# Eastland Network Limited

# Pricing Methodology Disclosure

**Pursuant to:**

**Requirements 22 and 23 of the Electricity Information Disclosure Requirements 2004**

**For Line Charges introduced on 31 March 2010**

**April 2010**

# Contents

# 1 Introduction

This document sets out Eastland Network Ltd's (ENL's) pricing methodology for the line charges in effect as at 31 March 2010.

ENL's pricing methodology has been prepared to comply with requirements 22 and 23 of the Electricity Information Disclosure Requirements 2004. The disclosure requirements require electricity lines businesses to annually disclose:

- The methodology used to calculate the prices charged.
- The key components of the revenue required to cover the costs and profits of the disclosing entity's line business activities, including cost of capital and transmission charges.
- The consumer groups used to calculate prices charged, including:
  - The rationale for the consumer grouping.
  - The method of determining which group consumers are in.
  - For each consumer group the statistics relating to that group.
- The method and rationale by which components of the revenue were allocated to consumer groups, and the numerical values of the different components.
- The method used to determine the proportion of charges which are fixed and the proportion which are variable, and the rationale for determining the proportions in this manner.

# 2 Pricing Principles

## *2.1 Regulation*

Electricity lines businesses are controlled by the requirements set out by the Commerce Commission in the Commerce Act (Electricity Distribution Default Price-Quality Path) Determination 2010. This means that ENL must comply with the default price-quality regulatory standards:

- A price path standard, representing the allowed annual change in lines business average prices; and
- A quality standard, comprising a reliability criterion.

The price path standard limits the annual change in average line charges to a maximum of CPI.

For this reason, although ENL's pricing methodology is designed to reflect the cost of supply, an adjustment to the final tariffs must be made to ensure that ENL will comply with the regulations and not breach the default price path (DPP).

## *2.2 Revenue*

Line charges should generate sufficient revenue for ENL to meet the following requirements, while also ensuring that ENL does not breach the DPP:

- Meet its contractual obligations for connection to the Transpower Grid;
- Meet its contractual obligations for the delivery of energy over its network to end-consumers;
- Comply with statutory requirements on public safety, environmental protection and quality of supply;
- Provide for new investment;
- Provide a commercially appropriate return on investment.

## *2.3 Efficiency*

Pricing should be economically efficient in the investment signals it creates. This is achieved by matching the price structure to the cost structure as closely as practical.

## *2.4 Even-handedness*

Pricing must be even-handed across different consumer groups. Specifically:

- The charges to various load groups using the network should vary according to their relative use of different assets;
- Where consumer groups receive different levels of service, services above average should be charged specifically to the groups demanding the higher levels of service;
- Where new investment is required those consumers who obtain benefit should be required to contribute towards the cost.

Pricing must also be even-handed in its treatment of retailers and provide for equal access as a matter of statutory requirement.

## *2.5 Simplicity*

Pricing must be kept as simple and as administratively efficient as practical. Specifically;

- Transmission charges should be separated from distribution charges.
- ENL should endeavour to ensure distribution costs are relatively stable over time.

## *2.6 Load management*

The pricing methodology should provide signals to encourage demand-side participation in load management.

## 3 Derivation of Revenue Requirement

The first step in developing network prices is to determine network costs and the targeted revenue requirement. The network cost structure for ENL for the 2010/2011 period is summarised in the following table and is comprised of two main components; distribution costs and transmission costs.

ENL classes Electricity Commission levies, Commerce Act levies and local body rates as distribution costs and passes them through in full to consumers.

| **Distribution Costs** | **Distribution Revenue Requirement 2010/11** |
|---|---:|
| Network Operations and Maintenance | 4,436,848 |
| Indirect Costs | 2,763,122 |
| Pass Through Costs (Non-Transmission) | 128,361 |
| Network Depreciation | 4,072,588 |
| Taxation | 1,333,460 |
| Target Return on Investment | 8,187,949 |
| **Total** | **20,922,327** |

| **Transmission Costs** | **Transmission Revenue Requirement 2010/11** |
|---|---:|
| Transpower | 6,374,036 |
| Avoided Transmission | 2,123,692 |
| Loss Rental Rebates | -55,000 |
| **Total** | **8,442,728** |

Table 1 – Revenue Requirement by component

### *3.1 Distribution revenue requirement*

The distribution revenue requirement is made up of the following components:

- Network Operation and Maintenance Costs
- Indirect Costs
- Pass Through Costs (Non-Transmission)
- Network Deprecation
- Taxation
- Target Return on Investment.

#### 3.1.1 Network operation and maintenance costs, indirect costs, pass through costs (non- transmission), network depreciation and taxation

The revenue requirement components including, network operation and maintenance, indirect, pass through (non transmission), network depreciation and taxation are based on budgeted costs for the 2010/11 period.

### 3.1.2 Target return on investment

Target return on investment provides a return on investment to network owners and is determined as a product of asset value and the weighted average cost of capital.

The asset values applied in this pricing methodology use the regulatory asset base roll forward value.

The target return on investment is determined using a weighted average cost of capital of 8.75%. This figure determines the target return required on network investment, however in practice different parts of the network provide different returns.

## *3.2 Transmission revenue requirement*

Power supply on the East Coast is capacity constrained primarily by the Transpower owned connection assets i.e. the spur assets dedicated to the regions use. Traditional solutions to upgrading capacity and security standards do not represent the least cost solution. The cost of Transpower provided solutions have been determined via the New Investment Agreement Methodology that Transpower applies to such upgrades.

ENL has determined that better load management, optimising the configuration of its sub-transmission system and the introduction of distributed generation present a lower risk and more economic solution. Consequently transmission recovery is intended to recognise the transmission benefit and avoidance of Transpower charges in order to fund these alternatives whether provided by ENL or another party.

The transmission revenue requirement is made up of the following components:

- Transpower Charges
- Avoided Transmission Charges
- Loss Rental Rebates.

### 3.2.1 Transpower

Transpower charges are comprised of two charges, connection charges and interconnection charges. Connection charges are a fixed annual amount and interconnection charges are a fixed rate per unit of regional co-incident peak demand.

### 3.2.2 Avoided transmission

Where an investor provides assets as an alternative to Transpower providing transmission services, such as distributed generation, the benefit of avoided transmission charges will be passed through to the investor on a deprival basis with value calculated per Transpower's transmission pricing methodology. The connection of generators to the ENL network, and the charge/rebates applicable are subject to ENL review on a case-by case basis.

Investment that increases capacity will be recognised via calculation of the connection charge, assuming Transpower upgrade. The benefit to consumers over the Transpower solution is that capacity can be delivered on a more capital-efficient basis. Investment that has the potential to reduce the regional co-incident peak demand at a GXP will be recognised via pass through of reductions in Tanspower's interconnection charge. Avoided transmission charges are based on the assessed impact of these alternatives will have on GXP load profiles both in terms of demand and kWhs.

The maximum potential for reduction in Transpower charges is dependent on operating assets in co-ordination with ENL'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 investor can equally be ENL, any retailer, any generator or independent party. However, the capacity requirement is capped at the ENL determined targets. Where there is a choice of alternative investments, preference will be given to the least cost solution to ENL 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.

Based on the regulations set out in the Commerce Act (Electricity Distribution Default Price-Quality Path) Determination 2010, a distribution company can pass through the costs of avoided transmission to its consumers and/or electricity retailers via line charges. ENL calculates the cost of avoided transmission as the sum of the following factors:

- Cost of Capital
- Depreciation Cost
- Direct Operating Costs
- Maintenance Costs
- Indirect Costs

### 3.2.3 Loss rental rebates

Transpower loss rental rebates are excluded from the revenue requirement as these rebates are passed on transparently via a separate rebate mechanism, to ENL's consumers and/or electricity retailers. A $55,000 administration fee is charged in relation to the determination of pass through amount payable to each retailer.

# 4 Consumer Groups

## 4.1 End-consumer grouping

From 31 March 2010 ENL changed consumer group classification from a high, medium, low density to a more simple high, low density classification. Consumers which previously belonged to the medium density classification have been migrated to either the high or low density groups dependent on their location on the ENL network.

Areas of the network which exhibit high consumer density have been identified in ENL's geographic information system (GIS) and the remainder of the network has been deemed low density. Separating the network and consumers into these new classifications allows ENL 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 ENL's GIS and extracting the corresponding network asset 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. ENL 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 increase the value of assets employed to supply consumers' increases.

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

- It is the consumer's primary and permanent place of residence, i.e. excludes holiday homes, Shearers quarters, garages, pumps, trust owned properties etc.
- Only one installation control point (ICP) on a consumers account can be classed as domestic whether on Eastland Network Ltd or elsewhere.
- The installation is used as a residence and not for business purposes.
- Does not exceed the following current limits:

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

- 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.

Accordingly, ENL employs the following consumer group classifications:

| **Consumer Groups** |
|---|
| **High Density** |
| Domestic |
| Low Capacity (0 to 3kVA) |
| Demand (0 to 30kVA) |
| Demand (31 to 100kVA) |
| Demand (101 to 300kVA) |
| TOU - Demand (301-500kVA) |
| TOU - Demand (501-1000kVA) |
| TOU - Demand (1001-4500kVA) |
| TOU - Demand (4501-6500kVA) |
| **Low Density** |
| Domestic |
| Low Capacity (0 to 3kVA) |
| Demand (0 to 30kVA) |
| Demand (31 to 100kVA) |
| Demand (101 to 300kVA) |
| TOU - Demand (301-500kVA) |
| TOU - Demand (501-1000kVA) |
| TOU - Demand (1001-4500kVA) |
| TOU - Demand (4501-6500kVA) |

Table 2 – Consumer Groups

# 5 Cost Allocation to Consumer Groups

## *5.1 Transition of cost of supply into consumer group tariffs*

In developing the new high-low density classification ENL completed a cost allocation exercise to determine the revenue requirement by consumer group that would be necessary to meet an efficient cost allocation. The cost allocation methodology set out in this document is based on that work and is included to demonstrate that ENL have used this methodology to inform the price changes required and demonstrate that a sound methodology underpins ENL's pricing decisions.

As ENL are 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 subject to changes in the regulations under which ENL operates.

## *5.2 Allocators*

ENL's cost of supply model (COSM) contains the following input assumptions and statistics for the purpose of cost allocation. Allocators are split into two groups, those that are load independent, and those that are load dependent.

*Load Independent*

- Connections - ICPs

*Load Dependent*

- Demand - Anytime Maximum Demand
- Demand - Co-incident Peak Demand
- Consumption - kWh
- Asset Replacement Cost

Capacity and security upgrades result in reconfiguration of network feeders. These can result in changes to the criteria used to allocate asset value, load and ICPs. It has therefore been necessary to assume a static model of network configuration in order to create some stability in pricing.

## *5.3 Allocation of revenue requirement among consumer groups*

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

### 5.3.1 Allocation of distribution revenue requirement

The total revenue requirement (as depicted in table 1 section 3) 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 and the statistics used are shown in Appendix 2.

General management, overheads and administration, depreciation on non-system fixed assets and non transmission pass through costs including Electricity Commission levies and Commerce Act levies have been allocated to consumer groups using each group's share of total connections. These costs do not vary with consumer asset usage and have been allocated on a fixed basis accordingly.

Target return on investment, deprecation, operations and maintenance, taxation and local body rates costs have been allocated to consumer groups based on each group's use of network assets measured in terms of asset value employed and split by demand share. For each density class ENL has extracted network asset data from the GIS and the associated values of these assets from the asset register. Where assets are shared by high and low density consumers, consumer group demand has been used to apportion the asset values between the two density classes. Following the determination of the asset values for high and low density consumers the asset values are broken down further into the individual consumer groups using each group's share of total assessed demand for the corresponding density class.

ENL have employed a network use cost allocation method for load dependent costs. This is consistent with the assumption that investment in network assets is driven by use. In general, peak demand drives the need for network augmentation and is created predominantly by domestic consumers. However in ENL's case there has been little growth in peak demand so an equal split of peak (co-incident) and anytime maximum demand has been used in assessing consumer group demand. This also ensures that non-domestic consumers contribute to network costs as the majority of planned future investment relates to asset renewal and improved reliability, as opposed to network augmentation, through which all consumers benefit not just those consuming during peak periods.

### 5.3.2 Allocation of transmission revenue requirement

ENL have allocated transmission costs to consumer groups using a close approximation to the methodology set out in Transpower's transmission pricing methodology. That is connection costs, where connection points are shared by more than one Transpower customer, are allocated based on each consumers share of anytime maximum demand at that connection point. In ENL's case connection charges are allocated to consumer group's based on their share of total anytime maximum demand. Interconnection charges are allocated to consumers based on their share of total co-incident peak demand on ENL's network.

Avoided transmission charges are allocated on the same basis as Transpower transmission charges.

# 6 Price Structure

ENL uses ICP billing for charging end consumers. However ENL 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

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

## *6.1 Domestic charges*

The low user fixed charge regulations cap fixed charges to domestic consumers at 15 cents per day. ENL have set domestic fixed charges at 15 cents per day which is less than that determined by the cost allocation described earlier. As such the remainder of the fixed cost allocated to domestic consumers is recovered through variable charges.

All domestic consumers receive the benefit of the 15 cents per day government policy intended to reward low consumption behaviour. As this is the only domestic fixed charge and is not optional, compliance with the 8,000 kWh per annum break-even requirement is automatic.

Three variable rates are offered to domestic consumers which reflect the metering options available on the ENL 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 ENL 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 has been introduced to encourage the connection of larger more efficient fixed wire storage capacity appliances. This tariff is applicable for those devices only and to the time period, half hour ending, 23:30 to 07:00

Transmission costs which 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.

## 6.2 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. ENL 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 as discussed in section 5.1 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 to 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 will 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.

To qualify for time-of-use (TOU) charges consumers are required to have a capacity requirement greater than or equal to 300kVA 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 Losses

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

However in the absence of agreed individual estimated loss calculations the following defaults can be applied to reconcile the difference between ICP and GXP meter readings. These are applicable to all time periods, at all GXPs and network locations.

Loss factors applicable to ENL

- 400V connected supplies 1.0705
- 11kV connected supplies 1.0475

# 8 Uneconomic Bypass

ENL do not consider there is any risk of uneconomic by pass.

## Appendix 1 – Consumer Group Cost Allocation

| **Tariff Group** | | Network Operations and Maintenance | Indirect Costs | Pass Through Costs (Non-Transmission) | Network Depreciation | Taxation | Transpower | Avoided Transmission | Loss Rental Rebates | **Direct Cost Recovery** | **Effective Return on Investment** | *Rounding Adjustment* | **Total Revenue** |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **High Density** | Domestic | 861,203 | 1,471,742 | 39,994 | 790,499 | 258,828 | 2,456,743 | 932,089 | -16,126 | 6,794,971 | 3,486,897 | | 10,281,868 |
| | Low Capacity (0 to 3kVA) | 2,951 | 9,177 | 204 | 2,708 | 887 | 8,045 | 2,524 | -83 | 26,412 | 41,436 | | 67,849 |
| | Demand (0 to 30kVA) | 193,848 | 185,606 | 6,654 | 177,933 | 58,259 | 514,900 | 141,208 | -4,640 | 1,273,770 | 1,966,541 | | 3,240,311 |
| | Demand (31 to 100kVA) | 145,855 | 26,546 | 3,183 | 133,881 | 43,836 | 397,699 | 124,758 | -4,290 | 871,468 | 937,949 | | 1,809,417 |
| | Demand (101 to 300kVA) | 51,282 | 5,244 | 1,053 | 47,072 | 15,412 | 231,780 | 72,709 | -2,522 | 422,030 | 336,123 | | 758,152 |
| | TOU - Demand (301-500kVA) | 29,240 | 2,185 | 588 | 26,840 | 8,788 | 132,158 | 41,458 | -1,726 | 239,530 | 194,358 | | 433,889 |
| | TOU - Demand (501-1000kVA) | 69,855 | 1,966 | 1,351 | 64,120 | 20,994 | 315,725 | 99,043 | -4,986 | 568,069 | 489,321 | | 1,057,390 |
| | TOU - Demand (1001-4500kVA) | 38,031 | 109 | 720 | 34,909 | 11,430 | 145,210 | 5,869 | -1,282 | 234,996 | -14,192 | | 220,804 |
| | TOU - Demand (4501-6500kVA) | 74,631 | 109 | 1,412 | 68,504 | 22,430 | 333,145 | 98,309 | -3,743 | 594,797 | -14,775 | | 580,021 |
| | **Total High Density** | **1,466,895** | **1,702,685** | **55,159** | **1,346,465** | **440,864** | **4,535,406** | **1,517,967** | **-39,397** | **11,026,044** | **7,423,657** | **0** | **18,449,701** |
| **Low Density** | Domestic | 1,714,538 | 664,862 | 43,108 | 1,573,777 | 515,291 | 1,063,814 | 403,612 | -7,744 | 5,971,258 | -197,631 | | 5,773,628 |
| | Low Capacity (0 to 3kVA) | 8,073 | 10,924 | 329 | 7,410 | 2,426 | 4,624 | 1,206 | -49 | 34,943 | 15,052 | | 49,995 |
| | Demand (0 to 30kVA) | 591,988 | 375,146 | 17,231 | 543,386 | 177,917 | 339,036 | 88,438 | -3,565 | 2,129,578 | 1,809,668 | | 3,939,246 |
| | Demand (31 to 100kVA) | 144,667 | 7,866 | 2,860 | 132,790 | 43,478 | 82,852 | 21,612 | -865 | 435,259 | 12,235 | | 447,494 |
| | Demand (101 to 300kVA) | 42,561 | 1,092 | 822 | 39,067 | 12,791 | 29,028 | 7,572 | -304 | 132,628 | -11,859 | | 120,769 |
| | TOU - Demand (301-500kVA) | 54,481 | 328 | 1,035 | 50,008 | 16,374 | 37,158 | 9,693 | -301 | 168,775 | -94,835 | | 73,939 |
| | TOU - Demand (501-1000kVA) | 42,811 | 109 | 811 | 39,296 | 12,866 | 29,198 | 7,616 | -123 | 132,584 | -103,402 | | 29,182 |
| | TOU - Demand (1001-4500kVA) | 370,834 | 109 | 7,007 | 340,389 | 111,451 | 252,920 | 65,975 | -2,651 | 1,146,036 | -663,582 | | 482,454 |
| | TOU - Demand (4501-6500kVA) | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | | 0 |
| | **Total Low Density** | **2,969,953** | **1,060,437** | **73,202** | **2,726,123** | **892,596** | **1,838,630** | **605,724** | **-15,603** | **10,151,062** | **765,645** | **0** | **10,916,707** |
| | *Rounding Adjustment* | | | | | | | | | | | | -1,354 |
| | **Total Network** | **4,436,848** | **2,763,122** | **128,361** | **4,072,588** | **1,333,460** | **6,374,036** | **2,123,692** | **-55,000** | **21,177,106** | **8,189,303** | **-1,354** | **29,365,055** |

## Appendix 2 - Consumer Group Statistics

| Consumer Group | Number of ICPs | | |
|---|---|---|---|
| | High Density | Low Density | Total |
| Domestic | 13,472 | 6,086 | 19,558 |
| Low Capacity (0 to 3kVA) | 84 | 100 | 184 |
| Demand (0 to 30kVA) | 1,699 | 3,434 | 5,133 |
| Demand (31 to 100kVA) | 243 | 72 | 315 |
| Demand (101 to 300kVA) | 48 | 10 | 58 |
| TOU - Demand (301-500kVA) | 20 | 3 | 23 |
| TOU - Demand (501-1000kVA) | 18 | 1 | 19 |
| TOU - Demand (1001-4500kVA) | 1 | 1 | 2 |
| TOU - Demand (4501-6500kVA) | 1 | - | 1 |
| Total | 15,586 | 9,707 | 25,293 |

| Consumer Group | Consumption (kWh) for each Consumer Group | | |
|---|---|---|---|
| | High Density | Low Density | Total |
| Domestic | 82,313,239 | 39,529,279 | 121,842,518 |
| Low Capacity (0 to 3kVA) | 421,546 | 249,884 | 671,430 |
| Demand (0 to 30kVA) | 23,681,660 | 18,196,135 | 41,877,795 |
| Demand (31 to 100kVA) | 21,897,627 | 4,417,715 | 26,315,342 |
| Demand (101 to 300kVA) | 12,871,923 | 1,553,035 | 14,424,958 |
| TOU - Demand (301-500kVA) | 8,812,280 | 1,535,522 | 10,347,802 |
| TOU - Demand (501-1000kVA) | 25,448,528 | 627,564 | 26,076,092 |
| TOU - Demand (1001-4500kVA) | 6,544,268 | 13,531,658 | 20,075,926 |
| TOU - Demand (4501-6500kVA) | 19,105,676 | - | 19,105,676 |
| Total | 201,096,747 | 79,640,792 | 280,737,539 |

| Consumer Group | AMD (kW) for each Consumer Group | | |
|---|---|---|---|
| | High Density | Low Density | Total |
| Domestic | 25,450 | 11,020 | 36,470 |
| Low Capacity (0 to 3kVA) | 105 | 71 | 176 |
| Demand (0 to 30kVA) | 7,601 | 5,195 | 12,797 |
| Demand (31 to 100kVA) | 5,214 | 1,270 | 6,484 |
| Demand (101 to 300kVA) | 3,039 | 445 | 3,484 |
| TOU - Demand (301-500kVA) | 1,733 | 569 | 2,302 |
| TOU - Demand (501-1000kVA) | 4,139 | 447 | 4,587 |
| TOU - Demand (1001-4500kVA) | 3,566 | 3,876 | 7,441 |
| TOU - Demand (4501-6500kVA) | 4,627 | - | 4,627 |
| Total | 55,474 | 22,893 | 78,368 |

| Consumer Group | CPD (kW) for each Consumer Group | | |
|---|---|---|---|
| | High Density | Low Density | Total |
| Domestic | 25,450 | 11,020 | 36,470 |
| Low Capacity (0 to 3kVA) | 69 | 33 | 102 |
| Demand (0 to 30kVA) | 3,856 | 2,415 | 6,270 |
| Demand (31 to 100kVA) | 3,406 | 590 | 3,996 |
| Demand (101 to 300kVA) | 1,985 | 207 | 2,192 |
| TOU - Demand (301-500kVA) | 1,132 | 265 | 1,397 |
| TOU - Demand (501-1000kVA) | 2,704 | 208 | 2,912 |
| TOU - Demand (1001-4500kVA) | 160 | 1,801 | 1,962 |
| TOU - Demand (4501-6500kVA) | 2,684 | - | 2,684 |
| Total | 41,447 | 16,539 | 57,985 |