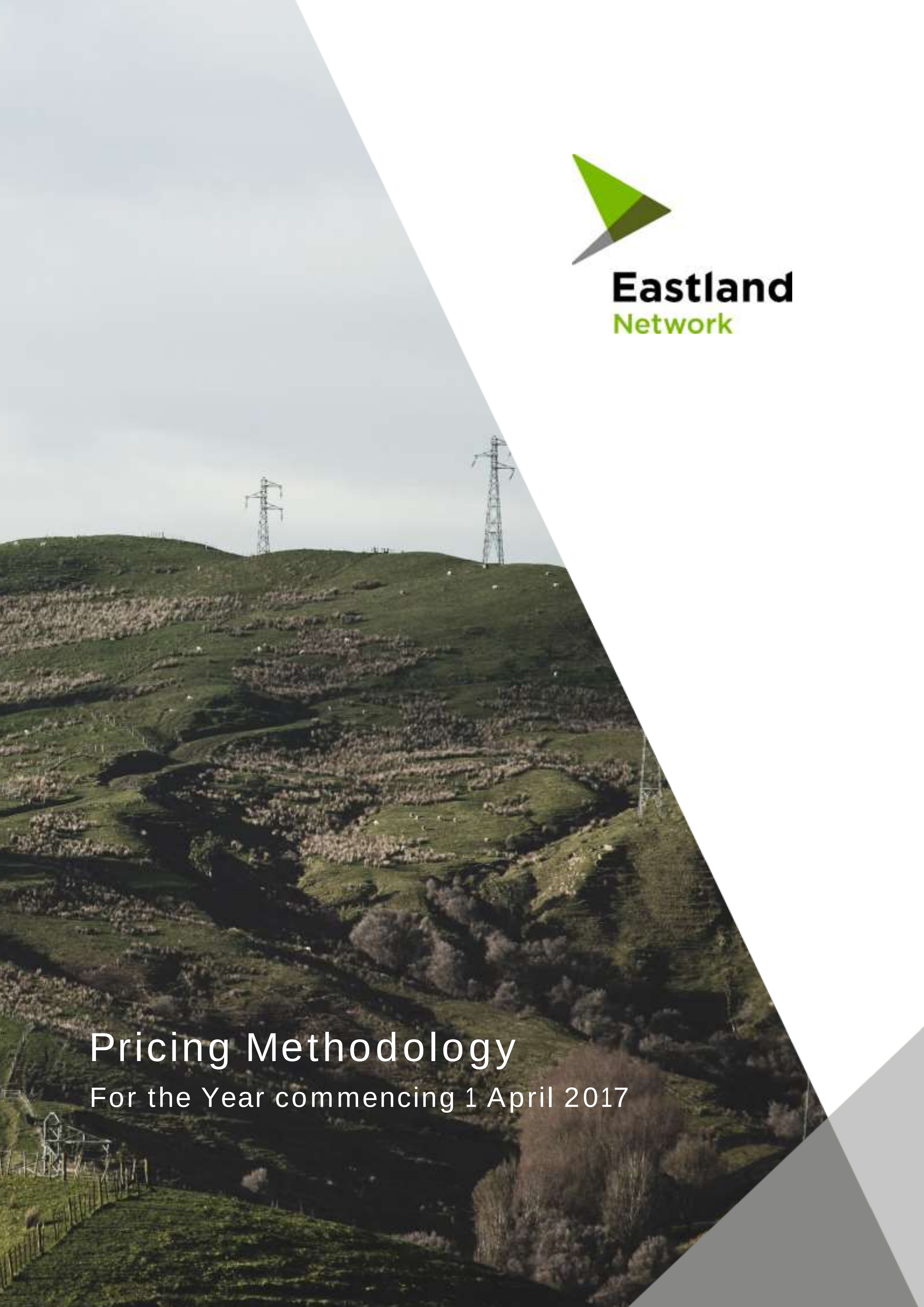

Pricing Methodology

For the Year commencing 1 April 2017

Contents

Glossary 3

Directors Certification 4

1. **Introduction** 5

2. **Target Revenue** 5

2.1 Pass through and Recoverable costs 6

2.1.1 Pass-through costs 6

2.1.2 Recoverable costs 6

2.2 Network Maintenance, System Operations & Network Support, Business Support, Depreciation and Taxation 9

2.3 Return on Investment 9

3. **Pricing Methodology Changes** 10

4. **Price Changes** 10

5. **Consumer Groups** 10

6. **Cost Allocation** 12

6.1 Allocators 12

6.1.1 ICP's 13

6.1.2 kWhs 13

6.1.3 Installed KVA 13

6.2 Allocation of Revenue Requirement 13

7. **Price Structure** 14

7.1 Domestic Charges 14

7.2 Non-Domestic Charges 15

7.3 Distributed Generation 16

7.3.1 Connection charges 16

7.3.2 Distributed Generation Allowance 16

8. **Distribution Loss Factors** 16

9. **Consumer Survey** 17

10. **Uneconomic Bypass** 17

11. **Pricing Principles** 18

11.1 Principle A 18

11.2 Principle B 19

11.3 Principle C 20

11.4 Principle D 21

11.5 Principle E 21

Appendix 1 – Consumer Group Target Revenue Allocation 22

Appendix 2 – Pricing Schedule 23

Glossary

AMP	Asset Management Plan
COSM	Cost of Supply Model
Distributed Generation	Generating plant that is electrically connected to a distribution network.
Domestic	A domestic customer is defined in the Eastland Network Tariff definitions and terms and conditions of supply.
DPP Regulations	Electricity Distribution Services Default Price-Quality Path Determination 2015.
EA	Electricity Authority.
EGCC	Electricity & Gas Complaints Commission.
GXP	Grid Exit Point. The point at which Eastland Network connects to the National Grid.
Input Methodology	Electricity Distribution Services Input Methodologies Determination 2012.
LFC Regulations	Electricity (Low Fixed Charge Tariff Option for Domestic Consumers) Regulations 2004.
MBIE	Ministry of Business, Innovation and Employment.
RCPD	Regional Coincident Peak Demand. Customer off-take at the Tuai Grid Exit Point (GXP) during a regional peak demand period
The Code	Electricity Industry Participation Code 2010.
TOU	Time of Use.

Directors Certification

Clause 2.9.1 of Section 2.9

We, Kievan Devine and Tony Gray, being directors of Eastland Network Limited certify that, having made all reasonable enquiry, to the best of our knowledge –

a) the following attached information of Eastland Network Limited prepared for the purposes of clause 2.4.1 of the Electricity Distribution Information 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.

Date this 15th day of March 2017

Signature

Signature

1. Introduction

This document sets out Eastland Network Limited's (Eastland) pricing methodology for the line charges in effect from 1 April 2017. This document aims to provide an understanding of how Eastland's prices are determined for consumers.

Each year Eastland is required to publish a pricing methodology that complies with the Electricity Distribution Information Disclosure Determination 2012.

Prices are set to recover the economic costs of owning and operating the Electricity Distribution Network that conveys electricity throughout the Gisborne and Wairoa districts. The economic costs include the recovery of the costs of operation plus an appropriate return on investment (cost of capital). Eastland also aims to develop economically efficient pricing to ensure that Eastland is able to invest in its network over time at an appropriate level and also that consumers are able to consider the value they receive when considering alternatives.

2. Target Revenue

Target Revenue is calculated as forecast costs (including tax) plus a return of capital (Depreciation) plus a return on capital. The table below shows the components of Forecast Target Revenue for Eastland Network for the 2017/18 pricing year compared with the 2016/17 year.

Table 1: Target Revenue

Target Revenue (000's)	2017/18	2016/17
Pass-through Costs	438	417
Recoverable Costs	10,796	10,306
Total Recoverable & Pass-through Costs	**11,234**	**10,723**
System Maintenance	5,909	5,667
System Operations & Network Support	1,522	1,411
Business Support	3,705	3,569
Total Operating Costs	**11,136**	**10,647**
Taxes	2,840	2,616
Depreciation	6,031	5,971
Return on Capital	9,713	8,965
Total Revenue Requirements	**40,954**	**38,922**
Less Other Income	(572)	(564)
Less Price Path Constraints	(3,931)	(2,864)
Target Revenue	**36,451**	**35,494**

2.1 Pass through and Recoverable costs

Pass through and recoverable costs are costs that are permitted under the DPP regulations to be passed through directly to consumers.

2.1.1 Pass-through costs

Pass-through costs are defined under clause 3.1.2 of the Electricity Distribution Services Input Methodologies Determination 2012 (Input Methodologies). These are costs that outside the control of Eastland and are associated with the supply of electricity distribution services. These costs include

- rates on system fixed assets payable to a local authority;
- levies payable
  - under section 53ZE of the Commerce Act 1986;
  - under regulations made under the Electricity Industry Act 2010; and
  - by all members of the Electricity and Gas Complaints Commissioner Scheme.
- Ministry of Business, Innovation and Employment levies and Electricity & Gas Complaints Commission levies.

Table 2: Pass-through costs

Pass-through costs (OOO's)	2017/18	2016/17
Rates on Network Assets	270	249
Levies	168	168
Total Pass-through costs	438	**417**

2.1.2 Recoverable costs

Recoverable costs are defined under clause 3.1.3 of the Electricity Distribution Services Input Methodology Determination 2012.

There are a number of costs specified in the Input Methodologies. Those applicable to the prices for Eastland for the 2017/18 year are

Table 3: Recoverable Costs

(000's)	2017/18	2016/17
Transpower charges	*6,336*	*6,074*
Avoided costs of Transmission for assets acquired from Transpower	*3,746*	*3,746*
Distributed Generation Allowance	*672*	*653*
Capex Wash-up allowance	*(177)*	*(167)*
Quality Incentive Allowance	*219*	
Total Recoverable Costs	***10,796***	***10,306***

2.1.2.1 Transpower Charges

Transpower charges are comprised of three charges, connection charges, interconnection charges and customer investment contract charges.

Connection charges are a fixed annual amount based on the connection assets used by Eastland at the point of connection to the transmission grid.

Interconnection charges are a fixed rate per unit (kW) of contribution to regional co-incident peak demand (RCPD). The RCPD is the average of the top 100 coincident peaks in any given year. The Transpower interconnection rate for the 2017/18 year is $123.98/kW (2016/17 - $114.64/kW).

The customer investment contract charges relate to metering assets that were installed as part of the acquisition of assets by Eastland Network from Transpower on 31 March 2015.

2.1.2.2 Avoided Transmission for assets acquired from Transpower

On the 31 March 2015, Eastland Network Limited acquired the majority of the local connection assets from Transpower. As a result, Eastland Network will avoid $3.745m per annum of connection charges from Transpower. Under section 3.1.3(1)(e) of the Input Methodologies, Eastland Network is able to continue to recover these avoided connection charges from customers through its line charges for a period of five years from the date of acquisition. The ability to recover these avoided charges in part offset the additional operational costs of these assets that were not permitted to be recovered through prices by the Commerce Commission for the 2015-2020 pricing period.

The avoided costs are included in transmission charges for the 2017/18 year and will continue until the 2019/20 year. The 2017/18 year is the third year in which these charges have been recovered.

2.1.2.3 Distributed Generation Allowance

Distributed generation is electricity generation that is connected to a distribution network. A distributed generation allowance is "any positive allowance for costs incurred and amounts payable, or negative allowance for amounts receivable, in relation to avoided transmission charges arising from distributed generation … "[1]

The regulations set out in the Electricity Distribution Services Default Price-Quality Path Determination 2015, allow a distribution company to recover the costs of avoided transmission from its consumers and/or electricity retailers via line charges.

Any distributed generation allowance made must be paid in accordance with the Pricing Principles in Schedule 6.4 of The Electricity Industry Participation Code 2010. Clause 2 of this schedule states that charges to Distributed Generators are

"… to be based on recovery of reasonable costs incurred by distributor to connect the distributed generator … and must include consideration of any identifiable avoided or avoidable costs"

Accordingly, where a generator provides an alternative to Transpower's transmission services, the benefit of avoided transmission charges will be passed through to the generator. The value of such benefit is based on the assessed impact that these alternatives will have on GXP load profiles both in terms of demand and kWhs and will be calculated in accordance with Transpower's transmission pricing methodology. The connection of generators to Eastland's network, and the charge/rebates applicable are subject to Eastland review on a case-by-case basis.

The maximum potential for reduction in Transpower charges is dependent on operating assets in co-ordination with Eastland's load management and any other party's capability. The level of risk sharing between providers will be subject to contracted terms between parties.

It should be noted that the generator can equally be Eastland, a retailer, or other independent party, however, the capacity requirement is capped at Eastland determined targets. Where there is a choice of alternatives, preference will be given to the least cost solution to Eastland on offer at the time of commitment. As with Transpower new investment agreements, the commitment will be locked in for an agreed period and not subject to optimisation.

Avoided Interconnection Charges

Investment that reduces the regional co-incident peak demand at a GXP will be recognised as a reduction in Transpower interconnection charges provided that solution is transmitting electricity during an RCPD period. The avoided cost of interconnection charge is calculated as the reduction in Eastland's RCPD due to the contribution from Distributed Generation. The kW's produced during an RCPD period is multiplied by the current Transpower Interconnection rate. The Interconnection rate for the 2017/18 year is $123.98/kW.

Avoided Connection Costs

A generator that increases the capacity of the distribution network may be recognised as an alternative to a Transpower upgrade of connection assets. There will be a benefit to consumers over the Transpower solution if that capacity can be delivered on a more economically-efficient basis.

The avoided cost of connection charge is the total amount of connection charges that have been avoided due to the presence of Distributed Generation on Eastland Network's network. Connection charges may be avoided either by:

- Avoiding a new transmission connection asset; or
- Avoiding an existing transmission connection asset.

[1] Definition from Electricity Distribution Services Methodologies Determination 2012

The amount of avoided connection charge is calculated based on the value of new transmission connection asset projects and/or existing transmission connection assets that have been avoided. The value of new transmission connection projects is converted to an avoided connection charge using Transpower's current pricing methodology for connection assets. The value of existing connection assets that are avoided is calculated based on the most recent connection charge (for the assets avoided) inflated to current costs. Avoided charges payable to the generator are capped so that the generator earns no more than their weighted average cost of capital on invested assets.

2.1.2.4 Capex Wash-up Allowance

Capex Wash-up Allowance is an adjustment to revenue as a result of under or over forecasting capital expenditure in the 2014/15 year. The 2014/15 capital expenditure forecast was used to determine allowable revenues for the 2015-2020 default price path. Where actual capex was less than forecast capex, the allowable revenue for that period is higher than it otherwise would have been if the actual amount was known. The opposite also occurs if actual capex was greater than forecast. The capex wash-up amount is calculated to return revenues back to the level they would have been had the actual expenditure been known. In Eastland's case, capex was lower than forecast consequently allowable revenues have been adjusted down by $177k for the 2017/18 pricing year.

2.1.2.5 Quality Incentive Allowance

For the 2015-2020 Default Price-Quality Path, the Commerce Commission introduced a Quality incentive Allowance which rewards or penalises those distribution businesses that over or under achieve against set quality targets. In the 2015/16 pricing year, Eastland Network exceeded quality targets and is therefore rewarded with an extra $219k allowable revenue for the current 2017/18 year.

2.2 Network Maintenance, System Operations & Network Support, Business Support, Depreciation and Taxation

The revenue requirement components including, network maintenance, system operations & network support, business support, depreciation and taxation are based on budgeted regulatory costs for the 2017/18 period.

2.3 Return on Investment

Return on investment revenue provides a return on investment to network owners and is determined as the product of regulated asset value at the beginning of the financial year plus regulated deferred tax and the weighted average cost of capital (WACC).

ROI = (RAB + RDT) x WACC

Where -

ROI	–	Return on Investment
RAB	–	Regulated Asset Base at the beginning of the pricing year
RDT	–	Regulated Deferred Tax as calculated in accordance with the clause 2.3.7 of the Input Methodology
WACC	-	Weighted Average Cost of Capital

The weighted average cost of capital for the 2015 – 2020 pricing years has been determined by the Commerce Commission as 7.19%[2], however, the price path threshold creates a cap on this return and the actual return on investment may vary from this.

3. Pricing Methodology Changes

There has been no change to the pricing methodology for the 2017/18 pricing year.

4. Price Changes

Overall prices increase by an of average 4.3%

Distribution prices (including distribution pass-through & recoverable charges) for 2017/18 have increased by 4.7% as permitted under price regulation[3].

Transmission prices have increased by an average of 3.7% due to increased Transmission costs of 2.6% plus the recovery of Transmission revenue under recovered in the 2016/17 year due to lower than expected volumes.

5. Consumer Groups

Areas of the network that exhibit high consumer density have been identified in Eastland Network geographic Information system (GIS) and the remainder of the network has been deemed low density. Separating the network and consumers into these categories allows Eastland to better examine the costs associated with supplying consumers in these two distinct areas and reflect the higher level of service offered to high density consumers. The high-low density segmentation exercise involved isolating areas of the network in Eastland Network's GIS and extracting the corresponding network assets employed, ICP density and consumer usage data.

Consumers within each density classification are classed as either domestic or non-domestic consumers. Domestic consumers are grouped together because they share a similar network usage profile. Domestic consumer's peak usage occurs between the hours of 7:30am and 9:30am in the morning and 5:30pm and 9:00pm in the evening which corresponds with network peak demand. In contrast non-domestic consumers do not typically share a similar peak usage profile due to the diverse nature of their operations and as such are not able to be grouped in a similar manner. Eastland therefore groups non-domestic consumers based on their assessed capacity requirements using their installed fuse rating or transformer capacities where transformers are dedicated to supply of an individual consumer. This approach recognises that as consumer capacity requirement increases the value of assets employed to supply consumers' increases.

An installation only qualifies for a domestic tariff if it satisfies the following:

[2] Cost of capital determination for electricity distribution businesses' default price-quality paths and Transpower's individual price-quality path [2014] NZCC 28

[3] Electricity Distribution Services Default Price-Quality Path Determination 2015

- It is the consumer's primary and permanent place of residence. Thereby excludes: Holiday homes, shearers' quarters, separately connected outbuildings, premises that constitute any part of premises described in the Residential Tenancies Act 1986.
- No other person residing in these premises is claiming primary domestic residence at another site whether on Eastland Network's distribution system or elsewhere in New Zealand.
- The connection does not supply electricity for any Non-Domestic, Business, or Commercial activity. Therefore, metering and electricity consumption must be for Domestic reasons only (i.e. mixed end use of electricity reverts to Non-Domestic supply).
- Does not exceed the following current limits:

1 Phase	Up to 62 amps
2 Phase	Up 42 amps per phase
3 Phase	Up to 32 amps per phase

For the avoidance of doubt, a person cannot have multiple primary places of residence eligible for the Electricity (Low Fixed Charge Option for Domestic Consumers) Regulations 2004.[4]

All consumers wishing to change classification to the Domestic definition will be required to make a declaration, and supporting documentation such as appearing on the local electoral roll.

Eastland Network also have a non-domestic Time of Use Tariff group. This tariff is available to non-domestic consumers who have a capacity requirement of greater than 201kVA. This tariff was introduced following consumer requests and will give consumers, who are still relatively low energy consumers by non-domestic levels, the ability to manage their loads more effectively and take advantage of a time of use tariff.

Accordingly, Eastland employs the following consumer group classifications for both high and low density consumers:

Domestic	0 – 30kVA
Non-Domestic Low capacity	0-3kVA (Street lighting)
Non-Domestic	0 – 30kVA
Non-Domestic	31 – 100kVA
Non-Domestic	101 – 300kVA
TOU	201 – 300kVA
TOU	301 – 500kVA
TOU	501 – 1000kVA
TOU	1001 – 4500kVA
TOU	4501 – 6500kVA
Generation	301 – 500kVA
Generation	501 – 1000kVA
Generation	1001 – 4500kVA
Generation	4501 – 6500kVA

[4] See Eastland Network Ltd Tariff definitions, terms and conditions of supply attached to the 2017/18 schedule of prices.

Within the Domestic and Non-Domestic classifications, consumers are also offered reduced pricing for load control. Other non-generation consumers have reduced pricing available to encourage use off-peak.

6. Cost Allocation

The Eastland Network cost of supply model is used to determine the revenue requirement by consumer group that is necessary to efficiently allocate costs and reflect the actual cost of its services. This cost model has quantified a number of categories where costs are under or over recovered. However, as Eastland Network is mindful of price shocks to consumers, the intention is to move prices towards those based on the revised cost allocation methodology over a period of 3-5 years. In doing so some load groups will face continual increases over this period while others will experience little or no change. It should be noted that future price movements may also be a result of changes in the regulations under which Eastland Network operates.

6.1 Allocators

Eastland Network's cost of supply model (COSM) contains the following input assumptions and statistics for the purpose of cost allocation. Eastland Network used the following statistics to allocate costs to consumer groups. This data was updated for the 2017/18 year.

Table 4: Allocators

Price category	ICP's	kWhs	Installed KVA	Avg RCPD Contribution
PDH0030	13,727	82,286,235	58,727	904,245
PDL0030	5,679	36,946,264	43,466	81,727
PNH0003	133	629,930	203	35
PNH0030	1,695	22,243,130	15,728	40,343
PNH0100	277	21,032,729	15,059	2,671
PNH0300	67	13,702,690	14,425	423
PTH0300	6	1,424,776	386	12
PNH0500	16	8,356,573	6,265	148
PNH1000	20	24,624,787	16,553	442
PNH4500	1	6,725,265	1,500	29
PNH6500	1	20,949,275	1,000	150
PNL0003	120	272,329	127	35
PNL0030	3,586	17,857,240	29,823	59,017
PNL0100	100	4,431,985	4,992	393
PNL0300	17	1,590,415	2,745	15
PTL0300	1	65,411	250	1
PNL0500	3	1,272,557	1,100	44
PNL1000	1	861,783	500	7
PNL4500	1	12,726,627	1,000	121
PNL6500	0	0	0	0

PNG0500	0	0	0	0
PNG1000	6	0	6,000	0
PNG4500	1	0	2,000	0
PNG6500	1	0	4,000	0
Totals	25,459	278,000,000	225,849	1,089,859

6.1.1 ICP's

ICP data is derived from forecasts of expected changes to ICPs during the forthcoming pricing year. This data is based on historical averages plus or minus expected changes.

6.1.2 kWhs

Forecast Annual kWh use is based on historical averages plus or minus expected changes as a result of growth, weather patterns and economic conditions.

6.1.3 Installed KVA

Installed KVA is based on the kVA of the transformer that each customer is attached to.

6.2 Allocation of Revenue Requirement

Following the determination of the allocators, the revenue requirement, comprised of distribution and transmission requirements, is allocated between consumer groups.

The total revenue requirement (as depicted in table 1) has been allocated to consumer groups using the allocation methodology set out in the paragraphs which follow. A summary of the final allocation is shown in Appendix 1.

Eastland Network allocates much of its asset based costs on the basis of capacity installed. This is to reflect the view that there is little growth in the Eastland Network region and that Eastland Network's costs are driven by long lasting assets and therefore largely fixed. It is also a reflection that electricity distribution assets have been built to meet the capacity requirements at a connection point. These assets are built to requirements irrespective of the actual volume of energy used.

Eastland Network have allocated transmission costs to consumer groups using a close approximation to the methodology set out in Transpowers transmission pricing methodology. Interconnection charges are allocated to consumers based on their share of total co-incident peak demand on Eastland's network. Connection costs are allocated on the basis of capacity to reflect the assets owned and operated by Transpower are built for a particular capacity within the region.

Distributed Generation Allowances are allocated on the basis of RCPD as any reduction in coincidental peak also reduces the Interconnection charges from Transpower.

Pass through costs are allocated on the basis of either capacity or ICP depending on whether the costs relate to assets built or overhead costs.

System Maintenance is allocated 80% based on capacity and 20% ICP. While these costs are largely driven by assets built, there is also some element of overhead which should be allocated on the basis of ICP. The 80/20 split is a best estimate.

Target return on investment and depreciation have been allocated to consumer groups based on capacity.

Table 5: Cost Allocation by Category

Cost Category	Allocator
Transmission costs - Variable	RCPD
Transmission costs – Fixed Component	Capacity
Pass-through costs	Capacity or ICP
System Maintenance	Capacity 80%, ICP 20%
Business Support	ICP
System Operations & Network Support	Capacity or ICP
Taxes	ICP
Depreciation	Capacity
Return on Capital	Capacity

7. Price Structure

Eastland uses ICP billing for charging end consumers. However Eastland does not charge all consumers their true cost of supply due to a number of factors including:

- Low user regulations which restrict the level of domestic fixed charges;
- The complexity, and potential arbitrary results in determining individual costs of supply;
- The desire to make the tariff schedule administratively simple;
- The desire to manage rate shock;
- There must be a smooth price transition between non-domestic consumer groups;
- Recognition of high levels of reliability in high density areas
- Revenue constraints imposed by the Commerce Commission Default Price Path Determination 2012

The implication is that for some consumer groups the target return on investment component of the revenue requirement is not fully recovered.

7.1 Domestic Charges

Since 2004 the low user fixed charge regulations cap fixed charges to domestic consumers at 15 cents (excl GST) per day. Eastland have set domestic fixed charges at 15 cents (excl GST) per day which is less than that determined by the COSM described earlier. As such the remainder of the fixed cost allocated to domestic consumers is necessarily recovered through variable charges.

The variable charges on our pricing schedule for domestic consumers reflect the metering options available on the Eastland Network. These are uncontrolled, controlled and night rates and are priced at progressively lower rates to encourage consumption/the shift of consumption to periods outside of peak demand.

Electricity delivered to consumers via controlled metering allows Eastland to switch off load via ripple control to appliances connected to the controlled meter during periods of peak electricity demand. The price reduction is achieved through the reduction in peak period demand which drives transmission interconnection charges.

The Night Rate Tariff, which excludes street lighting, is a time controlled night rate which was introduced to encourage the connection of larger more efficient fixed wire storage capacity appliances such as night-store heaters. This tariff was applicable for those devices only and to the time period, half hour ending, 23:30 to 07:00. This tariff has seen negative growth in terms of connections and consumption due to the change in technologies and move away from the use of night store heaters. This tariff therefore, has been closed to all new connections since 2011 and no further connections are permitted to connect to it. Eventually, this tariff will be phased out entirely.

Transmission costs that have been allocated to domestic consumers are recovered predominantly through variable charges with a small portion recovered through fixed daily charges. Transmission charges have been structured in the same manner as distribution charges.

7.2 Non-Domestic Charges

In contrast to domestic charges there are no additional regulatory constraints that apply to the determination of non-domestic charges. It is however vital to set prices in such a manner that price stability and certainty is achieved. Non-domestic consumers have often made long term investment decisions based on cost inputs (including electricity) and this must be factored into price determination. Eastland are therefore limited in the rate shock that can be imposed on non-domestic consumers and as such are bound by legacy pricing in this regard. In order to move toward more cost reflective pricing a transition period has been used. The cost of supply allocation previously examined has provided the direction in which non-domestic charges should move.

In addition, a smooth price transition between consumer groups as capacity requirements increase is required. This is to ensure that artificial incentives are not created for consumers to move from one capacity group to another to take advantage of lower prices available to consumer groups with different capacity requirements. This distorts a true cost of supply allocation but eliminates the price instability which flows from a cost of supply allocation where consumers move from one consumer group to another from year to year to exploit prices which relate to different capacity requirements.

Currently there is no location differential in the fixed charges for high and low density non-domestic consumers. However the cost allocation methodology used shows that the total value of assets used to supply low density consumers is significantly greater than that used to supply high density consumers. To reflect this finding an increase in the fixed charges to low density non-domestic consumers may be phased in over the transition period.

Variable charges to non-domestic consumers reflect the time of use pricing signals mentioned previously for domestic consumers. The process has been through a number of iterative cycles to smooth the transition from non-time of use to time of use options.

Time of Use (TOU) tariff is also available to large consumers. To qualify for TOU charges consumers are required to have a capacity requirement greater than 201kVA and TOU metering. These connections tend to have high load factors and have less opportunity to vary load during production hours. As such TOU consumers prefer a higher level of fixed charging which consequently results in reduced peak demand signalling. This reduces the sensitivity of total charges to variation in consumption, which is predominantly outside of peak times, and reflects the decision to recover the majority of non-domestic costs through fixed charges. Some peak signalling is retained in the variable charges to encourage demand side management. It follows that, non-domestic consumer group variable prices decrease as the capacity of the consumer group increases.

7.3 Distributed Generation

7.3.1 Connection charges

Distributed Generation pricing is determined in accordance with distributed generation pricing principles contained in Schedule 6.4 of Part 6 of the Electricity Industry Participation Code 2010.

Distributed Generation connection tariffs are capacity based and comprise a Fixed Distribution charge only. A variable distribution component for energy flow from the generation installation through the distribution network is not charged. Similarly fixed and variable Transmission charges are not applied to Distributed Generation that do not export to the transmission grid. This pricing means that the Distributed Generator, (based on generation capacity) is charged only for the distribution assets employed to connect and distribute energy produced. Therefore in accordance with the distributed generation pricing principles, distributed generators are charged no more than the incremental cost of connection to the network.

7.3.2 Distributed Generation Allowance

In accordance with the regulations Eastland makes payments to distributed generators for Avoided Cost of Transmission. Annually these payments are based on the generators actual contribution to the reduction of transmission charges. The reduction in Transmission charges is calculated as a reduction in interconnection charges. Interconnection charges are calculated on Eastland's contribution to the 100 peak regional demand periods. Consequently, any reduction in regional peak demand will reduce interconnection charges for Eastland network. If a distributed generator has provided energy into the network which reduces Eastland networks' demand during a regional peak period, this benefit of reduced charges is transferred to the distributed generator as required under the distributed generation pricing principles. The December 2016 draft decision on the Distributed Generation Pricing Principles removes the requirement to pay ACOT to distributed generators unless approved by Transpower. This draft decision makes the future of these payments to distributed generators very uncertain after October 2018.

As set out in the Eastland Connection and Operation of Distributed Generation Policy, where a Distributed Generator provides proven and long-term benefits to the distribution network, such as improvement of security of supply, Eastland may contract with the distributed generator to pay for any service they provide.

Payment for Reduction of Losses is not made, as the benefits are realised by the energy retailer and are passed on to end users. In addition, due to the varying load conditions typical in the distribution network, the assessment of the physical losses applicable to a single installation is typically complex, and as such Eastland does not financially recognise the reduction of losses.

8. Distribution Loss Factors

Line losses are determined as the metered energy (in kWh) measured by the metering equipment at each ICP multiplied by the appropriate loss factor. This calculates the equivalent energy at the GXP supplying that ICP for the purposes of the reconciliation agreement and the registry. The loss factor (appearing below) into which each ICP falls will be determined by the point within the distribution network voltage at which the metering for that ICP takes place, together with the particular circumstance of supply.

The allocation of losses is not a contracted line function service and Eastland does not charge specific recoveries for losses.

Loss factors applicable to Eastland changed from 1 April 2015 as a result of the acquisition of Eastland transmission spur assets from Transpower. This is because the metering point for Transpower changed from three GXP's to one GXP. Eastland have picked up the losses that were previously factored in Transmission into its Distribution network.

The undermentioned Loss Factors are applicable to all time periods, at the GXP.

Loss factors applicable to Eastland

• 400V connected supplies (LV Low Voltage)	1.1051
• 11kV connected supplies (HV High Voltage)	1.0822

Loss adjustment factors are reviewed annually and may be amended by Eastland from time to time, to ensure that they reflect unaccounted for energy on the distribution network as accurately as possible.

9. Consumer Survey

Each year Eastland commissions a survey seeking the views of consumers, last year the survey focussed specifically on pricing. The key conclusions of the November 2016 survey are

- Most domestic customers believe that $2.70 per day for line charges is good value.
- Most mass market customers could easily change their daily consumption patterns, but would stop short of allowing direct control of appliances.
- The Gisborne mass market in particular shows a preference for either fixed monthly charges, or a tariff with a low variable component.

10. Uneconomic Bypass

Uneconomic bypass will occur where the charges from Eastland Network are high enough to drive consumers to seek alternative options and the alternative option bears costs for the consumer but does not reduce costs of the same magnitude for the network. Uneconomic bypass will occur where the cost to the consumer of the alternative is lower than the price the network charges but higher than the incremental cost to the network of supplying the customer.

The incremental costs of supplying each new connection is very difficult to quantify but given that networks are built to have some spare capacity the cost would be minimal for each new connection added until such time as a step change in capacity is required. Eastland Network's pricing reflects a smoothed approach to capacity increases as the Eastland Network area has had flat demand for many years with relatively few additional connections each year. Where capacity increases are required for specific customers, capital contributions are required to pay for the additional capacity to reflect the cost drivers at a specific point where there is minimal or no benefit to existing customers. If there are benefits for other customers, this is reflected in the amount contributed so that the costs are spread across the customers that benefit. However, those specific costs are not reflected in the Eastland Network pricing schedule but are treated separately on a case by case basis.

The decreasing cost of emerging technologies such as solar and batteries is likely to encourage uneconomic bypass by some residential consumers. This is due to high variable charges enforced on the industry by the Low Fixed Charge regulations. Eastland is reviewing its options to move towards more innovative pricing structures which are more reflective of the cost of providing lines services, however it is expected that the process of change will take place over a number of years. Eastland will endeavour to engage with customers and key stakeholders during the next 18 - 24 months.

Other risk of uneconomic bypass could come from large customers who could potentially connect directly into the Transmission network, however Eastland Network views this risk to be highly unlikely as there are currently no consumers (existing or potential) of sufficient scale or close enough to Transmission lines to enable them to connect directly to Transpower's transmission lines. With the transfer of the Transpower assets to Eastland Network this possibility is now even more remote.

11. Pricing Principles

Information Disclosures require Eastland Network to demonstrate consistency with the pricing principles published by the Electricity Commission in March 2010 and adopted and amended by the Electricity Authority from time to time.

11.1 Principle 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

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

As Electricity distribution networks make very long-term decisions regarding investment in assets a prudent planning margin is built into assets installed to enable additional small increments to be gradually added until such time as new investment in infrastructure is required.

> "The planning margin is necessary given the very long lead-time to increase supply capacity in respect of 110kV Substations and 110kV transmission lines. Having headroom in the capacity is considered to be of particular importance in the Gisborne region given the unpredictability in growth associated with wood harvesting and related industrial activity[5]."

Consequently short-term incremental costs are minor or nil.

Where long-term incremental costs are incurred these costs are included in prices over the life of the assets. As there is little growth in the Eastland region, this is considered appropriate. Where there are areas of significant growth and corresponding constraints on the network, those requiring additional capacity are typically required to provide some capital contribution for the additional

[5] *Eastland Network Limited Asset management Plan – 2016 to 2026*

investment incurred. These additional investments are quite localised and therefore easily attributable to customer requests. As pricing for these localised areas are not easily separated from general pricing, capital contributions are appropriate. The value of these contributions will assist the customer to determine whether an alternative supply is a more beneficial solution for them and reduces the chance of cross-subsidies.

The standalone price is the cost of a consumer obtaining electricity from an alternative source. However as distribution costs are only approximately 45%[6] of the total cost of a power bill in the Eastland region, the cost of energy and retail margins will also influence the customer's decision.

Currently Eastland's pricing is heavily influenced by regulation and in particular the pricing structure has been developed to comply with the Electricity (Low Fixed Charge Tariff Option for Domestic Consumers) Regulations 2004 whereby fixed charges are limited to 15c per day. Consequently the remainder of the domestic revenue required is received through variable (c/kWh) pricing. While historically, this variable pricing has had the effect of allowing customers to reduce their power bills through energy efficiency initiatives, new opportunities to reduce usage via the network are being achieved through the instalment of small scale generation such as solar panels on rooftops. This is becoming more prevalent as the price of solar and batteries reduce. However the cost of these alternatives have not yet reduced to the point where standalone is more economic than connection to the network. Until such time that household scale electricity storage is cost effective, reliance on network delivered energy will still be required during seasonal & peak times.

Eastland Network's tariff structure divides customers according to capacity thereby signalling the economic cost of service provision based on capacity.

Eastland Network provides Time of Use (TOU) to larger consumers and discounted controlled load tariffs for residential consumers. These tariffs allow the customer or the network to reduce load during peak periods and consequently the consumer is rewarded with cheaper rates during peak times. This is a somewhat basic form of price signal and the economic benefits may not be passed through to customers with bundled and/or anytime packages. Consequently Eastland is looking at other options for sending price signals to consumers.

11.2 Principle 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.

This principle is based on Ramsey pricing where prices are inversely adjusted according to their elasticity of demand. That is, prices are higher for those customers who are less likely to change demand as a result of price changes.

The difficulty of applying this principle in practise is that a) it works to the detriment of domestic consumers as their demand is generally the least elastic; and b) obtaining reliable price elasticity information regarding various groups of customers is extremely difficult.

An alternative to this is to measure elasticity over time intervals rather than by customer groups[7]. It would be expected that peak periods during the cold winter evenings would be the least elastic and consequently prices during peak periods could be set to recover any shortfall in revenues from efficient incremental cost pricing.

6 *Quarterly Survey of Domestic Electricity Prices – 15 November 2015; Ministry of Business, Innovation & Employment*

7 *Regulation of the Power Sector, Springer-Verlag London 2013, Edited by Ignacio J Perez-Arriaga*

Eastland currently makes available Time of Use (TOU) pricing to larger commercial customers who have TOU metering installed which reduces peak loads on the network however as TOU pricing is not yet available for domestic customers, there is no recovery of any reduction in revenue during these peaks but is smoothed across all time periods for domestic customers. TOU pricing is not yet available for domestic connections due to the unavailability of accurate data across all consumers in this category but it is being considered as an option in the near future as the rollout of smart meters in the Eastland region gains more coverage.

11.3 Principle 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

As there is sufficient infrastructure and capacity on the Eastland Network to cover current and future foreseeable needs, the incremental cost of providing additional energy will be minimal. Therefore for the vast majority of customers, if they should disconnect from the network and incur the costs of an alternative supply arrangement it will be economically inefficient although there will be small pockets of rural and isolated customers where bypass will be economically efficient but there is likely to be a trade-off between efficiency and reliability. Further as the cost of connection to the network is currently less than the stand-alone cost of an alternative supply, Eastland considers there to be little economic incentive to bypass the network. However, with the decreasing price of solar and battery technology, Eastland has noticed an increase in the partial bypass of electricity supply on its network. This issue has been raised by the Electricity Authority[8] recently and as a result, Eastland network is in the process of developing more cost reflective pricing options to avoid the issue of cross-subsidies for those who have solar generation by those that don't. Any new pricing options are unlikely to be implemented prior to the next pricing period commencing 1 April 2020.

Eastland Network is willing, if the situation warrants, to discuss alternative arrangements with customers whose connections are remote and costly to maintain. Eastland does provide some flexibility with regard to capital contributions for new connections to counter uneconomic bypass. This enables Eastland and their customers to negotiate price-quality trade-offs.

There are no current or future planned industrial operations of sufficient scale and close enough to a GXP to connect directly to the Transmission grid. Large-scale off-grid alternatives are also not currently an economic alternative to connection to the distribution network.

Eastland Network has contractual arrangements with a related generator to provide large diesel powered generation to remote locations on its network. These generators provide security of supply at a significantly lower cost than building additional overhead lines. A comparison is undertaken each year to determine the costs saved by the network and costs incurred by the generator and

[8] Implications of evolving technologies for pricing of distribution services – Consultation paper; Electricity Authority 3 November 2015

avoided costs are paid to the generator provided that the benefits received are greater than the costs of the generator.

Eastland Network also requires installation of load control relays for all new connections to enable demand response on its network which is implemented regularly during daily peak periods. Where the relays are owned by Eastland Network, the cost to maintain and replace the relays are also borne by Eastland Network thereby ensuring load control is available as a tool for demand response.

11.4 Principle 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.

Development of prices is disclosed in this document which is publicly available. Tariff categories have remained unchanged for a number of years with relatively small increases year on year. Eastland Network is in the process of developing a pricing strategy to address concerns regarding emerging technologies. This strategy and change process will involve considerable engagement with end consumers, retailers, regulators and other key stakeholders.

11.5 Principle 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

Electricity distribution prices in the Eastland Network region are applicable to both the Wairoa and Gisborne networks and are the same across all retailers. This allows for simplicity across both regions and provides a level playing field for all retailers within the Eastland region. Eastland Network will continue to review the number of price categories it has and will attempt to rationalise tariffs as it is able to.

Eastland Network is currently reviewing its pricing structure with a view to developing a simpler pricing and where possible, closer alignment with other electricity distribution businesses. The aim of this exercise is to reduce complexity and therefore costs for all stakeholders however, greater alignment is more likely to occur with the implementation of cost reflective pricing options in 2020.

Appendix 1 – Consumer Group Target Revenue Allocation

Consumer Groups		Code	ICPs	Kwh	Distribution	Transmission	Total
Domestic	Domestic - High Density (Urban)	PDH0030	13,727	82,286,235	$ 8,871	$ 3,513	**$ 12,384**
	Domestic - Low Density (Rural)	PDL0030	5,679	36,946,264	$ 4,681	$ 1,876	**$ 6,557**
High Density (Urban)	Low Capacity 0-3 kVA)	PNH0003	133	629,930	$ 75	$ 42	**$ 117**
	Capacity 3 - 30kVA	PNH0030	1,695	22,243,130	$ 2,535	$ 1,339	**$ 3,875**
	Capacity 31 - 100kVA	PNH0100	277	21,032,729	$ 1,458	$ 826	**$ 2,285**
	Capacity 101 - 300kVA	PNH0300	67	13,702,690	$ 765	$ 422	**$ 1,187**
	TOU - Capacity (201-300 kVA)	PTH0300	6	1,424,776	$ 75	$ 39	**$ 114**
	Capacity (301-500kVA)	PNH0500	16	8,356,573	$ 331	$ 175	**$ 507**
	Capacity (501-1000kVA)	PNH1000	20	24,624,787	$ 857	$ 458	**$ 1,315**
	Capacity (1001-4500kVA)	PNH4500	1	6,725,265	$ 199	$ 108	**$ 307**
	Capacity (4501-6500kVA)	PNH6500	1	20,949,275	$ 581	$ 318	**$ 899**
Low Density (Rural)	Low Capacity 0-3 kVA)	PNL0003	120	272,329	$ 43	$ 24	**$ 67**
	Capacity 3 - 30kVA	PNL0030	3,586	17,857,240	$ 3,437	$ 1,693	**$ 5,129**
	Capacity 31 - 100kVA	PNL0100	100	4,431,985	$ 411	$ 230	**$ 641**
	Capacity 101 - 300kVA	PNL0300	17	1,590,415	$ 130	$ 70	**$ 200**
	TOU - Capacity (201-300 kVA)	PTL0300	1	65,411	$ 8	$ 4	**$ 12**
	Capacity (301-500kVA)	PNL0500	3	1,272,557	$ 56	$ 30	**$ 86**
	Capacity (501-1000kVA)	PNL1000	1	861,783	$ 35	$ 19	**$ 54**
	Capacity (1001-4500kVA)	PNL4500	1	12,726,628	$ 378	$ 209	**$ 587**
	Capacity (4501-6500kVA)	PNL6500	-	-	$ -	$ -	**$ -**
Distributed Generation (greater than 10kVA)	Generation Capacity (301-500kVA)	PNG0500	-	-	$ -	$ -	**$ -**
	Generation Capacity (501-1000kVA)	PNG1000	6	-	$ 63	$ -	**$ 63**
	Generation Capacity (1001-4500kVA)	PNG4500	1	-	$ 26	$ -	**$ 26**
	Generation Capacity (4501-6500kVA)	PNG6500	1	-	$ 39	$ -	**$ 39**
			25,459	**278,000,000**	**$ 25,054**	**$ 11,396**	**$ 36,450**

Appendix 2 – Pricing Schedule

Prices exclude GST

Energised ICP's are billed a Fixed daily charge as shown. Variable charges are shown as a per kWh charge as metered at the ICP.

				Line Charges Effective 1 April 2017					Line Charges Effective 1 April 2016					
	Price Category	**Tariff Code**	**Domestic Consumers**	**Distribution**	**Transmission**	**Total**	**Customer No's**		**Price Category**	**Tariff Code**	**Distribution**	**Transmission**	**Total**	**Customer No's**
High Density	**PDH0030**	**PDH0030FD**	Fixed Charges	$0.1125	$0.0375	**$0.1500**	13,727	**High Density**	**PDH0030**	**PDH0030FD**	$0.1125	$0.0375	**$0.1500**	13,707
		PDH0030UND	Variable Uncontrolled	$0.1177	$0.0471	**$0.1648**				**PDH0030UND**	$0.1124	$0.0454	**$0.1578**	
		PDH0030CND	Variable Controlled	$0.0612	$0.0245	**$0.0857**				**PDH0030CND**	$0.0584	$0.0236	**$0.0820**	
		PDH0030NTD	Variable Night	$0.0152	$0.0061	**$0.0213**				**PDH0030NTD**	$0.0146	$0.0059	**$0.0205**	
Low Density	**PDL0030**	**PDL0030FD**	Fixed Charges	$0.1125	$0.0375	**$0.1500**	5,679	**Low Density**	**PDL0030**	**PDL0030FD**	$0.1125	$0.0375	**$0.1500**	5,669
		PDL0030UND	Variable Uncontrolled	$0.1373	$0.0555	**$0.1928**				**PDL0030UND**	$0.1310	$0.0535	**$0.1845**	
		PDL0030CND	Variable Controlled	$0.0741	$0.0300	**$0.1041**				**PDL0030CND**	$0.0707	$0.0289	**$0.0996**	
		PDL0030NTD	Variable Night	$0.0177	$0.0072	**$0.0249**				**PDL0030NTD**	$0.0170	$0.0069	**$0.0239**	

				Line Charges Effective 1 April 2017					Line Charges Effective 1 April 2016					
	Price Category	**Tariff Code**	**Non Domestic Consumers - High Density**	**Distribution**	**Transmission**	**Total**	**Customer No's**		**Price Category**	**Tariff Code**	**Distribution**	**Transmission**	**Total**	**Customer No's**
High Density	**PNH0003**	**PNH0003FD**	Low Capacity (0 to 3kVA) - Fixed Charges	$0.2981	$0.1422	**$0.4403**	133	**High Density**	**PNH0003**	**PNH0003FD**	$0.2845	$0.1371	**$0.4216**	133
		PNH0003UND	Low Capacity (0 to 3kVA) - Variable Uncontrolled	$0.0956	$0.0562	**$0.1518**				**PNH0003UND**	$0.0912	$0.0542	**$0.1454**	
		PNH0003CND	Low Capacity (0 to 3kVA) - Variable Controlled	$0.0620	$0.0397	**$0.1017**				**PNH0003CND**	$0.0592	$0.0383	**$0.0975**	
		PNH0003NTD	Low Capacity (0 to 3kVA) - Variable Night	$0.0119	$0.0077	**$0.0196**				**PNH0003NTD**	$0.0114	$0.0074	**$0.0188**	
	PNH0030	**PNH0030FD**	Demand (0 to 30kVA) - Fixed Charges	$1.6757	$0.7365	**$2.4122**	1,695		**PNH0030**	**PNH0030FD**	$1.5996	$0.7102	**$2.3098**	1,680
		PNH0030UND	Demand (0 to 30kVA) - Variable Uncontrolled	$0.0685	$0.0404	**$0.1089**				**PNH0030UND**	$0.0655	$0.0390	**$0.1045**	
		PNH0030CND	Demand (0 to 30kVA) - Variable Controlled	$0.0446	$0.0262	**$0.0708**				**PNH0030CND**	$0.0426	$0.0253	**$0.0679**	
		PNH0030NTD	Demand (0 to 30kVA) - Variable Night	$0.0119	$0.0077	**$0.0196**				**PNH0030NTD**	$0.0114	$0.0074	**$0.0188**	
	PNH0100	**PNH0100FD**	Demand (31 to 100kVA) - Fixed Charges	$4.7483	$2.4915	**$7.2398**	277		**PNH0100**	**PNH0100FD**	$4.5282	$2.4026	**$6.9308**	276
		PNH0100UND	Demand (31 to 100kVA) - Variable Uncontrolled	$0.0470	$0.0276	**$0.0746**				**PNH0100UND**	$0.0448	$0.0266	**$0.0714**	
		PNH0100CND	Demand (31 to 100kVA) - Variable Controlled	$0.0306	$0.0178	**$0.0484**				**PNH0100CND**	$0.0291	$0.0172	**$0.0463**	
		PNH0100NTD	Demand (31 to 100kVA) - Variable Night	$0.0119	$0.0077	**$0.0196**				**PNH0100NTD**	$0.0114	$0.0074	**$0.0188**	
	PNH0300	**PNH0300FD**	Demand (101 to 300kVA) - Fixed Charges	$9.8342	$4.6981	**$14.5323**	67		**PNH0300**	**PNH0300FD**	$9.3875	$4.5305	**$13.9180**	66
		PNH0300UND	Demand (101 to 300kVA) - Variable Uncontrolled	$0.0383	$0.0224	**$0.0607**				**PNH0300UND**	$0.0365	$0.0216	**$0.0581**	
		PNH0300CND	Demand (101 to 300kVA) - Variable Controlled	$0.0249	$0.0145	**$0.0394**				**PNH0300CND**	$0.0237	$0.0140	**$0.0377**	
		PNH0300NTD	Demand (101 to 300kVA) - Variable Night	$0.0119	$0.0077	**$0.0196**				**PNH0300NTD**	$0.0114	$0.0074	**$0.0188**	
	PTH0300	**PTH0300FD**	TOU - Demand (201 to 300kVA) - Fixed Charges	$16.3906	$7.8301	**$24.2207**	6		**PTH0300**	**PTH0300FD**	$15.6460	$7.5507	**$23.1967**	6
		PTH0300EPD	TOU - Demand (201 to 300kVA) - Variable Evening Peak	$0.0362	$0.0200	**$0.0562**				**PTH0300EPD**	$0.0345	$0.0193	**$0.0538**	
		PTH0300MPD	TOU - Demand (201 to 300kVA) - Variable Morning Peak	$0.0339	$0.0187	**$0.0526**				**PTH0300MPD**	$0.0323	$0.0180	**$0.0503**	
		PTH0300OPD	TOU - Demand (201 to 300kVA) - Variable Off Peak	$0.0266	$0.0146	**$0.0412**				**PTH0300OPD**	$0.0254	$0.0141	**$0.0395**	
		PTH0300NTD	TOU - Demand (201 to 300kVA) - Variable Night	$0.0136	$0.0077	**$0.0213**				**PTH0300NTD**	$0.0130	$0.0074	**$0.0204**	
	PNH0500	**PNH0500FD**	TOU - Demand (301 to 500kVA) - Fixed Charges	$18.4768	$8.8266	**$27.3034**	16		**PNH0500**	**PNH0500FD**	$17.6374	$8.5117	**$26.1491**	16
		PNH0500EPD	TOU - Demand (301 to 500kVA) - Variable Evening Peak	$0.0362	$0.0200	**$0.0562**				**PNH0500EPD**	$0.0345	$0.0193	**$0.0538**	
		PNH0500MPD	TOU - Demand (301 to 500kVA) - Variable Morning Peak	$0.0339	$0.0187	**$0.0526**				**PNH0500MPD**	$0.0323	$0.0180	**$0.0503**	
		PNH0500OPD	TOU - Demand (301 to 500kVA) - Variable Off Peak	$0.0266	$0.0146	**$0.0412**				**PNH0500OPD**	$0.0254	$0.0141	**$0.0395**	
		PNH0500NTD	TOU - Demand (301 to 500kVA) - Variable Night	$0.0136	$0.0077	**$0.0213**				**PNH0500NTD**	$0.0130	$0.0074	**$0.0204**	
	PNH1000	**PNH1000FD**	TOU - Demand (501 to 1000kVA) - Fixed Charges	$28.6090	$13.6671	**$42.2761**	20		**PNH1000**	**PNH1000FD**	$27.3093	$13.1795	**$40.4888**	20
		PNH1000EPD	TOU - Demand (501 to 1000kVA) - Variable Evening Peak	$0.0362	$0.0200	**$0.0562**				**PNH1000EPD**	$0.0345	$0.0193	**$0.0538**	
		PNH1000MPD	TOU - Demand (501 to 1000kVA) - Variable Morning Peak	$0.0339	$0.0187	**$0.0526**				**PNH1000MPD**	$0.0323	$0.0180	**$0.0503**	
		PNH1000OPD	TOU - Demand (501 to 1000kVA) -Variable Off Peak	$0.0266	$0.0146	**$0.0412**				**PNH1000OPD**	$0.0254	$0.0141	**$0.0395**	
		PNH1000NTD	TOU - Demand (501 to 1000kVA) - Variable Night	$0.0136	$0.0077	**$0.0213**				**PNH1000NTD**	$0.0130	$0.0074	**$0.0204**	
	PNH4500	**PNH4500FD**	TOU - Demand (1001 to 4500kVA) - Fixed Charges	$71.5225	$34.1677	**$105.6902**	1		**PNH4500**	**PNH4500FD**	$68.2733	$32.9486	**$101.2219**	1
		PNH4500EPD	TOU - Demand (1001 to 4500kVA) - Variable Evening Peak	$0.0362	$0.0200	**$0.0562**				**PNH4500EPD**	$0.0345	$0.0193	**$0.0538**	
		PNH4500MPD	TOU - Demand (1001 to 4500kVA) - Variable Morning Peak	$0.0339	$0.0187	**$0.0526**				**PNH4500MPD**	$0.0323	$0.0180	**$0.0503**	
		PNH4500OPD	TOU - Demand (1001 to 4500kVA) - Variable Off Peak	$0.0266	$0.0146	**$0.0412**				**PNH4500OPD**	$0.0254	$0.0141	**$0.0395**	
		PNH4500NTD	TOU - Demand (1001 to 4500kVA) - Variable Night	$0.0136	$0.0077	**$0.0213**				**PNH4500NTD**	$0.0130	$0.0074	**$0.0204**	
	PNH6500	**PNH6500FD**	TOU - Demand (4501 to 6500kVA) - Fixed Charges	$108.8480	$51.9992	**$160.8472**	1		**PNH6500**	**PNH6500FD**	$103.9032	$50.1439	**$154.0471**	1
		PNH6500EPD	TOU - Demand (4501 to 6500kVA) -Variable Evening Peak	$0.0362	$0.0200	**$0.0562**				**PNH6500EPD**	$0.0345	$0.0193	**$0.0538**	
		PNH6500MPD	TOU - Demand (4501 to 6500kVA) - Variable Morning Peak	$0.0339	$0.0187	**$0.0526**				**PNH6500MPD**	$0.0323	$0.0180	**$0.0503**	
		PNH6500OPD	TOU - Demand (4501 to 6500kVA) - Variable Off Peak	$0.0266	$0.0146	**$0.0412**				**PNH6500OPD**	$0.0254	$0.0141	**$0.0395**	
		PNH6500NTD	TOU - Demand (4501 to 6500kVA) - Variable Night	$0.0136	$0.0077	**$0.0213**				**PNH6500NTD**	$0.0130	$0.0074	**$0.0204**	

Line Charges Effective 1 April 2017

	Price Category	Tariff Code	Non Domestic Consumers - Low Density	Distribution	Transmission	Total	Customer No's
Low Density	PNL0003	PNL0003FD	Low Capacity (0 to 3kVA) - Fixed Charges	$0.2981	$0.1422	**$0.4403**	120
		PNL0003UND	Low Capacity (0 to 3kVA) - Variable Uncontrolled	$0.1104	$0.0648	**$0.1752**	
		PNL0003CND	Low Capacity (0 to 3kVA) - Variable Controlled	$0.0849	$0.0457	**$0.1306**	
		PNL0003NTD	Low Capacity (0 to 3kVA) - Variable Night	$0.0164	$0.0087	**$0.0251**	
	PNL0030	PNL0030FD	Demand (0 to 30kVA) - Fixed Charges	$1.6757	$0.7365	**$2.4122**	3,586
		PNL0030UND	Demand (0 to 30kVA) - Variable Uncontrolled	$0.0718	$0.0421	**$0.1139**	
		PNL0030CND	Demand (0 to 30kVA) - Variable Controlled	$0.0468	$0.0274	**$0.0742**	
		PNL0030NTD	Demand (0 to 30kVA) - Variable Night	$0.0138	$0.0087	**$0.0225**	
	PNL0100	PNL0100FD	Demand (31 to 100kVA) - Fixed Charges	$4.7483	$2.4915	**$7.2398**	100
		PNL0100UND	Demand (31 to 100kVA) - Variable Uncontrolled	$0.0545	$0.0320	**$0.0865**	
		PNL0100CND	Demand (31 to 100kVA) - Variable Controlled	$0.0356	$0.0207	**$0.0563**	
		PNL0100NTD	Demand (31 to 100kVA) - Variable Night	$0.0138	$0.0087	**$0.0225**	
	PNL0300	PNL0300FD	Demand (101 to 300kVA) - Fixed Charges	$9.8342	$4.6981	**$14.5323**	17
		PNL0300UND	Demand (101 to 300kVA) - Variable Uncontrolled	$0.0435	$0.0256	**$0.0691**	
		PNL0300CND	Demand (101 to 300kVA) - Variable Controlled	$0.0283	$0.0166	**$0.0449**	
		PNL0300NTD	Demand (101 to 300kVA) - Variable Night	$0.0164	$0.0087	**$0.0251**	
	PTL0300	PTL0300FD	TOU - Demand (201 to 300kVA) - Fixed Charges	$16.3906	$7.8301	**$24.2207**	1
		PTL0300EPD	TOU - Demand (201 to 300kVA) - Variable Evening Peak	$0.0379	$0.0207	**$0.0586**	
		PTL0300MPD	TOU - Demand (201 to 300kVA) - Variable Morning Peak	$0.0356	$0.0195	**$0.0551**	
		PTL0300OPD	TOU - Demand (201 to 300kVA) - Variable Off Peak	$0.0278	$0.0155	**$0.0433**	
		PTL0300NTD	TOU - Demand (201 to 300kVA) - Variable Night	$0.0142	$0.0087	**$0.0229**	
	PNL0500	PNL0500FD	TOU - Demand (301 to 500kVA) - Fixed Charges	$18.4768	$8.8266	**$27.3034**	3
		PNL0500EPD	TOU - Demand (301 to 500kVA) - Variable Evening Peak	$0.0379	$0.0207	**$0.0586**	
		PNL0500MPD	TOU - Demand (301 to 500kVA) - Variable Morning Peak	$0.0356	$0.0195	**$0.0551**	
		PNL0500OPD	TOU - Demand (301 to 500kVA) - Variable Off Peak	$0.0278	$0.0155	**$0.0433**	
		PNL0500NTD	TOU - Demand (301 to 500kVA) - Variable Night	$0.0142	$0.0087	**$0.0229**	
	PNL1000	PNL1000FD	TOU - Demand (501 to 1000kVA) - Fixed Charges	$28.6090	$13.6671	**$42.2761**	1
		PNL1000EPD	TOU - Demand (501 to 1000kVA) - Variable Evening Peak	$0.0379	$0.0207	**$0.0586**	
		PNL1000MPD	TOU - Demand (501 to 1000kVA) - Variable Morning Peak	$0.0356	$0.0195	**$0.0551**	
		PNL1000OPD	TOU - Demand (501 to 1000kVA) -Variable Off Peak	$0.0278	$0.0155	**$0.0433**	
		PNL1000NTD	TOU - Demand (501 to 1000kVA) - Variable Night	$0.0142	$0.0087	**$0.0229**	
	PNL4500	PNL4500FD	TOU - Demand (1001 to 4500kVA) - Fixed Charges	$71.5225	$34.1677	**$105.6902**	1
		PNL4500EPD	TOU - Demand (1001 to 4500kVA) - Variable Evening Peak	$0.0379	$0.0207	**$0.0586**	
		PNL4500MPD	TOU - Demand (1001 to 4500kVA) - Variable Morning Peak	$0.0356	$0.0195	**$0.0551**	
		PNL4500OPD	TOU - Demand (1001 to 4500kVA) - Variable Off Peak	$0.0278	$0.0155	**$0.0433**	
		PNL4500NTD	TOU - Demand (1001 to 4500kVA) - Variable Night	$0.0142	$0.0087	**$0.0229**	
	PNL6500	PNL6500FD	TOU - Demand (4501 to 6500kVA) - Fixed Charges	$108.8480	$51.9992	**$160.8472**	0
		PNL6500EPD	TOU - Demand (4501 to 6500kVA) -Variable Evening Peak	$0.0379	$0.0207	**$0.0586**	
		PNL6500MPD	TOU - Demand (4501 to 6500kVA) - Variable Morning Peak	$0.0356	$0.0195	**$0.0551**	
		PNL6500OPD	TOU - Demand (4501 to 6500kVA) - Variable Off Peak	$0.0278	$0.0155	**$0.0433**	
		PNL6500NTD	TOU - Demand (4501 to 6500kVA) - Variable Night	$0.0142	$0.0087	**$0.0229**	

Line Charges Effective 1 April 2016

	Price Category	Tariff Code	Distribution	Transmission	Total	Customer No's
Low Density	PNL0003	PNL0003FD	$0.2845	$0.1371	**$0.4216**	119
		PNL0003UND	$0.1054	$0.0625	**$0.1679**	
		PNL0003CND	$0.0824	$0.0441	**$0.1265**	
		PNL0003NTD	$0.0159	$0.0084	**$0.0243**	
	PNL0030	PNL0030FD	$1.5996	$0.7102	**$2.3098**	3,604
		PNL0030UND	$0.0685	$0.0406	**$0.1091**	
		PNL0030CND	$0.0446	$0.0264	**$0.0710**	
		PNL0030NTD	$0.0132	$0.0084	**$0.0216**	
	PNL0100	PNL0100FD	$4.5282	$2.4026	**$6.9308**	99
		PNL0100UND	$0.0521	$0.0309	**$0.0830**	
		PNL0100CND	$0.0339	$0.0200	**$0.0539**	
		PNL0100NTD	$0.0132	$0.0084	**$0.0216**	
	PNL0300	PNL0300FD	$9.3875	$4.5305	**$13.9180**	17
		PNL0300UND	$0.0416	$0.0247	**$0.0663**	
		PNL0300CND	$0.0270	$0.0160	**$0.0430**	
		PNL0300NTD	$0.0159	$0.0084	**$0.0243**	
	PTL0300	PTL0300FD	$15.6460	$7.5507	**$23.1967**	1
		PTL0300EPD	$0.0362	$0.0200	**$0.0562**	
		PTL0300MPD	$0.0339	$0.0188	**$0.0527**	
		PTL0300OPD	$0.0265	$0.0149	**$0.0414**	
		PTL0300NTD	$0.0136	$0.0084	**$0.0220**	
	PNL0500	PNL0500FD	$17.6374	$8.5117	**$26.1491**	3
		PNL0500EPD	$0.0362	$0.0200	**$0.0562**	
		PNL0500MPD	$0.0339	$0.0188	**$0.0527**	
		PNL0500OPD	$0.0265	$0.0149	**$0.0414**	
		PNL0500NTD	$0.0136	$0.0084	**$0.0220**	
	PNL1000	PNL1000FD	$27.3093	$13.1795	**$40.4888**	1
		PNL1000EPD	$0.0362	$0.0200	**$0.0562**	
		PNL1000MPD	$0.0339	$0.0188	**$0.0527**	
		PNL1000OPD	$0.0265	$0.0149	**$0.0414**	
		PNL1000NTD	$0.0136	$0.0084	**$0.0220**	
	PNL4500	PNL4500FD	$68.2733	$32.9486	**$101.2219**	1
		PNL4500EPD	$0.0362	$0.0200	**$0.0562**	
		PNL4500MPD	$0.0339	$0.0188	**$0.0527**	
		PNL4500OPD	$0.0265	$0.0149	**$0.0414**	
		PNL4500NTD	$0.0136	$0.0084	**$0.0220**	
	PNL6500	PNL6500FD	$103.9032	$50.1439	**$154.0471**	0
		PNL6500EPD	$0.0362	$0.0200	**$0.0562**	
		PNL6500MPD	$0.0339	$0.0188	**$0.0527**	
		PNL6500OPD	$0.0265	$0.0149	**$0.0414**	
		PNL6500NTD	$0.0136	$0.0084	**$0.0220**	

Line Charges Effective 1 April 2017

	Price Category	Tariff Code	Non Domestic Consumers	Distribution	Transmission	Total	Customer No's
Generation	PNG0500	PNG0500FD	TOU - Demand (301 to 500kVA) - Fixed Charges	$18.1472	$0.0000	**$18.1472**	0
	PNG1000	PNG1000FD	TOU - Demand (501 to 1000kVA) - Fixed Charges	$28.6090	$0.0000	**$28.6090**	6
	PNG4500	PNG4500FD	TOU - Demand (1001 to 4500kVA) - Fixed Charges	$70.2472	$0.0000	**$70.2472**	1
	PNG6500	PNG6500FD	TOU - Demand (4501 to 6500kVA) - Fixed Charges	$106.9073	$0.0000	**$106.9073**	1
Distributed Generation	DG	DG	DG All Variable Distributed Generation	$0.0000	$0.0000	**$0.0000**	224

Line Charges Effective 1 April 2016

	Price Category	Tariff Code	Distribution	Transmission	Total	Customer No's
Generation	PNG0500	PNG0500FD	$17.4913	$0.0000	**$17.4913**	0
	PNG1000	PNG1000FD	$27.3093	$0.0000	**$27.3093**	6
	PNG4500	PNG4500FD	$67.7081	$0.0000	**$67.7081**	1
	PNG6500	PNG6500FD	$103.0432	$0.0000	**$103.0432**	1
Distributed Generation	DG	DG	$0.0000	$0.0000	**$0.0000**	148

End of document

This document is uncontrolled once downloaded or printed.

Printed: 12 January 2016

Eastland Network Ltd, 172 Carnarvon Street
PO Box 1048, Gisborne 4040, New Zealand

Tel 06 869 0700 | Fax 06 867 8563 | info@eastland.nz | eastland.nz