`

Pricing Methodology

For Delivery Prices Effective as at 1 April 2021

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

Alpine ENERGY

Contents

1. ABOUT ALPINE ENERGY

We supply electricity to over 33,513 individual connection points throughout South Canterbury. Our area of supply covers over 10,000 km² and is located on the East Coast of the South Island, between the Rangitata and Waitaki Rivers, and inland to Mount Cook on the main divide.

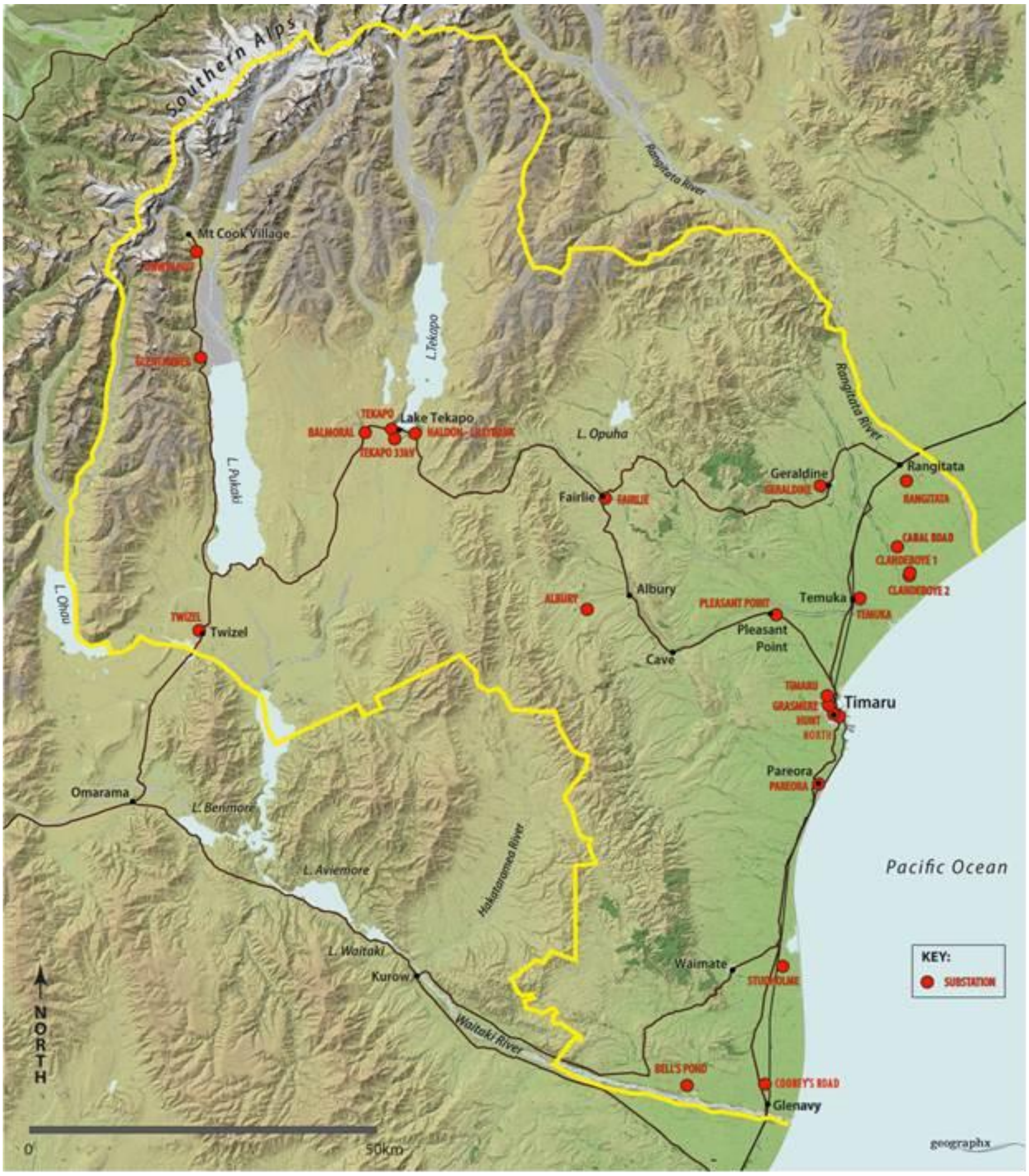

Figure 1 Alpine Energy network, and location of the seven GXPs and 24 substations on our network

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

1.1 We Want to Help You Understand how we Set Prices

This pricing methodology outlines our approach to setting electricity distribution delivery charges to apply from 1 April 2021.

Delivery charge describes the total price we charge to transport electricity from the national grid to consumer's homes and businesses.

Delivery prices include:

- Alpine Energy distribution charges
- Pass-through charges such as rates, levies, and wash-up charges that we must pay throughout the year
- Transpower's transmission charges
- Definitions of these charges are provided in the Glossary at the end of this document

The purpose of this document is to show how our electricity pricing methodology (or approach) sets delivery prices to recover the costs of supplying distribution services, from the appropriate consumers, most efficiently and fairly.

- This section describes the role of pricing, and the network, consumer, and regulatory characteristics we consider when developing prices
- Section 2 describes our current pricing approach, and our plans to evolve our pricing approach as consumer preferences and technology change how our network is used
- Section 3 describes changes we made to prices for 2021-22
- Section 4 describes how we set the standard and non-standard prices, and distributed generation pricing
- Section 5 describes the consumer groups paying delivery charges
- Section 6 describes how we calculate and allocate costs across consumer groups
- Section 7 describes how we assess the consumer impact of price changes
- Appendix A describes how the pricing approach aligns with the Pricing Principles published by the Electricity Authority
- Appendix B describes how we comply with clauses 2.2.1 to 2.4.5 of the Electricity Information Disclosure Determination 2012

1.2 Network Characteristics

Our distribution network is in good condition. Two-thirds of our capital expenditure over the next ten years to 2030 is targeted for the replacement and renewal of existing infrastructure. Network development capital expenditure accounts for a third of the investment in our network. This investment is specifically targeted for consumer connections, reliability safety and environment projects, and network augmentation.

Electricity is delivered to our network via seven grid exit points (GXPs) with Transpower and one embedded generator at the Opuha dam.

For the year ended March 2020, the electricity volume carried was 832 GWh with a maximum coincident system demand of 142 MW. By 2024/25 the volume carried is expected to increase to 910 GWh and maximum coincident system demand is expected to increase to 156 MW.

Energy consumed varies from year to year depending on wet or dry irrigation seasons, and severe or mild winters. Growth in coincident system demand has been about 2.49% per year over the last 18 years. Growth is expected to remain consistent with this trend.

More detail on the network characteristics for the seven supply areas is outlined in Table 1.

Measure	ABY	BPD	STU	TKA	TMK	TIM	TWZ	Total
ICPs	1675	638	3335	966	6937	18345	1644	33,540
O/H line (km)	624	205	613	257	998	1131	85	3913
UG line (km)	89	45	137	105	387	1000	86	1849
Main Substation	2	2	1	4	5	3	1	18
Peak demand (MW)	5.0	14.8	13.5	4.5	60.4	67.4	3.5	169.10
Energy (GWh)	24	52.4	67.7	22.5	294.1	364.1	16	840.8

Table 1 Network characteristics for the seven supply areas (GXPs)

Updated to 31 March 2020[1]. Note: Albury (ABY) energy is net of energy injected from the Opuha Generation

The main drivers influencing electricity demand in our area related to weather and economic activity. Economic activity in our area of operation strongly influences the configuration of our network.

Over the last decade, we have been through a major economic growth phase in South Canterbury mainly due to dairy conversions, irrigation schemes, and dairy processing. More detail of the impacts on network investment and operation impacts of the major demand drivers is in the 2019 Asset management plan and updates available at https://www.alpineenergy.co.nz/corporate/reports-and-publications/asset-management-plan.

THE table below summarises the main load type and forecast capacity adequacy for each GXP supply area (Source: Alpine Energy Limited, 2019 Asset Management Plan)

Location (GXP)	Load type and forecast capacity adequacy	Pricing Implications
Albury	Small townships, sheep & beef farming, some dairying. Adequate capacity to meet a small growing demand	No material growth with adequate capacity, no proposed pricing changes
Bells Pond	Dairy processing at Oceania Dairy Limited factory and on-farm dairying irrigation (Waihao Down irrigation scheme). Adequate capacity to meet the growing demand	Increased irrigation load with upgrades negotiated with the dairy factory directly, investigating irrigation pricing Options to manage peak loads
Studholme	Sheep and beef farming, some dairying, Fonterra Studholme dairy factory. Major replacements and upgrades will be required if there is an increase in Fonterra	No material growth with adequate capacity, investigating irrigation pricing options to manage peak loads

[1] https://www.alpineenergy.co.nz/__data/assets/pdf_file/0018/8541/ALPINE-ENERGY-AMP-2019.pdf (table 3.1)

Location (GXP)	Load type and forecast capacity adequacy	Pricing Implications
	demand requirements	
Tekapo **Twizel**	Twizel and Tekapo townships experiencing significant growth; dairy conversions and irrigation developments slowing due to land use/discharge requirements. Major upgrades expected in next 5 years	Growth-related costs being managed, no proposed pricing changes
Temuka	Temuka and Geraldine townships, dairying irrigation, and Fonterra Clandeboye dairy factory. Adequate capacity to meet a small growing demand. Major replacements and upgrades will be required if there is an increase in Fonterra demand requirements	GXP constrained, upgrades and pricing negotiated with the dairy factory, investigating irrigation pricing options to manage peak loads
Timaru	Timaru – residential, commercial, and light industrial. Upgrading supply to Washdyke industrial area. Adequate capacity to meet the growing demand	No material growth with adequate capacity, no proposed pricing changes

Table 2 Load type, forecast capacity adequacy, and pricing implications for main GXP supply areas

The network is experiencing congestion in some, mostly isolated, areas due to distributed generation exporting into the network. The list of export congestion areas is available on our website at https://www.alpineenergy.co.nz/customers/generating-electricity/export-congestion-areas.

If export congestion causes operational issues, we may interrupt the connection of any distributed generation to the distribution network or curtail either the operation or output of distributed generation, or both, and may temporarily disconnect the distributed generation from the distribution network.

1.3 Consumer Characteristics

With our network covering an area between the Rangitata and Waitaki rivers, from the coast to Mt Cook, we supply the communities of Timaru, Temuka, Waimate, and MacKenzie basin and surrounding areas. 15 electricity retailers were trading as 20 retail brands, supplying consumers on the Alpine network in December 2020.

About 42% of connections are served by one retailer. Except for six large consumers that we directly invoice for electricity line charges, our line charges are passed to consumers along with transmission charges and energy supply charges by the electricity retailers. Table 3 shows the number of consumers (ICPs) in each supply area.

Location	ICP Count	%
Timaru	16401	48.90%
Waimate	3675	10.96%
Temuka	3475	10.36%
Geraldine	2986	8.90%
Twizel	1637	4.88%
Pleasant Point	1256	3.74%

Fairlie	1176	3.51%
Lake Tekapo	838	2.50%
Pareora	466	1.39%
Orari	301	0.90%
Glenavy	264	0.79%
St Andrews	235	0.70%
Winchester	224	0.67%
Cave	208	0.6%
Albury	179	0.5%
Makikihi	112	0.3%
Mount Cook	107	0.3%
Grand Total	**33540**	**100%**

Table 3 Total ICP count and percentage of total by region on 31 March 2020

The Timaru GXP constitutes almost half of the Alpine Network connection points and consumption which is primarily residential, commercial, and small industrial customers. Figure 2 shows the load profile for Timaru.

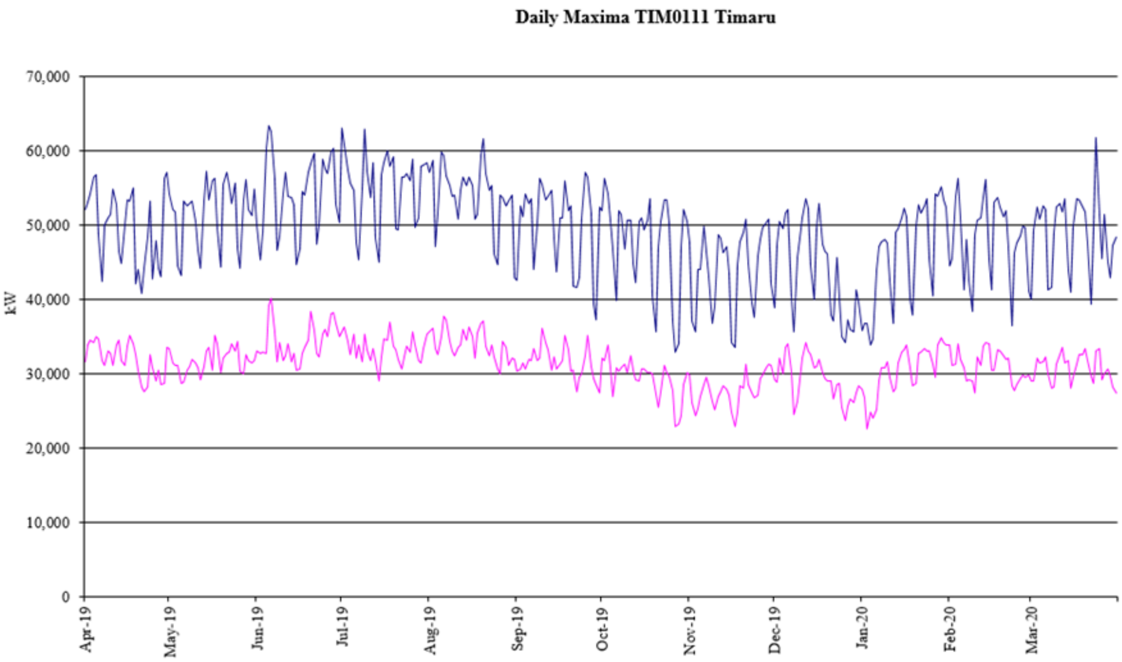

Figure 2 Daily maximum and minimum demand for Timaru April 2019 to March 2020

Winter peak loading occurs mainly at Timaru and Tekapo GXPs, although other urban areas, like Fairlie and Geraldine, also have significant demand for load during the winter months. Winter load demand may rise due to more regulation around air quality and particulate matter, restricting the use of fires for heating and placing greater demand on the network to service other forms of heating, such as heat pumps and other conventional electric heating.

The increase in tourism and subdivisions in Tekapo and Twizel is now also a driver we use in our forecasting models.

The peak demand in the dairy industry occurs in spring and extends into summer. Load requirements are for processing, on-farm milking, heating, and cooling as well as irrigation. Reliability of supply is therefore very important in this industry. As a result, most shutdowns for maintenance or network upgrade activities have to be planned for the dairy 'off' season.

At an individual farm level, operations are intensifying due to increasing cooling and holding standards. There is greater use of irrigation and new technologies. There is an increasing requirement for higher reliability of supply and better quality of supply than was previously the case. This growth has consumed most of our spare network capacity, with major new builds in areas where no infrastructure existed.

There has been significant growth in dairy farming and processing, bringing an increased demand from irrigation. Irrigation load is the main cause of summer peak loading at all the GXPs except Timaru, Tekapo, and Twizel although the increase in irrigation is tempered by local environmental restrictions on water use, land intensification, and nitrogen discharge limits.

Our large industrial and commercial consumers are mainly located in Timaru and more specifically around the port, Redruth, and Washdyke areas.

1.4 Regulatory Characteristics

Our pricing approach is influenced by a range of regulatory requirements, including obligations imposed by the Commerce Commission and Electricity Authority, and through the Electricity (Low Fixed Charge Tariff for Domestic Consumers) Regulations 2004.The main implications are:

- We are required to set prices to recover no more than the revenue allowed by the Commerce Commission's *Electricity Distribution Services Default Price-Quality Determination 2020, [2019] NZCC 21,* 27 November 2019 (DPP Determination). Sections 5-7 of this document describe how we set prices to recover no more than the allowed revenue
- We are required to disclose information about our pricing approach and prices by the Commerce Commission's Electricity Distribution Information Disclosure Determination 2012 – (consolidating all amendments as of 3 April 2018), 3 April 2018 (ID Determination). Appendix B describes how we meet the disclosure requirement
- We are expected to set efficient and cost-reflective prices consistent with the Electricity Authority's Distribution Pricing Principles published in June 2019. Appendix A describes how our pricing approach aligns with the Pricing Principles
- We are required to set prices for distributed generators connecting to and using our network according to Part 6 of the Electricity Industry Participation Code 2010 (the Code), relating to the pricing of distributed generation. Section 4 describes how we do this
- We are required to offer primary residence consumers a low fixed charge tariff option (of 15 cents/day) by the Electricity (Low Fixed Charge Tariff Option for Domestic Consumers) Regulations 2004 (the low fixed charge regulations). The Electricity Authority monitors and enforces the regulations

2. Current Pricing and Future Pricing Plans

We set delivery prices using a retail delivery approach, also referred to as an Installation Control Point (ICP) pricing methodology. The network service is priced at the consumer's metering point based on the electricity consumption at that point.

The price of our network service is set taking account of the network, consumer, and regulatory characteristics relevant to our network. Our goal is to set the price of our network service to reflect the cost of delivering that service to each consumer group. This means, to the extent practicable, using fixed charges to recover fixed costs and variable charges to recover variable costs.

2.1 CURRENT PRICING

Our network service prices for most connections have a three-part structure, with a fixed daily charge component, and two variable components with a volume-based charge for daytime usage (7 am to 11 pm) and a volume-based charge for night-time usage (11 pm to 7 am).

Network service prices for connections with time-of-use metering, and capacity greater than 15kVA have a four-part structure, with an additional fixed-like kw/day capacity charge component.[2]

An overview of the current price structure and price components for each consumer group is provided in Table 4 below. More detail on each consumer group is provided in Section 6.

Consumer group	Forecast # ICPs	Description	Fixed daily component($/day)	Fixed-like capacity component ($/kW/day)	Variable volume component ($/kwh – day)	Variable volume component ($/kwh – night)
LOWHCA	2135	Households using <9000kWh/year, controlled, high-cost area	$0.15		$0.11	$0.08
LOWLCA	10752	Households using <9000kWh/year, controlled, low-cost area	$0.15		$0.10	$0.07
LOWUHCA	19	Households using <9000kWh/year, uncontrolled, high-cost area	$0.15		$0.13	$0.10
LOWULCA	41	Households using <9000kWh/year, uncontrolled, low-cost area	$0.15		$0.12	$0.09
015HCA	5770	Households and small commercial, 0-15kVA, < 60amp fuse, no TOU metering, controlled, high-cost area	$1.44		$0.05	$0.02
015LCA	11340	Households and small commercial, 0-15kVA, <	$1.30		$0.05	$0.02

[2] The daily capacity charge component is fixed-like because the quantity (capacity of the connection) is fixed for the year, meaning the amount paid by the consumer does not vary with day-to-day consumption or any other factor but may vary year to year if the consumer chooses to vary their connection capacity.

		60amp fuse, no TOU metering, controlled, low-cost area				
015UHCA	36	Households and small commercial, 0-15kVA, < 60amp fuse, no TOU metering, uncontrolled, high-cost area	$2.03		$0.05	$0.02
015ULCA	40	Households and small commercial, 0-15kVA, < 60amp fuse, no TOU metering, uncontrolled, low-cost area	$1.87		$0.05	$0.02
360HCA	510	Commercial, 3 phase, 60 amp connection, no TOU metering, controlled, high-cost area	$6.13		$0.05	$0.02
360LCA	725	Commercial, 3 phase, 60 amp connection, no TOU metering, controlled, low-cost area	$4.42		$0.05	$0.02
360UHCA	14	Commercial, 3 phase, 60 amp connection, no TOU metering, uncontrolled, high-cost area	$6.60		$0.05	$0.02
360ULCA	14	Commercial, 3 phase, 60 amp connection, no TOU metering, uncontrolled, low-cost area	$5.01		$0.05	$0.02
ASSHCA	1266	Commercial, capacity > 15kVA, high cost area	$2.00	$0.14	$0.05	$0.02
ASSLCA	411	Commercial, capacity > 15kVA, low cost area	$1.37	$0.09	$0.05	$0.02
TOU400HCA	37	Households and small commercial connected to LV network, TOU metering, high-cost area	$1.41	$0.41	$0.02	$0.01
TOU400LCA	102	Households and small commercial connected to LV network, TOU metering, low-cost area	$1.11	$0.28	$0.02	$0.01
TOU11HCA	6	Commercial, connected to 11kV network, TOU metering, high cost area	$1.16	$0.23	$0.03	$0.01

TOU11LCA	4	Commercial, connected to 11kV network, TOU metering, low cost area	$1.12	$0.37	$0.02	$0.01

Table 4 Overview of current price structure and price components for each consumer group 2021/22

2.2 Economic Signals Delivered by Current Pricing

Alpine recovers the costs of delivering electricity to consumers through prices. Prices signal the value of the network service users receive at a location and point in time.

There is a relationship between prices, cost, and value of the network service and consumer's behaviour in using the network. e.g. a fixed charge pricing signal would encourage network use at any time and level for many consumers but would discourage connection for some consumers, particularly with low levels of consumption.

There are several long-term impacts of economic signalling in pricing:

- 'all you can eat' fixed pricing on an unconstrained network may result in increased consumer consumption resulting in congestion leading to higher levels of network investment
- If consumers opt for alternative energy supplies it could lead to consumers disconnecting or not connecting to the network. This would lead to a reduction in connections and revenue base over time.
- Variable volume-based charges discourages the use of the network. It also creates uncertainty in revenue and cost recovery as consumers can reduce electricity consumption behaviours.
- There could be adverse equity impacts where costs were increasingly borne by consumers without the ability to reduce electricity consumption.

Pricing structures that reflect fixed or avoidable (variable) costs should signal the cost of the service appropriately.

Currently, the fixed daily charge and demand charge (for connections with the metering capability to identify their contribution to loading) is recovered from the relevant time-of-use consumer groups.

Alpine's pricing is designed to recover the following costs:

- Operating expenditure relating to reliability, safety, and environment, routine and corrective maintenance and inspection, and system operations and network support
- Depreciation, revaluations, and regulatory tax
- Pass-through and recoverable costs, and transmission costs.

The variable volume-based day/night charges for all consumer groups are set to recover costs of:

- Operating expenditure relating to asset relocations, replacement and renewal, service interruptions and emergencies, system growth, and vegetation management
- Pass-through and recoverable costs, and transmission costs

These costs are considered variable as they vary with day-to-day use of the network and maybe avoided by a change to network use.

Prices are set to reflect the economic signals for investment as follows:

1) Individually billed customers' prices are based on the investment which Alpine has made to these large industrial connections and the contribution of transmission assets in use to provide these customers with electricity
2) Medium-sized connections with time-of-use metering are based on their share of assets and consumption within the Low and High costs areas of network density signalling the cost to serve
3) Low user customers prices are based on the Low Fixed Charge Tariff Option for Domestic Consumers) Regulations 2004
4) Mass market customers are based on a shared residual cost of network assets within the Low and High costs areas of network density signalling the cost to serve.

There is not currently complete alignment between fixed and avoidable costs, and fixed (and fixed-like) and variable charges. Table 5 lists the average proportion of revenue recovered from each consumer group by fixed (daily) and fixed-like (capacity) charges and by variable (volume) charges.

We estimate that the majority of our operational costs are fixed with a portion being avoidable depending on extreme events. Costs recovered through variable charges intend to manage consumer behaviour or future network investment.

The relationship between costs and charges can improve for most consumer groups due to the historical over-reliance on variable charges for revenue and cost recovery. The implication is pricing, on average, discourages the use of the network, and particularly given our network has spare capacity in most locations and times[3]. Additionally, current prices may undermine revenue and cost recovery and may contribute to adverse equity outcomes.
The correlation between prices and costs are being addressed as part of our plans to evolve our pricing.

Consumer group	Revenue recovered by fixed & fixed like charges %	Revenue recovered by variable charges %
LOWHCA	10	90
LOWLCA	10	90
015HCA	56	44
015LCA	55	55
360HCA	68	32
360LCA	54	46
ASSHCA	49	51
ASSLCA	46	54
TOU400HCA	76	24
TOU400LCA	60	40
TOU11HCA	45	55
TOU11LCA	63	38

Table 5 Average proportion of revenue recovered from each consumer group by fixed & fixed-like charges and variable charges

[3] https://www.alpineenergy.co.nz/__data/assets/pdf_file/0018/8541/ALPINE-ENERGY-AMP-2019.pdf, Appendix A.5 Demand Forecasts page 155

2.3 Evolving our Pricing and Prices

Our delivery prices are set to reflect our circumstances and the cost of delivering a safe, reliable electricity supply. We recognise the importance of evolving our pricing and prices as circumstances change. Our strategy involves a review of the asset allocation to various customer groups and providing improved pricing for irrigation customers. Our desired end state is a cost-reflective model providing retailers pricing which is easy to implement into their price offerings.

We are gradually rebalancing the proportion of costs recovered using fixed and fixed-like charges and variable charges by reducing the level of variable volume components.

We applied the reductions in allowable revenue for 2019/20 and 2020/21 to the variable component of pricing, thereby reducing the proportion of revenues recovered through variable charges and increasing the proportion of revenues recovered through fixed charges.

The changes improve the alignment of our pricing with our costs of supply, which are primarily fixed. Our goal is to work towards a pricing structure for all consumer groups which recovers costs and revenue and reflects economic costs to the extent practicable. Factors informing the rate and extent of change:

- Maximum allowable revenue determined by the Commerce Commission
- Consumer equity
- Pass-through of the network service price signals to consumers by the retailer
- Outcomes and implementation of the Electricity Price Review[4]
- Changes to the Electricity (Low Fixed Charge Tariff for Domestic Consumers) Regulations 2004
- Guidance from the Electricity Networks Association working groups
- Government policies to reduce emissions

Pricing changes being considered

We are considering several changes to our pricing approach to reflect changing network and consumer characteristics of our network.

The Commerce Commission's Default price path for the period 2020/21 to 2025/26 allows a total projected increase in allowed revenue of 8.22% over the period, following an initial 14.6% decrease from 2019/2020 to 2020/2021.

Changes to prices in coming years to reflect the increase to the maximum allowed revenue in any year will be applied to the fixed components consistent with our goal to rebalance the proportion of costs recovered using fixed and fixed-like charges and variable charges.

We are considering further changes, including:

- Options to address efforts to avoid charges through short-term disconnection, e.g., irrigators disconnecting during the winter. We think the underlying issue is the fixed charges which consumers pay when not using irrigation pumps over the winter months. The Alpine portion of the charge makes up the majority of a consumer's power bill when not being used. These charges cover fixed operating and monthly Transpower charges

[4] https://www.mbie.govt.nz/assets/electricity-price-review-final-report.pdf

- Options to address issues associated with non-residential and other ineligible consumers being included in the low user load group. The underlying issue is the incentive created by the Low user regulations to avoid charges
- Options to address issues relating to the Assessed ("ASS") price code category. The underlying issue is only a small number of consumers in this load group have half-hourly meters, resulting in assessed demand charges being set once only when the connection is livened

We will be looking at these issues, and the options, during 2021. Changes, if any, would be included in our published 2022 Pricing Methodology after the appropriate consultation with retailers.

Implementation and transition planning

We want to make sure changes to our pricing approach and pricing is implemented effectively, and without adverse impact for consumers or customers, particularly retailers.
We will develop implementation and transition plans for changes to our pricing as part of considering pricing issues and options.

The key to our implementation and transition planning is obtaining comprehensive half-hourly data. We started collecting more comprehensive monthly TOU data from 1 April 2019 when we changed billing practices. The collection of this information will be used to undertake further price modelling. Additionally, we are currently rolling out smart meters across our network. These meters give information about consumers' half-hour energy usage.

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 information when it becomes available. Changes, if any, would be included in our published 2022 Pricing Methodology after the appropriate consultation with retailers.

A key consideration in rebalancing fixed and variable charges to reflect economic costs are potential changes to consumer behaviour and impacts on equity. We will study the implications and undertake an appropriate engagement to develop transition plans.

3. PRICING CHANGES FOR 2021/22

We are changing delivery prices in 2021/22 as follows:

- Reducing our prices across all consumer price categories except for the Assessed and TOU400HCA groups

The reasons for the changes and the average impact on delivery prices are described below. Our prices reflect the price path under the DPP Determination.

Changes to price levels

We set prices to recover the allowable distribution revenue, transmission costs, and pass-through and recoverable costs.
Alpine's prices will decrease on average by 8.6% for 2021/22 to recover total costs of $54.105 million; a $4.67 million reduction compared to 2019/20. The reduction is due to the combined impact of:

- Maximum allowable (distribution) revenue for 2021/22 increases by 2% from $42.65 to $43.48 million

- Pass-through and recoverable costs decrease by 185% from $3.55 million to ($3.02) million. The reduction is due to an over-recovery of the pass-through balance in the prior year
- Transmission costs increase by 8% from $12.57 million to $13.64 million

Lines charge for mass-market customers in 2021/22 will decrease by an average of 1.6% compared to 2019/20. The median change in lines charges is a 2.9% decrease.

Lines charges for direct billed customers in 2021/22 will decrease by an average of 6%. The decrease is mainly due to lower transmission costs.

The change in revenue for each consumer group, and average delivery price change from the resulting changes to price levels are described in Table 6 below.

Consumer Group	$ Change in revenue 20/21 to 21/22	% Change in revenue 20/21 to 21/22	Average delivery price change ($)
LOWHCA	$48,703	4.19%	($68.83)
LOWLCA	($103,937)	(1.75%)	($0.19)
015HCA	($359)	(2.82%)	$0.00
015LCA	$5,762	28.28%	$0.00
360HCA	($820,832)	(13.10%)	($64.31)
360LCA	($2,128,709)	(17.84%)	($11.28)
ASSHCA	$3,033	7.16%	$0.00
ASSLCA	($4,137)	(8.76%)	$4.82
TOU400HCA	($152,727)	(8.35%)	$0.89
TOU400LCA	($349,173)	(13.89%)	($69.88)
TOU11HCA	($9,380)	(13.12%)	$0.00
TOU11LCA	($6,974)	(14.28%)	($69.88)

Table 6 Change in forecast revenue and average delivery prices between 2020/21 and 2021/22

We considered the consumer impact of the delivery price changes. Our approach to assessing and managing consumer impact of price changes is described in section 7.

Changes to the price structure

We have not changed any price structures for 2021/22.

4. How Prices are Set

Prices for consumers using our networks to consume electricity are set in two ways:

- Standard pricing for residential and most commercial consumers is supplied according to the price categories in the standard price schedule
- Non-standard direct-billed customers

We also set prices for distributed generators, including payments to distributed generators providing network support services. When setting prices, we consider the opportunity to share the value of deferring network investment.

We do this by introducing a discount to variable charges (to signal a benefit of changing behaviour) or by directly contracting with a party supplying a network support service.

4.1 Standard Pricing

We set standard prices using the following process.

We **determine consumer groups**. Section 5 gives more detail.

- Assign consumers (connections) to groups for allocating total costs

We calculate and allocate costs to consumer groups. Section 6 gives more detail.

- Confirm the total forecast allowed revenue we can recover for the year. Forecast revenue is determined by the Commerce Commission to reflect efficient costs of supplying distribution services
- Calculate expected costs for the year. The main component costs are operating costs (including administration costs), capital costs (including return on investment), and transmission costs (including ACOT)
- Allocate costs to each consumer group to as closely as possible align the benefit of access and use of the distribution service and cost of supplying the distribution service
- Determine price structures for each consumer group based on the relevant cost allocations and complying with the relevant legal requirements

We assess consumer impacts of pricing variations. Section 7 gives more detail.

- Check the impact on consumers of pricing variations and adjust pricing as needed

4.2 Non-Standard Pricing for Direct Billed Customers

For the period ending 31 March 2021, we had six direct billed customers with 12 ICPs connected to our network at present. We are not expecting any new direct billed connections before 31 March 2022.

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 consider 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

The following methodology is used for calculating prices for directly billed customers[5]. We enter into long-term contracts with direct billed customers. This gives Alpine the ability to negotiate outcomes that are consistent with market-like arrangements.

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

4.3 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 the 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 the 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.

4.4 Capital Contributions Based on the 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 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 0.75 then we would require a capital contribution of 75% of the total investment cost.

4.5 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.

4.6 Recovering the Cost of Existing Network Assets

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

4.7 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 the line/cable length to the total line/cable lengths in the network.
For substations, transformers, protection, and switchgear, costs are apportioned to the asset using the total demand or capacity[6] 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.

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

4.8 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 the under-recovery of our required revenue.

4.9 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 to which the consumer is connected. 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.

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[7]. 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.

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 must pay in entirety for that upgrade.
Capital contributions cover the cost of the work carried out, after 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[8].

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 2020 there were 423 distributed generators connected to our network.

- 409 distributed generators (less than 10kW capacity) installed at residential or commercial premises with a combined capacity of 1.6 MW
- 14 distributed generators (more than 10 kW capacity) with a combined capacity of 9.4 MW. One of these is the Opuha hydro installation with a 9MW capacity

[7] Some contracted service standards will differ for older contracts.
[8] www.alpineenergy.co.nz

Fees payable by distributed generators to us are set by the Electricity Authority under the *Electricity Industry Participation Code* (the Code)[9]. We neither '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 (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 under the Code, connection, 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 the 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[10].

5. Consumer Groups

We assign our 'standard consumers' to one of 13 load groups for pricing.

We supply our standard consumers under our use of system agreements we have with electricity retailers. The majority of the consumers on our network are standard consumers.

5.1 Assigning Standard Consumers into Load Groups

Table 7 below lists the 13 load groups and their defining characteristics. Consumers are assigned to a load group based on location, the capacity of the connection, maximum business day peak demand, and meter configuration.

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

9 Schedule 6.5, Electricity Participation Code 2010, Part 6, Connection of distributed generation.

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

Load group	Description
IND	Individually assessed sites – Directly Billed Customers

Table 7: Load groups

5.2 Location – 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:

- On each transformer
- Per kilometre of distribution line length

On average there are 13 times more ICPs per line km in the low-cost area compared to the high cost area. Capital expenditure costs and operating expenditure costs to service connections in rural areas that are less populated are higher (High-Cost Areas) than servicing clustered connections in towns (Low-Cost Areas).

5.3 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 group
- 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

5.4 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 fulfill 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[11] 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. This means the low user group pays less than the costs of supply, with these costs met by other consumers.

5.5 015, 360 and Assessed Demand Load Groups

ICPs not in the Low fixed charge load groups and without 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).

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

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

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 have three-phase 60 A connections. ASS load groups have a maximum capacity per phase greater than 60 A. This can include two-phase connections. Demand charges for consumers in the ASS load groups are calculated on the fuse size (installed capacity) of the connection.

The mass market and assessed demand groups are grouped by installed capacity and fuse size. The resulting capacity bands broadly reflect costs of supplying the distribution network by providing a proxy for relative use of the network, including during peak demand periods. Ideally, we would have actual peak demand data.

We are working toward obtaining this data via our smart meter roll-out. Currently, this information is only available on a case by case basis, on request, and normalised across the ICP sample from retailers.

5.6 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.

5.7 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 excludes the discount offered to consumers which provides us a demand response service by allowing the ability to control the load. The controllable load is critical for us during supply emergencies, and to avoid further investment in network capacity.

The variable volume-based charge for the low user groups is 0.0202 cents per kWh (day and night) higher without the discount applied to reflect the value of the demand response service provided by the consumer. The daily fixed charge for uncontrolled load for the 015 and 360 groups is $804.25 per year higher without the discount applied to reflect the value of the demand response service provided by the consumer.

6. Allocating Costs Across Consumer Groups

We set prices by calculating and allocating costs across each specific consumer group. The process involves:

- Confirming the total forecast revenue allowed by the Commerce Commission for the pricing year
- Identifying our major cost components, and whether the costs are fixed or avoidable
- Allocating costs to specific consumer groups
- Checking alignment between cost types and price components

6.1 Total Forecast Revenue

Our total required revenue recovers annual distribution, transmission, and pass through and recoverable costs, shown below[13].

[13] Please note the forecast business costs from 2020 AMP and Information Disclosures when prices are set.

Network-related costs	$ ’000
Operating expenditure	$20,157
Depreciation	$15,019
Return on capital	$5,284
Regulatory tax	$3,024
Pass-through costs and recoverable costs	($3,022)
Transmission	$13,642
Total revenue requirement	**$54,105**

Table 8: Revenue requirement for the year ending 31 March 2022

6.2 Major Cost Components

Our distribution revenue requirement recovers annual regulated network costs for the period 1 April 2021 to 31 March 2022 and includes:

- Operating expenditure
- Depreciation
- Revaluations
- Return on capital
- Regulatory tax
- Pass-through and recoverable costs
- Transmission

Each cost component is discussed in more detail below.

6.3 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 2022 are derived from our 10-year network Opex budget, found in schedule 11b of the 2020 to 2030 Asset Management Plan.

6.4 Depreciation

Depreciation is calculated on a straight-line basis in accordance with ID Determination using a standard life for the asset[14]. Depreciation costs for the year ending 31 March 2022 are forecast using historical depreciation on our regulatory asset base (RAB sourced from schedule 4 of the 2020 Information Disclosures Schedules[15].

6.5 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

14 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

15 The schedules can be found at www.alpineenergy.co.nz/corporate/disclosures

The change in our RAB is reflected in our return on investment.

6.6 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 2021. A vanilla WACC (67th percentile) of 4.23% has been applied.

Our RAB, as at 31 March 2020 was $205.6 million. This is an increase of approximately $4.1 million when compared to the value of our RAB as at 31 March 2019.

6.7 Regulatory Tax

We recover regulatory tax through our distribution charges. The forecast regulatory tax value for the period ending 31 March 2022 is $2.9 million and was sourced from the Commerce Commission forecasts for DPP3[16].

6.8 Pass Through and Recoverable Costs

Pass through and recoverable costs include:

- Rates
- Levies: Commerce Commission, Electricity Authority, and Utilities Disputes
- IRIS Adjustment for the current year
- Pass-through balance from the period ended 31 March 2020

We forecast the rates and levies based on historical averages. The pass-through balance is sourced from our Annual Compliance Statement for the year ending 31 March 2020.

6.9 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.

Allocating costs to specific consumer groups

The revenue allocated to each load group for the year ending 31 March 2022 is shown in Table 9 and 10 below.

Load group	Year ending 31 March 2021 Target Revenue $'000	Year ending 31 March 2020 Target Revenue $'000	Change in Target Revenue $'000	The% proportion of Load Group Target Revenue to Total Target Revenue
LOWHCA	$1,212	$1,163	$49	2.2%
LOWLCA	$5,830	$5,935	($105)	10.8%
LOWUHCA	$12	$13	($1)	0.0%
LOWULCA	$26	$20	$6	0.0%

16 Commerce Commission website, https://comcom.govt.nz/__data/assets/excel_doc/0025/191464/Financial-model-EDB-DPP3-final-determination-27-November-2019.xlsx

015HCA	$5,445	$6,266	($821)	10.1%
015LCA	$9,801	$11,930	($2,129)	18.1%
015UHCA	$45	$42	$3	0.1%
015ULCA	$43	$47	($4)	0.1%
360HCA	$1,676	$1,829	($153)	3.1%
360LCA	$2,165	$2,514	($349)	4.0%
360UHCA	$62	$72	($10)	0.1%
360ULCA	$42	$49	($7)	0.1%
ASSHCA	$12,498	$12,068	$430	23.1%
ASSLCA	$3,229	$3,871	($642)	6.0%
TOU400HCA	$1,481	$1,845	($364)	2.7%
TOU400LCA	$3,967	$4,230	($263)	7.3%
TOU11HCA	$1,236	$1,235	$1	2.3%
TOU11LCA	$788	$771	$17	1.5%
IND	$4,544	$4,878	($334)	8.4%
Total	**$54,104**	**$58,778**	**($4,674)**	**100.0%**

Table 9: Target revenues per load group

Load group	Distribution		Transmission		%		Total
	Fixed	Variable	Fixed	Variable	Fixed	Variable	
LOWHCA	$116,861	$877,732	-	$217,118	9.6%	90.4%	$1,211,712
LOWLCA	$588,574	$4,136,544	-	$1,105,369	10.1%	89.9%	$5,830,488
LOWUHCA	$1,041	$7,231	-	$4,091	8.4%	91.6%	$12,363
LOWULCA	$2,248	$14,764	-	$9,122	8.6%	91.4%	$26,134
015HCA	$3,040,466	$1,354,624	-	$1,050,170	55.8%	44.2%	$5,445,259
015LCA	$5,391,474	$2,483,860	-	$1,925,609	55.0%	45.0%	$9,800,943
015UHCA	$18,853	$10,498	$7,873	$8,138	58.9%	41.1%	$45,362
015ULCA	$18,508	$8,954	$8,697	$6,942	63.1%	36.9%	$43,100
360HCA	$1,141,055	$301,352	-	$233,622	68.1%	31.9%	$1,676,029
360LCA	$1,170,458	$560,182	-	$434,280	54.1%	45.9%	$2,164,920
360UHCA	$30,654	$16,012	$3,053	$12,413	54.3%	45.7%	$62,133
360ULCA	$22,410	$9,245	$3,034	$7,167	60.8%	39.2%	$41,855
ASSHCA	$5,070,638	$3,601,138	$1,034,036	$2,791,776	48.8%	51.2%	$12,497,588
ASSLCA	$1,006,623	$982,014	$479,421	$761,305	46.0%	54.0%	$3,229,363
TOU400HCA	$761,607	$232,875	$359,094	$127,394	75.7%	24.3%	$1,480,970
TOU400LCA	$1,682,613	$1,208,050	$678,373	$397,986	59.5%	40.5%	$3,967,022
TOU11HCA	$354,222	$449,136	$198,962	$234,051	44.7%	55.3%	$1,236,373

TOU11LCA	$273,768	$166,415	$218,857	$128,936	62.5%	37.5%	$787,975
IND	$3,349,472		$1,194,960		100.0%	0.0%	$4,544,432
Total	**$24,041,546**	**$16,420,625**	**$4,186,361**	**$9,455,489**	**52.2%**	**47.8%**	**$54,104,021**

Table 10: Proportion of target revenue collected through each price component

We allocate the required revenue to load groups using cost allocators described in Table 11 below.

Cost Component	Allocator	Rationale
Operating expenditure	ADMD Weighted RAB	Opex is related to the consumer's 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 the 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 groups 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. These costs are allocated evenly amongst ICPs, except for individual customers who pay an allocation of shared costs based on contractual terms.
Transmission	ADMD RCPD	Transmission charges are allocated to non-standard consumers based on the contribution to the regional coincident peak demand—new investment and connection charges and after diversity maximum demand—interconnection charges Transmission charges are allocated to standard consumers based on the groups' regional coincident demand—new investment and connection charges and after diversity maximum demand—interconnection charges
Pass-through and recoverable costs	ICP	Allocated to standard load groups based on ICP count

Table 11: Cost allocators used and rationale for selection

6.10 Allocating 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.

6.11 ALLOCATING PASS – THROUGH AND RECOVERABLE COSTS

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.

6.12 ALLOCATING TRANSMISSION COSTS

When calculating load group prices to recover annual transmission costs, we use Transpower's transmission costs effective from 1 April 2021. 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 (uncontrolled load). We allocate connection and new investment agreement costs to load groups using a load group's after diversity maximum demand, and interconnection costs using a load group's regional coincident peak demand. 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 load group's potentially controllable load.

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 as load group demand profiles.

Alignment between costs and prices

In this section, we discuss how we calculate prices for distribution, transmission, and pass-through components of our pricing. We use a combination of fixed, capacity, and variable pricing to recover distribution costs.

6.13 DAY / NIGHT VARIABLE VOLUME BASED CHARGES

The variable volume-based charges have lower night rates than a 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 days-to-night which is consistent with day/night consumption levels metered at GXPs on the network.

6.14 FIXED DAILY CHARGERS

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).

6.15 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 the remaining load groups

6.16 Calculating Pass Through and Recoverable Prices

We recover a load group's forecast pass through and recoverable costs through 50% fixed charges and 50% variable volume-based charges. Pass-through and recoverable costs are not avoidable by changes to network use. As such, over time we will rebalance the proportion recovered using fixed and variable charges to rely more on fixed charges. We do not use a demand charge to recover these costs.

7. Assessing Consumer Impacts

We assess the impact on consumers of each change to the price structure and price level. We take account of:

- The potential the price change will result in bill shock for consumers or a consumer group
- Whether the price structure is practicable for retailers to adopt and apply
- The transaction costs associated with applying the price structure

7.1 Assessing Impacts of Price Changes

We consider the impact of price changes on households and design our pricing to avoid bill shocks by ensuring by Load Group that the average bill in each Load Group is checked for reasonableness in comparison to the previous year.

The average delivery price for 2021-22 for all consumer groups remained unchanged or reduced compared to 2020-21, except for the ASSLCA and TOU400HCA groups.
Impact analysis focused on calculating the average annual and average daily decrease for each consumer group.

The average change (decrease) to prices for consumers in the ASSLCA group (411 customers) is 17%. The average decrease in prices for the TOU400HCA group (37 customers) is 20%. The impact on the average electricity bill is estimated to be a decrease of [4.7%] for ASSLCA consumers and [0.6%] for TOU400HCA consumers.

As a final check, we check whether our prices are in the subsidy-free zone and are between incremental and standalone costs. We estimate the long-run incremental cost (LRIC) as $82/kW (if all costs were recovered through a demand charge) and the stand-alone cost as $721/kW (based on our assessment of the lowest cost alternative of supplying power to each consumer group).

Standalone cost is defined as the costs of an alternative power supply. We assume the standalone cost for each price group is $0.52/kWh for mass-market prices and $0.28/kWh for our Time of Use prices. Our prices for all consumer groups are less than the estimated standalone cost.

7.2 Customer Engagement

In July 2020 we conducted a 'mass market' consumer survey. We received completed responses on supply reliability, inconvenience caused by interruptions, community disruption, and price. We also sought feedback on power bills and electric vehicles. The previous consumer survey was in July 2019.

The key message from most consumers across all market segments indicates there is still a limited interest in electric vehicles over the next 5 – 10 years depending on price and would prefer to charge their vehicles off-peak times at home. Customers would generally be more accepting of a fixed bill from Alpine. We will take these perspectives into account when considering our longer-term pricing direction.

The survey indicated an interest by some consumers and industrial customers in solar panels or batteries, with less interest in altering the time of their demand or operate on-site generation.

7.3 We Set Prices that are Practicable for Retailers to Adopt and Apply

Alpine considers the impact on retailers when adopting complex price structures. We, therefore, attempt to keep our pricing structure as uncomplicated and limited to a few categories as possible to reduce the need for retailers to interpret complex pricing or the need to upgrade their systems.

We consider our current pricing structure as easy to interpret. We also consider the appetite for retailers to pass through distribution pricing signals and access to smart meter data for pricing purposes.

8. 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

8.1 After a Copy of the Pricing Methodology

To get a copy of our Pricing Methodology you can

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

8.2 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 0800 22 33 40.

CERTIFICATION FOR THE YEAR BEGINNING 1 APRIL 2021 DISCLOSURES

PURSUANT TO SCHEDULE 17 CLAUSE 2.9.1 OF SECTION 2.9 ELECTRICITY DISTRIBUTION INFORMATION DISCLOSURE DETERMINATION 2021 (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 clause 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

Warren Boyce McNabb
26 February 2021

Don Mcgillivray Elder
26 February 2021

APPENDIX A: ALIGNMENT WITH PRICING PRINCIPALS

Table detailing alignment with 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 avoidable costs, and less than or equal to standalone costs)	The prices for each load group are less than standalone costs. Prices for each load group are above the long-run incremental cost of supply. The assessment is in section 7, page 32-33.
ii) Reflecting the impacts of network use on economic costs;	Prices for each load group signal the impacts of network use on economic costs using TOU pricing (including day/night). Prices for commercial and industrial customers also signal economic costs of network use with a capacity charge which can vary annually based on changes to customer connection capacity or peak demand. Most network costs are fixed and do not vary based on network use in the short term (ie, hourly, daily). Work is planned to clearly identify which network costs vary according to network use to confirm the correlation between fixed and variable costs and fixed and variable charges. Refer to section 2, pages 12-14. Removal or revision of the LFC Regulations is necessary to provide appropriate price signals to the LOW load group. The current regulated low fixed charge delivers a perverse price signal which materially over-values the impact of network use. Work is also planned to investigate pricing options to manage potential peak load increases in the Tekapo, Twizel, and Temuka regions. Refer to section 1, table 2.
iii) Reflecting differences in the network service provided to (or by) consumers	Prices reflect the difference in the network service provided to customers. We offer non-standard contracts for consumers with non-standard service requirements. Refer to section 4, pages 18-21, for discussion of the approach to supply standards for customers with non-standard contracts. We define our load groups to reflect differences in network service provided, based on location and capacity Prices for each load group are developed based on the cost to deliver the relevant network service. Refer to section 5, table 7 for a description of the network service provided to each load group.
iv) Encouraging efficient network alternatives	Network alternatives are considered as part of asset management planning. TOU prices are discounted for customers offering hot water control for peak load management. Refer to table 4 describing our pricing structures for each load group, and pages 23-24 describing the basis for controlled and uncontrolled pricing. Work is also planned to investigate pricing options to manage

	potential peak load increases in the Tekapo, Twizel, and Temuka regions. Refer to section 1, table 2.
b) Where prices that signal economic costs would under-recover target revenues, the shortfall should be made up by prices that least distort network use	
Most network costs are fixed and do not vary based on network use in the short term. Work is planned to clearly identify which network costs vary according to network use to confirm the correlation between fixed and variable costs and fixed and variable charges. Refer to section 2, pages 12-14. We are gradually rebalancing the proportion of costs recovered using fixed and fixed-like charges and variable charges to reduce pricing-related distortions on network use. Refer to page 14. Removal or revision of the LFC Regulations is necessary to provide appropriate (less-distortionary) price signals to the LOW load group.	
c) Prices should be responsive to the requirements and circumstances of end-users by allowing negotiation to:	
i) Reflect the economic value of services	We offer non-standard contracts to consumers who have non-standard network connection and operation requirements to appropriately reflect the economic value to them of the network service. Refer to section 4, pages 18-21, for discussion of the approach to supply standards for customers with non-standard contracts.
ii) Enable price/quality trade-offs	We regularly engage with consumers to test price/quality preferences via surveys. We also enable consumers to make price/quality trade-offs by offering controlled and uncontrolled prices. Refer to table 4 describing our pricing structures for each load group, and pages 23-24 describing the basis for controlled and uncontrolled pricing. Non-standard contracts are negotiated to reflect price/quality trade-offs. Refer to section 4, pages 18-21, for discussion of the approach to supply standards for customers with non-standard contracts.
d) Development of prices should be transparent and have regard to transaction costs, consumer impacts, and uptake incentives	
We regularly engage with consumers, retailers, shareholders on the construction of our delivery prices. In particular, we seek feedback from retailers on the practical implications of our pricing approach and any changes to pricing structures. We are managing the transaction costs on retailers by discussing pricing with other EBD's to help with the standardisation of tariffs, thereby reducing transaction costs for retailers and consumers. We consider the impact of price changes on households, and design our pricing to avoid bill shocks by ensuring by Load Group that the average bill in each Load Group is checked for reasonableness in comparison to the previous year. 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. Refer to section 7 for a discussion of the approach to assessing consumer impacts and engaging with retailers.	

APPENDIX B: ALIGNMENT WITH INFORMATION DISCLOSURE REQUIREMENTS

Table referencing section of the document demonstrating alignment with ID requirements

Pricing Principles	Alpine Energy Limited's Alignment to the Principles
2.4.1 Every EDB must publicly disclose, before the start of each disclosure year, a pricing methodology which-	
(1) Describes the methodology, in accordance with clause 2.4.3 below, used to calculate the prices payable or to be payable;	Refer to the description of the approach in this document.
(2) Describes any changes in prices and target revenues;	Refer to section 3, and table 6 for a description of the change in forecast revenue and average delivery prices for each consumer group between 2020/21 to 2021/22.
(3) Explains, in accordance with clause 2.4.5 below, the approach taken with respect to pricing in non-standard contracts and distributed generation (if any);	Refer to section 4, pages 18-20 for a description of the pricing approach for non-standard contracts. Refer to section 4, pages 21-22 for a description of the pricing approach for distributed generation.
(4) Explains whether, and if so how, the EDB has sought the views of consumers, including their expectations in terms of price and quality, and reflected those views in calculating the prices payable or to be payable. If the EDB has not sought the views of consumers, the reasons for not doing so must be disclosed.	Refer to section 7, pages 32-33 for a description of how we sought the views of consumers on price and quality expectations and how these views inform the pricing approach.
2.4.2 Any change in the pricing methodology or adoption of a different pricing methodology, must be publicly disclosed at least 20 working days before prices determined in accordance with the change or the different pricing methodology take effect.	
2.4.3 Every disclosure under clause 2.4.1 above must-	
(1) Include sufficient information and commentary to enable interested persons to understand how prices were set for each	Refer to section 5, pages 22-25 for a description of the assignment of consumers to a load group. Refer to table 9 and page 30 for a description of the method for allocating costs across consumer groups.

consumer group, including the assumptions and statistics used to determine prices for each consumer group;	Refer to pages 30-32 for a description of how prices are set to recover costs of supplying each consumer group.
(2) Demonstrate the extent to which the pricing methodology is consistent with the pricing principles and explain the reasons for any inconsistency between the pricing methodology and the pricing principles;	Refer Appendix A
(3) State the target revenue expected to be collected for the disclosure year to which the pricing methodology applies;	Refer to page 16 and table 7 for a statement of the target revenue for the year ending 31 March 2022.
(4) Where applicable, identify the key components of target revenue required to cover the costs and return on investment associated with the EDB's provision of electricity lines services. Disclosure must include the numerical value of each of the components;	Refer to table 7 for a statement of the key components of target revenue, and numerical values, for the year ending 31 March 2022.
(5) State the consumer groups for whom prices have been set, and describe– (a) the rationale for grouping consumers in this way; (b) the method and the criteria used by the EDB to allocate consumers to each of the consumer groups;	Refer to section 5 and table 7 for a description of consumer load groups, the reason for allocating consumers to a group, and allocation the method.
(6) If prices have changed from prices disclosed for the immediately preceding disclosure year, explain the reasons for changes, and quantify the difference in respect of each of those reasons;	Refer to section 3, pages 16-17, for a description of changes to price levels for 2021/22, including the reasons for the change. Refer to table 6 for quantification of the change for each consumer group.
(7) Where applicable, describe the method used by the EDB to allocate the target revenue among consumer groups, including the numerical values of the target revenue allocated to each	Refer to section 6, pages 25-32 for a description of the method for allocating costs (target revenue) among consumer groups. Refer to table 8 for the target revenue for each load group.

consumer group, and the rationale for allocating it in this way;	
(8) State the proportion of target revenue (if applicable) that is collected through each price component as publicly disclosed under clause 2.4.18.	Refer to table 9
2.4.4 Every disclosure under clause 2.4.1 above must, if the EDB has a pricing strategy-	
(1) Explain the pricing strategy for the next 5 disclosure years (or as close to 5 years as the pricing strategy allows), including the current disclosure year for which prices are set;	Refer to section 2, pages 14-16 for a description of how we plan to evolve our pricing over the coming years. The key objective is are gradually rebalancing the proportion of costs recovered using fixed and fixed-like charges and variable charges by reducing the level of variable volume components. More detail on the nature and timing for achieving this objective is being worked on.
(2) Explain how and why prices for each consumer group are expected to change as a result of the pricing strategy;	Refer to section 2, pages 14-16. Our goal is to work towards a pricing structure for all consumer groups which recovers costs and revenue and reflects economic costs to the extent practicable. Specific consumer impacts will be assessed as part of our future pricing workplan.
(3) If the pricing strategy has changed from the preceding disclosure year, identify the changes and explain the reasons for the changes.	Refer to section 2, pages 14-16. Our pricing approach has not fundamentally changed from the preceding disclosure year. However, we have more clearly identified the objectives through the development of our pricing workplan. This is now reflected in the pricing methodology document.
2.4.5 Every disclosure under clause 2.4.1 above must–	
(1) Describe the approach to setting prices for non-standard contracts, including– (a) The extent of non-standard contract use, including the number of ICPs represented by non-standard contracts and the value of target revenue expected to be collected from consumers subject to non-standard contracts;	Refer to section 4, pages 18-20 for a description of the pricing approach for non-standard contracts. For the period ending 31 March 2021, we had six direct billed customers with 12 ICPs connected to our network at present. We are not expecting any new direct billed connections before 31 March 2022. Refer to table 8 for the expected target revenue to be recovered from non-standard contract customers.
(b) How the EDB determines whether to use a non-standard contract, including any criteria used;	Refer to section 4, pages 18-20 for a description of the pricing approach for non-standard contracts, including criteria used. The decision to place a new connection onto a direct billed contract is made on a case-by-case basis.
(c) Any specific criteria or methodology used for determining	Refer to section 4, pages 18-20 for a description of the pricing approach for non-standard contracts, including the approach to

prices for consumers subject to non-standard contracts and the extent to which these criteria or that methodology are consistent with the pricing principles;	cost allocation and determining pricing. Prices for non-standard contracts are developed to be consistent with the pricing principles. Price structures for non-standard contract consumers reflect a close alignment between fixed and variable costs.
(2) Describe the EDB's obligations and responsibilities (if any) to consumers subject to non-standard contracts in the event that the supply of electricity lines services to the consumer is interrupted. This description must explain— (a) The extent of the differences in the relevant terms between standard contracts and non-standard contracts; (b) Any implications of this approach for determining prices for consumers subject to non-standard contracts;	Refer to section 4, pages 20-21 for a description of the service levels available to consumers subject to non-standard contracts, including the extent of differences to standard consumers.
(3) Describe the EDB's approach to developing prices for electricity distribution services provided to consumers that own distributed generation, including any payments made by the EDB to the owner of any distributed generation, and including the— (a) Prices; and (b) Value, structure, and rationale for any payments to the owner of the distributed generation.	Refer to section 4, pages 21-22 for a description of the approach to developing prices for network services provided to consumers with distributed generation.

Appendix C: 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:

1) Fixed component due to the standing losses of the zone substation and distribution transformers
2) 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 2020 was 1%.

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.

[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.

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 in respect of 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 **Customer**	Consumer Price Index—a measure of the change of a weighted average of prices in a basket of consumer goods and services 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 that do not vary with the number 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 is the increase in cost from an increase in network capacity that has occurred over 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 that are charged to Alpine Energy 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 the 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	The weighted average of the pre-corporate tax cost of debt and the cost of equity
Variable prices	Prices that vary with the number of kWh consumed
WACC	Weighted Average Cost of Capital—is the regulated rate of return on the company's assets.