Nelson Electricity Limited
Pricing Methodology Disclosure

For the period beginning 1 April 2018

The following information is disclosed in accordance with the Electricity Distribution Information Disclosure Determination 2012 under Part 4 of the Commerce Act 1986.

Contents

Director Certification

In accordance with the Commerce Act
Electricity Distribution Information Disclosure Determination 2012

Pricing Methodology for the period beginning 1 April 2018

SCHEDULE 17
Certification of Year-beginning Disclosures

Clause 2.9.1

We, Paul Donald LeGros and Oliver Rupert Kearney, being directors of Nelson Electricity Limited certify that, having made all reasonable inquiry, to the best of our knowledge:

a) The following attached information of Nelson Electricity Limited prepared for the purposes of clauses 2.4.1, 2.6.1, 2.6.3, 2.6.6 and 2.7.2 of the Electricity Distribution Information Disclosure Determination 2012 in all material respects complies with that determination.

b) The prospective financial or non-financial information included in the attached information has been measured on a basis consistent with regulatory requirements or recognised industry standards.

Signed		Signed	
Date	29 March 2018	Date	29 March 2018

Glossary and Abbreviations

Advanced Meter	Also called a smart meter. Is a meter with the ability to measure energy use at various time intervals and with operational two-way remote communications capability. Installed at a Category 1 or 2 metering installation point (≤500Amps).
Connection	A point of connection to an electricity distribution network as identified by an Installation Control Point (ICP) identifier.
Controlled Meter	A meter that measures load where there is functionality to control the energy provided to permanently wired appliances (e.g. a hot water cylinder) that are connected to the meter.
Distributor	A company that owns or operates the power lines that transport electricity on local networks. Terms also used are 'distribution company', 'lines company' and 'network company'.
Electricity Industry Act 2010 (Act)	An Act that regulates the operation of the New Zealand electricity industry.
Electricity Industry Participation Code (Code)	The Code sets out the duties and responsibilities that apply to industry participants and the Electricity Authority.
Electricity Information Exchange Protocol (EIEP)	EIEPs provide a set of standardised formats for business-to-business information exchanges.
Electricity Networks Association (ENA)	Association of all 29 New Zealand electricity distributors.
Information Disclosure (ID)	Electricity Distribution Information Disclosure Determination 2012.
Input Methodology (IM)	Electricity Distribution Services Input Methodologies Determination 2012.
Installation Control Point (ICP)	See Connection.
Kilowatt hour (kWh)	kilowatt hour is also known as a unit of electricity and is the basis of retail sales and reconciliation of electricity in the market.
Legacy meter	A meter that measures cumulative energy consumption (kWh) and does not have remote communications capability. Installed at a Category 2 ICP or lower (≤500Amps).
Low Fixed Charge Regulations (LFC Regulations)	Electricity (Low Fixed Charge Tariff Option for Domestic Consumers) Regulations 2004.
Loss Factor	Loss factors are declared by distributors and used to reflect the normal difference between energy injected into a network and energy delivered from the network in the reconciliation process.
Low Fixed Charge (LFC)	Low Fixed Charge.
Lower South region	Stipulated in the LFC regulations as consumers supplied by the Arthur's Pass, Castle Hill, Papanui, and Hororata grid exit points, or any grid exit point that is located further south.
Meter Categories (1, 2, 3, 4, and 5)	Defined in the Schedule 10.1 of the Code. See Appendix 6.
Meter register	An energy measurement device on a meter.
Peak Load	Peak half hourly demand, measured in kW or kVA.
Pricing Principles	The distribution pricing principles as published by the Electricity Commission in March 2010, adopted by the Electricity Authority.
Registry	The registry is a national database that contains information on every point of connection on local and embedded networks to which a consumer or embedded generator is connected.
ToU Meter	Category 3, 4, or 5 metering installation capable of recording kWh and at least one of kVArh and kVAh on a half-hourly basis
Transmission	Conveyance of electricity at high voltages through the Transmission network.
Transmission network	New Zealand's national transmission network (national grid) owned by Transpower New Zealand Limited.
Uncontrolled Meter	A meter that measures load where there is no load control functionality.
Unaccounted for Energy (UFE)	The difference between reported energy injected into a network and the reported energy extracted from the network after it has been adjusted using Loss Factors.

The Electricity Authority also publishes a glossary of key industry terms on its website.

1. Introduction

Background

Nelson Electricity Ltd (NEL) is the Electricity Distribution Business that delivers electricity to electricity users on behalf of energy retailers. NEL is responsible for managing and operating the electricity distribution network in the central Nelson city area.

By way of brief background, NEL was formerly the Municipal Electricity Department of the Nelson City Council. The Electricity Industry Reform Act 1998 required that all electricity companies split into either the supply business (generating and/or retailing electricity) or the delivery business (operating the local electricity network). In 1999, NEL sold its retail operation to focus on its electricity delivery business.

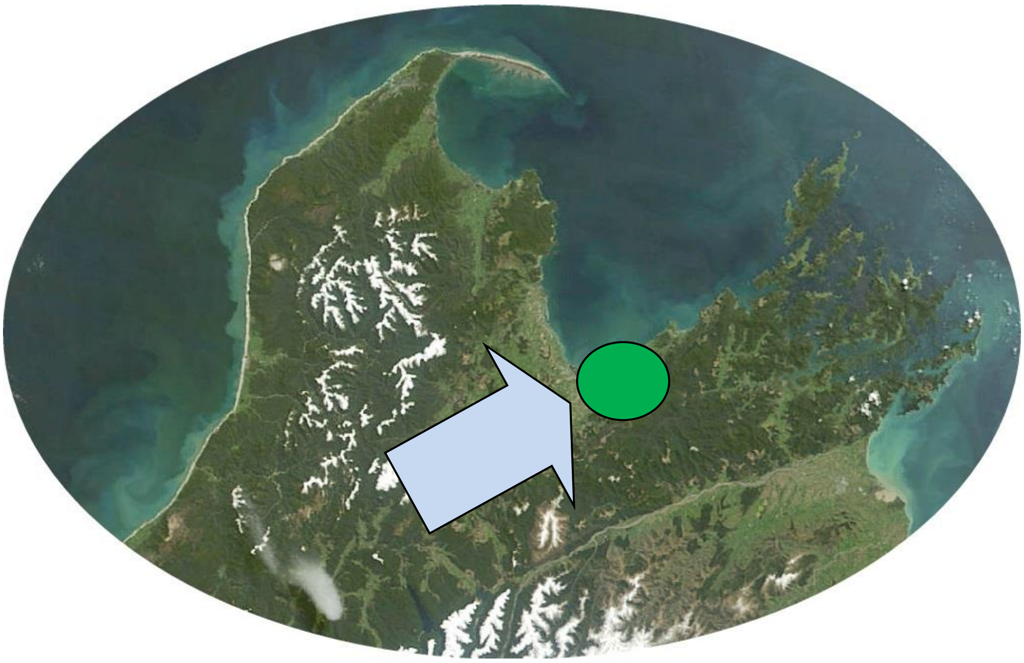


Figure 1 Nelson Electricity is located in Nelson city at the top of the South Island.

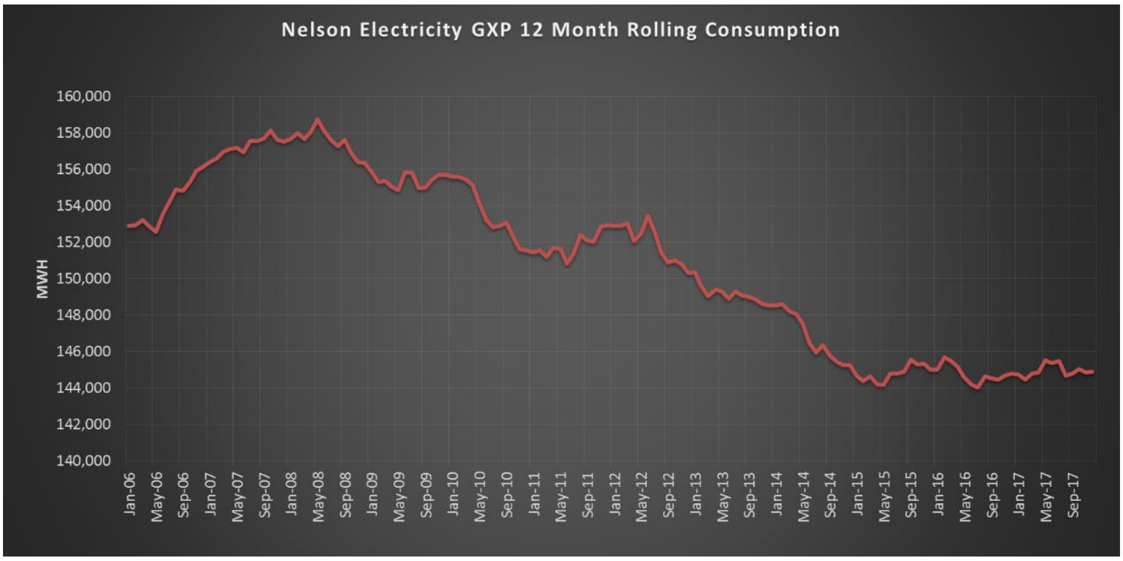
NEL is owned by Network Tasman and Marlborough Lines, each holding a 50% shareholding. The day to day operations are managed by a small team of executives, and all maintenance and capital work is outsourced to approved contractors by way of contestable tendering of works.

The NEL network comprises approximately 9,200 connections in a concentrated area of 24 square kilometres in the central Nelson city area. The connections are largely CBD, industrial and dense urban. NEL has a peak loading of 33.MW during winter months and distributes 139GWh annually through the network.

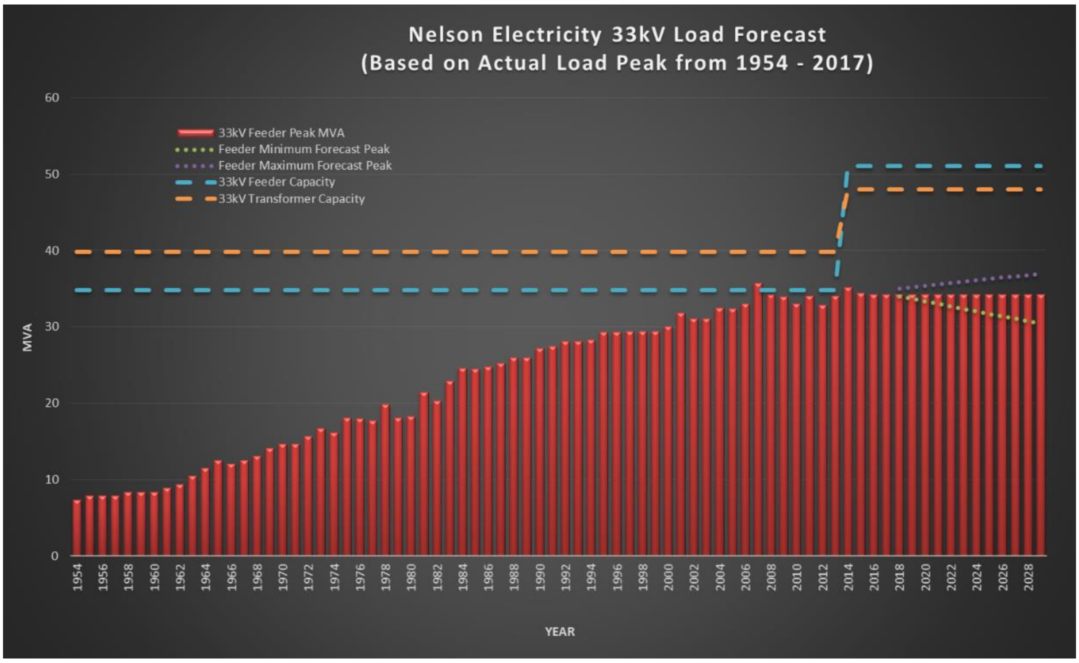
NEL derives its transmission services via Transpower's Stoke Substation which is seven kilometres from NEL's only Zone Substation at Haven Road.

Growth kWh and Peak Demand

NEL up until 2008 had consistent kWh growth of approximately 1.0% -1.5% per year. Since then kWh consumption has been reducing at approximately 1.0% per year and in the last two years consumption has been flat. The global financial crisis may have started the change in 2008 but it has continued due to a mixture of energy efficient appliances, LED lighting, improvements in home insulation, energy conservation due to higher electricity prices and the installation of solar PV.



Peak demand up until 2008 was also increasing at the same rate as kWh at approximately 1.0% - 1.5% but since 2008 has flattened off but not decreased. The reason for peak demand growth has not tracked downward with consumption due to the lower utilisation of load control at peak demand times. Load control is now principally being used for minimising transmission peaks as there are now no upper network constraints on the NEL network to manage load. The graph following demonstrates how the peak demand has flattened since 2008.



The short to medium outlook for NEL is a continued reduction in kWh consumption for the short to medium term for three key reasons:

- On average every connection is using less electricity.
- There is limited opportunity for new load/connections as there is limited undeveloped land available in the central Nelson city area.
- Any redevelopment of land typically uses less electricity.

Declining consumption has ramifications due to cost in managing the network which is largely the same of which NEL currently derives 47% of its revenue. So this creates a situation under the current pricing structure where costs are spread over less kWh.

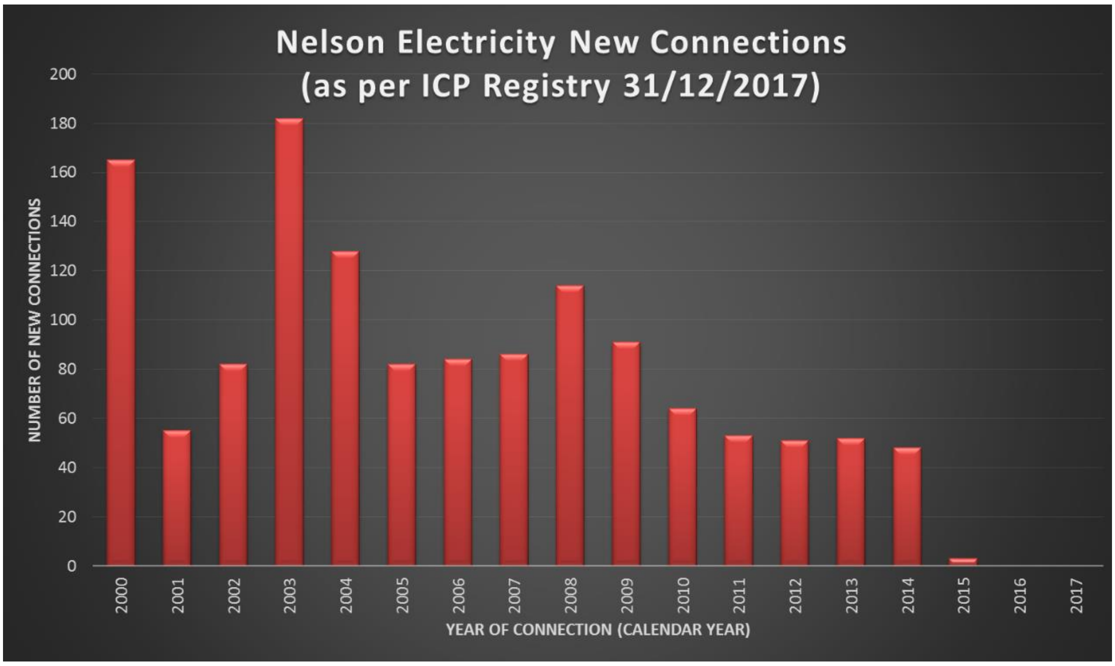
Growth Connection Numbers

Between 2010 and 2015 NEL has had on average 50 new ICPs a year. This is calculated as being the difference between decommissioned and new connections. Most are typically new residential connections.

Since 2015 decommissioned ICPs have offset the new ICPs which has meant that connection numbers have been flat for almost three years. This is, however, not an indication of no growth as many decommissioned sites are making way for new future connections and the applications are now coming through with many to be realised in 2018.

There are a number of small building and subdivision developments which are starting to eventuate and will bring new connections to the 50 per year level in 2018. The pricing will factor in 50 new ICPs for the upcoming year. Nelson City Council have set up Special Housing Areas as part of the Housing Accord. This has seen an increased level of development in the city. The numbers of new connections may increase beyond 50 but this report takes a conservative approach.

Some large commercial consumers are still looking at their costs and, as such, there may be some capacity downsize requests which could impact on revenue as changes are made.



Technology – Times are Changing

On top of flat consumption, there is an increased uncertainty as to how the effect of certain technologies and industry evolution will have on the role that the electricity network plays in the future. NEL recognises its place as the key infrastructure that supports the Nelson community and economy. Key areas of focus are as follows:

- Increasing numbers of solar PV installations;
- Increasing number of retailers providing many different pricing options for consumers;
- Introduction of battery storage;
- Electric vehicles and vehicle chargers;
- Internet of things.

The electricity consumer is likely to dictate the networks future with their decisions on uptake and utilisation of these technologies and switching to different pricing options as electricity retailers adapt and modify their offerings. NEL is, therefore, having to review its network pricing structure to ensure it is fit for the upcoming changes and ensure the network is sustainable for the long term.

The days where all electricity being sourced via the transmission system is disappearing. With distributed generation being installed the opportunity for new consumers with peer to peer trading of electricity is possible. The likely introduction of home scale batteries in years to come will take this opportunity a step further. NEL has to adapt to ensure the network can facilitate the changes and staying relevant for the community it serves.

NEL is actively working with the Electricity Network Association and also neighbouring networks to develop a form of service-based pricing that will meet the changing landscape. This will achieve two things:

- Ensure as much as practicable that all electricity consumers pay their "fair share" of the costs to provide the electrical infrastructure;
- The electricity consumer is able to make rational choices when investing in any new technologies.

It was envisaged last year that a new pricing structure would have been introduced for 1 April 2020 this remains the target date and is discussed in Section 7.

2. Regulatory Requirements

NEL is a natural monopoly and is not directly exposed to the competitive forces that drive other markets to deliver improved efficiency and service. To this extent NEL is classed as non-exempt from the control regime under the regulations for electricity network owners under the Commerce Act 1986. This means that NEL has to comply with the Electricity Distribution Services Default Price-Quality Path Determination 2015 (DPP) administered by the Commerce Commission. NEL also has to comply with the Electricity Distribution Information Disclosure Determination 2012 under Part 4 of the Commerce Act 1986 of which includes the disclosure of its Pricing Methodology. Recent changes also require the pricing methodology to demonstrate how NEL's pricing is in line with the Electricity Authority Distribution Pricing Principles.

NEL has taken all requirements into account in the preparation of this document.

Electricity Distribution Services Default Price-Quality Path Determination

NEL has to comply with the Electricity Distribution Services Default Price-Quality Path Determination 2015 (DPP). The Commerce Commission resets the Price-Quality path every five years. The 2018-2019 year will be the fourth of the current five year path from 1 April 2015 – 31 March 2020. Actual prices multiplied by actual quantities of two years previous must not exceed the price path.

Default Price Path Compliance Summary

NEL for the year ending 31 March 2018 year will not breach the Default Price-Quality Path (DPP). It did, however, breach the previous year and as such has worked with the Commerce Commission to ensure consumers are compensated.

31 March 2016 Compliance Breach Summary

NEL submitted its Annual Compliance Statement dated 16 June 2017 stating that it did not comply with its Price Path for the 12 month period ending on 31 March 2017 (2017 Assessment Period) as it had exceeded the Price Path by $91,793.

The Commission considered, and NEL acknowledged, that such instance of non-compliance amounted to a contravention of a price-quality requirement applying to regulated goods or services as described in section 87(1)(a) of the Act (Breach).

NEL asserted, and the Commission accepted the cause of the Breach was due to an inadvertent error by NEL.

A Settlement Agreement was executed on 21 November 2017 to resolve the Breach without litigation. In consideration of the Commission agreeing not to bring proceedings in relation to the Breach and NEL agreeing to reduce its “Notional Revenue” below its “Allowable Notional Revenue” in its Price Path for the assessment period ending 31 March 2019 (2019 Assessment Period) by at least $105,075 (being the over-recovered amount adjusted for the time value of money).

This requirement was taken into account when setting prices for the year starting 1 April 2018.

Electricity Distribution Information Disclosure Determination

The key requirements in complying with the disclosure of pricing methodologies is outlined in 2.4.1 – 2.4.5 of the Electricity Distribution Information Disclosure Determination 2012. The requirements outline the framework to demonstrate to the "Interested Person" how NEL allocates costs to different Load Groups and the basis on how prices are set.

Electricity Authority Distribution Pricing Principles

The Commission's final pricing principles are as follows:

Electricity Authority Pricing Principles
(a) Prices are to signal the economic costs of service provision, by:
(i) being subsidy free (equal to or greater than incremental costs, and less than or equal to standalone costs), except where subsidies arise from compliance with legislation and/or other regulation;
(ii) having regard, to the extent practicable, to the level of available service capacity; and
(iii) Signalling, to the extent practicable, the impact of additional usage on future investment costs.
(b) Where prices based on 'efficient' incremental costs would under-recover allowed revenues, the shortfall should be made up by setting prices in a manner that has regard to consumers' demand responsiveness, to the extent practicable.
(c) Provided that prices satisfy (a) above, prices should be responsive to the requirements and circumstances of stakeholders in order to:
(i) discourage uneconomic bypass;
(ii) allow for negotiation to better reflect the economic value of services and enable stakeholders to make price/quality trade-offs or non-standard arrangements for services; and
(iii) where network economics warrant, and to the extent practicable, encourage investment in transmission and distribution alternatives (e.g. distributed generation or demand response) and technology innovation.
(d) Development of prices should be transparent, promote price stability and certainty for stakeholders, and changes to prices should have regard to the impact on stakeholders.
(e) Development of prices should have regard to the impact of transaction costs on retailers, consumers and other stakeholders and should be economically equivalent across retailers.

NEL Commentary on Compliance with Electricity Authority Pricing Principles

NEL has prepared this pricing methodology in accordance with or as close as possible to the Electricity Authority Pricing Principles. It has to be recognised that consumer behaviour as a response to network pricing is limited. The line prices represent approximately 30% of the total electricity invoice they receive from electricity retailers so unless a network can significantly amplify or exaggerate the pricing differential levels then the consumer behaviour will be based on what the electricity retailer wants to achieve. In addition to that, in the setting of controllable line charges, any incentives in these areas are often reduced further through the interface the customer has with their electricity retailer. Additional meter costs for measuring controllable loads are typically loaded onto the controllable price further reducing the pricing incentive for the line price option.

Prices are set attempting to minimise cross subsidisation and price discrimination between load groups. A key success has been in the mass market with the combining of business and residential tariffs, excluding those who qualify and have opted to be on the low fixed charge option as per the Electricity (Low Fixed Charge Tariff Option for Domestic Consumers) Regulations 2004. This has reduced published pricing options for the mass market consumers also simplifying the pricing for electricity retailers to apply to their customers.

Upon completion of the new Zone Substation at Haven Road and installation of the new 33kV feeder in 2014, there have been changes in cost allocations given the reduced requirement for utilisation of ripple control for network related constraints or operational requirements. Ripple is now principally for minimising transmission related constraints so reducing transmission costs for consumers. Notwithstanding any material changes in growth forecasts or transmission pricing levels or transmission pricing methodology, it is expected that line prices will remain around similar levels but there is a potential for transmission costs to lower if the targeted use of ripple control is effective.

NEL does not have any other significant expenditure projects in the coming years that will materially affect line charges.

NEL currently offers a line price option for larger consumers to be on “Time of Use” (above 150kVA is compulsory). This option is of benefit if those consumers can manage their load during peak winter demand times and also incentivises the reduction of fused capacity. The consumer can choose what level of supply they require and will be charged accordingly - noting that the winter demand charges are set in the winter and applied for the following 12 months from 1 October each year.

The NEL pricing structure has remained stable for a number of years. The structure promotes stability and certainty. This does also minimise the transaction costs for retailers. Pricing is transparent and all retailers have access to and are charged the same line charges for each different classification of consumer. NEL has also taken into account retailer feedback into line charges. An example is the removal of a ripple control charge which was not part of the consumer’s line charge and was charged on a per retailer basis. The charge was rolled into the consumer line charges, this assisted retailers in reducing transaction costs.

Overarching the network pricing is that NEL takes into account the requirements of its stakeholders. These are as follows:

Stakeholder	Interests
Electricity Customers	Delivery of a safe, reliable, efficient and sustainable supply of electricity at minimum cost. Surveys across the board say that most consumers do not want to pay more for a more reliable network.
Electricity Retailers	Delivery of a safe, reliable, efficient and sustainable supply of electricity at minimum cost. Diverse views on pricing options / standardisation and transparent pass through.
Government (Ministry of Innovation and Economic Development, Commerce Commission, Electricity Authority)	Legislate and control compliance of statutory requirements and economic efficiency.
Landowners	Landowners with NEL assets on their property have interests in safety, easements and access requirements.
Property Developers	Property developers wish to ensure that connection policies and costs are fair and that network expansion plans are timely.
Shareholders	Achievement of an adequate return on investment and good corporate citizenship.
Territorial Local Authorities	Territorial authorities have interests in minimising environmental impacts, development of underground power systems, local economic development and in the control of assets in road reserves.
Transit NZ	Transit NZ are interested in controlling assets in road reserves.
Transpower	NEL relies on the Transpower grid to deliver electricity through to the NEL network and Transpower relies on the NEL network to deliver the electricity to end use customers.

Stakeholder interests have been identified and accommodated in the pricing of line charges through the following processes:

- The NEL Board of Directors agrees to an annual Statement of Corporate Intent which details corporate strategy with respect to pricing.

    - To ensure the Company complies with all legislative requirements including health and safety legislation and all industry initiatives in respect of public safety and health and safety in the workplace;
    - To operate as a successful business in the distribution of electricity and other related activities;
    - To have regard among other things the desirability of ensuring the efficient use of electricity;
    - To ensure that all services and responses to maintenance and fault requirements are provided with an appropriate standard of customer service;
    - To maintain existing levels of reliability;
    - To have consideration of the consumer for price and quality;
    - To improve operational efficiency and productivity;
    - To adopt non-discriminatory pricing and network access policies for all users of the NEL network;
    - To ensure that all resources, financial, physical, and human are utilised efficiently and economically;

- To achieve a commercially acceptable return and to seek to maximise the longer term value of shareholder's funds;
- To provide for future development of the network through investigation and the acquisition of land and physical assets as is appropriate;
- To ensure the company complies with all legislative requirements including health and safety legislation, and all industry initiatives in respect of safety in the workplace;
- To be a good employer providing;
  - ✦ Remuneration consistent with performance,
  - ✦ A safe, satisfying and stimulating work environment,
  - ✦ Equal employment opportunities.

- Corporate organisational goals and objectives support the pricing methodology consistent with the corporate mission.

"Nelson Electricity's principal mission is to own and operate the electricity network within the central Nelson area commensurate with appropriate standards of maintenance and reliability of supply whilst maximising shareholder value and providing a commercially acceptable return."

- Regular surveys of residential, commercial and large user customers provide valuable feedback on pricing, security and reliability of supply which assists in network planning, and on the price-quality trade-off. The key outcome is the majority of consumers are happy with current quality and don't want to pay any more for improved quality. Consumers also are not willing to subsidise the line charges of those investing in new technologies.

- Government and territorial authority legislation provides a key input into the way pricing is set.

Any conflicting stakeholder interests are managed by systems that ensure that appropriate levels of separation, accountability and authority are in place. Pricing decisions are ultimately made at Board level with appropriate supporting evidence and recommendations from the General Manager.

3. Distribution Network Characteristics

NEL is supplying the following types of connections:

- Unmetered/Builders temporary - 47
- Residential – 7,673
- Small / Medium business – 1,393
- Larger Business (Time of Use) – 94

NEL pricing combines the residential and small/medium businesses (Load Group 2) for the purposes of pricing as the load characteristics are similar. The Electricity (Low Fixed Charge Tariff Option for Domestic Consumers) Regulations 2004, require NEL to have a low fixed charge option for residential consumers using less than 8,000kWh per year (Load Group 1), which does result in some cross subsidisation between the two groups 1 and 2.

The network is centred on the business district of Nelson City and also the Port area, it has a larger proportion of business connections compared to most other networks in New Zealand as a result the network peaks are typically experienced in the morning instead of early evenings. The NEL network peaks are highest during the colder winter mornings when business load increasing to start the day and residential is dropping off after the morning breakfasts and showers, there is also a considerable level of electrical heating load as well.

NEL is a small network and, as such, it is assessed that there is no benefit in segmenting into different pricing areas. The prices are applied evenly across the whole network.

The NEL network is surrounded geographically by the Network Tasman network to the north and south. There is the ability for a very small number of consumers to bypass the NEL network where the neighbouring electrical infrastructure is nearby. The cost to bypass in almost all situations is uneconomic given the cost to install network infrastructure versus the payback through any potential reduced line charges. NEL would review any instance of potential uneconomic bypass and if necessary look at a non-standard pricing arrangement.

4. Discussion on the Existing Pricing Regime

The existing NEL delivery pricing has been developed and modified to cater to the changing dynamics of the network and to ensure there is fair allocation of costs applied to all consumers where possible. Given the network is small geographically, there is no real benefit to have multiple pricing regions. NEL as an Electricity Distribution Business sells capacity, the ability for electricity retailers to supply consumers with electricity. The consumer capacity limit is based on the fuses at the network connection point. The larger the fuses the greater the capacity available to the consumer at any time which potentially leads to higher capacity network infrastructure requirement to supply the network connection point.

Time of Use

The Time of Use pricing is for larger commercial connections. The pricing regime has not materially changed since its introduction in the early 1990s. The delivery prices are split into five separate categories and priced accordingly so to ensure as much as possible that the larger consumers are paying their fair share of delivery costs and with minimal cross subsidisation. The delivery prices in this group are clear and targeted which should incentivise the consumer to alter behaviour to minimise its delivery charges which will assist in optimising and maximising the utilisation of the network.

For Time of Use consumers the pricing is centred on the connection capacity (size of fuses or transformer) and contribution to the network and transmission peak demand. The consumer has the ability to change both of these to reduce their overall delivery charges and also assist in making the network more efficient. Given the pricing option has been in place for over 20 years most of the efficiency gains have already been achieved in this group.

The weighting of the pricing categories has been modified over time to cater to the changing pricing signals required for the load group to match changing costs.

Mass Market

All commercial and residential consumers (except consumers on the low fixed charge tariff option) have been grouped together to optimise the mass market pricing. There used to be a pricing differential between business and residential consumers but over time this differential was reduced and finally removed in 2009. It made it possible to link the two consumer groups together as it is also now extremely difficult to differentiate between the two groups where often there are businesses operating from home or bed and breakfasts as examples.

The linking of the groups also reduced the number of published line prices and simplified the pricing to be disclosed making it easier for retailers to administer NEL's prices and consumers easier to understand.

NEL also wanted to incentivise larger mass market consumers to optimise their electrical consumption and capacity. This was achieved by changing the fixed daily price which was a one size fits all to a price based on actual fuse size. This means the larger mass market consumers pay a fixed delivery price based on their connected fuse size which is their ability to consume a higher electrical demand. They also have the ability to reduce their fuse size (free of charge) if they can change their load consumption behaviour. This delivery price option has proved successful with many consumers opting to have their fuse sizes reduced which then provides for reserved network capacity to be utilised elsewhere.

Larger consumers in this group can also opt to go on to the Time of Use tariff if there is a benefit for them to manage their load further. This option is, however, seldom taken up. There is more of a migration from Time of Use tariff to mass market and this is a result of the retail pricing options rather than the NEL's delivery prices.

Electricity (Low Fixed Charge Tariff Option for Domestic Consumers) Regulations 2004

One complication with the capacity based fixed delivery price is the Electricity (Low Fixed Charge Tariff Option for Domestic Consumers) Regulations 2004 which means that a residential consumer using less than 8,000kWh must have access to a fixed delivery price of at most 15 cents per day. To comply with this regulation and to minimise delivery price options, NEL has assessed all residential consumers fuse capacity at 15kVA. Currently a residential consumer with a larger fuse size is only paying the standard price of the typical 15kVA connection.

The compounding effect is that the average residential consumer on the network currently uses approximately 6,750 kWh per year (based on 2015 consumption analysis) compared to 7,400kWh per year in 2008. This is 15% lower than the deemed average consumer as determined under this regulation. This exposes NEL to more cross subsidisation as more consumers switch to this price option. Of concern to NEL is currently up to 70% of all residential consumers would benefit from being on the Low Fixed Charge option (Group 1).

NEL is exploring options to remedy this issue to minimise the cross subsidisation that this regulation has created as it undermines the ability to adapt prices for changes in the network utilisation characteristics. Currently the consumers on Group 2 and Group 3 are subsidising the consumers on Group 1.

5. Changes to the 1 April 2018 Pricing

The NEL line charges will be changing 1 April 2018.

There is only one new price being introduced for Group 3 (Large Commercial) consumers in the delivery price schedule. For consistency across all Load Groups a Distributed Generation price for kWh exported onto the network has been in place for Load Groups 1 and 2 since 2014 and has now been introduced to Group 3 (Large Commercial). The price level will be the same for all three Load Groups. The Distributed Generation price was introduced to capture some of the incremental costs of these installations including safety audits at the network connection points and any isolations required when undertaking planned outages on the network. The site is checked to ensure the voltage is within the regulatory limits and that the site does not inject into network when street supply is lost.

There have been some terminology changes as described in Section 10 due to NEL preparing this disclosure document in line with the Electricity Networks Association – Pricing Guidelines for Electricity Distributors - 2016.

The new delivered line prices from 1 April 2018, as included in Section 11, will be decreasing by approximately 2.0% overall.

6. Derivation of Line Prices

The Derivation of Line Prices are described in the following sections:

- Customer Groups;
- Customer Group Statistics;
- Allocation and Recovery of Network and Transmission Charges;
- Cost Recovery per Load Group;
- Fixed versus Variable Charges.

Consumer Groups or Load Groups

NEL has split its consumers into five distinct consumer groups/load groups to assist in the fair allocation of costs and setting line price levels. The Groups are based on the type of connection which considers typical load patterns, fuse size and annual kWh consumption. The number of groups is set at five as a balance between minimising complexity and ensuring costs are appropriately apportioned between consumers. The groupings are relatively in line with other electricity networks in New Zealand.

- ***Load Group 0***
  Unmetered Load or Metered Builders Temporaries - this group is for the smaller/lower fused connections (under 15kVA) either metered or unmetered that do not fall into the other groups as listed below. Most of the connections are either metered builders temporary supplies or small unmetered supplies to telephone boxes and streetlights. This group has smaller connections with differing load characteristics so a fair allocation of costs is difficult to demonstrate but the overall revenue of this group is only 0.05% of total revenue (excluding local council streetlights), so they are grouped together.

- ***Load Group 1***
  Residential Consumers Low Fixed Charge Option – connections that are a residential home that exhibit a typical residential load profile using less than 8,000kWh per year. A residential connection is where electricity is supplied to a premise that is used or intended for occupation by a person principally as a place of residence. It does not include premises that constitute any part of premises described in Section 5(c) to (k) of the Residential Tenancies Act 1986 (which refers to places such as jails, hospitals, hostels, hotels, and other places providing temporary accommodation). The connection size is set at 15kVA. The Nelson Electricity Limited (NEL) Network Code allows for single phase 60amp, two phase 40 amp or three phase 30amp supplies to be classed as a residential connection. A residential type load profile not on the Low Fixed Charge option are typically categorised as Load Group 2.

- ***Load Group 2***
  Residential and Small Business Consumers – connections that are 15kVA up to 150kVA. Residential consumers not on Low User Option are also in this group. The residential and commercial consumers are grouped together as much as Electricity (Low Fixed Charge Tariff Option for Domestic Consumers) Regulations 2004 allow. Electricity networks key costs are driven based on capacity (the ability for a consumer to take as much electricity up to the fused capacity at the network connection point). While there is a difference in load profile from a typical business and a domestic connection it is proving more difficult as time goes on to differentiate between the two as many connections are a mixture of the two. To avoid complications in grouping allocations and number of tariffs, Load Group 2 joins the two consumer types together. By doing this it has removed any price discrimination which existed when commercial and residential were grouped separately.

- ***Load Group 3***
  Large Commercial Consumers with supply up to 2400kVA - this group is for any connection with a supply up to 2400kVA that wants to be on a Time of Use tariff. Time of Use tariffs were first offered to consumers in the early 1990s and the early rationale for the consumer being in this Group was if they used greater than 50,000kWh per year. The kWh requirement has since been removed and a mandatory requirement of connections with a capacity of greater than 150kVA to be Time of Use was introduced. Those below that limit can opt to be on Load Group 2 or Load Group 3. This group is ideal for consumers that have the ability to manage their peak demand to minimise line charges as the line charge regime for this group more accurately reflects the consumer's fair allocation of costs.

- ***Load Group 4***
  This group is for the largest commercial consumers on the network. Consumers with capacity supplied of greater than 3000kVA with supply from dedicated 11kV/400V substations.

Consumer Group Statistics

Statistics are collected and analysed as per the customer groupings as described in the previous section. This information is used as a base to NEL's pricing allocations as described further in this report. Information used for the 2018-2019 year is as follows:

- Number of Connections per group.

Number of Connections

Load Group	Connections
0	**47**
1	**3739**
2	**5327**
3	**93**
4	**1**
Total	**9,207**

- Anytime Peak per group.

Anytime Peak

Load Group	Peak kVA
0	250
1	12,713
2	21,308
3	12,840
4	3,110
Total	50,221

This is an assessment of each connections peak demand grouped into the five load groups.

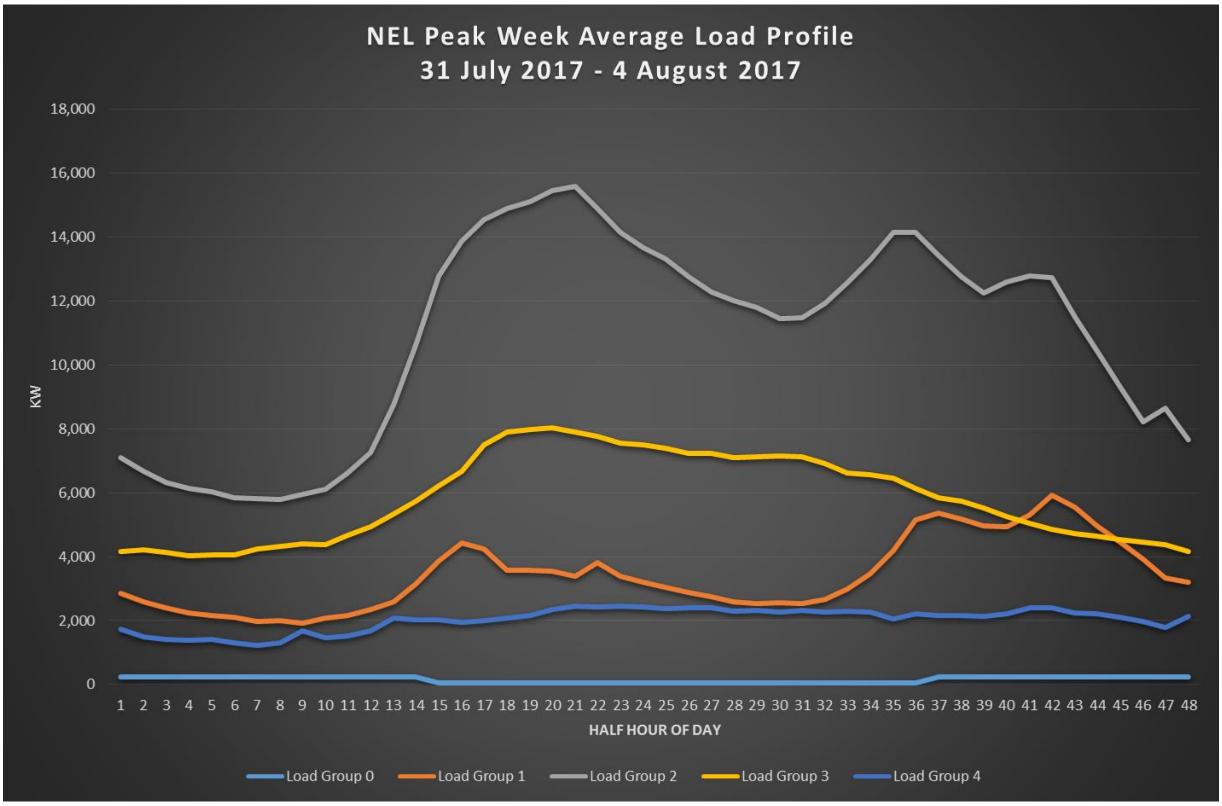
- Winter Demand Peak per group.

Control Period Demand (Winter Demand)
kVA

Load Group	8:30 am - 11:30 am	5:00 pm - 6:00 pm	CPD Allocation
0	57	256	137
1	4,331	5,861	4,943
2	17,724	16,089	17,070
3	9,148	7,333	8,422
4	2,790	2,505	2,676
Total	33,993	31,788	33,248

NEL has a winter load that peaks between 8:30 am - 11:30 am and 5:00 pm - 6:00 pm. The morning load is predominantly commercial load with the morning residential load dropping off and the evening peak is typically influenced by the residential load with the commercial load dropping off. The statistics required are to ensure the right pricing signals are sent to each group and that charges are as fair and equitable as possible to all connections. The Winter Demand is a critical part to the allocation of Transmission Costs between groups. It is also important when allocating costs for local network in allocating costs based on load group contribution to peak demand and maximum loading on assets.

The graph below shows the average peak winter load profile for the highest consumption week Monday 31 July 2017 – Friday 4 August 2017.



- GWh per group.

GWh

Load Group	Winter	Summer	Total
0	**0.47**	**0.50**	**0.97**
1	**9.91**	**9.15**	**19.06**
2	**31.16**	**30.55**	**61.71**
3	**19.33**	**24.91**	**44.24**
4	**5.91**	**6.74**	**12.64**
Total	**66.77**	**71.85**	**138.62**

These figures are estimated consumption per Load Group with no loss allocation back to GXP. Winter months are May – September, summer months are October – April. This is consumption only and is not offset by any distributed generation. The total consumption exported onto the NEL network for the year ending February 2017 was 0.24 GWh compared to 0.22 GWh for the previous 12 months.

- Regulatory Value of System Fixed Assets as at 31 March 2017 per group allocation

	Regulatory Value of System Fixed Assets					
Asset Group	**0**	**1**	**2**	**3**	**4**	**Total**
33kV Lines	**$32,765**	**$793,550**	**$2,641,218**	**$1,636,931**	**$485,879**	**$5,590,343**
Zone Sub	**$58,555**	**$1,418,197**	**$4,720,270**	**$2,925,452**	**$868,342**	**$9,990,817**
11kV Lines	**$38,063**	**$921,871**	**$3,068,319**	**$1,901,633**	**$564,449**	**$6,494,334**
11kV/400V Sub	**$35,180**	**$1,008,841**	**$3,343,657**	**$1,406,078**	**$208,678**	**$6,002,435**
400V Lines	**$54,773**	**$1,841,077**	**$6,081,407**	**$1,368,248**	**$0**	**$9,345,505**
Other	**$22,403**	**$542,602**	**$1,805,973**	**$1,119,277**	**$332,227**	**$3,822,482**
Total	**$241,739**	**$6,526,138**	**$21,660,845**	**$10,357,618**	**$2,459,576**	**$41,245,917**

Regulatory Asset Base Valuation allocation is assessed on each load group's utilisation of assets. As an example, Group 4 does not utilise any of the 400V lines so there is no value assigned.

- Cost of Capital

For the financial year commencing 1 April 2018 Nelson Electricity being a price controlled EDB, has used the Commerce Commission's WACC for the five year DPP price control period 1 April 2015 -31 March 2020. This 7.19% set at the 67th percentile (midpoint 6.72%).

The parameters used by the Commission in setting WACC are:

Parameters used to calculate vanilla WACC for EDB DPP and Transpower IPP (for the period commencing from 1 April 2015)

Parameter	Estimate
Risk-free rate	4.09%
Debt premium	1.65%
Leverage	44%
Equity beta	0.61
Tax adjusted market risk premium	7.0%
Average corporate tax rate	28%
Average investor tax rate	28%
Debt issuance costs	0.35%
Cost of debt	6.09%
Cost of equity	7.21%
Standard error of debt premium	0.0015
Standard error of WACC	0.011
Mid-point vanilla WACC	6.72%

Note: The cost of debt is calculated as the risk-free rate + debt premium + debt issuance costs. The cost of equity is calculated as the risk-free rate × (1- investor tax rate) + the equity beta × the tax adjustment market risk premium. The mid-point vanilla WACC is calculated as the cost of equity × (1 - leverage) + the cost of debt × leverage.

On the basis of the above input parameters, the NEL Weighted Average Cost of Capital (WACC) is 7.19% of Regulatory Asset Base = $2,966,000.

Allocation and Recovery of Network and Transmission Charges

Network Charges are set to recover indirect operating costs, direct operating costs, depreciation and cost of capital. The setting of the charges also takes into account historical charging practices and methodologies.

The company annual revenue requirements for 2018-2019 are:

Operating Costs (Network R&M)	$738,000
Transmission Costs	$3,254,000
Overhead Costs	$1,736,000
Depreciation	$1,521,000
Target Return (before tax)	$2,583,000

With NEL being a small predominantly urban network there was no need to sectionalise it into separate pricing areas. There is, however, one rural uneconomic line supplying a small number of consumers of which a separate pricing option is being considered.

Cost Recovery per Load Group

Following is a table outlining the cost recoveries per load group.

Load Group	Operating	Transmission	Overhead	Depreciation	Target Return	Total
0	$54,329	$19,226	$8,752	$8,914	$17,939	$109,161
1	$114,357	$486,538	$572,220	$240,660	$372,726	$1,786,502
2	$379,766	$1,680,179	$870,491	$798,773	$1,531,300	$5,260,510
3	$160,828	$814,406	$230,691	$381,951	$637,712	$2,225,589
4	$29,403	$254,593	$53,847	$90,700	$23,902	$452,445
Total	$738,684	$3,254,943	$1,736,000	$1,521,000	$2,583,580	$9,834,207

The methodology used for the above cost apportionment is as follows:

Operating Costs – Operating costs is the Operational Expenditure Budget that covers both the planned and unplanned network R&M expenditure on the network. The Operational Expenditure Budget is split into the different asset types as per the Regulatory Asset Value of System Fixed Assets table groups. The asset group expenses are then allocated to each load group first based on whether the Group utilises that class of asset (eg; Group 4 does not utilise the 400V network so does not contribute towards those associated costs) then through the assessed balance of each groups kWh consumption (60%) and Winter Demand contribution (40%). This percentage allocation attempts to provide a balance between a Groups peak demand utilisation and overall usage. Some re balancing is required for load group specific costs, eg; Group 0 where actual Council streetlighting associated maintenance costs of $40,000 are directly allocated to the associated tariff, this allocation is offset against Group 1 and 2 apportioned based on kWh.

Regulatory Value and Operating Cost Percentage Allocation						
	0	1	2	3	4	Total
33kV Lines	0.59%	14.20%	47.25%	29.28%	8.69%	100.00%
Zone Sub	0.59%	14.20%	47.25%	29.28%	8.69%	100.00%
11kV Lines	0.59%	14.20%	47.25%	29.28%	8.69%	100.00%
11kV/400V Sub	0.59%	16.81%	55.71%	23.43%	3.48%	100.00%
400V Lines	0.59%	19.70%	65.07%	14.64%	0.00%	100.00%
Other	0.59%	14.20%	47.25%	29.28%	8.69%	100.00%

Operational Cost Allocation						
Asset Group	0	1	2	3	4	Total
33kV Lines	$213	$5,167	$17,197	$10,658	$3,164	**$36,398**
Zone Sub	$253	$6,133	$20,413	$12,651	$3,755	**$43,206**
11kV Lines	$396	$9,600	$31,952	$19,803	$5,878	**$67,629**
11kV/400V Sub	$630	$18,077	$59,915	$25,196	$3,739	**$107,558**
400V Lines	$1,968	$66,162	$218,546	$49,170	$0	**$335,847**
Other	$868	$21,015	$69,946	$43,350	$12,867	**$148,046**
Sub Total	$4,329	$126,155	$417,969	$160,828	$29,403	**$738,684**
Reallocation	$40,000	-$9,438	-$30,562			**$0**
Total	$44,329	$116,717	$387,407	$160,828	$29,403	**$738,684**

- Transmission Costs – Transmission costs are an unavoidable cost, it covers the upstream costs from our sub-transmission connection points at STK0331. The major component in transmission costs is the Interconnection charge -Regional Coincident Peal Demand (RCPD) of the top of the south. Transmission peaks are typically encountered during the winter period. Transmission costs are apportioned based on each groups influence. This is achieved through peak demand analysis of each group as is being applied through transmission pricing. Groups 0, 1 and 2 currently recover transmission costs 100% via the kWh charge and for Groups 3 and 4 via a mixture of winter control period demand charge (45%) and a kWh charge (55%).

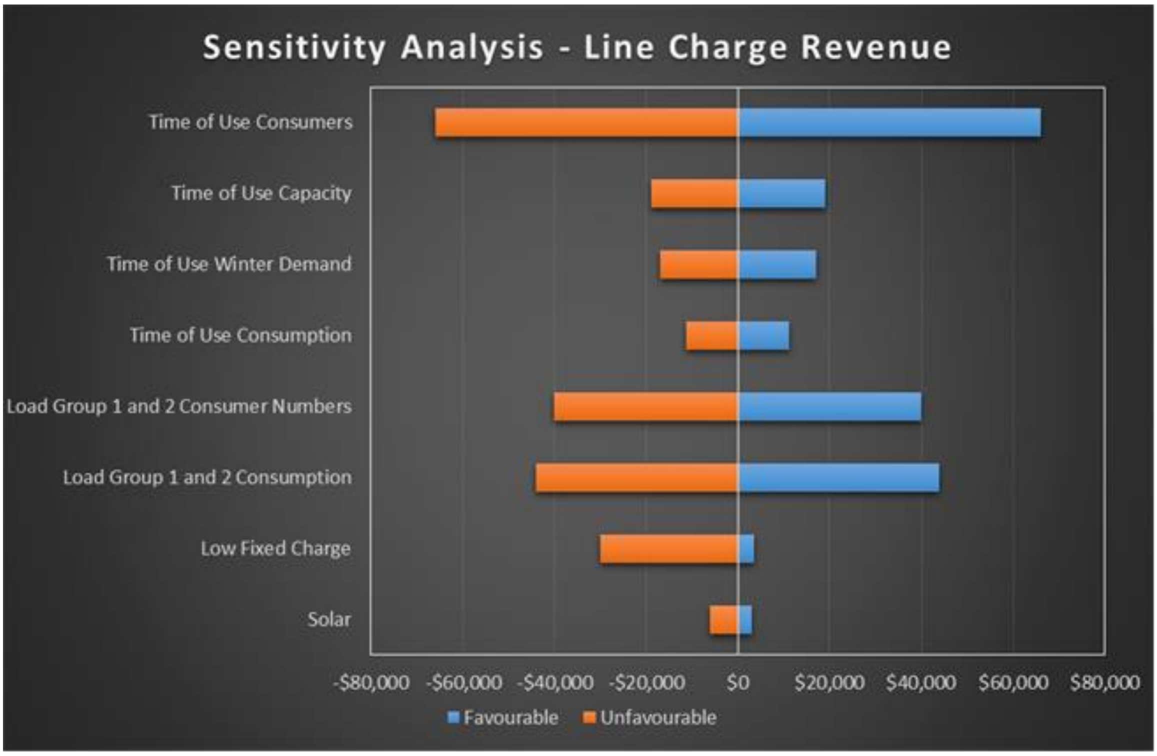
- Overhead Costs – Are apportioned by using two measures; the number of network connections and the maximum demand of the load group. This gives a balance of spreading overhead costs between the business of selling capacity and the number of consumers connected.

- Depreciation – This is apportioned by using the assessed depreciation using the NEL Regulatory Asset Base model as a base and follows the same rationale as Operating Costs (except without re-allocation of Load Group specific costs).

- Target Return - This is apportioned to load groups as per the Regulatory Asset Base % split per load group as per the rationale of the operating costs. It is, however, important to note that the Regulatory Asset Base valuation for assets installed prior to 2004 still undervalues the underground network value and so the target return takes this into account.

Sensitivity Analysis

The NEL revenue estimate for 2018-2019 is $9,834,000. There is a potential annual revenue variation of 2.25% or a range from $9,600 to $10,050 for the year.



Fixed versus Variable Charges

The proportion of charges that are deemed by NEL as fixed or variable have been set based on the historical pricing methodologies. NEL has maintained a pricing mix that has been consistent for well over 10 years and as this pricing methodology has worked well, there has been no compelling reason to change the proportions to any significant degree other than a minor incremental shift to a higher proportion of fixed prices when there is a pricing change.

The only major variation in price has been the provision of a low fixed charge price option for Residential consumers as required under the Electricity (Low Fixed Charge Tariff Option for Domestic Consumers) Regulations 2004. This introduces a cross subsidisation, which the pricing structures of previous years had been designed to remove.

Currently overall the proportions between fixed and variable line charges are 53% Fixed and 47% Variable, this compares to 50% Fixed and 50% Variable in 2007. Groups 1 and 2 have a higher variable proportion while groups 3, 4, and 5 have a higher fixed proportion. Refer to the table below.

Fixed Versus Variable	Fixed		Variable		Total
	%	$	%	$	$
Group 0	100%	$108,648	0%	$513	$109,161
Group 1	12%	$212,628	88%	$1,573,873	$1,786,502
Group 2	51%	$2,664,283	49%	$2,596,227	$5,260,510
Group 3	78%	$1,725,262	22%	$500,327	$2,225,589
Group 4	100%	$452,445	0%	$0	$452,445
Total	**53%**	**$5,163,266**	**47%**	**$4,670,940**	**$9,834,207**

It has to be recognised that consumer behavior as a response to network pricing is limited. The line price revenue represents only 30% of the total electricity invoice consumers receive from electricity retailers so unless a network can significantly amplify or exaggerate the pricing differential levels then the consumer behavior will be based on what the electricity retailer wants to achieve.

NEL is in the business of selling electrical capacity to consumers and most of its costs as identified in Section 6.4 are fixed. If the true proportion of fixed and variable costs were charged in the same proportions to all consumers, the fixed charge proportion of Groups 0, 1 and 2 consumers would increase significantly with the variable charges reduced. The incremental cost of any consumer using more kWhs, while not increasing their peak demand, is extremely low compared to a consumer wanting more capacity which there is a cost associated with the increases in peak demand.

For further breakdown on the revenue influence of specific prices, refer to Section 12 Price / Quanitity / Revenue Schedule.

- **Load Group 0 – Unmetered and Builders Temporary**
  Builders Temporary (metered) - Network costs are broken down into the following:

  - Daily Price (Fixed)
  - Uncontrolled kWh Price

  For the average Builders Temporary, fixed prices recover approximately 60% of total network costs.

  Unmetered Supply – Network costs are fully fixed with no variable component.

  Load Group 0 prices are predominantly fixed given that the low consumption does not make metering practical or economic for retailers in most cases. The only metered load in Group 0 is for builder's temporary connections. This type of connection is in Group 0 as the fuse size is low (limited to single phase 30 amps), the consumption is typically low, the load characteristics don't fit other load groups and the revenue impact is low.

- **Load Group 1 – Residential Consumers (Low Fixed Charge Option)**
  Network costs are broken down into the following:

  - Capacity Supplied Price is based on connection capacity of 15kVA
  - Variable kWh Price. This price value depends on whether the load is controlled by ripple control or uncontrolled. The controlled prices are lower than the uncontrolled price as NEL can ensure they are turned off at peak times, therefore, reducing peak demand associated costs. The main peak time cost is the transmission, which ultimately accounts for 33% of the total line charge revenue. There are two controlled options:

    a. Controlled (Hot water) – This is a key network control option to control supply to all hot water cylinders on the network. This can manage up to 10% of network load at peak demand times approximately 3MW. Typically supply is only controlled during the winter peak demand times to minimise transmission costs. Also used for other emergency load management purposes.

b. Night Only - This is an option for consumers that can utilise electricity in off peak times between 11pm and 7am, typically used for larger hot water cylinders and night storage heaters.

- Distributed Generation - A price is included based on kWh exported onto the NEL network. This price recovers some of the costs associated with the auditing and safety aspects of the distributed generation connection.

For the average Group 1 customer, fixed prices recover approximately 12% of total network costs.

This Group exists to comply with the Electricity (Low Fixed Charge Tariff Option for Domestic Consumers) Regulations 2004. Any eligible residential consumer can opt to be in this group. There are approximately 200 - 300 consumers per year shifting from Group 2 to Group 1. The average annual residential consumption is also reducing and for NEL it is now approximately 6,750 kWh per year and still reducing.

- **Load Group 2 – Connections from 15kVA – 150kVA (Residential and Commercial)**

Network costs are broken down into the following:

- Capacity Supplied Price. (based on fuse capacity (in kVA))
- Variable kWh Price. This price value depends on whether the load is controlled by ripple control or uncontrolled. The controlled tariff rates are lower than the uncontrolled rate as NEL can ensure they are turned off at peak times, reducing peak demand associated costs. The main peak time cost is the transmission, which ultimately accounts for 33% of the total line charge revenue. There are two controlled options:

a. Controlled (Hot water) – This is a key network control option to control supply to all hot water cylinders on the network. This can manage up to 10% of network load at peak demand times approximately 3MW. Typically supply is only controlled during the winter peak demand times to minimise transmission costs. Also used for other emergency load management purposes.

b. Night Only - This is an option for consumers that can utilise electricity in off peak times between 11pm and 7am, typically used for larger hot water cylinders and night storage heaters.

- Distributed Generation - A price is included based on kWh exported onto the NEL network. This price recovers some of the costs associated with the auditing and safety aspects of the distributed generation connection.

For the average Group 2 customer, capacity based charges recover approximately 51% of total network costs. All residential and business consumers are eligible from 15kVA up to 150kVA. It is designed so that the larger the fuse at the network connection point then the higher the fixed charges. The variable charges remain unchanged.

This Group has a price design to encourage consumers to manage their electricity use by providing an incentive to lower fused capacity. There is one current limitation with this design due to the Electricity (Low Fixed Charge Tariff Option for Domestic Consumers) Regulations 2004. The regulation ensures that for every pricing option a residential consumer can be eligible for, there must be a pricing option they can shift to that meets the requirements of the regulations eg; fixed daily charge of no greater than 15 cents per day. To meet the regulation NEL would require a significant increase in line pricing options by 40 (one set of four for each of the 10 potential fuse size combinations). To comply with the requirements and remove the potential complexity, the residential consumers in Group 2 (3,972) currently have their fused capacity set at 15kVA while non-residential (1,398) have capacity based on actual fuse size.

- **Load Groups 3 – Large Commercial**
  This Price Group is designed for the larger installations on the network. These sites must have Time of Use metering installed. NEL can set network prices based on the individual sites configuration and usage pattern more accurately. The prices in this category are explained below.

  1. **Metered Installation**. This is a fixed priced per connection, designed to capture the fixed network admin costs associated with each connection. The value is the same no matter what size.

  2. **Winter Demand**. The Winter Demand is a $/kVA/day fixed price and is a method of apportioning transmission and network peak demand costs. The measure is the single highest half hour kVA demand recorded in the months of June, July, and August between 8.30am-11.30am and 5pm-6pm. The winter demand assessment period excludes weekends and public holidays. The winter demand value is used for billing purposes from the October month for the following 12 months until reset again the after the following winter.

  3. **Capacity Supplied**. Capacity Supplied is a $/kVA/day fixed price and is the actual size of the connection to the Network (either fuse size or transformer size). This represents the maximum demand the site can draw from the network. This charge is used to recover local network costs.

  4. **Energy**. The Energy charge is a variable price based on the total energy consumption for the connection. This is used to recover both transmission and network costs.

  5. **Power Factor**. This monthly variable price is used to encourage consumers to maintain a power factor of greater than 0.95. The charge is for the kVAr required at peak time to bring the power factor up to 0.95. A charge is not applied if power factor at peak is > 0.95.

  6. **Distributed Generation**. This in a new variable price that is for kWh exported onto the network. This recovers costs associated with the auditing and safety aspects of the distributed generation connection.

Chargeable Capacity

The following is the typical fuse size combinations and associated capacity rating accepted at a Nelson Electricity Network Connection Point. Larger connections are on a case by case basis.

Fuse Rating Table

No. of Phases	Fuse size (Amps)	kVA Rating
3	30	15
2	40	15
3	40	28
1	60	15
2	60	30
3	60	45
1	80	20
2	80	40
3	80	60
1	100	23
2	100	46
3	100	69
3	125	87
3	150	105
3	160	110
3	200	138

The two phase 40 amp and three phase 30 amp supplies are assessed at the minimum capacity of 15kVA.

Changing Pricing Plan Limitations

Where a consumer has a choice of pricing plan NEL reserves the right to limit changes between pricing plans to one change in any 12 month period eg; NEL offers a Low Fixed Charge plan (Group 1) to qualifying residential connections and a standard plan (Group 2) for residential connections. This condition is included in the Use of System Agreement for the purposes of managing the risk of consumers shifting principally between the regulatory imposed Group 1 Pricing and the Group 2 Pricing to take advantage of the summer/winter differences.

7. Future Changes

Background

The old electricity supply model is starting to change from the one connection to the transmission grid and the network supplying thousands of electricity users, to many sources of electricity supply with distributed generation and batteries supplying the many electricity users. This can ultimately create an "uber type" market where electricity users may be able to sell/trade excess electricity to their neighbours. The important enabler is a robust electricity network that can cater to the changing consumer requirements.

NEL has been indicating that current network pricing needs to be reviewed given the rapid changes in the emerging technology space. The key technologies are:

- **Advanced Metering** – Provides electricity users the opportunity to make informed choices about their electricity use. The one size fits all approach with one meter reading every two months will disappear.

- **The Internet of Things (IOT) -** The network of physical devices, buildings and other items - embedded with electronics, software, sensors, and network connectivity that enables these objects to collect and exchange data.

- **Distributed Generation including Solar PV** – Providing electricity users a method of generating their own electricity.

- **Batteries** – Providing electricity users the ability to manage their electricity use through storage.

- **Electric Vehicles** – A new electrical load that can provide a lower cost means of transport.

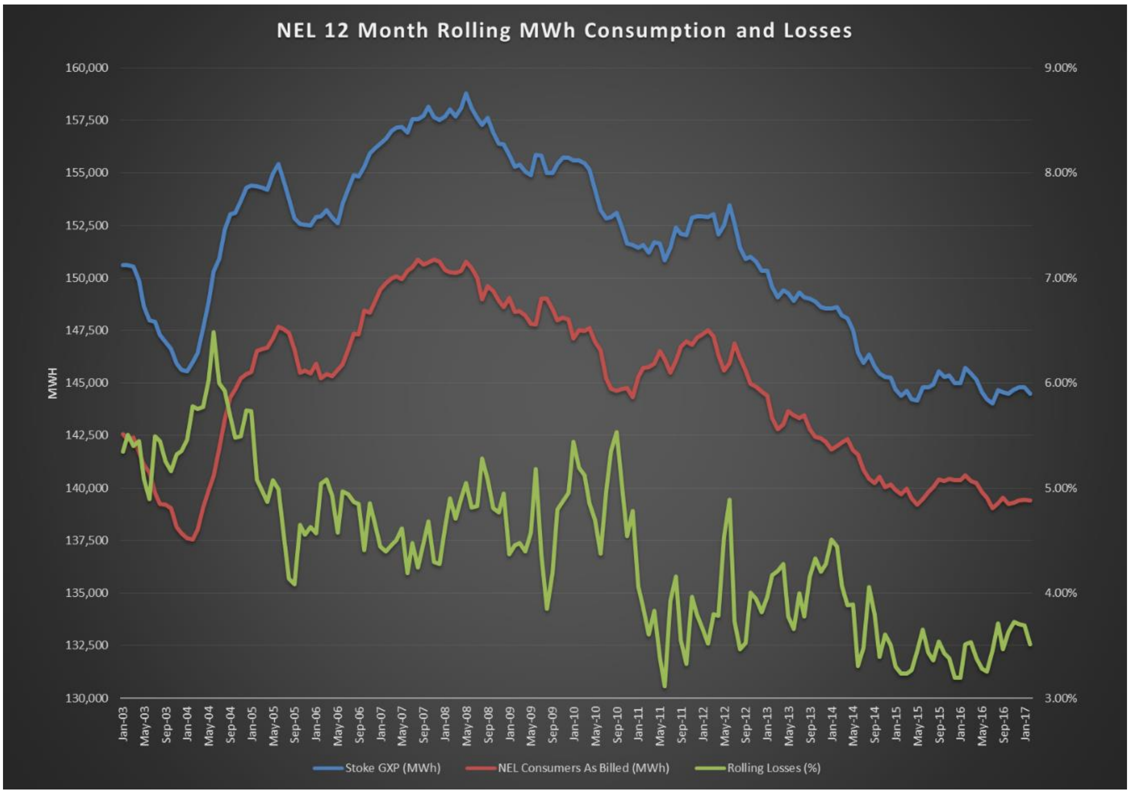
These technologies, particularly when used together, provide electricity users the ability to manage their electricity to their own personal advantage. Depending on their needs and pricing signals they react to, may or may not assist the network. There will also be a range of customer reliance on the electricity network from most that are 100% reliant to those who will use the network only as a backup option. Any new pricing structure needs to cater to both and all in between.

The electricity consumer will ultimately decide on the future viability and shape of the electricity network as they start to take advantage of these changes. It is clear to NEL that a new pricing methodology needs to be implemented that will stand the test of time taking into consideration these upcoming influences/changes. It will show a level of predictability/consistency to ensure that electricity users can make informed choices when deciding on investing money into any of these technologies and also how and when they utilise electricity from the network.

NEL is mindful of the magnitude of the change and as such has invested itself heavily into the review of technologies, consumer behaviour and pricing options. This has been achieved principally through working with both shareholders and also the ENA Distribution Pricing Working Group (DPWG) as well as keeping up to date with the advances being made with the technologies.

It is critical that any new pricing needs to align with other distribution networks in New Zealand as much as possible. The DPWG is completing a paper on future pricing which provides some assistance in this regard. Unfortunately with such a significant change, it takes time and as a result the plan to introduce a new pricing regime is planned for 1 April 20120.

Current Consumption Trends

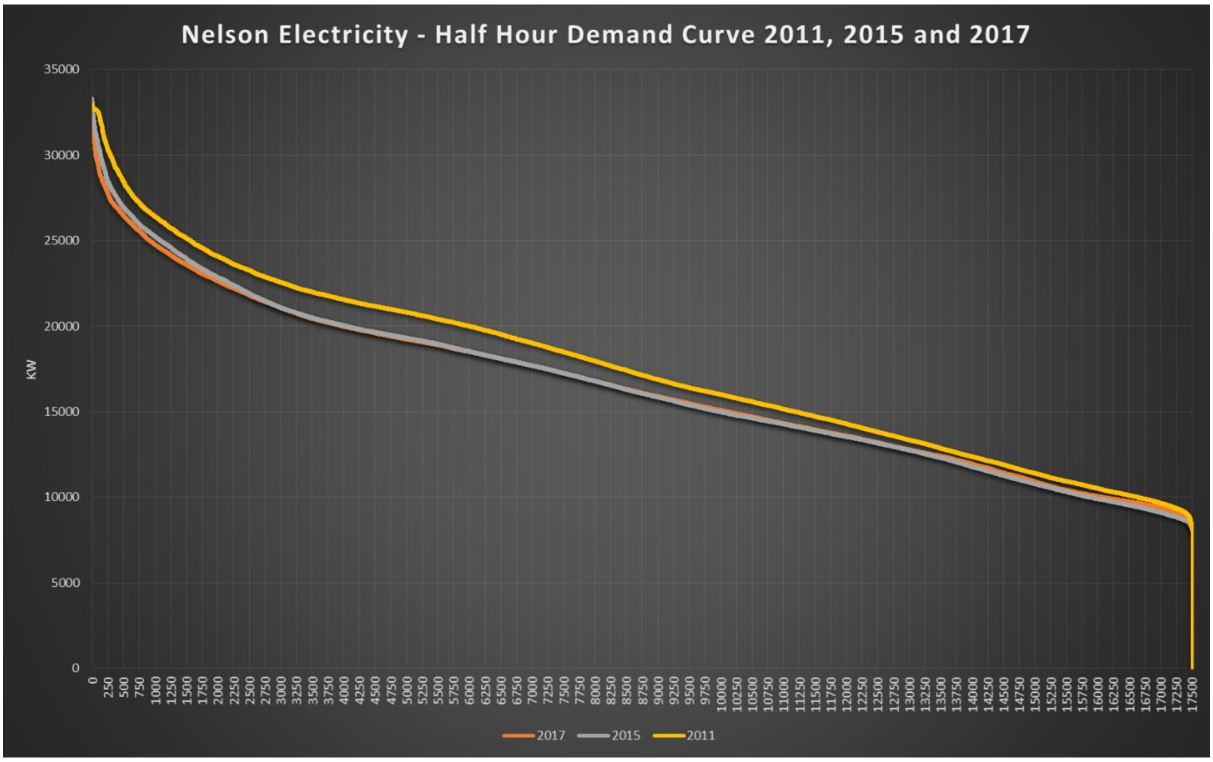


As discussed elsewhere in this document, electricity consumption on the NEL network has been declining since 2008. Analysis of all consumer groups gives some indications as to where the changes are taking effect. There is still a slow shift of residential consumers to the low user fixed charge option (Group 1). Analysis of billing reports have shown that the average residential consumption on a per consumer basis has decreased 8.8% since 2008 to approximately 6,750kWh per consumer. Other load groups are also showing a noticeable reduction in consumption. In total it is a reduction of 10GWh or 1.0% per year for eight years.

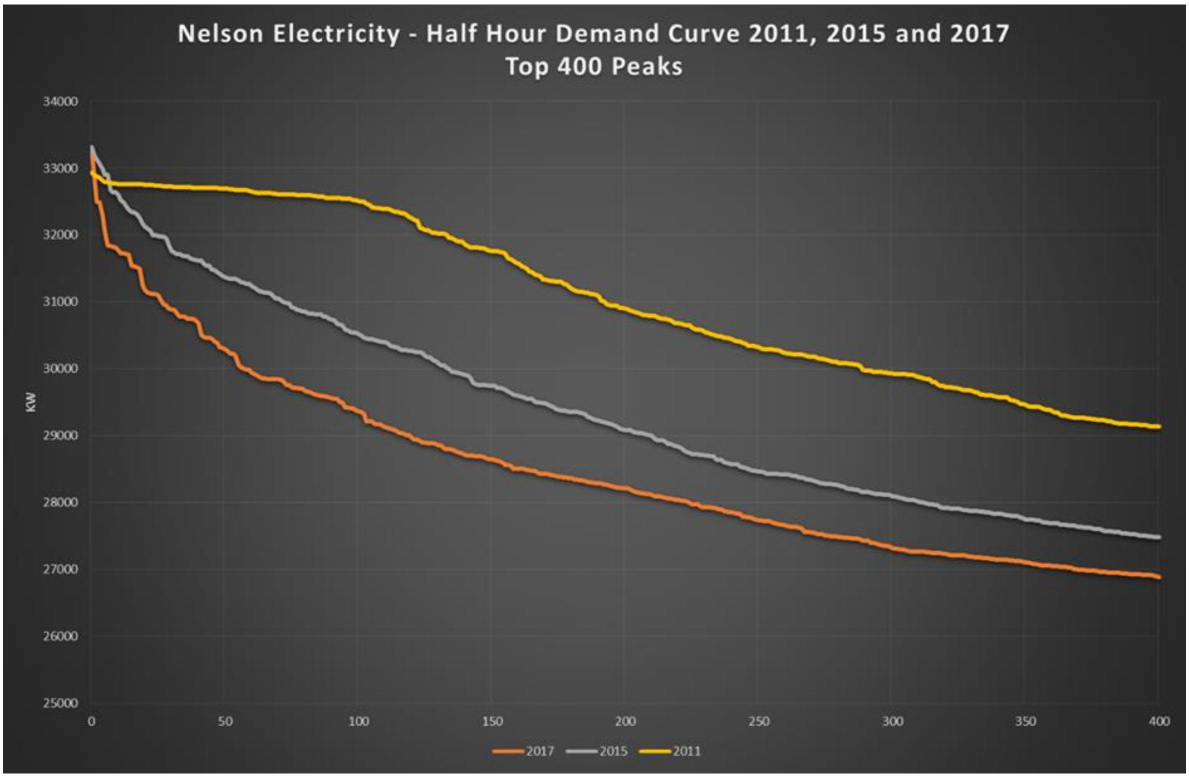
In 2014 a new 33kV feeder to Transpower and a new Zone Substation at Haven Road replacing the old substation on the same site was commissioned. The maximum available transmission / zone substation capacity with a security of supply level at n-1 for NEL increased from 35MVA up to 48MVA. The new 33kV feeder was primarily to increase feeder capacity to the network from 35MVA to 48MVA and the zone substation rated at 48MVA replaced as the equipment was reaching the end of its economic life. NEL **will have excess capacity** for the network for the foreseeable future as a result of these long term investments.

Use of load control has changed since 2014 when the new Zone Substation was completed. NEL only controls load using ripple control for minimising transmission peaks to reduce the following year transmission charges. The effect is that load control is not used as frequently as in previous years, which can mean that the network peak demand can be as high as previous years.

The half hour kW demand curve comparison graph below compares the 17,520 half hour demands for 2011, 2015 and 2017. This shows overall consumption has reduced since 2011 and that 2015 and 2017 were at similar levels.



When reviewing the top 400 peaks for each of the years 2011, 2015 and 2017 in the graph below you can see the 2011 year is influenced more by load control compared with 2015 and 2017. The 2011 top peaks flatten off where the 2015 and 2017 peaks do not. Note that in 2011 the network was constrained at the sub-transmission and Zone Substation level so load control was used extensively during the winter months. The 2015 and 2017 years have less use of load control at peak times due to the additional sub-transmission feeder and new Zone Substation in service eliminating the previous supply constraints.



Issues for Future Pricing Changes

NEL is mindful of the opportunity that in the coming couple of years advanced meters will be rolled out to the majority of electricity consumers in the Nelson area. This means there will be the increased consumption information available for consumers and provide retailers with more opportunity to introduce new price offerings, increasing pricing variations.

Given the network is now not constrained, network pricing is more about the **fair allocation of costs**. This provides electricity consumers with some price certainty when making long term investment decisions with any of the technologies mentioned in 7.0.

NEL has undertaken some work with regard to pricing structures and will be looking to implement changes when appropriate.

The development of a form of **service-based pricing** to ensure a fair allocation of costs will likely keep a fixed daily price based on fuse size or capacity but could shift away from simple kWh charges to a methodology that could focus on demand at critical times or a Time of Use pricing regime. The concept is to provide the electricity consumer the incentive to utilise electricity outside of peak demand times no matter whether they have access to new technology or not.

Introducing a demand component or a targeted time of use option while new to many will cater to the electricity consumer being able to make rational choices when investing in new technologies by providing incentives if they chose to shift electrical load out of network peak times. It has to be recognised that networks sell capacity or demand not kWhs. KWhs have been used as a proxy for demand up until now as this was the only method of measurement available with the electricity meter being read every one or two months. Advanced metering is the enabler that will provide the opportunity to make the change to include demand or targeted time of use.

There will be the complication of an increase in the number of line price options available to consumers, but this will be unavoidable. Consumers will need to be educated on the changes so they can understand the opportunities and implications.

NEL needs to minimise any potential additional cross subsidisation or price discrimination that may occur with the two types of metering (advanced metering and non-half hour) with the consumer potentially being able to opt for one or other. The ideal situation is to make any pricing change mandatory but not likely to occur so a transition period would be necessary.

Ripple control needs to be considered in any new pricing. This has been the most effective tool for networks in managing electrical load since its introduction. It is critical that this is retained. It is desirable that any new demand charging option excludes any load controlled by ripple control.

NEL needs to have a billing system that can cope with the increased data requirements. A new billing system is a key limitation to introducing new pricing options.

Pricing Issues

A pricing structure and transition plan needs to be in alignment as much as possible as other Networks. Consumers have to be taken along on the journey of the change for a smooth transition.

Electricity Retailers must also be taken along on the journey and have a billing system that can cater to the change. Also desirable to have a simple network pricing structure that compliments retailer pricing and not conflict.

The network pricing structure should be relatively simple to apply and understandable for electricity consumers.

Pricing needs to incentivise continued use of load control. Load control system is a key network tool and the benefit of this needs to be preserved.

New prices need to factor in any regulatory imposed pricing factors eg; Electricity (Low Fixed Charge Tariff Option for Domestic Consumers) Regulations 2004. There is a need to factor in any regulatory constraints when developing pricing structures and attempt to minimise any negative impact.

Seasonal price shock. In a true cost reflective pricing structure, most of the network cost recovery should occur during the winter months. This, however, is not necessarily the most appropriate for consumers and a methodology should balance out the desire for consumers to have less variance on a season to season basis versus being truly cost reflective.

Individual customer price shock. Any pricing change has winners and losers. Introducing a new pricing structure is necessary to ensure there is a structure that attempts to ensure all electricity consumers pay their fair share of network related costs. This will also ensure that the network will remain viable for the Nelson City community.

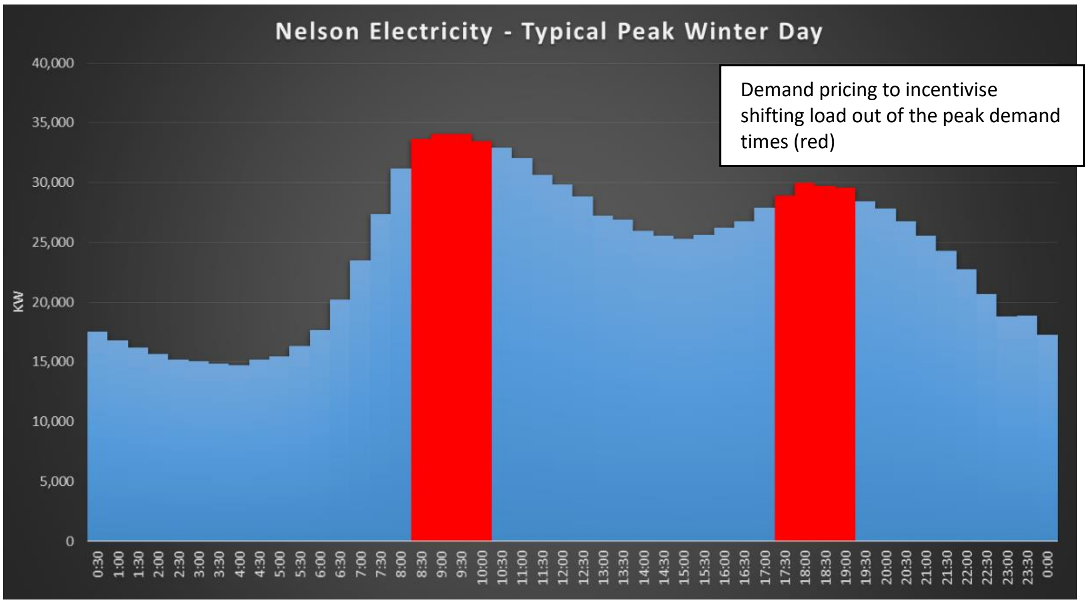
Pricing Options

NEL has been looking at a number of pricing options. The following are two viable alternatives which are currently being explored. The objective is to provide a pricing structure that will ensure that network costs are applied and recovered in a fair manner for all electricity consumers.

Option 1 - Capacity and Demand

Capacity Charge - based on fuse size or capacity limiting option using advanced meter. Currently all consumers have a capacity charge based on the size of the fuses at their Network Connection Point.

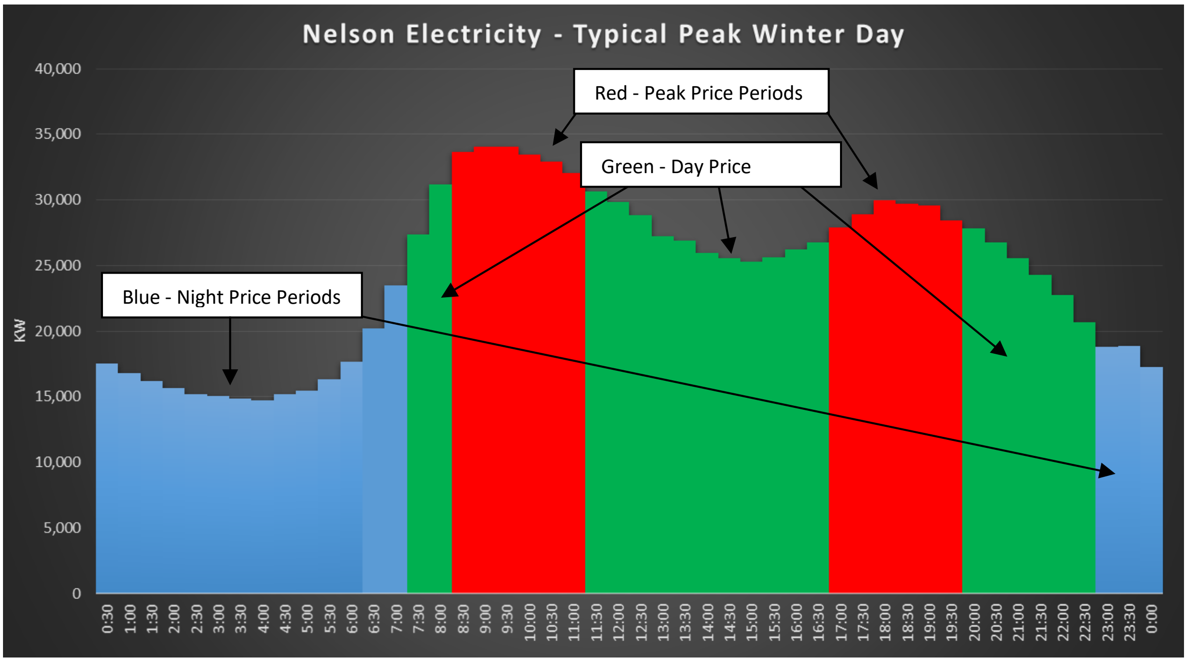
Demand Charge - Introducing a control period **demand charge** during peak demand timeframes. The timeframe to be set based on the likely transmission peak pricing times (typically match Nelson network peak demand times). Peak demand excludes any hot water load control.



Option 2 - Capacity and Time of Use

Capacity Charge - based on fuse size or capacity limiting option using advanced meter. Currently all consumers have a capacity charge based on the size of the fuses at their Network Connection Point.

Time of Use – Introduce time of use pricing. Have two or three pricing bands with high peak time pricing, a day time price with a low night time price. This will provide consumers with the opportunity to reduce costs by shifting consumption to different times of the day.



Future Pricing Summary

Any pricing change will likely be implemented at 1 April 2020 at the very earliest given the limited time to consult with retailers and implement a change any earlier. The time of implementation will more likely be later to coincide with two likely key pricing influence changes, those being:

- The Default Price Quality Path reset for the period 2020 – 2025. This will apply from 1 April 2020.

- The Transmission Pricing Methodology (TPM) changes. Transmission costs account for 33% of total line charge revenue. The TPM change will mean a requirement to adjust prices.

This timeframe will be in alignment other electricity networks. A clear intent will be signalled well in advance of the change to enable time to consult fully with retailers and consumers.

Future Pricing Roadmap

The Electricity Authority wrote to NEL in October 2016 requesting we publish our plan for introducing our new efficient line pricing. This Roadmap has now been updated to take into consideration the changes as discussed in this document. The Roadmap is included as Section 13 of this document. This outlines the estimated timelines as of February 2018 for NEL to have introduced a new pricing regime. There are still a number of issues being worked through which may alter the anticipated introduction of 1 April 2020, some of which are outlined elsewhere in this document.

Customer Consideration

Overview
NEL communicates with customers mainly by way of radio advertising, news print and website covering issues relevant at the time including pricing.

NEL also surveys customers periodically to get a better understanding of their wants and needs and where NEL can improve.

Informal feedback as a result of the price and quality information from the mass market indicates customers have lost touch with the role an Electricity Distribution Business plays in the electrical industry since the separation of Line and Energy companies in 1999. The mass market customer only considers the total electricity bill value without separating out delivery prices. The perception to them is that electricity prices are always increasing and have little regard to the fact that delivery prices have remained the same or at similar levels while retail electricity prices have increased (up until recent times). Consequently it is difficult in some instances to discuss and demonstrate price versus quality trade-offs.

Consistent outcomes from surveys of both large and small consumers is that they are happy with current reliability and not willing to pay more for an improved reliability. Also they do not want to pay less for a less reliable supply.

Customer Consideration into Future Pricing is a Difficult Area
Forty percent of the customers interviewed in 2016 considered that it was at least reasonably important to have an understanding of line charges. A further 34% were classified as thinking that the issue was one of 'moderate importance'.

Just over half the total sample indicated an interest in organising their household to take advantage of lower pricing options. A proposed monthly power bill saving of $5 did not attract any support, while savings of over $20 per month had the greatest response.

There is also increased interest in investing in new technologies in the next 2 years.

- Solar Panels 12%
- Electric Vehicles 7%
- Home Batteries 6%

One of the key outcomes is that on the question **- "***Would you be prepared to pay a little bit extra on your monthly bill so as to subsidise the electricity line charges of users who have invested in new technologies, like solar panels?"* Only 8% supported the idea of subsidising those who invest in new technologies. This demonstrates that whatever new pricing is introduced, that the pricing must ensure as much as possible that all consumers pay their fair share of Line Charges.

8. Non Standard Contracts

NEL will consider offering a non-standard contract to consumers it can be demonstrated that there is a benefit to both parties to do so. The key consideration would be if the consumer is large enough typically over 1,000kVA connected capacity and can manage peak load for the benefit of minimising any peak demand times, either transmission or network related.

The management of peak load could be through load shedding or utilisation of distributed generation.

Currently there is two non-standard contracts in place and all other consumers are charged as per the pricing schedule attached to this document. The expected revenue to be received in the upcoming year is $341,000 from the two non-standard contracts.

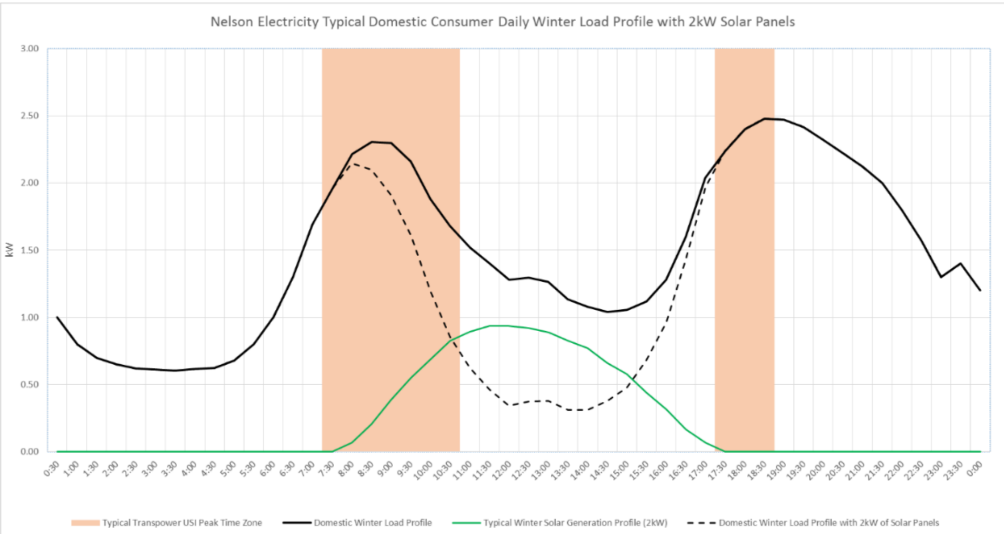
In determining a non-standard contract line charge, NEL would determine the potential reduction in costs associated with a consumer connection if they were able to manage their load in a particular way. An example is a consumer being able to manage load in the transmission upper South Island peak demand times with greater accuracy than the current time of use pricing allows. This may result in a lowering of transmission charges for NEL which the consumer could benefit from.

NEL will consider any application from a consumer for a non-standard if it can be demonstrated that there is a benefit for both parties to do so, whether it be due to load management, distributed generation or bypass potential.

9. Distributed Generation

NEL allows the connection of distributed generation to its network. There are additional requirements for these connections to satisfy NEL that these connections are safe. The requirements are posted on the NEL website www.nel.co.nz.

While these connections can inject electricity back into the NEL network the timing of this, if through solar, is not at a time when NEL would benefit and assist in reducing network costs. NEL's infrastructure is designed to meet the peak capacity of the network which is on the coldest winter mornings when there is high levels of cloud cover. The benefit of any solar distributed generation is negligible.

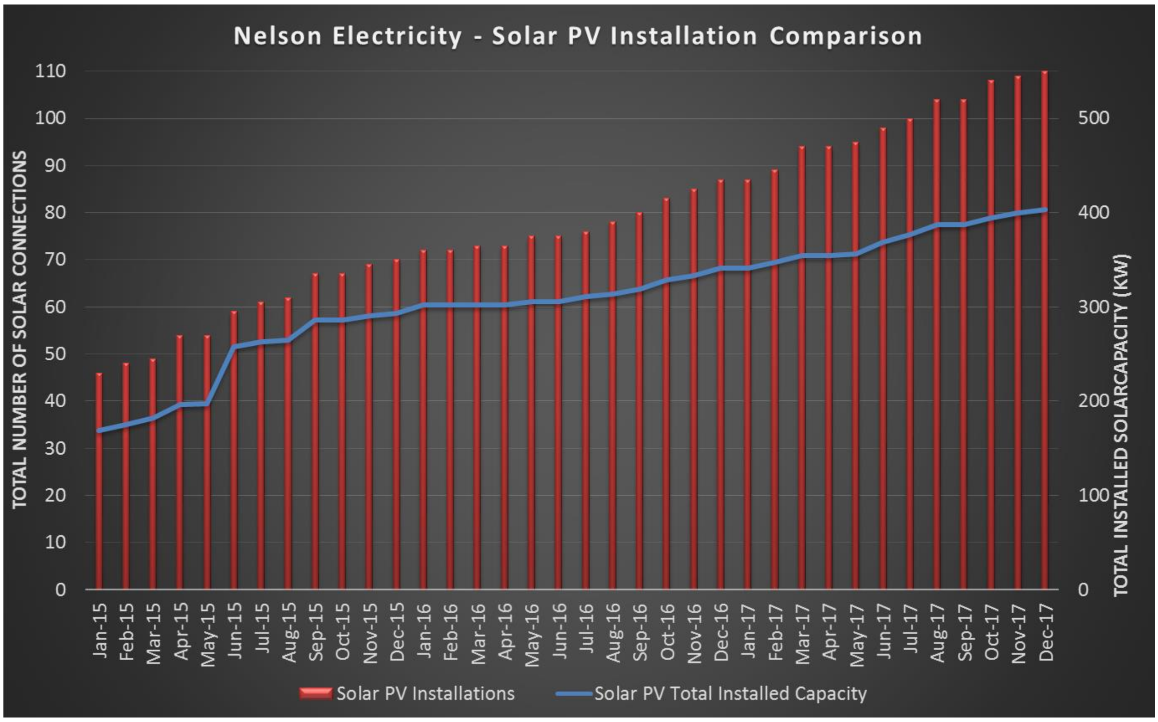


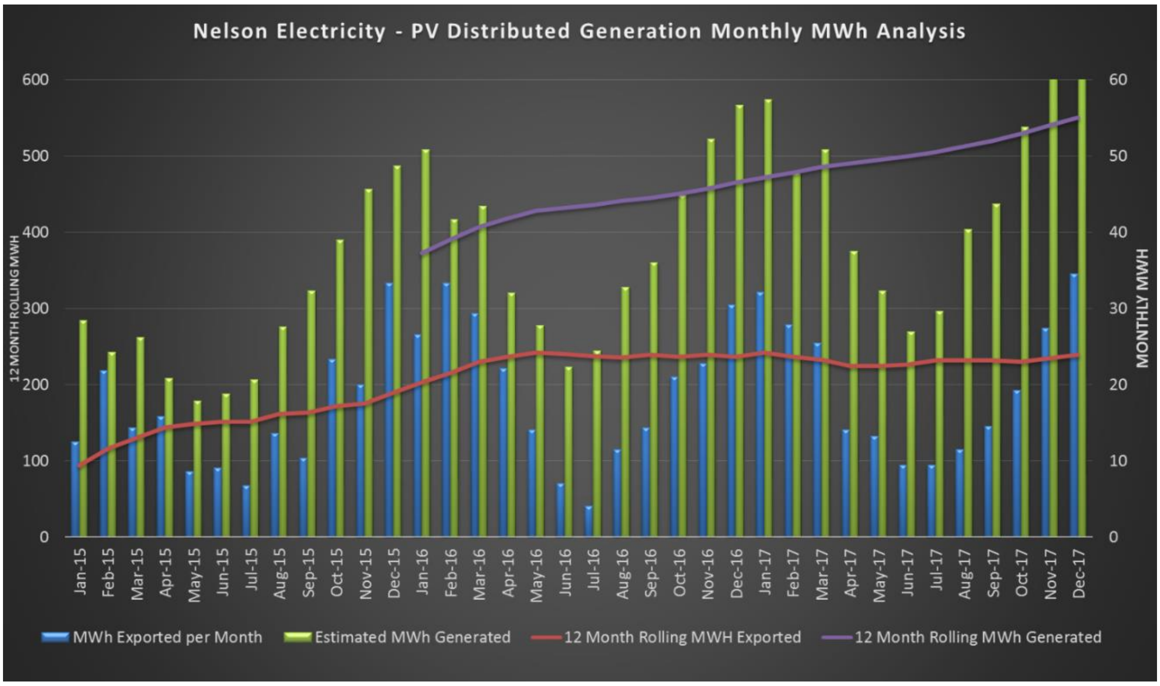
For this reason, NEL does not offer any pricing benefit for distributed generation connections for either local line or transmission charges. Analysis of existing installations is being undertaken to ensure that any exported electricity is within the related voltage limits and of appropriate quality.

NEL has been reviewing the costs associated with processing new distributed connections and auditing of the connections as there are additional costs associated with managing these connections to ensure they comply with appropriate standards. A new price option was created from 1 April 2014 for the exporting of kWh on to the NEL network for Groups 1 and 2, and now introduced to Group 3 from 1 April 2018. Although the level of the price is only 0.5 cents per kWh, it is designed to capture some of the safety audit costs of distributed generation sites. As an example, the annual audit cost is approximately $15 per year and the 0.5 cents per year will only recover $10 per year at 2,000kWh per site.

As the installed price of distributed generation decreases, the financial viability for consumers to install increases. NEL is mindful that connections which have solar PV installed do not contribute fairly to their cost to supply electricity as their peak electricity usage in the middle of winter is not materially changed - as per the graph above. This issue will be addressed appropriately when new pricing is introduced as per Section 7. Any electricity consumer looking to invest in distributed generation must take this into consideration.

There are currently 110 distributed generation installations on the network (as at December 2017) totalling 403kW of generating capacity. There were 23 new installations in the last 12 months. It is expected that the numbers will slowly increase as the installed price decreases.





10. Electricity Networks Association – Pricing Guidelines for Electricity Distributors 2016

The Electricity Networks Association in New Zealand in 2015 completed a Distribution Pricing Guideline and updated in 2016 for the purpose of the assisting electricity distribution businesses to describe and present their distribution prices in a consistent manner.

This Pricing Methodology as far as practical has been written to be in line with the guidelines to provide increased consistency with other networks. It is expected that over time that as the guidelines get developed further, then this pricing methodology be improved further.

11. Pricing Schedule

Nelson Electricity Ltd
Delivery Price Schedule
From 1 April 2018

NELSON ELECTRICITY LTD

Nelson Electricity Ltd is adjusting delivery prices effective 1 April 2018.

The prices in this schedule are used to charge electricity retailers for the delivery of electricity over the Nelson Electricity electricity network. Electricity retailers determine how to allocate this cost together with energy, metering and other retail costs when setting the retail prices that appear on a customer's power account.

Nelson Electricity distributes electricity to connections in the central Nelson city including most of the Port, Port Hills, Nelson South, Toi Toi, Brook, Wood, Nelson East and CBD areas.

				New Delivery Prices from 1 April 2018			Existing Delivery Prices		
Price Code	**Description**	**Consumer Numbers**	**Units**	**Distribution Price**	**Transmission Price**	**Delivery Price**	**Distribution Price**	**Transmission Price**	**Delivery Price**
Load Group 0									
Builders Temporary (7kVA)		15							
0-BT	Builders Temp - Fixed		$/day	0.6300	0.0000	**0.63000**	0.6190	0.0000	**0.61900**
0-BT	Builders Temp - Anytime		$/kWh	0.06479	0.02651	**0.09130**	0.06398	0.02850	**0.09248**
Unmetered Connection (< 1 kW)		32							
0-UM	Unmetered - Fixed		$/day	0.0600	0.0000	**0.06000**	0.0590	0.0000	**0.05900**
0-UM	Maximum Demend		$/kW/day	0.6200	0.4600	**1.08000**	0.6150	0.4940	**1.10900**
Streetlighting		1							
0-SL	Streetlight		$/day	225.8000	57.2000	**283.00000**	224.0000	61.0000	**285.00000**
Load Group 1									
Residential Low Fixed Charge (15kVA)		3900							
1-Fixed	Fixed		$/kVA/day	0.0100	0.0000	**0.01000**	0.0100	0.0000	**0.01000**
1-24hr	Anytime		$/kWh	0.06479	0.02651	**0.09130**	0.06398	0.02850	**0.09248**
1-Water	Controlled (Hot Water)		$/kWh	0.03894	0.01506	**0.05400**	0.03872	0.01615	**0.05487**
1-Night	Night Rate (11pm-7am)		$/kWh	0.02451	0.00889	**0.03340**	0.02418	0.00950	**0.03368**
1-DG	Distributed Generation		$/kWh	0.00500	0.00000	**0.00500**	0.00500	0.00000	**0.00500**
Load Group 2 (from 15kVA to 150kVA)									
General - Residential and Commercial		5220							
2-Fixed	Fixed		$/kVA/day	0.0652	0.0000	**0.06520**	0.0646	0.0000	**0.06460**
2-24hr	Anytime		$/kWh	0.01929	0.02651	**0.04580**	0.01915	0.02850	**0.04765**
2-Water	Controlled (Hot Water)		$/kWh	0.01284	0.01506	**0.02790**	0.01264	0.01615	**0.02879**
2-Night	Night Rate (11pm-7am)		$/kWh	0.00996	0.00889	**0.01885**	0.00979	0.00950	**0.01929**
2-DG	Distributed Generation		$/kWh	0.00500	0.00000	**0.00500**	0.00500	0.00000	**0.00500**
Load Group 3 LARGE COMMERCIAL (up to 2400kVA)									
TIME OF USE		94							
3-Fixed	Metered Installation		$/day	1.2000	0.0000	**1.20000**	1.1900	0.0000	**1.19000**
3-WD	Winter Demand (kVA)		$/kVA/day	0.12768	0.08232	**0.21000**	0.1267	0.0969	**0.22363**
3-24hr	Energy		$/kWh	0.00263	0.01137	**0.01400**	0.0026	0.0133	**0.01587**
	Capacity Supplied (one of)								
T-03	T-03	16kVA – 42kVA	$/day	2.1000	0.0000	**2.10000**	2.0760	0.0000	**2.07600**
T-04	T-04	43kVA – 69kVA	$/day	3.4500	0.0000	**3.45000**	3.4180	0.0000	**3.41800**
T-05	T-05	70kVA – 110kVA	$/day	5.5000	0.0000	**5.50000**	5.4470	0.0000	**5.44700**
T-06	T-06	111kVA – 138kVA	$/day	6.9000	0.0000	**6.90000**	6.8330	0.0000	**6.83300**
T-07	T-07	139kVA – 218kVA	$/day	10.9000	0.0000	**10.90000**	10.7940	0.0000	**10.79400**
T-08	T-08	219kVA – 300kVA	$/day	15.0000	0.0000	**15.00000**	14.8550	0.0000	**14.85500**
T-09	T-09	301kVA – 500kVA	$/day	25.0000	0.0000	**25.00000**	24.7580	0.0000	**24.75800**
T-10	T-10	501kVA – 750kVA	$/day	37.5000	0.0000	**37.50000**	37.1360	0.0000	**37.13600**
T-11	T-11	751kVA – 1000kVA	$/day	50.0000	0.0000	**50.00000**	49.5150	0.0000	**49.51500**
T-12	T-12	1001kVA – 1500kVA	$/day	75.0000	0.0000	**75.00000**	74.2730	0.0000	**74.27300**
T-13	T-13	1501kVA – 2000kVA	$/day	100.0000	0.0000	**100.00000**	99.0300	0.0000	**99.03000**
T-15	T-15	2400kVA	$/day	120.0000	0.0000	**120.00000**	118.8360	0.0000	**118.83600**
3-DG	Distributed Generation		$/kWh	0.0050	0.0000	**0.00500**			
3-PF	Power Factor <0.95		$/kVAr/mth	6.5000	0.0000	**6.50000**	6.5000	0.0000	**6.50000**

All prices exclude GST. All prices as shown above are also available from our website www.nel.co.nz

Pricing Guide - Details on how these delivered prices are applied are included in our Pricing Guide which is available on our website.

Load Group 0 - Unmetered loads that meet Electricity Authority Unmetered Load Guidelines and Metered Builders Temporary Supplies(Builders Temp > 7kVA use Load Group 2).

Load Group 1 - Residential households (principal place of residence only) with connection capacity of 15kVA using less then 8,000kWh per year as required to comply with the Electricity (Low Fixed Charge Tariff Option for Domestic Consumers) Regulations 2004.

Load Group 2 - Available to <u>all</u> residential and commercial connections with capacity from 15kVA to 150kVA.

Load Group 1 & 2 - All existing residential households have an assessed connection capacity of 15kVA.

Load Group 3 - Available to any large commercial connections up to 2400kVA with Time of Use metering.

Load Group 1, 2 and 3 - Distributed Generation charge is for electricity exported into the Nelson Electricity network.

Any questions about the line charges, please email us at enquiry@nel.co.nz, or phone (03) 546-0486.

12. Price / Quantity / Revenue Schedule

Revenue Table using 31 March 2019 Prices and 2018/2019 Quantities

Number of Days:	365										
Tariff or Fee	Number of ICPs at 31/03/2019 From Registry	Billed kWh at 31/3/2019	Billed kVA at 31/3/2019	Billed Days at 31/3/2019	Distribution Charges				Notional Distribution Revenue ($)		Total Revenue ($)
					Fixed			Variable (c/kWh)	Fixed	Variable	
					$/day	c/kVA/day	Other				$P_{,2019}$ $Q_{,2019}$
Group 0											
Streetlights	1	967,026	-	365	283.00000				103,295		103,295
Unmetered Fixed	32	-	-	4,816	0.06000				289		289
Unmetered Capacity		-	1,702	-		108.00000			1,838		1,838
Builders Temp	15	-	-	5,120	0.63000				3,226		3,226
BT-kWh		5,624	-	-				9.13000	-	513	513
									108,648	**513**	**109,161**
									100%	**0%**	
Group 1											
Fixed	3,900	-	21,262,830	-		1.00000			212,628		212,628
Anytime		13,425,464	-	-				9.13000	-	1,225,745	1,225,745
Controlled		6,134,057	-	-				5.40000	-	331,239	331,239
Nightrate		493,789	-	-				3.34000	-	16,493	16,493
DG		79,397	-	-				0.50000	-	397	397
									212,628	**1,573,873**	**1,786,502**
									12%	**88%**	
Group 2		-	-	-							
Fixed	5,220	-	40,863,241	-		6.52000			2,664,283		2,664,283
Anytime		50,674,668	-	-				4.58000	-	2,320,900	2,320,900
Controlled		9,206,964	-	-				2.79000	-	256,874	256,874
Nightrate		937,304	-	-				1.88500	-	17,668	17,668
DG		156,900	-	-				0.50000	-	784	784
									2,664,283	**2,596,227**	**5,260,510**
									51%	**49%**	
Time of Use		-	-	-							
Metered Installation Charge	91	-	-	32,834	1.20000				39,400		39,400
Energy		33,789,928	-	-				1.40000	-	473,059	473,059
Winter Demand		-	3,909,442	-		21.00000			820,983		820,983
Capacity Supply (Sum of kVA)		-	10,311,852	-		5.00000			515,593		515,593
Power Factor (kVAr)		-	5,345	-			6.50000		34,743		34,743
DG		-	-	-				0.50000			
Direct Connection		-	-	-							
Energy		10,367,951	-	-				0.26300	-	27,268	27,268
Installation	2	-	-	730	1.20000				876		876
Winter Demand		-	674,378	-		12.76800			86,105		86,105
Capacity Supplied		-	1,423,500	-		5.00000			71,175		71,175
Power Factor (kVAr)		-	1,107	-			6.50000		7,195		7,195
Transpower Cold Storage		-	-	-			40,135		40,135		40,135
Transpower NMDHB		-	-	-			109,058		109,058		109,058
DG								0.50000	-	-	-
									1,725,262	**500,327**	**2,225,589**
									78%	**22%**	
TOU Sealord		-	-	-							
Fixed	1	12,618,994	-	-			452,445		452,445		452,445
Power Factor (kVAr)		-	-	-			6.50000		-		-
DG								0.50000	-	-	-
									452,445	**-**	**452,445**
									100%	**0%**	
									5,163,266	**4,670,940**	**9,834,207**
Σ $P_{,2019}$ $Q_{,2019}$	**9,262**	**138,621,767**							**53%**	**47%**	

13. Future Pricing Roadmap Table

Future Pricing Roadmap Chec EDB : *Nelson Electricity Limited*

Roadmap Stages	Activities	2018 Q1	2018 Q2	2018 Q3	2018 Q4	2019 H1	2019 H2	2020 H1	2020 H2	2021	2022	2023	2024	2025	2026	Resource requirements
1. Initiate pricing reform																
Problem Identification & Discovery	Justification and early modelling	x														NEL
Define overall objectives for reform	Set overall goals including target dates or date ranges	x														NEL / ENA / Shareholders
Develop strategy to deliver reform	Develop ideas on how to go ahead (including long list of future pricing options if available)	x														NEL / ENA / Shareholders
Communicate	Prepare and publish future pricing roadmap, include reasoning and and why it's important	x														NEL
Identify challenges	eg, resourcing implications, billing systems, EIEP1 file formats, AMI penetration and technology, accessing data		x													NEL - New Billing System
Consult retailers	Socialise ideas & plans with retailers			x												NEL / ENA
Establish high level plan	Gain commitment to reform, agree plan, allocate resources				x											NEL
Gather basic data for analytics	What do we need to know to progress reform? (eg. AMI penetration? Survey customers?)				x											NEL / ENA / Shareholders
Define pathway	Prepare final strategic pricing plan (including target dates)				x											NEL / ENA / Shareholders
Alignment across EDBs	Compare plan with other EDB's, form coalitions				x											NEL / ENA / Shareholders
2. Plan changes in more detail																
Develop detailed plans, including:	Identify issues/prepare detailed pricing reform plans				x											NEL / ENA / Shareholders
- customer interactions	Establish research program and focus groups (retailer + end-user)				x											NEL / ENA / Shareholders
- pricing trials to test ideas	Conduct in-market testing, examine impact on customer groups				x											NEL / ENA / Shareholders
- data analysis to assess customer impacts	Narrow down preferred options and test market impacts					x										NEL / ENA / Shareholders
- implementation and transition arrangements	Identify what will drive success					x										NEL / ENA / Shareholders
- feedback loops and issues resolution	Develop processes to account for stakeholder views and review against target dates. Participate in ENA					x										NEL / ENA / Shareholders
- communication	Educate customers and retailers about change						x									NEL / ENA / Shareholders
- regulatory compliance	Check plan meets regulatory expectations						x									NEL / ENA / Shareholders
3. Manage roll out of new pricing options																
Develop transition strategies	Incentivise and manage take-up over time for retailers and customers						x									NEL / ENA / Shareholders
Adopt risk management approach	Identify and manage risks to markets, customers, EDBs *(eg political and financial risks)*										x					NEL / ENA / Shareholders
Implement New Pricing	Introduce the new pricing options							x								NEL
Review progress and make adjustments	Actively consider progress towards outcomes over time												x			NEL
Ongoing customer interactions	Monitor customer responses and manage as required												x			NEL

14. Loss Factors to Apply for the Period 1 April 2018 – 31 March 2019

Loss Factors will remain unchanged for the year. An assessment was undertaken in December 2017 which has shown that both technical and non-technical losses remain unchanged in the range of 3.5% - 4.0%.

Loss Code	Description	Loss Factor Consumption	Loss Factor Generation
L0	Group 0 Unmetered and Builders Temporary Supply	1.044	1.019
L1	Group 1 Residential (Low Fixed Charge Option)	1.044	1.019
L2	Group 2 Residential and Business	1.044	1.019
L3	Group 3 Large Commercial - Supplied from 400V Network	1.033	1.022
L4	Group 4 Large Commercial - Direct 400V feed from transformer	1.033	1.022
L5	Group 5 Large Commercial - Dedicated Transformer 400V Metering	1.033	1.022
L6	Group 6 Large Commercial - Dedicated Transformer 11kV Metering	1.027	1.017