Alpine Energy limited

Pricing Methodology

For Delivery Charges, effective as at 1 April 2016

Pursuant to the requirements of clause 2.4 of the Electricity Information Disclosure Determination 2012 – (consolidated in 2015)

Certification for Year-beginning Disclosures

Pursuant to Schedule 17

Clause 2.9.1 of section 2.9

Electricity Distribution Information Disclosure

Determination 2012 – (consolidated in 2015)

We, Stephen Richard Thompson and Alister John France, being directors of Alpine Energy Limited certify that, having made all reasonable enquiry, to the best of our knowledge:

a) The following attached information of Alpine Energy's prepared for the purposes of clauses 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.

Stephen Richard Thompson	Alister John France
24 February 2016	24 February 2016

Table of contents

1. Introduction

This pricing methodology outlines our approach to the setting of delivery charges effective from 1 April 2016.

What are delivery charges?

The term 'delivery charge' describes the total price we charge for the provision of electricity distribution services.

Delivery charges are made up of our distribution charges, Transpower's transmission charges plus other charges such as rates, levies and wash-up charges (known as pass through and recoverable costs) which we must pay throughout the year.

Definitions of these charges are provided in the Glossary on page 33.

Our network

We are an electricity distribution business (EDB) located in the South Canterbury region of New Zealand.

Our network has a replacement value of more than $166.3 million, and connects approximately 31,700 consumers through seven local grid exit points (GXPs) at: Bells Pond, Temuka, Timaru, Studholme, Albury, Tekapo, and Twizel. Figure 1 on page 4 shows the location of the seven GXPs and substations on our network.

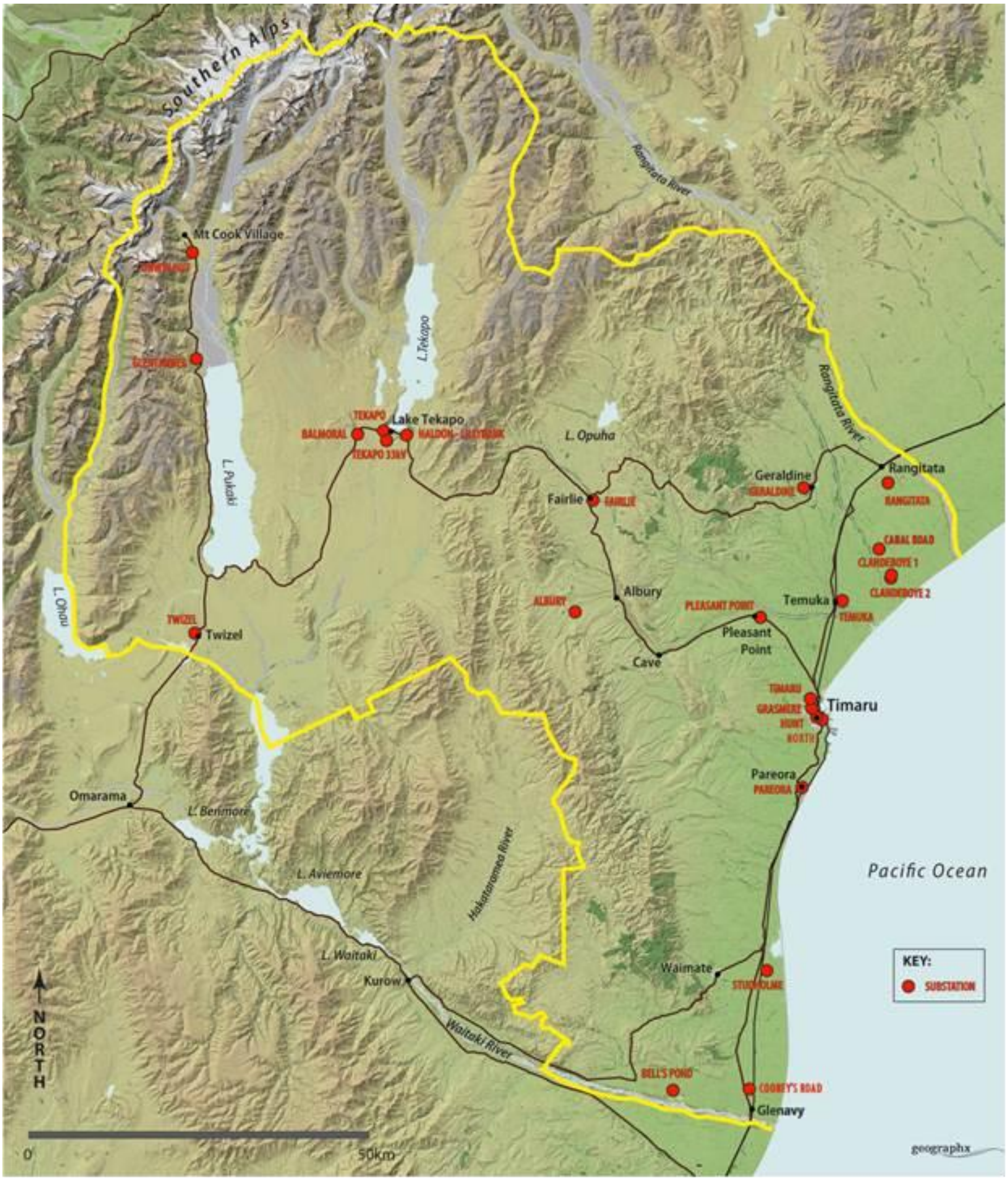
We are owned by the community we serve

We are 100% owned by the South Canterbury community through our shareholders.

- Timaru District Council (47.5%)
- LineTrust South Canterbury (40%)
- Waimate District Council (7.54%)
- Mackenzie District Council (4.96%).

Our ownership structure means that our consumers are our shareholders. As shareholders our consumers benefit directly, through an annual dividend payment and indirectly, though services provided by local councils.

Figure 1: Map of our network



Our pricing is regulated

In 2016, delivery charges by EDBs are subject to the following regulations:

- Commerce Commission, under Part 4 of the *Commerce Act 1986* (Part 4):
    - *Electricity Distribution Services Default Price–Quality Determination 2015, [2014] NZCC 33,* 28 November 2014 (DPP Determination)
    - The Commerce Commission's *Electricity Distribution Information Disclosure Determination 2012 – (consolidated in 2015)*, 24 March 2015 (IDD2015)
- Electricity Authority under:
    - the *Electricity (Low Fixed Charge Tariff Option for Domestic Consumers) Regulations 2004* (the low fixed charge regulations)
    - Part 6 of the *Electricity Industry Participation Code 2010* (the Code), relating to the pricing of distributed generation.

We are of the view that our pricing methodology is consistent with the above regulations. More detailed discussion of how we meet the Electricity Authority's pricing principles can be found in section 14 on page 26.

2. Overview of our Pricing Methodology

Our approach to setting annual delivery charges is to ensure we efficiently recover our network related costs[1] from those who use the network. As well as efficiency considerations, we also take into account the need to balance complexity with transparency, and the need to smooth price changes over time.

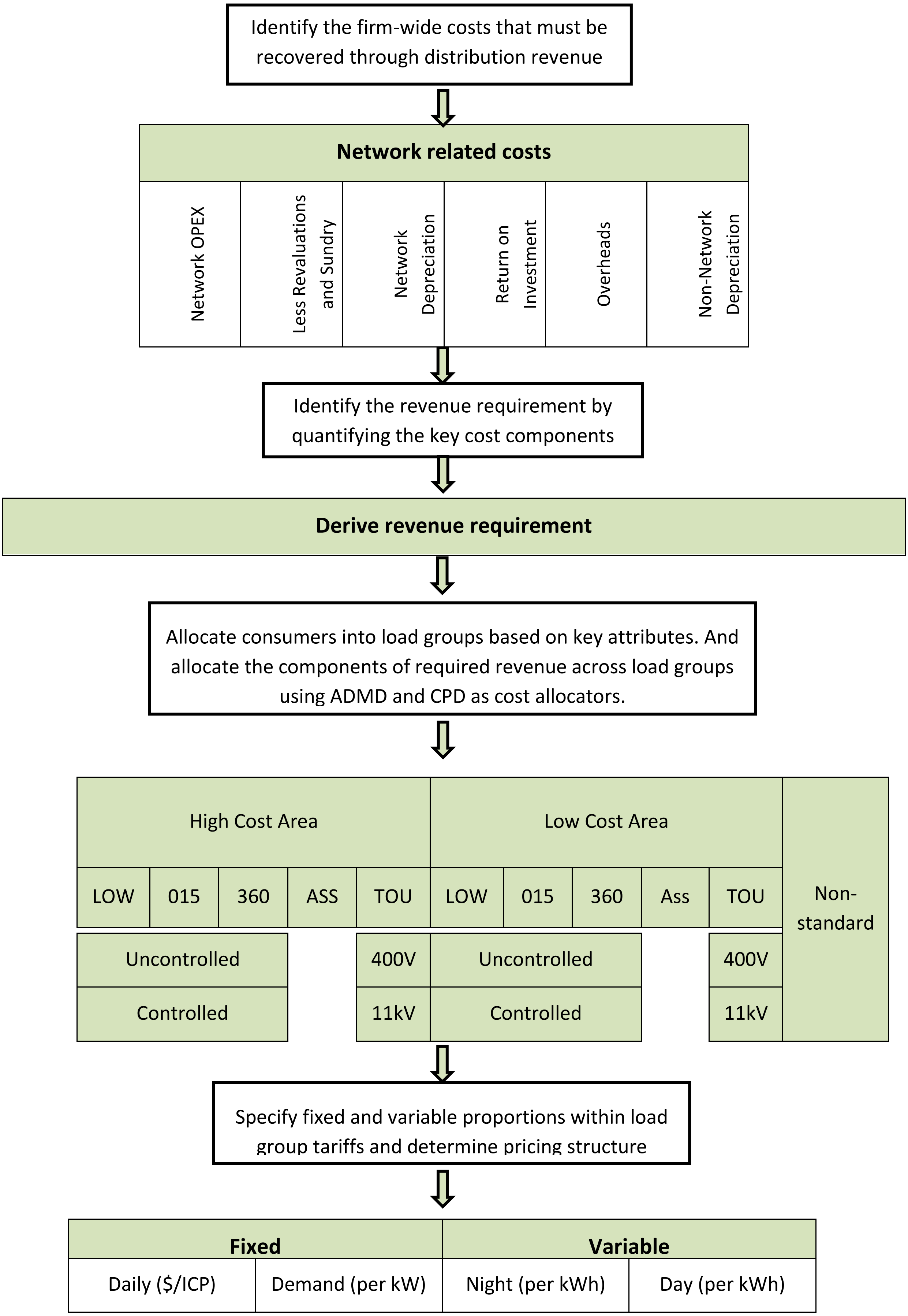
When setting delivery charges each year we use a five step process, described below.

1. Identify the annual revenue required by quantifying the key cost components.
2. Determine the key attributes of each load group and assign consumers into load groups for the purposes of allocating costs.
3. Allocate the revenue required to network assets using appropriate cost drivers
4. Determine the network assets a load group uses and assign respective asset costs to each load group.
5. Recover annual costs from load groups through fixed and variable charges.

Our five steps are described further in Figure 2 on page 6, which shows our approach to recovering distribution prices. We also use a similar but simplified approach to recovering pass through and recoverable costs as well as our transmission costs.

[1] This includes both short and long run costs

Figure 2: Key steps to recovery distribution costs



3. Our revenue requirement

Our revenue requirement is equal to our network related costs[2] including the return on investment in our network. Our network related costs arise from three sources:

i) Distribution costs
ii) Pass-through and recoverable costs
iii) Transmission costs

The revenue requirement, from which delivery charges are calculated, effective from 1 April 2016, is made up of the network related costs shown in Table 1 below.[3]

Table 1: Revenue requirement 2016/17

Network related costs	In $'000
Operating expenditure	14,462
Revaluations and sundry income	-146
Depreciation	10,375
Return on investment	12,772
Recovery of revenue forgone from RCP1[4]	5,288
Pass-through costs—i.e., rates and levies	317
Transmission	16,336
Impact of price cap	-2,084
Total revenue requirement	**57,320**

Revenue requirement for distribution services

Our revenue requirement for distribution services is made up of the following components[5]:

- Operating expenditure
- Revaluations and sundry income
- Depreciation
- Return on investment

[2] Network related costs include costs directly attributable to the network, and costs which not directly attributable to the network i.e. costs which are shared by network and non-network services such as accounting and ICT costs.

[3] Please note the forecast business costs are in 2014/15 dollar terms.

[4] Regulatory control period 1(RCP1) was for the period 1 April 2010 to 31 March 2015.

[5] For 2016, we will recover pass through, and recoverable costs in a separate model to our distribution prices.

Operating expenditure

Operating expenditure (Opex) are costs incurred through our everyday operations related to the provision of electricity distribution services. The two main costs components are:

- maintenance on network assets including related non network overhead
- quality of service.

Maintenance costs are derived from our network maintenance programme, which is driven by safety requirements, security of supply objectives, fault response, and repair.

Our Asset Management Plan (AMP) contains details of our planned maintenance programme and 10 year forecast expenditure for each component of Opex.[6]

Revaluations and sundry income

Where components of the regulatory asset base have been revalued upwards it is recognised as revenue. Because this revenue is not recovered through prices we must deduct it from our required revenue. For the same reason sundry income must also be deducted from the revenue required.

If revaluations and sundry income were included in the revenue required, the total revenue required would be more than target revenue.

Revaluations are sourced from our regulatory asset base.

Depreciation

Depreciation is calculated on a straight–line basis in accordance with information disclosure guidelines using a standard life for the asset[7]. Depreciation costs are sourced from the roll forward of our regulatory asset base each year.

Return on investment

Our return on investment has been calculated using the regulated weighted average cost of capital (WACC) on the network regulatory asset base in line with the DPP Determination. A vanilla WACC (67th percentile) of 7.19% has been applied.

Our regulatory asset base, as at 31 March 2015, is approximately $166.3 million. This is an increase of approximately $9.5 million when compared to the value of our regulatory asset base in the prior year. The replacements of assets that have reached their useful lives, and growth on our network have contributed to the increase in our regulatory asset base over the last year.

---

[6] A copy of our AMP can be found on our website at http://www.alpineenergy.co.nz/disclosures/sub-menu-modid-159/49-assett-management-plan

[7] Standard lives for each asset group is determined by the Commerce Commission, *Handbook of Optimised Deprival Valuation of System Fixed Assets of electricity Lines Businesses*, 30 August 2004, table A.1, page 33.

Revenue requirement for pass-through and recoverable

Pass through and recoverable costs include:

- rates
- commerce commission levies and other industry levies
- claw back and wash-up allowance[8]

Each year we receive notification from the Commerce Commission, Electricity Authority, and from local authorities of charges that will apply to us in the following year. We use these notifications to calculate prices for each load group to recover these costs.

Revenue requirement for transmission

Each year prior to setting our distribution prices we receive next year's transmission pricing from Transpower for each GXP on our network. We use these to calculate transmission prices for each load group.

4. Our load groups

Standard Consumers

Our 'standard consumers' are those consumers that can be assigned to one of our 13 load groups (shown at Table 2) who have a supply contract with a retailer, and do not have an individual supply agreement with us.

We supply our standard consumers under our use of system agreements we have with electricity retailers. Our current agreement takes into account the Electricity Authority's principles taken from its Model Use of System Agreement, published in 2003. We are currently negotiating with retailers on this current agreement and should have most retailers signed by December 2016.

The majority of the consumers on our network are standard consumers.

Allocating Standard Consumers into Load Groups

We have 13 load groups as shown in Table 2 on page 11. Consumers are assigned to a load group based on:

i) location—i.e., high cost area or low cost area

[8] Please refer to Schedule 5C and 5D respectively of the DPP Determination.

ii) fuse size at the individual connection point (ICP)

iii) maximum business day peak demand

iv) meter type—for example, half hour metering is mandatory for consumers within the time of use group (TOU) load group.

High Cost and Low Cost area allocation

For standard consumers the revenue requirement is initially allocated to high cost areas (HCA) and low cost areas (LCA), using our geographic information system (GIS). The cost areas represent the number of consumers:

i) on each transformer

ii) per kilometre of distribution line length.

Connections in the HCA represent approximately 30% of total consumers, 41% of annual consumption, and 47% of installed capacity. This suggests that LCA, and HCA connections are distinguishable by their use of network assets and profiles, as well as by connection density. As a general rule LCA density[9] is thirteen times greater than HCA density.

Allocation of consumers to load groups within cost areas

Consumers in high cost areas and low cost areas are split into the following load groups:

- low fixed charge groups
- mass market installed capacity groups:
  - 015—(0-15 kVA single phase 60 A connection)
  - 360—(45 kVA three phase 60 A connection)
- assessed demand groups based on fuse size
- time of use groups for LV and 11kV connections with half hour metering.

Low Fixed Charge load group

Our approach to complying with the low fixed charge regulations is to have a separate low fixed charge load group for every 015 load group. Hence we have four Low user load groups for the four 015 load groups.

The average consumer[10] in the Low fixed charge load groups should pay no more than an average consumer in the equivalent 015 load group (e.g. LOW HCA, 015 HCA).

[9] ICPs per transformer

[10] Under the Low Fixed Charge Tariff regulations an ‘average consumer’ for the lower South Island uses 9000 kWh of electricity per year

Table 2: Load groups

Load Group	Description
LOWHCA	Domestic consumers[11] that consume less than 9,000 kWh per annum – high cost area
LOWLCA	Domestic consumers that consume less than 9,000 kWh per annum – low cost area
015HCA	0-15kVA and up to 60 Amp fuse – high cost area
015LCA	0-15kVA and up to 60 Amp fuse – low cost area
360HCA	3 x 60 Amp fuses – high cost area
360LCA	3 x 60 Amp fuses – low cost area
ASSHCA	Assessed demand over 15kVA – high cost area
ASSLCA	Assessed demand over 15kVA – low cost area
TOU400HCA	Time of use 400 volt supply – high cost area
TOU400LCA	Time of use 400 volt supply – low cost area
TOU11HCA	Time of use 11kV supply – high cost area
TOU11LCA	Time of use 11kV supply – low cost area
IND	Individually assessed sites

015, 360, and Assessed demand load groups

ICPs not in the Low fixed charge load groups and without half hour, time of use (TOU) meters[12] installed, fall into one of three load groups:

1. 15 kVA; (015 load group)
2. 3 x 60 A;(360 load group)
3. Assessed demand (ASS load groups).

ICPs in the 015 load group are single phase and have a maximum capacity of 15 kVA[13] (60 A). ICPs in the 360 load groups are connected with three phase 60 A connections. Assessed load groups have a maximum capacity per phase greater than 60 A. This can include two phase connections also. Demand charges for consumers in the ASS load groups are calculated on the fuse size of the connection.

[11] The objective of the low fixed charge regulations is to ensure that electricity retailers offer a low fixed charge tariff option or options for delivery electricity to **domestic consumers at their principal place of residence** that will **assist low-use consumers and encourage energy conservation**. [emphasis added]

[12] Some ICPs in the Assessed load groups may have half hour metering installed but choose to remain in the Assessed group.

[13] We also allow 3x32 A connections on a case by case basis into the 015 groups.

Time of Use load groups

ICPs in the TOU load groups have TOU meters installed which record kWh consumption every half an hour. From TOU meters we can calculate the anytime maximum demand (AMD), and coincident (network) peak demand (CPD), which are used to allocate costs to load groups, and calculate demand charges.

Uncontrolled load

Uncontrolled load tariffs are charged to consumers in the LOW, 015, and 360 load groups whose load we are not able to control during periods of high demand. The uncontrolled load tariff is in place to incentivise consumers to offer up controllable load, such as hot water load. Controllable load is critical for us to be able to shed load during supply emergencies, and to avoid further investment in network capacity.

The low user groups pay an additional variable charge of $0.0266 cents per kWh, for both day and night variable charges, for uncontrollable load. 015 and 360 consumers pay an additional fixed charge of $239.24 per annum for uncontrollable load.

5. Allocation of revenue requirement

The first step in calculating prices for each load group is the allocation of network related costs to network assets, and the allocation of network assets to load groups. Once we have identified the annual cost to service each load group we design prices to recover these costs in a way which signals to consumers the long run costs of operating our network.

Distribution

Our pricing model allocates costs to load groups in a way that reduces cross subsidisation[14] between users of the network, so that those that use the assets pay for them. Since the majority of our network costs are influenced by a load group's demand for power, we allocate network costs by the load group's ADMD and or CPD.

LV load group allocation

LV asset costs, distribution lines and cable costs, are first allocated to high cost and low cost area load groups, based on the high cost area load group's ADMD for LV power to the total ADMD for LV power by all LV load groups.

For example the ADMD for LV power by HC area load groups is 77.73 MW and the total ADMD for LV power all load groups is 157.87 MW, a proportion of 49% .

[14] Cross subsidisation occurs when one consumer or consumer group (load group) pays more than their share of costs based on use of assets. By paying more than their share they pay some of the costs incurred by another consumer/consumer group.

LV asset costs are allocated to the high cost area by multiplying the total LV asset cost by 0.49. Some HC cost area assets are then multiplied by a cost differential that recognises the increased cost to service assets in high cost areas. Assets which are multiplied by a cost differential include:

- distribution lines and cables
- distribution switchgear for LV
- distribution substations
- distribution transformers
- LV lines and cables
- other network assets (including load control).

The remaining asset cost is then assigned to low cost load groups.

Once LV network asset costs have been adjusted for high cost areas, network assets and their associated costs are allocated to LV load groups based on the load groups ADMD to total ADMD of all users of the asset. The exception is load control costs which are spread across all load groups including HV groups, on the basis that reduced transmission costs benefit all users. Load control costs are allocated by the load group’s regional coincident peak demand (RCPD) to total RCPD demand for all load groups.

A portion of HV asset costs are allocated to LV load groups using a weighted demand made up of a load group’s ADMD (25%) and CPD (75%). This is done because a portion of a HV asset’s costs comes from servicing peak demand, and because the majority of our GXPs will peak around the network peak in summer. This means that a load group’s contribution to network peak demand will have a direct effect on network costs.

HV load group allocation

HV assets include:

- sub-transmission
- zone substations
- distribution lines and cables
- distribution switchgear
- customer service connections.

HV assets are allocated to all load groups using the load group’s weighted demand (25% ADMD and 75% CPD) to total weighted demand of all users of the assets, to reflect that usage around peak periods impacts directly on our costs.

Distribution lines and cable costs are allocated to HV load groups including a cost differential for the high cost area HV load group (TOU11HCA). The cost differential reflects the increased cost per ICP for distribution lines and cables in high cost areas.

Load Group statistics

Table 3 on page 15 shows ICP numbers, ADMD, weighted demand and regional coincident peak demand (RCPD), as at 31 March 2015, for each load group. This information is used to allocate required revenue to load groups[15].

Deriving maximum demands

We receive half hour kWh data for all TOU load groups and for each GXP on our network. This data enables us to calculate ADMD and CPD for TOU groups, for the network, and a combined total for all non-TOU (non-half hour metered) load groups.

Without half hour meters at an ICP (such as smart meters), we must estimate the ADMD and CPD for non TOU load groups. For the Low and 015 groups we use sample data from maximum demand indicators on residential LV transformers to estimate a population ADMD. For the non-TOU load groups, 360, and ASS, we allocate the remaining non-TOU ADMD and CPD portion based on name plate capacity of pumps attached and estimated demand profiles.

The maximum demands that we have used will be further refined with the installation of smart meters all non TOU load groups.

Revenue requirement allocated to load groups

We have allocated the components of the revenue requirements to load groups using the cost allocators as set out in Table 5 on page 17.

Table 4 on page 16 shows the allocation of required revenue to load groups including an allocation of the load control fee to LOW, 015 and 360 load groups.

Pass-through and recoverable revenue requirement

Please refer to 'Calculating pass through and recoverable prices' on page 19.

Transmission revenue requirement

Please refer to 'Calculating transmission prices' on page 19.

[15] We use lagged quantities of two years when setting prices. This allows consistency with the default price-quality path (DPP).

Table 3: Load group statistics as at 31 March 2015

Load group	ICP numbers	ADMD (MW)	CPD (MW)	Weighted demand (MW)	RCPD (MW)
LOWHCA	1,311	2.69	0.33	0.56	2.62
LOWLCA	7,360	15.12	1.84	3.17	14.72
LOWUHCA	9	0.02	0.00	0.00	0.02
LOWULCA	23	0.05	0.01	0.01	0.05
015HCA	5,984	12.30	1.50	2.58	11.97
015LCA	14,047	28.87	3.51	6.05	28.09
015UHCA	35	0.07	0.01	0.02	0.07
015ULCA	46	0.09	0.01	0.02	0.09
360HCA	453	5.44	5.44	5.44	2.27
360LCA	696	8.35	8.35	8.35	3.48
360UHCA	13	0.16	0.16	0.16	0.07
360ULCA	8	0.10	0.10	0.10	0.04
ASSHCA	1,180	53.10	41.30	42.48	5.90
ASSLCA	354	15.93	12.39	12.74	4.25
TOU400HCA	35	3.95	3.90	3.91	3.87
TOU400LCA	103	11.63	11.49	11.50	11.40
TOU11HCA	6	4.79	4.34	4.39	2.87
TOU11LCA	4	3.19	2.90	2.93	1.92
Total	**31,667**	**165.85**	**97.57**	**104.41**	**93.70**

Table 4: Allocation of revenue requirement to load groups prior to LOW user regulation allocation

Load Group	2015/16 Target Revenue (in millions)	2016/17 Target Revenue (in millions)	Growth in Target Revenue (in millions)	Proportion of Load Group Target Revenue to Total Target Revenue
LOWHCA	0.54	0.64	0.10	1.1%
LOWLCA	3.33	3.85	0.52	6.7%
LOWUHCA	0.00	0.01	0.00	0.0%
LOWULCA	0.01	0.01	0.00	0.0%
015HCA	5.47	5.63	0.16	9.8%
015LCA	11.89	11.72	0.17	20.5%
015UHCA	0.02	0.05	0.02	0.1%
015ULCA	0.03	0.05	0.02	0.1%
360HCA	1.22	1.39	0.18	2.4%
360LCA	1.73	2.17	0.44	3.8%
360UHCA	0.04	0.05	0.01	0.1%
360ULCA	0.02	0.02	0.00	0.0%
ASSHCA	11.26	14.83	3.57	25.9%
ASSLCA	3.41	3.68	0.27	6.4%
TOU400HCA	1.18	1.61	0.43	2.8%
TOU400LCA	4.48	4.12	0.36	7.2%
TOU11HCA	1.14	1.28	0.14	2.2%
TOU11LCA	0.76	0.76	0.00	1.3%
IND	4.46	5.42	0.97	9.5%
Total	**51.00**	**57.30**[16]	**4.85**	**100%**

[16] Target revenue is different from our revenue requirement because of a need to comply with our regulatory price cap.

Table 5: Cost allocators used and rationale for selection

Cost Component	Allocator	Rationale
Operating expenditure	ADMD Weighted CPD	The incurrence of network Opex is represented through the consumers' contribution towards the assets' overall utilisation. Therefore demand related allocators have been used. LV related costs are allocated to load groups based on ADMD and HV related costs are allocated to load groups based on weighted CPD.
Recovery of revenue forgone from RCP1	ADMD Weighted CPD	LV related costs are allocated to load groups based on ADMD and HV related costs are allocated to load groups based on weighted CPD.
Revaluations and sundry income	ADMD Weighted CPD	Revaluations arise from the indexation of fixed assets which is related to the investment driven by each load group. Therefore demand related allocators have been used. LV related costs are allocated to load groups based on ADMD and HV related costs are allocated to load groups based on weighted CPD.
Depreciation	ADMD Weighted CPD	Depreciation is compensation to our owners for the reduction in asset values that occur over time. Depreciation is allocated to load groups based on the load group's contribution to the network and local peaks. HV related depreciation is allocated to groups based on weighted CPD with LV related depreciation allocated to groups based on ADMD. Allocating costs in this manner reflects that future costs to upgrade and or replace assets are driven by consumer use of the asset at peak times.
Return on investment	ADMD Weighted CPD	Our owners are compensated for investing in Alpine Energy through a return on the value of the asset base. We recover this value based on the structure of the network asset base (regulatory asset base), where network assets are planned and built around providing future capacity requirements That is we recover the return on investment based on load group demand to the demand of all users. In this case we use both ADMD and CPD as discussed above.
Non network costs	Pro rata basis	Non network costs are generally not driven by consumer demand for power. Therefore these costs are allocated evenly amongst ICPs, with the exception of individual customers.

6. Calculating our prices

In this section we discuss how we calculate prices to recover our revenue requirements for distribution costs, transmission, and pass through and recoverable costs.

Distribution

Once we have allocated costs to load groups, based on the load group's use of the network, we calculate fixed, demand and variable charges to recover distribution costs.

Fixed to variable cost recovery ratio

The advantages to using both fixed and variable charges are explained at Table 6 on page 19. Overall we find that for consumers who do not have TOU metering, a ratio of 50% fixed to 50% variable cost recovery, creates the most efficient outcomes. When consumers do have TOU metering, the demand charge allows us to reduce the fixed to variable ration in favour of fixed, as the demand charge helps to signal the costs of providing future capacity.

The variable component is further split into day and night

We split our charges, with lower night rates to give incentives for shifting load into off–peak (night) periods. Where a consumer has a TOU meter or day/night meters the actual usage is applied. Where a consumer has standard metering, consumption is split 70:30 under the assumption that day time consumption is greater than night time consumption.

Fixed daily charges

Fixed daily charges are calculated by dividing each load group's respective revenue requirement by the number of ICP's. Assessed demand and TOU load groups also have a fixed charge based on the installed capacity, or business day peak demand respectively.

Impact of Low Fixed Charge Regulations

We calculate tariffs for the LOW load groups using a four step process.

1. We deduct from the LOW load group revenue requirement, the total fixed charge we can recover under the Low fixed charge regulations ($0.15 per day).
2. We establish the remaining revenue requirement that we need to recover for the LOW load groups through variable charges.
3. We then calculate the LOW day night variable prices using 'goal seek', so that the total annual price for an average consumer (consuming 9000 kWh p.a.) in the LOW load groups, is not higher than an average consumer would pay in alternative 015 groups.

4. We allocate the excess LOW user revenue requirement that we cannot recover under regulation to remaining load groups.

Table 6: The fixed variable cost recovery ratio

Advantage of fixed variable ratio	Rationale
Signal future cost of capacity upgrades	A large fix charge (without demand charges[17]) discourages efficient use of the network as it does signal the cost of using the network at peak times. For those consumers without TOU metering a variable charge acts as a proxy of capacity and signals the future cost of using the network at peak times.
Recognition of cost structures	A large fixed cost aligns with the fact that the majority of network costs in the short run are fixed. For consumers with TOU metering we can recover more revenue through fixed and demand charges (where the demand charge is fixed for the year) and thereby reduce the risk to revenue from a drop in consumption. As the demand charge removes the need to use a variable to charge as a proxy for capacity.
Protecting revenue from reduction in consumption	Most costs are fixed in the short run meaning that revenue should in theory be recovered from fixed charges. Recovering revenue through Fixed charges also reduces the risk that revenue falls due to a reduction in consumption.

Calculating pass through and recoverable prices

When calculating load group prices to recover annual pass through and recoverable costs, we use forecast rates and levies from local authorities, the Commerce Commission, and the Electricity Authority.

We allocate forecast pass through and recoverable costs to load groups, by multiplying the forecast annual pass through and recoverable cost by the number of ICPs in a load group to total ICPs on the network.

We recover a load group’s forecast pass through and recoverable costs through 50% fixed charges and 50% variable charges. We do not use a demand charge to recover these costs.

Calculating transmission prices

When calculating load group prices to recover annual transmission costs, we use Transpower’s transmission costs for the 2016/17 pricing year. From the total we remove

[17] We fix demand charges for the pricing year and therefore include demand charges as a fixed annual cost when calculating the fixed variable ratio. In this instance however we are discussing fixed charges less demand charges.

the annual transmission revenue we expect to recover from direct billed customers, before allocating the remainder to load groups.

From the remaining transmission costs, we also remove the revenue we expect to receive from consumers who pay extra for not having hot water on load control. We then divide the remainder into connection / new investment agreement (NIA) costs and interconnection costs based on historic proportions for recovering these costs.

We allocate the connection / NIA costs to load groups using a load group's AMD to the total AMD of all load groups. We allocate interconnection costs using a load group's regional coincident peak demand[18] (RCPD) to the total RCPD of all load groups.

We recover pass through and recoverable costs through fixed, demand, and variable (consumption) charges. For those consumers in the 015 and 360 load groups with uncontrolled hot water we add an increase to their fixed daily charge of $0.6537. For consumers in the LOW user groups we increase their variable charges by $0.0266 / kWh.

7. Changes in delivery charges

The median price increase from 2015/16 to 2016/17 is 10%.

Our 2016/17 prices reflect the changes made to the price path under the DPP Determination.

Of greatest impact to our 2016/17 prices were the:

i) changes made to the allocation of transmission, pass through and remaining recoverable costs

ii) a change to the fixed to variable recovery of costs ratio.

A copy of the 2016/17 and 2015/16 pricing schedules are included at Attachment A and B of this pricing methodology.

Please note that for variable charges day—is between 7am and 11pm and night—is between 11pm and 7am.

8. What are capital contributions

In addition to the delivery charge revenue that we receive from our consumers we also receive capital contributions from any consumer that requires to be connected to our

[18] For load groups without half hour metering we estimate RCPD based on the upper South Island RCPD, the network and half hour RCPD, as well load group demand profiles.

network or need upgrades to their existing connection[19]. In 2014/15 we received $3.5 million in capital contributions. We have forecast to collect $2.4 million in capital contributions for 2016/17.

These capital contributions cover the cost of the work carried out less rebates. This means that, as a general rule, there are no remaining costs to be recovered through delivery charges except ongoing maintenance costs. Without a capital contribution these extensions or upgrades would be uneconomic under standard delivery charges.

For larger builds generally over $500,000, we will calculate the risk of the investment to ourselves and use this to determine capital contributions payable. When calculating risk we invite the investor to comment on our risk score, and resulting capital contributions.

A copy of our *New Connections and Extensions Policy* can be found on our website[20].

9. Direct billed customers

We have five direct billed customers (9 ICPs) connected to our network at present and expect one more to contract with us over the next 12 months.

We are forecast to recover $3.3 million in distribution charges and $2.4 million in transmission charges for the 2016/17 year from direct billed customers.

The decision to place a new connection onto a direct billed contract is made on a case by case basis. When making this decision we take into account the:

- cost of the build
- number of new assets required
- extent of the existing network that will be used by the new connection
- capital contribution paid
- ongoing costs that will be recovered through delivery charges
- required security of supply.

[19] Costs of upgrades to an existing connection can be shared where there are network benefits to the upgrade. Where the upgrade to the sole benefit of the consumer the consumer must pay in entirety for that upgrade.

[20] http://www.alpineenergy.co.nz/our-network

Difference between direct bill and standard agreement security standards

Customers on a direct billed contract can expect one planned outage each year and an unplanned outage of two hours every five years, plus a momentary unplanned outage every two years[21]. These service standards are not available to consumers on the shared distribution charges model.

For both direct billed customers and consumers on the shared network we give a minimum of four working days' notice before a planned shutdown occurs. We do not guarantee supply or offer compensation if supply is lost to any connection.

Methodology for recovering costs from direct billed customers

The following methodology is used for calculating prices for directly billed customers[22]. Because we enter into long term contracts with direct billed customers we are able to negotiate outcomes which are consistent with market like arrangements.

Calculation and recovery of the cost of new assets

The capital contribution paid for new assets can reduce the ongoing delivery charges that the customer will pay.

If a capital contribution equals the total value of the new assets allocated to the customer the customer may not pay cost of capital or depreciation charges for these new assets. They will however pay for ongoing maintenance charges for these assets through their delivery charges.

If the capital contributions do not cover the full cost of the value of new assets used by the customer, then the remaining value of the asset (after capital contributions) will be used to calculate cost of capital charges, and depreciation charges. Depreciation charges are calculated on a remaining life basis, with age of the asset taken from the Commerce Commission's Optimised Deprival Value Handbook (2004).

Return on capital charges applies the Commerce Commission's weighted average cost of capital for the industry and recovers this from the closing value of the new asset (adjusted for inflation) from the previous year, using a midyear cash flow.

Capital contributions based on perceived risk of the investment

We calculate the value of the capital contribution on the perceived risk of the investment. The perceived risk is calculated using a risk algorithm which we fill out then pass to the

[21] Some contracted service standards will differ for older contracts. .

[22] For some direct billed customer's the pricing methodology will differ to the one described above due to prior long term contracts in place.

customer for comment. The risk algorithm calculates a percentage score which translates to the percentage of the total investment cost that should be paid as a capital contribution. For example if the risk algorithm calculates risk to be 75% then we would require a capital contribution of 75% of the total investment cost.

Maintenance charges payable

Maintenance charges effectively bank the cost of maintaining assets. That is, while new assets will have little maintenance after the first year of service, the maintenance charge will cover future replacement costs. However the maintenance charge will not cover future costs to upgrade capacity.

Recovering the cost of existing network assets

If the customer also requires the use of the existing Alpine network then cost of capital charges, depreciation and maintenance charges apply for these assets.

Allocators for recovering costs

The portion that a customer will pay for the use of existing network assets will depend on the most relevant cost driver for that asset. For lines and cables, costs are apportioned to the customer based on the customer's line/cable length to the total line/cable lengths in the network.

For sub-stations, transformers, protection, and switchgear, costs are apportioned to the asset using the total anytime maximum demand (AMD) of all users of the asset to the total AMD on the network. Costs are then apportioned to the customer according to the customer's AMD to the total AMD on the asset.

Recovering the future costs of grid upgrades in capacity

Please note that our costs are fixed in the short term so that a drop in demand (or consumption) will have little or no impact on our short term (annual) costs. However, a decrease in demand over the long term can delay or prevent cost to upgrade network capacity.

At present we do not recover long run marginal costs through a demand charge instead we recover costs for added capacity when these costs occur.

Recovery of transmission costs

Transmission costs are passed through to the consumer according to the consumers AMD to the total AMD of all users of the grid exit point (GXP) the customer is connected to. The exception is the interconnection charge which is charged out to the consumer at the Transpower rate per kW of demand during the regional peak periods (RCPD).

10. Distributed generation on our network

Our network provides the means for distributed generators of all types and sizes to convey electricity through our network to end users.

Connected to our network are approximately:

- 160 small distributed generators with less than 10 kW and a combined capacity of 0.65 MW that are installed at residential or small business premises
- one distribution generator that generates at 8 MW[23].

These 160 distributed generators total some 8.7 MW of distributed generation that can flow through our network at any given time.

Fees payable by distributed generators to us are set by the Electricity Authority under the Code.[24] We do not currently 'pay', nor 'charge', distributed generators for the electricity that they convey down our lines. Payment for distributed generation is made by retailers and the rates can be found on the respective retailer websites.

We encourage generators of solar energy (photo voltaic cells), wind, water (hydroelectric) or fossil fuels such as diesel or natural gas that have energy that is surplus to their requirements to sell into the network. We do this by allowing generators to use our distribution network without incurring any network charges[25]. This is an alternative to paying Avoided Cost of Transmission (ACOT) benefits.

ACOT payments are made by contract on a case by case basis.

Information about connection to our network and our application process for connection and operation of distributed generation by both small and large distributed generators is available on our website.[26]

11. Calculation of loss factors

Losses represent the percentage of electricity entering the network that is lost during the delivery to ICPs. The quantity of electricity metered at ICP reported is net of losses. To determine each retailer's purchase responsibilities, the electricity measured at the consumer's meter is multiplied by a 'loss factor'. There are two main components to loss factors:

---

[23] Opuha hydro installation with maximum generation of 8 MW.

[24] Schedule 6.5, Electricity Participation Code 2010, Part 6, Connection of distributed generation.

[25] In accordance with the Code a connection fee and inspection and living fees do apply.

[26] http://www.alpineenergy.co.nz/our-network/sub-menu-modid-156/40-solar-distributed-generation

i) fixed component due to the standing losses of the zone substation and distribution transformers

ii) variable components arising from the heating effects of the resistive losses in the delivery conductors.[27]

The loss percentage reported under the information disclosure requirements for the year ended 31 March 2015 was 3.6%.

Losses can vary by connection

The following loss factors applied by us are as follows:

- 33kV dedicated—1.02
- 11KV general—1.05
- 400V general—1.07

Losses for 11kV consumers will be some 2% less than 400V consumers because there are no distribution transformer losses. Dedicated 33kV line, which provides N-1 security to meet reliability of supply requirements, result in effective losses of less than 2% for loads around 15MW.

12. Overview of our consumer survey

In March 2014 we conducted a 'mass market' consumer survey of approximately 500 consumers randomly from our seven GXP supply areas. We received 275 completed responses in regard to perceptions around supply reliability, inconvenience caused by interruptions, community disruption, and price.

Most surveyed consumers believe that their electricity supply reliability is similar to what it has been over the last few years, with about 13% believing that supply reliability has improved and only 7% believing that supply reliability has deteriorated.

From the consumer survey, we also asked about the influence of the 2013 storms.

Road closures and building collapses as a result of the 2013 storms were few, with 68% of surveyed consumers reporting no damage. About 65% of surveyed consumers experienced no inconvenience from electricity supply interruptions resulting from the storms, with a further 27% experiencing some personal inconvenience.

When asked how much extra they might be prepared to pay, about 81% of surveyed consumers indicated that they were not willing to pay any additional delivery charges to reduce the risk of prolonged supply interruptions due to storms.

[27] The resistive losses are proportional to the square of the load current and occur in all network conductors and in the zone substations and distribution transformers.

Except for the duration of supply interruptions during the 2013 storms, the survey results appear homogeneous and do not reveal any particular market segments as experiencing interruptions or expressing preferences that are significantly different to the total results.

13. Rollout of smart meters

We are currently rolling out smart meters across our network. These meters give real time information about consumers' usage. Once the rollout is complete, real time information on all load groups' usage will be available.

Our current delivery charges do not reflect the information that will be available after the roll-out is complete. We intend to consider how our lines charges might be structured in a way that anticipates and enables us to use this available information.

14. How we align with the pricing principles

To see how we align with the Electricity Pricing Authority Pricing Principles please refer to Appendix A—How we align with the pricing principles.

15. Our pricing strategy

Our pricing strategy is to conform to regulations for every pricing period.

Please contact us

We welcome questions about our pricing methodology. Questions can be forwarded to:

Sara Carter
General Manager - Commercial and Regulatory
Alpine Energy Limited
03 6874 306
sara.carter@alpineenergy.co.nz

If you have a compliant about our service please contact us on 03 687 4300. If we can't resolve your compliant, you can contact the Electricity and Gas Complaints Commissioner for a free and independent complaints service at agcomplaints.co.nz or on 0800 22 33 40.

Appendix A—How we align with the pricing principles

Table 7: Electricity Authority Pricing Principles

Pricing Principles	Alpine Energy Limited's Alignment to the Principles
(a) Prices are to signal the economic costs of service provision by:	
(i) being subsidy free (equal to or greater than incremental costs, and less than or equal to standalone costs), except where subsidies arise from compliance with legislation and/or other regulation	Cross subsidies occur where prices charged to a consumer or consumer group do not recover the long run incremental costs of providing the line service to them. We calculate long run incremental costs as the increase in consumption from an increase in $1 of system growth capital expenditure. We define standalone cost as the lowest cost alternative of supplying power to each consumer group. Our standalone costs are $775/kW and our long–run incremental costs (LRIC) are $55/kW if we were to recover all charges through a demand charge. Table 9 shows that the forecast revenue in $/kW per load group is equal to or greater than the incremental cost and less than the standalone cost for each load group; demonstrating that our prices are subsidy free.

Table 9: variable distribution price per load group

Load Group	$/kW
LOWLCA	$187.49
LOWUHCA	$137.27
LOWULCA	$259.75
015HCA	$199.60
015LCA	$139.23
015UHCA	$115.23
015ULCA	$144.30
360HCA	$103.49
360LCA	$151.74
360UHCA	$107.12
360ULCA	$143.03
ASSHCA	$119.08
ASSLCA	$119.66
TOU400HCA	$ 63.83
TOU400LCA	$147.01
TOU11HCA	$ 81.76
TOU11LCA	$130.22

Pricing Principles	Alpine Energy Limited's Alignment to the Principles
(ii) having regard, to the extent practicable, to the level of available service capacity	We use TOU pricing (including day night) and capacity/demand based pricing where possible to encourage consumers to use the network outside of peak periods where capacity constraints may occur.
(iii) signalling, to the extent practicable, the impact of additional usage on future investment costs	As above we use TOU (including day night pricing) and demand charges to encourage consumers to consume outside of peak periods, in order to reduce future expenditure on the network.
(b) Where prices based on 'efficient' incremental costs would under–recover allowed revenues, the shortfall should be made up by setting prices in a manner that has regard to consumers' demand responsiveness, to the extent practicable.	
This principle encourages distributors to direct the recovery of network fixed costs towards those consumers who are less price-responsive and will therefore reduce their demand by the lowest amount. This means that we must consider how different consumer groups might respond to changes in price. However, considering how different consumer groups might respond to change in price is very difficult for us to determine as we hold limited information about price elasticity of demand as information at the consumer level is held by retailers. Therefore we apply this principle at a principle-based level by measuring the impact of changes on price on the 'average consumer' when we set prices for standard customers. Our prices to individual customers take into account their willingness to pay when we transact cost of supply agreements with them	
(c) Provided that prices satisfy (a) above, prices should be responsive to the requirements and circumstances of stakeholders in order to:	
(i) discourage uneconomic bypass	This principle aims to ensure that prices that enable the recovery of fixed network costs do not drive any consumers to an alternative solution that increases total costs to all parties involved (i.e., uneconomic bypass). We have calculated standalone costs for standard consumers based on estimated annualised life cycle costs ($/kWh) of standalone generation. Our pricing for standard load groups is below our calculated standalone cost. For non-standard consumers we manage this risk through long term contracts negotiated with the consumer concerned.

Pricing Principles	Alpine Energy Limited's Alignment to the Principles
(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	This principle reflects the regulators concern that monopoly service providers have few incentives to actively engage with their consumers. Consumer engagement should allow prices to more closely resemble 'market–like' transactions where consumers have the ability to communicate their expectations and preferences to the regulated firm. We align with this principle through our annual consumer surveys and through our engagement with non–standard consumers. The surveys help us to understand price quality trade-offs from the consumer's perspective. That is, whether consumers are willing to pay more for a higher quality service and also what the impact of specific events (e.g., severe weather) had on them. As a result of our interactions with our non-standard consumers, we understand the preferences of these consumers well. The non–standard contracts are also negotiated to reflect price/quality trade–offs.
(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	We pay Avoided Cost of Transmission (ACOT) benefits to a small number of large distributed generators on a contractual basis. This is to encourage such generators to generate during peak transmission periods. However, we do not pay ACOT to small distributed generators as they make a very small contribution to avoiding transmission costs. Instead we allow generators to use our distribution network without incurring network charges.
(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	

Pricing Principles	Alpine Energy Limited's Alignment to the Principles
We are of the view that our delivery charges are understandable for stakeholders (for example, consumers, retailers, shareholders, and us). Our delivery charges have been developed in a manner that intends to promote certainty and price stability. When we have had to increase delivery charges we have done so uniformly with due regard given to the impact on stakeholders of any changes in prices and/or transaction costs. Consumers have a reasonable expectation that our delivery charges will be stable and will not shift significantly over time. Increases to our delivery charges have been, and will continue to be, consistent with the limits placed on us under the DPP determination by the Commerce Commission.	
(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	
This principle encourages EBDs to recognise the costs that they can impose on retailers, consumers and other stakeholders and to find ways to minimise those costs. We are managing the transaction costs on retailers by discussing pricing with other EBD's Island in order to help with standardisation of tariffs. If tariffs are overly complex this creates costs for retailers and consumers. We are of the view that our tariffs are not overly complex and should not impose high transaction costs on retailers and consumers. We also believe that our pricing methodologies maintain economic equivalence across retailers.	

Attachment A—2016 delivery charges

Delivery prices effective as at 1 April 2016

Alpine Energy	Pricing Schedule effective as at 1 April 2016	Delivery Charges				Number of
		Fixed *per day*	Day *per kWh*	Night *per kWh*	Demand *per kW/per day*	Consumers *as at 31/12/2015*
LOWHCA	Low User (controlled) high cost area	$0.15	$0.1001	$0.0620	$0.0000	1,386
LOWLCA	Low User (controlled) low cost area	$0.15	$0.0958	$0.0577	$0.0000	7,679
LOWUHCA	Low User (uncontrolled) high cost area	$0.15	$0.1265	$0.0884	$0.0000	9
LOWULCA	Low User (uncontrolled) low cost area	$0.15	$0.1222	$0.0841	$0.0000	25
015HCA	Single Phase (controlled) high cost area	$0.97	$0.0668	$0.0286	$0.0000	5,965
015LCA	Single Phase (controlled) low cost area	$0.87	$0.0668	$0.0286	$0.0000	13,815
015UHCA	Single Phase (uncontrolled) high cost area	$1.63	$0.0668	$0.0286	$0.0000	35
015ULCA	Single Phase (uncontrolled) low cost area	$1.52	$0.0668	$0.0286	$0.0000	45
360HCA	Three Phase (controlled) high cost area	$4.40	$0.0668	$0.0286	$0.0000	461
360LCA	Three Phase (controlled) low cost area	$3.28	$0.0668	$0.0286	$0.0000	700
360UHCA	Three Phase (uncontrolled) high cost area	$5.06	$0.0668	$0.0286	$0.0000	14
360ULCA	Three Phase (uncontrolled) low cost area	$3.94	$0.0668	$0.0286	$0.0000	9
ASSHCA	Assessed demand high cost area	$1.50	$0.0668	$0.0286	$0.1610	1,211
ASSLCA	Assessed demand low cost area	$0.97	$0.0668	$0.0286	$0.1139	356
TOU400HCA	Time-of-Use metering at 400 V high cost area	$0.93	$0.0202	$0.0086	$0.4589	36
TOU400LCA	Time-of-Use metering at 400 V low cost area	$0.75	$0.0170	$0.0073	$0.3410	106
TOU11HCA	Time-of-Use metering at 11 kV high cost area	$0.92	$0.0229	$0.0098	$0.3843	6
TOU11LCA	Time-of-Use metering at 11 kV low cost area	$0.82	$0.0206	$0.0088	$0.3347	4

Notes:

Delivery charges include distribution and transmission charges and excludes metering charges.

Fixed Charges accrue daily at the rate of 1/365th of the annual amount. The Fixed Transmission charge for sites in the 015UHCA, 015ULCA, 360UHCA and 360ULCA load groups is a special charge for the provision of electric water heating that cannot be controlled by Alpine Energy via a ripple relay.

Variable Charges are made up of day unit charges which are levied in respect of all units used between 7am and 11pm and night unit charges which are levied in respect of the period 11pm to 7am. Charges are based on metering at the Grid Exit Points supplying the network with a reduction for the declared network loss level to emulate usage metered on site. The additional distribution charge of 3.33 cents/kWh for day and night usage in the LOWHCA and LOWUHCA load groups, and 2.90 cents/kWh for day and night usage in the LOWLCA and LOWULCA load groups is charged based on usage advised by electricity retailers. The additional variable transmission charge of 2.64 cents/kWh for day and night usage for sites in the LOWUHCA and LOWULCA load groups is a Special Charge for provision of electric water heating that cannot be controlled by us via a ripple relay, and is charged based on usage advised by electricity retailers.

Demand Charges only apply to sites with a demand (kW) charge. The demand level at these sites is assessed and set by us and is available on request. The charge accrues daily at the rate of 1/365th of the annual amount.

All Charges are GST exclusive. GST is payable in addition to the charges. Additional terms and conditions detailed in our Use of System Agreement and Memorandum of Understanding may also apply.

Attachment B—2015 delivery charges

Delivery prices effective as at 1 April 2015

Alpine Energy	Pricing Schedule effective as at 1 April 2015	Delivery Charges Fixed *per day*	Day *per kWh*	Night *per kWh*	Demand *per kW/per day*	Number of Consumers *as at 31/12/2014*
LOWHCA	Low User (controlled) high cost area	$0.15	$0.0933	$0.0483	$0.0000	1,200
LOWLCA	Low User (controlled) low cost area	$0.15	$0.0867	$0.0417	$0.0000	7,090
LOWUHCA	Low User (uncontrolled) high cost area	$0.15	$0.1199	$0.0748	$0.0000	8
LOWULCA	Low User (uncontrolled) low cost area	$0.15	$0.1133	$0.0682	$0.0000	16
015HCA	Single Phase (controlled) high cost area	$0.97	$0.0598	$0.0147	$0.0000	6,091
015LCA	Single Phase (controlled) low cost area	$0.81	$0.0598	$0.0147	$0.0000	14,328
015UHCA	Single Phase (uncontrolled) high cost area	$1.63	$0.0598	$0.0147	$0.0000	36
015ULCA	Single Phase (uncontrolled) low cost area	$1.47	$0.0598	$0.0147	$0.0000	53
360HCA	Three Phase (controlled) high cost area	$3.98	$0.0598	$0.0147	$0.0000	445
360LCA	Three Phase (controlled) low cost area	$3.32	$0.0598	$0.0147	$0.0000	689
360UHCA	Three Phase (uncontrolled) high cost area	$4.63	$0.0598	$0.0147	$0.0000	14
360ULCA	Three Phase (uncontrolled) low cost area	$3.98	$0.0598	$0.0147	$0.0000	8
ASSHCA	Assessed demand high cost area	$0.63	$0.0598	$0.0147	$0.1677	1,173
ASSLCA	Assessed demand low cost area	$0.51	$0.0598	$0.0147	$0.1565	356
TOU400HCA	Time-of-Use metering at 400 V high cost area	$0.40	$0.0212	$0.0048	$0.4014	35
TOU400LCA	Time-of-Use metering at 400 V low cost area	$0.37	$0.0212	$0.0048	$0.3644	103
TOU11HCA	Time-of-Use metering at 11 kV high cost area	$0.42	$0.0211	$0.0049	$0.3491	6
TOU11LCA	Time-of-Use metering at 11 kV low cost area	$0.35	$0.0212	$0.0048	$0.3309	4

Notes:

Delivery charges include distribution and transmission charges and excludes metering charges.

Fixed Charges accrue daily at the rate of 1/366th of the annual amount. The Fixed Transmission charge for sites in the 015UHCA, 015ULCA, 360UHCA and 360ULCA load groups is a special charge for the provision of electric water heating that cannot be controlled by Alpine Energy via a ripple relay.

Variable Charges are made up of day unit charges which are levied in respect of all units used between 7am and 11pm and night unit charges which are levied in respect of the period 11pm to 7am. Charges are based on metering at the Grid Exit Points supplying the network with a reduction for the declared network loss level to emulate usage metered on site. The additional distribution charge of 3.35 cents/kWh for day and night usage in the LOWHCA and LOWUHCA load groups, and 2.69 cents/kWh for day and night usage in the LOWLCA and LOWULCA load groups is charged based on usage advised by electricity retailers. The additional variable transmission charge of 2.66 cents/kWh for day and night usage for sites in the LOWUHCA and LOWULCA load groups is a Special Charge for provision of electric water heating that cannot be controlled by us via a ripple relay, and is charged based on usage advised by electricity retailers.

Demand Charges only apply to sites with a demand (kW) charge. The demand level at these sites is assessed and set by us and is available on request. The charge accrues daily at the rate of 1/366th of the annual amount.

All Charges are GST exclusive. GST is payable in addition to the charges. Additional terms and conditions detailed in our Use of System Agreement and Memorandum of Understanding may also apply.

Glossary

ADMD	After Diversity Maximum Demand—the simultaneous maximum demand of a group of homogeneous consumers,
Code	The Electricity Industry Participation Code 2010
Consumer	A person that consumes or acquires electricity lines services
CPD	Coincident Peak Demand—relates to the consumer's off-take at the connection location during a peak demand period
CPI	Consumer Price Index—a measure of the change of a weighted average of prices in a basket of consumer goods and services
Customer	A legal entity with which we have a direct contractual relationship, in the form of a user of supply agreement for example, retailers and large consumers
Delivery charges	Charges that recover **distribution costs**, **pass through and recoverable costs.** Where **pass through and recoverable costs** include **transmission costs**
Demand	The rate of expending electrical energy expressed in kilowatts (kW) or kilovolt amperes (kVA)
Distributor	Alpine Energy Limited as the operator and owner of the electricity distribution network
Distributed Generation	Electricity generation that is connected and distributed within the distribution network, the electricity generation being such that it can be used to avoid or reduce transmission demand costs. Also referred to as 'embedded generation'
Distribution cost	Costs to operate and maintain the distribution network
Distribution network	The network of electricity assets that distribution network companies such as Alpine Energy own and operate, to deliver electricity from the transmission network to consumers.
DPP	Default Price-Quality Path—with which non-exempt suppliers of electricity line services comply under Part 4 of the Commerce Act 1986

EDB	Electricity Distribution Business—a business that is responsible for delivering electricity from the national grid to consumers
GIS	Geographic Information System—is used to isolate assets on a network and to identify low cost and high cost areas
GXP	Grid Exit Point—a point of connection between Transpower's transmission system and our distribution network
ICP	Installation Control Point—a point of connection on the Distributor's network, which the Distributor nominates as the point at which a retailer is deemed to supply electricity to a consumer
Long run incremental costs	LRIC The increase in cost from an increase in network capacity that has occurred over a period of time long enough for all costs to be variable.
Mass market	The majority of electricity consumers, predominantly residential and small business
Part 4	Part 4 of the Commerce Act 1986 governing the regulation of EDBs as administered by the Commerce Commission
RCPD	Regional Coincident Peak Demand —relates to the consumer's off-take at the connection location during a regional peak demand period
Pass through and recoverable costs	Costs which are charged to Alpine Energy which are then 'passed through' consumers. Costs include: • rates • commerce commission levies and other industry levies • **transmission costs**
Pricing Principles	Guidelines published by the Electricity Authority that specify the information that a Distributor should make available
TOU	Time Of Use—is a consumer that is metered according to their electricity consumption for a particular period (usually half–hourly) allowing pricing that varies depending on time of day and measurement of peak demands

Transmission costs	The cost of maintaining the national electricity grid. Transmission costs are charged to distribution companies who recover these costs from users of the network through **delivery charges**
Uncontrollable Load	The load that we are not able to control i.e., switch off during periods of high demand such as electrical water heating
Vanilla WACC	Weighted average of the pre–corporate tax cost of debt and the cost of equity
WACC	Weighted Average Cost of Capital—is the regulated rate of return on the company's assets.