HORIZON ENERGY DISTRIBUTION LIMITED

Pricing Methodology
For Line Charges introduced on 1 April 2015

4 March 2015

Electricity Distribution Information Disclosure Determination 2012

Disclosure of Pricing Methodologies (Pursuant to Part 4 of Commerce Act 1986)

Contents

1. Glossary

AMD	Anytime Maximum Demand
COS	Cost of Supply
DG	Distributed Generation
DPP	Default Price-Quality Path
DRC	Depreciated Replacement Cost
GXP	Grid Exit Point
HV	High Voltage
ICP	Installation Control Point
kVA	Kilowatt Ampere
kW	Kilowatts
kWh	Kilowatt Hour
LRR	Loss Rental Rebates
LV	Low Voltage
NMD	Network Maximum Demand
NZ IAS	New Zealand Equivalent to International Accounting Standard
RC	Replacement Cost
TPM	Transmission Pricing Methodology

2. Introduction

Horizon Energy Distribution Limited ("Horizon Energy") has set out in this document the pricing methodology for line charges introduced on 1 April 2015 (i.e. 2015/16 line charges).

Horizon Energy's pricing methodology has not changed from last year as such no consultation has taken place with consumers. The transitional process has continued, as had been signalled in prior methodologies, and consulted upon in 2010 when redefining domestic load groups (applicable to 2011/12 line charges). As such Horizon Energy has maintained previous progress in the movement of line charges towards fixed tariffs where there is an economic requirement to ensure capacity and quality of service within the network is maintained.

2.1. Strategy

Horizon Energy continues with the process commenced in 2011/12 to transition pricing to align more closely with the cost of supplying customers, including the re-balancing of charges to rural customers. In addition, the process of maintaining the fixed tariff portion in all load groups continues, so as to ensure the appropriate level of investment in the network continues to be maintained.

Horizon Energy will be considering the introduction of uncontrolled tariffs and power factor tariffs for select consumer groups as part of a possible tariff restructuring process, which may also include revision on the availability of standard and non-standard domestic groups.

3. Regulatory Considerations

Horizon Energy's pricing methodology is subject to the following regulations:

- The Commerce Commission's *Electricity Distribution Information Disclosure Determination 2012* ("IDD2012"), set under Part 4 of the Commerce Act 1986 ("the Act");
- The Electricity Authority's *Distribution Pricing Principles and Information Disclosure Guidelines 2010;*
- The *Electricity (Low Fixed Charge Tariff Option for Domestic Consumers) Regulations 2004* ("the low fixed charge regulations"); and
- *Part 6 of the Electricity Industry Participation Code* ("the Code"), relating to the pricing of distributed generation.

The key requirements of these regulations are summarised below. Horizon Energy has developed and disclosed a pricing methodology consistent with these regulations.

3.1. Information Disclosures

Clause 2.4.1 to 2.4.5 of the IDD2012 sets out the following requirements relating to the disclosure of pricing methodologies:

Clause 2.4.1
Every Electricity Distribution Business ("EDB") must publicly disclose, before the start of each disclosure year, a pricing methodology which:

(1) Describes the methodology, in accordance with clause 2.4.3 below, used to calculate the prices payable or to be payable;

(2) Describes any changes in prices and target revenues;

(3) Explains, in accordance with clause 2.4.5 below, the approach taken with respect to pricing in non-standard contracts and distributed generation (if any);

(4) Explains whether, and if so how, the EDB has sought the views of consumers, including their expectations in terms of price and quality, and reflected those views in calculating the prices payable or to be payable. If the EDB has not sought the views of consumers, the reasons for not doing so must be disclosed.

Clause 2.4.2
Any change in the pricing methodology or adoption of a different pricing methodology, must be publicly disclosed at least 20 working days before prices determined in accordance with the change or the different pricing methodology take effect.

Clause 2.4.3
Every disclosure under clause 2.4.1 above must:

(1) Include sufficient information and commentary to enable interested persons to understand how prices were set for each consumer group, including the assumptions and statistics used to determine prices for each consumer group;

(2) Demonstrate the extent to which the pricing methodology is consistent with the pricing principles and explain the reasons for any inconsistency between the pricing methodology and the pricing principles;

(3) State the target revenue expected to be collected for the disclosure year to which the pricing methodology applies;

(4) Where applicable, identify the key components of target revenue required to cover the costs and return on investment associated with the EDB's provision of electricity lines services. Disclosure must include the numerical value of each of the components;

(5) State the consumer groups for whom prices have been set, and describe:

- (a) the rationale for grouping consumers in this way;
- (b) the method and the criteria used by the EDB to allocate consumers to each of the consumer groups;

(6) If prices have changed from prices disclosed for the immediately preceding disclosure year, explain the reasons for changes, and quantify the difference in respect of each of those reasons;

(7) Where applicable, describe the method used by the EDB to allocate the target revenue among consumer groups, including the numerical values of the target revenue allocated to each consumer group, and the rationale for allocating it in this way;

(8) State the proportion of target revenue (if applicable) that is collected through each price component as publicly disclosed under clause 2.4.18.

Clause 2.4.4

Every disclosure under clause 2.4.1 above must, if the EDB has a pricing strategy:

(1) Explain the pricing strategy for the next 5 disclosure years (or as close to 5 years as the pricing strategy allows), including the current disclosure year for which prices are set;

(2) Explain how and why prices for each consumer group are expected to change as a result of the pricing strategy;

(3) If the pricing strategy has changed from the preceding disclosure year, identify the changes and explain the reasons for the changes.

Clause 2.4.5

Every disclosure under clause 2.4.1 above must:

(1) Describe the approach to setting prices for non-standard contracts, including-

(a) the extent of non-standard contract use, including the number of ICPs represented by non-standard contracts and the value of target revenue expected to be collected from consumers subject to non-standard contracts;

(b) how the EDB determines whether to use a non-standard contract, including any criteria used;

(c) any specific criteria or methodology used for determining prices for consumers subject to non-standard contracts and the extent to which these criteria or that methodology are consistent with the pricing principles;

(2) Describe the EDB's obligations and responsibilities (if any) to consumers subject to non-standard contracts in the event that the supply of electricity lines services to the consumer is interrupted. This description must explain-

(a) the extent of the differences in the relevant terms between standard contracts and non-standard contracts;

(b) any implications of this approach for determining prices for consumers subject to non-standard contracts;

(3) Describe the EDB's approach to developing prices for electricity distribution services provided to consumers that own distributed generation, including any payments made by the EDB to the owner of any distributed generation, and including the-

(a) prices; and

(b) value, structure and rationale for any payments to the owner of the distributed generation.

3.2. Pricing Principles

The pricing principles referred to in clause 2.4.3(2) of the IDD2012 were developed by the Electricity Commission in 2010 (and adopted by the Electricity Authority). These pricing principles detail economic, consumer and sector-specific considerations relevant to EDB pricing. Adoption of the pricing principles is currently voluntary, but EDBs must disclose the extent to which their pricing methodologies are consistent with the principles.
The Electricity Authority's Distribution Pricing Principles are as follows:

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

The pricing principles are accompanied by a set of Information Disclosure Guidelines that details relevant information which is useful for EDBs to provide in order to demonstrate consistency against the pricing principles. The disclosure guidelines require the following disclosures (which are similar to, but not exactly the same as the IDD2012 requirements):

- Prices are to be based on a well-defined, clearly explained and published methodology, with any material revisions to the methodology notified and clearly marked.
- The pricing methodology must demonstrate:
    - How the methodology links to the pricing principles and any non-compliance;
    - Rationale for consumer groupings and method for determining the allocation of consumers to consumer groups;
    - Quantification of key components of costs and revenues;
    - An explanation of the cost allocation methodology and the rationale for the allocation to each consumer group;
    - An explanation of the derivation of the tariffs to be charged to each consumer group and the rationale for the tariff design; and
    - Pricing arrangements used to share the value of any deferral of investment in distribution and transmission assets, with the investors in alternatives such as distributed generation or load management; where alternatives are practicable and where network economics warrant.

- The pricing methodology should also:
  - Employ industry standard terminology, where possible; and
  - Where a change to the previous pricing methodology is implemented, describe the impact on consumer classes and transition arrangements implemented to introduce the new methodology.

We have considered each pricing principle in developing our line charges to apply from 1 April 2015. At the end of this document we include a summary demonstrating the extent to which our pricing methodology is consistent with each principle. Additional information has also been provided throughout this document to provide further explanation on our pricing methodology consistent with the Information Disclosures Guidelines.

In addition to the pricing principles and information disclosure guidelines the Electricity Authority has been considering introducing *Criteria for assessing alignment against the Information Disclosure Guidelines and Principle Principals* as well as an economic and decision-making framework that would overlay the current pricing principles. A decision is outstanding on whether to adopt these changes. Accordingly, we have not considered these in this pricing methodology.

3.3. Low Fixed Charge Regulation

The low fixed charge regulations require electricity retailers to offer domestic consumers a tariff option with a fixed charge not exceeding 30 cents per day (excluding GST and after prompt payment discounts) which is targeted at consumers using less than 8,000 kWh for annual consumption. Variable charges must be set such that these consumers are no worse off than other domestic consumers at 8,000 kWh for annual consumption.

To facilitate retailers meeting their obligations, distributors are also required to offer a similar tariff option to domestic consumers, in which the distributor's daily fixed charge must not exceed 15 cents per day. Consumers taking up this option should be no worse off than domestic consumers at 8,000kWh.

3.4. Distributed Generation Pricing Principles

Part 6 of the Code sets out requirements for the connection of distributed generation to electricity distribution networks. It details a regulated connections process as well as regulated terms and conditions that will apply should parties fail to agree to an alternative connection contract.

The regulated terms for connection of distributed generation require that connection charges payable by a distributed generator must be determined in accordance with pricing principles set out in schedule 6.4. Clause 2 of Schedule 6.4 requires distributors to set prices based on reasonable costs to comply with connection and operation standards within the network, including consideration of any identifiable avoided costs (clause 2 of Schedule 6.4). Additionally, clause 2(a) of schedule 6.4 sets a price cap at the incremental cost of connecting distributed generation, net of any avoided costs that an efficient market operation service provider would be able to avoid as a result of the connection of the distributed generation.

4. Pricing Methodology Overview

In developing our pricing methodology, and the associated line charge tariffs we undertake the following key steps:

- Determine the amount of revenue to be recovered via line charges for the pricing period, in this case 1 April 2015 – 31 March 2016;
- Consider how to group consumers into load groups for pricing purposes and determine the key attributes of each load group for the purpose of allocating the revenue requirement and calculating tariffs;
- Allocate the revenue requirement to load groups; and
- Determine the structure of tariffs to apply to each load group for the pricing period.

Our 2015/16 pricing methodology remains consistent with the 2014/15 pricing methodology and we set out our approach to each of these steps in the following sections of this report.

5. Target Revenue

This section describes how Horizon Energy establishes the target revenue requirement to be recovered through lines charges.

5.1. Regulatory Limitations

Horizon Energy is subject to the Default Price-Quality Path ("DPP") regulation under Part 4 of the Act. The Commerce Commission reset the DPP on 28 November 2014 (with effect from 1 April 2015) in Electricity Distribution Services Default Price-Quality Path Determination 2015 (NZCC33).

The total target revenue requirement for the 12 month period commencing 1 April 2015 is determined on the basis of the maximum allowable revenue Horizon Energy may recover from lines charges consistent with Horizon Energy complying with the Electricity Distribution Services Default Price-Quality Path Determination 2015.

5.2. Target Revenue Requirement

Table 1 provides the target revenue requirement building block for electricity lines services for the 12 month period commencing 1 April 2015.

Table 1: Revenue Building Blocks (Before Tax)

Cost Item	Revenue Requirement ($)
Connection Charges	3,471,875
Interconnection Charges	3,192,094
Avoided Transmission	2,216,731
Electricity Authority Levies	99,277
Electricity & Gas Complaints Commissioner Scheme Levies	9,051
Commerce Act Levies	53,411
Local Body Rates	203,765
Business Support	3,593,242
System Management and Operations	2,365,733
Line Maintenance	2,840,439
Depreciation on Network Assets	4,598,011
Depreciation on Non-Network Assets	596,718
Pre Tax Return on Assets	7,356,617
Total Revenue Requirement	**30,596,965**

The above revenue requirement of $30.6M consists of distribution revenue of $21.4M and pass-through revenue of $9.2M. This is inclusive of allowable recoverable costs and pass-through costs and after adjusting for the difference between DPP allowed quantities and 2015/16 projected quantities.

The comparable revenue requirement for 2014/15 was $31.4M.

Recoverable costs that may be recovered through lines charges under the DPP include Transpower charges and avoided transmission charges. The target revenue requirement includes forecasts of these costs as described as follows:

- *Transpower charges,* including connection, interconnection and notional embedding charges. Interconnection charges are calculated based on a rate per unit of coincident peak demand, determined based on Horizon Energy's share of the Upper North Island regional peaks. Connection charges are a fixed annual amount which recoups Transpower's costs associated with connection assets built to connect Horizon Energy's network to the national grid.
- *Avoided transmission charges:* DG connected to Horizon Energy's network provides local benefits to distribution consumers through avoiding Transpower charges. Horizon Energy passes on these benefits to distributed generators by way of avoided transmission payments. This is in turn recovered from distribution consumers through the annual revenue requirement. The basis for determining the avoided transmission charge is the Transmission Pricing Methodology ("TPM").

Loss rental rebates are excluded from the revenue requirement as these are passed directly to retailers and contracted customers, and thus do not impact on line charges.

The various levies and rates are passed through directly to consumers.
Annual operating, maintenance and administration costs reflect the budgeted costs for providing lines services for the pricing period.

The depreciation component of the revenue requirement reflects the return of our capital investment in network and non-network assets required in the provision of electricity lines services. The depreciation charge is calculated from Horizon Energy's financial reporting asset values which have been established on a fair value basis in accordance with NZ IAS 16.

The return on asset component is a product of the calculation that includes maximum allowable revenue set by the Commerce Commission less operational expenditure.

The Commerce Commission has set a target return on the asset base, using the 67th percentile estimate of vanilla WACC at 7.19% for the 2015-20 regulatory period.

The target revenue requirement is presented on a pre-tax basis exclusive of GST.

6. Consumer Groups

6.1. Disaggregation of Load Groups

The pricing methodology seeks to fairly allocate costs amongst various consumer groups (load groups). Horizon Energy has chosen to separate consumers groups into load groupings in recognition of each group's respective network capacity utilisation. Network capacity is the primary service that EDBs provide and is a key driver of network costs. Consumer groupings based on typical consumer load profiles therefore align pricing to our costs and the service we provide.

Load group disaggregation has been determined after consideration of the end use characteristics, location and capacity requirements of each connection. All connections are able to be classified by their service main fuse, selected from a range of national standard sizes.

Consumers are also classified into domestic or non-domestic consumers. Non domestic consumers are further classified as general, network maximum demand, non-metered supplies or major consumers.

Domestic consumers have been grouped together because they share similar network usage profiles. Typically, domestic load profiles indicate peak consumption from 7:30am - 9:30am and 5:30pm - 9:00pm. In addition it is necessary to distinguish between those domestic consumers which are subject to the low user fixed charge regulations and those which are not. As the low user fixed charge regulations only apply to primary residences, domestic consumers are allocated into one of the following load groups:

- Low user domestic (primary residence eligible for low fixed charges under the *Electricity (Low Fixed Charge Tariff Option for Domestic Consumers) Regulations 2004*);
- Standard domestic (8,000 kWh annual consumption and above); and
- Non-standard domestic (low user domestic not eligible for the low user fixed charge regulations, e.g. Holiday homes).

In contrast, non-domestic consumers exhibit a wide range of load profiles due to the diverse nature of their commercial activities. It is also more practical to distinguish and charge these consumers by their load usage given the availability of data. Accordingly, it is appropriate to group these consumers together based on their assessed capacity requirements using their installed fuse rating or assessed installed transformer capacities. This approach reflects the fact that increased capacity requirements impose a greater demand on the value of assets required to supply these consumers.

Non-domestic consumers are allocated into the following load groups:

N1U or N1	1 phase 60 Ampere only
N2U or N2R	3 phase 60 Ampere (no 2 phase availability)
N3U or N3R	3 phase 100 Ampere (no 1 phase or 2 phase availability)
N4U or N4R	3 phase 160 Ampere (no longer offered)
N5U or N5R	3 phase 160 Ampere (no longer offered)

Horizon Energy also groups all non-domestic consumers which are unmetered (including street lighting and electric fence units) into an ‘other’ load group.

Non-domestic consumers with a connection of greater than 3 phase 100 Ampere are grouped as Network Maximum Demand (“NMD”) consumers (with the exception of those who may already be on capacity group 4 or 5 tariffs). This group is metered on maximum demand in order to assess individual capacity requirements. This enables capacity based pricing for these larger non-domestic consumers. Capacity Group 4 and 5 tariffs are no longer available to new connections and existing customers are expected to move to NMD tariffs over time. Therefore customers do not face an overlap in the choices available.

Further distinction is made between those domestic and capacity consumers located in urban and rural areas. For pricing purposes, Horizon Energy’s distribution network has been segregated into urban and rural regions. The urban areas are the towns and built up areas of Kawerau, Edgecumbe, Whakatane and Opotiki. The rural areas make up the balance of the network. The boundaries, determined previously, have been retained to avoid unnecessary disruption to consumers and to minimise transaction costs.

The distinction between urban and rural networks is used for those components of our pricing methodology where the customer and network characteristics indicate that differential costs and therefore tariff levels are justified in order to reflect fair prices to all consumers.

In summary, Horizon Energy has adopted standard load groupings assumed for pricing purposes as follows:

Table 2: Standard Load Groups

Load Groups	
Domestic	
LUDU	Urban Low User Domestic
LUDR	Rural Low User Domestic
SDU	Urban Standard Domestic
SDR	Rural Standard Domestic
NSDU	Urban Non-standard Domestic
NSDR	Rural Non-standard Domestic
Capacity Groups	
N1U	Urban Capacity Group 1 (0-14 kVA)
N1R	Rural Capacity Group 1 (0-14 kVA)
N2U	Urban Capacity Group 2 (15-42 kVA)
N2R	Rural Capacity Group 2 (15-42 kVA)
N3U	Urban Capacity Group 3 (43-70 kVA)
N3R	Rural Capacity Group 3 (43-70 kVA)
N4U	Urban Capacity Group 4 (71-100 kVA)
N4R	Rural Capacity Group 4 (71-100 kVA)
N5U	Urban Capacity Group 5 (>100 kVA)
N5R	Rural Capacity Group 5 (>100 kVA)
Network Maximum Demand	
NMD	Network Maximum Demand
Specials	
UV	U/Veranda Lights
EF	Electric Fence
SL	Street Lights
PCM 24	PCM 24 Hour
PCMN	PCM Night Only

Table 3 below sets out the key characteristics of each load group.

Table 3: Statistics Relevant to Standard Load Groups

Load Groups		Number of ICPs	Consumption (kWh)	AMD (kW)	Share of Total Assets (DRC%)
Domestic					
LUD	Low User Domestic	11,056	55,402,102	18,059	19.7%
SD	Standard Domestic	7,914	60,990,000	19,881	21.7%
NSD	Non-standard Domestic	717	1,954,022	1,434	1.8%
Capacity Groups					
N1U	Urban Capacity Group 1 (0-14 kVA)	610	3,323,577	1,221	1.0%
N1R	Rural Capacity Group 1 (0-14 kVA)	912	3,063,791	1,824	2.8%
N2U	Urban Capacity Group 2 (15-42 kVA)	802	13,128,622	4,410	3.7%
N2R	Rural Capacity Group 2 (15-42 kVA)	1,776	24,466,639	9,770	15.1%
N3U	Urban Capacity Group 3 (43-70 kVA)	268	10,266,294	3,484	2.9%
N3R	Rural Capacity Group 3 (43-70 kVA)	314	14,361,654	4,078	6.3%
N4U	Urban Capacity Group 4 (71-100 kVA)	48	2,751,079	1,198	1.0%
N4R	Rural Capacity Group 4 (71-100 kVA)	38	2,379,728	950	6.3%
N5U	Urban Capacity Group 5 (>100 kVA)	31	2,393,673	1,085	0.9%
N5R	Rural Capacity Group 5 (>100 kVA)	27	1,648,826	945	1.5%
Network Maximum Demand					
NMD	Network Maximum Demand	145	45,809,164	12,325	9.5%
Specials					
UV	U/Veranda Lights	14	-	1	0.0%
EF	Electric Fence	16	-	2	0.0%
SL	Street Lights	22	2,188,822	550	1.3%
PCM 24	PCM 24 Hour	77	-	116	0.2%
PCMN	PCM Night Only	17	-	9	0.0%

In addition to standard load groupings, several large consumers with dedicated assets and/or non-standard service requirements are treated separately as non-standard consumers. They are hence removed from other non-domestic load groups.

The majority of this document addresses the pricing methodology for those consumers on standard contract terms. The methodology for setting prices for non-standard contracts and distributed generation is described in detail in section 7 and 8 below.

7. Non-Standard Contracts

Horizon Energy has seven non-standard contracts with large consumers that have dedicated assets. The target revenue for non-standard contracts is $4.1M. For commercial reasons, prices and revenue figures for individual contract are not shown in detail.

Horizon Energy's minimum criteria for determining whether to enter into a non-standard contract include:

- Peak demand above 1.5 MVA; or
- There is an existing non-standard contract up for replacement.

7.1. Non-Standard Pricing Methodology

The methodology for determining prices for non-standard consumers follows a similar approach to that for standard contracts. A cost-based building block is calculated to determine prices applicable to each non-standard consumer. Prices seek to recover:

- The full cost of dedicated assets, including:
  - a return of capital (i.e. depreciation)
  - a return on capital (using a pre-tax weighted average cost of capital of 10.2%)
  - operations and maintenance
- An allocation of shared asset costs (as above), which are apportioned to non-standard consumers based on their capacity utilisation of those assets.
- An allocation of transmission charges based on coincident peak, capacity utilisation; and
- A share of general overheads, including rates and levies, based on an allocation of shared assets.

7.2. Pricing Principles

The process for determining line charges for non-standard consumers aligns with the pricing principles, as follows:

- Prices have been set to signal the economic cost of the service provided, and are subsidy free within each consumer group. The incremental cost for connection of the next additional unit for supply is minimal. However prices are set greater than the incremental cost of the assets in use because the costs of shared assets are apportioned among all standard load groups and are in addition to incremental costs associated with the provision of dedicated assets. The stand alone cost would require the customer to meet the full cost of each asset used to deliver supply and will, by necessity, be higher. This is perhaps best evidenced by the fact that even the largest non-standard consumers have accepted the terms of the contract and not attempted to bypass the network to achieve a lower stand alone cost.
- To the extent practicable, prices reflect the capacity requirements of major customers. This is because cost allocations are based on maximum demand drivers and capacity utilisation of shared assets.
- Non-standard prices implicitly signal the impact of additional usage on future investment costs. This is because negotiations centre on the provision of dedicated assets, capacity and coincident demand which provide a pre-specified level of service for a given price. Any requirement for additional capacity or service capability above that provided for in contracts will need to be recouped in renegotiated prices.
- Discussions held on pricing and willingness to pay as part of contract negotiations determines the demand responsiveness of non-standard consumers.

- Non-standard pricing is offered to some consumers partly in order to discourage uneconomic bypass. Discussions over price and quality trade-offs are also inherent in the use of non-standard contracts.
- Allowances have been made within non-standard pricing for distributed generation, where applicable. For instance, one non-standard consumer is given a discount in recognition of its use of distributed generation.
- Careful consideration is given to the impact on large consumers when setting prices, with the use of fixed pricing promoting certainty for large consumers. Pricing schedules are transparently provided to non-standard consumers, and are typically accompanied by a detailed explanation on the methodology undertaken.
- Billing for large consumers is on a fixed monthly basis, and is limited to seven non-standard contracts, thereby limiting the transactional costs for retailers and direct billed large consumers.

7.3. Specific Obligations to Non-Standard Consumers

Horizon Energy has a commitment to large customers to ensure supply is maintained within the agreed quality thresholds. These obligations and responsibilities are not substantially different to those of consumers on standard contracts.

When a large industrial customer requests higher reliability than a standard customer, there is typically a requirement for specific assets to be installed to achieve an improved service level. The large customer pays for the use of the extra assets in the normal way. This allows a transparent price versus quality trade off to all parties.

8. Distribution Generation

Horizon Energy has a published policy on Distributed Generation consisting of two parts, being for connections under 10kW, and for others with larger generation. The policy has been prepared in accordance with Part 6 of the Electricity Industry Participation Code 2010.

Horizon Energy has a number of embedded generating stations that predate the regulations and those generators receive benefits if they can reduce transmission charges payable by Horizon Energy and therefore the end customers.

The current policy provides for sharing the benefits of avoiding transmission charges with generators when the scale and consistency of supply justify it. The policy includes sections on:

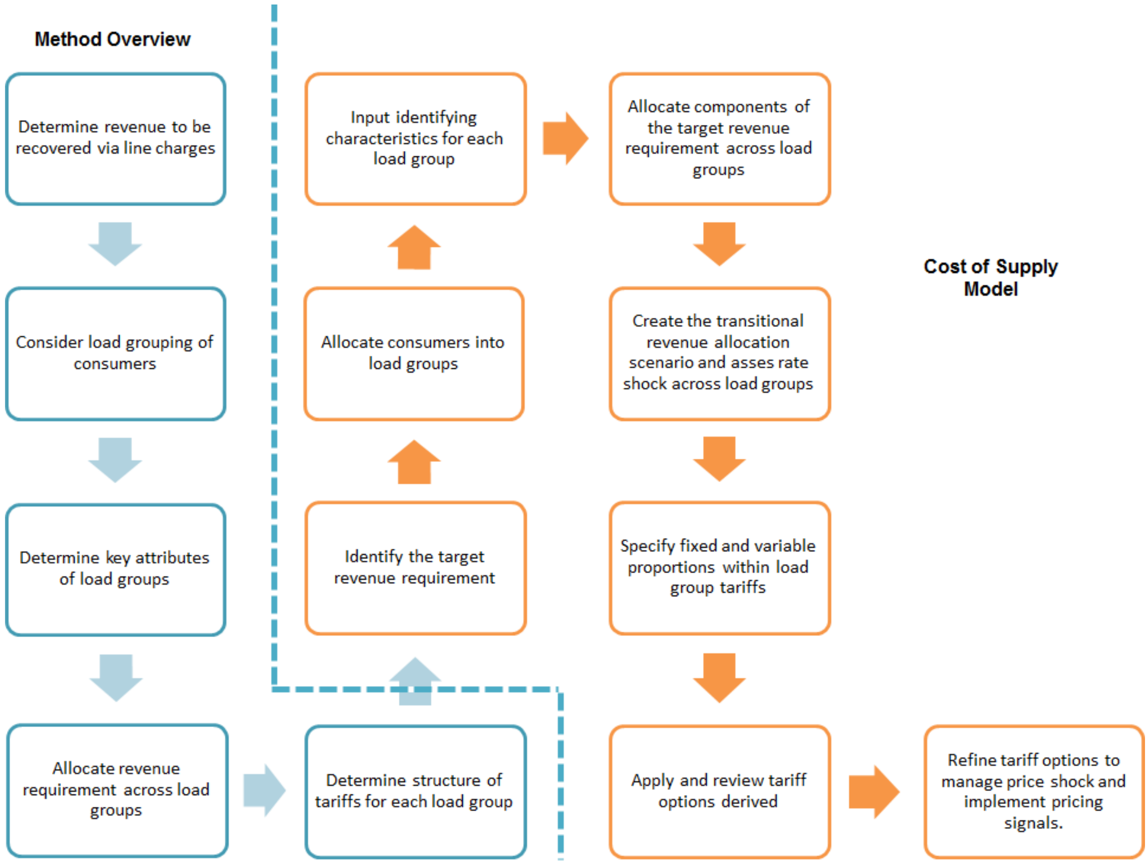
- The Connection Process;
- Network Charges;
- Technical Requirements;
- Data Requirements; and
- Useful Links.

Recently, only small solar generation without storage has been connected. Horizon Energy does not receive any benefit from these units and therefore is not able to pass any benefits to the owners of that generation.

Line charges are attributed to both load and injection within the network, thereby any injection from distributed generation will incur standard line charges attributed to the applicable consumer group. The rate applied for injection at 1 April 2015 is $0k/kwh.

9. Revenue Allocation to Standard Load Groups

9.1. Overview of Pricing Process



9.2. Cost of Supply Model

Horizon Energy has developed a Cost of Supply ("COS") model which separately allocates each component of the revenue requirement to load groups using appropriate cost allocators. The COS modelling process comprises the following key calculations:

- Identify the target revenue requirement to be recovered from line charges, by cost component as outlined above;
- Allocate consumers into load groups consistent with the existing load group structure discussed above;
- Input identifying characteristics for each load group (e.g. number of ICPs, kWh, etc.) which are used to allocate costs;

- Allocate each component of the target revenue requirement to the proposed load groups using cost of supply allocators (refer below) in order to determine the amount of revenue to be recovered from each load group;
- In addition derive a modified set of revenue allocations such that the revenue to be recovered from each load group is not materially different from the previous year, taking into account changes in customer numbers and consumption. This generates a transitional revenue allocation scenario which is used to analyse and manage potential rate shock for individual consumers;
- Once the revenue requirement for each load group is determined, specify the proportion of fixed and variable, distribution and transmission tariffs in order to test alternative tariff options;
- Apply the tariff options derived for each load group across the consumption bands evident in each load group to test the impact on high/average/low use consumers within each load group; and
- Refine the tariff options as required in order to meet regulatory requirements, manage price shock and implement pricing signals consistent with the pricing principles.

9.3. Allocation of Target Revenue Requirement to Standard Load Groups

The target revenue requirement is specified as a number of different cost categories as outlined above. The COS model incorporates sufficient flexibility to allocate individual cost components to load groups using a range of applicable allocators. To some extent the range of allocators is limited by data availability and in some instances proxies have been used.

The relevant allocators which are currently available to Horizon Energy are:

- Installation Control Point ("ICP") count
- Load (kWh)
- Anytime Maximum Demand ("AMD")
- Depreciated Replacement Cost of System Fixed Assets ($)

We have allocated the components of the target revenue requirement using the cost allocators set out below in Table 4.

Table 4: Summary of Cost Allocators Used for Revenue Requirements

Cost Item	Requirement ($)	Cost Allocator
Connection Charges	3,471,875	Anytime Maximum Demand
Interconnection Charges	3,192,094	Anytime Maximum Demand
Avoided Transmission	2,216,731	Anytime Maximum Demand
Electricity Authority Levies	99,277	ICP Count
Electricity & Gas Complaints Commissioner Scheme Levies	9,051	ICP Count
Commerce Act Levies	53,411	Asset Related Allocator
Local Authority Rates	203,765	Asset Related Allocator
Business Support	3,593,242	ICP Count
System Management and Operations	2,365,733	Asset Related Allocator
Line Maintenance	2,840,439	Asset Related Allocator
Depreciation on Network Assets	4,598,011	Asset Related Allocator
Depreciation on Non-Network Assets	596,718	ICP Count
Target Pre Tax Return on Assets	7,356,617	Asset Related Allocator
Total Revenue Requirement	**30,596,965**	

This allocator selection demonstrates the underlying cost drivers for electricity supply, being the provision, operation and maintenance of network assets of a given service capacity. In recognition of this we have selected allocators which best reflect the usage of assets and demand for capacity for each customer group. Similarly, transmission charges have also been allocated based on capacity utilisation. This reflects Transpower's requirement to provide adequate capacity (and maintain the availability of that capacity) in the national grid.

General management, administration and overhead costs, EA levies and non-network assets are allocated to load groups on the relative number of connections, recognising that these costs are shared by all consumers equally.

9.4. Information Used for Cost Allocators

The following information is used for the purpose of cost allocation.

- ICPs – The number of ICPs within each load group are used to allocate components of the revenue requirement which are deemed to be shared equally across all ICPs;
- Load (kWh) – Annual consumption is an allocator which may be used to share components of the revenue requirement between load groups. Previously, this was applied to LRR revenues. However, under the current COS modelling assumptions, this is no longer used as all LRR revenues are now assumed to be passed on directly.
- Anytime Maximum Demand (kW) – Each load group's maximum demand is used to allocate transmission charges, consistent with TPM which apportions transmission charge via peak demand signals. For major industrial customers the peak coincident with RCPD is used to match TPM. For mid-range customers the price signal reflects the local capacity required to supply and as their load pattern is similar to the network's, the use of AMD does not disadvantage them. The remaining load groups are known to follow a profile that is similar to the Network as a whole and therefore the use of AMD is simple, effective and fair. Asset related allocators ($) –The most recent financial reporting DRC valuation asset register is used for this purpose as this is the most recent asset register

available with sufficient granularity. Assets are allocated into load groups as follows:

a) Depreciated Replacement Cost ("DRC") is allocated into the following network components:
    - Sub transmission;
    - Zone substations;
    - Distribution HV/LV; and
    - Street lighting assets.
b) Assets dedicated to the major industrial consumers are extracted from the above asset groups.
c) Street lighting assets are allocated directly to the street lighting load group.
d) In order to allocate the non-dedicated assets between rural and urban network segments it is assumed:
    - The sub transmission backbone including zone substation assets are shared equally across the entire network; and
    - Distribution assets located in the urban and rural areas are dedicated to those consumers located in urban and rural zones respectively. In order to achieve this all of the distribution assets are allocated into urban and rural zones by designating feeders as urban or rural. Locational identifiers from the fixed asset valuation are available for the purpose of ascribing all distribution assets to a feeder.
e) The sub transmission, zone substation, urban distribution and rural distribution assets are shared between urban and rural domestic, urban and rural capacity, NMD and special load groups on the basis of the anytime maximum demand of each load group.
f) Once the asset values are ascribed to each load group, the proportion of the depreciated asset value assigned to each load group is used to apportion asset related components of the revenue requirement (e.g. line maintenance, depreciation, and profit).

9.5. Revenue Requirement Allocation to Load Groups

Using the methodology and assumptions outlined above, the revenue requirement for 2015/16 is allocated to load groups as set out in table 5 and 6.

Table 5 compares 2015/16 revenue allocations to previous 2014/15 revenue allocations, and highlights the transition of load group cost allocations to a fully cost reflective allocation over time, such as the movement of revenue from network maximum demand consumers, and re-allocation to capacity consumers. Also reflected are changes in load profiles, such as where consumers have moved from the N1 capacity load group to the non-standard domestic load group.

Table 5: Allocation of Revenue Requirement to Standard Load Groups

Load Groups		2015/16 Revenue ($)	2014/15 Revenue ($)	Revenue Change ($)
Domestic				
LUD/SD	Low User and Standard Domestic	13,020,938	13,381,376	- 360,438
NSD	Non-standard Domestic	530,002	489,475	40,527
Capacity Groups				
N1	Capacity Group 1 (0-14 kVA)	1,192,733	1,107,811	84,922
N2	Capacity Group 2 (15-42 kVA)	4,665,910	4,767,671	- 101,761
N3	Capacity Group 3 (43-70 kVA)	2,218,871	1,933,234	285,637
N4	Capacity Group 4 (71-100 kVA)	591,930	545,176	46,754
N5	Capacity Group 5 (>100 kVA)	561,123	487,638	73,484
CC	Capacity Concession	-	-	-
Network Maximum Demand				
NMD	Network Maximum Demand	3,387,002	3,319,127	67,875
Specials				
UV	U/Veranda Lights	3,591	4,492	- 901
EF	Electric Fence	4,184	4,134	50
SL	Street Lights	291,203	270,337	20,866
PCM 24	PCM 24 Hour	51,137	41,937	9,200
PCMN	PCM Night Only	5,871	5,756	114

Table 6 provides a detailed breakdown of cost allocations for each load group, by transmission and distribution components of revenue, for fixed and variable tariff types.

Table 6: Allocation of Revenue Requirement (Detailed) to Standard Load Groups

Load Groups		Distribution Revenue ($)			Transmission Revenue ($)			Total Revenue ($)
		Fixed	Variable	Distribution	Fixed	Variable	Transmission	
Domestic								
LUD	Low User Domestic	-	4,955,439	4,955,439	606,167	824,021	1,430,188	6,385,627
SD	Standard Domestic	3,523,395	1,658,632	5,182,028	1,453,283	-	1,453,283	6,635,311
NSD	Non-standard Domestic	368,011	53,000	421,011	108,991	-	108,991	530,002
Capacity Groups								
N1	Capacity Group 1 (0-14 kVA)	784,347	176,123	960,470	232,263	-	232,263	1,192,733
N2	Capacity Group 2 (15-42 kVA)	1,488,552	2,099,660	3,588,212	1,077,698	-	1,077,698	4,665,910
N3	Capacity Group 3 (43-70 kVA)	534,699	1,109,435	1,644,134	574,736	-	574,736	2,218,871
N4	Capacity Group 4 (71-100 kVA)	132,685	295,965	428,650	163,279	-	163,279	591,930
N5	Capacity Group 5 (>100 kVA)	154,336	252,505	406,841	154,282	-	154,282	561,123
CC	Capacity Concession	-	-	-	-	-	-	-
Network Maximum Demand								
NMD	Network Maximum Demand	1,434,189	1,016,100	2,450,290	936,712	-	936,712	3,387,002
UV	U/Veranda Lights	3,485	-	3,485	106	-	106	3,591
EF	Electric Fence	4,062	-	4,062	122	-	122	4,184
SL	Street Lights	249,403	-	249,403	41,801	-	41,801	291,203
PCM 24	PCM 24 Hour	42,359	-	42,359	8,778	-	8,778	51,137
PCMN	PCM Night Only	5,225	-	5,225	646	-	646	5,871

9.6. Urban/Rural Differentiation

Special consideration has been given to the characteristics of connections located in urban and rural areas, and the different demands they make on the network. Connection density is a factor which influences differences in the costs of supply between urban and rural network locations. More investment is required in rural areas to provide the same connection capacity when compared to urban areas given the greater distances, on average between connections. However connections located in urban areas are generally larger on average due to the higher intensity of non-domestic connections.

In addition, network configuration and shorter response times generally result in higher service quality in urban areas when compared to rural areas. This offsets in part the investment imbalance.

For the purpose of the 2015/16 pricing methodology the following approach has been adopted in respect of urban/rural tariff differentials:

- Transmission charges are the same for urban and rural consumers within each load group reflecting the fact that the transmission service delivery occurs up to the Grid Exit Point ("GXP") and thus is equivalent for all like customers irrespective of location on the distribution network;
- Distribution costs are allocated separately to urban and rural consumers for the domestic and general capacity load groups. No rural/urban allocation is undertaken for NMD or large consumers as the tariff methodologies applied to consumers within these groups are specific to the characteristics of each individual consumer;
- For domestic consumers, the urban and rural tariffs are equalised. This occurs because of the constraints of the *Electricity (Low Fixed Charge Tariff Option for Domestic Consumers) Regulations 2004* and the requirement to maintain revenue equivalence with the cross over to the standard domestic tariff at 8,000 kWh. Urban and rural tariff codes have been maintained and Horizon Energy plans to consider possible differentiation between rural and urban domestic tariffs in the future; and
- For general capacity consumers, urban and rural tariffs are implemented in order to recover the distribution component of the underlying costs for each network segment. The target revenue recovery is determined by the COS model (as outlined above) and the fixed and variable components of revenue are determined using the methodology outlined previously. This is the same underlying methodology as applied in previous years where urban/rural differentials have also been charged to general capacity consumers.

10. Tariff Structure

10.1. Key Considerations

Given there are numerous combinations of tariffs possible, Horizon Energy has developed its tariff structure upon consideration of the following relevant factors:

- The extent to which Horizon Energy's underlying costs are fixed or variable;
- Mitigation of revenue risk associated with passing on transmission and avoided transmission charges;
- The impact of the *Electricity (Low Fixed Charge Tariff Option for Domestic Consumers) Regulations 2004* and the requirement to maintain a daily fixed charge and revenue equivalence based on kWh usage;
- The manner in which costs can be shared between low, medium and high volume users within each load group;

- The existing tariff structures and the need to moderate step changes in any one pricing year;
- Appropriately signalling future investment costs through use of tariff structures that create incentives on consumers regarding incremental load, energy efficiency, demand management and capacity utilisation;
- A desire for transaction and tariff simplicity;
- The availability of information necessary to implement certain tariff options;
- Retailer pricing structures and the likelihood of retailers repackaging tariffs and disrupting the intended pricing incentives;
- The likelihood of uneconomic bypass of the distribution system; and
- The service levels provided to different load groups.

10.2. Tariff Mix

The tariff approach adopted for 2015/16 is consistent with the existing approach in place for 2014/15.

As transmission charges (as a component of recoverable costs) are substantially known at the time prices are set, Horizon Energy continues to remove revenue risk associated with the recovery of these external costs, by passing these through to consumers as fully fixed charges (subject to low user regulatory constraints and transitional arrangements).

For distribution related costs, Horizon Energy continues to balance the trade-offs between revenue risk, energy efficiency, contributions to incremental capacity, intergroup cross subsidy (between low and high users within each standard load group) and tariff simplicity.

Horizon Energy's rationale is that all customers must contribute to the required cost recovery through the fixed charge component regardless of energy consumption. This recognises that the majority of Horizon Energy's network investments are sunk and fixed (i.e. having already been made and having no alternative use). Nevertheless, a variable element to pricing structures is seen as important for sending appropriate signals to consumers regarding the impact their usage has on future investment costs. It also better recognises relative usage of existing capacity by different load groupings.

Accordingly, the distribution component of the revenue recovery for all load groups (with the exception of large and NMD consumers) comprises:

- A unit charge (c/kWh) recovered on the basis of electricity consumption; and
- A fixed charge ($/day/ICP) recovered for every ICP within each load group on a consistent basis.

For NMD consumers, a more sophisticated tariff structure (consistent with the 2013/14 tariff structure) is provided which better reflects the diversity of consumers within this tariff group and the ability (given the additional information available about these consumers) to price on a capacity and demand basis, as follows:

- A unit charge (c/kWh) recovered on the basis of electricity consumption;
- A fixed charge ($/kVA/day) recovered for every unit of installed capacity for each consumer; and
- A fixed charge ($/kW) recovered for every unit of assessed peak demand for each consumer.

Table 7: Percentage Revenue Allocation across Tariff Codes

Load Group		Tariff	Revenue %
Low User Domestic			
	Low User Domestic	HET001/HET003	1.99%
	Low User Domestic	HET012/HET013	18.93%
Standard Domestic			
	Standard Domestic	HET030/HET031	16.30%
	Standard Domestic	HET050/HET051	5.43%
Non-standard Domestic			
	Non-standard Domestic	HET032/HET033	1.56%
	Non-standard Domestic	HET052/HET053	0.17%
General - Urban			
N1U	Urban Capacity Group 1 (0-14 kVA)	HET016	1.34%
N1U	Urban Capacity Group 1 (0-14 kVA)	HET040	0.19%
N2U	Urban Capacity Group 2 (15-42 kVA)	HET017	1.96%
N2U	Urban Capacity Group 2 (15-42 kVA)	HET041	1.60%
N3U	Urban Capacity Group 3 (43-70 kVA)	HET018	1.31%
N3U	Urban Capacity Group 3 (43-70 kVA)	HET042	1.31%
N3U	Urban Capacity Group 4 (71-100 kVA)	HET019	0.52%
N3U	Urban Capacity Group 4 (71-100 kVA)	HET043	0.52%
N3U	Urban Capacity Group 5 (>100 kVA)	HET020	0.51%
N3U	Urban Capacity Group 5 (>100 kVA)	HET044	0.42%
CCU	Urban Capacity Concession	HET021	0.00%
General - Rural			
N1R	Rural Capacity Group 1 (0-14 kVA)	HET022	1.99%
N1R	Rural Capacity Group 1 (0-14 kVA)	HET045	0.18%
N2R	Rural Capacity Group 2 (15-42 kVA)	HET023	6.45%
N2R	Rural Capacity Group 2 (15-42 kVA)	HET046	5.28%
N3R	Rural Capacity Group 3 (43-70 kVA)	HET024	2.32%
N3R	Rural Capacity Group 3 (43-70 kVA)	HET047	2.32%
N4R	Rural Capacity Group 4 (71-100 kVA)	HET025	0.45%
N4R	Rural Capacity Group 4 (71-100 kVA)	HET048	0.45%
N5R	Rural Capacity Group 5 (>100 kVA)	HET026	0.50%
N5R	Rural Capacity Group 5 (>100 kVA)	HET049	0.41%
CCR	Rural Capacity Concession	HET027	0.00%
Network Maximum Demand			
NMD	Network Maximum Demand	HET074	2.77%
NMD	Network Maximum Demand	HET076	4.99%
NMD	Network Maximum Demand	HET077	3.33%
Specials			
UV	U/Veranda Lights	HET009	0.01%
EF	Electric Fence	HET006	0.01%
SL	Street Lights		0.95%
		HET008	0.00%
PCM 24	PCM 24 Hour	HET115	0.17%
PCMN	PCM Night Only	HET116	0.02%
Non-standard Contracts	Large Consumers		13.34%

11. Distribution Pricing Principles

Horizon Energy's pricing methodology remains consistent with the Electricity Commission's *Distribution Pricing Principles and Information Disclosure Guidelines 2010*.

The following section provides a brief summary of the extent to which each principle is reflected in this year's pricing methodology.

11.1. Principle A: Signalling the Economic Cost of Service Provision

The revenue allocation approach adopted by Horizon Energy reflects an average approach to the allocation of the revenue requirement between consumer groups. By definition, for each consumer group, this results in a revenue allocation which falls somewhere between incremental cost and stand alone cost on the basis that the cost allocators used are a representation of the underlying cost drivers of the business.

It is not practical to accurately estimate the stand-alone costs for small individual consumers which are supplied a common service via a meshed and integrated network. However, it is obvious that stand alone costs would be much higher than average costs for consumers given the scale efficiencies in supplying them from an integrated network. For example, the cost of providing dedicated circuits and equipment to individual load groups (i.e. domestic) would most certainly exceed that of providing assets shared by all load groups and allocated to consumers based on their relative usage. Conversely in the majority of cases the incremental cost of supplying a domestic consumer is limited to the increase in transmission charges. This of course only holds true until a section of the network becomes fully loaded, at which stage the incremental cost balloons to unacceptable levels for an individual customer and closer to but still a long way below the stand alone cost. The use of a uniform average allocation of costs to a group provides an equitable result typically above the incremental cost but below the stand alone cost.

In our view, the greatest risk that prices exceed stand-alone cost is where consumers are situated close to a GXP or where they have alternative supply options (i.e. own generation or use of alternative fuels) such that they can bypass the distributor network. Only a handful of large consumers are likely to have the scale to approach Transpower for a GXP connection or to install their own energy supply to bypass the distribution network. We consider that use of non-standard contracts facilitates negotiation with consumers who believe their stand alone cost is lower than price therefore avoiding the risk of breaching stand-alone cost.

It is also difficult to estimate the incremental cost of supplying each consumer an additional unit of capacity. The COS model considers the impact of the tariff groups capacity on the network costs and allocates it per kW. This produces a result that is both fair and reasonable to consumers. However, it is reasonable to assume that the incremental cost of connecting each additional mass market consumer to the network is relatively small.

Furthermore, capital contributions and infrastructural contributions charged upon connection of a consumer to the network go some way to ensuring that prices exceed the incremental cost of connection beyond the cost of installing service mains and dedicated equipment and that existing customers do not meet all the cost of replacing the spare capacity used up.
Accordingly, Horizon Energy considers that our tariffs are consistent with pricing principle (a)(i) and fall within a subsidy free range.

Horizon Energy's use of dividing consumers into groups according to installed capacity is consistent with pricing principle (a)(ii), which suggests prices should have regard to the level of available service capacity. This is because their installed capacity is reflective of the underlying cost drivers associated with incrementally supplying each load group. Therefore, prices increase across these load groups as demand for capacity increases. The COS model allocates the costs of providing capacity within the network based on the AMD of each consumer group. In this way, the AMD of the large number of domestic consumers is used to ensure they meet their share of the cost of providing that capacity. Because of the diversity and the numbers involved the demand for this group is predictable to a sufficiently measureable level.

In terms of pricing principle (a)(iii), which deals with signalling the impact of future usage on future investment costs, the most relevant price for this purpose is a demand charge. However, this is only possible for consumers where demand information, such as half hourly metering, is available (such as the NMD load group). Weaker signals are provided for smaller load groups through the use of kWh variable charges. This is a reasonable proxy for demand where consumer demand data is not available, and the consumer's consumption is markedly distinct to the average, while having regard to transaction costs, tariff simplicity (refer below) and standard industry practice. It is also currently necessary to charge a kWh charge in order to comply with the low fixed charge regulations. The anticipated increasing use of small unregulated distributed generation will reduce the usefulness of kWh consumption as a proxy for capacity in the near future.

Further information on future investment is contained in the Asset Management Plan. The Asset Management Plan can be found on the Horizon Energy website with all other information disclosures.

These conclusions along with the regulatory constraints of the weighted average price cap and the *Electricity (Low Fixed Charge Tariff Option for Domestic Consumers) Regulations 2004* indicate that the pricing methodology adopted by Horizon Energy is consistent with the economic cost of service provision principle.

11.2. Principle B: Efficiency and Demand Responsiveness

Pricing principle (b) asserts the Ramsey Pricing principle. The use of marginal cost pricing by natural monopolies will under recover their total revenue requirement (given marginal costs are typically low) and accordingly prices set with reference to marginal costs must be scaled up to recover the full cost of providing electricity lines services. Ramsey pricing suggests that such scaling should take into account the price elasticity of each load group, and those consumers with lower price elasticities should bear a higher proportion of scaling.

In practice this is a difficult principle to apply as price elasticity information is difficult to obtain and it is likely the price elasticity will differ within each of Horizon Energy's load groups. For example, different commercial users are likely to have very different price elasticity's depending on the importance of their electricity supply in meeting their business requirements. In addition, Horizon Energy's interposed arrangements with energy retailers limits the information available to us about the characteristics of our consumers.

However, by recovering a considerable portion of revenue by way of variable charges we indirectly reflect each consumer's willingness to pay. In addition, non-standard pricing with large consumers also directly reflects their willingness to pay for the dedicated services they receive.

11.3. Principle C(i)-(ii): Responsive to the Needs of Stakeholders

Non-standard contracts facilitate the negotiation of price and quality trade-offs (Principle C(i)) and provide a mechanism to address uneconomic bypass (Principle C(ii)). Individual prices are determined for each of the major industrial consumers located on Horizon Energy's network. These reflect the specific assets associated with the supply of line function services to these customers, and the quality of service requirements of these customers. Prices negotiated in this manner are likely to be consistent with the economic value to the consumer of the specific service offering. Non-standard prices may also reflect a discount on standard prices where a consumer has alternative supply options which mean it may bypass the network.

Similarly, our pricing methodology specifically recognises the installed capacity requirements of each individual NMD consumer and provides a combination of capacity and demand prices which consumers may select depending on their capacity requirements. This combined with the variable consumption based tariff provides the appropriate mix of prices to ensure the demands of these consumers are adequately reflected in the prices they pay, enabling the stakeholders to make trade-offs for services following the pricing principle (c)(ii).

Prices charged to the remaining domestic and non-domestic consumers are unable to be differentiated in the same way due to lack of information about each individual consumer and the uniform supply arrangements for these consumers which are connected to the main distribution network. This is consistent with the uniform quality of service provided to general consumers, with some differential reflected in the urban/rural regions of the network.

11.4. Principle C(iii): Encourage Investment in Transmission and Distribution Alternatives

Horizon Energy has a number of significant embedded generators already connected to the network which effectively substitute for investments in the transmission and distribution system. Distributed generation customers receive avoided transmission payments which are provided to them in a transparent nature consistent with TPM. Any new DG is offered the same terms and conditions. These payments promote the use of DG as an alternative to network based investments. Financial impact for DG customers include; a reduction in variable network charges, lower contribution to Transpower's interconnection charges due to reduced peak demand, and with lower apportioned costs for network asset due to lower maximum demand.

While encouraging of other investment under the pricing principle (c)(iii), Horizon Energy's ability to pass onto other consumers the benefits of investment in distribution or transmission alternatives is currently limited by the metering capability provided to our customers.

11.5. Principle D: Transparency, Promote Price Stability and Have Regard to the Impact on Stakeholders

We consider that the information presented in this pricing methodology as well as our tariff schedule published on our website set out the prices to be charged and approach to developing these prices in a transparent manner.

Retailers are notified of changes to tariffs in advance of forty working days prior to changes taking effect. Consumers are notified of changes to tariffs in advance of twenty working days prior to changes taking effect.

There have been no new tariff structure changes introduced since the 2011/12 pricing year that might impact upon consumers. However, Horizon Energy continues transitioning certain load groups to a full cost allocation recover basis.

Careful consideration was given to the tariff structure changes introduced in 2011/12 and specific transitional arrangements remain in place to limit the impact of these on individual consumers for the forthcoming year. This includes limits on the maximum change that cost allocations between load groups and no change in the fixed and variable revenue recoveries within each load group in order to manage the impact on low and high users within each load group.

Horizon Energy plans to continue reviewing these arrangements in future years until our revenue allocation objectives are fully met.

11.6. Principle E: Give Regard to Transaction Costs and Economic Equivalence Across Retailers Principles

Horizon Energy's tariff structure is simple, limited to fixed daily and variable consumption tariffs for all but a small number of the largest consumers. Load groupings are broadly consistent with industry standards, including domestic groups and capacity groupings for non-domestic consumers. These attributes help to minimise transaction costs for both retailers and consumers.

Horizon Energy's urban and rural boundaries have not been changed; inherently the characteristics that define these areas have also remained the same.

All posted tariffs apply to all customers within each relevant load group, for all retailers. No distinction is made between retailers.

Certification for Year-beginning Disclosure – Pricing Methodology

Clause 2.9.1 of section 2.9

We, JOHN MCDONALD and ANTHONY DE FARIAS, being directors of HORIZON ENERGY DISTRIBUTION LIMITED certify that, having made all reasonable enquiry, to the best of our knowledge -

a) the following attached information of HORIZON ENERGY DISTRIBUTION LIMITED prepared for the purposes of clause 2.4.1 of the Electricity Distribution Information Disclosure Determination 2012 in all material respects complies with that determination.

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

Dated: 22 day of January 2015

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JOHN MCDONALD

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ANTHONY DE FARIAS