



HORIZON ENERGY DISTRIBUTION LIMITED

Pricing Methodology For Line Charges introduced on 1 April 2011

3 February 2011

Electricity Information Disclosure Amendment Requirements Notice 2006

Disclosure of Pricing Methodology (Pursuant to Requirements 22 & 23 Part 4A of Commerce Act 1986)

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1. Pricing Methodology

1.1. Background

Requirements 22 and 23 of the Electricity Information Disclosure Requirements 2004, (retained by the transition provisions in the Electricity Distribution (Information Disclosure) Requirements 2008 (2008 IDR)) require the following information to be publicly disclosed annually:

- The methodology used to calculate the prices charged.
- The key components of revenue required to cover costs and profits including the cost of capital and transmission charges.
- The consumer groups used to calculate prices including:
 - The rationale for the consumer grouping;
 - How consumers are assigned to each consumer group; and
 - Relevant statistics for each consumer group.
- Method for allocating the revenue required to recover lines business costs from each consumer group and the rationale for the allocation method adopted.
- The method adopted for determining the proportion of fixed and variable charges and the rationale for the method adopted.

In addition, in February 2010 the Electricity Commission published its Distribution Pricing Principles and Information Disclosure Guidelines (2010 IDG). These contain a set of pricing principles and guidelines for information to be disclosed regarding the extent to which the pricing methodology adopted by an electricity distributor complies with those principles. The disclosure guidelines require the following disclosures (which are similar to, but not exactly the same as the 2008 IDR disclosure 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.

The methodology and information presented in this document complies with the 2008 IDR disclosure requirements as well as the new 2010 IDG.

1.2. Pricing Principles

The 2010 Electricity Commission'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 (eg: 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.

We have considered each of these principles in developing our line charges to apply from 1 April 2011. At the end of this document we include a summary demonstrating how each principle has been incorporated into our methodology.

1.3. Pricing Methodology

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 2011 – 31 March 2012;
- 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.

We set out our approach to each of these steps in the following sections of this report.

2. Revenue Requirement

2.1. External Limitations

Horizon Energy must comply with the requirements of Part 4 of the Commerce Act (1986). Subpart 6 provides for a Default Price-Quality Path (DPP) to apply which includes limitations on the amount of revenue able to be recovered by Horizon Energy by way of line charges. Thus our total revenue requirement for the 12 month period commencing 1 April 2011 is determined on the basis of our best estimate of the allowable revenue consistent with Horizon Energy complying with the DPP.

Accordingly, our total revenue requirement is developed using a building block model of each component of cost consistent with providing electricity lines services, with an adjustment to those costs to ensure compliance with the DPP.

2.2. Revenue Building Blocks

Table 1 sets out the pre-tax revenue building blocks for electricity lines services for the 12 month period commencing 1 April 2011.

Table 1 – Revenue Building Blocks (Before Tax)

Cost Item	Total Network (\$)
Connection Charges	1,844,542
Interconnection Charges	1,912,256
Notional Embedding	1,170,672
Avoided Transmission	3,282,204
Excess Interconnection	(138,954)
EC Levies	62,244
Commerce Act Levies	63,895
Local Body Rates	126,924
General Management, Administration and Overheads	3,400,653
System Management and Operations	1,866,570
Routine and Preventative Maintenance	1,541,202
Refurbishment and Renewal Maintenance	623,044
Fault and Emergency Maintenance	734,686
Depreciation on Network Assets	3,837,410
Depreciation on Non-Network Assets	533,409
Capacity Concession	(16,076)
Target Pre Tax Return on Assets	14,564,752
DPP Regulatory Constraint	(6,607,887)
Total Revenue Requirement	28,801,545

The revenue building blocks comprise transmission and avoided transmission charges forecast to be incurred by Horizon Energy during the period, to be passed onto consumers by way of line charges. These include Transpower's connection and interconnection charges. Interconnection charges reflect a rate per unit of coincident peak demand, determined using regional peaks. Connection charges are a fixed annual amount reflective of the connection assets Transpower has specifically built to connect Horizon Energy's network to the backbone of the national grid.

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.

Where a distributed generator provides local benefits by avoiding Transpower charges, Horizon Energy passes through this benefit to the distributed generator by way of an avoided transmission charge. This is recovered from consumers via the annual revenue requirement. The basis for determining the avoided transmission charge is Transpower's pricing methodology.

In addition, annual operating, maintenance and administration costs reflect the budgeted costs for providing lines services for the pricing period. These include other pass through costs permitted under the DPP such as local body rates and industry levies.

The depreciation component of the revenue requirement reflects the annual charge associated with the consumption of the asset base (including system and non system fixed assets) associated with 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 derived from a target return on the asset base. This is derived using a pre-tax weighted average cost of capital of 10.2%.

The above revenue requirement is presented on a pre tax basis.

2.3. Impact of DPP

The DPP for the pricing period commencing 1 April 2011 limits Horizon Energy's allowable revenues to \$28.802m after adjusting for the difference between DPP allowed quantities and 2011/12 actual quantities. Accordingly the return on asset component of the revenue requirement is reduced by \$6.608m as demonstrated in Table 1 above.

3. Load Groups

3.1. Disaggregation of Load Groups

The pricing methodology employed seeks to fairly allocate costs amongst various consumer groups (load groups). 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 classified as domestic or non-domestic consumers. Non domestic consumers are further classified as general, network maximum demand, non metered supplies or major consumers.

Domestic consumers are 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 low user regulations)
- Standard domestic (8000 kWh annual consumption and above)
- Non standard domestic (low user domestic not eligible for the low user regulations eg: holiday homes).

In contrast non-domestic consumers exhibit a wide range of load profiles due to the diverse nature of their commercial activities. Accordingly it is more 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.

Consumers are allocated into the general non domestic load groups as follows:

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

In addition, it is possible to separate out from general non-domestic consumers those which are non standard, or which have certain limitations in terms of pricing. Accordingly, 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 subject to demand metering in order to assess individual capacity

requirements. This enables capacity based pricing for these larger non domestic consumers.

In addition major consumers with dedicated assets are treated individually and are hence removed from other non domestic load groups.

The remainder of the document addresses the pricing methodology for those consumers on standard contract terms.

Thus the load groupings assumed for pricing purposes are as follows:

Table 2 – 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

As illustrated above, 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 area makes 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 network is used for those components of our pricing methodology, where the customer characteristics and network characteristics indicate that differential costs and therefore tariff levels are justified in order to reflect fair prices to all consumers.

3.2. Changes to Load Groups Introduced in 2011

The majority of the load group structure is consistent with 2010. However for the first time Horizon Energy has segregated the domestic load group into low user, standard and non standard domestic load groups. Previously all domestic users were grouped together, and charged a tariff consistent with the low user fixed charge regulations with the exception of holiday homes which were grouped in with the small general (N1) consumers.

The previous approach, while simple, did not allow us to fully reflect the demands all domestic consumers make on the network and incorporated elements of cross subsidy between large/small and permanent/non permanent domestic consumers. By segregating into the three domestic load groups we have introduced a more economically robust basis for cost allocation and tariff design for all domestic consumers.

3.3. Characteristics of Each Load Group

Table 3 below sets out the key characteristics of each load group, for the purpose of the pricing methodology.

Table 3 – Statistics Relevant to Load Groups

Load Groups		Number of ICPs	Consumption (kWh)	AMD (kW)	Share of Total Assets (RC%)
Domestic					
LUD	Low User Domestic	13,384	66,521,923	19,623	24.5%
SD	Standard Domestic	5,284	53,256,768	15,710	19.6%
NSD	Non-standard Domestic	314	912,906	282	0.3%
Capacity Groups					
N1U	Urban Capacity Group 1 (0-14 kVA)	661	3,332,006	1,024	1.0%
N1R	Rural Capacity Group 1 (0-14 kVA)	1,110	3,337,112	1,040	1.8%
N2U	Urban Capacity Group 2 (15-42 kVA)	743	12,772,807	3,696	3.5%
N2R	Rural Capacity Group 2 (15-42 kVA)	1,992	24,883,054	7,253	12.5%
N3U	Urban Capacity Group 3 (43-70 kVA)	256	9,389,085	2,697	2.5%
N3R	Rural Capacity Group 3 (43-70 kVA)	309	13,061,092	3,766	6.5%
N4U	Urban Capacity Group 4 (71-100 kVA)	58	3,054,732	866	0.8%
N4R	Rural Capacity Group 4 (71-100 kVA)	45	3,030,883	784	6.5%
N5U	Urban Capacity Group 5 (>100 kVA)	32	2,614,340	813	0.8%
N5R	Rural Capacity Group 5 (>100 kVA)	28	1,938,415	550	0.9%
Network Maximum Demand					
NMD	Network Maximum Demand	151	43,157,766	12,607	12.5%
Specials					
UV	U/Veranda Lights	23	8,395	2	0.0%
EF	Electric Fence	23	16,790	5	0.0%
SL	Street Lights	22	2,225,626	630	1.6%
PCM 24	PCM 24 Hour	71	310,980	91	0.1%
PCMN	PCM Night Only	18	32,850	9	0.0%

4. Revenue Allocation to Load Groups

4.1. 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 a set of cost allocators. The COS model comprises the following key calculations:

- Identify the total revenue requirement to be recovered from line charges, by component (eg: transmission charges, system management and operations costs, depreciation etc) as outlined above.
- Allocate consumers into load groups consistent with the existing 2010 load group structure.
- Input identifying characteristics for each load group (eg: number of ICPs, kWh etc).
- Map all consumers into new load groups consistent with the revised load group structure as outlined above, and reallocate the identifying characteristics accordingly.
- Allocate each component of the 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 assuming that the revenue to be recovered from each of the proposed load groups is no more than +/- 10% of the revenue currently recovered from those consumers in order to generate a transitional revenue allocation scenario. This approach has been adopted to 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.
- Refine the tariff options as required in order to meet regulatory requirements, manage price shock and implement pricing signals consistent with the pricing principles.

4.2. Allocation of Revenue to Load Groups

The revenue requirement is specified as a number of different cost categories as outlined above. The COS model includes sufficient flexibility to allocate each cost component to load groups using a range of different allocators. To some extent the range of allocators is limited by data availability and in some instances proxies have been developed for this purpose.

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

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

The 2011/12 revenue requirement is estimated to be \$28.802 million. We have allocated the components of the revenue requirement using the cost allocators set out in Table 4.

This allocator selection demonstrates the underlying drivers for electricity supply services, being the provision and maintenance of adequate capacity. Thus we have selected allocators which best reflect the demand for capacity of each customer group. We have used these for those categories of cost within the overall revenue requirement which are directly related to the provision and maintenance of capacity. This also includes transmission charges, which reflect Transpower's requirement to provide adequate capacity (and maintain the availability of that capacity) for the national grid.

4.3. Information Used for Cost Allocators

The following information is used for the purpose of the 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 commensurate with the demand each connected consumer places on those services provided to them.
- Load (kWh) – Annual consumption is also an allocator which may be used to share components of the revenue requirement between load groups, although 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) – for each load group is used to allocate transmission charges, consistent with Transpower's pricing methodology principles which effectively share the majority of the transmission charge via peak demand signals. This data is known for NMD and industrial consumers. It is estimated for the remaining load groups by using an assumed value for the average domestic consumer, and extrapolating the remaining load groups based on average load within each load group relative to the average domestic consumer.
- 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 and allocated into load groups as follows:

- a) Asset Replacement Cost (RC) and Depreciated Replacement Cost (DRC) are allocated into the following network components:
 - Sub transmission
 - Zone substations
 - Distribution HV/LV
 - 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;
 - 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 total asset value assigned to each load group is used to apportion asset related components of the revenue requirement (eg: maintenance, depreciation and profit). RC is used for this purpose as it is independent of age.

4.4. Revenue Requirement Allocation to Load Groups

Using the methodology and assumptions outlined above, the forecast revenue requirement for 2011/12 is allocated to load groups as follows. This reflects a transitional allocation method, which reflects movement towards more fully cost reflective allocations, but which limits movement between load groups to no more than +/-10% of revenue for the forthcoming year.

Table 4: Allocation of Revenue Requirement to Load Groups

Load Groups		Distribution Revenue (\$)	Transmission Revenue (\$)	Total Revenue (\$)
Domestic				
LUD/SD	Low User and Standard Domestic	9,533,800	2,780,938	12,314,738
NSD	Non-standard Domestic	135,982	22,182	158,163
Capacity Groups				
N1	Capacity Group 1 (0-14 kVA)	1,053,115	162,382	1,215,496
N2	Capacity Group 2 (15-42 kVA)	3,252,595	861,759	4,114,354
N3	Capacity Group 3 (43-70 kVA)	1,366,391	508,672	1,875,062
N4	Capacity Group 4 (71-100 kVA)	346,419	129,824	476,243
N5	Capacity Group 5 (>100 kVA)	264,047	107,271	371,318
CC	Capacity Concession	(16,076)	-	(16,076)
Network Maximum Demand				
NMD	Network Maximum Demand	2,890,454	992,269	3,882,723
Specials				
UV	U/Veranda Lights	1,047	176	1,223
EF	Electric Fence	2,440	352	2,792
SL	Street Lights	201,646	45,748	247,394
PCM 24	PCM 24 Hour	29,741	6,613	36,354
PCMN	PCM Night Only	2,914	689	3,603

Table 5: Allocation of Revenue Requirement (Detailed) to Load Groups

Load Groups		Distribution Revenue (\$)			Transmission Revenue (\$)			Total Revenue (\$)
		Fixed	Variable	Total Distribution	Fixed	Variable	Total Transmission	
Domestic								
LUD	Low User Domestic	-	5,725,197	5,725,197	748,597	823,849	1,572,446	7,297,643
SD	Standard Domestic	444,013	3,364,590	3,808,603	962,469	246,023	1,208,492	5,017,095
NSD	Non-standard Domestic	89,896	46,086	135,982	22,182	-	22,182	158,163
Capacity Groups								
N1	Capacity Group 1 (0-14 kVA)	571,897	481,217	1,053,115	162,382	-	162,382	1,215,496
N2	Capacity Group 2 (15-42 kVA)	972,286	2,280,308	3,252,595	861,759	-	861,759	4,114,354
N3	Capacity Group 3 (43-70 kVA)	23,492	1,342,899	1,366,391	508,672	-	508,672	1,875,062
N4	Capacity Group 4 (71-100 kVA)	8,403	338,015	346,419	129,824	-	129,824	476,243
N5	Capacity Group 5 (>100 kVA)	-	264,047	264,047	101,144	6,127	107,271	371,318
CC	Capacity Concession	(16,076)	-	(16,076)	-	-	-	(16,076)
Network Maximum Demand								
NMD	Network Maximum Demand	1,367,804	1,522,650	2,890,454	992,269	-	992,269	3,882,723
Specials								
UV	U/Veranda Lights	1,047	-	1,047	176	-	176	1,223
EF	Electric Fence	2,440	-	2,440	352	-	352	2,792
SL	Street Lights	201,646	-	201,646	45,748	-	45,748	247,394
PCM 24	PCM 24 Hour	29,741	-	29,741	6,613	-	6,613	36,354
PCMN	PCM Night Only	2,914	-	2,914	689	-	689	3,603

5. Tariff Structure

5.1. Key Considerations

As there are infinite combinations of tariffs possible, Horizon Energy has developed its tariff structure after consideration of the following factors:

- The extent to which Horizon Energy's underlying costs are fixed or variable.
- The manner in which transmission and avoided transmission charges are determined and the associated revenue risk that may arise in the manner in which these are passed on to consumers.
- The impact of the low user fixed charge regulations and the requirement to maintain revenue equivalence at the 8000kWh cross over between low user domestic and standard domestic tariffs.
- 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.
- The signals that certain tariff structures send to consumers regarding incremental load, energy efficiency, demand management and capacity utilisation.
- Transaction simplicity/complexity and the availability of the information necessary to implement certain tariff options.
- The likelihood or otherwise of retailers repackaging tariffs and disrupting the intended pricing incentives.
- The likelihood of uneconomic bypass of the distribution system.
- The service levels provided to different load groups.

5.2. Tariff Mix

The tariff approach adopted for 2011/12 is significantly influenced by the historical position, whereby Horizon Energy recovered in 2010/11 73% of revenue (excluding that recovered from major customers) as variable revenue. This included recovery of all transmission related costs and a large proportion of distribution related costs.

In developing the 2011/12 tariffs, the manner in which transmission and distribution costs is recovered has been revisited. This has partly arisen now that the new transmission pricing methodology (TPM) has been implemented, and its impact on the Transpower charges allocated to Horizon Energy each year are better understood. The TPM also influences the avoided transmission component of transmission charges, as outlined above.

As transmission charges are now known with certainty at the time prices are set, Horizon Energy has decided to remove any revenue risk associated with the recovery of these external costs, and to pass these through to consumers as fully fixed charges (subject to low user regulatory constraints and transitional arrangements). Previously these were passed on as fully variable charges to all load groups with the exception of the majors.

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

Horizon Energy's rationale is that all customers requesting and having a supply made available, must contribute to the required cost recovery through the fixed charge component regardless of energy consumption. This is seen as the fairest way to minimise cross subsidisation between customer groups. However having a variable element in the charge means customers can influence the final amount charged which is consistent with our load management and energy efficiency objectives as well as assisting in meeting some of the economic pricing principles (refer section 6).

Accordingly, the distribution component of the revenue recovery for all load groups (with the exception of majors 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 2010/11 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.

5.3. Transitional Assumptions

In order to manage the revenue impact of the fixed and variable revenue recoveries on low and high users within each load group, Horizon Energy has capped the amount of revenue to be recovered from each load group by way of fixed charges. These caps have been derived from historical ratios with a modest step up in the fixed proportion for the 2011/12 year for most load groups to reflect the policy of moving transmission charges to fully fixed from fully variable charges. The resulting revenue allocations are as follows.

Table 6 – Percentage Revenue Allocation Across Load Groups

Load Groups		Fixed Revenue (%)	Variable Revenue (%)
Domestic			
LUDU	Urban Low User Domestic	10%	90%
LUDR	Rural Low User Domestic	10%	90%
SDU	Urban Standard Domestic	29%	71%
SDR	Rural Standard Domestic	27%	73%
NSDU	Urban Non-standard Domestic	72%	28%
NSDR	Rural Non-standard Domestic	70%	30%
Capacity Groups			
N1U	Urban Capacity Group 1 (0-14 kVA)	59%	41%
N1R	Rural Capacity Group 1 (0-14 kVA)	61%	39%
N2U	Urban Capacity Group 2 (15-42 kVA)	38%	62%
N2R	Rural Capacity Group 2 (15-42 kVA)	47%	53%
N3U	Urban Capacity Group 3 (43-70 kVA)	33%	67%
N3R	Rural Capacity Group 3 (43-70 kVA)	25%	75%
N4U	Urban Capacity Group 4 (71-100 kVA)	33%	67%
N4R	Rural Capacity Group 4 (71-100 kVA)	25%	75%
N5U	Urban Capacity Group 5 (>100 kVA)	25%	75%
N5R	Rural Capacity Group 5 (>100 kVA)	30%	70%
Network Maximum Demand			
NMD	Network Maximum Demand	61%	39%
Specials			
UV	U/Veranda Lights	100%	0%
EF	Electric Fence	100%	0%
SL	Street Lights	100%	0%
PCM 24	PCM 24 Hour	100%	0%
PCMN	PCM Night Only	100%	0%

5.4. 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 2011/12 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 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 major 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 low user fixed charge regulations and the requirement to maintain revenue equivalence with the cross over to the standard domestic tariff at 8,000kWh. In addition, the introduction of the standard and non standard domestic tariff this year is deemed to be a significant enough change for this year. 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.
- 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.

5.5. Impact of Tariff Structure Changes on Domestic Load Groups

As noted above, the key change introduced in 2011/12 is the segregation of domestic consumers into three load groups.

The following criteria have been applied to determine the appropriate pricing group for domestic consumers;

Low User Domestic Group:

Available only to consumers meeting the requirements of the low user fixed charge regulations e.g. (must be used for residential purposes and must be the primary residence) As this tariff is cheaper up to 8,000kWh then any consumer historically consuming over 8,000kWh has been moved to the Standard Domestic option.

Standard Domestic Group:

This group is for all domestic consumers consuming greater than 8,000kWh. Consumers previously not eligible for the low user option and charged on a General Capacity option have been moved to this option as have all low users with consumption greater than 8,000kWh. This is the most cost effective option for large domestic consumers.

Non-standard Domestic Group:

This option is for low user domestic consumers not eligible for the low user regulations eg: holiday homes. All non eligible domestic consumers with consumption less than 8,000kWh have been moved to this group.

Table 7 – Domestic Load Group Remapping

Previous Load Groups	Estimated Number of ICPs (@ 31/3/11)	New Load Groups	Estimated Number of ICPs (@ 31/3/11)
Domestic		Domestic	
		Low User Domestic	13,384
		Standard Domestic	5,284
		Non-standard Domestic	314
Total Domestic	18,668	Total Domestic	18,982
Capacity Group 1		Capacity Group 1	
Urban Capacity Group 1 (0-14 kVA)	871	Urban Capacity Group 1 (0-14 kVA)	661
Rural Capacity Group 1 (0-14 kVA)	1,214	Rural Capacity Group 1 (0-14 kVA)	1,110
Total Capacity Group 1	2,085	Total Capacity Group 1	1,771
Total Number of ICPs Affected	20,753		20,753

The following table illustrates the tariffs which would have applied to each group had they not been moved to a new load group and those which will apply to them for the forthcoming year.

Table 8 – Tariff Impact for those affected by the Load Group Remapping

Domestic Load Groups	New Tariffs		Previous Tariffs	
	Fixed (\$/day)	Variable (c/kWh)	Fixed (\$/day)	Variable (c/kWh)
Low User Domestic	0.150	9.583	0.150	9.194
Standard Domestic	0.758	6.811	0.150	9.194
Urban Non-standard Domestic	0.972	6.718	1.254	6.328
Rural Non-standard Domestic	0.972	6.718	1.310	6.448

6. Distribution Pricing Principles

Although the Electricity Commission's distribution pricing principles have been published for the first time this year the principles are not inconsistent with the pricing methodology approach adopted by Horizon Energy in previous years.

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

6.1. Economic Costs of Service Provision Principle

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, this results in a revenue allocation which falls somewhere between stand alone cost and incremental cost on the basis that the cost allocators used are a reasonable representation of the underlying cost drivers of the business. Thus Horizon Energy's tariffs fall within a subsidy free range.

It is not possible to accurately estimate the stand alone costs for most consumers which are supplied a common service via a meshed and integrated network. However it is possible to conclude that stand alone costs would be higher than average costs for those consumers given the scale efficiencies in supplying them from an integrated network.

In addition, it is difficult to estimate the incremental cost of supplying each consumer each additional unit of capacity. However, it is reasonable to assume that the incremental cost of connecting each additional general consumer to the network is small. These conclusions along with the regulatory constraints of the weighted average price cap and the low user fixed charge regulations indicate that the pricing methodology adopted by Horizon Energy is consistent with the economic cost of service provision principle.

In addition, Horizon Energy's capacity banded load group structure is consistent with the principle of having regard to the level of available service capacity, as prices increase across these bands as demand for capacity increases.

In terms of 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 is available (such as the NMD load group). Weaker signals are provided for smaller load groups through the use of variable charges, as a reasonable proxy for demand, while having regard to transaction costs (refer below) and standard industry practice.

6.2. Efficiency and Demand Responsiveness Principles

This principle is similar to the Ramsey Pricing principle which suggests that natural monopolies which use marginal cost prices will under recover their total revenue requirement and accordingly such prices must be scaled up in some manner. Ramsey pricing suggests the scaling should take into account the price elasticity of each load group, and those with lower price elasticities should bear a higher proportion of the scaling.

In practice this is a difficult principle to apply as price elasticity information is difficult to obtain and it is likely the price elasticities will be different within each of Horizon Energy's load groups (for example different commercial users are likely to have very different price elasticities 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 services they receive.

6.3. Responsive to the Needs of Stakeholders Principle

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 specific quality of service requirements of these customers. This is consistent with the economic value of the services to the customer and includes specific prices for service offerings which are 'non-standard'. By definition this approach assists in avoiding uneconomic bypass.

A similar approach is adopted for NMD customers, where the pricing methodology specifically recognises the installed capacity requirements of each individual NMD consumer and provides a combination of capacity and demand prices which reflect the capacity utilisation of each individual consumer. 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.

Prices charged to the remaining general 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.

6.4. Encourage Investment in Transmission and Distribution Alternatives Principle

Horizon Energy has a number of significant embedded generators already connected to the network. These investors receive avoided transmission payments which are provided to them in a transparent nature consistent with Transpower's TPM. Any new distributed generation is offered the same terms and conditions.

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 its customers.

6.5. Transparency, Promote Price Stability and Have Regard to the Impact on Stakeholders Principles

The tariff schedule sets out the prices to be charged in a transparent manner. There have been minimal tariff structure changes introduced since the 2010/11 year and these changes impact only the domestic load groups. This pricing methodology documents how these have been derived.

Careful consideration has been given to the changes introduced in 2011/12 and specific transitional arrangements have been put in place to limit the impact of the changes in tariffs on individual consumers for the forthcoming year. These include limits on the amount of revenue recovery transferred between load groups for the year as well as limits on the step changes 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 these transitional arrangements in future years until our revenue allocation objectives are fully met.

6.6. 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. The load grouping is consistent with industry standards, including domestic groups and capacity groupings for non domestic consumers.

All posted tariffs apply to all customers within each relevant load group, for all retailers.