LINE PRICING METHODOLOGY

ELECTRICITY INVERCARGILL LIMITED (EIL) NETWORK AS AT 1 APRIL 2025

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GLOSSARY OF TERMS

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

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

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

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

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

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

ENA is the Electricity Networks Aoteroa

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

Residential and General Customers include most customers with a Contract Capacity up to and including 100 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 100kVA.

Installation Control Point (ICP) is the point of connection between the Electricity Invercargill Limited 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 utilising 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).

1. INTRODUCTION

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

We first provide contextual information about the EIL's network (**section 2**), then present an overview of our prices and how they are set (**section 3**). **In section 4**, we discuss our forward pricing strategy. We then assess our pricing against the Authority's Distribution Pricing Principles (**section 5**). This is followed by a more detailed discussion of how overall target revenue is determined, how that revenue is allocated to customer groups, and the methodology used to convert the revenue requirement into prices (**sections 6 to 9**). Charges that would be applied for generators connected to EIL's network are described (**section 10**).

Changes made to the previous methodology include:

- **Pricing Strategy Implementation** - Further Implementation of EIL's pricing strategy of increasing the recovery of revenue through fixed charges. EIL is increasing the price differential between the "peak" and "shoulder" periods of the variable line charges to encourage more usage in the shoulder and night periods.

- **Phase out of Low-User Fixed Charges (LFC)** – In line with regulation changes, EIL has continued to phase out LFC charges to support the move towards more cost-reflective pricing. RY26 is the fourth year of a five-year phase out that will be completed in RY27 and results in fixed charges for residential consumers increasing, from $0.60 per day to $0.75 per day from 1 April 2025.

- **Subsidy Free Zone** – We develop further on our calculation and discussion of long run marginal cost and identify the subsidy free zone (pages 21-25).

2. BACKGROUND INFORMATION ABOUT EIL

2.1 The EIL Network

Electricity Invercargill Limited is an electricity network asset company formed in 1991. The company is owned by the Invercargill City Council through its subsidiary company Invercargill City Holdings Ltd (ICHL). It is a wholly owned subsidiary of Invercargill City Holdings Limited (ICHL).

EIL owns the electricity network assets in Invercargill City and the Bluff township area. PowerNet Limited (PowerNet) manages the network assets owned by EIL.

A geographically compact network, EIL supplies more than 17,700 connections to residential, commercial and industrial customers.

EIL's service area includes two fully urban, geographically separate areas comprising of the city of Invercargill (except for some of the outer regions supplied from The Power Company Limited's surrounding network) and the township of Bluff. The Invercargill area network is almost entirely underground; only a few streets remain as overhead construction. The Bluff network is predominantly overhead line due to the difficulty associated with laying cable in the rocky subsurface.

The high proportion of underground cabling means that the EIL network consistently performs as one of the most reliable networks in New Zealand.

Transpower's Invercargill Transmission Grid Exit Point (GXP) substation is the 33 kV supply point for both the Invercargill and Bluff network areas. In addition, a limited backup supply is available from the North Makarewa GXP. Bluff is supplied at 11 kV via The Power Company Limited's (TPCL's) overhead sub-transmission lines, and the Bluff zone substation.

EIL's distribution network includes 23km of 11kV lines and 156km of 11kV underground cables. With more than 400 distribution substations, comprising 11 kV switchgear and distribution transformers, the distribution network supplies over 452 km of low voltage network operating at 400/230 V. EIL has 26.4 ICPs per KM of line, which is the 4th highest customer density ranking out of the 29 New Zealand Distributors.

2.2 Network Investment

As at end March 2024, the value of EIL's network assets in its Regulatory Asset Base was $113 million. Over the next three years, EIL intends to invest capital of $22.91 million in its network, of which the majority relates to asset replacements ($15.30 million).

EIL's network is generally unconstrained and with a maximum demand growth forecast of only 0.4% per annum, EIL is currently forecasting system growth capital expenditure during the next three years of $1,237,000.

2.3 Uptake of evolving technology

Several technologies have the potential to change the way customers use and generate electricity. Pricing has a role to play in providing efficient signals about the economic costs of using electricity networks. In that context, we provide a summary of existing and expected uptake of a number of these technologies: solar, electric vehicles and battery storage.

Solar (Photovoltaic) connections

As of January 2025, EIL had 167 solar connections to its network, representing 0.94% of all EIL ICPs. This is below the national average of 3.34% and significantly lower than the 5.54% rate in the top ten highest uptake EDB areas. There has been a slight acceleration in uptake on EIL's network: the average number of new solar connections per month over the 12 months leading to January 2025 was 1.91, compared to 1.3 and 1.1 in the two preceding 12-month periods.

EIL explores the potential for growth in solar uptake and impact on the network in the company's Asset Management Plan (AMP). The annual customer engagement survey shows that the percentage of people already using solar has grown from the previous year by 65%, indicating a rising interest in solar panels and an increasing recognition of solar photovoltaic systems as a valuable investment.

At the same time, the number of people not intending to adopt solar panels has increased 12% from the previous year. The main barriers to adoption are economic reasons with the payback period being a key factor in purchase decisions. The rising cost of living has also made consumers more cautious about investments. Other considerations that may limit solar uptake are factors like property ownership and other subsidized energy-saving options, such as home insulation and heat pumps. These alternatives are seen as cost-effective and offer better returns.

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

Electric vehicles

There are approximately 517 electric vehicles registered in the EIL area[1]. With rising fuel costs, increasing concerns about global warming, and the impact of carbon emissions, we expect electric vehicle adoption in New Zealand to continue growing each year, despite the end of the Clean Car rebate.

The annual customer engagement survey reveals a 76% increase in the number of people already using electric vehicles compared to the previous year, showing a growing interest in EV adoption. However, the number of people not planning to adopt an EV has also risen by 21%.

As EIL explains in the AMP, EVs have the potential to have large impacts on network demand with sufficient adoption. Prices are an important means for signalling peak periods and enabling customers to choose whether to charge off-peak or pay a premium and charge during peak periods.

If customers choose not to charge off-peak in response to price signals, EV charging may increase peak demand, triggering greater investment. This effect will be greatest on the suburban LV network in built-up urban and semi-urban areas as the upstream MV network generally has sufficient capacity to allow for the forecast increases in load from EVs.

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

Energy storage

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

The annual customer engagement survey reveals a 23% increase in the number of people already using battery energy storage system (BESS) compared to the previous year, showing a growing interest in BESS adoption. However, the number of people not planning to adopt BESS has also risen by 6%. The main reason for this reluctance is the high upfront cost and long payback period, which is a concern given the rising cost of living. Many customers are also uncertain about the immediate benefits of batteries, despite the potential long-term savings. To encourage adoption, EIL's future pricing would aim to reward customers where batteries benefit the network. EIL may also focus on educating customers about the long-term financial and environmental advantages.

Storage gives customers some control over their demand without impacting their consumption and could make it possible for customers to go "off-grid" with a sufficiently sized generation source. However, there is significant uncertainty in this area around the viability of alternative battery chemistries and the timing of their introduction; the regulatory environment and the extent to

[1] EV Registrations in the Invercargill City Territorial Authority

which electricity distribution businesses will be able to utilise storage services; and future pricing structures and the level of responsiveness of the public to load-driven pricing signals.

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

2.4 PowerNet Limited Network Management Agreement

PowerNet is contracted to manage the network assets of EIL in accordance with a Network Management Agreement (Agreement).

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

3. EIL PRICING OVERVIEW

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

EIL uses "GXP billing" for its residential and general connections. This means that variable consumption charges are based on electricity volumes injected into the network at the Transpower grid exit points, rather than based on the usage at individual customer connection 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 ultimately transferred back into the pricing.

3.1 Consumer load groups used for pricing

There are two defined types of consumers for the purposes of EIL's pricing: Residential and General consumers; and Individual Consumers (for which prices are connection-specific).

3.1.1 Individual Consumers

These consumers have half-hour or time-of-use meters, including kVA maximum demand registers.

In most cases these installations have contract capacities in excess of 100kVA. Due to their size, these consumers have a higher impact on the network design and operation and therefore this 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.

Individual factors considered in cost allocations to individual line charge customers include:

- Connections having dedicated transformers.
- Low percentage use of the low voltage network
- Low diversity as capacity and demand increases
- Customer owned transformers.
- Additional security and back supplies, n-1.
- Higher importance on network maintenance

These consumers, through the half-hour or time-of-use metering, have individual profiles, which are used to calculate the line charges. Metering of these consumers includes kVA demand metering which provides the winter or seasonal peak demand and also the anytime peak demand. The latter figures are used in the calculation of line charges and to determine the contract capacity. For these consumers, the contract capacity is based on the next highest standard transformer size above their anytime 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.

3.1.2 Residential and General Consumers

The Residential and General category includes all residential connections and general single and 3 phase connections up to 100kVA capacity. Prices for these customers include a daily charge and a kWh price applied to energy used during the Peak period, which is defined as 7am to 11am and 5pm to 9pm, the Shoulder period, which is defined as 11am to 5pm and 9pm to 11pm and energy usage during the Night period 11pm to 7am.

Prices for Residential and General Consumers vary according to:

- **Capacity:**
  - General connections are split between single and three phase categories, they are then further disaggregated into load groups based on the size of the service fuse or size of transformer supplying them. The differentials between load groups reflect the use of the network assets for each group and the diversity each group has around peak load times.
  - Residential connections are either 8 kVA or 15 kVA. 8kVA residential connections require a 32-amp circuit breaker to be installed on the main switchboard to control the complete installation. This capacity is only allowed for single-phase installations.
  - Different consumer groups are based on practical fuse sizes. For pricing purposes, all residential consumers are classed as single-phase irrespective of whether they are supplied two-phase or three-phase. This is due to the fact that for many of the consumers there was no choice in their method of supply and there are many older multi-phase residential installations. All old residential consumer installations are classed as “historic residential”.
- **Control:** Whether there is significant controllable load on the premises. If so, the connection qualifies for a “with off peak” line charge, which is lower than the “all peak” prices that apply connections without significant controllable load. The eligibility for a “with off peak” line charge is determined on the basis that at least 25% of the total annual energy consumption is separately metered on a ripple-controlled tariff, such as a water heater or consumed between 23:00 and 07:00 hours.
- **Low Users and Standard Users:** In line with the Electricity (Low Fixed Charge Tariff Option for Domestic Consumers) Regulations 2004, residential customers consuming less than 9000 kWh per annum are able to transfer to the Residential Low Fixed Charge Option tariffs. From 1 April 2022 the Low fixed Charge Tariff Option is being phased out over a 5-year

period by the Government. The phase out allows distributors to increase the daily fixed charge by an additional 15 cents per day for each of the 5 years, and when it reaches 90 cents per day in 5-years' time it will be removed altogether. To be eligible for the Low Fixed Charge Tariff Option the connection must meet the residential definition of "*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. The connection must meet the definition of "Domestic premises" under Section 5 of the Electricity Industry Act 2010*".

These options attract a lower fixed daily charge and a higher variable consumption charge. Retailers with customers on these pricing plans must submit the monthly consumption amounts for these customers in a separate file to PowerNet.

The consumer specific pricing options available for Residential and General Consumers are as follows:

Contract Capacity Group	Code
Residential	
Standard Residential (8kVA 1 Phase) - All Peak	ND08P
Standard Residential (8kVA 1 Phase) - With Off Peak	ND08Q
Standard Residential (15kVA 1 Phase) - All Peak	ND20P
Standard Residential (15kVA 1 Phase) - With Off Peak	ND20Q
Residential Low User (15kVA 1 Phase) - All Peak	NDL20P
Residential Low User (15kVA 1 Phase) - With Off Peak	NDL20Q
Residential Low User (8kVA 1 Phase) - All Peak*	NDL08P
Residential Low User (8kVA 1 Phase) - With Off Peak*	NDL08Q
General Single Phase	
Street Lights (1 Phase) per street light	NS001L
1 kVA 1 Phase - All Peak	NS001P
8 kVA 1 Phase - All Peak	NS008P
8 kVA 1 Phase - With Off Peak	NS008Q
15 kVA 1 Phase - All Peak	NS020P
15 kVA 1 Phase - With Off Peak	NS020Q
General Three Phase	
15 kVA 3 Phase - All Peak	NT015P
15 kVA 3 Phase - With Off Peak	NT015Q
30 kVA 3 Phase - All Peak	NT030P
30 kVA 3 Phase - With Off Peak	NT030Q
50 kVA 3 Phase - All Peak	NT050P
50 kVA 3 Phase - With Off Peak	NT050Q
75 kVA 3 Phase - All Peak	NT075P
75 kVA 3 Phase - With Off Peak	NT075Q
100 kVA 3 Phase - All Peak	NT100P
100 kVA 3 Phase - With Off Peak	NT100Q

3.2 Summary of target revenue and pricing changes

EIL has made a significant change to its pricing structure as we moved to more cost-reflective pricing from 1 April 2022. Changes made to EIL's pricing for are:

- Time of Use (TOU) pricing for Residential and General Customers replaced the existing Day/Night variable (kWh) line charge price structure. TOU now consists of three time periods for variable line charge prices these being:

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

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

  Night period 11pm to 7am.

- In line with the Government announced phase out of the Electricity (Low Fixed Charge Tariff Option for Domestic Consumers) Regulations 2004 EIL has increased the daily fixed charge to the Residential Low Fixed Charge Option customers.

- The differential between the "Peak" and "Shoulder" variable line charge prices has been increased to strengthen the signal for customers to use power in the non-peak periods.

EIL is regulated by the Commerce Commission Default Price-Quality Path determination 2025. 1 April 2025 will be year 1 of the Commerce Commissions reset determination for the Default Price-Quality Path (DPP4). DPP4 contains some significant changes to the revenue allowances and recovery mechanisms. Target revenue for 2025/26 is calculated at $23.676 million, increasing from $19.622 million the previous year. Below is a summary revenue for both transmission costs and distribution price components broken down by the two customer group categories for the 2025-26 year. We also outline the change in revenue compared with the previous year:

Year 2025-26	**Residential & General**	**Individual**	**Total**
Distribution	$14,449,767	$2,500,233	$16,950,000
Pass-through costs	$329,484	$3,213	$332,697
Recoverable costs	$1,037,351	$210,731	$1,248,082
Transmission	$3,684,269	$1,460,911	$5,145,180
Total	$19,500,871	$ 4,175,088	$23,675,959
Revenue from previous year			
Distribution	$11,231,475	$1,997,513	$13,228,988
Pass-through costs	$302,282	$2,947	$305,229

Recoverable costs	$1,230,073	$265,649	$1,495,722
Transmission	$3,287,616	$1,304,805	$4,592,421
Total	$15,103,423	$ 3,177,938	$19,622,360

Pass-through and recoverable costs have now been itemized, as this is a requirement of the Default Price-Quality Path. Transmission changes relate to a change in Transpower's line pricing methodology (outlined in section 7).

On average lines charges will increase by 20.6% from 1 April 2025. Residential customer pricing is as follows:

	Unit	2024/25	2024/25	2024/25	2025/26	2025/26	2025/26
Fixed Charges							
Residential – Off Peak	$/day	**0.9183**			**1.1938**		
Residential Low User – Off Peak	$/day	**0.5000**			**0.6500**		
Variable Charges		**Peak**	**Shoulder**	Night	**Peak**	**Shoulder**	**Night**
All except low user	c/kWh	**6.64**	**5.346**	1.00	**7.636**	**5.565**	**1.00**
Low User Off Peak	c/kWh	**9.283**	**6.914**	**1.00**	**10.72**	**8.016**	**1.00**

3.3 Customer consultation

Where significant changes in pricing structure are considered, EIL through PowerNet consults with customers and retailers.

Even in the absence of significant pricing change, EIL seeks the views of consumers as part of the Asset Management Process (AMP) and has reflected these views in the published AMP. This included

1. A face to face survey with key clients including expectations on price and current service
2. A bulk phone survey of current customers including expectations on price and quality
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), and capacity (equipment loadings) both impact on the cost of supply and subsequently prices charged. Price can 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.

4. PRICING STRATEGY

Given that EIL's pricing to Individual Customers is highly cost reflective and service based, the focus of the pricing strategy has primarily been on the structure of pricing for residential and general customers.

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

EIL's costs including Transpower charges are increasingly being fixed, EIL's strategy is to ensure that these fixed costs are passed onto customers and that a larger proportion of EIL's overall revenue is recovered through the fixed daily charges. From 1 April 2025 we continue this strategy and pass through the majority of the price increases through an increase to the prices of the fixed charges. Half hour metered individually assessed line charge customers who currently have their annual line charge recovered 50% through the fixed charge and 50% through the variable charge will have this increased to 60% fixed charge and 40% through the variable line charge.

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

4.1 Time of Use (TOU) Pricing

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

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

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

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

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

4.2 TOU price implementation.

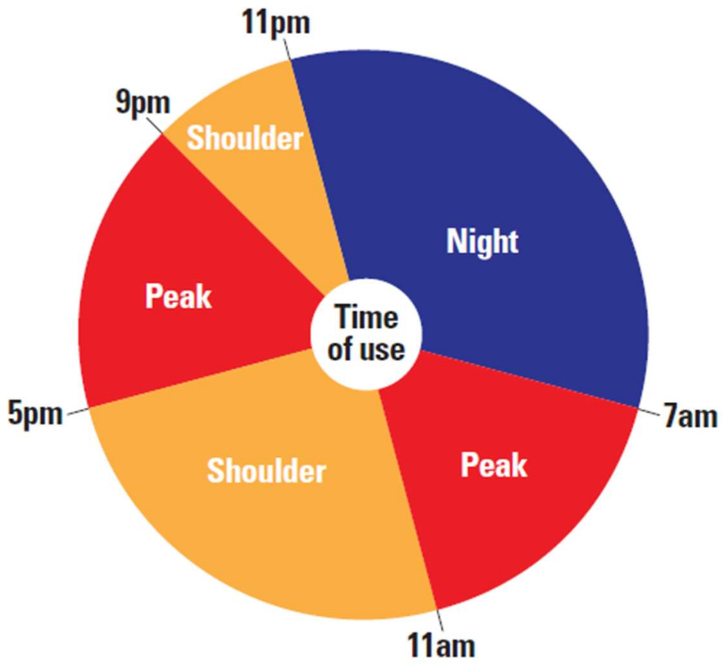
PowerNet has engaged in work streams to enable TOU pricing including billing system changes; engagement with retailers seeking support and feedback on best practice to implementing a change to TOU and how the necessary data will be provided; and preparing TOU pricing models along with comprehensive customer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

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

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

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

Graph: EIL TOU time periods



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

4.3 Installed Capacity (Charges)

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

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

Currently 47% of EIL's total line charge revenue is from fixed charges, with the 5-year phase out of the Low Fixed Charge and the fact that the majority of costs are fixed, EIL will look to increase the share of total revenue from fixed charges over time to 60%.

4.4 Customer Impact Analysis

The change in consumers' lines charges as a result of TOU will depend on usage profiles, but generally TOU implementation will have the least bill impact of available price reform options.

EIL has completed extensive impact analysis of a shift to installed capacity and TOU pricing. The analysis involved modelling over 53% of the residential and general customers who had more than 12 months' worth of half hourly smart meter data. Each ICP was overlaid with a NZ deprivation level index rating which was derived by the University of Otago using NZ census data to enable us to evaluate the impact at a socioeconomic level. Summarized in the below table we examine the break-down of energy usage by customer category by deprivation level.

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

Summarized in the below table we examine the break-down of energy usage by customer category by decile level:

EIL: General Descriptive Statistics :Consumption

EIL ICP Spilt per Decile and Sample Data	Total	Depreviation Decile									
		Advantaged			Middle NZ				Most Deprived		
		1	2	3	4	5	6	7	8	9	10
Network ICP Count											
Residential	15,328	527	968	1,088	776	1,107	931	2,593	2,416	2,927	1,995
% of Total Network 17,411 ICPs	88%	3%	6%	6%	4%	6%	5%	15%	14%	17%	11%
% of Residential 15,238 ICPs	100%	3%	6%	7%	5%	7%	6%	17%	16%	19%	13%
Residential Standard	8,781	403	659	730	454	643	527	1,456	1,375	1,519	1,015
% of Total Network 17,411 ICPs	50%	2%	4%	4%	3%	4%	3%	8%	8%	9%	6%
% of Residential 15,238 ICPs	57%	3%	4%	5%	3%	4%	3%	9%	9%	10%	7%
% of Standard 8,781 ICPs	100%	5%	8%	8%	5%	7%	6%	17%	16%	17%	12%
Residential Low User	6,547	124	309	358	322	464	404	1,137	1,041	1,408	980
% of Total Network 17,411 ICPs	38%	1%	2%	2%	2%	3%	2%	7%	6%	8%	6%
% of Residential 15,238 ICPs	43%	1%	2%	2%	2%	3%	3%	7%	7%	9%	6%
% of Low User 6,547 ICPs	100%	2%	5%	5%	5%	7%	6%	17%	16%	22%	15%
Sample Average Consumption kWh		11,126 kWh, 12% of Residential			9,887 kWh, 20% of Residential				9,825kWh, 26% of Residential		
Residential Standard kWh	10,114	11,218	11,480	10,750	10,237	10,389	9,846	9,599	9,748	9,965	9,712
Residential Low User kWh	6,187	7,063	6,605	6,421	6,709	6,320	6,352	6,273	5,984	6,002	5,920
		6,596kWh, 5% of Residential			6,354kWh, 15% of Residential				5,973kWh, 22% of Residential		
SAMPLE ICP COUNT 53% of In Scope ICPs											
Residential Standard 52% of Group	4,598	213	348	381	239	329	271	827	747	782	461
Residential Low 56% of Group	3,658	70	188	196	176	242	229	668	589	770	530
Commercial ICP											
EIL 8kVA 31% of Group	57	0	0	1	1	2	1	12	7	22	11
EIL 15kVA 45% of Group	33	1	0	0	0	2	0	1	3	15	11
EIL 20kVA 39% of Group	142	0	3	4	2	1	5	29	18	58	22
EIL 30kVA 48% of Group	318	0	5	4	4	14	4	33	12	144	98
EIL 50kVA 46% of Group	176	1	3	6	1	5	3	11	18	99	29
EIL 75kVA 31% of Group	40	0	1	0	3	2	1	5	1	19	8
EIL 100kVA 27% of Group	20	0	0	0	2	0	2	2	1	8	5

* In Scope ICPs - All ICPS that do not have an Individual price calculated

- EIL 88% Residential with 42% of total ICPs, **7,338 ICPs in the Most Deprived Band**
- Sample Consumption indicates the Annual kWh for both Standard & Low User decreases as the decile becomes more deprived
- 26%, 3,429 Residential ICPs who are the most deprived, cannot take advantage of the Low User – as they are over the breakeven 9,000kWh.
- 5%, 791 Residential ICPs who are the Most Advantaged have benefited from the Low User regulations

In the table below we analyze the impact by customer group and decile level of the move to TOU variable pricing:

EIL Average Annual Bill Impact by Installed Capacity & TOU Pricing option with Deprivation Levels & Customer Groups					
EIL: Fixed + TOU: YEAR ONE Avg Annual Bill Impact by Price Category and Depreviation Band	ICP Sample No.	Avg Annual Energy Useage kWh	Avg Annual Line Charge	Avg Change to Annual Line Charge	
Residential 88%				%	$
Standard Residential 57%	4,598	10,114	$858	0.27%	$2.33
Standard Residential decile 10 - 8 (Most Deprived)	1,990	9,825	$844	0.18%	$1.51
Standard Residential decile 7- 4 (Middle NZ)	1,666	9,887	$845	0.30%	$2.56
Standard Residential decile 3-1 (Advantaged)	942	11,126	$910	0.40%	$3.67
Standard Domestic Decile 10	461	9,712	$834	0.19%	$1.55
Standard Domestic Decile 1	213	11,218	$922	0.34%	$3.12
Low User 43%	3,658	6,187	$550	0.11%	$0.59
Low User decile 10 - 8 (Most Deprived)	1,889	5,973	$531	0.08%	$0.43
Low User decile 7- 4 (Middle NZ)	1,315	6,354	$565	0.12%	$0.66
Low User decile 3-1 (Advantaged)	454	6,596	$586	0.18%	$1.05
Low User Decile 10	530	5,920	$523	0.10%	$0.53
Low User Decile 1	70	7,063	$630	0.13%	$0.83
Commercial 11%					
General 30kVA	318	15,026	$1,442	-1.24%	-$18.15
General 50kVA	176	33,688	$3,089	-1.17%	-$36.64
General 75kVA	40	59,785	$5,736	-0.44%	-$25.47
General 100kVA	20	58,173	$6,256	-0.52%	-$32.80

4.5 Economic Cost Estimates

As we look to further develop our pricing, we need to have a greater understanding of our economic cost of supply. To do this, we have developed a methodology to estimate Long-run marginal cost of supply (LRMC), and this will help with setting the time of use prices in the future and could also assist to calculate our subsidy-free consumer range.

- Long Run Marginal Cost (LRMC) provides a measure of the forward-looking economic cost of network use. It can be used to formulate price signals about the costs that will be incurred in future as a result of network use.
- For example, if peak usage increases, how much additional cost will be incurred by the network?
- There are several methodologies that can be used to estimate the economic cost of incremental network use. We have used the Average Incremental Cost methodology (AIC), which unitises forecast network costs that are demand-driven by incremental demand. We applied this methodology because it:
  - uses information that is already prepared for network management and disclosure purposes, rather than requiring network models of hypothetical changes in demand.
  - is the most widely adopted and well-established method used in Australia, where AIC has been used for a number of years to set price levels, and this provides precedent on calculation and application to pricing.
  - However, we note that, particularly for small networks this methodology can provide volatile results as investment is lumpy.

LRMC Methodology

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

- Sourced capex from EIL's system growth capex forecasts. We then used a WACC estimate with a 40-year assumption on asset lives to calculate annualised incremental capex.
- Included incremental opex by applying an opex factor to system growth capex. The opex factor was calculated using 2023 opex as a % of RAB (adjusted for average asset life) to estimate incremental opex as a % of incremental capex.

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

Estimates of LRMC per kW

	EIL
DPP4 WACC (8.94% pre-tax)	$27.04

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

  the DPP4 WACC (6.44% post-tax, adjusted for tax is 8.94% pre-tax)

LRMC-based TOU kWh Prices

A key output of the LRMC analysis is the LRMC-based peak price of 0.88 c/kWh for EIL. This low LRMC reflects low system growth capex compared with other networks – i.e., excess capacity in network, and the economics of an urban underground network.

The LRMC-based off-peak price is zero.

	Probability of System Peak (assumptions)	**Number of hours per annum**	**LRMC price *(FY2025 price for comparison)***
Peak	95%	2,920	$0.0088 *($0.07636)*
Shoulder	5%	2,920	$0.0005 *($0.05564)*
Off-peak	0%	2,920	$0.0000 *($0.0100)*

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

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

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

The LRMC-based kWh prices imply fixed charges that are higher than EIL's existing fixed charges. These results support the continued rebalancing of prices to increase the proportion of revenue earned through fixed charges, as the networks have done for the FY2026 year.

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

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

Subsidy -free test

The Electricity Authority's Distribution Pricing Principles state that:

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

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

We estimated avoidable and standalone costs for each of our three load groups and found that for each group, our target revenue lies between avoidable and standalone costs, satisfying the subsidy-free test, as shown in the following tables and chart.

Table 1 Avoidable costs by load group

	Residential	General	Individual
Avoidable opex ($000)	$1,636	$743	$209
Transmission ($000)	$2,590	$1,094	$1,461
Avoidable cost ($000)	$4,226	$1,837	$1,670
Revenue ($000)	$14,612	$4,878	$4,175
Revenue > Avoidable cost?	Yes	Yes	Yes

Table 2 Standalone costs by load group

	Residential	General	Individual
Depreciation	$2,720	$1,842	$1,316
Return on capital (pre-tax)	$7,617	$5,280	$3,883
Opex	$4,144	$1,998	$962
Transmission	$2,590	$1,094	$1,461
Total standalone costs	$17,071	$10,214	$7,622
Revenue	$14,612	$4,878	$4,175
Revenue < Standalone costs	Yes	Yes	Yes

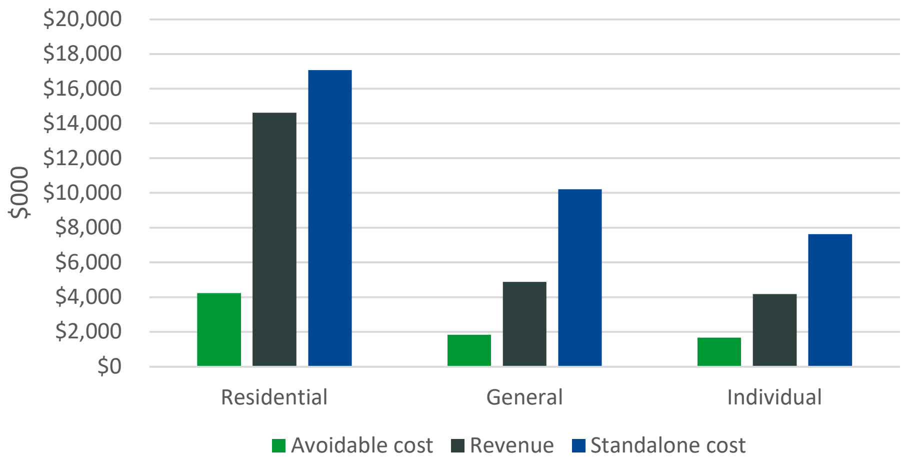
There are numerous ways to estimate avoidable and standalone costs. Rather than use a methodology that involves remodelling the network, we used the readily available and audited data published in our information disclosures.

To estimate avoidable costs, we first identified which types of assets could be abandoned if each consumer groups was no longer supplied. We then used data published in our information disclosures to estimate the avoidable costs associated with abandoning those assets.

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

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

Figure 1 Subsidy-free test



Topics for further consideration

- Treatment of replacement capex – This analysis has focussed on system growth capex. Arguably some replacement capex could be included as replacement may include some degree of capacity increase to cater to future growth.

- The LRMC estimates have focussed only on signalling the economic costs of distribution. Following the TPM revisions, Transpower's pricing to EDBs no longer contains congestion signals to pass on. However, a refinement to the LRMC estimates is to consider signalling congestion at GXPs – that is, where we expect that a GXP will need to be upgraded due to growing demand, those costs can be signalled in LRMC prices. Due to this exclusion from the current LRMC calculations, the estimates presented above likely understate the true economic cost of peak usage.

- Individually priced customers - The LRMC cost per kW can be used to inform the peak demand component of individual customer pricing.

5. PRICING PRINCIPLES ASSESSMENT

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

The 2019 Distribution Pricing Principles:

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

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

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

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

(iv) encouraging efficient network alternatives.

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

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

(i) reflect the economic value of services; and

(ii) enable price/quality trade-offs.

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

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

5.1 Prices are to signal the economic costs of service provision

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

The PowerNet cost of supply model allocates costs to individual customers based on their geographical location and taking into account the share of the actual assets employed to supply them. 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.

It is not easy to accurately establish the stand-alone costs for most customers supplied by a common service via a meshed network. However, we can conclude that stand alone costs would be higher than average costs for those customers given the scale efficiencies in supplying them from a meshed network. EIL believes that the cost allocators used in the model are a representation of the underlying cost drivers of the business and therefore is subsidy free with regards to customers groups.

The methodology attempts to minimise cross subsidisation between the larger individual consumers and between consumer load groups. EIL applies the same pricing to residential and general customers in Invercargill and Bluff. While there may be some differences in the cost of supply, a single set of prices is considered to be the most pragmatic option given the small number of connections in Bluff - only 5% of the population in EIL's network area is in Bluff. The pricing region of EIL's network in terms of both km^2 and the number of connections is relatively small as compared with price regions on a number of other networks.

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

Reflecting the impacts of network use on economic costs

EIL's pricing structure uses capacity-based load groups to ensure prices have regard to the level of service capacity and encourages the use of controlled energy consumption by having a price differential in the fixed charge for group customers. Load control can be utilised to keep charges down by managing GXP load when maximum demand reaches the capacity of that GXP and managing load on feeders during temporary arrangements to manage constraints.

While EIL's network currently does not face significant capacity constraints, decarbonisation developments such as increased uptake of electric vehicles and heating conversions may bring some network assets closer to capacity limits (especially on LV networks). In this context, EIL has taken a forward-looking approach to pricing. EIL has put in place a TOU pricing structure that can be readily used to signal network constraints when needed (for example, by strengthening the peak signal price). Having TOU in place now also means that EIL can better understand and develop the responsiveness of customers to signals before they need to be relied upon.

While the previous day/night pricing structure did provide a signal about when network demand is typically lowest, the new TOU structure provides an improved signal of times when network demand is typically highest. If demand growth creates network constraints, the peak price can be increased to reflect the increased marginal cost of network usage and assists in deferring network upgrades.

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

EIL's peak times are outlined in the methodology 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. Residential customers have the option to put some of their appliances on controlled tariffs to qualify for the off-peak fixed charge.

Customers are encouraged to use energy at shoulder and night periods 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 customer is then financially rewarded, as the consumption does not attract any variable line charge. The "whole house TOU tariff" can reward consumers financially through prudent management of their power requirements.

EIL's peak demand component of the line charge provides a large reward to customers who invest in distribution alternatives.

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

Different levels of daily charges for residential and general consumers with controlled as compared with uncontrolled connections reflect that controlled load has different service availability than uncontrolled load.

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

Encouraging efficient network alternatives

The locational specific pricing that is incorporated into Individual Customer charges assists in providing signals on the cost of network provision in particular locations that can then be compared against network alternatives to encourage efficient decision-making by consumers. While geographic pricing isn't used by EIL for residential and general customers, the network is very compact such that there is unlikely to be significant impacts of this on decisions regarding network alternatives.

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

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

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

EIL also notes that while the recovery of sunk or fixed costs from variable charges will distort usage to some extent, reasonably low uptake of evolving technologies (PV, EVs) on EIL's network area for the foreseeable future (as discussed in section 2.3) likely means that there will be limited adverse consequences from variable charges at this point.

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

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

As is discussed in section 9, in some cases non-standard prices and contracts are appropriate. This may be the case where, for example, a customer has enhanced security arrangements. In situations where customers have significant capital contributions or new investment agreements, robust commercial contracts incorporating prudential requirements are prudent to mitigate the risk of these assets being stranded. These contracts can also assist in avoiding uneconomic by-pass of the network when negotiating commercial arrangements and encourage growth within the network. EIL's individual pricing for large customers and individual account management to industrial and large commercial customers addresses the risk of bypass by negotiating arrangements that, as closely as is practical, reflect the network costs incurred by each individual consumer.

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

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

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

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

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

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

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

Through the disclosure of the line pricing methodology, the costs allocated to each consumer group are transparent. This allows stakeholders to make informed decisions between capacity-based price categories.

EIL has maintained its fixed pricing structure and differentials between peak and off-peak fixed charges and has introduced Peak, Shoulder and Night consumption periods for variable charges to give stability and certainty to customers who have invested in controllable load due to the price differential and potential savings when the investment is made.

Price levels for individual consumers each year are based on the previous year's performance and projections for the current year following discussions with the consumer when required.

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

Once the line charges have been established by the methodology, the pricing structure is straight forward, limited to a fixed daily charge and variable consumption tariffs for the majority of customers. EIL recognises that whilst the pricing structure is simple, there is a number of options with peak/off-peak options available within each capacity group. The Electricity (Low Fixed Charge Tariff Option for Domestic Consumers) Regulations 2004 requiring a low fixed charge option for each residential tariff has also greatly 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).

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

EIL uses "GXP billing" for its residential and general connections, which saves on administration costs, and ultimately should result in lower costs and prices.

With regard to uptake incentives, because pricing is at a GXP level for residential and general customers, EIL's pricing structure (eg, TOU) is necessarily applied for all customers at a wholesale level. Whether EIL's pricing structure is passed on to end consumers or repackaged is a decision made by retailers.

EIL's pricing from 1 April 2022 did incorporate structural changes and as a result, consumer impacts of the change in price levels were predicted with thorough analysis.

5.5 Revenue Requirement for the Year Ended 31 March 2026

The following table lists the revenue allowances as per the Commission’s Electricity Distribution Services Default Price-Quality Path Determination 2025.

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

The inputs have concernedly resulted in lower price reset outcomes. The inputs include out of date market risk premiums (2016) and narrow time bands for calculations of interest costs used in the WACC calculation and in the reset calculation non-independent use of inflation assumptions from parties with vested interests in a mid-range inflation outcome.

Allowable Revenue is calculated based on various building block inputs including network operating expenditure (opex), non-network opex, a return of capital employed (depreciation), a return on capital employed (based on asset values and the WACC) and regulatory tax.

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

Forecast allowable revenue RY26 ($000)	
Forecast net allowable revenue	16,950
Forecast pass through costs	5,478
Forecast recoverable costs	1,248
Total	23,676

Pass-through costs are made up of:

Forecast Pass-through Costs RY26 ($000)	
Rates on system fixed assets	221
Commerce Act levies	52
Electricity Authority levies	48
Utilities Disputes levies	12
Transpower transmission charges	4,805
New investment contract charges	340
Total forecast pass-through costs	**5,478**

Recoverable costs are made up of:

Forecast Recoverable Costs RY26 ($000)	
IRIS incentive adjustment	-311
Quality incentive adjustment	3
Wash-up draw down amount	1,529
Fire and emergency NZ levies	28
Innovation project allowance	-
Total forecast recoverable costs	**1,248**

6. METHOD FOR COST ALLOCATION

6.1 Allocations

EIL uses a cost of supply model which uses a number of key inputs or cost drivers which can be determined and appropriately allocated between the relevant consumers and consumer groups.

The key cost drivers used within this model are:

- Transmission Grid Asset Management costs (Connection, Benefit Based, Residual and Transitional Cap)
- Sub-transmission network costs split into a "supply" component and a "maintenance" component – 66,000 and 33,000V line and cables and 4 zone substations.
- Distribution network costs split into a "supply" component and a "maintenance" component - 11,000, 400V networks and distribution Substations.
- Overhead non asset related direct costs.
- Ownership costs comprising depreciation return on investment and other costs of ownership.
- Pass Through Costs

Each consumer or consumer groups' share of the use of the above assets and costs are then calculated to reflect their respective use. The objective is to reflect the share of the costs in a robust and equitable manner and the line charges be structured so that the network investment and line charges are responsive to the consumer and consumer groups' behavior or pattern of usage.

6.2 Customer Profiles

The derivation of the line charges is based on seven consumer profile parameters. They are:

- The Contract Capacity kVA (kW) of the installation
- The Winter Peak demand kVA (kW) (0700-1100 hours and 1700-2100 hours, each weekday between May and September inclusive)
- The Winter Peak energy MWh (0700-1100 hours and 1700-2100 hours, each weekday between May and September inclusive)
- The Winter Day energy MWh (0700-2300 hours, May to September inclusive)
- The Summer Day energy MWh (0700-2300 hours, October to April inclusive)
- The Total energy for the 12-month period MWh.

- Coincident Peak demand with Transpower's individual GXP residual charge peak times, individual customers only

6.3 Transpower and Sub-transmission costs

The basis of allocation of Transpower and Sub-transmission costs is on the after diversity maximum demand for each customer during the periods of network maximum demand. Similarly, the allocation of the distribution costs is on an after-diversity distribution capacity of the customer's installation.

The EIL methodology takes into account the duration that the customer impacts on the peak loading hours of the network. This is achieved by allocating some of the Transmission, Sub-transmission and distribution costs based on the Winter Peak energy and the Winter Day energy.

This in effect reduces the charges for a customer who incurs just one half hour peak for the whole winter or is only impacting on the peak hours for part of the winter and increases the charges for those customers who are impacting regularly on the peak periods during the whole winter.

It has the effect of integrating the peak demand over a longer period.

6.4 Winter Peak

The Winter Peak demands for the various customers and customer groups have a diversity factor applied to them, which reflects to some extent their impact on the total after diversity maximum demand on the network. These diversity factors, based on their peak demands, are as follows:

Up to 21kVA = 17%

Between 21kVA and 110kVA = ramp function from 17% - 37.5%

Between 110kVA and 2,000kVA = ramp function from 37.5% - 75%

Above 2000kVA = 75%.

These diversity factors reflect the increased diversity of a large number of smaller customers compared to less diversity for the larger customers.

6.5 Contract Capacities

Similarly, diversity factors are applied to the contract capacities of the various customers. These diversity factors are as follows:

- For connections up to 16kVA = 25%
- For connections between 16kVA and 100kVA = ramp function from 25% - 33%
- For connections between 101kVA and 2,000kVA = ramp function from 33% - 70%
- For connections above 2,000kVA = 70%.

These diversities reflect the differing impacts of the different sized customers on the local capacity of the reticulation system. There is an increased diversity between the smaller customers than with the large customers with respect to the capital investment in the local distribution network.

6.6 Sub-transmission and Distribution split

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

6.6.1 Supply

The "supply" part is based on the depreciation of the network assets, other ownership costs and required return on the assets, the latter using the companies weighted average cost of capital.

6.6.2 Maintenance

The "maintenance" part is based on the Maintenance Works Programme for the current year.

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

The profile parameters for determining the line charges for the individual customers, grouped by capacity are:

Contract Capacity kVA	Number of Connections	Coincident Peak Demand Reading kVA	Peak Demand Reading kVA	Total Energy Reading MWh	Peak Reading MWh	Winter Day Reading MWh	Summer Day Reading MWh
30	2	20	25	38	8	19	15
50	2	58	51	149	22	44	47
75	6	178	243	776	100	294	329
100	10	305	550	1,500	187	512	611
150	38	2,127	3,290	6,661	1,083	2,469	2,670
200	39	2,833	3,920	9,897	1,510	3,605	4,083
300	30	3,360	4,770	13,158	1,710	4,437	5,300
500	30	5,502	7,295	22,807	3,096	7,798	8,862
750	8	1,501	1,842	7,603	864	2,318	2,865
1000	4	978	1,086	4,706	398	1,032	1,344
1250	1	600	649	2,418	326	950	1,138
1750	1	1,027	1,218	6,369	656	1,777	2,478

The profile parameters for determining the line charges for the Residential and General customers are:

Consumer Capacity	Code	Number of Connections	After Diversity Peak Demand kW	Total Energy Group MWh	Winter Peak Group MWh	Winter Day Group MWh	Summer Day Group MWh
Residential							
Residential (8kVA 1 Phase) - All Peak *	ND08P	47	82	341	64	144	123
Residential (8kVA 1 Phase) - With Off Peak *	ND08Q	83	104	509	72	193	179
Standard Residential (15kVA 1 Phase) - All Peak	ND20P	1,291	3,842	16,030	3,007	6,765	5,764
Standard Residential (15kVA 1 Phase) - With Off Peak	ND20Q	7,490	18,553	91,058	12,813	34,587	32,089
Residential Low User (15kVA 1 Phase) - All Peak	NDL20P	23	2,932	6,796	1,275	2,868	2,444
Residential Low User (15kVA 1 Phase) - With Off Peak	NDL20Q	106	12,122	33,053	4,651	12,555	11,648
Residential Low User (8kVA 1 Phase) - All Peak*	NDL08P	1,107	47	175	33	74	63
Residential Low User (8kVA 1 Phase) - With Off Peak*	NDL08Q	5,496	168	735	103	279	259
General Single Phase							
Street Lights (1 Phase) per street light	NS001L	5,567	716	2,343	440	989	842
1 kVA 1 Phase - All Peak	NS001P	41	43	329	62	139	118
8 kVA 1 Phase - All Peak	NS008P	148	205	856	161	361	308
8 kVA 1 Phase - With Off Peak	NS008Q	11	13	64	9	24	22
15 kVA 1 Phase - All Peak	NS020P	260	719	3,000	563	1,266	1,079

Consumer Capacity	Code	Number of Connections	After Diversity Peak Demand kW	Total Energy Group MWh	Winter Peak Group MWh	Winter Day Group MWh	Summer Day Group MWh
15 kVA 1 Phase - With Off Peak	NS020Q	82	193	948	133	360	334
General Three Phase							
15 kVA 3 Phase - All Peak	NT015P	74	203	845	159	357	304
15 kVA 3 Phase - With Off Peak	NT015Q	7	18	87	12	33	31
30 kVA 3 Phase - All Peak	NT030P	552	3,440	10,205	1,915	4,307	3,670
30 kVA 3 Phase - With Off Peak	NT030Q	106	562	1,960	276	745	691
50 kVA 3 Phase - All Peak	NT050P	334	4,239	13,754	2,580	5,805	4,946
50 kVA 3 Phase - With Off Peak	NT050Q	64	704	2,688	378	1,021	947
75 kVA 3 Phase - All Peak	NT075P	117	2,811	7,819	1,467	3,300	2,812
75 kVA 3 Phase - With Off Peak	NT075Q	15	308	1,009	142	383	356
100 kVA 3 Phase - All Peak	NT100P	75	2,779	5,153	967	2,175	1,853
100 kVA 3 Phase - With Off Peak	NT100Q	7	245	535	75	203	189

7. COST ALLOCATIONS TO CAPACITY GROUPS

This section describes the cost allocations to each capacity group and individual customers using the methodology described above.

7.1 Transmission Charges

Transmission charges reflect the Transpower grid asset management costs incurred by EIL based on the Invercargill point of supply.

1 April 2025 sees the continuation of Transpower's new pricing methodology. The new methodology replaces the old interconnection charges with three new charges, a Benefit Based Charge, Residual Charge and a Transitional Cap, the pass through of these charges and the connection charge is outlined below.

The Connection Charge methodology remains unchanged.

Transpower transmission charges have four components:

(a) Connection charge

(b) Benefit Based charge

(c) Residual charge

(d) Transitional Cap

7.1.1 Connection Charge

The Transpower connection charge is based on the Transpower local assets utilised to provide the supply.

In the case of the Invercargill point of supply the connection charge is incurred and allocated by PowerNet between TPCL and EIL, each network is connected to the transmission grid there.

The total connection charge for Invercargill is $1,164,477. EIL's share is of the connection charge is $624,240.

The connection charges which include the Transpower new investment charges are applied to customers on the basis of the following allocation:

- Winter Peak Demand 70%
- Winter Peak Energy 20%
- Winter Day Energy 10%

For individual customers this equates to:

$6.86 per kVA Peak Demand.

$3.05 per Winter Peak MWh.

$1.00 per Winter Day MWh

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

- $6.61 per kVA Peak Demand
- $3.35 per Winter Peak MWh
- $1.10 per Winter Day MWh

The difference in the two sets of rates above reflects the difference in losses and diversity factors between the large individual customers and the smaller customer groups.

7.1.2 Benefit Based Charge (BBC)

The costs of new and some historic interconnection investments (the BBIs) will be allocated to the beneficiaries of those investments through the BBC.

BBIs include investments in new interconnection assets or interconnection transmission alternatives and the replacement or refurbishment of existing ones.

The cost recovered through the BBCs for a BBI is referred to as the BBI's "covered cost" and includes the BBI's capital components (return of and on capital expenditure) and an allocation of Transpower's total operating costs (including overheads).

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

The NPB of each BBI is derived by historic load flow analysis (MWh) it is therefore proposed to allocate BBCs on an annual energy consumption basis.

EIL's annual Benefit Based charge is $644,870.

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

Individual Customers:

Total Annual Energy Consumption $2.35/MWh

Residential and General Customers:

Total Annual Energy Consumption $2.35/MWh

7.1.3 Residual Charge (RC)

Residual Charges recover Transpower's remaining revenue that is not recovered through other transmission charges. Residual charges are paid by Transpower load customers only, in proportion to their historic (or, for new load customers, estimated) maximum gross demand.

Gross load excludes contributions from batteries when charging or discharging other than their storage losses.

The initial (baseline) allocations of Residual Charges are in proportion to Transpower customers' maximum gross demand (kW) at the grid exit point averaged across the four financial years (FYs) from FY 2015/16 to FY 2018/19, i.e., the period 1 July 2015 to 30 June 2019. For a Transpower load customer that did not exist on 1 July 2014, including a new load customer, Transpower estimates maximum gross demand based on the customer's assets and the assets connected to them being fully operational.

Load customers' initial allocations are adjusted annually based on changes in their lagged average gross energy usage (kWh) over the period of four financial years commencing eight financial years ago, e.g., for PY 2025/26 the relevant period is from FY 2017/18 to FY 2020/21.

The annual Residual Charge for EIL is $3,873,664.

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

For individual customers this equates to the following charge:

Point of Supply	Per kVA Average Gross Demand
Invercargill	$62.66

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

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

Point of Supply	Per kVA After Diversity Maximum Demand
Invercargill	$50.30

7.1.4 *Transitional Cap*

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

The Transitional cap is allocated to customers based on their share of the overall Benefit Based and Residual Charges.

The annual Transitional Cap for EIL is $2,407

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

For the residential and general customers, once total amount of Transitional Cap allocated to the individual customers is deducted from the total network Transitional Cap charge, the result is the amount to be allocated to all the residential and general customers. The sum of the annual BBC and Residual Charge for each load group customer is divided by the sum of the total Benefit Based Charge and Residual Charge for the network, this percentage is then multiplied by the annual Transitional Cap amount for the network to calculate the annual Transitional Cap charge for each customer, the annual allocation amount is then multiplied by the number of ICP's in the load group to calculate the Residual amount for the load group.

7.1.5 *Recovery of Transpower Charges*

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

For residential and general customers, the total Transpower (connection, benefit based, residual and transitional cap) charges are recovered through the fixed daily charge.

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

Residential and General Connections	Code	Transpower Fixed Daily Charge $per day
Residential Standard		
Small Residential (8kVA 1 Phase) - All Peak	ND08P	$0.2674
Small Residential (8kVA 1 Phase) - With Off Peak	ND08Q	$0.2326
Residential (15kVA 1 Phase) - All Peak	ND20P	$0.5349
Residential (15kVA 1 Phase) - With Off Peak	ND20Q	$0.4652
Residential Low Fixed Charge		
Residential Low Fixed Charge Fixed Charge Option (15kVA 1 Phase) - All Peak	NDL20P	$0.4893
Residential Low Fixed Charge Fixed Charge Option (15kVA 1 Phase) - With Off Peak	NDL20Q	$0.4218
Residential Low Fixed Charge Fixed Charge Option (8kVA 1 Phase) - All Peak	NDL08P	$0.2617
Residential Low Fixed Charge Fixed Charge Option (8kVA 1 Phase) - With Off Peak	NDL08Q	$0.2272
General Single Phase		
Street Lights (1 Phase) per street light	NS001L	$0.0222
1 kVA 1 Phase - All Peak	NS001P	$0.2238
8 kVA 1 Phase - All Peak	NS008P	$0.2674
8 kVA 1 Phase - With Off Peak	NS008Q	$0.2326
15 kVA 1 Phase - All Peak	NS020P	$0.5349
15 kVA 1 Phase - With Off Peak	NS020Q	$0.4652
General Three Phase		
15 kVA 3 Phase - All Peak	NT015P	$0.5015
15 kVA 3 Phase - With Off Peak	NT015Q	$0.4362
30 kVA 3 Phase - All Peak	NT030P	$1.0757
30 kVA 3 Phase - With Off Peak	NT030Q	$0.9303
50 kVA 3 Phase - All Peak	NT050P	$2.2507
50 kVA 3 Phase - With Off Peak	NT050Q	$1.9493
75 kVA 3 Phase - All Peak	NT075P	$4.0958
75 kVA 3 Phase - With Off Peak	NT075Q	$3.5392
100 kVA 3 Phase - All Peak	NT100P	$6.2239
100 kVA 3 Phase - With Off Peak	NT100Q	$5.3516

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

Currently the recovery of total line charge revenue is on a 47%/53% split between fixed and variable charges, EIL's strategy is to recover more line charge revenue through the fixed daily charge, this will be achieved by increasing the fixed charge percentage each year, this will allow all of the Transpower charges to be recovered through the fixed daily charge over time. From 1 April 2024 the half hour metered individual line charge customers will have 60% of the total line charge recovered from the fixed daily charge.

Non half hour metered individual customers have varying levels of recovery of the total line charge through the fixed charge, this is due to the variable line charge price being fixed at the residential and general customers GXP variable line charge price. For these customers the recovery of the Transpower charge through the fixed daily charge is determined by the level of the fixed daily charge. This is now a closed tariff group, and customers are being transitioned to other options.

7.1.6 Transpower Revenue for Individual Customers

The total Transpower revenue for individual customers grouped by capacity is shown in the following table:

Consumer Capacity kVA	Number of Connections	Transpower Revenue per Consumer Group	Average Line Charge
30	2	$1,389.87	$694.93
50	2	$4,150.56	$2,075.28
75	6	$14,056.04	$2,342.67
100	10	$24,828.73	$2,482.87
150	38	$162,788.88	$4,283.92
200	39	$218,224.54	$5,595.50
300	30	$263,766.75	$8,792.23
500	30	$436,665.43	$14,555.51
750	8	$122,118.02	$15,264.75
1000	4	$77,306.40	$19,326.60
1250	1	$47,395.25	$47,395.25
1750	1	$88,220.40	$88,220.40

7.1.7 Transpower Revenue for Residential and General Customers

The total Transpower revenue for residential and general customers is shown in the following table.

Consumer Capacity	Code	Number of Connections	Transpower Charge	Transpower Revenue per Consumer Group
Residential				
Residential (8kVA 1 Phase) - All Peak *	ND08P	47	$97.62	$4,587.99
Residential (8kVA 1 Phase) - With Off Peak *	ND08Q	83	$84.91	$7,047.24
Standard Residential (15kVA 1 Phase) - All Peak	ND20P	1290.5	$195.23	$251,949.21
Standard Residential (15kVA 1 Phase) - With Off Peak	ND20Q	7490	$169.81	$1,271,898.99
Residential Low User (15kVA 1 Phase) - All Peak	NDL20P	1107	$178.58	$197,690.24
Residential Low User (15kVA 1 Phase) - With Off Peak	NDL20Q	5496	$153.94	$846,062.29
Residential Low User (8kVA 1 Phase) - All Peak*	NDL08P	23	$95.54	$2,197.31
Residential Low User (8kVA 1 Phase) - With Off Peak*	NDL08Q	106	$82.92	$8,789.79
General Single Phase				
Street Lights (1 Phase) per street light	NS001L	5567	$8.10	$45,114.15
1 kVA 1 Phase - All Peak	NS001P	41	$81.67	$3,348.47
8 kVA 1 Phase - All Peak	NS008P	148	$97.62	$14,447.30
8 kVA 1 Phase - With Off Peak	NS008Q	11	$84.91	$933.97

Consumer Capacity	Code	Number of Connections	Transpower Charge	Transpower Revenue per Consumer Group
15 kVA 1 Phase - All Peak	NS020P	259.5	$195.23	$50,663.17
15 kVA 1 Phase - With Off Peak	NS020Q	82	$169.81	$13,924.66
General Three Phase				
15 kVA 3 Phase - All Peak	NT015P	74	$183.03	$13,544.34
15 kVA 3 Phase - With Off Peak	NT015Q	7	$159.20	$1,114.40
30 kVA 3 Phase - All Peak	NT030P	552	$392.62	$216,725.15
30 kVA 3 Phase - With Off Peak	NT030Q	106	$339.58	$35,995.03
50 kVA 3 Phase - All Peak	NT050P	334	$821.51	$274,382.75
50 kVA 3 Phase - With Off Peak	NT050Q	64	$711.49	$45,535.32
75 kVA 3 Phase - All Peak	NT075P	117	$1,494.97	$174,912.04
75 kVA 3 Phase - With Off Peak	NT075Q	15	$1,291.80	$19,377.05
100 kVA 3 Phase - All Peak	NT100P	75	$2,271.74	$170,380.60
100 kVA 3 Phase - With Off Peak	NT100Q	7	$1,953.35	$13,673.44

7.2 Sub-transmission Charges

Sub-transmission charges are based on the Sub-transmission costs (66kV and 33kV network) and the zone substation costs.

There are two components making up the Sub-transmission charges:

(a) Supply charge

(b) Maintenance charge

7.2.1 Supply Charge

The supply charge is based on the required return on the assets by the shareholder and depreciation.

All the costs of the Sub-transmission network and zone substations are averaged and allocated on the basis of the relative asset value compared to the total network asset value.

The supply charge for the EIL city area zone substations is $1,516,268 and for the 33kV line and cables is $758,134 giving a total supply charge for EIL City of $2,274,402.

As EIL also supplies power to Bluff through TPCL 33kV line and Bluff zone substation there is a supply charge of $536,322 for this zone substation and the Sub-transmission lines.

The supply charges for EIL City and EIL Bluff is allocated across all customers on the following basis:

Winter Peak Demand	70%
Winter Peak energy	20%
Winter Day energy	10%

7.2.2 Maintenance Charge

The maintenance charges for the EIL city zone substations and Sub-transmission system total $506,997 and for EIL Bluff total $90,108

The total Sub-transmission maintenance charges are allocated across the customers on the following basis:

Total Energy	50%
Winter Peak Demand	50%

7.2.3 Sub-transmission Charges for Individual Customers above 100 kVA

EIL City

(a)	Sub-transmission Supply charge	$26.62 per kVA Winter Peak Demand
(b)	Sub-transmission Supply charge	$11.87 per Winter Peak MWh
(c)	Sub-transmission Supply charge	$3.91 per Winter Day MWh
(e)	Sub-transmission Maintenance charge	$1.00 per Commercial Total MWh
(f)	Sub-transmission Maintenance charge	$4.24 per kVA Winter Peak Demand

EIL Bluff

(a)	Sub-transmission Supply charge	$87.19 per kVA Winter Peak Demand
(b)	Sub-transmission Supply charge	$42.22 per Winter Peak MWh
(c)	Sub-transmission Supply charge	$10.59 per Winter Day MWh
(e)	Sub-transmission Maintenance charge	$2.19 per Commercial Total MWh
(f)	Sub-transmission Maintenance charge	$11.37 per kVA Winter Peak Demand

7.2.4 Sub-transmission Charges for Residential and General Customers

After the revenue from the individual customers has been subtracted from the total the remaining Residential and General Customer charges are as follows:

EIL City

(a)	Sub-transmission Supply charge	$25.73 per kVA Winter Peak Demand
(b)	Sub-transmission Supply charge	$12.95 per Winter Peak MWh
(c)	Sub-transmission Supply charge	$4.21 per Winter Day MWh
(d)	Sub-transmission Maintenance charge	$1.04 per Residential Total MWh
(e)	Sub-transmission Maintenance charge	$1.04 per Commercial Total MWh
(f)	Sub-transmission Maintenance charge	$3.97 per kVA Winter Peak Demand

EIL Bluff

(a)	Sub-transmission Supply charge	$95.42 per kVA Winter Peak Demand
(b)	Sub-transmission Supply charge	$50.03 per Winter Peak MWh
(c)	Sub-transmission Supply charge	$15.61 per Winter Day MWh
(d)	Sub-transmission Maintenance charge	$2.56 per Residential Total MWh
(e)	Sub-transmission Maintenance charge	$2.56 per Commercial Total MWh
(f)	Sub-transmission Maintenance charge	$9.70 per kVA Winter Peak Demand

7.3 Distribution Charges

Distribution charges are based on the distribution costs which include 11,000 and 400V line and cables and distribution substations and transformers.

There are three components making up the distribution charges:

(a) Supply charge

(b) Maintenance charge

(c) Transformer charge

In calculating the distribution charges an allowance is made for the fact that customers above 150kVA have normally 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 distribution charges are multiplied by a factor of 60% for both EIL City and EIL Bluff.

7.3.1 Supply Charge

The supply charge is based on the required return on the assets by the shareholder and depreciation.

All the costs of the distribution network are averaged, and the supply charge is allocated on the basis of the relative asset value compared to the total network asset value.

The supply charges are as follows:

(a) Overhead lines, Underground Cables, and Distribution Substations

EIL City	$8,465,831
EIL Bluff	$379,067

(b) The supply charge is allocated across all customers on the following basis:

Contract Capacity	70%
Winter Peak Energy	20%
Winter Day Energy	10%

7.3.2 Maintenance Charge

The maintenance charges are as follows:

(a) Overhead lines, Underground Cables and Distribution Substations

EIL City	$1,520,990
EIL Bluff	$240,156

(b) The maintenance portion is allocated across all customers on the following basis:

Total Energy	50%
Contract Capacity	50%

7.3.3 Distribution Transformers

The transformer charges are as follows:

EIL Supply	$1,516,268
EIL Maintenance	$400,260

The transformer portion of the distribution charges is allocated across consumers on the following basis:

Number of transformers and transformer capacity 100%.

7.3.4 Distribution Charges for Individual Customers

EIL City

(a)	Distribution Supply charge	$45.94 per kVA Contract Capacity
(b)	Distribution Supply charge	$44.18 per Winter Peak MWh
(c)	Distribution Supply charge	$8.78 per Winter Day MWh
(d)	Distribution Maintenance charge	$3.01 per Commercial Total MWh
(e)	Distribution Maintenance charge	$5.90 per kVA Contract Capacity

EIL Bluff

(a) Distribution Supply charge $29.48 per kVA Contract Capacity

(b) Distribution Supply charge $28.87 per Winter Peak MWh

(c) Distribution Supply charge $5.51 per Winter Day MWh

(d) Distribution Maintenance charge $5.56 per Commercial Total MWh

(e) Distribution Maintenance charge $13.3465 per kVA Contract Capacity

Transformer Charges

(a) Distribution Transformer supply charge $389.79 per Transformer

(b) Distribution Transformer maintenance charge $887.50 perTransformer

The Transformer charge of $389.79 per transformer is multiplied by a price ratio depending on the size of the transformer. The ratios for the different sized transformers are shown below.

Transformer Size	Ratio applied
15kVA Transformer	1
30kVA Transformer	1.44
50kVA Transformer	1.88
75kVA Transformer	2.30
100kVA Transformer	3.00
150kVA Transformer	5.00
200kVA Transformer	7.40
300kVA Transformer	8.16
500kVA Transformer	11.20
750kVA Transformer	14.00
1,000kVA Transformer	15.00
1,250kVA Transformer	20.20
1,500kVA Transformer	21.00

7.3.5 Distribution Charges for Residential and General Customers

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

EIL City

(a)	Distribution Supply charge	\$47.20 per kVA Contract Capacity
(b)	Distribution Supply charge	\$51.99 per Winter Peak MWh
(c)	Distribution Supply charge	\$17.10 per Winter Day MWh
(d)	Distribution Maintenance charge	\$3.56 per Residential Total MWh
(e)	Distribution Maintenance charge	\$3.56 per Commercial Total MWh
(f)	Distribution Maintenance charge	\$5.91 per kVA Contract Capacity
(g)	Distribution Transformer charge	\$10.55 per kVA Contract Capacity

EIL Bluff

(a)	Distribution Supply charge	\$39.15 per kVA Contract Capacity
(b)	Distribution Supply charge	\$40.75 per Winter Peak MWh
(c)	Distribution Supply charge	\$13.58 per Winter Day MWh
(d)	Distribution Maintenance charge	\$9.51 per Residential Total MWh
(e)	Distribution Maintenance charge	\$9.51 per Commercial Total MWh
(f)	Distribution Maintenance charge	\$16.50 per kVA Contract Capacity
(g)	Distribution Transformer charge	\$10.55 per kVA Contract Capacity

The model applies a 2.5% discount for the residential and single-phase general customers compared to three phase general customers of similar size. This is to reflect the reduced investment in network assets for single phase customers.

7.4 Non asset related Overheads

The overhead charges are based on 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.

These charges are split equally over the total customer base.

The total overhead costs are $2,258,939

The charge per customer is $127.57

7.5 EIL Charges

7.5.1 EIL Revenue for Individual Customers

The total EIL revenue for individual customers grouped by capacity is shown in the following table.

Consumer Capacity kVA	Sub-transmission Charge	Distribution Charge	Overhead Charge	Total EIL Charge
15	$0.00	$0.00	$0.00	$0.00
30	$321.90	$2,519.06	$292.71	$3,133.67
50	$902.22	$5,042.42	$292.71	$6,237.35
75	$4,834.25	$24,454.02	$878.12	$30,166.39
100	$14,503.99	$38,614.23	$1,463.54	$54,581.76
150	$78,466.85	$220,191.80	$5,561.45	$304,220.10
200	$90,478.91	$308,470.82	$5,707.80	$404,657.53
300	$112,641.14	$329,022.54	$4,390.62	$446,054.30
500	$204,915.54	$545,108.16	$4,390.62	$754,414.32
750	$47,647.32	$214,959.99	$1,170.83	$263,778.15
1000	$23,915.85	$144,209.37	$585.42	$168,710.64
1250	$18,818.96	$53,070.29	$146.35	$72,035.61
1750	$127,550.25	$78,490.54	$146.35	$206,187.14

7.5.2 EIL Revenue for Residential and General Customers

The total EIL revenue for residential and general customers is shown in the following table.

Consumer Capacity	Code	Number of Connections	Sub-transmission Charge	Distribution Charge	Overheads	Total EIL Revenue
Residential						
Residential (8kVA 1 Phase) - All Peak *	ND08P	47	$4,768	$13,535	$5,996	$24,298
Residential (8kVA 1 Phase) - With Off Peak *	ND08Q	83	$5,050	$20,123	$10,588	$35,761
Standard Residential (15kVA 1 Phase) - All Peak	ND20P	1,291	$189,128	$732,219	$164,624	$1,085,971
Standard Residential (15kVA 1 Phase) - With Off Peak	ND20Q	7,490	$894,165	$3,628,528	$955,469	$5,478,163
Residential Low User (15kVA 1 Phase) - All Peak	NDL20P	1,107	$128,976	$535,416	$141,216	$805,608
Residential Low User (15kVA 1 Phase) - With Off Peak	NDL20Q	5,496	$509,362	$2,263,254	$701,103	$3,473,718
Residential Low User (8kVA 1 Phase) - All Peak*	NDL08P	23	$2,999	$6,489	$2,934	$12,422
Residential Low User (8kVA 1 Phase) - With Off Peak*	NDL08Q	106	$10,049	$25,455	$13,522	$49,026
General Single Phase						
Street Lights (1 Phase) per street light	NS001L	5,583	$32,300	$133,982	$260	$166,542
1 kVA 1 Phase - All Peak	NS001P	41	$2,721	$7,470	$5,230	$15,421
8 kVA 1 Phase - All Peak	NS008P	148	$9,131	$41,727	$18,880	$69,737
8 kVA 1 Phase - With Off Peak	NS008Q	11	$582	$2,650	$1,403	$4,635

Consumer Capacity	Code	Number of Connections	Sub-transmission Charge	Distribution Charge	Overheads	Total EIL Revenue
15 kVA 1 Phase - All Peak	NS020P	260	$32,019	$146,326	$33,103	$211,448
15 kVA 1 Phase - With Off Peak	NS020Q	82	$8,671	$39,512	$10,460	$58,643
General Three Phase						
15 kVA 3 Phase - All Peak	NT015P	74	$9,728	$39,296	$9,440	$58,464
15 kVA 3 Phase - With Off Peak	NT015Q	7	$942	$3,209	$893	$5,044
30 kVA 3 Phase - All Peak	NT030P	552	$147,157	$564,958	$70,416	$782,532
30 kVA 3 Phase - With Off Peak	NT030Q	106	$24,181	$92,722	$13,522	$130,425
50 kVA 3 Phase - All Peak	NT050P	334	$183,163	$656,428	$42,607	$882,197
50 kVA 3 Phase - With Off Peak	NT050Q	64	$31,423	$107,797	$8,164	$147,384
75 kVA 3 Phase - All Peak	NT075P	117	$118,497	$373,396	$14,925	$506,818
75 kVA 3 Phase - With Off Peak	NT075Q	15	$13,177	$40,978	$1,913	$56,069
100 kVA 3 Phase - All Peak	NT100P	75	$101,123	$236,833	$9,567	$347,523
100 kVA 3 Phase - With Off Peak	NT100Q	7	$10,267	$19,132	$893	$30,292

7.6 Pass-Through Costs

Pass-through costs (excluding transmission costs) are costs relating to rates on network fixed assets charged to EIL by local authorities and industry levies imposed by the Commerce Act, the Authority and Utilities Disputes.

The total estimated Pass-through costs for 2025-26 are $332,697.

Pass-through costs are recovered by $18.79 per ICP.

7.6.1 Recoverable costs & Wash-up Draw Down Amount

Recoverable costs recover 3 components.

- Quality Incentive Scheme – an adjustment either positive or negative is allocated to EIL based on the previous years' performance against the networks target SAIDIs and SAIFIs, for the 2025-26 year this adjustment is $27,646.

- IRIS incentive adjustment – an additional recoverable cost has been allocated to EIL due to the amount of opex and capex completed over the previous regulatory control period. For the 202,54-2,65-year EIL will recover -$311,464.

- Fire Emergency New Zealand is a new recoverable cost introduced by the Commission to allow future increases and decreases to be shared with customers. For the 2025 -26 year the allowance is $27,646.

Wash-up draw down Amount is the difference between EIL's actual allowable revenue for the period 2023-24 minus the actual revenue for the period 2023-24. The wash-up amount is $1,528,979.

The total recoverable costs and wash-up draw down amount is $1,248,081, 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 7.2.1 and 7.3.1 above and is included in their values.

7.7 Loss Constraint Excess Payment

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

7.7.1 Line Charge Revenue for Individual Customers

The line charge revenue for individual customers grouped by capacity is shown in the following table.

Consumer Capacity kVA	Number of Connections	Line Charge Revenue per Consumer Group	Average Line Charge
30	2	$4,524	$2,262
50	2	$10,388	$5,194
75	6	$44,222	$7,370
100	10	$79,410	$7,941
150	38	$467,009	$12,290
200	39	$622,882	$15,971
300	30	$709,821	$23,661
500	30	$1,191,080	$39,703
750	8	$385,896	$48,237
1000	4	$246,017	$61,504
1250	1	$119,431	$119,431
1750	1	$294,407.54	$294,408

7.7.2 Line Charge Revenue for Residential and General Customers

The line charge revenue for residential and general customers is shown in the following table.

Consumer Capacity	Code	Number of Connections	Line Charge Revenue per Consumer Group
Residential			
Residential (8kVA 1 Phase) - All Peak *	ND08P	35	$31,326
Residential (8kVA 1 Phase) - With Off Peak *	ND08Q	78	$46,508
Standard Residential (15kVA 1 Phase) - All Peak	ND20P	1,195	$1,440,505
Standard Residential (15kVA 1 Phase) - With Off Peak	ND20Q	7,104	$7,275,332
Residential Low User (15kVA 1 Phase) - All Peak	NDL20P	1,046	$1,080,587
Residential Low User (15kVA 1 Phase) - With Off Peak	NDL20Q	5,364	$4,658,785
Residential Low User (8kVA 1 Phase) - All Peak*	NDL08P	12	$15,858
Residential Low User (8kVA 1 Phase) - With Off Peak*	NDL08Q	69	$62,826
			Group
General Single Phase			

Consumer Capacity	Code	Number of Connections	Line Charge Revenue per Consumer
Streetlights (1 Phase) per street light	NS001L	5,183	$225,081
1 kVA 1 Phase - All Peak	NS001P	39	$20,410
8 kVA 1 Phase - All Peak	NS008P	148	$91,289
8 kVA 1 Phase - With Off Peak	NS008Q	11	$6,050
15 kVA 1 Phase - All Peak	NS020P	260	$282,150
15 kVA 1 Phase - With Off Peak	NS020Q	82	$78,205
General Three Phase			
15 kVA 3 Phase - All Peak	NT015P	70	$77,567
15 kVA 3 Phase - With Off Peak	NT015Q	6	$6,643
30 kVA 3 Phase - All Peak	NT030P	521	$1,070,176
30 kVA 3 Phase - With Off Peak	NT030Q	100	$178,351
50 kVA 3 Phase - All Peak	NT050P	320	$1,234,243
50 kVA 3 Phase - With Off Peak	NT050Q	60	$205,960
75 kVA 3 Phase - All Peak	NT075P	110	$725,753
75 kVA 3 Phase - With Off Peak	NT075Q	14	$80,333
100 kVA 3 Phase - All Peak	NT100P	73	$548,048
100 kVA 3 Phase - With Off Peak	NT100Q	6	$46,596

8. HOW FIXED AND VARIABLE PRICES ARE SET

Individual Customers

The total line charge is split into fixed charges and variable charges. The fixed/variable split is 60:40. With more costs, in particular Transpower costs, being of a fixed nature EIL will be increasing the fixed charge percentage split of the total line charge to match.

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

In the case of all non-half hour metered individual line charge installations the variable charge is a standard charge GXP rate of $0.07636 per Peak kWh, $0.05565 per Shoulder kWh and $0.0100 per Night kWh. The fixed charge is then calculated as the difference between the total charge and the total variable charge. This method of calculating the fixed charge accounts for the fact that some installations have negative fixed charges.

Residential and General Customers

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

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

TOU pricing periods are:

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

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

Night period 11pm to 7am.

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

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

- Variable line charge is a compromise between a totally fixed charge that would benefit the large consumer within a load group, and a totally variable charge that would benefit the small consumer within a load group.
- As stated above, the fixed and variable charge allows the larger consumer in a load group to pay more which reflects to some extent their reduced diversity on the maximum demands seen at Sub-transmission and transmission level. Although the distribution network in the vicinity of the

premises has to have enough capacity to supply the full capacity of the installation, the remainder of the network is designed to take into account the diversity between consumer demands. As a general rule, the less energy a consumer uses, the greater the diversity, hence the less capital investment required to supply. A totally fixed line charge does not take this into account so there would need to be more load sub-groups such as very small, small, medium, large, and very large domestic consumers besides the existing All Peak and With Off Peak categories.

- It is important to note that the variable charge is cheaper during, Shoulder and Night time periods, so residential consumers with large night loads, such as storage or water heating, do not pay extra as this consumption is utilising network assets, the capacity of which is designed on the basis of and costs recovered by the peak load in daytime hours. This encourages better utilisation of the network and less capital investment.

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

- Consumers also have the opportunity to shift load to night time to receive immediate benefits.

- If a consumer is expanding its business, the variable charges mean that the line owner can receive some immediate extra revenue, and it can also cushion the increase in line charges for the following year.

- The practical application of a variable component of the line charge for the Residential and General resulted in a necessity for a uniform variable charge and individual fixed charges for each segment. EIL uses the 'GXP billing" approach for the Residential and General customers, where variable charges are based on electricity volumes measured at the Transpower grid exit points. Quantities are determined by the wholesale electricity market reconciliation process with adjustments for embedded networks and individual customer quantities.

9. NON- STANDARD CONTRACTS

EIL 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 these situations where customers have significant capital contributions, 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.

There are currently no ICPs on non-standard contracts.

9.1 Line Services Interruptions

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

Customers on non-standard contracts who have standard security arrangements are subject to the same restoration arrangements as customers on standard contracts. Customers can choose to have N security arrangements but may wait longer periods for restoration.

10. DISTRIBUTED GENERATION

EIL's line pricing methodology and Part 6 of the Electricity Industry Participation Code 2010 applies to Distributed Generation connected to the electricity network for varying capacities. Currently there is no large-scale Distributed Generation connected to the network.

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 EIL.

In other situations, there may be incremental costs incurred by EIL due to investigation and network modifications required. As with all customers seeking connection to the EIL 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.

10.1 Financial Transactions with Distributed Generators

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

Financial transactions that can occur when Distributed Generation is connected to the electricity network are:

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

10.2 Capital Contributions

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

10.3 New Investment Agreement and / or Delivery Services Agreement Charges

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

10.4 Avoided Transmission Charge revenue

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

10.5 Energy Reporting

Where distributed generation is connected to the distributor's network, kWh being exported onto the distributor's network must be submitted to the distributor. The format the data is submitted must match the format of the ICPs other submitted data, e.g., either EIEP1 or EIEP3 format. For clarity, export onto the distributor's network, and consumption off the distributor's network, are to be reported separately under the relevant price options (i.e. they should not be netted off).

The introduction of a zero-price export price will ensure that retailers provide export kWh volumes for all small-scale DG connections (i.e. solar).

APPENDIX 1: COMMERCE COMMISSION INFORMATION DISCLOSURE REQUIREMENTS

In the below table we describe the relevant sections of this methodology where we demonstrate compliance with the key sections of the Commission's Electricity Distribution Information Disclosure Determination 2012 requirements:

IDD Section	Key sections of methodology demonstrating compliance
2.4.1 (1)	Sections 3, 5-9
2.4.1 (2)	Section 3.2
2.4.1 (3)	Sections 9 & 10
2.4.1 (4)	Section 3.3
2.4.2	Section 4 & 7
2.4.3 (1)	Section 6
2.4.3 (2)	Section 4
2.4.3 (3)	Section 5
2.4.3 (4)	Section 5
2.4.3 (5) (a) , (b)	Section 3
2.4.3 (6)	Section 3.2
2.4.3 (7)	Sections 6 & 7
2.4.3 (8)	Appendix 2
2.4.4 (1-3)	Section 4
2.4.5 (1) (a) to (c)	Section 9
2.4.5 (2) (a) & (b)	Section 9
2.4.5 (3) (a) & (b)	Section 10

APPENDIX 2: LINE CHARGE TABLES

Line Charge Breakdown for Individual Customers

ICP Number	Contract Capacity kVA	Trans Power Charge	Sub-transmission Charge	Distribution Charge	PowerNet Charge	Pass Through Costs	Total Line Charge	Fixed Charge per annum	Variable Charge per Day MWh
880323NV-EBD	150	$9,231.92	$3,881.75	$8,428.45	$127.57	$18.79	$21,688.48	$13,013.09	$20.30
9003081NV-0FF	200	$1,811.43	$631.86	$6,812.28	$127.57	$18.79	$9,401.93	$5,641.16	$45.81
8803298NV-3CC	500	$16,299.28	$6,581.24	$17,872.36	$127.57	$18.79	$40,899.23	$24,539.54	$29.58
740649NV-C13	75	$2,343.98	$586.48	$3,847.77	$127.57	$18.79	$6,924.59	$4,154.75	$34.84
7446911NV-954	150	$6,331.12	$1,790.61	$6,249.84	$127.57	$18.79	$14,517.93	$8,710.76	$32.57
880327NV-FB7	300	$14,858.68	$5,817.56	$14,643.04	$127.57	$18.79	$35,465.64	$21,279.38	$19.10
836598NV-F14	300	$10,710.72	$3,455.84	$11,334.76	$127.57	$18.79	$25,647.67	$15,388.60	$26.45
8102959NV-5D5	300	$11,307.92	$5,008.99	$12,385.91	$127.57	$18.79	$28,849.17	$17,309.50	$27.93
900350NV-C69	100	$3,515.29	$1,054.39	$3,888.54	$127.57	$18.79	$8,604.57	$5,162.74	$35.15
734802NV-A50	150	$7,027.78	$1,028.79	$5,656.26	$127.57	$18.79	$13,859.19	$8,315.51	$46.95
734355NV-C9C	300	$5,431.59	$1,000.73	$8,349.41	$127.57	$18.79	$14,928.08	$11,926.26	$76.36
850948NV-9C2	30	$612.75	$39.97	$1,019.74	$127.57	$18.79	$1,818.81	$1,091.29	$363.76
900327NV-4FE	50	$1,635.02	$39.97	$1,718.31	$127.57	$18.79	$3,539.64	$2,123.79	$707.93
8803283NV-7B5	150	$7,587.24	$3,627.35	$7,754.36	$127.57	$18.79	$19,115.30	$11,469.18	$18.95
740385NV-DE7	200	$6,540.00	$2,063.99	$8,257.37	$127.57	$18.79	$17,007.72	$10,204.63	$25.61
9003503NV-035	200	$4,103.66	$1,327.33	$7,444.25	$127.57	$18.79	$13,021.60	$7,812.96	$43.86
8509006NV-D55	150	$3,986.43	$1,294.83	$6,141.21	$127.57	$18.79	$11,568.82	$6,941.29	$22.18

ICP Number	Contract Capacity kVA	Trans Power Charge	Sub-transmission Charge	Distribution Charge	PowerNet Charge	Pass Through Costs	Total Line Charge	Fixed Charge per annum	Variable Charge per Day MWh
724497NV-C15	150	$8,249.19	$2,957.39	$6,753.53	$127.57	$18.79	$18,106.47	$10,863.88	$30.18
880344NV-C87	300	$11,348.88	$3,765.47	$11,451.02	$127.57	$18.79	$26,711.73	$4,128.55	$76.36
724445NV-1D2	300	$9,550.28	$2,454.65	$9,308.94	$127.57	$18.79	$21,460.23	$12,876.14	$59.77
7559027NV-3C7	200	$7,407.22	$2,722.51	$8,825.61	$127.57	$18.79	$19,101.70	$11,461.02	$25.97
7433294NV-FC6	150	$2,209.45	$680.87	$5,211.98	$127.57	$18.79	$8,248.66	$4,011.84	$76.36
743331NV-CBF	150	$4,308.97	$2,415.18	$5,725.37	$127.57	$18.79	$12,595.87	$4,079.20	$76.36
900330NV-399	500	$27,275.10	$11,499.79	$24,900.60	$127.57	$18.79	$63,821.85	$38,293.11	$19.28
740373NV-C7F	200	$5,993.48	$1,480.99	$7,376.12	$127.57	$18.79	$14,996.95	$8,998.17	$46.57
721862NV-A61	30	$777.12	$281.94	$1,499.31	$127.57	$18.79	$2,704.72	$1,622.83	$33.65
8803601NV-E7B	150	$5,642.71	$2,389.99	$5,654.85	$127.57	$18.79	$13,833.91	$4,559.90	$76.36
734326NV-501	200	$4,084.71	$1,438.66	$7,330.82	$127.57	$18.79	$13,000.55	$7,103.44	$76.36
734325NV-9C1	150	$1,924.25	$335.85	$4,807.21	$127.57	$18.79	$7,213.67	$4,866.82	$76.36
734165NV-163	750	$10,200.86	$375.60	$20,363.43	$127.57	$18.79	$31,086.24	$18,651.74	$816.10
7447401NV-751	500	$15,995.44	$4,728.75	$17,027.99	$127.57	$18.79	$37,898.54	$22,739.12	$27.84
8541431NV-DF3	150	$4,353.23	$2,005.28	$4,905.92	$127.57	$18.79	$11,410.79	$7,963.45	$76.36
722703NV-43B	200	$6,698.84	$2,376.76	$8,646.46	$127.57	$18.79	$17,868.42	$10,721.05	$24.86
90030815NV-060	500	$4,872.39	$5,013.68	$18,057.62	$127.57	$18.79	$28,090.05	$16,854.03	$22.11
900356NV-DE6	300	$11,521.49	$4,000.10	$11,018.18	$127.57	$18.79	$26,686.13	$16,011.68	$31.39
8665558NV-6AF	200	$2,714.53	$1,091.58	$7,057.86	$127.57	$18.79	$11,010.33	$6,606.20	$50.82
740394NV-B0F	200	$5,598.43	$1,068.06	$7,122.31	$127.57	$18.79	$13,935.16	$6,508.02	$76.36
9003071NV-0E8	500	$22,552.25	$2,888.91	$14,648.94	$127.57	$18.79	$40,236.46	$24,141.88	$70.36
8509026NV-000	500	$8,178.58	$3,416.43	$16,281.10	$127.57	$18.79	$28,022.47	$16,813.48	$27.23

ICP Number	Contract Capacity kVA	Trans Power Charge	Sub-transmission Charge	Distribution Charge	PowerNet Charge	Pass Through Costs	Total Line Charge	Fixed Charge per annum	Variable Charge per Day MWh
834399NV-617	500	$114.19	$80.57	$12,994.31	$127.57	$18.79	$13,335.42	$8,001.25	$2,667.08
7551948NV-7E0	300	$5,652.51	$3,485.64	$11,005.54	$127.57	$18.79	$20,290.04	$12,174.03	$28.22
9003385NV-2F6	150	$4,031.57	$2,453.56	$6,667.29	$127.57	$18.79	$13,298.78	$7,979.27	$19.30
7302939NV-E0B	150	$3,594.13	$1,546.63	$6,845.19	$127.57	$18.79	$12,132.30	$7,279.38	$74.66
734424NV-A86	100	$1,688.73	$495.34	$3,472.46	$127.57	$18.79	$5,802.89	$3,481.73	$39.71
835871NV-C17	500	$15,128.14	$2,884.46	$15,803.07	$127.57	$18.79	$33,962.02	$20,377.21	$41.71
74471011NV-36B	200	$14,197.78	$4,008.90	$9,081.76	$127.57	$18.79	$27,434.80	$16,460.88	$44.15
74471015NV-261	150	$2,469.90	$569.79	$5,155.07	$127.57	$18.79	$8,341.11	$5,004.67	$46.31
9003117NV-793	300	$20,072.69	$7,256.85	$13,435.41	$127.57	$18.79	$40,911.30	$24,546.78	$25.68
90037054NV-AED	1250	$47,395.25	$18,818.96	$53,070.29	$127.57	$18.79	$119,430.86	$119,430.86	$0.00
900305NV-92E	750	$10,848.20	$3,876.81	$24,607.32	$127.57	$18.79	$39,478.68	$23,687.21	$47.62
900306NV-5EE	750	$8,937.92	$4,776.57	$23,230.17	$127.57	$18.79	$37,091.01	$22,254.60	$54.19
744103NV-5A5	750	$14,138.93	$5,986.59	$26,855.34	$127.57	$18.79	$47,127.21	$28,276.33	$22.99
734318NV-162	300	$2,781.59	$1,742.60	$9,404.91	$127.57	$18.79	$14,075.46	$8,445.27	$32.76
754696NV-0EE	200	$6,707.41	$3,359.08	$9,589.88	$127.57	$18.79	$19,802.73	$11,881.64	$26.83
831121NV-B96	300	$2,097.57	$1,121.90	$8,859.03	$127.57	$18.79	$12,224.85	$7,334.91	$44.71
755825NV-937	200	$4,767.46	$3,067.29	$7,340.87	$127.57	$18.79	$15,321.97	$6,805.30	$76.36
7433014NV-08B	500	$18,047.17	$5,677.23	$17,413.17	$127.57	$18.79	$41,283.93	$24,770.36	$33.76
9003083NV-07A	500	$15,316.96	$7,788.32	$21,702.26	$127.57	$18.79	$44,953.91	$26,972.34	$19.23
880363NV-C18	200	$2,649.67	$1,002.45	$7,287.37	$127.57	$18.79	$11,085.85	$6,651.51	$31.41
880302NV-FAD	150	$3,471.79	$1,763.89	$6,401.91	$127.57	$18.79	$11,783.95	$7,070.37	$20.75
8803047NV-B57	150	$1,823.23	$492.72	$4,954.91	$127.57	$18.79	$7,417.22	$4,450.33	$73.60

ICP Number	Contract Capacity kVA	Trans Power Charge	Sub-transmission Charge	Distribution Charge	PowerNet Charge	Pass Through Costs	Total Line Charge	Fixed Charge per annum	Variable Charge per Day MWh
73015753NV-A0E	150	$2,150.25	$1,488.40	$6,084.33	$127.57	$18.79	$9,869.33	$5,921.60	$22.39
8803625NV-224	200	$6,851.16	$3,117.02	$9,515.31	$127.57	$18.79	$19,629.84	$11,777.91	$21.03
7301152NV-DC2	750	$16,633.24	$6,322.95	$27,006.37	$127.57	$18.79	$50,108.91	$30,065.35	$26.94
9003212NV-9DF	100	$2,238.85	$567.90	$3,668.46	$127.57	$18.79	$6,621.57	$3,972.94	$27.94
7301908NV-756	100	$2,604.64	$1,142.93	$4,148.68	$127.57	$18.79	$8,042.60	$4,825.56	$22.31
880308NV-D3C	75	$2,915.46	$1,555.61	$5,014.68	$127.57	$18.79	$9,632.10	$5,779.26	$22.50
7301973NV-CDF	75	$3,134.57	$1,219.09	$4,922.33	$127.57	$18.79	$9,422.35	$5,653.41	$22.08
8803164NV-3C6	75	$3,114.70	$928.25	$4,437.31	$127.57	$18.79	$8,626.61	$5,175.97	$27.87
8803165NV-F83	50	$2,515.55	$862.26	$3,324.11	$127.57	$18.79	$6,848.26	$4,108.96	$30.50
744611NV-08F	300	$7,704.06	$3,302.14	$10,660.35	$127.57	$18.79	$21,812.90	$13,087.74	$31.97
9003603NV-336	300	$19,583.89	$7,448.15	$18,832.51	$127.57	$18.79	$46,010.91	$27,606.54	$24.50
9003051NV-DBD	300	$13,266.36	$4,753.59	$11,491.45	$127.57	$18.79	$29,657.75	$17,794.65	$29.68
7757907NV-783	500	$12,504.10	$5,731.45	$16,811.00	$127.57	$18.79	$35,192.91	$21,115.74	$36.27
7757994NV-4A4	200	$6,813.65	$2,897.06	$8,081.91	$127.57	$18.79	$17,938.96	$10,763.38	$39.58
880336NV-95F	500	$18,064.23	$9,206.00	$20,758.06	$127.57	$18.79	$48,174.64	$28,904.79	$23.43
8803031NV-F85	200	$5,915.07	$3,003.43	$9,015.86	$127.57	$18.79	$18,080.72	$10,848.43	$19.62
880321NV-E38	200	$4,732.19	$2,988.85	$9,154.79	$127.57	$18.79	$17,022.18	$10,213.31	$17.84
8665382NV-F7A	200	$7,286.55	$3,773.71	$8,802.37	$127.57	$18.79	$20,008.98	$2,888.55	$76.36
7343223NV-F0C	200	$8,421.34	$2,758.50	$9,071.45	$127.57	$18.79	$20,397.64	$12,238.59	$37.95
755822NV-4FD	300	$9,585.68	$2,561.34	$9,414.44	$127.57	$18.79	$21,707.82	$13,024.69	$58.28
750191NV-4A6	150	$4,157.90	$1,735.83	$5,725.37	$127.57	$18.79	$11,765.45	$3,248.78	$76.36
733395NV-F13	200	$3,207.26	$1,109.74	$6,983.94	$127.57	$18.79	$11,447.29	$5,435.46	$76.36

ICP Number	Contract Capacity kVA	Trans Power Charge	Sub-transmission Charge	Distribution Charge	PowerNet Charge	Pass Through Costs	Total Line Charge	Fixed Charge per annum	Variable Charge per Day MWh
880317NV-84F	300	$1,216.14	$326.08	$8,283.09	$127.57	$18.79	$9,971.66	$5,982.99	$102.24
8365737NV-155	300	$15,390.23	$6,026.87	$12,281.55	$127.57	$18.79	$33,845.00	$20,307.00	$25.35
9003244NV-058	300	$8,954.46	$3,614.50	$11,995.62	$127.57	$18.79	$24,710.93	$14,826.56	$19.62
8509245NV-937	200	$6,448.28	$2,875.10	$9,314.88	$127.57	$18.79	$18,784.62	$11,270.77	$18.40
7447592NV-D72	150	$1,278.56	$528.57	$4,776.98	$127.57	$18.79	$6,730.47	$1,980.60	$76.36
880361NV-C9D	500	$24,003.93	$10,168.30	$23,714.94	$127.57	$18.79	$58,033.52	$34,820.11	$19.22
744655NV-320	200	$3,853.96	$1,431.74	$7,794.48	$127.57	$18.79	$13,226.54	$7,935.92	$28.22
931741NV-60C	500	$14,936.58	$16,501.95	$17,843.18	$127.57	$18.79	$49,428.07	$29,656.84	$27.90
7341276NV-90B	200	$3,808.25	$1,274.53	$7,445.36	$127.57	$18.79	$12,674.49	$7,604.70	$28.35
7341272NV-801	150	$1,977.19	$498.75	$5,033.29	$127.57	$18.79	$7,655.59	$4,593.35	$46.71
733399NV-C0D	100	$2,879.62	$826.50	$3,952.35	$127.57	$18.79	$7,804.83	$4,682.90	$27.62
7447142NV-C31	200	$7,608.40	$2,366.93	$8,537.08	$127.57	$18.79	$18,658.76	$11,195.25	$27.20
900392NV-B03	750	$24,740.36	$8,775.26	$29,700.88	$127.57	$18.79	$63,362.86	$38,017.72	$21.97
7344583NV-C71	150	$3,228.36	$388.69	$4,501.61	$127.57	$18.79	$8,265.02	$7,997.72	$76.36
900325NV-47B	500	$31,835.47	$14,416.10	$28,487.56	$127.57	$18.79	$74,885.49	$44,931.29	$16.10
8509962NV-AA6	75	$1,331.64	$349.79	$3,276.15	$127.57	$18.79	$5,103.94	$3,062.36	$37.13
7317032NV-617	200	$7,517.60	$2,481.49	$8,159.51	$127.57	$18.79	$18,304.95	$10,982.97	$33.01
9003573NV-568	200	$8,780.80	$3,572.30	$7,540.47	$127.57	$18.79	$20,039.92	$7,353.90	$76.36
880375NV-73A	300	$7,488.40	$3,239.05	$9,407.54	$127.57	$18.79	$20,281.34	$6,408.79	$76.36
880309NV-179	300	$6,411.01	$2,782.79	$10,720.66	$127.57	$18.79	$20,060.82	$12,036.49	$24.50
8144266NV-0A8	200	$6,882.68	$2,535.69	$9,110.91	$127.57	$18.79	$18,675.64	$11,205.38	$23.59
880329NV-C2C	1000	$39,691.56	$19,238.68	$52,085.98	$127.57	$18.79	$111,162.57	$66,697.54	$23.19

ICP Number	Contract Capacity kVA	Trans Power Charge	Sub-transmission Charge	Distribution Charge	PowerNet Charge	Pass Through Costs	Total Line Charge	Fixed Charge per annum	Variable Charge per Day MWh
755884NV-D6D	200	$4,391.57	$1,097.76	$7,071.71	$127.57	$18.79	$12,707.40	$7,624.44	$53.32
755813NV-F40	150	$10,209.60	$2,522.33	$6,073.14	$127.57	$18.79	$18,951.42	$11,370.85	$85.17
7205085NV-6A2	100	$3,254.21	$1,684.22	$4,387.25	$127.57	$18.79	$9,472.03	$5,683.22	$20.17
8305967NV-D0E	500	$2,893.08	$5,276.31	$13,606.18	$127.57	$18.79	$21,921.92	$13,153.15	$135.20
7501996NV-A4D	150	$2,033.78	$666.35	$5,443.17	$127.57	$18.79	$8,289.65	$1,325.59	$76.36
7341792NV-7BE	200	$5,234.58	$2,446.86	$8,206.10	$127.57	$18.79	$16,033.90	$9,620.34	$24.61
9003235NV-940	500	$23,944.65	$7,924.05	$21,265.47	$127.57	$18.79	$53,280.53	$31,968.32	$24.32
7229001NV-0AF	100	$2,342.27	$1,128.65	$3,947.59	$127.57	$18.79	$7,564.87	$4,538.92	$27.56
880397NV-D05	500	$12,446.06	$5,294.71	$23,184.57	$127.57	$18.79	$41,071.69	$24,643.02	$30.32
880395NV-D80	1000	$14,096.24	$1,155.39	$29,602.69	$127.57	$18.79	$45,000.67	$27,000.40	$164.33
724187NV-3BD	150	$6,794.97	$2,792.98	$6,379.83	$127.57	$18.79	$16,114.13	$9,668.48	$30.41
760737NV-A1C	500	$14,569.51	$5,807.20	$16,656.93	$127.57	$18.79	$37,179.99	$22,308.00	$45.03
7227011NV-2C2	300	$2,661.00	$1,001.51	$8,477.28	$127.57	$18.79	$12,286.15	$7,371.69	$67.50
9003995NV-251	300	$7,943.52	$1,548.46	$9,673.39	$127.57	$18.79	$19,311.72	$11,587.03	$44.14
82029943NV-B5B	150	$2,733.09	$746.11	$4,887.07	$127.57	$18.79	$8,512.62	$7,002.50	$76.36
835083NV-C88	300	$800.18	$1,582.11	$8,488.94	$127.57	$18.79	$11,017.59	$6,610.55	$158.85
825292NV-886	500	$15,839.65	$8,102.12	$19,828.73	$127.57	$18.79	$43,916.86	$26,350.11	$23.96
740340NV-747	150	$3,853.17	$1,483.82	$6,005.11	$127.57	$18.79	$11,488.46	$2,712.92	$76.36
7433753NV-0E6	150	$4,018.05	$1,883.00	$6,326.93	$127.57	$18.79	$12,374.33	$1,729.75	$76.36
900384NV-021	500	$28,390.71	$9,649.57	$21,178.57	$127.57	$18.79	$59,365.20	$35,619.12	$29.00
900385NV-C64	1000	$17,570.99	$1,731.49	$30,963.12	$127.57	$18.79	$50,411.96	$30,247.17	$347.67
7302313NV-BC5	75	$1,215.68	$195.03	$2,955.78	$127.57	$18.79	$4,512.84	$2,707.71	$81.34

ICP Number	Contract Capacity kVA	Trans Power Charge	Sub-transmission Charge	Distribution Charge	PowerNet Charge	Pass Through Costs	Total Line Charge	Fixed Charge per annum	Variable Charge per Day MWh
7302304NV-CA2	150	$2,233.25	$782.68	$5,199.03	$127.57	$18.79	$8,361.31	$4,137.37	$76.36
900383NV-DEB	500	$6,874.09	$3,251.69	$14,624.15	$127.57	$18.79	$24,896.28	$14,937.77	$66.53
900313NV-20C	300	$2,801.75	$1,530.07	$9,701.72	$127.57	$18.79	$14,179.89	$8,507.93	$32.01
7403555NV-A42	200	$6,319.59	$2,039.11	$8,056.14	$127.57	$18.79	$16,561.19	$9,936.72	$36.28
7447635NV-BA4	300	$11,288.59	$3,622.96	$11,511.34	$127.57	$18.79	$26,569.24	$15,941.55	$27.53
735249NV-D8B	200	$4,457.66	$280.22	$6,106.02	$127.57	$18.79	$10,990.25	$10,820.33	$76.36
735248NV-1CE	500	$10,641.37	$4,971.27	$16,524.48	$127.57	$18.79	$32,283.48	$19,370.09	$60.32
850908NV-B67	750	$24,359.52	$10,856.40	$32,355.39	$127.57	$18.79	$67,717.66	$40,630.60	$18.94
734110NV-971	300	$5,849.79	$2,384.80	$9,766.04	$127.57	$18.79	$18,146.98	$10,888.19	$34.27
900358NV-E7D	500	$2,187.82	$2,067.88	$14,314.89	$127.57	$18.79	$18,716.94	$11,230.16	$48.10
734460NV-929	200	$1,219.19	$457.55	$6,609.74	$127.57	$18.79	$8,432.83	$5,059.70	$63.80
724179NV-031	100	$1,013.49	$269.06	$3,149.77	$127.57	$18.79	$4,578.68	$2,747.21	$68.61
8425758NV-FE5	150	$4,352.54	$1,673.13	$6,084.76	$127.57	$18.79	$12,256.78	$7,354.07	$28.05
7302953NV-36A	500	$7,882.73	$5,448.00	$18,798.05	$127.57	$18.79	$32,275.13	$19,365.08	$22.45
900351NV-02C	200	$9,005.21	$3,539.31	$10,642.51	$127.57	$18.79	$23,333.38	$14,000.03	$17.52
7341793NV-BFB	100	$3,568.60	$1,000.22	$3,854.63	$127.57	$18.79	$8,569.81	$5,141.88	$28.46
734188NV-482	300	$13,713.33	$4,677.57	$13,039.94	$127.57	$18.79	$31,577.19	$18,946.31	$20.97
724111NV-DD5	150	$7,028.29	$1,810.91	$5,201.75	$127.57	$18.79	$14,187.31	$8,512.38	$65.72
7227390NV-8CE	200	$3,485.17	$708.62	$6,718.69	$127.57	$18.79	$11,058.83	$6,635.30	$55.99
900308NV-675	750	$12,258.99	$6,677.15	$30,841.10	$127.57	$18.79	$49,923.60	$29,954.16	$48.15
8305981NV-63B	500	$16,914.95	$7,233.51	$18,337.57	$127.57	$18.79	$42,632.38	$25,579.43	$38.14
832431NV-6DE	1000	$5,947.61	$1,790.30	$31,557.57	$127.57	$18.79	$39,441.84	$23,665.10	$54.16

ICP Number	Contract Capacity kVA	Trans Power Charge	Sub-transmission Charge	Distribution Charge	PowerNet Charge	Pass Through Costs	Total Line Charge	Fixed Charge per annum	Variable Charge per Day MWh
760735NV-A99	150	$3,199.50	$1,402.68	$5,388.51	$127.57	$18.79	$10,137.04	$6,082.22	$46.92
900319NV-09D	200	$4,175.34	$826.09	$6,870.20	$127.57	$18.79	$12,017.98	$7,210.79	$60.41
866506NV-01C	500	$16,196.91	$1,329.84	$13,800.38	$127.57	$18.79	$31,473.48	$18,884.09	$188.75
7433107NV-FE2	200	$8,041.41	$1,204.71	$7,093.74	$127.57	$18.79	$16,486.21	$9,891.72	$71.40
740630NV-71F	150	$6,572.51	$1,494.20	$5,920.10	$127.57	$18.79	$14,133.17	$8,479.90	$44.28
7433292NV-E49	500	$9,853.27	$5,228.61	$16,429.83	$127.57	$18.79	$31,658.06	$18,994.84	$36.01
8509025NV-CC0	300	$11,600.44	$5,296.03	$12,947.38	$127.57	$18.79	$29,990.21	$17,994.12	$21.27
8803032NV-345	150	$4,411.24	$1,110.19	$5,940.64	$127.57	$18.79	$11,608.43	$6,965.06	$31.82
744608NV-473	300	$8,762.66	$3,005.33	$10,529.02	$127.57	$18.79	$22,443.36	$13,466.02	$29.64
933534NV-759	200	$729.47	$2,863.07	$6,680.18	$127.57	$18.79	$10,419.08	$6,251.45	$29.51
931749NV-418	300	$3,411.35	$14,827.46	$10,604.13	$127.57	$18.79	$28,989.29	$17,393.57	$24.69
930503NV-F8B	100	$1,723.02	$6,334.77	$4,144.51	$127.57	$18.79	$12,348.65	$7,409.19	$29.21
930505NV-E04	150	$4,202.12	$8,286.06	$5,686.66	$127.57	$18.79	$18,321.19	$6,627.40	$76.36
920755NV-4EA	150	$4,783.88	$9,657.97	$7,104.10	$127.57	$18.79	$21,692.31	$13,015.38	$28.29
931776NV-C3E	150	$3,779.20	$4,127.13	$5,256.59	$127.57	$18.79	$13,309.28	$5,376.90	$76.36
9406013NV-102	500	$6,610.13	$6,747.42	$13,571.31	$127.57	$18.79	$27,075.22	$16,245.13	$48.69
9406011NV-187	500	$16,296.68	$20,000.17	$18,670.88	$127.57	$18.79	$55,114.09	$33,068.45	$27.46
931746NV-BC6	200	$7,515.92	$9,990.30	$7,157.03	$127.57	$18.79	$24,809.61	$14,885.77	$49.62
9408016NV-48D	1750	$88,220.40	$127,550.25	$78,490.54	$127.57	$18.79	$294,407.54	$176,644.52	$27.67
931760NV-71C	150	$1,572.04	$1,581.75	$4,854.74	$127.57	$18.79	$8,154.88	$4,001.21	$76.36
931704NV-9E6	200	$2,247.63	$3,199.75	$6,557.46	$127.57	$18.79	$12,151.20	$7,290.72	$43.71
934525NV-5D1	150	$1,976.47	$2,570.82	$5,004.72	$127.57	$18.79	$9,698.37	$4,686.88	$76.36

Line Charge Breakdown for Residential and General Customers

Capacity	Code	Number of Connections	Transpower Charge	Sub transmission Charge	Distribution Charge	PowerNet Overheads	Pass through Costs	Fixed Charge per Day
Residential								
Residential (8kVA 1 Phase) - All Peak *	ND08P	47	$4,588	$4,768	$13,535	$5,996	$2,439	$0.9304
Residential (8kVA 1 Phase) - With Off Peak *	ND08Q	83	$7,047	$5,050	$20,123	$10,588	$3,700	$0.6572
Standard Residential (20kVA 1 Phase) - All Peak	ND20P	1290.5	$251,949	$189,128	$732,219	$164,624	$102,585	$1.7191
Standard Residential (20kVA 1 Phase) - With Off Peak	ND20Q	7490	$1,271,899	$894,165	$3,628,528	$955,469	$525,270	$1.1938
Residential Low User (20kVA 1 Phase) - All Peak	NDL20P	1107	$197,690	$128,976	$535,416	$141,216	$77,289	$0.7500
Residential Low User (20kVA 1 Phase) - With Off Peak	NDL20Q	5496	$846,062	$509,362	$2,263,254	$701,103	$339,004	$0.6500
Residential Low User (8kVA 1 Phase) - All Peak*	NDL08P	23	$2,197	$2,999	$6,489	$2,934	$1,239	$0.7500
Residential Low User (8kVA 1 Phase) - With Off Peak*	NDL08Q	106	$8,790	$10,049	$25,455	$13,522	$5,010	$0.6500
General Single Phase								
Street Lights (1 Phase) per street light	NS001L	5583	$45,244	$32,300	$133,982	$260	$14,177	$0.1428
1 kVA 1 Phase - All Peak	NS001P	41	$3,352	$2,721	$7,470	$5,230	$1,637	$0.6676

8 kVA 1 Phase - All Peak	NS008P	148	$14,447	$9,131	$41,727	$18,880	$7,105	$0.9304
8 kVA 1 Phase - With Off Peak	NS008Q	11	$934	$582	$2,650	$1,403	$481	$0.6473
20 kVA 1 Phase - All Peak	NS020P	259.5	$50,663	$32,019	$146,326	$33,103	$20,039	$1.7191
20 kVA 1 Phase - With Off Peak	NS020Q	82	$13,925	$8,671	$39,512	$10,460	$5,637	$1.1938
General Three Phase								
15 kVA 3 Phase - All Peak	NT015P	74	$13,544	$9,728	$39,296	$9,440	$5,559	$1.4375
15 kVA 3 Phase - With Off Peak	NT015Q	7	$1,114	$942	$3,209	$893	$484	$0.9304
30 kVA 3 Phase - All Peak	NT030P	552	$216,725	$147,157	$564,958	$70,416	$70,920	$2.4073
30 kVA 3 Phase - With Off Peak	NT030Q	106	$35,995	$24,181	$92,722	$13,522	$11,931	$1.6384
50 kVA 3 Phase - All Peak	NT050P	334	$274,383	$183,163	$656,428	$42,607	$77,663	$4.9154
50 kVA 3 Phase - With Off Peak	NT050Q	64	$45,535	$31,423	$107,797	$8,164	$13,040	$3.3378
75 kVA 3 Phase - All Peak	NT075P	117	$174,912	$118,497	$373,396	$14,925	$44,022	$10.0937
75 kVA 3 Phase - With Off Peak	NT075Q	15	$19,377	$13,177	$40,978	$1,913	$4,886	$7.3429
100 kVA 3 Phase - All Peak	NT100P	75	$170,381	$101,123	$236,833	$9,567	$30,144	$12.2782
100 kVA 3 Phase - With Off Peak	NT100Q	7	$13,673	$10,267	$19,132	$893	$2,631	$8.9006

Variable Line Charge Prices	**Peak** $/kWh	**Shoulder** $/kWh	**Night** $/kWh
Residential Standard & General	$0.07636	$0.055647	$0.01000

Residential Low Fixed Charge Fixed Charge Option (8kVA	$0.079630	$0.052562	$0.01000
Residential Low Fixed Charge Fixed Charge Option 15kVA	$0.10724	$0.080158	$0.01000