# LINE PRICING METHODOLOGY

## OtagoNet Joint Venture Electricity Network

## For prices applicable from 1 April 2019

Issued 25 March 2019

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# 1. 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.

**Coincident Grid Maximum Demand** is the average of the 100 demand measurements of the customer, which are coincident with the 100 highest demands, which occur on the Transpower grid in the lower South Island region during the assessment period 1 September to 31 August, which the Transpower Interconnection charges are based.

**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 OtagoNet's electricity network.

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

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

**Grid Exit Point (GXP)** means the Grid Exit Point and is the connection point between the Transpower grid and the OtagoNet 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 OtagoNet 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 Low 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).

## 2. CHANGES TO PRICING METHODOLOGY

There have been no material changes to OJV’s pricing methodology since the previous methodology was published in March 2018.

Clause 11.2 Distributed Generation has been updated to reflect the changes to Schedule 6.4 of the Electricity Industry Participation Code (Code) and a requirement to separately report exported Distributed Generation to the distributor has been added.

In all other aspects the methodology has no changes to the previous edition.

# 3. 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.

To a large extent existing electricity networks are natural monopolies and are subject to regulations, which are intended to protect the customers from monopolistic behaviour and be a substitute for the normal commercial competitive pressures on market driven companies.

The regulations have been developed under the Commerce Act 1986 (the Act) which is administered by the Commerce Commission. Details of the relevant regulations are in Appendix 1.

The Act 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 2019.

OJV also has to specify the extent of its compliance with the 2010 Electricity Authority's Distribution Pricing Principles and Information Disclosure Guidelines (Guidelines).

In addition to the Electricity Authority's Guidelines, the Commerce 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 Commerce Commission in October 2012. Compliance with the ID Determination is outlined in Section 14.

OJV views this methodology as being fully compliant with the 2010 Electricity Authority's Distribution Pricing Principles.

## 4. BACKGROUND

OJV owns the electricity distribution network in the lower southeastern part of the South Island named the Otago Region and a small network in the Frankton area of Queenstown named 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 14,963 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. The network consists of 19 kilometres of underground cable supplying a mix of 1,750 commercial and residential customers. Lakeland is supplied by the Transpower Frankton GXP and has one 23 MW zone substation.

OtagoNet’s joint venture owners are EIL, and 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, Half Way 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 Retailers’ (e.g. Trustpower, Meridian). 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.

## 5. PRICING PRINCIPLES AND OVERVIEW

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.

### 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 nighttime usage.

### 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.

**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 Commerce 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 6.3% for the regulatory control period ended 31 March 2020, with subsequent resets for further five-year periods. Annual increases in regulated revenue are restricted to a calculation based on the CPI.

**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 over simplifying 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.

**Regulatory Constraints on Pricing Methodologies**

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

**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 sub transmission 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.

The line charges relating to supplying domestic, small rural and urban customers have been averaged in recognition of the Electricity Industry Act, which indicates that any changes to urban and rural line charges should be consistent.

# 6. 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 & 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.

## 6.1 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 & 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 transfomers.
- 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 sub group 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.

## 6.2 Residential & General Customers (domestic, small commercial, farms etc.) - Otago Region

The Residential & 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 & 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 daytime and nighttime rates for energy used in those periods.

*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.

### 6.3 Residential & 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 principle 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 require 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 set at 15 cents/day, which is the maximum fixed charge permitted under the Electricity (Low Fixed Charge Tariff Option for Domestic Consumers) Regulations 2004.

*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.

- **kVA-km Charge**

For the LT207 and LT276 load groups (assessed capacity 150 kVA or greater) the costs associated with HV lines and cables and sub transmission lines and cables are recovered by a kVA-km charge. The total kVA-km for each connection is the product of the connection capacity in kVA and the circuit distance from the distribution substation supplying the connection to the OJV zone substation and then to the nearest Transpower supply point.

This charge recognizes that additional investment in lines and cables is required to supply network connections that are a long way from Transpower supply points compared to those that are close to a Transpower supply point. At more remote locations, alternatives to electricity may be more appropriate and this component signals this fact.

**2. Control Period Demand Charge**

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

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

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

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

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

## 7. 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:

### 7.1 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".

### 7.2 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.

### 7.3 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 week day 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 Half Way 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 sub transmission 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.

### 7.4 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 week day 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 "Low 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 Low Period Energy contribution to the line charges is insignificant in comparison and encourages customers to shift load into the nighttime 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.

### 7.5 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 100 highest peaks for the lower South Island occur.

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

## 7.6 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 7-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.

## 7.7 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.

Sub transmission 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 sub transmission 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.

## 8. ELECTRICITY NETWORK ASSETS AND COSTS

### OtagoNet Costs

The following table lists the costs OJV will incur and enables us to consider the drivers behind the costs to be incurred. This is the line charge revenue OJV forecasts to recover during the year ending 31 March 2020 i.e. our total targeted revenue by region:

### Otago Region

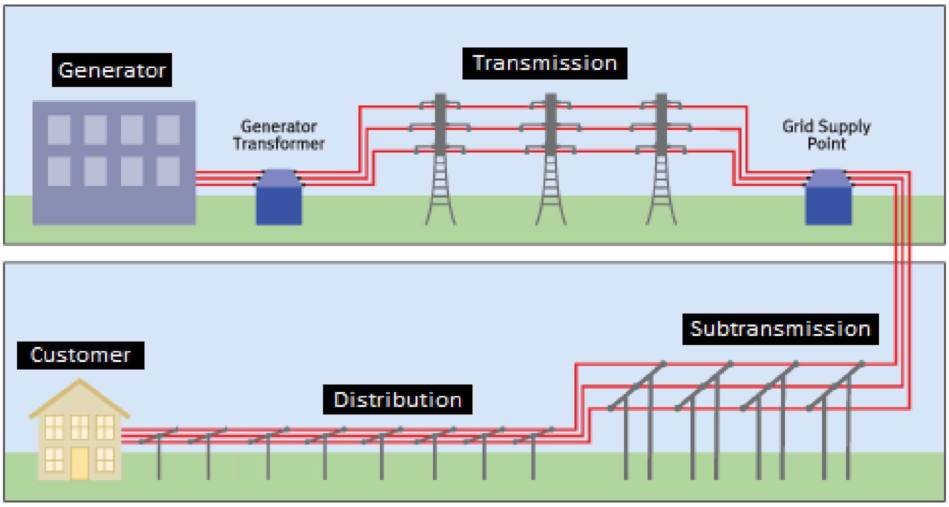
| | | | |
|---|---|---|---|
| **Transmission** | | | **$7,902,627** |
| Transpower Connection and Interconnection charges<br>Avoided transmission costs to Distributed Generators<br>Avoided transmission cost due to asset purchase at Palmerston | | | |
| **Pass-through & Recoverable Costs** | | | **$502,292** |
| Network rates, industry levies, Capex wash-up and Quality Incentive | | | |
| **Administration & Governance** | | | **$2,418,970** |
| Administration - non asset related direct costs. | | | |
| **Operation and Maintenance** | | | **$5,007,698** |
| Field services operation and maintenance costs | | | |
| **Ownership** | | | **$23,960,624** |
| Asset Value<br>(average carrying value of regulatory asset) -<br>($182,966,279 + $187,394,572) / 2 | $185,180,425 | | |
| OtagoNet required return (after tax) 6.3% | | $11666,366 | |
| Taxation | | $ 4,536,919 | |
| Depreciation and write offs | | $ 7,757,339 | |
| **Costs to be Recovered** | | | **$39,792,211** |
| **Under recovery of costs to meet DPP requirement** | | | **($5,623,179)** |
| **Costs Allowed to be Recovered (Total Target Revenue)** | | | **$34,169,032** |

Table 8-A OJV Costs

## Lakeland Region

| | |
|---|---|
| **Transmission** | **$803,270** |
| Transpower Connection and Interconnection charges | |
| **Pass-through & Recoverable Costs** | **$6,843** |
| Network rates, industry levies and Capex wash-up | |
| **Administration & Governance** | **$463,683** |
| Administration - non asset related direct costs. | |
| **Operation and Maintenance** | **$118,400** |
| Field services operation and maintenance costs | |
| **Ownership** | **$3,277,647** |
| Asset Value<br>(average carrying value of regulatory asset) -<br>($29,404,380 + $33,351,369) / 2 $31,377,875<br><br>OtagoNet required return (after tax) 6.3% $ 1,976,806<br>Taxation $ 768,740<br>Depreciation and write offs $ 532,101 | |
| **Costs to be Recovered** | **$4,669,843** |
| **Under recovery of costs** | **($2,885,845)** |
| **Costs to be Recovered (Total Target Revenue)** | **$1,783,998** |

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 **sub transmission 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 sub transmission 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.

# 9. COST ALLOCATION

## 9.1 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.

The component of Transpower's charges to recover its investment and operation costs of the four GXPs located at Naseby, Half Way 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 Half Way Bush GXP in Dunedin to Palmerston, from Transpower. The connection charges that OJV has saved through this purchase are able to be recovered as avoided transmission investment for a period of five years, last year was the last of the 5-year period so this avoided transmission investment is no longer recovered through connection charges.

The second component of Transpower's charges is to recover Transpower's investment and operation of the main grid. They are known as the Interconnection Charges.

The Interconnection Charges incurred by OJV reflect OJV's actual load on its total network and its share of the load on the grid in the south of the South Island when that part of the grid is delivering the maximum power through it.

The third component of the transmission costs is the Avoided Transmission Charge(s) which is paid to a Distributed Generator to reflect its contribution to reducing the load on Transpower's grid and hence its Interconnection Charges to OJV. OJV is also able to recover these costs.

Loss Constraint Excess Payments are credits rebated by Transpower as a result of money received from the Clearing Manager for the Wholesale Electricity Market and are excluded from the Transmission Charges. The payments are part of OJV's revenue and are applied across the board to reduce the energy rates.

### 9.1.1. Connection Charges

As the Connection Charges are to recover the costs of the local assets at each of the GXPs, 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 2019/20 with the charges are shown in Table 9-A.

| GXP | Annual Connection Charges | GXP Peak kW Demand | Annual MWh | Rate per kW of GXP Peak Demand |
|---|---|---|---|---|
| Balclutha | $1,074,857 | 25,373 | 153,082 | $42.36 |
| Half Way Bush (including Avoided Transmission investment) | $254,820 | 4,226 | 48,000 | $60.30 |
| Naseby | $653,190 | 31,840 | 196,127 | $20.51 |
| **Total or Average - Otago Region** | **$1,982,867** | **61,439** | **397,209** | **$32.27** |
| **Frankton – Lakeland Region** | **$212,727** | **4,248** | **11,126** | **$50.08** |

Table 9-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 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.

To mitigate against one off occurrences and provide a better reflection of the impact of the customer demand on the Connection Charges, the pricing methodology also takes into account the duration of the customer’s power usage. This is achieved by allocating some of the Connection Charges to the Peak Period Energy volumes.

This in effect reduces the charges for a customer who incurs just one half hour peak during the whole peak period or is only impacting on the GXP peak demand period for a small part thereof and increases the charges for those customers which have a higher potential impact on the GXP peak demand periods.

It was decided to spread the allocation of the Connection Charges across the Shoulder and Low Period Energy as well, reflecting the availability and use of the GXP assets on a 24/7 basis. The rates for the Shoulder and Low Period Energy, although somewhat arbitrary, do provide a relatively strong signal to shift load out of the Peak Period Energy times.

For most customers the average rates per kW of GXP peak demand and average Peak, Shoulder and Low Period Energy rates per MWh will apply.

The Peak, Shoulder and Low Period Energy rates are based on the total MWh delivered through the GXP.

The allocation of the Connection Charges is thus as follows:

| | |
|---|---|
| ADMD of the customer | 40% |
| Peak Period Energy used by the customer | 30% |
| Shoulder Period Energy used by the customer | 20% |
| Low Period Energy used by the customer | 10% |

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

Loss factors are applied to the GXP rates in Table 9-A and Table 9-B to produce the equivalent customer rates.

The peak demand and energy profile rates for the allocation of the Connection Charges are shown in Table 9-B.

| GXP | GXP Peak Demand $/kW | Peak Period Energy $/mWh | Shoulder Period Energy $/mWh | Low Period Energy $/mWh |
|---|---|---|---|---|
| Balclutha | $16.94 | $10.21 | $2.77 | $2.44 |
| Half Way Bush | $24.12 | $8.49 | $2.12 | $1.70 |
| Naseby | $8.21 | $6.32 | $1.30 | $1.01 |
| **Average –Otago Region** | **$12.91** | **$8.32** | **$1.96** | **$1.60** |
| **Frankton- - Lakeland** | **$20.03** | **$32.59** | **$6.39** | **$8.49** |

Table 9-B GXP Profiles

As stated above the average rates (with loss factors added) are applied to customers' ADMD and energy usage.

The total Connection Charges revenue from the Individual Customers is to be $1,479,216 or 67% of the total Transpower Connection Charges.

One major customer accounts for approximately 23% of these costs.

### 9.1.2. Interconnection Charges

The Interconnection Charges are by definition demand based. The projected demands on each individual GXP when the electricity demand on the southern South Island grid is at its peak are shown in Table 9-C.

Included in the table are the Avoided Transmission Charges, which are paid to the embedded generators. Embedded generators at Paerau and Falls Dam are connected to the network supplied through the Naseby GXP and the Mt Stewart wind farm is connected through at the Balclutha GXP.

| GXP | Annual Interconnection Charges | GXP Grid Coincident Peak Demand | Cost per kW of Grid Peak Demand |
|---|---|---|---|
| Balclutha | $2,353,420 | 21,516 | $109.38 |
| Half Way Bush | $581,136 | 5,313 | $109.38 |
| Naseby | $1,609,089 | 14,711 | $109.38 |
| Generation | $1,375,563 | 12,576 | $109.38 |
| **Total or Average - Otago Region** | **$5,919,208** | **54,116** | **$109.38** |
| **Frankton – Lakeland Region** | **$590,543** | **5,399** | **$109.38** |

Table 9-C GXP Interconnection Charges and Profile

The allocation of the Interconnection Charges is ideally based on the coincident demands of the customers during the periods of grid maximum demand.

**For Individual Customers without Time-of-Use meters the Interconnection Charges are based on the ADMD.**

To mitigate against one off occurrences and provide a better reflection of the impact of the customer demand on the grid maximum demand, the pricing methodology also takes into account the duration of the customer's demand. This is achieved by allocating some of the Interconnection Charges to the Peak, Shoulder and Low Period Energy volumes.

This in effect reduces the charges for a customer who incurs just one half hour peak during the whole grid maximum demand period or is only impacting on the grid maximum demand period for a small part thereof and increases the charges for those customers who have a higher potential impact on the grid maximum demand.

The Interconnection Charges for the non-TOU Individual Customers are based on a combination of the ADMD of the Individual Customer (50%), its Peak (30%), Shoulder (15%) and Low (5%) Energy consumed. All the rates are averaged across the customer base.

Table 9-D below shows the Interconnection Charges rates passed through to the Individual Customers.

| | Coincident Demand Rate $/kW | ADMD Rate $/kVA | Peak Energy Rate $/mWh | Shoulder Energy Rate $/mWh | Low Energy Rate $/mWh |
|---|---|---|---|---|---|
| Rates for all GXP's Otago region | $109.38 | $53.93 | $20.69 | $5.86 | $2.39 |
| Frankton GXP – Lakeland Region | $109.38 | $54.69 | $75.39 | $17.73 | $11.79 |

Table 9-D Interconnection Charge Rates

For Individual Customers with Half Hour Metering the Interconnection Charges are based on the loading or demand of the customer coincident with the grid maximum demands. This is known as the Coincident Grid Maximum Demand. This is calculated after the event.

After the Connection and Interconnection Charges have been allocated to the Individual Customers, the remaining charges are then allocated across the Group Customers based on the respective Group Customer segment profiles.

All the charges are averaged so Group Customers bear the same average rates for the Connection and Interconnection Charges irrespective of their location and from which GXP they are supplied.

The total Interconnection Charges revenue from the Individual Customers is projected to be $3,835,371 or 59% of the total Interconnection charges.

### 9.2 Sub transmission Cost Allocation

The sub transmission 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 sub transmission lines connected directly or indirectly to the zone substation.

Each zone substation's respective share of the sub transmission 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 sub transmission network to be allocated to one or more zone substations.

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

The modern equivalent replacement value of the sub transmission line segments for the Otago region is $33,135,995 and $1,119,413 for the Lakeland region. The total annual revenue required from these assets by the owners is $3,938,325 the Otago region and $153,498 for 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 for the Otago region is $31,324,000 and $3,386,836 for the Lakeland region. The total annual revenue required from these assets by the owners is $3,271,307 for Otago and $363,303 for Lakeland. The sub transmission lines maintenance budget of $258,105 in Otago and $18,932 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

$731,297 for Otago and $51,113 for Lakeland is allocated across the zone substations based on a weighting proportional to the relative size of the substation.

Table 9-E shows the annual costs of the sub transmission 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 sub transmission network configuration.

| Zone Substation | Total Annual Cost per Zone Substation |
|---|---|
| Charlotte | $190,996 |
| Clarks | $218,092 |
| Clinton | $266,909 |
| Clydevale | $288,763 |
| Deepdell | $90,902 |
| Elderlee St | $380,977 |
| Falls Dam | $74,899 |
| Finegand | $139,334 |
| Glenore | $101,982 |
| Golden Point | $228,717 |
| Greenfields | $199,752 |
| Hindon | $291,406 |
| Hyde | $113,936 |
| Kaitangata | $165,728 |
| Lawrence | $629,780 |
| Macraes Mine | $235,492 |
| Mahinerangi | $162,815 |
| Merton | $362,464 |
| Middlemarch | $294,131 |
| Milburn | $295,081 |
| North Balclutha | $127,800 |
| Oturehua | $82,103 |
| Owaka | $289,492 |
| Paerau | $260,661 |
| Paerau Hydro | $606,123 |
| Palmerston | $295,534 |
| Patearoa | $159,720 |
| Port Molyneux | $131,415 |
| PPCS | $134,331 |
| Pukeawa | $82,127 |
| Ranfurly | $166,266 |
| Stirling | $127,310 |
| Waihola | $188,605 |
| Waipiata | $103,305 |
| Waitati | $326,363 |
| Wedderburn | $126,880 |
| **Totals** | **$7,940,929** |
| **Remarkables** | **$567,916** |

Table 9-E Sub Transmission Annual Costs

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

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

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

The annual cost of each zone substation is then allocated across the maximum demand, Peak, Shoulder and Low Period volumes of energy as shown below with the rates shown in Table 9-F:

| | |
|---|---|
| Peak Demand | 25% |
| Peak Period Energy | 25% |
| Shoulder Period Energy | 40% |
| Low Period Energy | 10% |

| Sub transmission Profile Rates | | | | |
|---|---|---|---|---|
| **Zone Substation** | **Subtrans $ per kVA** | **Subtrans $ per Peak mWh** | **Subtrans $ per Shoulder mWh** | **Subtrans $ per Low mWh** |
| Charlotte | $9 | $13 | $7 | $4 |
| Clarks | $198 | $234 | $123 | $57 |
| Clinton | $32 | $48 | $20 | $12 |
| Clydevale | $20 | $67 | $20 | $12 |
| Deepdell | $119 | $367 | $141 | $87 |
| Elderlee St | $22 | $28 | $14 | $9 |
| Falls Dam | $14 | $14 | $6 | $2 |
| Finegand | $30 | $46 | $21 | $12 |
| Glenore | $33 | $65 | $27 | $16 |
| Golden Point | $18 | $29 | $8 | $3 |
| Greenfields | $30 | $66 | $15 | $6 |
| Hindon | $385 | $592 | $227 | $104 |
| Hyde | $37 | $74 | $29 | $13 |
| Kaitangata | $33 | $44 | $20 | $10 |
| Lawrence | $129 | $161 | $80 | $43 |
| Macraes Mine | $2.36 | $3 | $1 | $0 |
| Mahinerangi | $1,018 | $1,347 | $592 | $259 |
| Merton | $36 | $52 | $20 | $11 |
| Middlemarch | $90 | $157 | $69 | $36 |
| Milburn | $26 | $73 | $29 | $21 |
| North Balclutha | $11 | $15 | $8 | $4 |
| Oturehua | $154 | $226 | $104 | $52 |
| Owaka | $49 | $67 | $31 | $18 |
| Paerau | $214 | $530 | $334 | $139 |
| Palmerston | $32 | $49 | $19 | $11 |
| Patearoa | $22 | $40 | $25 | $11 |
| Port Molyneux | $51 | $81 | $37 | $19 |
| PPCS | $5 | $11 | $4 | $1 |
| Pukeawa | $43 | $151 | $60 | $36 |
| Ranfurly 33kV | $21 | $28 | $12 | $7 |
| Stirling | $8 | $26 | $5 | $2 |
| Waihola | $41 | $54 | $31 | $18 |
| Waipiata | $17 | $39 | $22 | $10 |
| Waitati | $52 | $98 | $37 | $22 |
| Wedderburn | $185 | $294 | $142 | $74 |
| Remarkables | $27 | $18 | $2 | $2 |

Table 9-F Sub transmission 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 sub transmission annual charge.

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

The respective sub transmission revenues from the Individual and Residential & General Customers are as follows:

| | Otago | Lakeland |
|---|---|---|
| **Individual Customers** | $2,018,492 | $110,077 |
| **Residential & General** | $5,922,437 | $457,839 |
| **Total** | $7,940,929 | $567,916 |

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

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

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.

## 9.3 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.

### 9.3.1 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 9-G 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 | $1,032,914 | $334,772 |
| Line Length Urban km (11kV) | 120km | 10km |
| Cost per km of urban line (11kV and 400V) | $8,608 | $5.23/kVA/km |
| Distribution Line Rural annual costs | $12,900,547 | |
| Line Length Rural km (11kV) | 3000km | |
| Cost per km of rural line (11kV and 400V) | $4,300 | |

Table 9-G 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 & General Customers the remaining distribution Line costs are allocated on an average basis using the same methodology as described above for the sub transmission charges.

### 9.3.2 Distribution Transformer Component

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

Table 9-H 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 $2,657,937 in the Otago region and $112,433 in the Lakeland region. The distribution transformers maintenance costs to be recovered in the Otago region are $215,087 and $15,818 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 | $528.74 |
| Transformer 30kVA | 30 | 588 | 17,640 | $615.03 |
| Transformer 50kVA | 50 | 364 | 18,200 | $730.10 |
| Transformer 75kVA | 75 | 31 | 2,325 | $873.92 |
| Transformer 100kVA | 100 | 121 | 12,100 | $1,092.89 |
| Transformer 150kVA | 150 | 0 | 0 | $1,380.55 |
| Transformer 200kVA | 200 | 99 | 19,800 | $1,668.20 |
| Transformer 300kVA | 300 | 72 | 21,600 | $2,243.51 |
| Transformer 500kVA | 500 | 48 | 24,000 | $3,394.13 |
| Transformer 750kVA | 750 | 12 | 9,000 | $4,832.41 |
| Transformer 1,000kVA | 1,000 | 6 | 6,000 | $6,270.69 |
| Transformer 1,250kVA | 1,250 | 0 | 0 | $7,708.97 |
| Transformer 1,500kVA | 1,500 | 0 | 0 | $9,147.25 |
| **Total** | | **4,180** | **173,250** | |

Table 9-H Distribution Transformers

## 9.4 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 $155.76 per year in the Otago region and $13.92 in the Lakeland region.

### 9.5 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 Electricity Authority and the Electricity Gas Complaints Commissioner Scheme and the Pass-Through Balance from the previous year.

The total estimated Pass-through costs for 2019 -20 are -$824,403 in the Otago region and $6,843 in the Lakeland region

Pass-through costs are recovered by -$54.80 per ICP in the Otago region and $4.07 per ICP in the Lakeland region.

### 9.6 Recoverable Costs

Recoverable costs recover 2 components

1. Capex wash-up – an additional recoverable cost has been allocated to OJV due to the amount of capital work completed over the past 12 months, for the 2019-20 year OJV will recover $1,470,000.
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 2019-20 year this adjustment is -$143,305.

The total recoverable costs amounts to $1,326,695 this is allocated to the customer groups on the same methodology basis as the supply costs of the sub-transmission and distribution costs outlined in section 9.2 & 9.3 above.

### 9.7 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 2019 -20 year. We also outline the change in revenue compared with the previous year:

| Otago Region Year 2019-20 | Group Customers | Individual | Total |
|---|---|---|---|
| Distribution | $23,241,685 | $2,522,428 | $25,764,113 |
| Transmission | $2,897,404 | $5,005,223 | $7,902,627 |
| Pass-through costs | -$818,869 | -$5,534 | -$824,403 |
| Recoverable costs | $1,184,700 | $141,995 | $1,326,695 |
| **Total** | **$26,504,920** | **$7,664,112** | **$34,169,032** |

| **Lakeland Region Year 2019-20** | | | |
|---|---|---|---|
| Distribution | $740,707 | $233,178 | $973,885 |
| Transmission | $493,354 | $309,915 | $803,270 |
| Pass-through costs | $6,802 | $41 | $6,843 |
| **Total** | **$1,240,863** | **$543,134** | **$1,783,998** |

| **Otago Region Year 2018-19** | **Group Customers** | **Individual** | **Total** |
|---|---|---|---|
| Distribution | $22,854,068 | $2,626,197 | $25,480,265 |
| Transmission | $3,194,146 | $5,812,057 | $9,006,203 |
| Pass-through costs | $863,475 | $5,821 | $869,296 |
| Recoverable costs | $1,246,623 | $158,543 | $1,405,166 |
| **Total** | **$28,158,312** | **$8,602,618** | **$36,760,930** |
| **Lakeland Region Year 2018-19** | | | |
| Distribution | $521,992 | $225,508 | $747,500 |
| Transmission | $370,013 | $262,634 | $632,647 |
| Pass-through costs | $5,355 | $48 | $5,403 |
| **Total** | **$897,360** | **$488,190** | **$1,385,550** |

2019-20 is the fifth year of a five-year reset period under the Commerce 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.

Pass-through and recoverable costs have now been itemised out, as this is now a requirement of the Default Price-Quality Path. These costs were previously included in the "Distribution" revenue.

Transmission changes relate to a decrease in Transpower's interconnection charge rate of 3.8% and a 5-year pricing incentive for the purchase of the Transpower Palmerston GXP ending.

# 10. 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 Day 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.

The ratio of fixed charges per ICP to the variable energy charges is arbitrary as the line charge calculation produces an annualised fixed charge based on the various parameters referred to previously.

## 10.1 Individual Customers

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 are independent of the quantity of energy delivered.

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 day time 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 50:50 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 | Maximum 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 10-A 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 Sub trans % | 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 10-B Individual Customer Electrical and Physical Parameters

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

| ICP Number | Transmission | Sub transmission | 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 10-C Individual Customer Typical Line Charge Components

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

### 10.2 Residential & General Customers

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

# 11. OTHER MATTERS

## 11.1 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 2019/2020 year is $3.784m.

## 11.2 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<br>(paid by the Distributed Generator to OtagoNet) | All capacities |
| Capital Contribution<br>(paid by the Distributed Generator to OtagoNet) | All capacities where incremental costs are incurred by the network |
| New Investment Agreement charge<br>(paid by the Distributed Generator to OtagoNet) | For capacities > 500kW |
| Recovery of High Voltage Direct Current (HVDC) Transmission Charges paid by the Distributed Generator to OtagoNet) | Where the Distributed Generation is injected into the Transmission Network |
| Avoided Transmission Charges<br>(paid by OtagoNet 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.

## HVDC Transmission Charges

HVDC 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 Transmission Charge revenue

Avoided Transmission Charge revenue is 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 Electricity Authority Transmission Pricing Methodology (TPM), for the period 1 September to 31 August.

The Transpower interconnection charge is then applied over the period 1 April to 31 March. This lag can result in a one-year delay in the allocation of revenue to Distributed Generators.

The revenue paid to Distributed Generators is based on the annual interconnection rate set by Transpower under the TPM. The Avoided Transmission Charge revenue allocation to Distributed Generators is subject to change in the TPM.

Avoided Transmission Charge payments are only paid to Distributed Generators who the Electricity Authority determines are necessary to enable Transpower to meet the grid reliability standards under Schedule 6.4 of the Electricity Industry Participation Code (Code) or have a connection agreement with OtagoNet Joint Venture for such payments. Distributed Generators must also be submitting full half hour metered export consumption data to the network on a monthly basis to be eligible for payments.

## 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).

## 11.3 Capital Contributions

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

## 11.4 Consumer Consultation

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 Commerce Commission when calculating the DPQP price resets.

## 12. ELECTRICITY AUTHORITY PRICING PRINCIPLES COMPARISON

In this section OJV sets out the Electricity Authority's 2010 pricing principles and how it considers it complies:

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

**i. being subsidy free (equal to or greater than incremental costs, and less than or equal to stand alone costs) except where subsidies arise from compliance with legislation and/or other regulation;**

**ii. having regard, to the extent practicable, to the level of available service capacity; and**

**iii. signalling, to the extent practicable, the impact of additional usage on future investment costs.**

The OJV network cost allocation model allocates costs to Individual Customers based on their geographical location and taking into account their share of the actual assets employed to supply them. 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 recovers revenue in between the stand alone costs and the incremental cost of supply.

OJV takes subsidy free prices to mean that for each customer group, the revenues from that group should not be below the cost of connecting that customer group to the network (incremental costs), or, be greater than the costs of supplying that group, as if they were the only customer group (stand-alone costs). It is not easy to accurately establish the stand alone costs for most customers supplied by a common serviced network. 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 common serviced network. OJV believes that the cost allocators used in the model are a representation of the underlying cost drivers of the business.

The methodology attempts to minimise cross subsidisation between the Individual Customers and between them and the Group Customers.

New connections to the network pay a capital contribution if the expected revenue from the line charges 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 cost.

The day/night energy component provides a strong signal to customers to reduce their costs by utilising spare network capacity at night thus reducing capital investment in the network.

Individual Customers have a capacity based charge along with a peak demand charge as this is because the most significant cost driver that influences investment requirements in the network is the combined peak demand of all customers 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.

**b. Where prices based on 'efficient' incremental costs would under-recover allowed revenues, the shortfall should be made up by setting prices in a manner that has regard to consumers' demand responsiveness, to the extent practicable.**

OJV believes that this principle is similar to the Ramsey Pricing principle which is a form of price discrimination used by monopolies, where those customers with inelastic demand face higher charges as their consumption is least likely to be distorted as a result.

This principle is difficult to apply as price elasticity information is difficult to obtain and it is likely the price elasticity's will be different within each load group.

A rule of thumb from experience led to the conclusion that a 10% increase in charges would result in a 1% decrease in usage for about six to nine months, after which usage would return to normal as customers adjusted to the new prices and returned to previous habits and patterns of usage. The imposition of higher fixed charges has resulted in a noticeable number of disconnections of premises such as farm sheds as customers have looked for ways of reducing costs.

In the past OJV has not found it practicable to assess customers' demand responsiveness and set charges accordingly to recover lost revenue. These changes, including the loss of revenue from the introduction of the "Low Fixed Charges", have been addressed in future price adjustments. Revenue growth from new connections has also tended to compensate for revenue reduction from more efficient use.

OJV also uses tariff structures, which have variable charges to recover predominately-fixed charges, which can differentiate different customers' elasticity but also results in a degree of annual revenue uncertainty due to climate and economic variations.

**c) Provided that prices satisfy the above, prices should be responsive to the requirements and circumstances of stakeholders in order to:**

- **i. Discourage uneconomic bypass;**
- **ii. Allow for negotiation to better reflect the economic value of services and enable stakeholders to make price/quality trade-offs or non-standard arrangements for services; and**
- **iii. Where network economics warrant, and to the extent practicable, encourage investment in transmission and distribution alternatives (eg: distributed generation or demand response) and technology innovation.**

The main risk of bypass is that large customers will choose to connect directly to the Transpower 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 practical, reflect the network costs incurred by each Individual Customer.

OJV's pricing model for Individual Customers ensures that the price is cost reflective and takes into consideration a distance factor from the customer 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 network cost component. This component also allows for the shared use of those assets.

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

Each zone substation has individual costs allocated to it based on the substation assets and the share of the use of the sub transmission network as determined by load flow analysis. These individual zone substation costs are allocated to the Individual Customers 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 customer.

During the consultation process with customers, particularly the Individual Customers, and often when they are extending or requiring a new supply, price/quality trade-offs are discussed and offered. These are often in the form of offering the customer an (n-1) supply or could even involve peak demand limitations or individual voltage limits to reduce the capital investment and customer contribution required. Customers who choose to enhance the level of supply would have the extra costs reflected in their line charges.

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 night through the use of night store heaters, heating the hot water or using their appliances such as clothes driers, washing machines etc during this period. The owner is then financially rewarded as the consumption attracts a low variable line charge. The "whole house day/night tariff" can reward owners financially through prudent management of their power requirements.

The network has a number of embedded generators connected to it. These generators receive avoided transmission payments if they have been generating during Transpower's top 100 peak times for the lower south island. These payments are also offered to any new investors in distributed generation. OJV's peak demand component of the line charge provides a large reward to customers who invest in distribution alternatives.

**d Development of prices should be transparent, promote price stability and certainty for stakeholders, and changes to prices should have regard to the impact on stakeholders.**

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 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.

**e) Development of prices should have regard to the impact of transaction costs on retailers, consumers and other stakeholders and should be economically equivalent across retailers.**

All retailers who use the network are subject to the same tariff schedules therefore OJV considers that its prices are economically equivalent across all Retailers.

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 Group Customer connections. 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 alternative is for a further breakdown of the GXP energy volumes into "peak" and "shoulder" rates or "congestion" and "non congestion" periods, which would be differentially charged to the retailers. This would sharpen the signal to the retailers and end use consumers.

## 13. INFORMATION DISCLOSURE GUIDELINES COMPLIANCE

The Electricity Industry Act 2010 provides for the Electricity Authority to set line pricing methodologies and disclosure requirements for Electricity Distribution Businesses (EDBs) such as OJV. In February 2010 the Electricity Authority's predecessor the Electricity Commission, published its distribution Pricing Principles and Information Disclosure Guidelines. (the Guidelines)

These contain a set of pricing principles and guidelines for information to be disclosed regarding the extent to which the pricing methodology adopted by an electricity distributor complies with those principles. This appendix outlines the relevant section or sections of our methodology, and provides additional comment where required, to address the disclosure requirements of the Guidelines.

<table>
<tr><td>(a)</td><td colspan="3">Prices are to be based on a well-defined, clearly explained and published methodology, with any material revisions to the methodology notified and clearly marked.<br>(This methodology addresses the first requirement. Any changes to the methodology are outlined in section 5.)</td></tr>
<tr><td rowspan="7">(b)</td><td colspan="3">The pricing methodology must demonstrate:</td></tr>
<tr><td>i.</td><td>How the methodology links to the pricing principles and any noncompliance;</td><td>(See section 12)</td></tr>
<tr><td>ii.</td><td>Rationale for customer groupings and method for determining the allocation of customers to customer groups;</td><td>(See sections 6 & 7)</td></tr>
<tr><td>iii.</td><td>Quantification of key components of costs and revenues;</td><td>(See sections 8 & 9,)</td></tr>
<tr><td>iv.</td><td>An explanation of the cost allocation methodology and the rationale for the allocation to each customer group;</td><td>(See sections 7,8,9,)</td></tr>
<tr><td>v.</td><td>An explanation of the derivation of the tariffs to be charged to each customer group and the rationale for the tariff design; and</td><td>(See sections 6 & 10)</td></tr>
<tr><td>vi.</td><td>Pricing arrangements used to share the value of any deferral of investment in distribution and transmission assets, with the investors in alternatives such as distributed generation or load management; where alternatives are practicable and where network economics warrant.</td><td>(See section 7 & 11)</td></tr>
<tr><td rowspan="2">(c)</td><td colspan="3">The pricing methodology should also:</td></tr>
<tr><td>i.</td><td>Employ industry standard terminology, where possible; and</td><td>(Industry standard terminology is consistently used)</td></tr>
</table>

# 14. 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**<br>*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; | (Section 5) |
| | (2) Describes any changes in **prices** and **target revenues**; | (Section 9.5) |
| | (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); | (Sections 11.1 and 11.2) |
| | (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 11.4) |
| 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. | (n/a – no 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** | (Section 9) |
| | (2) Demonstrate the extent to which the pricing methodology is consistent with the **pricing principles** and explain the reasons for any inconsistency between the pricing methodology and the **pricing principles** | (Section 12) |
| | (3) State the **target revenue** expected to be collected for the **disclosure year** to which the pricing methodology applies | (Section 8 – Table 8-A) |
| | (4) Where applicable, identify the key components of **target revenue** required to cover the costs and return on | (Section 8 – Table 8-A) |

| | | |
|---|---|---|
| | 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 6) |
| | (b) the method and the criteria used by the **EDB** to allocate **consumers** to each of the **consumer groups**; | (Section 6) |
| | (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 10) |

| | | |
|---|---|---|
| 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 9 & 10) |
| | (8) State the proportion of **target revenue** (if applicable) that is collected through each **price component** as **publicly disclosed** under clause 2.4.18 | (Section 9 &10) |
| 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 | (n/a) |
| | (2) Explain how and why **prices** for each **consumer group** are expected to change as a result of the **pricing strategy** | (n/a) |
| | (3) If the **pricing strategy** has changed from the preceding **disclosure year**, identify the changes and explain the reasons for the changes | (n/a – no change in pricing strategy) |
| 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 11.1) |
| | (b) how the **EDB** determines whether to use a **non-standard contract**, including any criteria used | (Section 11.1) |
| | (c) any specific criteria or methodology used for determining **prices** for **consumers** subject to **non-** | (Section 11.1) |

| | | | | |
|---|---|---|---|---|
| | | | **standard contracts** and the extent to which these criteria or that methodology are consistent with the **pricing principles** | |
| | (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 11.1) |
| | | (b) | any implications of this approach for determining **prices** for **consumers** subject to **non-standard contracts** | (Section 11.1) |
| | (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 11.2) |
| | | (b) | value, structure and rationale for any payments to the owner of the **distributed generation** | (Section 11.2) |

# APPENDIX 1 – SCHEDULE OF PRICES

## OTPO - OtagoNet Joint Venture

Delivery Price Schedule for Residential & General Connections

| Residential and General Connections | Code | Number of Consumers | Charges Effective from: | Pass Through Fixed Price Annual $per kVA of supply capacity | Distribution Price Annual $per kVA of supply capacity | Total Fixed Price Annual $per kVA of supply capacity |
|---|---|---|---|---|---|---|
| Delivery Prices effective from 1 April 2019<br>**Fixed Prices** | | | | | | |
| Residential Standard - Fixed Price | 1A | 1755 | 1-Apr-19 | $ 5.7452 | $62.0832 | $67.8284 |
| Residential Standard - Fixed Price | 1B | 4803 | 1-Apr-19 | $ 5.7452 | $62.0832 | $67.8284 |
| | | | | | | |
| | | | | Pass Through Fixed Price $per Day | Distribution Price $per Day | Total Fixed Price $per Day |
| Residential Low Fixed Charge - Fixed Price | 7 | 3773 | 1-Apr-19 | $ 0.0185 | $0.1315 | $0.1500 |
| Residential Low Fixed Charge - Fixed Price | 8 | 1229 | 1-Apr-19 | $ 0.0185 | $0.1315 | $0.1500 |
| | | | | Pass Through Fixed Price Annual $per kVA of supply capacity | Distribution Price Annual $per kVA of supply capacity | Total Fixed Price Annual $per kVA of supply capacity |
| General Connection Group - Fixed Price per kVA of Supply Capacity | 2 | 3289 | 1-Apr-19 | $ 5.7452 | $62.08320 | $67.8284 |
| | | | | Pass Through 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-19 | $ 33.0240 | $235.20600 | $268.23 |
| | | | | Pass Through Fixed Price $ per lamp watt per annum | Distribution Price $ per lamp watt per annum | Total Fixed Price $ per lamp watt per annum |
| Street Lights Fixed Price per lamp watt per annum | 6 | 9 | 1-Apr-19 | $ 0.0617 | $0.43930 | $0.5010 |
| | | | | | | |
| **Variable Volume Prices**<br>Day | | | | Pass Through 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-19 | $ 0.01783 | $0.12703 | $0.14486 |
| Variable Volume prices for codes 7 & 8 metered at the ICP | | | 1-Apr-19 | $ 0.03023 | $0.21530 | $0.24553 |
| Night | | | | Pass Through 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-19 | $ 0.00206 | $0.01464 | $0.01670 |
| Variable Volume prices for codes 7 & 8 metered at the ICP | | | 1-Apr-19 | $ 0.003160 | $0.022486 | $0.025646 |

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. Residential consumers may only change their price code once per 12 month period.

**Volume Prices**

The volume prices shown apply to the Day MWh Purchases as metered at the Transpower Grid Supply Point, except for codes 7 & 8 which are metered at the ICP
Day is defined as 0700 - 2300 hours.
Summer Day means the period of time from 07:00 until 23:00 on all days between the 1st of October and 30th of April.

Winter Day means the period of time from 07:00 until 23:00 on all days between the 1st of May and the 30th September.

Night means the period of time from 23:00 until 07:00 on all nights of the year.

Grid Exit Point means the Transpower substation that supplies the customer. The Retailer's energy for classes 1,2,5 & 6 is calculated by subtracting the day and night kWh figures, plus losses, of the Individual customers and Residential Low User Option from the Retailer's reconciled energy at each grid exit point.

Supply Capacity kVA means the maximum average electrical demand over any half-hour period measured in kVA. This may be measured by half-hour demand metering or measured by portable logging equipment or assessed from nameplate ratings of connected equipment. The minimum capacity is 10kVA for all Residential and General connections.

With Off - Peak - The eligibility for a "with off peak" delivery price is determined on the basis that at least 25% of the total energy consumption is separately metered and contolled by a ripple relay, such as a water heater or consumed between 23:00 and 07:00 hours.

**All prices are GST exclusive.**

**Line Losses:**

All ICPs except for Individually assessed customers have a loss factor of 1.0750 Code OTPOGXP

**Power Factor Charges**

All charges assume a power factor of not less than 0.95 lagging.
Non-Domestic customers may have a data logger installed to assess their power factor. If a non-domestic customer has a power factor of less than 0.95 lagging and after a period of 12 months notice has not been corrected then an annual power factor charge of $80 per kVA will be applied.
The kVA is based on the total kVA less kVA at 0.95 power factor. The kVA will be assesed on the average of the 12 highest kWH half hour periods during the assessment period.

Application of the power factor charge will be at the sole discretion of the Distributor.

## Half Hour Metered Individual Line Charge Customers – Otago & Lakeland Region

| ICP Number | Number of Consumers | Contract Capacity kVA | Charges effective from | Pass-through portion of Fixed Price per Day | Total Fixed Price per Day | Pass-through portion of Variable Price per Day kWh | Total Variable Price per Day kWh |
|---|---|---|---|---|---|---|---|
| **Otago Region** | | | | | | | |
| 0001090833TG6F1 | 1 | 300 | 1-Apr-19 | $ 7.38 | $ 14.51 | $ 0.07586 | $ 0.16417 |
| 0001120438TGE4C | 1 | 150 | 1-Apr-19 | $ 3.55 | $ 13.20 | $ - | $ - |
| 0001230615TG210 | 1 | 200 | 1-Apr-19 | $ 12.84 | $ 24.01 | $ 0.01563 | $ 0.03214 |
| 0001230783TG57C | 1 | 1000 | 1-Apr-19 | $ 48.67 | $ 81.63 | $ 0.02886 | $ 0.05248 |
| 0001230785TG4F3 | 1 | 200 | 1-Apr-19 | $ 13.92 | $ 24.78 | $ 0.01919 | $ 0.03716 |
| 0001230940TG858 | 1 | 750 | 1-Apr-19 | $ 42.86 | $ 114.14 | $ 0.02451 | $ 0.08112 |
| 0001230990TG51A | 1 | 500 | 1-Apr-19 | $ 26.30 | $ 61.89 | $ 0.02478 | $ 0.06905 |
| 0001231005TGF1B | 1 | 2500 | 1-Apr-19 | $ 216.11 | $ 449.11 | $ 0.02119 | $ 0.05053 |
| 0001231172TGE88 | 1 | 750 | 1-Apr-19 | $ 107.94 | $ 219.24 | $ 0.01656 | $ 0.03831 |
| 0001250655TG2ED | 1 | 30 | 1-Apr-19 | $ 2.05 | $ 8.16 | $ - | $ - |
| 0001320515TGD9E | 1 | 75 | 1-Apr-19 | $ 1.89 | $ 4.51 | $ 0.03209 | $ 0.08235 |
| 0001321124TGB82 | 1 | 150 | 1-Apr-19 | $ 1.28 | $ 9.74 | $ - | $ - |
| 0001370505TG447 | 1 | 50 | 1-Apr-19 | $ 13.31 | $ 26.96 | $ - | $ - |
| 0001370610TG0A6 | 1 | 200 | 1-Apr-19 | $ 10.95 | $ 18.24 | $ 0.07123 | $ 0.12664 |
| 0001401195TG9B3 | 1 | 50 | 1-Apr-19 | $ 14.71 | $ 25.95 | $ - | $ - |
| 0001450225TGAD6 | 1 | 150 | 1-Apr-19 | $ 18.48 | $ 25.82 | $ 0.01576 | $ 0.02289 |
| 0001450400TGCCA | 1 | 100 | 1-Apr-19 | $ 13.58 | $ 19.48 | $ 0.01483 | $ 0.02213 |
| 0001452050TGB83 | 1 | 100 | 1-Apr-19 | $ 7.89 | $ 12.02 | $ 0.01433 | $ 0.02274 |
| 0001491270TGA81 | 1 | 200 | 1-Apr-19 | $ 7.07 | $ 10.90 | $ 0.03176 | $ 0.05090 |
| 0001520870TGB4E | 1 | 150 | 1-Apr-19 | $ 13.21 | $ 17.94 | $ 0.03102 | $ 0.04338 |
| 0001580380TGEBF | 1 | 50 | 1-Apr-19 | $ 4.86 | $ 10.74 | $ 0.04869 | $ 0.12054 |
| 0001640675TGEE6 | 1 | 100 | 1-Apr-19 | $ 23.63 | $ 117.19 | $ - | $ - |
| 0001690827TGC31 | 1 | 500 | 1-Apr-19 | $ 2.42 | $ 13.21 | $ - | $ - |
| 0001700063TGC3B | 1 | 1750 | 1-Apr-19 | $ 82.96 | $ 185.74 | $ - | $ - |
| 0001710106TGF61 | 1 | 150 | 1-Apr-19 | $ 8.88 | $ 51.22 | $ - | $ - |
| 0001710108TGCFA | 1 | 150 | 1-Apr-19 | $ 14.43 | $ 87.38 | $ - | $ - |
| 0001730075TG635 | 1 | 200 | 1-Apr-19 | $ 6.97 | $ 20.45 | $ - | $ - |
| 0001730339TG48D | 1 | 150 | 1-Apr-19 | $ 13.85 | $ 38.53 | $ - | $ - |
| 0001730798TGCD6 | 1 | 200 | 1-Apr-19 | $ 2.04 | $ 7.37 | $ - | $ - |
| 0001730830TG9D2 | 1 | 500 | 1-Apr-19 | $ 43.66 | $ 127.22 | $ - | $ - |
| 0001730881TG725 | 1 | 200 | 1-Apr-19 | $ 7.31 | $ 21.32 | $ - | $ - |
| 0001731161TG536 | 1 | 200 | 1-Apr-19 | $ 16.86 | $ 47.42 | $ - | $ - |
| 0001731175TGE91 | 1 | 200 | 1-Apr-19 | $ 24.20 | $ 67.92 | $ - | $ - |
| 0001731255TG0C7 | 1 | 300 | 1-Apr-19 | $ 17.72 | $ 45.92 | $ 0.01513 | $ 0.04784 |
| 0001760343TG035 | 1 | 300 | 1-Apr-19 | $ 16.79 | $ 32.15 | $ 0.01858 | $ 0.03948 |
| 0001772060TG902 | 1 | 200 | 1-Apr-19 | $ 36.34 | $ 83.58 | $ - | $ - |

| | | | | | | | |
|---|---|---|---|---|---|---|---|
| 0001772165TGD49 | 1 | 200 | 1-Apr-19 | $ 9.47 | $ 27.02 | $ - | $ - |
| 0001780560TGADB | 1 | 50 | 1-Apr-19 | $ 9.82 | $ 20.02 | $ - | $ - |
| 0001811005TG57F | 1 | 300 | 1-Apr-19 | $ 5.50 | $ 16.18 | $ 0.02826 | $ 0.10388 |
| 0001820703TGB7E | | 200 | 1-Apr-19 | $ 15.33 | $ 40.06 | $ 0.01314 | $ 0.04195 |
| 0001830031TGBE0 | 1 | 150 | 1-Apr-19 | $ 2.09 | $ 23.63 | $ - | $ - |
| 0001830497TGE71 | 1 | 300 | 1-Apr-19 | $ 7.37 | $ 31.95 | $ 0.00917 | $ 0.06371 |
| 0001830541TGBB8 | 1 | 3500 | 1-Apr-19 | $ 467.11 | $ 1,165.70 | $ - | $ - |
| 0001830828TGF11 | 1 | 200 | 1-Apr-19 | $ 1.53 | $ 11.83 | $ - | $ - |
| 0001830903TG594 | 1 | 200 | 1-Apr-19 | $ 0.72 | $ 8.14 | $ - | $ - |
| 0001840612TG6CA | 1 | 100 | 1-Apr-19 | $ 19.30 | $ 42.63 | $ 0.01309 | $ 0.03344 |
| 0001930500TG134 | 1 | 100 | 1-Apr-19 | $ 3.85 | $ 7.23 | $ 0.01869 | $ 0.03718 |
| 0001940050TG680 | 1 | 200 | 1-Apr-19 | $ 19.94 | $ 42.57 | $ 0.02033 | $ 0.04974 |
| 0001940060TG178 | 1 | 500 | 1-Apr-19 | $ 69.70 | $ 153.78 | $ 0.01993 | $ 0.05126 |
| 0001940090TG16F | 1 | 200 | 1-Apr-19 | $ 7.33 | $ 18.21 | $ 0.02102 | $ 0.06161 |
| 0001940095TGC20 | 1 | 500 | 1-Apr-19 | $ 14.87 | $ 39.33 | $ 0.02287 | $ 0.07418 |
| 0001940100TG78C | 1 | 300 | 1-Apr-19 | $ 29.70 | $ 77.08 | $ 0.01399 | $ 0.04458 |
| 0001940110TGD21 | 1 | 300 | 1-Apr-19 | $ 15.47 | $ 37.80 | $ 0.02423 | $ 0.07062 |
| 0001940350TG583 | 1 | 150 | 1-Apr-19 | $ 9.78 | $ 19.43 | $ 0.01728 | $ 0.03810 |
| 0001940650TG086 | 1 | 300 | 1-Apr-19 | $ 31.96 | $ 56.15 | $ 0.02662 | $ 0.05112 |
| 0001940905TGACE | 1 | 150 | 1-Apr-19 | $ 11.85 | $ 24.00 | $ 0.01588 | $ 0.03607 |
| 0001940907TGA4B | 1 | 500 | 1-Apr-19 | $ 45.26 | $ 77.14 | $ 0.03081 | $ 0.05712 |
| 0001940910TGD2C | 1 | 1000 | 1-Apr-19 | $ 73.19 | $ 168.48 | $ 0.01206 | $ 0.03280 |
| 0001941000TGF28 | 1 | 200 | 1-Apr-19 | $ 27.18 | $ 49.10 | $ 0.02207 | $ 0.04382 |
| 0001950500TG36C | 1 | 200 | 1-Apr-19 | $ 19.62 | $ 26.56 | $ 0.02316 | $ 0.03243 |
| 0001950550TGB64 | 1 | 500 | 1-Apr-19 | $ 21.92 | $ 31.57 | $ 0.02365 | $ 0.03563 |
| 0001950800TG664 | 1 | 300 | 1-Apr-19 | $ 7.17 | $ 12.17 | $ 0.04017 | $ 0.07243 |
| 0001950850TGE6C | 1 | 500 | 1-Apr-19 | $ 4.58 | $ 10.01 | $ 0.04976 | $ 0.12112 |
| 0001950900TGF60 | 1 | 150 | 1-Apr-19 | $ 18.63 | $ 26.75 | $ 0.01963 | $ 0.02944 |
| 0001951100TGECD | 1 | 150 | 1-Apr-19 | $ 15.24 | $ 31.50 | $ 0.01676 | $ 0.03919 |
| 0001951200TGDCE | 1 | 500 | 1-Apr-19 | $ 13.55 | $ 29.36 | $ 0.05250 | $ 0.13027 |
| 0001951320TG99F | 1 | 500 | 1-Apr-19 | $ 15.31 | $ 32.82 | $ - | $ - |
| 0001951350TGCC2 | 1 | 200 | 1-Apr-19 | $ 3.24 | $ 7.50 | $ 0.02442 | $ 0.06294 |
| 0001951500TG2CC | 1 | 300 | 1-Apr-19 | $ 38.97 | $ 55.05 | $ 0.01444 | $ 0.02136 |
| 0001951600TG1CF | 1 | 150 | 1-Apr-19 | $ 12.27 | $ 17.09 | $ 0.03034 | $ 0.04366 |
| 0001951750TG0C3 | 1 | 200 | 1-Apr-19 | $ 19.51 | $ 27.30 | $ 0.01977 | $ 0.02878 |
| 0001951790TG72C | 1 | 500 | 1-Apr-19 | $ 31.35 | $ 44.69 | $ 0.02165 | $ 0.03232 |
| 0001952100TGC2D | 1 | 750 | 1-Apr-19 | $ 47.16 | $ 77.49 | $ - | $ 0.06697 |
| 0001952400TG928 | 1 | 150 | 1-Apr-19 | $ 10.68 | $ 17.26 | $ 0.02768 | $ 0.04745 |
| 0001952500TG02C | 1 | 500 | 1-Apr-19 | $ 42.41 | $ 66.42 | $ 0.02300 | $ 0.03847 |
| 0001952510TGA81 | 1 | 200 | 1-Apr-19 | $ 1.03 | $ 5.94 | $ - | $ - |
| 0001990133TG0E5 | 1 | 7250 | 1-Apr-19 | $ 338.12 | $ 673.55 | $ - | $ - |
| 0001990220TG58B | 1 | 7500 | 1-Apr-19 | $ 1,686.73 | $ 2,002.64 | $ - | $ - |
| 0002011523TGC1A | 1 | 150 | 1-Apr-19 | $ 5.13 | $ 27.79 | $ - | $ - |
| 0002110863TGE7B | 1 | 300 | 1-Apr-19 | $ 13.71 | $ 27.78 | $ 0.01754 | $ 0.03991 |
| 0002381026TGF20 | 1 | 200 | 1-Apr-19 | $ 35.97 | $ 110.74 | $ 0.01308 | $ 0.05329 |
| 0002641192TGCFF | 1 | 200 | 1-Apr-19 | $ 17.49 | $ 114.77 | $ - | $ - |

| | | | | | | | |
|---|---|---|---|---|---|---|---|
| 0002700906TGC46 | 1 | 150 | 1-Apr-19 | $ 11.39 | $ 23.61 | $ - | $ - |
| 0002751750TG11E | 1 | 200 | 1-Apr-19 | $ 10.90 | $ 45.15 | $ - | $ - |
| 0002751765TGBA9 | 1 | 200 | 1-Apr-19 | $ 2.94 | $ 16.97 | $ - | $ - |
| 0002751767TGB2C | 1 | 200 | 1-Apr-19 | $ 10.42 | $ 57.27 | $ - | $ - |
| 0002751847TG976 | 1 | 200 | 1-Apr-19 | $ 16.14 | $ 44.97 | $ - | $ - |
| 0002751838TG3F5 | 1 | 200 | 1-Apr-19 | $ 9.84 | $ 28.27 | $ - | $ - |
| 0002751858TGC05 | 1 | 150 | 1-Apr-19 | $ 9.48 | $ 27.10 | $ - | $ - |
| 0002781189TG85A | 1 | 200 | 1-Apr-19 | $ 6.62 | $ 24.68 | $ - | $ - |
| 0002841699TG73F | 1 | 200 | 1-Apr-19 | $ 13.32 | $ 37.14 | $ - | $ - |
| 0002842004TG365 | 1 | 75 | 1-Apr-19 | $ 16.09 | $ 42.97 | $ - | $ - |
| 0002871188TGFF9 | 1 | 150 | 1-Apr-19 | $ 13.14 | $ 37.27 | $ - | $ - |
| 0003752355TG409 | 1 | 500 | 1-Apr-19 | $ 34.52 | $ 90.31 | $ - | $ - |
| 0003752365TG3F1 | 1 | 100 | 1-Apr-19 | $ 6.81 | $ 16.40 | $ 0.01428 | $ 0.04009 |
| 0003752380TG404 | 1 | 200 | 1-Apr-19 | $ 13.04 | $ 32.36 | $ - | $ - |
| 0002751848TG6A8 | 1 | 300 | 1-Apr-19 | $ 15.52 | $ 44.93 | $ - | $ - |
| 0002841739TG624 | 1 | 200 | 1-Apr-19 | $ 10.52 | $ 33.38 | $ - | $ - |
| 0001730849TG2DE | 1 | 500 | 1-Apr-19 | $ 12.79 | $ 30.96 | $ - | $ - |
| 0003752367TG374 | 1 | 100 | 1-Apr-19 | $ 6.99 | $ 18.79 | $ - | $ - |
| | | | | | | | |
| **Lakeland Region** | | | | | | | |
| 950325LN3F5 | 1 | 1000 | 1-Apr-19 | $ 212.71 | $ 339.11 | | |
| 950335LN958 | 1 | 750 | 1-Apr-19 | $ 55.41 | $ 118.21 | | |
| 950330LN417 | 1 | 750 | 1-Apr-19 | $ 56.33 | $ 120.82 | | |
| 950315LN40D | 1 | 150 | 1-Apr-19 | $ 14.21 | $ 40.29 | | |
| 950320LNEBA | 1 | 150 | 1-Apr-19 | $ 20.07 | $ 49.18 | | |
| 950934LNF17 | 1 | 500 | 1-Apr-19 | $ 41.11 | $ 104.27 | | |
| 959018LN4F5 | 1 | 750 | 1-Apr-19 | $ 192.80 | $ 294.89 | | |
| 952055LN6EB | 1 | 300 | 1-Apr-19 | $ 24.76 | $ 53.46 | | |
| 959005LN103 | 1 | 500 | 1-Apr-19 | $ 66.24 | $ 112.58 | | |
| 952081LNAA3 | 1 | 1000 | 1-Apr-19 | $ 165.56 | $ 255.24 | | |

| LLNW - OtagoNet Joint Venture - Lakeland Region Pricing Schedule<br>Prices Effective from 1 April 2019 | | | | | | |
|---|---|---|---|---|---|---|
| **Standard Residential Connections** | | | | | **Per Annum** | |
| **Fixed Charges** | **Capacity** | **Description** | **Code** | **Distribution** | **Pass-through** | **Total** |
| | 15 kVA | Single phase 63 amp | LD15 | $32.6675 | $22.0825 | $54.7500 |
| | 15 kVA | Three phase 20A MCB | LM15 | $32.6675 | $22.0825 | $54.7500 |
| | 8 kVA | Single Phase 32A MCB | LD08 | $8.9425 | $6.0590 | $15.0015 |
| **Variable Charges** | | | **Code** | | **(cents / kWh)** | |
| | Uncontrolled 24hr | Summer | S24S | 6.16 | 4.16 | 10.32 |
| | Uncontrolled 24hr | Winter | S24W | 9.27 | 6.26 | 15.53 |
| | Controlled 20 | 20 Hour Supply | S20C | 4.21 | 2.85 | 7.06 |
| | Controlled 16 | 16 Hour Supply | S16C | 2.27 | 1.54 | 3.81 |
| | Night Boost 5 | 13 Hour Supply | S13C | 3.09 | 2.09 | 5.18 |
| | Night Boost 3 | 11 Hour Supply | S11C | 1.78 | 1.20 | 2.98 |
| | Night Only | 8 Hour Supply | S08C | 0.78 | 0.52 | 1.30 |

| **General Connections** | | | | | **$ per Day** | |
|---|---|---|---|---|---|---|
| **Capacity** | **Description** | **Code** | | **Distribution** | **Pass-through** | **Total** |
| 1 kVA | Single Phase 5A MCB+ | LS001 | Fixed Charges | $0.3657 | $0.2469 | $0.6126 |
| 2 kVA | Single Phase 63 amps++ | LS002 | | $0.7238 | $0.4887 | $1.2125 |
| 8 kVA | Single Phase 32A MCB | LS008 | | $0.4164 | $0.2811 | $0.6975 |
| 15 kVA | Single Phase 63 amps | LS015 | | $0.7188 | $0.4854 | $1.2042 |
| 23 kVA | Single Phase 100 amps | LS023 | | $0.9072 | $0.6126 | $1.5198 |
| 28 kVA | Two Phase | LT028 | | $1.0973 | $0.7410 | $1.8383 |
| 15 kVA | Three Phase 20A MCB | LT015 | | $0.7188 | $0.4854 | $1.2042 |
| 24kVA | Three Phase 32A MCB | LT024 | | $0.9452 | $0.6383 | $1.5835 |
| 41 kVA | Three Phase 63 amps | LT041 | | $1.5916 | $1.0747 | $2.6663 |
| 69 kVA | Three Phase 100 amps | LT069 | | $2.6562 | $1.7936 | $4.4498 |
| 103 kVA | Three Phase 150 amps | LT103 | | $3.9490 | $2.6665 | $6.6155 |
| 138 kVA | Three Phase 200 amps | LT138 | | $5.2798 | $3.5651 | $8.8449 |
| 172 kVA | Three Phase 250 amps | LT172 | | $16.7189 | $11.2893 | $28.0082 |
| 207 kVA | Three Phase 300 amps | LT207 | | $19.9701 | $13.4846 | $33.4547 |

| | | | | | | |
|---|---|---|---|---|---|---|
| 276 kVA | Three Phase 400 amps | LT276 | | $24.9300 | $16.8338 | $41.7638 |
| | | | | Per Annum | | |
| | | | | Distribution | Pass-through | Total |
| **Capacity** | **Description** | **Code** | | **$/kW** | **$/kW** | **$/kW** |
| 1 kVA | Single Phase 5A MCB+ | LS001 | Control Period Demand | $0.0000 | $0.0000 | $0.0000 |
| 2 kVA | Single Phase 63 amps++ | LS002 | | $0.0000 | $0.0000 | $0.0000 |
| 8 kVA | Single Phase 32A MCB | LS008 | | $120.9587 | $81.6763 | $202.6350 |
| 15 kVA | Single Phase 63 amps | LS015 | | $120.9587 | $81.6763 | $202.6350 |
| 23 kVA | Single Phase 100 amps | LS023 | | $131.8480 | $89.0293 | $220.8773 |
| 28 kVA | Two Phase | LT028 | | $131.8480 | $89.0293 | $220.8773 |
| 15 kVA | Three Phase 20A MCB | LT015 | | $120.9587 | $81.6763 | $202.6350 |
| 24kVA | Three Phase 32A MCB | LT024 | | $131.8480 | $89.0293 | $220.8773 |
| 41 kVA | Three Phase 63 amps | LT041 | | $131.8480 | $89.0293 | $220.8773 |
| 69 kVA | Three Phase 100 amps | LT069 | | $131.8480 | $89.0293 | $220.8773 |
| 103 kVA | Three Phase 150 amps | LT103 | | $131.8480 | $89.0293 | $220.8773 |
| 138 kVA | Three Phase 200 amps | LT138 | | $131.8480 | $89.0293 | $220.8773 |
| 172 kVA | Three Phase 250 amps | LT172 | | $105.2555 | $71.0729 | $176.3284 |
| 207 kVA | Three Phase 300 amps | LT207 | | $105.2555 | $71.0729 | $176.3284 |
| 276 kVA | Three Phase 400 amps | LT276 | | $105.2555 | $71.0729 | $176.3284 |

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

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 OtagoNet.

| 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% |