Pricing Methodology

For Delivery Prices, effective as at 1 April 2019

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

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Contents

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, Warren Boyce McNabb and Don Mcgillivray Elder, being directors of Alpine Energy Limited certify that, having made all reasonable enquiry, to the best of our knowledge:

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.

a) 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.

WB McNabb

Warren Boyce McNabb
7 February 2019

Don Mcgillivray Elder
7 February 2019

1. Purpose of our pricing methodology

This pricing methodology outlines our approach to setting delivery prices effective from 1 April 2019.

The meaning of delivery prices

The term ‘delivery charge’ describes the total price we charge to transport electricity from the national grid to consumer’s homes and businesses.

Delivery prices include 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) that we must pay throughout the year.

Definitions of these charges are provided in the Glossary on page 37.

Our network

We are an electricity distribution business (EDB) located in the South Canterbury region of New Zealand. Our electricity network has a regulatory value of $199.6 million as at 31 March 2018.

Our network connects over 32,900 consumers to the national transmission network through seven local grid exit points (GXPs):

- Albury
- Bells Pond
- Studholme
- Tekapo
- Temuka
- Twizel
- Timaru

Figure 1: **Map of our network** on page 5 shows the location of the seven GXPs and 24 substations on our network.

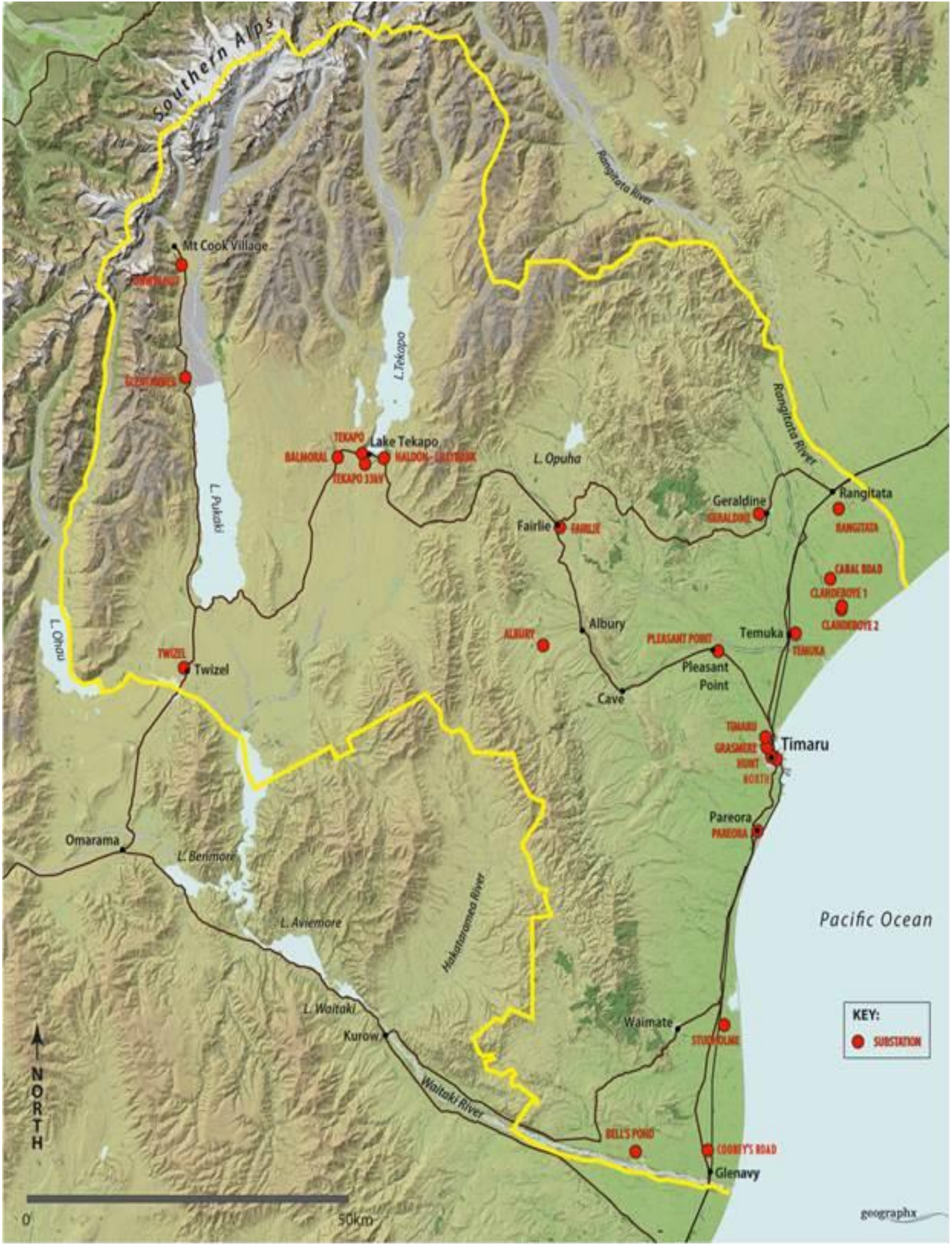
We are owned by the community we serve

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

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

Since many of our consumers are also ratepayers to the local councils, they benefit directly from our revenue, through an annual dividend payment and indirectly, through services provided by local councils.

Figure 1: Map of our network



Our pricing is regulated

In 2019, we are subject to the following regulations enforced by the:

- 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 – (consolidating all amendments as of 3 April 2018), 3 April 2018 (ID Determination)
- 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.

This pricing methodology meets the obligations of these regulations. More detailed discussion of how we meet the Electricity Authority's pricing principles can be found at Appendix A on page 29.

2. Overview of our Pricing Methodology

We set annual delivery prices to ensure we efficiently recover our network related long and short run costs from those who use the network. We do so by taking into account the need to balance complexity with transparency.

When setting delivery prices, we first calculate our required revenue (explained in detail in Section 3 from page 10). We then calculate the distribution, transmission, and pass through and recoverable price components.

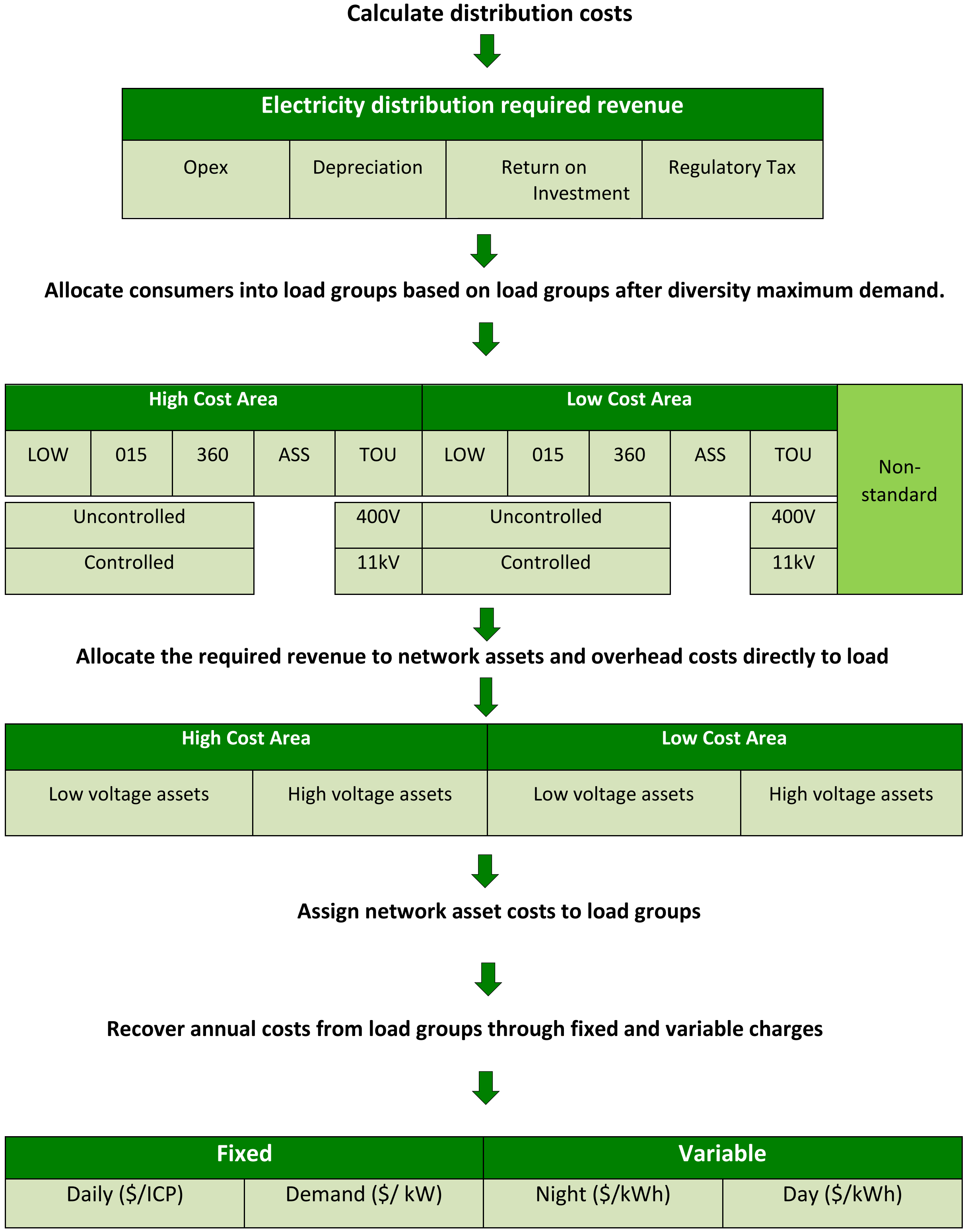
Distribution price components

When calculating distribution prices, we use a five-step process.

1. Identify the annual required revenue by quantifying the key cost components.
2. Determine the key attributes of each load group and assign consumers into load groups to allocate costs.
3. Allocate the revenue required to network assets using appropriate cost drivers, and overhead costs directly to load groups.
4. Assign network assets to load groups and allocate respective asset costs to each load group.
5. Recover annual costs from load groups through both fixed and variable charges.

Figure 2 over the page shows the key steps to our distribution costs recovery.

Figure 2: Key steps to recovering distribution costs



Calculate distribution costs

Electricity distribution required revenue			
Opex	Depreciation	Return on Investment	Regulatory Tax

Allocate consumers into load groups based on load groups after diversity maximum demand.

High Cost Area					Low Cost Area					Non-standard
LOW	015	360	ASS	TOU	LOW	015	360	ASS	TOU	
Uncontrolled				400V	Uncontrolled				400V	
Controlled				11kV	Controlled				11kV	

Allocate the required revenue to network assets and overhead costs directly to load

High Cost Area		Low Cost Area	
Low voltage assets	High voltage assets	Low voltage assets	High voltage assets

Assign network asset costs to load groups

Recover annual costs from load groups through fixed and variable charges

Fixed		Variable	
Daily ($/ICP)	Demand ($/ kW)	Night ($/kWh)	Day ($/kWh)

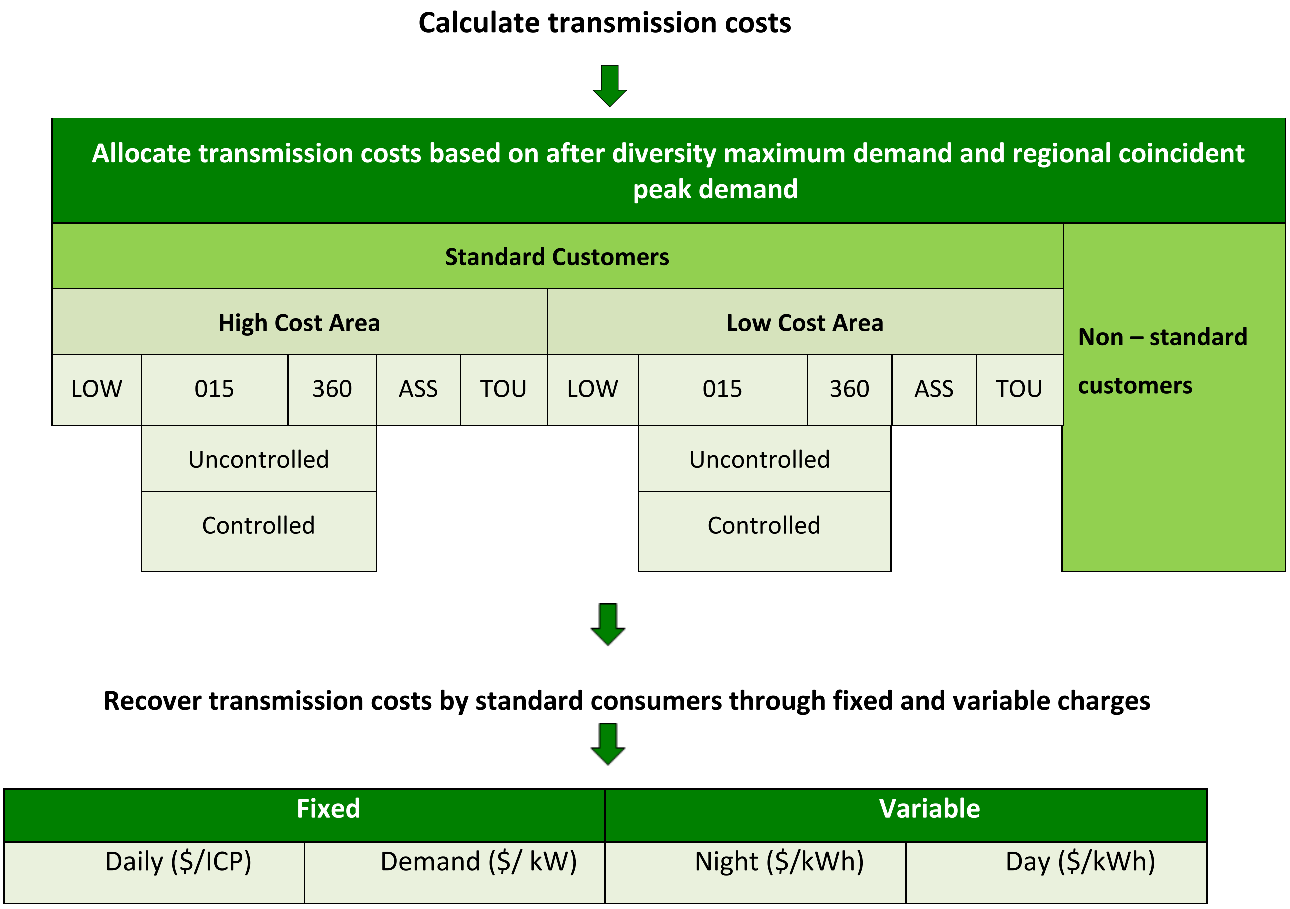
Transmission pricing components

When calculating transmission prices, we use a six-step process.

1. Identify the Transpower charges effective 1 April of the coming year.
2. Identify the wash-up (over or under recovery) of transmission charges from the prior regulatory year.
3. Allocate the transmission costs to standard and non-standard consumers.
4. Costs allocated to non-standard consumers are derived based on that consumer's contribution to the regional coincident peak demand—new investment and connection charges and after diversity maximum demand—interconnection charges.
5. The remaining costs are allocated to standard consumer's load groups using regional coincident demand—new investment and connection charges and after diversity maximum demand—interconnection charges.
6. Costs allocated to standard customers are recovered through both fixed and variable charges.

Figure 3 below shows the key steps to our transmission cost recovery.

Figure 3: Key steps to recovering transmission costs



Pass-through and recoverable cost components

When calculating pass-through and recoverable cost prices, we use a four-step process.

1. Identify the pass-through and recoverable costs in accordance with the DPP Determination.
2. We allocate the costs to the standard load groups based on ICP count per load group.
3. Derive a price per ICP by dividing the allocated costs by the number of ICPs per load group.
4. Recover annual costs from load groups through both fixed and variable charges.

Figure 4 below shows the key steps to our pass-through and recoverable cost recovery.

Figure 4: Key steps to recovering pass-through and recoverable costs

Calculate pass-through and recoverable costs

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Pass-through and recoverable costs components						
Rates	Levies	Claw-back	NPV Wash-up	Quality Incentive	Capex wash-up	Pass-through balance

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Allocate pass-through and recoverable costs based on ICP numbers									
High Cost Area					**Low Cost Area**				
LOW	015	360	ASS	TOU	LOW	015	360	ASS	TOU
Uncontrolled				400V	Uncontrolled				400V
Controlled				11kV	Controlled				11kV

⬇

Recover pass-through and recoverable costs through fixed and variable charges

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Fixed	Variable	
Daily ($/ICP)	Night ($/kWh)	Day ($/kWh)

3. Our total required revenue

Our total required revenue recovers annual distribution, transmission, and pass through and recoverable costs, shown in Table 1 below[1].

Table 1: Revenue requirement for the year ending 31 March 2020

Network-related costs	In $'000
Operating expenditure	17,387
Depreciation	12,897
Return on capital	14,705
Regulatory tax	8,319
Pass-through costs and recoverable costs	10,609
Transmission	19,139
Total revenue requirement	**83,056**

Revenue requirement for distribution services

Our distribution revenue requirement recovers annual regulated network costs for the period 1 April 2019 to 31 March 2020 and includes:

- Depreciation
- operating expenditure
- revaluations
- return on investment
- regulatory tax.

Each cost component is discussed in more detail below.

Depreciation

Depreciation is calculated on a straight-line basis in accordance with ID Determination using a standard life for the asset[2]. Depreciation costs for the year ending 31 March 2020 are forecast using historical depreciation on our regulatory asset base (RAB sourced from schedule 4 of the 2018 Information Disclosures Schedules[3].

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[1] Please note the forecast business costs are in 2017/18 dollar terms when prices are set.

[2] 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

[3] The schedules can be found at www.alpineenergy.co.nz/corporate/disclosures

Operating expenditure

Operating expenditure (Opex) are costs incurred through our business as usual 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.

Forecast maintenance costs for the year ending 31 March 2020 are derived from our 10-year network Opex budget, found in schedule 11b of the 2018 to 2028 Asset Management Plan.

Revaluations of the regulatory asset base

Our regulatory asset base (RAB) is revalued by—

> Opening RAB value – depreciation + revaluations + assets commissioned – disposals + assets lost/found + adjustment for asset allocation = closing RAB value

The change in our RAB is reflected in our return on capital calculations discussed below.

Return on investment

Our return on investment has been calculated using the regulated weighted average cost of capital (WACC) on a forecast value for network RAB as at 31 March 2020. A vanilla WACC (67th percentile) of 7.19% has been applied.

Our RAB, as at 31 March 2018 was $199.6 million. This is an increase of approximately $20.6 million when compared to the value of our RAB as at 31 March 2017.

Regulatory tax

We recover regulatory tax through our distribution charges. The forecast regulatory tax value for the period ending 31 March 2020 is $8.3 million and was forecast using data from schedule 5a of the 2018 Information Disclosures Schedules [4].

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[4] Available on our website, www.alpineenergy.co.nz

Required revenue for transmission costs

In November each year, we receive a notice of the coming year's transmission pricing from Transpower for each GXP on our network. We use this notice to calculate transmission prices for each load group.

Required revenue for pass-through and recoverable costs

Pass through and recoverable costs include:

- rates
- levies: Commerce Commission, Electricity Authority, and Utilities Disputes
- claw back and NPV wash-up allowance
- Capex wash-up allowance
- Pass-through balance from the period ended 31 March 2018.

We forecast the rates and levies based on historical averages. The claw back and NPV wash-up allowance are sourced from Schedule 5C and 5D respectively of the DPP Determination. The Capex wash-up is provided by the Commerce Commission[5]. The pass-through balance is sourced from our Annual Compliance Statement for the year ending 31 March 2018.

The pass-through balance from 2018 increases 2019 delivery prices

In the 2018 pricing year, we under recovered $3.2 million of pass through and recoverable costs from consumers. Over the 2019 pricing year, we will need to recover this amount through higher delivery prices in accordance with the default price path regulation[6].

The 2018 pass through balance was mainly attributable to quantities in the 015LCA being 71.6 GWh (or 14%) lower than forecast. Lower than forecast quantities resulted in us under recovering $4.4 million from customers in the 015 load groups, which accounts for approximately 86% of the total under recovery.

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: Load groups, on page 15) 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.

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[5] Electricity Distribution 2015-20 Default Price-quality Path Guidance: Capex wash-up adjustment calculation sheet, Version 2.0, 11 December 2015.

[6] Please refer to clause 8.6 (b) (ii) of the DPP Determination.

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

Assigning standard consumers into load groups

We have 13 load groups as shown in Table 2: Load groups, on page 15. Consumers are assigned to a load group based on:

1. location in the high-cost area or low-cost area
2. fuse size at the individual connection point (ICP)
3. maximum business day peak demand
4. 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 allocated to high-cost area and low-cost area, using our geographic information system (GIS). The cost areas represent the number of consumers:

1. on each transformer
2. per kilometre of distribution line length.

As a general rule low-cost area density, in ICPs per transformer, is 13 times greater than high-cost area density.

Allocation of consumers to load groups within cost areas

Consumers in the high-cost area and the low-cost area 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 (ASS) demand groups based on fuse size
- TOU groups for LV and 11kV connections with half-hour metering.

Low Fixed Charge load group

We must comply with the *Electricity (Low Fixed Charge Tariff Option for Domestic Consumers) Regulations 2004*, which state that we must offer a fixed tariff for ‘domestic’ consumers of no more than $0.15 per day. A domestic consumer is defined by the regulations as a person who purchases electricity for their ‘principal place of residence’ (clause 4(1)).

We fulfil Low fixed charge obligations by offering the Low user load groups that pay a daily fixed price of $0.15. We also ensure that an 'average' consumer[7] in the Low load groups pays no more than an 'average' consumer in an alternate 015 load group, by adjusting the costs allocated to the Low user load groups. However, to comply with regulations some cross-subsidisation of Low user groups by other groups does occur.

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[8] 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 (60 A), although we may also allow a 3x32 A connection on a case by case basis. ICPs in the 360 load groups are connected with three phase 60 A connections'. ASS 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 (installed capacity) of the connection.

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 after diversity maximum demand (ADMD), 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 electrical hot water heating load we are not permitted to control during periods of high demand. The uncontrolled load tariff is in place to incentivise consumers to offer up controllable load. Controllable load is critical for us during supply emergencies, and to avoid further investment in network capacity.

The low user groups pay an additional variable charge of $0.0267 cents per kWh, for both day and night variable charges, for uncontrollable load. 015 and 360 consumers pay an additional annual fixed charge of $240.06 for uncontrollable load.

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[7] The regulations define 'average', on the South Island, as a consumer who consumes 9,000 kWh annually.

[8] Some ICP's in the assessed load groups may have half hour metering installed but choose to remain in the assessed group.

Table 2: Load groups

Load group	Description
LOWHCA	Primary residence that consumes less than 9,000 kWh per annum – high-cost area
LOWLCA	Primary residence that consumes 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

5. Allocation of revenue requirement

This section describes how our distribution, transmission, and pass through costs are allocated to load groups.

Recovering annual distribution costs

Our pricing model allocates distribution costs to load groups in a way that reduces cross-subsidisation between users of the network, so that those that each load groups pays for the assets that the load group uses.

We do this by allocating costs based on each load group's demand we do this as demand is the main cost driver of distribution costs.

We allocate network costs by the load groups after diversity maximum demand.

Economic rationale for allocation of costs to load group

Economic theory states that we should calculate prices using the long run marginal cost of supplying power to consumers. In theory, prices calculated on long run marginal cost, will influence consumer demand for power to a level of demand that maximises economic welfare and long term benefits to consumers.

For the year ending 31 March 2020 and beyond we have forecast load group demand to create a smooth increase in demand from year to year, as well as smoothed forecasts for Opex. Smoothed forecast demand, in conjunction with forecast returns to capital, enables us to calculate prices based on the long run marginal costs.

Load Group statistics

Table 3, over the page, shows load group statistics for the period ending 31 March 2020, for each load group. This information is used to allocate the required distribution revenue to load groups.

Allocation of required revenue to load groups

The revenue allocated to each load group for the year ending 31 March 2020 is shown in Table 4: Target revenues per load group, on page 18. We allocate the required revenue to load groups using cost allocators described in Table 5: Cost allocators used and rationale for selection on page 19.

Pass–through and recoverable revenue requirement

The revenue requirement for pass-through and recoverable costs are split across 50% fixed charges and 50% variable charges. We do not use a demand charge to recover pass-through or recoverable costs. For more details on how these charges are calculated, refer to *Calculating pass through and recoverable prices* on page 21.

Transmission revenue requirement

We allocate the transmission revenue requirements based on each load groups regional coincident peak demand (RCPD). We have metering data for the direct billed and customers in the ASS and TOU load groups. For all other load groups (i.e., LOW, 015 and 360) we allocate the revenue requirement based on the loads groups potentially controllable load. For more details on how these charges are calculated, refer to *Calculating transmission prices* on page 21.

Table 3: Load group statistics for the period ending 31 March 2020

Load group	ICP numbers	ADMD	Allocation	RCPD
LOWHCA	1,541	1.03	0.0323	2.0
LOWLCA	8,847	5.58	0.1380	2.0
LOWUHCA	14	0.01	0.0003	2.0
LOWULCA	23	0.01	0.0003	2.0
015HCA	6,299	6.30	0.1980	2.0
015LCA	13,613	12.73	0.3148	2.0
015UHCA	31	0.04	0.0011	2.0
015ULCA	47	0.04	0.0011	2.0
360HCA	558	1.36	0.0428	5.0
360LCA	801	2.67	0.0661	5.0
360UHCA	15	0.07	0.0022	5.0
360ULCA	14	0.04	0.0010	5.0
ASSHCA	1,347	17.02	0.5347	5.0
ASSLCA	406	4.85	0.1198	12.0
TOU400HCA	39	2.90	0.0911	110.7
TOU400LCA	105	12.85	0.3178	110.7
TOU11HCA	6	3.10	0.0973	479.0
TOU11LCA	4	1.66	0.0411	479.0
Total	**33,710**	**72.26**		**1232.4**

Table 4: Target revenues per load group

Load group	Year ending 31 March 2020 Target Revenue $'000	Year ending 31 March 2019 Target Revenue $'000	Growth in Target Revenue	Proportion of Load Group Target Revenue to Total Target Revenue
LOWHCA	1,289	1,083	188	2%
LOWLCA	6,741	5,566	1,083	8%
LOWUHCA	16	13	3	0%
LOWULCA	19	$16	3	0%
015HCA	7,793	6,639	1,045	9%
015LCA	15,513	13,551	1,739	19%
015UHCA	48	45	3	0%
015ULCA	64	59	4	0%
360HCA	2,216	1,730	458	3%
360LCA	3,198	2,741	412	4%
360UHCA	88	63	24	0%
360ULCA	54	34	20	0%
ASSHCA	22,193	15,473	6,466	27%
ASSLCA	5,888	4,805	1,003	7%
TOU400HCA	2,474	2,341	94	3%
TOU400LCA	6,279	5,713	473	8%
TOU11HCA	1,913	1,796	88	2%
TOU11LCA	1,054	1,032	5	1%
IND	5,310	5,877	-664	6%
Total	**82,150**	**68,577**	**12,447**	**100%**

Table 5: Cost allocators used and rationale for selection

Cost Component	Allocator	Rationale
Operating expenditure	ADMD Weighted RAB	Opex is related to the consumers use of the network in terms of required capacity and utilisation (demand). Opex is allocated to load groups based on after diversity maximum demand. Network Opex is allocated to asset sub-categories based on the weighted average of each ODV asset category to the total regulatory assets base.
Recovery of revenue forgone from RCP1	ADMD Weighted RAB	Impact of any over or under-recovery under the price cap is allocated to load groups based on after diversity maximum demand. Total cost is allocated to asset sub-categories based on the weighted average of each ODV asset category to the total regulatory assets base.
Revaluations and sundry income	NA	Revaluations are recovered through return on investment component, which takes into account the revaluation of the RAB each year.
Depreciation	ADMD Weighted Depreciation	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 after diversity maximum demand. Total cost is allocated to asset sub-categories based on the weighted average of each ODV asset category to the total depreciation.
Return on investment	ADMD	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 RAB, where network assets are planned and built around providing future capacity requirements That is we recover the return on investment based on load group after diversity maximum demand.
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 who pay an allocation of shared costs based on contractual terms.

6. Calculating our prices

In this section, we discuss how we calculate prices for distribution, transmission, and pass through components of our pricing.

Calculating distribution prices

We use a combination of fixed and variable pricing to recover distribution costs. The advantages to using both fixed and variable charges are explained at Table 6: The fixed variable cost recovery ratio on page 21. Overall we find that for consumers who do not have TOU metering, a ratio of approximately 50% fixed to 50% variable cost recovery, creates the most efficient outcomes, as long-run margin costs based costs form around 50% of distribution required revenue. Economic theory suggests that non-long run margin cost based costs should be recovered through a fixed charge.

When consumers do have time of use metering, we recover approximately 60% of charges through a demand charge and the remainder through fixed and variable charges.

Day / night variable charges

We recover variable charges with lower night rates than day, to offer incentives for shifting load into off-peak (night) periods. Where a consumer has a time of use meter or day/night meters, the actual usage is applied. Where a consumer has standard metering, consumption is split 70:30 day to night which is consistent with day/night consumption levels metered at GXPs on the network.

Fixed daily charges

Fixed daily charges are calculated by multiplying the total load group revenue requirement by the load group's fixed to variable ratio, and then dividing the fixed portion by load group ICP numbers. With ASS and TOU load groups, the fixed portion of the revenue requirement is multiplied by a demand charge ratio to calculate the portion of costs recovered through a demand charge. The demand charge itself is calculated by dividing the total load group costs recovered from a demand charge, by either the load group's assessed capacity (in the case of the assessed groups) or the load groups after diversity maximum demand (for TOU groups).

Low fixed charge group prices

We calculate tariffs for the LOW load groups using a three-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 then calculate the LOW day night variable prices using the corresponding 015 load group variable charges, 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 the corresponding 015 groups.

3. 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 fixed charge (without demand charges[9]) 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 does signal the 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.
Protecting revenue from reduction in consumption	Recovering revenue through fixed charges 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 effective from 1 April 2019. From the total, we remove 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 remove the revenue we expect to receive from consumers who pay extra for not giving us control of their hot water cylinder. We allocate connection and new investment agreement costs to load groups using a load group's after

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[9] 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.

diversity maximum demand, and interconnection costs using a load group's regional coincident peak demand.

For load groups without half hour metering, we estimate regional coincident peak demand based on the upper South Island regional coincident peak demand, the network and half hour regional coincident peak demand, as well load group demand profiles.

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 $0.6559. For consumers in the LOW user groups, we increase their variable charges by $0.0267 / kWh.

7. Changes in delivery prices

The median delivery price increase from 1 April 2018 to 1 April 2019 is 17%. The increase is attributable to:

i) wash-up of pass through and recoverable costs from the 2017/18 year of $3.2 million
ii) wash-up of transmission costs from the 2017/18 year of $1.3 million
iii) CPI+11% increase under the default price-quality path of $7.7 million.

Our prices reflect the price path under the DPP Determination.

A copy of the pricing schedule effective from 1 April 2018 and effective from 1 April 2019 are included at Attachment A – 2019 delivery prices and Attachment B – 2018 delivery prices at pages 33 and 35 respectively.

8. 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 network or needs upgrades to their existing connection. Costs of upgrades to an existing connection can be shared where there are network benefits to the upgrade. Where the upgrade is for the sole benefit of the consumer the consumer must pay in entirety for that upgrade.

For the year ending 31 March 2018 we received $4.1 million in capital contributions. We are forecasted to collect $2 million in capital contributions for the year ending 31 March 2020.

Capital contributions cover the cost of the work carried out less rebates. If 100% of capital costs are paid by capital contributions, there should be no remaining costs to be recovered through delivery prices except ongoing operational costs (i.e. Opex). Without a capital contribution, these extensions or upgrades would be uneconomic under standard delivery prices.

For larger builds generally over $500,000, we will calculate the risk of the investment and use this to determine the percentage of 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[10].

9. Direct billed customers

For the period ending 31 March 2018, we had seven direct billed customers (12 ICPs) connected to our network at present. We are not expecting any new direct billed connections before 31 March 2020.

We are forecast to recover $3.9 million in distribution charges and $2 million in transmission charges for over the year ending 31 March 2020 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 prices
- required security of supply.

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[11]. 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[12]. Because we enter into long term contracts with direct billed customers we are able to negotiate outcomes which are consistent with market like arrangements.

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[10] www.alpineenergy.co.nz

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

[12] For some direct billed customers, the pricing methodology will differ to the one described above due prior long term contracts in place.

Calculation and recovery of the cost of new assets

The capital contribution paid for new assets can reduce the ongoing delivery prices 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 prices.

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 and depreciation charges. Depreciation charges are calculated on a remaining life basis, with the age of the asset taken from the Commerce Commission's *Optimised Deprival Value Handbook (2004)*.

When calculating the return on capital charges we apply the Commerce Commission's weighted average cost of capital for the industry, and the closing regulatory value of the new asset (adjusted for inflation) from the previous year, using a midyear cash flow.

Capital contributions based on perceived risk of 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 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 existing network assets 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 demand or capacity[13] of all users of the asset including the direct billed customer, to the total demand or capacity of the asset type across the network. Costs are then apportioned to the customer according to the customer's demand or capacity to the total demand/capacity relevant to 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 consumption will have little or no impact on our short term (annual) costs. However, a decrease in consumption over the long term can delay or prevent upgrades in network capacity due to under-recovery of our required revenue.

Recovery of transmission costs

Transmission costs are passed through to the customer according to the customer's demand to the total demand of all users of the GXP the consumer is connected to. The exception is the interconnection charge which is charged out to the consumer at the Transpower rate per kW of consumer demand during the regional coincident peak demand.

10. Distributed generation on our network

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

As at 31 March 2018 connected to our network were:

- 324 small distributed generators installed at residential or commercial premises at a combined capacity of 0.34 MVA
- one embedded generator that generates at 8 MW[14].

Fees payable by distributed generators to us are set by the Electricity Authority under the *Electricity Industry Participation Code* (the Code)[15]. We neither 'pay', or '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 (photovoltaic cells), wind, water (hydroelectric) or fossil fuels such as diesel or natural gas that have energy 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, although in accordance with the Code, connection,

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[13] The use of demand or capacity will depend on the type of asset that the cost relates to.

[14] Opuha hydro installation with maximum generation of 9 MW.

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

inspection and livening fees still apply. This is an alternative to paying Avoided cost of distribution benefits.

Avoided cost of transmission (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[16].

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 ICPs 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:

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[17].

The loss percentage reported under the information disclosure requirements for the year ended 31 March 2018 was 3.8%.

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 provides N-1 security to meet reliability of supply requirements results in effective losses of less than 2% for loads around 15MW. N-1 security refers to the ability to provide power even after the loss of one transformer.

12. Overview of our consumer survey

In July 2016 we conducted a 'mass market' consumer survey of approximately 500 mass market customers, 50 irrigation customers and 30 non-food industrial processing consumers. We received completed responses in regard to views on supply reliability,

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

[17] 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.

inconvenience caused by interruptions, community disruption, and price.

The key message from most consumers across all market segments is that there is limited ability or desire to change the time, season, or way in which electricity is used. This translates into a limited appetite for participating in demand management, despite the possibility of reduced line charges.

At best, there are seemingly isolated market segments and industrial customers that have some willingness to have solar panels or batteries installed, but seem unwilling to alter the time of their demand or operate on-site generation.

In February 2017, we also conducted a survey of consumers on their opinions of new technologies such as rooftop solar, and batteries. The most significant results from the survey are:

- Most customers are not willing to install either (rooftop) solar or batteries.
- The few customers that are willing to install solar or batteries would want their monthly line charge to decrease by more than $20.
- Customers have a preference for Alpine to own and install both solar and batteries at Alpine’s expense.
- Most customers could easily change the time of day that they use certain appliances.
- Very few customers would be happy for Alpine to interrupt certain appliances when electricity is expensive. The remaining majority were fairly evenly split between either wanting to use their appliances regardless of the cost or receiving cost signals and then choosing whether to respond.

13. Rollout of smart meters

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

Our current delivery prices do not reflect the information that will be available after the roll-out is complete. We intend to consider how our delivery 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 on page 29.

15. Do you have any questions?

We are happy to answer any questions about our pricing methodology that you might have.

We can be contacted on 03 687 4300 or email us at Analyst@alpineenergy.co.nz

After a copy of the pricing methodology?

To get a copy of our Pricing Methodology you can:

- go to our website at https://www.alpineenergy.co.nz
- call us at 03 687 4300, and we can email or post you a copy
- drop into our offices at 24 Elginshire Street, Washdyke between 8:30 am and 4:30 pm.

Complaints Process

If you have a complaint about our service, please contact us on 03 687 4300. We will respond to your complaint by:

(i) confirming with you that you are making a formal complaint rather than wanting to talk through an issue with us

(ii) acknowledging the complaint within 2 working days

(iii) answering your complaint within 20 working days.

If we can't resolve your complaint, you can contact Utilities Disputes Ltd, formerly known as the Electricity and Gas Complaints Commissioner, on http://www.utilitiesdisputes.co.nz or on 0800 22 33 40.

Appendix A – How we align our pricing principles

Table 7: Electricity Authority Pricing Principles

<table>
<tr><th>Pricing Principles</th><th>Alpine Energy Limited's Alignment to the Principles</th></tr>
<tr><td colspan="2">a) Prices are to signal the economic costs of service provision by:</td></tr>
<tr><td>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</td><td>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 $721/kW and our long–run incremental costs (LRIC) are $82/kW if we were to recover all charges through a demand charge. Table 8 shows that the forecast revenue in $/kW per load group is equal to or greater than the incremental cost and less than the standalone cost for each load group; demonstrating that our prices are subsidy free.
Table 8: Variable distribution price per load group
<table>
<tr><th>Load Group</th><th>$/kW</th></tr>
<tr><td>LOWLCA</td><td>$314.53</td></tr>
<tr><td>LOWUHCA</td><td>$270.25</td></tr>
<tr><td>LOWULCA</td><td>$621.00</td></tr>
<tr><td>015HCA</td><td>$313.93</td></tr>
<tr><td>015LCA</td><td>$259.26</td></tr>
<tr><td>015UHCA</td><td>$223.70</td></tr>
<tr><td>015ULCA</td><td>$243.70</td></tr>
<tr><td>360HCA</td><td>$209.99</td></tr>
<tr><td>360LCA</td><td>$102.27</td></tr>
<tr><td>360UHCA</td><td>$117.13</td></tr>
<tr><td>360ULCA</td><td>$157.10</td></tr>
<tr><td>ASSHCA</td><td>$175.56</td></tr>
<tr><td>ASSLCA</td><td>$107.29</td></tr>
<tr><td>TOU400HCA</td><td>$76.72</td></tr>
<tr><td>TOU400LCA</td><td>$248.30</td></tr>
<tr><td>TOU11HCA</td><td>$293.28</td></tr>
<tr><td>TOU11LCA</td><td>$199.95</td></tr>
</table></td></tr>
<tr><td>ii) having regard, to the extent practicable, to the level of available service capacity</td><td>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.</td></tr>
</table>

	It would be ideal to calculate available service capacity for each load group. However, ICPs within load groups are distributed across our seven GXPs. Meaning that ICPs in one load group may be in different geographical areas. Unless we move to geographic base pricing, requiring an increase in complexity, reporting available service capacity is problematic. At this stage we have decided to limit the number of load groups to reduce complexity and transactions costs on retailers.
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. For 2019 and beyond we have forecast load group demand to create a smooth increase in demand from year to year, as well as smoothed forecasts for Opex to approximate long run margin costs. Previously step changes in load group demand (based on prior year data) would create material changes in prices one year to the next. By smoothing out demand and costs, costs are allocated more evenly year to year, causing an even change in load group prices.

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 retailers hold information at the consumer level. 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 of $721 as shown on page 28. For non-standard consumers we manage this risk through long term contracts negotiated with the consumer concerned.
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 one large distributed generator 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

We are of the view that our delivery prices are understandable for stakeholders (for example, consumers, retailers, shareholders, and us). Our delivery prices have been developed in a manner that intends to promote certainty and price stability.

When we have had to increase delivery prices 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 prices will be stable and will not shift significantly over time. Increases to our delivery prices 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 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.

The work by the Electricity Networks Association on our behalf to standardise tariffs and nomenclature will also help in this regard.

Attachment A – 2019 delivery prices

		Delivery Charges				**Number of**
	Pricing Schedule effective as at 1 April 2019	**Fixed** *per day*	**Day** *per kWh*	**Night** *per kWh*	**Demand** *per kW/per day*	**Consumers** *as at 31/3/2020*
LOWHCA	Low User (controlled) high cost area	$0.1500	$0.1511	$0.0945	$0.0000	1,541
LOWLCA	Low User (controlled) low cost area	$0.1500	$0.1454	$0.0888	$0.0000	8,847
LOWUHCA	Low User (uncontrolled) high cost area	$0.1500	$0.1773	$0.1206	$0.0000	14
LOWULCA	Low User (uncontrolled) low cost area	$0.1500	$0.1709	$0.1142	$0.0000	23
015HCA	Single Phase (controlled) high cost area	$1.4281	$0.0992	$0.0425	$0.0000	6,299
015LCA	Single Phase (controlled) low cost area	$1.2883	$0.0992	$0.0425	$0.0000	13,613
015UHCA	Single Phase (uncontrolled) high cost area	$2.0710	$0.0992	$0.0425	$0.0000	31
015ULCA	Single Phase (uncontrolled) low cost area	$1.9134	$0.0992	$0.0425	$0.0000	47
360HCA	Three Phase (controlled) high cost area	$6.0684	$0.0992	$0.0425	$0.0000	558
360LCA	Three Phase (controlled) low cost area	$4.3791	$0.0992	$0.0425	$0.0000	801
360UHCA	Three Phase (uncontrolled) high cost area	$6.5970	$0.0992	$0.0425	$0.0000	15
360ULCA	Three Phase (uncontrolled) low cost area	$5.0260	$0.0992	$0.0425	$0.0000	14
ASSHCA	Assessed demand high cost area	$1.9803	$0.0992	$0.0425	$0.2091	1,347
ASSLCA	Assessed demand low cost area	$1.3510	$0.0992	$0.0425	$0.1548	406
TOU400HCA	Time-of-Use metering at 400 V high cost area	$1.3909	$0.0294	$0.0126	$0.5737	39
TOU400LCA	Time-of-Use metering at 400 V low cost area	$1.0963	$0.0263	$0.0113	$0.4494	105
TOU11HCA	Time-of-Use metering at 11 kV high cost area	$1.1475	$0.0459	$0.0197	$0.3986	6
TOU11LCA	Time-of-Use metering at 11 kV low cost area	$1.1110	$0.0336	$0.0144	$0.4551	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 5.20 cents/kWh for day and night usage in the LOWHCA, 4.63 cents/kWh for day and night usage in the LOWLCA load groups, 5.14 cents/kWh for day and night usage in the LOWUHCA, and 4.50 cents/kWh for day and night usage in the LOWULCA load groups is charged based on usage advised by electricity retailers. The additional variable transmission charge of 2.67 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.

Attachment B – 2018 delivery prices

		Delivery Charges				**Number of**
	Pricing Schedule effective as at 1 April 2018	**Fixed** *per day*	**Day** *per kWh*	**Night** *per kWh*	**Demand** *per kW/per day*	**Consumers** *as at 31/3/2019*
LOWHCA	Low User (controlled) high cost area	$0.1500	$0.1273	$0.0795	$0.0000	1,498
LOWLCA	Low User (controlled) low cost area	$0.1500	$0.1223	$0.0745	$0.0000	8,572
LOWUHCA	Low User (uncontrolled) high cost area	$0.1500	$0.1531	$0.1053	$0.0000	13
LOWULCA	Low User (uncontrolled) low cost area	$0.1500	$0.1478	$0.1000	$0.0000	22
015HCA	Single Phase (controlled) high cost area	$1.2256	$0.0837	$0.0359	$0.0000	6,213
015LCA	Single Phase (controlled) low cost area	$1.1021	$0.0837	$0.0359	$0.0000	13,646
015UHCA	Single Phase (uncontrolled) high cost area	$1.8635	$0.0837	$0.0359	$0.0000	31
015ULCA	Single Phase (uncontrolled) low cost area	$1.7324	$0.0837	$0.0359	$0.0000	46
360HCA	Three Phase (controlled) high cost area	$5.2534	$0.0837	$0.0359	$0.0000	511
360LCA	Three Phase (controlled) low cost area	$3.8076	$0.0837	$0.0359	$0.0000	735
360UHCA	Three Phase (uncontrolled) high cost area	$5.8311	$0.0837	$0.0359	$0.0000	14
360ULCA	Three Phase (uncontrolled) low cost area	$4.4489	$0.0837	$0.0359	$0.0000	10
ASSHCA	Assessed demand high cost area	$1.7159	$0.0837	$0.0359	$0.1858	1,306
ASSLCA	Assessed demand low cost area	$1.1537	$0.0837	$0.0359	$0.1371	389
TOU400HCA	Time-of-Use metering at 400 V high cost area	$1.1925	$0.0259	$0.0111	$0.5075	37
TOU400LCA	Time-of-Use metering at 400 V low cost area	$0.9309	$0.0231	$0.0099	$0.3947	105
TOU11HCA	Time-of-Use metering at 11 kV high cost area	$0.9658	$0.0407	$0.0174	$0.3561	6
TOU11LCA	Time-of-Use metering at 11 kV low cost area	$0.9328	$0.0293	$0.0126	$0.3921	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 4.36 cents/kWh for day and night usage in the LOWHCA, 3.86 cents/kWh for day and night usage in the LOWLCA load groups, 4.29 cents/kWh for day and night usage in the LOWUHCA, and 3.76 cents/kWh for day and night usage in the 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 1/365th 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.

Glossary

ACOD	Avoided Costs of Distribution – A reduction in distribution costs when demand for power is reduced at network peak times or provided by local generation during network peak times
ACOT	Avoided Costs of Transmission – A reduction in transmission costs when demand for power is reduced at transmission peak times or provided by local generation during transmission peak times
ADMD	After Diversity Maximum Demand—the simultaneous maximum demand of a group of consumers with similar power requirements
Capacity	The maximum power supplied by a network asset. With respect to consumer capacity, it refers to the size of the network assets directly connected to the consumer.
Code	The Electricity Industry Participation Code 2010
Consumer	A person that consumes electricity supplied by our network
Commerce Commission	A government body tasked with regulating our price and quality of service
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 use of supply agreement (e.g. retailers and large consumers)

Delivery prices	Prices that recover distribution, transmission, pass through and recoverable costs.
Demand	The amount of electricity required to power equipment at a point in time, 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 costs	Costs associated with building and maintaining our electricity 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
Electricity Authority	A government body tasked with promoting efficiency in the electricity industry and who make changes to the Electricity Industry Participation Code, which we must comply with
Fixed prices	Prices which do not vary with the amount of kWh consumed
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
HCA	High cost area – an area of the network which has higher distribution costs per ICP than the LCA due to lower ICP density
High voltage	Network assets that supply electricity at or above 11,000 V
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
LCA	Low cost area – an area of the network which has lower distribution costs per ICP than the HCA due to higher ICP density
Load group	A group of consumers with similar network connection characteristics such as location or capacity requirements
Low user	A consumer in a Low load group
Low voltage	Network assets that supply electricity at 400 V
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
Network asset	An asset that is primarily used to transport electricity between the national transmission grid and local consumers of electricity

Part 4	Part 4 of the Commerce Act 1986 governing the regulation of EDBs as administered by the Commerce Commission
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
RAB	Regulatory Asset Base - The value our network assets would have in a competitive market if this existed, as determined 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
Required revenue	The revenue we require to cover the annual costs of providing electricity distribution services
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 prices
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

Variable prices	Prices which vary with the amount of kWh consumed
WACC	Weighted Average Cost of Capital—is the regulated rate of return on the company’s assets.