixed line charges, therefore this year the majority of the price increases are being recovered through an increase in the fixed daily charge with variable line charge prices (except for Lakeland and Low Users) being held at existing levels Individual Customers. In line with OJV's pricing strategy and the advantage of TOU variable charges we have increased the price differential between the "Peak" and "Shoulder" prices to encourage the use of shoulder and night pricing. The night price will remain unchanged.

Line charges for a customer are derived from the costs allocated based on the value of the network assets required to supply the maximum demand of the customer and of the quantity of energy delivered at peak times.

Instead of Individual Customers paying a fixed amount each year, the decision was made to apply the derived annual line charge on a "fixed and variable (energy)" basis.

The application of the fixed and variable charges is not based on the derivation of the line charge but is an application of the calculated line charge to the Retailers to pass on to the Individual Customers.

The variable charge component is based on daytime energy usage, i.e. between 07:00 and 23:00 hours. Hence, night time consumption does not contribute directly to the line charge account.

The calculated Individual Customer line charge is split 60:40 between a fixed and variable charge.

The objectives of applying the line charges on a fixed and variable basis are as follows:

a) It is a means whereby OJV can share the risk of climatic variations and be responsive to changes in the local economy. It has been well received in the commercial market that when a customer has a production downturn or invests in energy conservation measures, there is an immediate response through a reduction in the variable charges.

b) Customers also have the opportunity to shift load to night time to receive immediate benefits.

c) If an Individual Customer is expanding the business with consequent increases in energy consumption, the variable charge means that OJV receives some immediate extra revenue, and it can also cushion the increase in line charges for the following year.

Due to the uncertain and variable consumption levels of some customers including irrigation supplies and embedded networks, the line charges for these customers are recovered by a 100% fixed line charge.

The following tables provide examples how the consumption profiles and other customer parameters of three customers are applied in the calculation of their line charges.

Three typical Individual Customer electricity consumption profile parameters are shown in Table 10-A.

ICP Number	Contract Capacity kVA	Co-incident Peak Demand kVA	Total Energy mwah	Peak Period Energy mwah	Shoulder Period Energy mwah	Low Period Energy mwah
0001230990TG51A	500	389	890	169	500	221
0001230785TG4F3	200	93	275	41	162	73
0001231172TGE88	750	591	2,465	361	1,496	608

Table 8-F Individual Customer Energy Profiles

Other Individual Customer parameters used in the line charges calculation are shown in Table 10-B.

ICP Number	Diversity Factor	Grid Peak Coincident Demand kVA	Loss Factor Subtrans %	Loss Factor Diction %	Radial Distance from Zone Sub km	Share of 11kV Feeder %
0001230990TG51A	**0.67**	**151**	**5.1**	**3.4**	**11.8**	**12.42**
0001230785TG4F3	**0.38**	**42**	**3.2**	**1.6**	**2.9**	**3.06**
0001231172TGE88	**0.81**	**323**	**3.2**	**3.2**	**11.2**	**36.66**

Table 8-G Individual Customer Electrical and Physical Parameters

The calculated line charges for the three Individual Customers are shown in Table 10-C.

ICP Number	Transmission	Subtransmission	Distribution	Pass-through	Total Line Charge
0001230990TG51A	**$40,658**	**$36,327**	**$10,956**	**$18**	**$87,958**
0001230785TG4F3	**$9,471**	**$4,221**	**$2,212**	**$18**	**$15,922**
0001231172TGE88	**$70,710**	**$40,648**	**$32,587**	**$18**	**$143,963**

Table 8-H Individual Customer Typical Line Charge Components

A table showing all the Individual Customer ICP line charges is in Appendix 1.

8.8 Residential and General Customers

After the line charges for the individual customers have been determined, the line charges for the Residential and General customers are calculated based on the remaining targeted revenue, which is recovered based upon the estimated consumption and capacities.

In 2022 we introduced installed capacity and TOU variable pricing for the Residential and General customers.

The introduction of TOU variable pricing is a way to move to more cost reflective and service based pricing and is a way of encouraging efficient network use and investment, for the long term benefit of our customers. By efficient use of the network, we mean increasing the use of the network within its existing capacity, including by shifting load outside of peak periods, and incentivising new load to also go onto the network outside of peak periods. More energy delivered across the network without incurring costly upgrades means lower cost per unit of energy delivered for all of us.

TOU pricing periods are:

Peak period, which is defined as 7am to 11am and 5pm to 9pm

Shoulder period, which is defined as 11am to 5pm and 9pm to 11pm

Night period 11pm to 7am.

TOU enables us to increase prices at times when there is congestion on the network and reduce them at times when there is plenty of capacity. This sends a price signal to transfer load outside of congestion periods and incentivises growth in consumption at times when there is no incremental cost for us to deliver the additional energy.

The application of fixed and variable charges is an application of the line charge to the end-use consumer. The objectives behind the fixed and variable charges are as follows:

- Variable line charge is a compromise between a totally fixed charge that would benefit the large consumer within a load group, and a totally variable charge that would benefit the small consumer within a load group.
- As stated above, the fixed and variable charge allows the larger consumer in a load group to pay more which reflects to some extent their reduced diversity on the maximum demands seen at subtransmission and transmission level. Although the distribution network in the vicinity of the premises has to have enough capacity to supply the full capacity of the installation, the remainder of the network is designed to take into account the diversity between consumer demands. As a general rule, the less energy a consumer uses, the greater the diversity, hence the less capital investment required to supply. A totally fixed line charge does not take this into account so there would need to be more load sub-groups such as very small, small, medium, large and very large domestic consumers besides the existing All Peak and With Off Peak categories.
- It is important to note that the variable charge is cheaper during, Shoulder and Night time periods, so residential consumers with large night loads, such as storage or water heating, do not pay extra as this consumption is utilising network assets, the capacity of which is designed on the basis of and costs recovered by the peak load in daytime hours. This encourages better utilisation of the network and less capital investment.
- It is a means whereby the line owner can share the risk of climatic variations and be responsive to changes in the local economy. It has been well received in the commercial market that when a consumer has a production downturn or invests in energy conservation measures, there is an immediate response through a reduction in the variable charges.
- If a consumer is expanding its business, the variable charges mean that the line owner can receive some immediate extra revenue and it can also cushion the increase in line charges for the following year.
- The practical application of a variable component of the line charge for the Residential and General resulted in a necessity for a uniform variable charge and individual fixed charges for each segment. OJV uses the 'GXP billing" approach for the Residential and General customers, where variable charges are based on electricity volumes measured at the Transpower grid exit points. Quantities are determined by the wholesale electricity

market reconciliation process with adjustments for embedded networks and individual customer quantities.

9 OTHER MATTERS

9.1 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.

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.

Target revenue from ICP's on Non-standard contracts

The total target revenue from ICP's on Non-standard Contracts for the 2024/2025 year is $3.118M.

9.2 Distributed Generation

OJV's line pricing methodology applies to Distributed Generation connected to the electricity network for high voltage 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 off take 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.

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 the OJV 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 High Voltage Direct Current (HVDC) Transmission Charges paid by the Distributed Generator to OJV)	Where the Distributed Generation is injected into the Transmission Network
Avoided Transmission Charges (paid by OJV to the Distributed Generator)	Where the Distributed Generation reduces Interconnection Charges at peak times

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.

Benefit Based Transmission Charges

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

Avoided Cost of Transmission (ACOT)

Avoided cost of transmission charge payments were allocated to Distributed Generators based on their generation demand injected into the network coincident with Transpower's top 100 demand peaks for the lower South Island, under the TPM, for the period 1 September to 31 August. With the change this year to the Transpower pricing methodology, the Electricity Authority has removed the unit of measure that was the basis of the ACOT payments to distributed generators.

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).

9.3 Capital Contributions

Capital Contributions are calculated in accordance with OJV's published Capital Contribution policy.

10 ELECTRICITY AUTHORITY PRICING PRINCIPLES COMPARISON

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

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

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

The OJV cost of supply model allocates costs to individual customers based on their geographical location, taking into account their share of the actual assets employed to supply them. Some existing charges for commercial and industrial customers do not have a structured methodology and are based on historic pricing. The remaining Group Customers have the resulting costs allocated to them on an averaged basis once the individual customers' costs have been deducted from the total costs. This methodology results in a cost allocation which is likely to recover revenue in between the stand-alone costs and the incremental cost of supply.

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 with regards to customer groups.

The methodology attempts to minimise cross subsidisation between the larger individual consumers and between consumer load groups.

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.

Reflecting the impacts of network use on economic costs

OJV’s pricing structure uses capacity-based load groups to ensure prices have regard to the level of service capacity.

The introduction of Peak, Shoulder and Night energy of charges to residential and general customers for Otago region customers provides a strong signal to consumers to utilise spare network capacity at shoulder and night times’ thus reducing capital investment in the network. Pricing for residential connections to the Lakeland network 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.

The move to TOU pricing will serve to refine and improve the signals of the previous day/night structure. Looking to the future, and the potential for developments such as electric vehicles, 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.

With regard to charges for individual customers, these 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 prices 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.

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.

Reflecting differences in network service provided to (or by) consumers

By nature of ICP billing, the Lakeland network is able to have pricing that provides reduced differentiated prices for controlled load, reflecting that controlled load has different service availability than uncontrolled load. It provides multiple controlled load options to residential customers.

For individual customers, pricing reflects that different assets are used by different customers, which could also be associated with different service levels.

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 provides signals on when network alternatives can aid in meeting peak loads or in smoothing peaks through load shifting. There are a range of ways of providing these signals that incorporated in OJV’s pricing (eg, TOU pricing in Otago and Controlled Period Demand pricing for General customers connected to the Lakeland network). It is envisaged that TOU pricing in the Otago network 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 are arguably fairer than a single fixed charge for each and every ICP. 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. TPC is continuing to follow the transition path in the LFC Regulations for increasing fixed charges to low users.

OJV also notes that while the recovery of sunk or fixed costs from variable charges will distort usage to some extent, reasonably low uptake of evolving technologies (PV, EVs) for the foreseeable future likely means that there will be limited adverse consequences from variable charges.

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 10, 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 subtransmission 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.

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

OJV's new price structure for customers over 140kVA has been in place since 2002. The other pricing structures have been in place for years before 2002 before last years' change to TOU variable pricing and have only seen changes 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 (ie, 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.

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11 ELECTRICITY DISTRIBUTION INFORMATION DISCLOSURE DETERMINATION 2012 COMPLIANCE

This section demonstrates compliance with the Commerce Commission's Electricity Distribution Information Disclosure Determination – October 2012.

Clause:

2.4	**Pricing and Related Information** *Disclosure of pricing methodologies*	
2.4.1	Every **EDB** must **publicly disclose**, before the start of each **disclosure year**, a pricing methodology which- (1) Describes the methodology, in accordance with clause 2.4.3 below, used to calculate the **prices** payable or to be payable; (2) Describes any changes in **prices** and **target revenues**; (3) Explains, in accordance with clause 2.4.5 below, the approach taken with respect to pricing in **non-standard contracts** and **distributed generation** (if any); (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 3) (Section 8.7) (Section 10) (Section 10.4)
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.	change in methodology)
2.4.3	Every disclosure under clause 2.4.1 above must - (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** (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** (3) State the **target revenue** expected to be collected for the **disclosure year** to which the pricing methodology applies (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; (5) State the **consumer groups** for whom **prices** have been set, and describe- (a) the rationale for grouping **consumers** in this way;	 (Section 8) (Section 11) (Section 7) (Section 7) (Section 5)

	(b) the method and the criteria used by the **EDB** to allocate **consumers** to each of the **consumer groups**;	(Section 5)
	(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 8, 7.7)
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 8 and 9)
	(8) State the proportion of **target revenue** (if applicable) that is collected through each **price component** as **publicly disclosed** under clause 2.4.18	(Sections 8 and 9)
2.4.4	Every disclosure under clause 2.4.1 above must, if the **EDB** has a **pricing strategy** -	
	(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	(Section 4)
	(2) Explain how and why **prices** for each **consumer group** are expected to change as a result of the **pricing strategy**	(Section 4)
	(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 above must -	
	(1) Describe the approach to setting **prices** for **non-standard contracts**, including -	
	(a) the extent of **non-standard contract** use, including the number of **ICP**s represented by **non-standard contracts** and the value of **target revenue** expected to be collected from **consumers** subject to **non-standard contracts**	(Section 10)
	(b) how the **EDB** determines whether to use a **non-standard contract**, including any criteria used	(Section 10)
	(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 are consistent with the **pricing principles**	(Section 10)
	(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**	(Section 10)
	(b) any implications of this approach for determining **prices** for **consumers** subject to **non-standard contracts**	(Section 10)
	(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	(Section 10)
	(b) value, structure and rationale for any payments to the owner of the **distributed generation**	(Section 10)

APPENDIX 1 – 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 2024 Fixed Prices						
Residential Standard - Fixed Price	1A	1755	1-Apr-24	$10.46	$53.5055	$63.9639
Residential Standard - Fixed Price	1B	4803	1-Apr-24	$10.46	$53.5055	$63.9639
				Transpower Fixed Price $per Day	Distribution Price $per Day	Total Fixed Price $per Day
Residential Low Fixed Charge - Fixed Price	7	3773	1-Apr-24	$0.2536	$0.3464	$0.6000
Residential Low Fixed Charge - Fixed Price	8	1229	1-Apr-24	$0.2536	$0.3464	$0.6000
General Connection Group - Fixed Price per kVA of Supply Capacity	2	3289	1-Apr-24	$16.9080	$47.05590	$63.9639
				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-24	$59.1984	$193.75160	$252.95
				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-24	$0.1251	$0.34800	$0.47310
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, 5, 6 metered at the GXP			1-Apr-24	$0.00000	$0.11279	$0.11279
Variable Volume prices for codes 7 & 8 metered at the ICP			1-Apr-24	$0.00000	$0.18250	$0.18250
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, 5, 6 metered at the GXP			1-Apr-24	$0.00000	$0.09941	$0.09941

Variable Volume prices for codes 7 & 8 metered at the ICP			1-Apr-24	$0.00000	$0.171823	$0.17182
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, 5, 6 metered at the GXP			1-Apr-24	$0.00000	$0.02280	$0.02280
Variable Volume prices for codes 7 & 8 metered at the ICP			1-Apr-24	$0.000000	$0.027240	$0.027240

Half Hour Metered Individual Line Charge Customers – Otago and Lakeland Region

ICP Number	Number of Consumers	Contract Capacity kVA	Charges effective from	Transpower portion of Fixed Price per Day	Total Fixed Price per Day	Transpower portion of Varible Price per Day kWh	Total Variable Price per Day kWh
Otago Region							
0001090833TG6F1	1	300	1-Apr-24	$ 2.30	$ 16.36	$ 0.15	$ 0.15
0001120438TGE4C	1	150	1-Apr-24	$ 4.26	$ 11.84	$ -	$ -
0001230615TG210	1	200	1-Apr-24	$ 10.89	$ 21.51	$ 0.01	$ 0.02
0001230783TG57C	1	1,000	1-Apr-24	$ 34.10	$ 74.90	$ 0.02	$ 0.03
0001230785TG4F3	1	200	1-Apr-24	$ 13.37	$ 22.97	$ 0.01	$ 0.02
0001230940TG858	1	750	1-Apr-24	$ 28.98	$ 104.99	$ 0.04	$ 0.06
0001230990TG51A	1	500	1-Apr-24	$ 6.06	$ 14.85	$ 0.03	$ 0.11
0001231005TGF1B	1	2,500	1-Apr-24	$ 335.61	$ 515.79	$ 0.02	$ 0.04
0001231172TGE88	1	750	1-Apr-24	$ 92.17	$ 212.32	$ 0.01	$ 0.02
0001250655TG2ED	1	30	1-Apr-24	$ 2.27	$ 6.97	$ -	$ -
0001320515TGD9E	1	75	1-Apr-24	$ 6.88	$ 10.53	$ 0.02	$ 0.04
0001321124TGB82	1	150	1-Apr-24	$ 12.71	$ 22.90	$ -	$ -
0001370505TG447	1	50	1-Apr-24	$ 11.90	$ 24.58	$ -	$ -
0001370610TG0A6	1	200	1-Apr-24	$ 5.69	$ 16.49	$ 0.06	$ 0.08
0001401195TG9B3	1	50	1-Apr-24	$ 10.78	$ 19.26	$ -	$ -
0001450225TGAD6	1	150	1-Apr-24	$ 15.44	$ 21.90	$ 0.01	$ 0.02
0001450400TGCCA	1	100	1-Apr-24	$ 13.72	$ 17.42	$ 0.01	$ 0.02
0001450055TG58C	1	300	1-Apr-24	$ 23.53	$ 28.55	$ 0.02	$ 0.03
0001452050TGB83	1	100	1-Apr-24	$ 6.68	$ 10.69	$ 0.01	$ 0.01
0001491270TGA81	1	200	1-Apr-24	$ 1.38	$ 6.25	$ 0.02	$ 0.03
0001520870TGB4E	1	150	1-Apr-24	$ 8.92	$ 15.54	$ 0.02	$ 0.03
0001580380TGEBF	1	50	1-Apr-24	$ 4.29	$ 11.53	$ 0.05	$ 0.09
0001640675TGEE6	1	100	1-Apr-24	$ 14.47	$ 86.08	$ -	$ -
0001690827TGC31	1	500	1-Apr-24	$ 0.90	$ 9.60	$ -	$ -
0001700063TGC3B	1	1,750	1-Apr-24	$ 94.98	$ 244.60	$ -	$ -
0001710106TGF61	1	150	1-Apr-24	$ 10.62	$ 52.25	$ -	$ -
0001710108TGCFA	1	150	1-Apr-24	$ 20.86	$ 99.62	$ -	$ -
0001730075TG635	1	200	1-Apr-24	$ 14.13	$ 25.93	$ -	$ -
0001730339TG48D	1	150	1-Apr-24	$ 16.77	$ 31.23	$ -	$ -
0001730798TGCD6	1	200	1-Apr-24	$ 0.97	$ 5.32	$ -	$ -
0001730830TG9D2	1	500	1-Apr-24	$ 74.40	$ 137.29	$ -	$ -
0001730881TG725	1	200	1-Apr-24	$ 19.28	$ 40.10	$ -	$ -
0001731161TG536	1	200	1-Apr-24	$ 25.77	$ 51.96	$ -	$ -
0001731175TGE91	1	200	1-Apr-24	$ 33.47	$ 73.97	$ -	$ -
0001731255TG0C7	1	300	1-Apr-24	$ 23.37	$ 56.43	$ 0.02	$ 0.04
0001731183TGF09	1	150	1-Apr-24	$ 12.43	$ 22.32	$ -	$ -
0001731193TG5A4	1	150	1-Apr-24	$ 15.60	$ 36.33	$ -	$ -
0001731355TG9C3	1	300	1-Apr-24	$ 34.68	$ 72.76	$ -	$ -
0001740775TG38E	1	300	1-Apr-24	$ 16.05	$ 24.39	$ 0.03	$ 0.05
0001760225TG74E	1	300	1-Apr-24	$ 14.10	$ 28.67	$ 0.01	$ 0.02
0001760343TG035	1	300	1-Apr-24	$ 9.02	$ 30.64	$ 0.01	$ 0.02

0001772060TG902	1	200	1-Apr-24	$ 29.03	$ 74.56	$ -	$ -
0001772165TGD49	1	200	1-Apr-24	$ 17.72	$ 36.30	$ -	$ -
0001731110TGC2E	1	150	1-Apr-24	$ 18.42	$ 30.73	$ -	$ -
0001780560TGADB	1	100	1-Apr-24	$ 9.20	$ 23.02	$ -	$ -
0001811005TG57F	1	300	1-Apr-24	$ 1.90	$ 15.27	$ 0.15	$ 0.26
0001820703TGB7E		200	1-Apr-24	$ 13.08	$ 36.54	$ 0.01	$ 0.03
0001830031TGBE0	1	150	1-Apr-24	$ 5.54	$ 29.34	$ -	$ -
0001830497TGE71	1	300	1-Apr-24	$ 11.35	$ 36.46	$ 0.01	$ 0.05
0001830541TGBB8	1	4,500	1-Apr-24	$ 510.33	$ 1,133.06	$ -	$ -
0001830828TGF11	1	200	1-Apr-24	$ 5.65	$ 14.09	$ -	$ -
0001830903TG594	1	200	1-Apr-24	$ 6.03	$ 18.29	$ -	$ -
0001840612TG6CA	1	100	1-Apr-24	$ 18.47	$ 37.58	$ 0.01	$ 0.02
0001940050TG680	1	200	1-Apr-24	$ 15.59	$ 41.62	$ 0.01	$ 0.03
0001940060TG178	1	500	1-Apr-24	$ 57.25	$ 164.86	$ 0.01	$ 0.03
0001940090TG16F	1	200	1-Apr-24	$ 7.63	$ 21.35	$ 0.01	$ 0.03
0001940095TGC20	1	500	1-Apr-24	$ 1.01	$ 33.21	$ 0.04	$ 0.06
0001940100TG78C	1	500	1-Apr-24	$ 42.68	$ 85.54	$ 0.01	$ 0.03
0001940110TGD21	1	300	1-Apr-24	$ 6.16	$ 33.69	$ 0.02	$ 0.04
0001940350TG583	1	150	1-Apr-24	$ 3.31	$ 15.09	$ 0.01	$ 0.02
0001940650TG086	1	300	1-Apr-24	$ 10.13	$ 32.58	$ 0.03	$ 0.04
0001940905TGACE	1	150	1-Apr-24	$ 7.28	$ 22.66	$ 0.01	$ 0.02
0001940907TGA4B	1	500	1-Apr-24	$ 13.49	$ 60.82	$ 0.02	$ 0.03
0001940910TGD2C	1	1,000	1-Apr-24	$ 47.31	$ 95.02	$ 0.01	$ 0.02
0001941000TGF28	1	200	1-Apr-24	$ 24.70	$ 47.47	$ 0.01	$ 0.03
0001950500TG36C	1	200	1-Apr-24	$ 11.43	$ 19.75	$ 0.01	$ 0.02
0001950550TGB64	1	500	1-Apr-24	$ 16.20	$ 26.37	$ 0.01	$ 0.02
0001950800TG664	1	300	1-Apr-24	$ 6.86	$ 8.78	$ 0.03	$ 0.10
0001950850TGE6C	1	500	1-Apr-24	$ 5.44	$ 9.61	$ 0.08	$ 0.24
0001950900TGF60	1	150	1-Apr-24	$ 14.35	$ 23.16	$ 0.01	$ 0.02
0001951100TGECD	1	300	1-Apr-24	$ 29.37	$ 52.08	$ 0.01	$ 0.02
0001952110TG680	1	500	1-Apr-24	$ 41.88	$ 44.47	$ 0.01	$ 0.05
0001951200TGDCE	1	500	1-Apr-24	$ 0.71	$ 23.98	$ 0.12	$ 0.13
0001951320TG99F	1	500	1-Apr-24	$ 10.53	$ 25.84	$ -	$ -
0001951350TGCC2	1	200	1-Apr-24	$ 1.32	$ 3.85	$ 0.30	$ 0.94
0001951500TG2CC	1	300	1-Apr-24	$ 32.85	$ 47.31	$ 0.01	$ 0.02
0001951600TG1CF	1	150	1-Apr-24	$ 9.90	$ 16.83	$ 0.02	$ 0.03
0001951750TG0C3	1	200	1-Apr-24	$ 15.10	$ 22.34	$ 0.01	$ 0.02
0001951790TG72C	1	500	1-Apr-24	$ 21.86	$ 42.28	$ 0.03	$ 0.03
0001952100TGC2D	1	750	1-Apr-24	$ 58.15	$ 99.22	$ 0.03	$ 0.05
0001952400TG928	1	150	1-Apr-24	$ 5.75	$ 17.91	$ 0.03	$ 0.03
0001952500TG02C	1	500	1-Apr-24	$ 38.81	$ 60.33	$ 0.02	$ 0.03
0001952510TGA81	1	200	1-Apr-24	$ 1.51	$ 6.21	$ -	$ -
0001990133TG0E5	1	7,250	1-Apr-24	$ 869.90	$ 1,246.06	$ -	$ -
0001990220TG58B	1	7,500	1-Apr-24	$ 1,527.77	$ 1,808.87	$ -	$ -
0002011523TGC1A	1	150	1-Apr-24	$ 17.45	$ 65.45	$ -	$ -
0002110863TGE7B	1	300	1-Apr-24	$ 12.45	$ 34.62	$ 0.01	$ 0.02

0002381026TGF20	1	200	1-Apr-24	$ 29.10	$ 107.75	$ 0.01	$ 0.04
0002641192TGCFF	1	200	1-Apr-24	$ 16.70	$ 79.30	$ -	$ -
0002700906TGC46	1	150	1-Apr-24	$ 12.20	$ 23.22	$ -	$ -
0002742401TGC51	1	300	1-Apr-24	$ 4.84	$ 10.24	$ 0.01	$ 0.02
0002751710TG3BB	1	300	1-Apr-24	$ 21.74	$ 64.16	$ -	$ -
0002751750TG11E	1	200	1-Apr-24	$ 21.28	$ 53.14	$ -	$ -
0002751765TGBA9	1	200	1-Apr-24	$ 2.40	$ 9.82	$ -	$ -
0002751767TGB2C	1	200	1-Apr-24	$ 13.35	$ 53.19	$ -	$ -
0002751847TG976	1	200	1-Apr-24	$ 18.57	$ 40.29	$ -	$ -
0002751838TG3F5	1	200	1-Apr-24	$ 11.29	$ 27.13	$ -	$ -
0002751858TGC05	1	150	1-Apr-24	$ 19.15	$ 37.49	$ -	$ -
0002781189TG85A	1	200	1-Apr-24	$ 6.72	$ 16.07	$ -	$ -
0002841699TG73F	1	200	1-Apr-24	$ 6.69	$ 15.23	$ -	$ -
0002841432TGBF3	1	150	1-Apr-24	$ 10.06	$ 18.51	$ -	$ -
0002842004TG365	1	75	1-Apr-24	$ 13.03	$ 37.21	$ -	$ -
0002871188TGFF9	1	150	1-Apr-24	$ 6.65	$ 16.73	$ -	$ -
0003752355TG409	1	500	1-Apr-24	$ 66.74	$ 115.02	$ -	$ -
0003752365TG3F1	1	100	1-Apr-24	$ 10.56	$ 20.45	$ 0.01	$ 0.03
0003752380TG404	1	200	1-Apr-24	$ 18.65	$ 36.95	$ -	$ -
0001450001TGC8E	1	300	1-Apr-24	$ 32.14	$ 41.21	$ 0.01	$ 0.01
0002751848TG6A8	1	300	1-Apr-24	$ 33.94	$ 61.47	$ -	$ -
0002841739TG624	1	200	1-Apr-24	$ 12.62	$ 31.61	$ -	$ -
0001730849TG2DE	1	500	1-Apr-24	$ 42.26	$ 63.37	$ -	$ -
0003752367TG374	1	100	1-Apr-24	$ 8.50	$ 16.70	$ -	$ -
Lakeland Region							
950325LN3F5	1	1000	1-Apr-24	$ 130.85	$ 338.89	$ -	$ -
950335LN958	1	750	1-Apr-24	$ 27.39	$ 88.36	$ -	$ -
950330LN417	1	750	1-Apr-24	$ 29.86	$ 105.34	$ -	$ -
950315LN40D	1	150	1-Apr-24	$ 9.20	$ 36.14	$ -	$ -
950320LNEBA	1	150	1-Apr-24	$ 12.04	$ 42.84	$ -	$ -
950934LNF17	1	500	1-Apr-24	$ 44.89	$ 134.10	$ -	$ -
959018LN4F5	1	750	1-Apr-24	$ 117.68	$ 306.23	$ -	$ -
959005LN103	1	500	1-Apr-24	$ 46.02	$ 119.15	$ -	$ -
952081LNAA3	1	1500	1-Apr-24	$ 151.97	$ 389.87	$ -	$ -
9593601LND5E	1	750	1-Apr-24	$ 55.43	$ 152.95	$ -	$ -
9595701LN19A	1	500	1-Apr-24	$ 40.50	$ 116.21	$ -	$ -
951901LN400	1	1000	1-Apr-24	$ 94.20	$ 196.86	$ -	$ -
986001LN538	1	500	1-Apr-24	$ 38.05	$ 114.16	$ -	$ -

LLNW - OtagoNet Joint Venture - Lakeland Region Pricing Schedule

Prices Effective from 1 April 2024

Standard Residential Connections

Fixed Charges	Capacity	Description	Code	Distribution ($ Per Day)	Transpower ($ Per Day)	Total ($ Per Day)
	15 kVA	Single phase 63 amp	LD15	$0.3299	$0.2701	$0.6000
	15 kVA	Three phase 20A MCB	LM15	$0.3299	$0.2701	$0.6000
	8 kVA	Single Phase 32A MCB	LD08	$0.2326	$0.0910	$0.3236

Variable Charges			Code	Distribution (cents / kWh)	Transpower (cents / kWh)	Total (cents / kWh)
	Uncontrolledl 24hr	Summer	LD24S	11.56	0.00	11.56
	Uncontrolledl 24hr	Winter	LD24W	17.39	0.00	17.39
	Controlled 20	20 Hour Supply	LD20C	7.04	0.00	7.04
	Controlled 16	16 Hour Supply	LD16C	5.52	0.00	5.52
	Night Boost 5	13 Hour Supply	LD13C	5.80	0.00	5.80
	Night Boost 3	11 Hour Supply	LD11C	3.34	0.00	3.34
	Night Only	8 Hour Supply	LD08C	1.46	0.00	1.46
	Distributed Generation	24 Hour Supply	LDDG24	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	$0.7674	$0.0127	$0.7801
2 kVA	Single Phase 63 amps++	LS002		$1.5213	$0.0227	$1.5440
8 kVA	Single Phase 32A MCB	LS008		$0.8100	$0.0783	$0.8883
15 kVA	Single Phase 63 amps	LS015		$1.2896	$0.2438	$1.5334
23 kVA	Single Phase 100 amps	LS023		$1.6243	$0.3110	$1.9353
28 kVA	Two Phase	LT028		$1.9713	$0.3695	$2.3408
15 kVA	Three Phase 20A MCB	LT015		$1.3079	$0.2255	$1.5334
24kVA	Three Phase 32A MCB	LT024		$1.7054	$0.3110	$2.0164
41 kVA	Three Phase 63 amps	LT041		$2.7811	$0.6142	$3.3953
69 kVA	Three Phase 100 amps	LT069		$4.5529	$1.1134	$5.6663
103 kVA	Three Phase 150 amps	LT103		$6.8786	$1.5455	$8.4241
138 kVA	Three Phase 200 amps	LT138		$8.9942	$2.2688	$11.2630
172 kVA	Three Phase 250 amps	LT172		$25.5915	$4.7242	$30.3157
207 kVA	Three Phase 300 amps	LT207		$31.9764	$4.2343	$36.2107
276 kVA	Three Phase 400 amps	LT276		$39.2552	$5.9491	$45.2043

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		$0.00000	$0.00000	$0.00000
8 kVA	Single Phase 32A MCB	LS008		$0.70694	$0.00000	$0.70694
15 kVA	Single Phase 63 amps	LS015		$0.70694	$0.00000	$0.70694
23 kVA	Single Phase 100 amps	LS023		$0.77058	$0.00000	$0.77058
28 kVA	Two Phase	LT028		$0.77058	$0.00000	$0.77058

15 kVA	Three Phase 20A MCB	LT015		$0.70694	$0.00000	$0.70694
24kVA	Three Phase 32A MCB	LT024		$0.77058	$0.00000	$0.77058
41 kVA	Three Phase 63 amps	LT041		$0.77058	$0.00000	$0.77058
69 kVA	Three Phase 100 amps	LT069		$0.77058	$0.00000	$0.77058
103 kVA	Three Phase 150 amps	LT103		$0.77058	$0.00000	$0.77058
138 kVA	Three Phase 200 amps	LT138		$0.77058	$0.00000	$0.77058
172 kVA	Three Phase 250 amps	LT172		$0.52289	$0.00000	$0.52289
207 kVA	Three Phase 300 amps	LT207		$0.52289	$0.00000	$0.52289
276 kVA	Three Phase 400 amps	LT276		$0.52289	$0.00000	$0.52289
Variable Charges			**Code**	**(cents / kWh)**		
	Uncontrolledl 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	24 Hour Supply	LNDG24	0.00	0.00	0.00

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 principle 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.

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 2: 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%