Pricing Methodology

For Delivery Prices Effective as at 1 April 2023

Pursuant to the requirements of clause 2.4 of the Electricity Information Disclosure Determination 2012 (consolidated 2021)

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Section 1: About Alpine Energy & Our Pricing Methodology

Introduction

We are a non-exempt EDB and must comply with the Commerce Commission's Default Price-Quality Path (DPP3) Determinations.[1] We proudly own, maintain, and operate the electricity distribution network that that delivers electricity to over 33,500 homes and businesses in South Canterbury. We deliver an essential lifeline service which is critical to support our region's economic growth. We also have an important role to play in New Zealand's transition to a low-carbon future.

Our network stretches over 10,000 km^2 of South Canterbury bounded between the Rangitata River to the north and the Waitaki River to the south. Our network extends west to the Southern Alps as far as Aoraki Mt Cook Village, while the coast is the natural eastern boundary, as shown in

We have seven grid exit points (GXP) on our network as shown in Figure below.

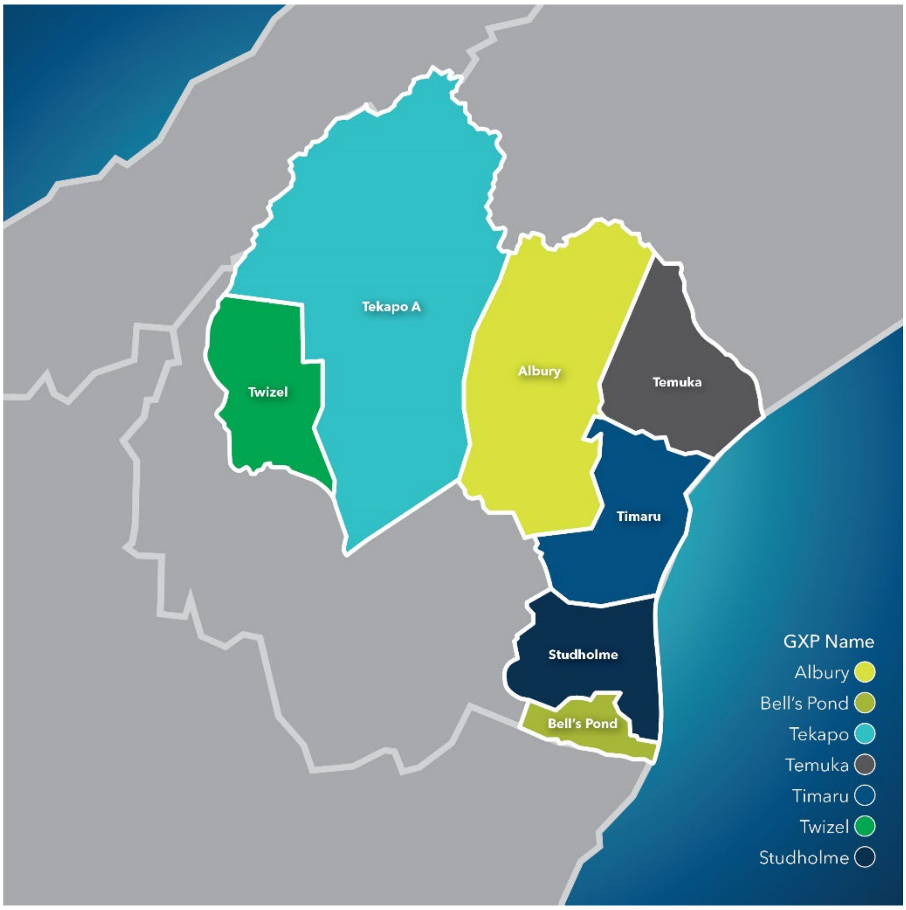

Figure 1: Our Network

[1] Commerce Commission, Default Price-Quality Path 2020-25

We are owned by Timaru District Holdings Limited (TDHL) (a subsidiary of Timaru District Council), 45.7%, LineTrust South Canterbury, 40%, by Waimate District Council, 7.54%, and by Mackenzie District Council, 4.69%. This ownership model ensures that we deliver long-term benefits and cost-effective services to the South Canterbury community.

We want to help you understand how we set prices

This pricing methodology outlines our approach to setting electricity distribution lines charges to apply from 1 April 2023.

Delivery charge describes the total price we charge to provide electricity from the national grid to consumers' 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.

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.

We have not fundamentally changed our pricing methodology from the previous pricing year (1 April 2022 – 31 March 2023) but, in line with the Electricity Authority's Distribution Pricing Principles, we continue to move towards more cost reflective pricing through decreasing variable charges and increasing fixed charges.

Transpower changed the Transmission Pricing Methodology for the pricing year starting 1 April 2023. We followed the guidance in the Electricity Authority's Distribution Pricing Practice Note (version 2.2, issued October 2022) to the extent possible. This is explained in Section 6.

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. 18 electricity retailers, trading as 23 retail brands supply consumers on the our network.

About 36% 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 1 below shows the number of consumers (ICPs) in each supply area.

Supply area	ICP Count	%
Timaru	16,189	48.2%
Waimate	3,721	11.1%
Temuka	3,456	10.3%
Geraldine	3,102	9.2%
Twizel	1,749	5.1%
Pleasant Point	1,256	3.8%
Fairlie	1,202	3.5%
Lake Tekapo	877	2.6%
Pareora	471	1.4%
Orari	304	0.9%
Glenavy	271	0.8%
St Andrews	238	0.7%
Winchester	220	0.7%
Cave	211	0.6%
Albury	183	0.5%
Makikihi	115	0.3%
Mount Cook	108	0.3%
Total	**33,673**	**100%**

Table1: Total ICP count and percentage of total by region on 28 February 2023

The Timaru GXP constitutes almost half of our network connection points and consumption is primarily residential, commercial, and small industrial customers.

Regulatory frameworks

Our pricing approach is influenced by a range of regulatory requirements, including those set 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, [2020] NZCC 3,* 20 May 2020 (DPP Determination/DPP3). Sections 5-7 of this document describe how we set prices to recover no more than the allowable revenue.
- We are required to disclose information about our pricing approach and prices by the Commerce Commission's Electricity Distribution Information Disclosure Determination 2022 – (consolidating all amendments as of 25 November 2022), (ID Determination). [2] Appendix B describes how we meet the disclosure requirements.

[2] https://comcom.govt.nz/__data/assets/pdf_file/0036/299439/5B20225D-NZCC-36-Electricity-Distribution-Information-Disclosure-Targeted-review-Tranche-1-Amendment-Determination-2022-red-lined-version-25-November-2022.pdf

- 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. The Electricity Authority's Distribution Pricing Practice Note (version 2.2, issued October 2022) provides further guidance for setting distribution prices.
- 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 30 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.

Section 2: Current pricing and future pricing plans

Introduction

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.

We have not fundamentally changed our pricing methodology from the previous pricing year (1 April 2022 – 31 March 2023) but, in line with the Electricity Authority's Distribution Pricing Principles, we continue to move towards more cost reflective pricing through decreasing variable charges and increasing fixed charges.

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.[3]

An overview of the current price structure and price components for each consumer group is provided in Table 2 below. More detail on each consumer group is provided in Section 6.

[3] 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.

Consumer group	Forecast # ICPs	Description	Fixed daily component	Fixed-like capacity component	Variable volume component	Variable volume component
			$/day	$/kW/day	$/kWh	$/kWh
LOWHCA	2,365	Households using <9000kWh/year, controlled, high-cost area	$0.45	$0.00	$0.1041	$0.0993
LOWLCA	11,184	Households using <9000kWh/year, controlled, low-cost area	$0.45	$0.00	$0.0960	$0.0912
LOWUHCA	15	Households using <9000kWh/year, uncontrolled, high-cost area	$0.45	$0.00	$0.1034	$0.0986
LOWULCA	43	Households using <9000kWh/year, uncontrolled, low-cost area	$0.45	$0.00	$0.0938	$0.0890
015HCA	5,818	Households and small commercial, 0-15kVA, < 60amp fuse, no TOU metering, controlled, high-cost area	$2.79	$0.00	$0.0088	$0.0040
015LCA	11,167	Households and small commercial, 0-15kVA, < 60amp fuse, no TOU metering, controlled, low-cost area	$2.59	$0.00	$0.0088	$0.0040
015UHCA	39	Households and small commercial, 0-15kVA, < 60amp fuse, no TOU metering, uncontrolled, high-cost area	$2.78	$0.00	$0.0088	$0.0040
015ULCA	37	Households and small commercial, 0-15kVA, < 60amp fuse, no TOU metering, uncontrolled, low-cost area	$2.54	$0.00	$0.0088	$0.0040
360HCA	540	Commercial, 3 phase, 60-amp connection, no TOU metering, controlled, high-cost area	$9.32	$0.00	$0.0088	$0.0040
360LCA	756	Commercial, 3 phase, 60-amp connection, no TOU metering, controlled, low-cost area	$8.04	$0.00	$0.0088	$0.0040
360UHCA	14	Commercial, 3 phase, 60-amp connection, no TOU metering, uncontrolled, high-cost area	$10.29	$0.00	$0.0088	$0.0040
360ULCA	15	Commercial, 3 phase, 60-amp connection, no TOU metering, uncontrolled, low-cost area	$7.75	$0.00	$0.0088	$0.0040
ASSHCA	1,314	Commercial, capacity > 15kVA, high-cost area	$9.81	$0.21	$0.0088	$0.0040
ASSLCA	409	Commercial, capacity > 15kVA, low-cost area	$7.04	$0.16	$0.0088	$0.0040
TOU400HCA	36	Households and small commercial connected to LV network, TOU metering, high-cost area	$7.00	$0.52	$0.0075	$0.0033
TOU400LCA	99	Households and small commercial connected to LV network, TOU metering, low-cost area	$6.35	$0.46	$0.0095	$0.0040
TOU11HCA	4	Commercial, connected to 11kV network, TOU metering, high-cost area	$7.32	$0.49	$0.0098	$0.0042
TOU11LCA	4	Commercial, connected to 11kV network, TOU metering, low-cost area	$6.38	$0.56	$0.0096	$0.0041

Table 2: Overview of current price structure and price components for each consumer group 2023-23

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. It might encourage each connection to be optimised to be as small as possible, especially if choice is possible with a larger variety of connection sizes on offer. It would discourage low load factor customers, encouraging them to select more appropriate sources of energy.

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, requiring higher levels of network investment, but specifying capacity limits in the higher consumption periods could promote better behaviour (TOU capacity pricing).
- 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. However, if customers with high-cost supplies opt for other energy sources more suitable for peaky loads, the average cost of electricity supply could be reduced.
- Variable volume-based charges discourage 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 may be avoided by a change to network use.

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

- 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.
- 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.
- Low user customers prices are based on the Low Fixed Charge Tariff Option for Domestic Consumers) Regulations 2004.
- 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 3 below 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.[4] 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.

[4] https://www.alpineenergy.co.nz/__data/assets/pdf_file/0014/17105/Alpine-Energy-AMP-2021-FINAL.pdf

Consumer group	Revenue recovered by fixed & fixed like charges %	Revenue recovered by variable charges %
LOWHCA	22%	78%
LOWLCA	24%	76%
015HCA	93%	7%
015LCA	93%	7%
360HCA	96%	4%
360LCA	94%	6%
ASSHCA	93%	7%
ASSLCA	92%	8%
TOU400HCA	91%	9%
TOU400LCA	84%	16%
TOU11HCA	83%	17%
TOU11LCA	88%	12%

Table 3: Average proportion of revenue recovered from each consumer group by fixed & fixed-like charges and variable charges

Evolving our pricing and prices

The energy sector is ever evolving in response to new consumer demands, new technologies and decarbonisation. We are also entering the penultimate year of the Default Price-Quality Path P3, which brings uncertainty around the changes in the Regulatory Frameworks we will need to account for in our pricing going forward. We see this new environment as an opportunity to design and redesign our pricing in response to an evolving market and consumer needs and demands. We do not currently have a pricing strategy as defined by the Commerce Commission's Electricity Distribution Information Disclosure Determination 2022 – (consolidating all amendments as of 25 November 2022). We have commissioned the development of an Energy Strategy for South Canterbury which will be completed in the next 12 months. This will provide us with detailed information on what the future of our network may look like, including roadmaps of future network congestion. Using this information, and in consultation with our consumers, we will develop a pricing strategy and roadmap and new pricing methodology to align with the effective date of DPP4 (1 April 2025).

Our current 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. It is our intention to simplify the pricing options on offer to customers to assist with optimal choices for the desired service, while aligning the pricing with the cost structure of the EDB business. It is envisaged that customers should be able to specify the required size of their connection (just about the only variable available to customers when specifying the delivery service from an EDB) and pay accordingly.

Our vision is to Empower Our Communities and the importance of developing pricing which is the right fit for all in our community and helps our customers to make informed energy choices is critically important to us.

We are rebalancing the proportion of costs recovered using fixed and fixed-like charges and variable charges by reducing the level of variable volume components. Our target is to achieve 80% of revenue from fixed and fixed-like charges to ensure the pricing outcome is aligned with our cost structure. Ensuring pricing neutrality for residential customers on the low fixed cost price plans at the 9,000 kWh per year consumption level limits the flexibility of this rebalancing exercise.

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, and specifically the outcomes from the DPP4 reset.
- Changes in the Electricity Distribution Business Input Methodologies determined by the Commerce Commission.
- Consumer equity, considering first mover disadvantages.
- Pass-through of the network service price signals to consumers by the retailer.
- 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.

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.
- 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.
- Options for electric vehicle (EV) charging pricing.
- Options for pricing categories specifically for small charitable organisations that support the wellbeing of South Cantabrians.

We will be looking at these issues and options during 2023 and 2024, in combination with the outcomes of the South Canterbury Energy Strategy mentioned above. Using this information and in consultation with our consumers and retailers, we will develop a pricing strategy and roadmap and new pricing methodology to align with the effective date of DPP4 (1 April 2025).

Implementation and transition planning

We want to make sure changes to our pricing approach are 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 once the roll-out is complete. We intend to consider how our lines charges might be structured in a way that anticipates and enables us to use smart meter data. Changes, if any, would be included in our published 2024 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.

Section 3: Pricing changes for 2023/24

Introduction

We have changing delivery prices in 2023/24 as follows:

- We have increasing prices across all consumer price categories.
- We have kept the variable pricing components (kWh rates) mostly constant, increasing the daily charges to provide for the increased revenue requirements, except for the LOW pricing categories where the daily charge is controlled by the Low Fixed Cost regulations.

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.

The total forecast revenue from prices (i.e., the total revenue we are allowed to collect in the next regulatory year under the DPP Determination) is $63.149 million for 2023/24. This represents and overall increase of 10% on the prior year revenue from prices.

The average increase in our lines charges across all consumer groups (excluding our six direct billed customers) is 12.9%. The increase is mainly because of:

- The phase out of the Low Fixed User Charges Regulations (LFC Regulations) resulting in a 15-cent increase in the fixed charged for LOW users (up to 45 cents from 30 cents in the prior year);
- Our decision to start transitioning away from a volume-based pricing model (i.e., decreasing our dependency on consumption). As a result, the recovery through fixed charges is increasing to 82% (PY: 53%); and
- Adjusting the forecast quantities to be more closely aligned with the actual consumption trends for the past few years.

For an average residential consumer (on LOW and 015 load groups), representing more than 30,000 of our ICPs, this will result in an average annual increase of less than $110 (i.e., less than $10 a month). Our larger consumers will have larger $-value increases but lower percentages of their total line charges.

Regardless of how we set our pricing structure, the retailers ultimately determine how these are passed through to the consumers in their pricing structures.

The prices for the six direct billed customers were set based on the methodologies in their individual conveyance agreements. The distribution charges are mainly adjusted for inflation based on the change in the PPI over a 12-month period. Many of these older contracts pass transmission costs through using the old Transmission Pricing Methodologies. We are commencing a review of all our conveyance agreements as part of our work to understand our customers' future energy needs. In the meantime, we have applied an interim methodology to pass transmission costs to our direct billed customers. The total Transpower transmission charges for Alpine Energy decreased by 3.95% from

2022/23 to 2023/24, and this reduction will be passed through to all our directly billed customers to accommodate this change transparently and fairly.

The change in revenue for each consumer group, and average delivery price change from the resulting changes to price levels are described Table 4 below.

Load Group	Avg. Annual lines charges for FY22/23	Avg. Annual lines charges for FY23/24	Annual Avg. increase / (decrease) in whole dollars	Avg. increase / (decrease) as a percentage from last year
LOWHCA	635	746	111	17.5%
LOWLCA	599	696	97	16.2%
015HCA	988	1,096	108	10.9%
015LCA	897	1,016	120	13.3%
360HCA	3,154	3,560	405	12.9%
360LCA	2,855	3,146	291	10.2%
ASSHCA	9,368	10,532	1,163	12.4%
ASSLCA	7,772	8,648	876	11.3%
TOU400HCA	40,737	45,594	4,857	11.9%
TOU400LCA	42,378	47,840	5,462	12.9%
TOU11HCA	275,395	305,166	29,771	10.8%
TOU11LCA	213,384	241,118	27,734	13.0%

Table 4: Change in forecast revenue and average delivery prices between 2022/3 and 2024/24

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 2023/24.

Section 4: How prices are set

Introduction

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 (standard consumers).
- Non-standard for direct-billed customers (IND).

Defining our consumer groups

We assign our standard consumers to one of 13 load groups for pricing. We supply our standard consumers under our Default Distribution Agreements we have with electricity retailers. The majority of the consumers on our network are standard consumers. We have six direct billed customers with 12 ICPs connected to our network.

Table 5 below lists the 13 consumer (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
IND	Individually assessed sites – Directly Billed Customers

Table 5: Load groups

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).

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

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 $0.45 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 $0.45. We also ensure that an 'average' consumer 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. [5] This means the low user group pays less than the costs of supply, with these costs met by other consumers.

The Low Fixed Charge obligations are currently being phased out with a $0.15 increase in fixed charges over a five-year period effective, 1 April 2022. This is the second year of five and accordingly, the $0.45 per day fixed charge for Low Users is in place.

015, 360 and assessed demand load groups

ICPs not in the Low Fixed Charge load groups and without time of use (TOU) meters installed, fall into one of three load groups: [6]

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 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

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

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

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.

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.

IND load group

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

We enter long-term contracts with direct billed customers. This gives us the ability to negotiate outcomes that are consistent with market-like arrangements.

The methodology applied to determine the delivery prices for direct billed customers is specific to each customer. Section 5 provides more details on how the prices are determined for INDs and distributed generators.

Methodology applied in setting our prices for 2023/24

In setting the prices we have followed the steps below:

Step 1: Determine the total allowable revenue under the DPP

In the current year we were capped by the 10% increase from the prior year forecast revenue from prices in accordance with the DPP Determination. Our maximum forecast revenue from prices was therefore capped at $63.149 million, represented in Table 6 below.

Component	Value ($000)
Distribution revenue	45,252
Pass-through and recoverable costs (excluding transmission costs)	2,982
Transmission costs	14,162
Opening wash-up balance account (to the maximum allowed)	753
Total	**63,149**

Table 6: Maximum forecast revenue from prices

This represents the total amount of revenue that we are allowed to forecast to collect through our lines charges across all our consumer groups.

Step 2: Determine the forecast revenue for individually billed customers (INDs) and deduct from the total

The pricing methodologies for the INDs are set out in their individual conveyance agreements. The adjustments year-on-year was mainly for CPI. Many of these contracts still have some RCPD (regional coincident peak demand) transmission elements included in the contracts, which now no longer exist under the new TPM. We have therefore determined the pass-through of these customers' transmission charges in accordance with the same methodology Transpower has introduced in the TMP which is based on the assets allocated specifically to these customers in accordance with their contracts. We have been transparent with the customers in the increase letters sent to them to signal the change and that we will be performing a full review of all conveyance agreements in the next 12 months to ensure that our methodologies in the old contracts are refreshed and aligned with current day best practices.

The lines charges for the INDs are set out in Table 7 below, showing a comparison with the prior year prices.

Component	2023/24 ($'000)	2022/23 ($'000)
Forecast distribution charges	3,237	2,967
Transmission charges	2,073	2,158
Total	**5,310**	**5,125**

Table 7: Total revenue allocated to IND load group

With the INDs being set at a total of $5.310 million, the remaining revenue to be allocated between the load groups was $57.839 million.

Step 3: Forecast quantities

The forecast quantities consist of two parts – ICP numbers and kWh. The ICP numbers are used for the fixed portion of the prices and the kWhs are used for the variable portion of the prices.

Forecasts of connections (ICPs) are based on existing connections with a 1% growth on average. This is based on historical increases in network connections, analysing the trends for each pricing category, to arrive at the estimate for growth in the number of total ICPs. We estimated the average number of active ICP's on the network to be 33,869 (starting the financial year at 33,701 and ending at 34,013) when setting the fixed charges for 2023/2024.

kWh growth is notoriously volatile on Alpine Energy's network, with changes to agricultural irrigation volumes dictating the outcome. Our forecast is based on an analysis of volumes for each pricing category, and an expectation of average irrigation volumes, with low growth expectations for all customer categories. We applied historical trends to arrive at growth rates aligned with the observed long-term growth. As a result, the volumes for 2023/24 are forecast to be 0.3% higher than the five-year average volume delivered to customers, with a monthly profile aligned with historic trends and an average irrigation scenario. A warmer winter and a wetter summer than expected could result in lower volumes than forecast, and vice versa.

In addition to forecasting the total kWhs, we made assumptions on day versus night consumption. We used the actual Day/Night volumes from prior year to determine an estimate of Day/ Night consumption. In line with the prior year, the split is on average 70:30 Day/Night.

The forecast number of ICPs and kWh for FY24 is shown in Table 8 below:

Load group	Forecast Quantities - 31 March 2024			
	Day *kWh*	Night *kWh*	Demand *Demand kW*	Avg Number of ICPs
LOWHCA	9,369,397	4,015,456	-	2,365
LOWLCA	44,012,170	18,862,358	-	11,184
LOWUHCA	72,128	30,912	-	15
LOWULCA	178,717	76,593	-	43
015HCA	40,548,201	17,377,801	-	5,818
015LCA	70,696,993	30,298,711	-	11,167
015UHCA	355,245	152,248	-	39
015ULCA	251,282	107,692	-	37
360HCA	7,684,709	3,293,447	-	540
360LCA	14,644,814	6,276,349	-	756
360UHCA	436,824	187,210	-	14
360ULCA	281,518	120,651	-	15
ASSHCA	85,734,864	36,743,513	109,148	1,314
ASSLCA	26,364,904	11,299,245	37,085	409
TOU400HCA	15,988,152	6,843,449	7,421	36
TOU400LCA	68,869,752	31,192,248	22,536	99
TOU11HCA	17,807,681	6,840,683	5,646	4
TOU11LCA	10,249,205	4,442,169	4,077	4
	413,546,557	**178,160,735**	**185,913**	**33,859**

Table 8: Forecast quantities

Step 4: Determine the lines charges for each load group

The determination of the lines charges for each load group in not merely a mechanical exercise using the forecast quantities and the total revenue allocated to remaining load groups (i.e. excluding INDs). There are multiple other factors that influence our approach to pricing including ensuring customers do not experience price shocks, ensuring revenue adequacy, maintaining logical relationships between price categories, ensuring compliance with LFC regulations and transitioning to a higher percentage fixed charges in a pragmatic manner. Balancing these considerations requires meticulous assessment of the impact of the split between fixed and variable charges for each load groups.

We ran scenario analysis to determine what we believe is a fair and equitable outcome for all our consumers.

The assumptions, estimations and scenario analysis resulted in the following pricing outcomes:

- Increased fixed charges for all consumer groups across the board to achieve the 80/20 fixed vs variable charge split.
- Apart from the LOW load groups (see bullet point below) we passed through all transmission charges as a fixed charge, i.e., the variable charges for the transmission charges component of the lines charges have become $0 for all load groups except LOW. This is in keeping with the new Transmission Pricing Methodology and the guidance provided by the Electricity Authority.
- To comply with the LFC Regulations we made the fixed transmission charge component $0 for FY24. [7] The fixed distribution charge is $0.45 as stipulated in the LFC Regulations.

The resultant lines charges, by load group for distribution and transmission charges respectively, for 2023/24 are shown in Table 9 below.

[7] Electricity (Low Fixed Charge Tariff Option for Domestic Consumers) Regulations 2004 and Electricity (Low Fixed Charge Tariff Option for Domestic Consumers) Amendment Regulations 2021, i.e. the LFC Regulations

Load group	Distribution				Recovery of Pass-Through Costs				Transmission			
	Fixed	Variable Day	Variable Night	Demand	Fixed	Variable Day	Variable Night	Demand	Fixed	Variable Day	Variable Night	Demand
	per day	*per kWh*	*per kWh*	*per kW/per day*	*per day*	*per kWh*	*per kWh*	*per kW/per day*	*per day*	*per kWh*	*per kWh*	*per kW/per day*
LOWHCA	$0.4408	$0.0527	$0.0517	$0.0000	$0.0092	$0.0260	$0.0222	$0.0000	$0.0000	$0.0254	$0.0254	$0.0000
LOWLCA	$0.4408	$0.0468	$0.0458	$0.0000	$0.0092	$0.0260	$0.0222	$0.0000	$0.0000	$0.0232	$0.0232	$0.0000
LOWUHCA	$0.4408	$0.0522	$0.0512	$0.0000	$0.0092	$0.0260	$0.0222	$0.0000	$0.0000	$0.0252	$0.0252	$0.0000
LOWULCA	$0.4408	$0.0452	$0.0442	$0.0000	$0.0092	$0.0260	$0.0222	$0.0000	$0.0000	$0.0226	$0.0226	$0.0000
015HCA	$1.6856	$0.0021	$0.0011	$0.0000	$0.4847	$0.0067	$0.0029	$0.0000	$0.6234	$0.0000	$0.0000	$0.0000
015LCA	$1.5401	$0.0021	$0.0011	$0.0000	$0.4847	$0.0067	$0.0029	$0.0000	$0.5696	$0.0000	$0.0000	$0.0000
015UHCA	$1.6729	$0.0021	$0.0011	$0.0000	$0.4847	$0.0067	$0.0029	$0.0000	$0.6187	$0.0000	$0.0000	$0.0000
015ULCA	$1.4998	$0.0021	$0.0011	$0.0000	$0.4847	$0.0067	$0.0029	$0.0000	$0.5547	$0.0000	$0.0000	$0.0000
360HCA	$6.9020	$0.0021	$0.0011	$0.0000	$0.4847	$0.0067	$0.0029	$0.0000	$1.9300	$0.0000	$0.0000	$0.0000
360LCA	$5.6877	$0.0021	$0.0011	$0.0000	$0.4847	$0.0067	$0.0029	$0.0000	$1.8678	$0.0000	$0.0000	$0.0000
360UHCA	$7.2977	$0.0021	$0.0011	$0.0000	$0.4847	$0.0067	$0.0029	$0.0000	$2.5121	$0.0000	$0.0000	$0.0000
360ULCA	$5.4068	$0.0021	$0.0011	$0.0000	$0.4847	$0.0067	$0.0029	$0.0000	$1.8612	$0.0000	$0.0000	$0.0000
ASSHCA	$5.0371	$0.0021	$0.0011	$0.1791	$0.4847	$0.0067	$0.0029	$0.0000	$4.2924	$0.0000	$0.0000	$0.0266
ASSLCA	$3.5407	$0.0021	$0.0011	$0.1281	$0.4847	$0.0067	$0.0029	$0.0000	$3.0172	$0.0000	$0.0000	$0.0344
TOU400HCA	$3.4146	$0.0074	$0.0032	$0.3917	$0.4847	$0.0001	$0.0001	$0.0000	$3.0960	$0.0000	$0.0000	$0.1262
TOU400LCA	$2.9828	$0.0094	$0.0040	$0.3782	$0.4847	$0.0001	$0.0000	$0.0000	$2.8793	$0.0000	$0.0000	$0.0863
TOU11HCA	$3.1082	$0.0098	$0.0042	$0.4038	$0.4847	$0.0000	$0.0000	$0.0000	$3.7316	$0.0000	$0.0000	$0.0834
TOU11LCA	$2.6268	$0.0096	$0.0041	$0.3876	$0.4847	$0.0000	$0.0000	$0.0000	$3.2661	$0.0000	$0.0000	$0.1744

Table 9: 2023/2024 lines charges for all standard load groups

Section 5: Non-standard contracts

Introduction

We enter into non-standard agreements with large or unique electricity users and distributed generators. These contracts are negotiated on a case-by-case basis. The general principles we apply in these negotiations are outline below.[8]

Over the next 12 months we will undergo a revision of our new customer connections policies and our large user contracts, consulting with our current consumers in the IND load group. We will also be developing a framework and contract for connecting large scale distributor generation to our network.

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.

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.

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.

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

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 do 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 the 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 substations, transformers, protection, and switchgear, costs are apportioned to the asset using the total demand or capacity of all users of the asset including the direct billed customer, to the total demand or capacity of the asset type across the network. [9] 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

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.

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. With the revised Transmission Pricing Methodology (to be introduced on 1 April 2023) this allocation is done based on a five-year average of previous charges (taking into account longer term variations in demand of the consumer) to ensure it is aligned with the methodology employed in the new Transmission Pricing Methodology.

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.[10] 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.

[9] The use of demand or capacity will depend on the type of asset that the cost relates to.
[10] Some contracted service standards will differ for older contracts.

Capital contributions

In addition to the delivery charge revenue that we receive from our customers, we also receive capital contributions from any customer requiring a connection to our network or an 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 customer, they will pay for all works.

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. Without a capital contribution, these extensions or upgrades would be uneconomic under standard delivery prices.

For larger builds, generally over $500,000, we 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[11]. This policy is currently undergoing a review and a new policy will be released in the next 12 months.

Distributed generation on our network

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

Fees payable by distributed generators to us are set by the Electricity Authority under the *Electricity Industry Participation Code* (the Code)[12]. 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.

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[13].

[11] www.alpineenergy.co.nz

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

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

Section 6: Target Revenue

Introduction

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 (as described in Section 4).
- checking alignment between cost types and price components.

Total target revenue

Our total required revenue recovers annual distribution, transmission, and pass through and recoverable costs, shown below.[14]

Network-related costs	$ '000
Operating expenditure	$20,572
Depreciation	$16,397
Return on capital	$5,357
Regulatory tax	$3,065
Pass-through costs and recoverable costs	$936
Transmission	$14,254
Wash up claimed	$2,568
Total revenue requirement	**$63,149**

Table 10: Revenue requirement for the year ending 31 March 2024

Major cost components

Our distribution revenue requirement recovers annual regulated network costs for the period 1 April 2023 to 31 March 2024 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.

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

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 2024 are derived from our 10-year network OPEX budget, found in schedule 11b of the 2023-2033 Asset Management Plan.

Depreciation

Depreciation is calculated on a straight-line basis in accordance with ID Determination using a standard life for the asset.[15] Depreciation costs for the year ending 31 March 2024 are forecast using historical depreciation on our regulatory asset base (RAB sourced from schedule 4 of the 2022 Information Disclosures Schedules[16].

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 investment.

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 2023. A vanilla WACC (67th percentile) of 4.23% has been applied.

Our RAB, as at 31 March 2022 was $238 million.

Regulatory tax

We recover regulatory tax through our distribution charges. The forecast regulatory tax value for the period ending 31 March 2024 is $3.3 million and was sourced from the Commerce Commission forecasts for DPP3.[17]

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15 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

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

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

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
- Revenue Wash Up Amount

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.

Transmission costs

Then transmission costs are based on the pricing schedules received from Transpower for 2023/24.

Allocating costs to specific consumer groups

The target revenue allocated to each load group for 2023/24 is shown in Table 11 below. The allocation is based on the same methodology described in Section 4.

Load group	Year ending 31 March 2023 ($'000)	Year ending 31 March 2024 ($'000)	Change ($'000)	The% Total Target Revenue
LOWHCA	$1,672	$1,759	$87	2.8%
LOWLCA	$7,350	$7,781	$431	12.3%
LOWUHCA	$18	$13	-$5	0.0%
LOWULCA	$53	$31	-$22	0.0%
015HCA	$5,713	$6,375	$662	10.1%
015LCA	$9,692	$11,347	$1,655	18.0%
015UHCA	$51	$43	-$8	0.1%
015ULCA	$43	$37	-$6	0.1%
360HCA	$1,709	$1,921	$212	3.0%
360LCA	$2,037	$2,377	$340	3.8%
360UHCA	$68	$57	-$11	0.1%
360ULCA	$41	$46	$5	0.1%
ASSHCA	$13,238	$13,849	$611	21.9%
ASSLCA	$3,057	$3,535	$478	5.6%
TOU400HCA	$1,508	$1,643	$135	2.6%
TOU400LCA	$4,018	$4,839	$821	7.7%
TOU11HCA	$1,274	$1,222	-$52	1.9%
TOU11LCA	$741	$964	$223	1.5%
IND	$5,126	$5,310	$184	8.4%
Total	**$57,408**	**$63,149**	**$5,741**	**100.0%**

Table 11: Target revenue by load group

The cost components are allocated on the basis described in Table 12 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	N/A	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	Fixed	Transmission charges are allocated to non-standard consumers based on the same rules used by the transmission pricing methodology: a five year average historic pricing period, scaled to the actual Transpower prices. Transmission charges are allocated to standard consumers based the price category of the connection, with no variable component, to align it with the fixed nature of the transmission pricing methodology. Transmission charges for the low fixed cost residential customers are variable components to ensure compliance with the relevant regulations.
Pass-through and recoverable costs	ICP	Allocated to standard load groups based on ICP count

Table 12: Allocation drivers

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.

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.

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.

Allocating transmission costs

When calculating load group prices to recover annual transmission costs, we use Transpower's transmission costs effective from 1 April 2023. From the total, we remove the annual transmission revenue we expect to recover from direct billed customers, before allocating the remainder to load groups.

Due to the short lead times from receiving the final transmission prices before implementation, the allocation of costs to the load groups will for 2023/24 be based on the historical allocations, adjusted to reflect changes in ICP numbers per load group, and scaled for the actual revenue requirements from Transpower. The future cost allocation methodology will be refined during the next 12 months.

The different charges explained

The different charges that make up the full lines charge for each load group are explained below.

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.

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).

Low fixed charge group prices

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

- We deduct from the LOW load group revenue requirement; the total fixed charge we can recover under the Low Fixed Charge regulations ($0.45 per day).
- We then calculate the LOW day-night variable prices using the corresponding 015 load group fixed and 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.
- We allocate the excess LOW user revenue requirement that we cannot recover under regulation to the remaining load groups.

Calculating pass-through and recoverable prices

We previously recovered 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, and for 2023/24 we kept the variable charges constant and adjusted for higher revenue requirements by increasing the fixed charges only. We do not use a demand charge to recover these costs.

Section 7: Assessing Consumer Impacts

Introduction

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.

Assessing impacts of price changes

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

Because of the adjustment towards less reliance on variable charges, we calculated the expected price change for low consuming customers in each pricing category, by reducing the volume to 25% of the average of each pricing category. This check informed us of the number of customers exposed to high increases in their total electricity bill.

The average price paid for the delivery service in each pricing category approaches the average cost to provide the delivery service for a typical customer in that pricing category. The relatively low consuming customers in such a pricing category who might experience a higher-than-expected price increase had in fact been paying significantly less than the cost to supply them, and even if it is unfortunate to have such high increases, it is the only way to adjust the prices towards covering the cost of the service.

Customer engagement

In October 2022, Key Research surveyed 342 of our customers across all seven GXPs to assess perceptions of reliability, outages and notifications, pricing, and uptake of new technologies and electric vehicles.

The survey revealed that areas with the largest proportion of satisfied customers included:

- Delivering a safe power supply (83% satisfied).
- Providing a reliable power supply (81% satisfied).
- The attitude of staff (78% satisfied).
- How helpful staff are (77% satisfied).
- Minimising the number of outages (75%).

This reflects well on our ongoing efforts to maintain a safe and reliable network and our priority of putting customers first through quality customer service across the business.

Areas with the largest proportion of dissatisfied customers included:

- How well we communicate about the things we are doing (20% dissatisfied).
- How we deal with customer issues in a timely manner (19% dissatisfied).
- Lines charges are good value (18% dissatisfied).
- How well we keep customers informed about power supply matters (18% dissatisfied).
- How well we communicate about keeping safe around electricity (17% dissatisfied).

These responses reinforce what we know about increasing customer expectations for real-time information about network outages and planned work, as well as greater expectations for more proactive communications across all business activities.

The survey also revealed that our customers have little willingness for increased lines charges to improve the reliability of service provided; with 80% preferring to maintain current levels instead of increasing or reducing prices with associated changes to service.

This result is consistent with our previous survey responses and is an important input when determining the level of network investment into reliability associated projects and required pricing structures to support this.

The information from our customer surveys helps us understand our consumers' needs and future plans, which we will use to inform the development of our pricing strategy and methodology over the next 12 to 18 months.

We set prices that are practicable for retailers to adopt and apply

We consider 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.

We will consult with the retailers in the next 12 – 18 months as we work on our pricing strategy and the subsequent changes to our methodology.

Section 8: Do You Have any Questions

Introduction

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:

- 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

Complaints process

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

- Confirming with you that you are making a formal complaint rather than wanting to talk through an issue with us
- Acknowledging the complaint within 2 working days
- 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 2023 Disclosures

Pursuant to Schedule 17
Clause 2.9.1 of Section 2.9
Electricity Distribution Information Disclosure Determination 2012 (consolidated in 2015)

We, Warren McNabb and Linda Robertson being directors of Alpine Energy Limited certify that, having made all reasonable enquiry, to the best of our knowledge:

a) The following attached information of Alpine Energy's prepared for the purposes of clause 2.4.1 of the Electricity Distribution Information Disclosure Determination 2012 in all material respects complies with that determination.
b) The prospective financial or non-financial information included in the attached information has been measured on a basis consistent with regulatory requirements or recognised industry standards

Warren McNabb
28 March 2023

Linda Robertson
28 March 2023

Appendix A: Alignment with Pricing Principals

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.
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 (i.e., 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.
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 5 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 4.
iv) Encouraging efficient network alternatives	Network alternatives are considered as part of asset management planning. Refer to Table 2 describing our pricing structures for each load group.
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.	

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 5.
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 Section 7. Non-standard contracts are negotiated to reflect price/quality trade-offs. Refer to Section 5 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

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 for a description of the change in forecast revenue and average delivery prices for each consumer group between 2022/23 to 2023/24.
(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 5 for a description of the pricing approach for non-standard contracts and 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 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.	N/a – we have not changed our pricing model from the prior year.
2.4.3 Every disclosure under clause 2.4.1 above must-	
(1) Include sufficient information and commentary to enable interested persons to understand how prices were set for each consumer group, including the assumptions and statistics used to	Refer to Sections 4 and 6.

determine prices for each consumer group;	
(2) Demonstrate the extent to which the pricing methodology is consistent with the pricing principles and explain the reasons for any inconsistency between the pricing methodology and the pricing principles;	Refer Appendix A
(3) State the target revenue expected to be collected for the disclosure year to which the pricing methodology applies;	Refer to Section 6, Table 10.
(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 Section 6, Table 10.
(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 4.
(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.
(7) Where applicable, describe the method used by the EDB to allocate the target revenue among consumer groups, including the numerical values of the target revenue allocated to each consumer group, and the rationale for allocating it in this way;	Refer to Section 6.
(8) State the proportion of target revenue (if applicable) that is	Refer to table 11.

collected through each price component as publicly disclosed under clause 2.4.18.	
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 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. 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. 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 5 for a description of the pricing approach for non-standard contracts. For the period ending 31 March 2022, we had six direct billed customers with 12 ICPs connected to our network at present. Refer to table 7 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 5 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 prices for consumers subject to non-standard contracts and the extent to which these criteria or that methodology are consistent with the pricing principles;	Refer to Section 4 for a description of the pricing approach for non-standard contracts, including the approach to 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	Refer to Section 5 for a description of the service levels available to consumers subject to non-standard contracts, including the

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;	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 5 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:

- Fixed component due to the standing losses of the zone substation and distribution transformers
- Variable components arising from the heating effects of the resistive losses in the delivery conductors[18]

The loss percentage reported under the information disclosure requirements for the year ended 31 March 2022 was 3.6%.

The following loss factors are applied by us:

- 33kV dedicated–1.02
- 11KV general–1.019
- 400V general–1.049

[18] 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

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	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 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.