Pricing Methodology 2019 - 2020

For Line Charges, effective 1 April 2019 to 31 March 2020
(Pursuant to Electricity Information Disclosure Requirements)

www.topenergy.co.nz

TOP ENERGY® Te Puna Hihiko

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1. Introduction

Top Energy Limited (Top Energy) is the electricity distribution network in the Mid and Far North of the Northland region. The network distributes some 326,000,000 kWh of electricity to over 32,000 electricity consumers, who also own the company through the Top Energy Consumer Trust (TECT).

This pricing methodology document describes our key considerations and approach to setting distribution prices effective 1 April 2019. It also sets out our plans and pricing strategy.

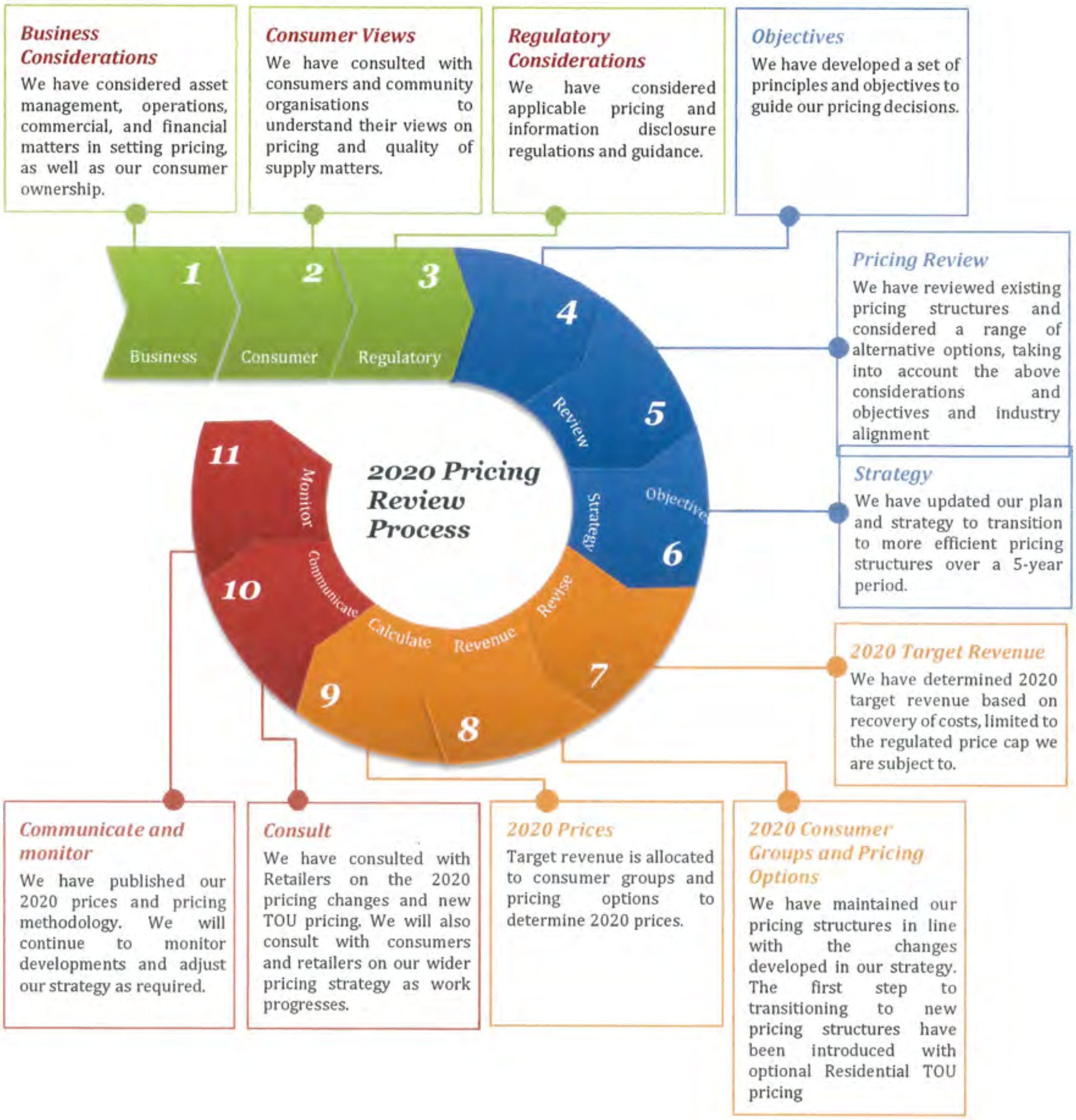
The pricing methodology is structured as follows:

- **Section 2** summarises our approach and key decisions for setting prices in 2019-20
- **Section 3** summarises key considerations we have taken account of in making decisions on pricing
- **Section 4** details our principles and objectives, recent review, and plans and strategy for pricing
- **Section 5 to 7** provides further detail on how prices are set, including:
  - how target revenue is determined
  - key decisions on consumer groups and available pricing options
  - how target revenue is allocated to each consumer and price option
- **Appendix 1** provides director certification of this pricing methodology
- **Appendix 2** provides a glossary of common terms used in this document
- **Appendix 3** maps compliance against section 2.4 of the ID Determination
- **Appendix 4** describes how this pricing methodology is consistent with the Electricity Authority's pricing principles published in February 2010
- **Appendix 5** details distribution prices that will apply from 1 April 2019

2. Summary of how prices are set

2.1. Process for setting prices

The following diagram illustrates Top Energy's process for reviewing and setting prices in 2019-20.



2.2. How prices are calculated

Prices have been set to recover our 2019-20 target revenue. Target revenue is calculated to recover our forecast costs but is limited by a price cap determined by the Commerce Commission. Unit prices (comprising a daily fixed charge and/or a consumption-based variable charge) are calculated for each pricing option we offer by allocating target revenue:

- directly to a consumer, where costs are known for specific consumer groups
- using cost allocators for shared costs, which are based on consumer numbers or usage characteristics.

Figure 1 illustrates how target revenue is allocated to consumer groups and prices.

Figure 1: Calculation of prices

Notes: UM: Unmetered, IND: Industrial, DG: Distributed Generation

2.3.Key changes to prices in 2019-20

We have continued the focus on our pricing methodology over the past few years. A review of our pricing approaches was commenced in 2014 followed by incremental changes which opened up commercial TOU periods for more consumers. In 2016 and 2017, following consultation with key stakeholders, we improved the efficiency and effectiveness of our pricing by achieving alignment with the industry with reference to the ENA's Distribution Pricing Guides (August 2015 and revised September 2016). This, combined with acquiring a subset of TOU smart meter data for mass market customers, has assisted in the implementation of optional residential TOU prices from 1 April 2019 and will support any future changes.

This year we are introducing one significant change to our price structure. As part of our move to more cost reflective distribution pricing, optional residential time of use (TOU) pricing is now available. The discount paid by Top Energy will continue to be a posted discount and included in the price schedule. Distribution prices have increased by 10.9% on average to recover allowable revenues permitted under the price cap regulation. These increases will be recovered through an increase in fixed and variable charges for residential and commercial customers and the balance through fixed charges for larger Industrial customers. Industrial (IND) consumers will continue to be assessed based on specific assets used. Overall prices have increased by 8.5%. Appendix 5 provides further detail on prices.

Top Energy's pricing strategy is dependent on the outcomes of the Electricity Pricing review which is currently underway. In particular, the review supports that the Government issue a policy statement on distribution pricing. If a government policy statement is issued or other relevant changes are implemented, Top Energy will review its pricing strategy and consult consumers and stakeholders accordingly.

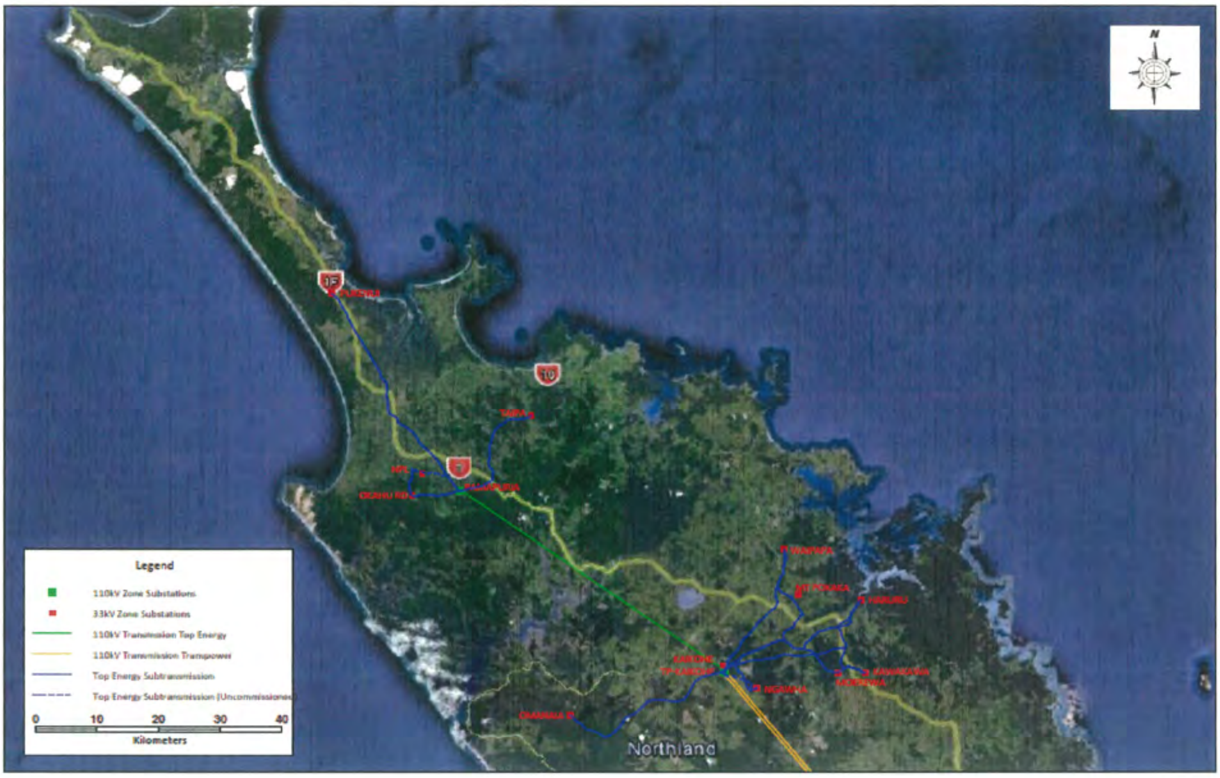
3. Pricing considerations

3.1. Business considerations

Top Energy is the local electricity distribution network in the Mid and Far North of the Northland region. Top Energy's network begins in Hukerenui, approximately 25km north of Whangarei and ends at Te Paki, 20 km south of Cape Reinga. It spans from the East Coast to the West Coast. The supply area is sparsely populated with no dominant urban centre and is recognised as one of the more economically depressed areas of the country.

The company is an integral part of the Far North community. It is owned by its customers through TECT. Consumer trust ownership means that surpluses not required for the operation and development of the network are returned to consumers via sales discounts on electricity bills and through a dividend to TECT. Top Energy also employs more than 155 people and is one of the largest employers in the Far North.

The utilisation of the network is heavily weighted towards small consumers, representing 99% of connections and over 78% of maximum demand. This is evidenced by the fact that average consumption is the one of the lowest in the country at 10,282 kWh/consumer. Top Energy's pricing structures are therefore strongly focussed on the needs of the residential and general consumer groups, with only a few large connections.



The network receives supply from the national grid at the Kaikohe substation and from local generation at Ngawha. The Kaikohe substation supplies the southern part of the network directly, with the northern part of the network supplied from a single transmission circuit to Kaitaia. Electricity is then distributed to consumers across long distribution feeders supplied from a limited number of zone substations.

This configuration is a legacy of a network design focused on providing electricity to a sparsely populated, economically deprived area, at a time when cost rather than reliability was the main driver for network development. Over 35% of Top Energy's lines were originally built using subsidies provided by the Rural Electrical Reticulation Council (RERC). This levy assisted post-war farming development in remote areas and enabled the supply of electricity to consumers located in sparsely populated rural areas, which would otherwise have been uneconomic to service.

The original network infrastructure was also developed at a time when Kaikohe and Kaitaia were the dominant urban centres. This is no longer the case, with growth now occurring in the Bay of Islands and Kerikeri as well as the East Coast peninsulas. This is where the existing infrastructure is weakest.

Many existing lines now require extensive rebuilding and refurbishment. Many assets are located in sparsely populated rural areas which remain uneconomic in some circumstances. However, Top Energy is required by legislation to maintain a power supply to consumers that were connected to these lines prior to 1993.

Within this environment, Top Energy has had to invest to meet both growth in new areas, while maintaining an appropriate level of service in existing high-cost network areas. The costs of these investments need to be reflected in prices going forward.

3.2. Consumer views

To inform our decisions regarding the above investments, in 2009 Top Energy consulted with consumers on our proposed network developments and consumer expectations for prices and the quality of service they receive. This was completed via a telephone survey.

The survey results established that 80% of consumers wished to see network reliability improve. There was overwhelming support from community organisations for the construction of a second 110 kV circuit to secure the electricity supply to the Kaitaia region. Accordingly, we embarked on a programme to improve security of supply in which $180 million would be spent over 10 years; the single largest expansion in the history of the network.

Since 2009, regular telephone surveys and focus groups have been completed to gauge customer views on our progress and incorporate any new insights into asset management planning and pricing approaches.

In 2018, Top Energy completed a comprehensive telephone satisfaction survey to understand residential and commercial customer satisfaction and experience with the services provided.

The key results were:

- 85% of customers are satisfied with their current supply reliability. This is down from 90% in 2016
- Customers are reasonably open to adopting new energy technologies, with around half using LED lighting and a quarter using gas hot water or heating. Solar panels and LED lighting are the new technologies most likely to be adopted over next 12 months
- The key motivator to change power company is to save money, with 80% commercial and two-thirds residential customers citing this as main reason. Although saving money is the key motivator, only 5,500 (18%) changed during the past year

The survey also measures the current levels of satisfaction with levels of price and quality. Feedback from the last two surveys indicates that both residential and commercial consumers are generally satisfied with the current levels of service, with the majority not willing to pay higher prices for increased reliability. This was demonstrated most recently in the 2018 customer survey, with the results shown below.

Source: Key Research customer survey 2018

Surveys will continue to be completed annually to provide a benchmark of customer satisfaction and preferences over time.

To compliment the telephone surveys, Top Energy ran focus groups, in conjunction with the ENA, with customers in Kerikeri and Kaitaia in 2017. The focus groups included 6-8 representative Top Energy customers and provided in-depth discussed with customers on their views about the electricity sector, different pricing structures to recover distribution costs and Top Energy.

The key customer insights from the focus groups were:

- Top Energy customers are more engaged with electricity than groups in Christchurch and Auckland primarily due to higher cost
- Customer understanding that higher distribution costs are due to lower population, relative remoteness and high relative infrastructure needs
- Higher electricity costs, combined with lower incomes, appear to drive a number of cost saving behaviours and consideration of electricity alternatives including solar and gas. High upfront costs and long payback time has limited uptake
- Low Fixed Charge Tariff (LFCT) was thought to be targeted at elderly and / or those living alone. The number of customers on the LFCT in the Top Energy network was higher than expected
- Top Energy has a strong local brand. We are perceived as being highly responsive in emergency situations, solid community involvement and contribution, and highly visible in the community

The residential TOU trial will also enable Top Energy to better understand customers views and behavioural changes on cost reflective pricing. The annual surveys and focus groups continue to assist us in our review of our current pricing and future developments.

3.3. Regulatory considerations

Top Energy is subject to regulations which influence our pricing decisions as well provide guidance on how prices should be set. These are summarised in Figure 2.

The Commerce Commission determines the lines charge revenue which it considers is sufficient to recovery our reasonable costs, as well as an appropriate return on investment.

We must also publish a range of information on our prices and pricing methods. This pricing methodology is prepared pursuant to these requirements (see Appendix 3).

The Electricity Authority's pricing principles and information disclosure guidelines also provide useful guidance on setting economically efficient prices. We have considered the extent to which our pricing methodology aligns with these principles in Appendix 4.7. Currently these are under review and if new pricing principles are introduced Top Energy will evaluate our alignment with those new principles.

Figure 2: Summary of relevant regulations

Regulation	How this affects Top Energy's prices
Electricity Distribution Services Default Price-Quality Path Determination 2015 (DPP)	Prices must not exceed allowable revenues determined by the Commerce Commission
Section 2.4 of the Electricity Distribution Information Disclosures Requirements (ID)	Requires Top Energy to publish certain information on prices and pricing methods
Distribution Pricing Principles and Information Disclosure Guidelines (Pricing Principles)	Provides guidance on: • economic principles and market considerations for setting prices • information that should be made available to support pricing methodologies
The Electricity (Low Fixed Charges Options for Domestic Consumers) Regulations 2004 (LFC Regulations)	Requires Top Energy to offer a price option to domestic consumers that has a fixed daily price not exceeding 15 cents.
The Electricity Industry Participation Code, Part 6 - pricing of distributed generation.	Limits prices for distributed generation to the incremental costs of connecting generation to the network, considering any avoided costs.
The Electricity Industry Participation Code, Part 12A.	Top Energy must consult with retailers in relation to any changes to pricing structures.

3.4. Stakeholder (Retailer) considerations

In accordance with the requirements of the Electricity Industry Participation Code, Top Energy has engaged with all retailers that have connections on our Network when we have intended to make changes to our pricing structures.

In July 2018 Top Energy, in conjunction with Northpower, undertook the first of two consultations on cost reflective distribution pricing. The consultation focussed on the proposed choice of TOU pricing, retailers' capabilities to provide the data for billing purposes and whether the retailers were likely to offer TOU options to their customers.

Detailed responses were received from 13 retailers including all five major retailers. Nearly all the retailers who responded selected TOU as the preferred pricing structure, for mass market customers, from the options shortlisted by the Electricity Networks Association. The key reasons provided were:

- TOU was the option which is easiest for consumers to understand; and
- TOU was the most practical option to implement for retailers and the wider industry

Retailers stressed the need for reformed pricing to allow for legacy meters, non-communicating advanced meters and retailers who unable to provide data and/or bill TOU. For Top Energy and Northpower, this means that TOU options must be either:

- Conducted as limited trials, with consumers opting-in; or
- If there is a compulsory aspect (such as all new connections), then an opt-out option is required for consumers with legacy meters, non-communicating advanced meters and retailers who unable to provide data.

This issue of half hour meter installation is heightened for Top Energy as smart meter penetration is only 62% and we have been informed that the main roll-out is now complete.

A second round of consultation was completed in October 2018 on specific TOU structures and parameters for the trial. This included a workshop with the largest retailer. Feedback from retailers from both rounds of consultations was considered in the design of the TOU pricing.

In addition, Top Energy have notified all retailers, that have connections in our network, that one closed pricing code with 70 customers will be discontinued. This was delayed from 1 April 2018 based on feedback from retailers who requested additional time to manage the customer impact. This was also stated in our published price schedule 1 April 2018.

In addition to this formal notification, Top Energy has engaged stakeholders through attendance at industry workshops (e.g. ENA Strategic Pricing Working Group), informal discussions and face to face meeting with retailers, or when new retailers sign up for a Use of System Agreement. Three new retailers started trading on the network in the last year taking the total number of retailers to 23. One retailer exited the market and transferred their customers to another retailer.

4. Pricing Decisions

4.1. Pricing objectives

Top Energy has adopted the following six pricing objectives, informed by the above considerations:

1. Prices provide an adequate return to the shareholder within the restrictions of the Commerce Commission's price control regime
2. Prices are economically efficient, transparent, and simple to understand, but also recognise the socio-economic needs of consumers and the region
3. Prices reflect a fair and efficient allocation of cost, regardless of actual volumes of electricity consumed
4. Prices provide consumers with opportunities to significantly reduce their charges where they are able to make changes in their usage of the network to reduce Top Energy's long run costs
5. Price stability and certainty is maintained by signaling changes in advance and by transitioning these changes over an appropriate timeframe to avoid price shock
6. Prices do not differentiate urban and rural consumers

These objectives are informed by the key considerations discussed in the previous section, including business considerations, consumer feedback, industry and regulatory guidance (in particular the Electricity Authority pricing principles).

Trade-off exists across these objectives which must be balanced. Our current focus in meeting these objectives is:

- To allocate costs fairly between consumer groups
- To establish a range of price options that reflect consumer requirements e.g. new residential TOU trial pricing
- That prices reflect the potential demand and capacity required by consumers
- To comply with regulatory requirements
- To appropriately recover pass through costs
- To achieve a rate of return acceptable to shareholders.

4.2. Five-year pricing strategy

Top Energy developed a plan and strategy to progress the key findings from the 2014 pricing review and to transition to new pricing structures. The five-year plan is unchanged from last year, with the key deliverables on track with trial residential TOU pricing being implemented on 1 April 2019. This has been assisted by Top Energy gaining access to anonymised half-hourly metering data from two retailers and collaboration with Northpower.

Top Energy is still working towards the 1 April 2020 timeline for initial implementation of new pricing structures. This aligns with the EAs view in their consultation paper: More efficient distribution prices – 11 December 2018 "that distributors should not wait until 2020 to start their transition to more efficient prices". This pricing strategy is dependent on the outcomes of the Electricity Pricing Review which is currently underway. In particular, the review supports that the Government issue a policy statement on distribution pricing. If a Government Policy Statement is issued or other relevant changes are implemented, Top Energy will review this pricing strategy and consult consumers and stakeholders accordingly.

The timeframe to develop and implement these changes is considered appropriate, factoring in:

- The need to collect and analyse available pricing and billing information
- New consumer insights and pricing applications made available by the roll out of smart meters (note: that now with 62% of smart meters currently installed up from 50% 12 months ago, a reasonable amount of data is just becoming available to enable work on understanding trends and usage patterns)
- Upcoming pricing guidance expected to be provided through:
    - The Government Electricity Pricing review including low user charge regulations
    - The Electricity Authority's review of electricity distribution pricing regulations including clarification on the published guidelines, and DG pricing
    - The Electricity Network Association's (ENAs) ongoing work stream to evaluate network pricing solutions and implementation considerations. Top Energy is represented on the ENA working group
- Consultation with consumers and retailers
- Sufficient time to transition prices to avoid price unreasonable shock to individual consumers.

The following table highlights the journey that has been completed to date and the planned approach to achieve Top Energy's objective of demand and/ or capacity-based pricing by 2021.

Figure 3: Top Energy's pricing strategy

2016/2018	Year 1 (2018/2019)	Year 2 (2019/2020)	Year 3 (2020/2021)	Year 4 (2021/2022)
COMPLETED	COMPLETED	ASSESS AND COMMUNICATE	IMPLEMENT	IMPLEMENT
Redefine Commercial TOU periods to reflect actual peaks – align with industry	Update COSM	Trial new TOU pricing on 1 April 2019	Implement demand or capacity based pricing e.g. TOU	Refinement of new pricing structures
Participate in industry reviews and align where suitable	Access and analysis of smart meter data	Assess impact of Government electricity pricing review		New pricing implemented for all customers (Apr 2022)
Engage with customers through surveys and focus group	Develop and model impacts of new TOU pricing structures	Develop and model impacts of various pricing structures including new technologies e.g. solar and EV		Update COSM
Access smart meter roll out	Collaboration with Northpower on Pricing	Consult with stakeholders on planned changes		
		Extend COSM model		

It is difficult to quantify the full impact of these changes at this stage. Initial analysis of a sample of half hour data shows that if all our eligible residential customers were migrated to our new trial TOU pricing, given no behaviour change, greater than 80% of customers would get a change in their line charges by + / - 5 % relative to the single price rate. We plan to provide further information on how consumers will be impacted, including behavioural changes, along with the resources required to implement as our TOU trial and review progresses.

A key issue identified in implementing our price strategy is the roll out of smart meters to all our customers. In the EA consultation paper "More efficient distribution prices - 11 December 2018" the availability of smart meter data was central to pricing reform. Currently, only 62% of connections have smart meters installed and these are concentration in populated areas. See table below. The growth of smart meters has slowed over the last year as many retailers appear to have stopped their smart meter roll out programmes well short of completion (Note: of the top 6 retailers, which account for 97% of customers, they have only 68% of customers with smart meters).

Density	**HHR penetration (%)**
REMOTE	46%
RURAL	59%
URBAN	65%

The availability of smart meters limits our ability to offer new pricing structures and for customers to potentially benefit. The concentration of non-smart meters in remote low-socioeconomic areas is of concern as our most vulnerable customers may not only be able benefit but could also be negatively impacted as more network costs are pushed onto those without smart metering.

In October 2016, the Electricity Authority (EA) outlined their expectations that distributors would publish their plans for adopting efficient price structures. The plans are to include information that signals to stakeholders, including retailers and consumers, the distributor's goals and timeframes including:

- A clear outline of the process the distributor will adopt, including the nature of the consultation that will be undertaken with retailers and other stakeholders
- A timeline with the key milestones
- Discussion of distributor resourcing implications including how resources will be allocated.

Top Energy has fully complied with the EA's expectations. In last year's pricing methodology Top Energy's roadmap, that was provided to the EA, was published. An updated version, submitted to the EA, is outlined in the table below showing progress and key timelines and the good progress achieved to date.

Figure 4: Top Energy's future pricing roadmap

Roadmap Stages	Activities	Timeline (Pricing Years)					
		2017/18	2018/19	2019/20	2020/21	2021/22	2022/23
1. Initiate pricing reform							
Problem Identification & Discovery		C					
Define overall objectives for reform	Set overall goals including target dates or date ranges	C					
Develop strategy to deliver reform	Develop ideas on how to go ahead (including long list of future pricing options if available)	C					
Communicate	Prepare and publish future pricing roadmap, include reasoning and and why it's important	C					
Identify challenges	eg, resourcing implications, billing systems, EIEP1 file formats, AMI penetration and technology, accessing data	C					
Customer consultation	Customer focus groups on potential future pricing options in collaboration with the ENA	C					
Consult retailers	Socialise ideas & plans with retailers		C				
Establish high level plan	Gain commitment to reform, agree plan, allocate resources		C				
Gather basic data for analytics	What do we need to know to progress reform (eg. AMI penetration, customer groups)		C				
Define pathway	Prepare final strategic pricing plan (including target dates)		C				
Alignment across EDBs	Compare with other EDB's, form coalitions where appropriate		C				
2. Plan changes in more detail							
Access to data for analysis	Secure rights to half hour metering data from Retailers for analysis		C	X			
Develop detailed plans, including:	Identify issues/prepare detailed pricing reform plans			X			
- customer interactions	Establish program and focus groups (retailer + end-user)	C	C	X			
- data analysis to assess customer impacts	Narrow down preferred options and test market impacts (where applicable)		C	X			
- implementation and transition arrangements	Identify what will drive success		C	X			
Trial new pricing structures (ToU)	Identify options and trial with customers			X			
- feedback loops and issues resolution	Develop processes to account for stakeholder views and review against target dates.			X			
- communication	Educate customers and retailers about change		C		X		
- regulatory compliance	Check plan meets regulatory expectations	C	C		X		
3. Manage roll out of new pricing options							
Develop transition strategies	Incentivise and manage take-up over time for retailers and customers					X	
Adopt risk management approach	Identify and manage risks to markets, customers, EDBs *(eg political and financial risks)*						X
Review progress and make adjustments	Actively consider progress towards outcomes over time					X	
Ongoing customer interactions	Monitor customer responses and manage as required						
4. Regulatory Enablers							
Form of price control	Change to revenue CAP from Weighted Average Price Cap				X		
5. Implementation of new pricing options							
Trial pricing structures	New pricing structures available to customers (Optional)			C			
New pricing structures	New pricing structures for new customers and optional for existing customers **(Subject to Electricity Pricing Review)**				1-Apr		
New pricing for all customers	Full implementation **(Subject to Electricity Pricing Review)**						1-Apr

4.3. Pricing review

Top Energy's pricing strategy has provided the framework for activity over the last two years and for the changes being made this year. To assist in the delivery of the framework, in 2016 Top Energy joined the ENA's Distribution Pricing Working Group (DPWG), to better understand and be involved in industry discussions on pricing and assist in industry alignment with the transition from a historical pricing structure. In addition, Top Energy and Northpower have worked closely together to delivery common trial pricing structures for Northland. This includes joint consultation of retailers and implementing the same time bands for the TOU trial. Further collaboration is planned this year including analysis of trial results and impacts of new technologies.

The current pricing review started in 2014 with the development by PwC of a cost of service model (COSM) and look at more efficient pricing structures. Initial analysis suggested that the pricing methodology could be improved to better reflect economic, regulatory and industry best practice. Based on this review, Top Energy investigated moving from largely consumption-based pricing towards prices based on demand/capacity-utilisation with time of use consumption charges which better reflect the service we provide and cost structure (i.e. network capacity). The main changes and activities to date are:

- Modernising the pricing structure to achieve better industry alignment e.g. ENAs distribution pricing guidelines, residential consumer group with Low User and Standard User category and the introduction of TOU pricing for non-residential customers

- Representation on the ENA Strategic Pricing Working Group to look at what cost-effective pricing means in practice including pricing structure design, customer testing and analysis using half hour metering data
- Consideration of the options outlined in the ENAs 2017 paper "A Guideline Paper for Electricity Distributors on new pricing options" which covered five network pricing types that either on their own or in combination that could be used to meet the pricing objectives
- Focus Groups in Kaitaia and Kerikeri, in conjunction with the ENA, to get feedback from customers on pricing options outlined in the ENAs Guidance paper
- Evaluation of pricing options and potential impact on customers through analysis using customer half hour meter, updating our cost to serve model and focus group insights
- Development of a trial residential TOU pricing, in collaboration with Northpower and retailers

Implementation of these forms of pricing are dependent on the roll out of smart meters, with the rollout currently sitting at 62% of ICP's. This has meant a phased approach is required.

In 2018, the Cost to Serve model was updated and showed that, under the current pricing, most customer groups covered the cost (excluding Return on Capital) of their supply of electricity. The main exceptions were Low User customers in rural areas across the network.

The key areas of focus this year will be on the implementation and analysis of new residential trial TOU prices on 1 April 2019, consideration of new technology and further stakeholder engagement. An analysis of capacity-based pricing will also be completed for commercial customers.

The objectives of the TOU trial are:

- Transition Top Energy distribution pricing to a more cost-reflective structure
- Incorporation of new technologies by providing more accurate economic pricing signals to owners and prospective owners of PV and incentivise off-peak home charging of EV's
- Facilitate electricity retailers to pass-through distribution price signals
- To the extent that is practical, align Top Energy's peak pricing periods with other distributors, with retailers and with the ENA working group recommendations.

Top Energy have actively engaged retailers and Northpower to assist in delivery of these objectives including design, operational processes and consideration of customer behaviour. The trial is initially limited to 500 customers', but this is subject to review if required.

As part of the pricing review, Top Energy have developed a framework to consider the impact of new technologies on our network and appropriate actions including timing. The framework outlines the key triggers points for new technology penetration e.g. Electric Vehicle or Solar and proposed action by Top Energy. This framework will be further refined over this year and be considered as part of our asset management strategy. Lastly, Top Energy will continue to actively engage with stakeholders, customers and Government agencies to ensure that Top Energy delivers to the objectives.

5. Target revenue

The first step in the pricing process is to establish the total target revenue to be recovered through prices. Distribution prices are set to generate sufficient revenue for Top Energy to recover its costs, subject to DPP allowable revenues. These costs are discussed in further detail:

Figure 5: 2019-20 Breakdown of Target

COMPONENTS OF TARGETED REVENUE	(1 April 2019 to 31 March 2020)	(1 April 2018 to 31 March 2019)	% change
Transpower Charges	5,328,932	5,339,058	-0.2%
Avoided Cost of Transmission (ACOT)	2,752,881	2,821,722	-2.4%
Pass-through Costs	263,489	208,806	26.2%
Other recoverable Costs	2,801,374	2,544,061	10.1%
Pass Through subtotal	**11,146,676**	**10,913,647**	2.1%
Network Maintenance Costs	6,139,000	6,188,000	-0.8%
Overheads	9,961,000	9,650,000	3.2%
Depreciation	9,056,890	8,043,886	12.6%
Pre tax ROI charge	22,055,137	20,797,249	6.0%
Distribution subtotal	**47,212,027**	**44,679,135**	5.7%
Annual Revenue Requirement	**58,358,703**	**55,592,782**	5.0%
DPP Compliance Adjustment	- 3,773,582	- 6,392,424	-41.0%
TOTAL TARGET REVENUE*	**54,585,121**	**49,200,358**	10.9%

The total Target Revenue has increased by $5.4m (10.9%). This is driven by the increase in the asset base from the last regulatory period and the corresponding increases allowed under the DPP.

5.1. Price cap regulation

Top Energy has set total target revenue for 2019-20 at $54.6 complying with the default price path (DPP) and based on consumption and connections forecasts. The target revenue is after any posted line charge discounts that are paid to consumers through a reduction in their electricity bill. Posted discounts are forecast to be in the vicinity of $5.25m for the year, representing 10% of target revenue before the discount.

Under the 2015 DPP Determination, Top Energy was allowed a price increase of 8.29% in the 2015-16 pricing year and CPI + 7% price increases in the four subsequent pricing years plus clawbacks. This decision was based on an allowable return on investment for the 2016-2020 regulatory period of 7.19% (67th percentile vanilla Weighted Average Cost of Capital (WACC)).

In addition, Top Energy is allowed to recover pass-through and recoverable costs including transmission charges, Avoided Transmission, Avoided Distribution, rates, levies, claw-back and NPV wash-up.

5.2. Transpower charges

Top Energy passes through all transmission charges at cost in accordance with the DPP and its own pricing principles. The transmission charge is equitably distributed across all customers. Transmission charges include:

- Connection Charges – Transpower charges for use of Kaikohe GXP connection assets to which Top Energy's network connects to the national grid
- Interconnection Charges – Transpower charges for use of core grid assets based on Top Energy's share of Regional Coincident Peak Demand (RCPD) in Transpower's Upper North Island demand measurement region
- New investment charges – Transpower contractual charges for grid connection capacity and security upgrades determined by agreement between Transpower and Top Energy.

5.3. Avoided Transmission – Distributed generation

Avoided transmission and voltage support charges may be payable to embedded generators of greater than 1MW output when suitable terms have been negotiated with Top Energy. Avoided interconnection charges are paid in recognition of a generator's contribution to reducing Top Energy's share of Transpower RCPD peaks.

5.4. Avoided Distribution – Distributed generation

Avoided distribution may be payable to embedded generators of greater than 1MW output when suitable terms have been negotiated with Top Energy.

5.5. Other Pass-through costs

This includes rates and regulatory levies.

5.6. Other recoverable costs

The DPP allows Top Energy to recover an allowance for the under-recovery of allowable revenues in previous assessment periods (comprising a "Claw-back" and "NPV Wash-Up" allowance). This allowance is $2.5m in 2019-2020.

5.7. Network costs

Network costs comprise mainly maintenance costs. These are derived from the network maintenance programme which provides consumers with acceptable levels of safety and reliability, including an allowance for repairs following faults. The amount is determined in conjunction with Top Energy's Asset Management Plan.

5.8. Non-Network costs

These are costs incurred in managing the day to day operations of the business, including management, finance and administration costs, as well as system operations and network support.

5.9. Depreciation

Depreciation represents the return of Top Energy's asset investment and is estimated using 2018 Regulatory Asset Base (RAB) roll-forward.

5.10. Pre-Tax WACC

A pre-tax return on investment is derived by applying a pre-tax weighed average cost (WACC) to Top Energy's regulatory asset base (RAB). Our 2020 WACC estimate of 8.76% is based on the DPP WACC (7.19%) expressed on a pre-tax basis.

5.11. DPP compliance adjustment

This represents an adjustment to our breakdown of costs to ensure compliance with allowable revenues under the DPP. In the 2019-20 year, the adjustment is negative as Top Energy is charging below what is required to achieve the allowable return on the investment in the network. This has occurred as Top Energy's price path is smoothed under the DPP to prevent any potential price shocks to consumers (e.g. 7% + CPI per year).

6. Consumer Groups and Pricing Options

6.1. Cost drivers

We have sought to align our consumer groups and pricing options to reflect differences in the key drivers of our costs. Approximately, 81% of our costs is associated with directly investing in, maintaining and operating the network, as well as receiving supply from Transpower. The remaining 19% is associated with general management and administration of the business. Top Energy considers that our network cost drivers are:

- peak demand
- the length of circuit required to supply consumers
- the number of consumer connections
- dedicated asset costs.

The cost drivers that are relevant to Top Energy's current pricing methodology are peak demand, the number of connections, and dedicated asset costs, as discussed below.

Peak demand

Top Energy builds capacity in the network to meet forecast demand. As demand increases, Top Energy must consider further investments in capacity. Consumers' peak usage of existing network capacity is therefore a key driver of future costs. For instance, the network potentially faces capacity constraints in a number of growth areas (as identified in 3.1 Business considerations) and Top Energy has undertaken a large investment programme in these areas to meet forecast demand.

Circuit length

The distance between a consumer's premises and the point of supply to the network influences the length of lines and cables required to deliver electricity to consumers. Effectively, consumers that are further away from the Kaikohe GXP create relatively higher costs for Top Energy.

In our view, it is not practical, or necessarily fair, to distinguish individual consumers by circuit length. However, groups of consumers within network sub-regions can be distinguished. Recently, as part of our Cost to Serve model update, we investigated the merits of adopting pricing sub-regions, reflecting urban, rural and remote and Northern, Eastern and Western network supply areas, respectively. While some cost differences were evident across these regions, potentially justifying different prices, consumers have sent a clear message that rural and remote consumers should pay no more than urban areas. For similar reasons, we have decided not to distinguish between the Eastern, Western and Northern networks.

Therefore, while circuit length is a relevant cost driver, Top Energy has decided not to reflect this in pricing other than for Industrial customers.

Consumer connections

New connections create investment and ongoing operations and maintenance costs. Top Energy's policy is for consumers to contribute towards capital costs in an upfront capital contribution. Remaining connection related costs must therefore be recovered through pricing.

Consumer specific costs

As a general principle, costs that are specific to individual consumers or groups of consumers should be directly recovered from these consumers, where practical. The provision of street-lighting and community lighting is an example of a cost that is only caused by a specific group. Transmission and assets costs for large industrial consumers can also be identified and prices set to reflect these costs through non-standard contracts.

Pricing distinctions could also be made based on network regions (discussed above), use of the high voltage network only, and use of dedicated transformers. However, our review of pricing suggests there is little benefit for Top Energy in disaggregating prices to reflect these costs.

6.2. Consumer Groupings

Prices are disaggregated into four consumer groups, which reflect the use of assets, connection profiles, and contribution to maximum demand, consistent with key network cost drivers:

Figure 4: Consumer Groups

Consumer Group	Criteria	Rationale	Pricing and commercial terms
Larger	Large commercial and Industrial loads consuming >200,000kWh per annum, with a fuse capacity of 110kVa or greater	Pricing incentivises the efficient use of network capacity by large loads through variable charges levied on peak, shoulder and off-peak time of use periods for Large Commercial.	Standard
		Industrial loads are distinguished by much larger load size, time of use metering and Transpower and Top Energy's distribution costs can be identified for each consumer.	Non-Standard
Residential	Loads have similar capacity with a common load profile which is often controllable	Recognises the large majority of small load connections with or without access to time of use meters and providing compliance for low user regulations.	Standard
General	All connections that do not fit within other consumer groups	Same pricing options as 'standard residential' are available. In addition, pricing incentives through General Advanced variable charges levied on peak, shoulder and off-peak TOU periods. Also recognises that some connections will be without TOU meters.	Standard
Unmetered	Street and community lighting and other unmetered connections	This group recognises the unique cost and network usage profile of street and community lighting.	Standard

6.3. Summary of pricing options

Top Energy offer the following pricing options within the above consumer groups.

Figure 5: Pricing Options

<table>
<tr><th>Price Code</th><th>Description and rationale</th><th>MWh</th><th>ICPs</th></tr>
<tr><td>Industrial
(IND)</td><td>Fixed price recovery of costs associated with industrial loads consuming >3,000,000kWh per annum and a fuse capacity of 110kVa or greater.</td><td>42,766</td><td>3</td></tr>
<tr><td>Large Generation
(LDG)</td><td>Fixed price recovery of costs associated with the connection of large-scale distributed generation into the distribution network.</td><td></td><td>3</td></tr>
<tr><td>Micro Generation
(DG)</td><td>Variable price recovery of costs associated with the connection of small-scale distributed generation into the distribution network. Currently set at zero.</td><td>3,000</td><td></td></tr>
<tr><td>General Advanced Metering
(TOU) and (GA)</td><td>TOU is the default code for all customers with an annual consumption exceeding 200,000kWh but less than 3,000,000kWh (TOU). Total charges for this plan include a fixed price for each day connected and a variable consumption price based on kWh consumption during three pricing periods, representing peak, shoulder and off-peak demand periods, as follows:

GA Advanced metering is for small commercial connection with pricing beneficial for customers using between 30,000 and 200,000 kWh (GA) per annum.

Both have pricing in the following time periods.
Peak: 07:00-9:30 and 17:30-20:00
Shoulder: 09:30-17:30 and 20:00-23:00
Off-peak: 23:00-07:00</td><td>50,064</td><td>148</td></tr>
<tr><td>Residential</td><td>Residential ICP's can have the following metering configurations: Uncontrolled, All inclusive, Day/Night and Controlled
<table>
<tr><th>Meter configuration</th><th>Total usage (MWh)</th></tr>
<tr><td>Uncontrolled</td><td>24,141</td></tr>
<tr><td>All Inclusive</td><td>123,649</td></tr>
<tr><td>Day</td><td>4,350</td></tr>
<tr><td>Night</td><td>1,689</td></tr>
<tr><td>Controlled</td><td>687</td></tr>
<tr><td>Total</td><td>154,517</td></tr>
</table>Where:</td><td>154,517</td><td>27,043</td></tr>
</table>

<table>
<tr><td></td><td> Uncontrolled (UN24): This plan includes a fixed price for each day connected and a variable consumption price. Variable prices are set higher than other controlled codes to incentivise consumers to take up controlled or D/N prices.
All Inclusive (IN18): This plan includes a fixed price for each day connected and a variable consumption price and requires that Top Energy can control load for up to 6 hours per day. The load offered must be at least 3 kW (e.g. a hot water cylinder). Variable prices are set higher than other controlled codes as the supply is a single meter and therefore it is not possible to determine the actual portion of controlled and uncontrolled load.
Day/Night (D16, N8): This plan includes a fixed price for each day connected and two variable consumption prices during a day (7am to 11pm) and night period (11pm-7am). New customers form 1April 2019 will require a minimum of 3kWcontrollable load for 6 hours during any one day. All customers on Day Night on 31 March 2018 can remain on this tariff.
Controlled 20 (CN): Top Energy can control load for up to 4 hrs per day and the load offered must be at least 10 kW. This is available to customers in conjunction with other configurations. Prices are lower than under the UN and IN price options to encourage consumers to offer up large interruptible loads. </td><td></td><td></td></tr>
<tr><td>General</td><td> General ICP's can have the following metering configurations: Uncontrolled, All inclusive, Day/Night and Controlled
<table>
<tr><th>Meter configuration</th><th>Total usage (MWh)</th></tr>
<tr><td>Uncontrolled</td><td>53,398</td></tr>
<tr><td>All Inclusive</td><td>5,186</td></tr>
<tr><td>Day</td><td>8,557</td></tr>
<tr><td>Night</td><td>3,757</td></tr>
<tr><td>Controlled</td><td>3,806</td></tr>
<tr><td>Total</td><td>74,703</td></tr>
</table>
See above for definitions. </td><td>74,703</td><td>5,208</td></tr>
<tr><td>UM</td><td>Prices for streetlights (UML) are based on a price per lamp equivalent. Other connections (UMG) are supplied with continuous supply less than 500watts. Prices are wholly fixed.</td><td></td><td>57</td></tr>
<tr><td>UM
(CLOSED)</td><td> 11 different prices targeted at a range of unmetered supply configurations including:

9 different street and community lighting configurations
Continuous supply equipment less than 500watts (e.g. Battery Chargers, Electric Fences, Irrigation, PCM Cabinets, Phone Booths, Radio Repeaters, TV Boosters)
Intermittent supply equipment (Fire Sirens, Railway Crossing Lights, Traffic Counters).
</td><td>1,109</td><td>188</td></tr>
</table>

Prices are wholly fixed given these connections are not metered. This plan is closed to new consumers from 1 April 2016

6.4. Industrial (Non-Standard)

Industrial pricing aims to recover Top Energy's costs to service these consumers. To meet these consumers' requirements, Top Energy charge a wholly fixed annual price divided into twelve equal payments. There is no variable component. This fixed charge comprises the following individual charge items:

- Transpower Connection charges
- Transpower Interconnection Charges
- Avoided transmission charges payable to embedded generators
- Avoided distribution charges payable to embedded generators
- Top Energy connection and interconnection charges for its sub-transmission assets
- Top Energy operations and maintenance charges

The charges have been calculated consistent with network cost drivers on the basis of:

- Asset usage (e.g. no low voltage or distribution level costs are assigned to these consumers as they connect directly into the sub-transmission system)
- Coincident peak demand (i.e. to directly allocate Transpower charges)

Top Energy does not have additional obligations or responsibilities regarding interruptions to supply for non-standard connections beyond those incorporated in its standard contracts. While additional circuit redundancy and specialist equipment is provided to these consumers in some circumstances, which is sometimes beyond what is provided to many standard connections, these consumers pay for this enhanced level of security on a cost recovery basis.

Top Energy may introduce non-standard pricing for specific regional development initiatives e.g. Energy park

6.5. General Advanced Metering

Pricing comprises of a fixed and variable component. Fixed prices have been set to maintain historical linkages, reduce stranding risk associated with larger connections, as well as reflect the proportion of asset used compared to other pricing options.

Variable rates are set relatively higher during periods of peak demand and progressively lower during shoulder and off-peak demand periods. These time periods have been designed:

- To align with typical demand periods on the network
- To incentivise consumers to shift demand from peak periods to shoulder periods and from shoulder to off-peak periods

- To maintain consistency with industry standard TOU periods
- To maintain consistency with the Day/Night pricing periods.

6.6. Residential/General

This pricing is where the connection does not have access to half hour data or chooses not to select a plan that uses half hour data. This is common for residential connections. A daily fixed price is levied on these plans as follows:

- a 15 cent per day is applied to all Residential consumers who meet the criteria of being a low user (LR) to comply with the low user fixed charge regulations and the Retailer has requested the low user (LR) code
- A $1.20 per day is applied to all Residential consumers who do not meet the low user criteria
- A $1.20 per day is applied to all other consumers who are not Residential

A base line variable price is charged to all uncontrolled consumers (UN). Discounts to this standard price are applied to Day/Night, recognising their contribution to reducing peak demand, and Controlled plans (All Inclusive and Controlled 20), to incentivise consumers to offer up controllable load.

Optional trial TOU variable pricing will be available from 1 April 2019. This pricing will have three price periods – Peak, Shoulder and Off-peak. These prices better reflect the underlying costs of providing line services and rewards customers for reducing peak demand.

6.7. Unmetered

Unmetered pricing is wholly fixed. Fixed charges have historically been set with reference to historical amounts and rolled forward by inflation.

6.8. Distributed generation

Under Part 6 of the Electricity Industry Participation Code, Top Energy must price distributed generation at no more than the incremental cost of connecting this generation, taking into account any avoided costs.

Top Energy has not developed separate charges for distributed generation, other than for negotiated avoided transmission, avoided distribution and voltage support payments to large scale generators (greater than 1MW output). These generators are able to demonstrate on an annual basis that they are making a material contribution towards Top Energy avoiding additional transmission costs.

Avoided Cost of Transmission (ACOT) payments can no longer be paid to new generation connected to Top Energy's network. This reflects recent changes to the distribution generation regulations under Part 6 of the Electricity Industry Participation Code (the Code). New distributed generation customers will have to directly approach and contract with Transpower to receive ACOT payments. Top Energy will continue to pay existing ACOT arrangements for distributed generation connected to the network on 6 December 2016 and which are on the Electricity Authority's published list of eligible Upper North Island distributed generation.

Existing large-scale distributed generation (>1MW)

Connection charges have been set to recover the costs through a non-standard contract.

Avoided interconnection charges may be paid to generators that are connected to the Top Energy's network and which have actively contributed to reducing Top Energy's contribution to RCPD peaks, used to set Transpower's interconnection charges. Avoided transmission and voltage support charges are calculated based on the notified Transpower charges for the applicable pricing period. This requires appropriate metering facilities at each site, so that the contribution to RCPD or voltage support charge reductions can be verified.

Other distributed generation

Top Energy considers that other distributed generation customers (e.g. small-scale solar PV) already receive a significant benefit through reduced distribution consumption prices, to the extent that electricity generated on site reduces the amount of electricity delivered via the network. Conversely, the cost to Top Energy of servicing these connections (i.e. an average domestic connection) is not reduced by the presence of the distributed generation, especially if the connection requires access to the network at times of peak demand. Accordingly, we believe that some connections with distributed generation are paying less than the incremental cost of providing the connection to that consumer.

While there are only a relatively small number of distributed generation connections on the network, the planned move to demand / capacity pricing and a higher proportion of fixed charges will ensure that consumers with distributed generation pay a fair share of costs, to satisfy cost recovery and fairness considerations under Top Energy pricing objectives.

6.9. Discounts

The discount methodology is unchanged and will continue to be a posted discount. The same consumption-based methodology will continue to be applied. Discounts calculated on this basis represent approximately $5.25m and will be processed through the retailers to be applied to consumer invoices.

6.10. Capital contributions

A customer may be required to make an upfront contribution to the cost of extending or upgrading the network (e.g. arising from connecting to the network). This contribution pre-funds Top Energy's investment, with these costs excluded from line charges.

The value of the Capital Contribution is calculated from the total cost of extension work and reduced by the value of the Top Energy connection subsidy. The contribution represents the uneconomic cost of constructing the line but does not grant any ownership rights; Top Energy retaining ownership, and responsibility for repairs and refurbishment of the reticulated extension.

Capital Contributions may be non-refundable or refundable depending on the circumstances. Standard charges and requirements apply to typical connection configurations.

The full details of the methodology for determining capital contributions is publicly disclosed on the website www.topenergy.co.nz/network/network-disclosures/

7. Calculation of Prices

Tariffs are calculated by allocating costs to consumer groups and prices, based on assumed splits between fixed and variable tariffs. Figure 7 summarises the allocators used to allocate target revenue and the rationale for these decisions.

Figure 6: Summary of cost allocators used to set prices

Cost Category	Allocator used	Rationale
Transmission costs	*Interconnection charges and ACOT - DG:* Coincident share of RCPD (kW) for industrial consumers and Anytime Maximum Demand (AMD) for other connections	Allocation of interconnection charges aligns with Transpower's use of RCPD to apportion charges at a national level.
	Connection charges and ACOT - Transmission: Share of AMD	Connection charges represent investment in GXP capacity. AMD broadly represents usage of this capacity.
Network Costs	Customer group demand on the system as a percentage of ORC	Spreads maintenance cost weighted by the replacement cost of assets (recognising higher maintenance is usually attributed to higher cost assets).
Non-Network Costs	Regulatory Asset Base (RAB)	Spreads costs that are relatively static with the size of a customer's **asset base, per feeder.**
Depreciation	IND: Demand (kW) General Advanced: RAB Residential/General/UM: RAB	Allocation based on utilisation of asset utilisation, which broadly corresponds with depreciation representing use of capital.
Pre-tax ROI	RAB	Allocates return in proportion to value of assets RAB, consistent with regulatory framework.

The above allocation approach results in the following allocations of target revenue to consumer groups.

Figure 7: Cost allocation results

				$000s	Distribution $'000's					Revenue		
Consumer Group	Regulatory Asset Base 2018($m)	Number of ICPs	Energy Consumption Forecast 2020 (GWh)	Transmission, Other Pass-through and Recoverable Costs 2020	Network Costs (Maintenance)	Non-Network Costs (Overheads)	Depreciation	Posted Discount	Pre tax WACC	Annual Revenue Requirement	DPP compliance Adjustment	Total 2020 Target Revenue
IND	5.8	3	42.8	878	141	230	209	21	487	1,966	(148)	1,818
TOU	8.7	58	37.6	1,383	213	345	314	43	721	3,019	1,067	4,085
GA	5.1	90	12.5	414	125	203	185	54	396	1,377	605	1,983
LDG	0.8	3	-	0	19	30	27	-	67	143	(79)	64
Unmetered'	1.9	245	1.1	-	47	77	70	-	170	365	112	477
LR	88.3	14,706	63.5	2,929	2,153	3,494	3,177	2,052	5,684	19,490	(7,375)	12,114
SR	91.5	12,337	89.6	3,017	2,231	3,619	3,291	2,310	5,704	20,172	(2,109)	18,063
General Commercial	49.6	5,208	74.7	2,526	1,209	1,962	1,784	764	3,581	11,827	4,154	15,981
Total	252	32,650	321.7	11,147	6,139	9,961	9,057	5,245	16,810	58,359	(3,774)	54,585

Appendix 5 summarises the resulting prices for 2019-2020 which are also located on the Top Energy website;

www.topenergy.co.nz/network/network-disclosures/

Appendix 1 – Certification for Year Beginning Disclosures

Certification for Year-beginning Disclosures

Pursuant to Schedule 17

Clause 2.9.1 of section 2.9

Electricity Distribution Information Disclosure Determination 2012

We, Euan Richard Krogh and Gregory Mark Steed, being directors of Top Energy Limited certify that, having made all reasonable enquiry, to the best of our knowledge –

a) The following attached information of Top Energy Limited 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.

E R Krogh

G M Steed

26 March 2019

Appendix 2 - Glossary

ACOT	Avoided Cost of Transmission
ACOD	Avoided Cost of Distribution
AMD	Anytime Maximum Demand, which is defined as the average of the 12 highest off-take quantities for the customer at the connection location during the Capacity Measurement Period.
Capacity Measurement Period	12-month period starting 1 September and ending 31 August inclusive, immediately prior to the commencement of the pricing year.
Consumer	A purchaser of electricity from the Retailer where the electricity is delivered via the distribution network and is interchangeable with customer.
Consumption Data	Data provided by the Retailer to the Distributor as required under the Use of System Agreement, showing details of the measured electricity consumption on the distribution network.
Code	The Electricity Industry Participation Code 2010.
Demand	The rate of expending electrical energy expressed in kilowatts (kW) or kilovolt amperes (kVA).
Distributor	Top Energy as the operator and owner of the distribution network.
Distributed Generation (DG)	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.
ENA	Electricity Networks Association
GXP	Grid Exit Point, a point of connection between Transpower's transmission system and Top Energy's distribution network.
GST	Goods and Services Tax as defined in the Goods and Services Tax Act 1985.
HV	High Voltage, voltage above 1,000 volts.
ICP	Installation Control Point. 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.
IND	Industrial Customer defined by Top Energy.
Line Prices	The prices levied by Top Energy on Consumers for the use of the Network as described in this Pricing Methodology.
Load Control Equipment	The equipment (which may include, but is not limited to, ripple receivers and relays) which is from time to time installed in a consumer's premises for the purpose of receiving load management service signals.

LV	Low voltage. Voltage up to 1,000 volts, generally 230 or 400 volts for supply to most Consumers.
Pricing Year	12-month period from 1 April to 31 March the following year.
RPDP	Regional Peak Demand Period, relates to an Upper North Island defined by Transpower where Top Energy is located. The half hour in which any of the 100 highest regional demands occurs during the capacity measurement period for the relevant pricing year.
RCPD	Regional Coincident Peak Demand, relates to the customer's off-take at the connection location during a regional peak demand period.
Retailer	The supplier of electricity to Consumers with installations connected to the distribution network.
ToU	Time of Use Customer, who is metered according to their electricity consumption for a particular period (usually half-hourly).
Transpower	Transpower (NZ) Limited
UN	Uncontrolled

Appendix 3 – Compliance with ID determination

ID Clause	Information Disclosure requirement	Pricing Methodology Reference
2.4.1	Every EDB must publicly disclose, before the start of each disclosure year, a pricing methodology which:	This Pricing Methodology will be published on our website prior to 1 April 2019.
2.4.1(1)	Describes the methodology, in accordance with clause 2.4.3 below, used to calculate the prices payable or to be payable;	See below for document references to compliance against clause 2.4.3.
2.4.1(2)	Describes any changes in prices and target revenues;	Prices have increased for all customers by an average of 8.5% when comparing 2019 and 2020 pricing schedules. See section 2.3 Changes in target revenues are described in Section 5.
2.4.1(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);	See section 6.4 and 6.8
2.4.1(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.	Public consultation was completed during 2018 / 2019 (see section 3.2)

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.	Any changes will be disclosed on 1 March 2019.
2.4.3	Every disclosure under clause 2.4.1 above must-	
2.4.3(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 determine prices for each consumer group;	Top Energy considers this document provides sufficient information on how prices have been set but will continually review for improvements.
2.4.3(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;	See Appendix 4 TEL considers our pricing is broadly consistent with the pricing principles but we also discuss how potential changes to our pricing methodology will align more closely with these principles.
2.4.3(3)	State the target revenue expected to be collected for the disclosure year to which the pricing methodology applies;	See section 5.
2.4.3(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;	See section 5.

2.4.3(5)	State the consumer groups for whom prices have been set, and describe- • the rationale for grouping consumers in this way; • the method and the criteria used by the EDB to allocate consumers to each of the consumer groups;	See Section 6.2.
2.4.3(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;	See section 2.3 and Appendix 5
2.4.3(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;	See tables in Section 7.
2.4.3(8)	State the proportion of target revenue (if applicable) that is collected through each price component as publicly disclosed under clause 2.4.18.	See tables in Section 7.
2.4.4	Every disclosure under clause 2.4.1 above must, if the EDB has a pricing strategy-	
2.4.4(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;	Our pricing strategy is discussed in section 4.2
2.4.4(2)	Explain how and why prices for each consumer group are expected to change as a result	See section 4.2
2.4.5	Every disclosure under clause 2.4.1 above must-	

2.4.5(1) (a), (b), (c)	Describe the approach to setting prices for non-standard contracts, including- • 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; • how the EDB determines whether to use a non-standard contract, including any criteria used; • 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 is consistent with the pricing principles;	See Section 6.4 and appendix 5
2.4.5(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- • the extent of the differences in the relevant terms between standard contracts and non-standard contracts; • any implications of this approach for determining prices for consumers subject to non-standard contracts;	See Section 6.4

2.4.5(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- • prices; and • value, structure and rationale for any payments to the owner of the distributed generation.	See Section 6.8
2.9.1	Where an EDB is required to publicly disclose any information under clause 2.4.1, clause 2.6.1 and sub-clauses 2.6.3(4) and 2.6.5(3), the EDB must at that time publicly disclose a certificate in the form set out in Schedule 17 in respect of that information, duly signed by 2 directors of the EDB.	Completed and attached as Appendix 1

Appendix 4 – EA Pricing Principles

Pricing principles	Extent to which pricing methodology is consistent with pricing principle
(a) Prices are to signal the economic costs of service provision by:	
(i) being subsidy free (equal to or greater than incremental costs, and less than or equal to standalone costs), except where subsidies arise from compliance with legislation and/or other regulation	We interpret 'incremental cost' as the additional cost of connecting a consumer, comprising connection costs, network upgrades, and incremental operating costs. Top Energy requires a capital contribution for new connections and asset upgrades if the expected line charge revenue from the connection is less than the associated incremental capital cost (i.e. an uneconomic connection). Accordingly, distribution prices will typically be in addition to incremental capital costs. Remaining incremental operating costs resulting from a new connection will be recovered through distribution prices. Over the last ten years a new connection has contributed approximately $300 per annum (real) to operating expenditure. An uncontrolled consumer (UN) would need to consume less than 1,020kWh in a year for prices to fall below this incremental cost (i.e. based on the 15 cents per day fixed charge and existing UN prices). This highlights that the application of the 15 cents per day low fixed charge creates cross-subsidisation at very low levels of consumption. Top Energy considers 'stand alone cost' means the cost for a consumer to disconnect from the distribution network and install onsite generation. Solutions do exist for small loads to disconnect from the network through installation of onsite solar generation and batteries. However, these systems are relative expensive when compared to

	distribution supply. For example, a 7kW solar system, 15kW battery system with diesel generator can cost more than $40,000 to install. We estimate this would cost $0.70/kWh over a 15-year period and the installation is funded by a mortgage. This is significantly more expensive than the average 41c/kWh charge Top Energy's consumers pay (source: MBIE quarterly survey of electricity prices, 15 November 2018). Nevertheless, the cost of installing these systems is falling rapidly and Top Energy will continue to keep a watch on this market and respond appropriately through pricing.
(ii) having regard, to the extent practicable, to the level of available service capacity	Top Energy's primary service is to provide capacity in the distribution network. We are currently considering the adoption of demand/capacity and TOU based prices for all consumers facilitated through smart meters. On 1 April 2019 a residential TOU trial will be implemented. This will align pricing more closely with the level of available service capacity. Nevertheless, current pricing structures do recognise available service capacity in the network as follows: • Consumer groups recognise different load sizes • Many network and transmission related costs are allocated to consumer groups in proportion to demand • Capital contributions help fund the uneconomic proportion of new investments in capacity • Consumption based prices provide a broad incentive to reduce consumption • Industrial sites (IND) are charged for specific asset usage and therefore the capacity these assets provide, and are apportioned transmission charges directly based on their contribution to RCPD • TOU/Advanced Metering and Day/Night prices structures encourage consumers to shift load outside peak usage periods

	• Controlled prices encourage consumers to offer up controllable load which Top Energy can use to manage congestion during interruptions to supply, when the network maybe constrained
(iii) signaling, to the extent practicable, the impact of additional usage on future investment costs	For the same reasons discussed above, Top Energy's pricing structures signal the cost of investing in additional network capacity. Top Energy's plans to move to demand/capacity or TOU pricing will improve these signals.
(b) Where prices based on 'efficient' incremental costs would under-recover allowed revenues, the shortfall should be made up by setting prices in a manner that has regard to consumers' demand responsiveness, to the extent practicable	This principle suggests that consumers with a higher willingness to pay should pay relatively more than consumers with a lower willingness to pay. Top Energy considers pricing based on willingness to pay should be linked to the level of service provided. This is a common pricing practice in many competitive markets. For instance, the UN24 and CN20 pricing options give consumers a choice over whether heating loads are interrupted. Consumers that are unwilling to have supply interrupted pay relatively more than a customer that is willing to accept a slightly lower level of service. Similarly, consumers on Day/Night and TOU pricing options that do not want to shift load to off peak periods pay more for using electricity at time that suits them.
(c) Provided that prices satisfy (a) above, prices should be responsive to the requirements and circumstances of stakeholders in order to:	
(i) discourage uneconomic bypass	Top Energy is not aware of any disconnections arising from uneconomic bypass of its network. Small scale DG (e.g. solar connections on houses) creates a risk of uneconomic bypass that is detrimental to Top Energy. However, as discussed, we consider it is currently uneconomic for a consumer to disconnect from the network in this manner.

	However, in many cases these connections demand power at peak times, however, contribute very little at non-peak times. Connections with small scale DG therefore contribute little to fixed costs of connecting them to the network. A move towards capacity/demand/TOU pricing and a higher proportion of fixed charges will address this issue. The latter has been introduced in this pricing year. Another potential area of uneconomic bypass is where large loads are situated close to a Transpower GXP and could bypass Top Energy's network to connect directly to the Grid. Only one large industrial load (based in Kaitaia) would be of a size sufficient to connect to Transpower's network. It would be uneconomic for this consumer to connect to the nearest GXP at Kaikohe which is 70km away.
(ii) allow for negotiation to better reflect the economic value of services and enable stakeholders to make price/quality trade-offs or non-standard arrangements for services	Capital contributions and non-standard contracts provide a mechanism where a consumer can request assets that provide a higher level of service. The costs of specific assets are either recovered upfront through a capital contribution or within pricing. Consumers can also request alternative pricing structures under non-standard contracts to address their own risks (e.g. IND prices are wholly fixed).
(iii) where network economics warrant, and to the extent practicable, encourage investment in transmission and distribution alternatives and technology innovation	Avoided transmission, Avoided distribution and voltage support charges may be payable to embedded generators of greater than 1MW output. This may help justify investments in local generation
(d) Development of prices should be transparent, promote price stability and certainty for	The pricing strategy explained in this document provides stakeholders with an overview of Top Energy's plans for prices over the next several years. We plan to continue to consult with consumers and retailers to seek their

stakeholders, and changes to prices should have regard to the impact to stakeholders	feedback on any changes which will be incorporated into any pricing decisions. Any changes will be transitioned over a reasonable period to avoid price shock to consumers.
(e) Development of prices should have regard to the impact of transaction costs on retailers, consumers and other stakeholders and should be economically equivalent across retailers	The same price structures apply to all retailers supplying consumers on Top Energy's network. We do not consider our pricing structures provide an advantage to any individual retailer. The new TOU trial time periods from 1 April 2019 are consistent with Top Energy's existing commercial TOU time periods. These were established after considering standard practices used by other distributors, consultation with other EDBs and retailers, and to minimise transaction costs for retailers with reference to peaks on Top Energy's network. Future pricing innovation will continue to reference to standard distribution sector pricing solutions developed in conjunction with the ENA. Transmission and distribution charges are bundled for all consumers except large industrials.

Appendix 5 - Network Line Charges 2019 – 2020

2019 / 20 Price Schedule

Effective from 1st April 2019. All prices exclude GST.

Consumer Group	Category Code	Price Code	Register Code	Description	Daily Fixed Charge ($/Day)	Total ($/kWh)	Distribution Discount Component	Capped Discount kWh
Residential								
	Low User (LR) No. of Users 14,456							
		LRF		LRF Daily Price	0.1500		0.1350	1kWh or greater
		LUC	UN24	LRF Uncontrolled		0.2719	0.1100	1,130
		LA	IN18	LRF All inclusive		0.2069	0.1100	
		LFC	CN20	LRF Controlled 20		0.0872	-	
		LD	D16	LRF Day		0.2429	0.1100	
		LN	N8	LRF Night		0.0829	-	
		DG	92	Exported Micro generation		-	-	
	Standard User (SR) No. of Users 12,087							
		SRF		SRF Daily Price	1.2000		0.1350	1kWh or greater
		SUC	UN24	SRF Uncontrolled		0.2241	0.1100	1,130
		SA	IN18	SRF All inclusive		0.1590	0.1100	
		SFC	CN20	SRF Controlled 20		0.0710	-	
		SD	D16	SRF Day		0.1914	0.1100	
		SN	N8	SRF Night		0.0710	-	
		DG	92	Exported Micro generation		-	-	
General								
	General User (G) No. of Users 5,208							
		GF		GRF Daily Price	1.2000		0.1350	1kWh or greater
		GUC	UN24	GRF Uncontrolled		0.2241	0.1100	1,130
		GA	IN18	GRF All inclusive		0.1590	0.1100	
		GFC	CN20	GRF Controlled 20		0.0710	-	
		GD	D16	GRF Day		0.1914	0.1100	
		GN	N8	GRF Night		0.0710	-	
		DG	92	Exported Micro generation		-	-	
	General Advanced User (GA) No. of Users 90							
		GAF	TOU or SM	GF Daily price on HHR	9.6170		0.5500	1kWh or greater
		G1	See note 1.4	GRF Peak		0.2032	0.0030	1,092,500
		G2	See note 1.4	GRF Shoulder		0.1381	0.0030	
		G3	See note 1.4	GRF Off peak		0.0710	-	
		DG	92	Exported Micro generation		-	-	
Larger Connections								
	Large User (TOU) $/Day No. of Users 64							
		TOUF	TOU or SM	TOUF Daily price on HHR (a capable meter and greater than 200,000 kwh/pa)	27.6159		0.5500	1kWh or greater
		TOU1	See note 1.4	TOU Peak		0.1650	0.0030	1,092,500
		TOU2	See note 1.4	TOU Shoulder		0.1121	0.0030	
		TOU3	See note 1.4	TOU Off peak		0.0085	-	
		DG	92	Exported Micro generation		-	-	
Unmetered (STL)								
	Closed 1.4.2016 for new connetions No. of users 2,519							
		UMLSH		Unmetered suppy consisting of Pedestrian Crossing, Streetlights, Bollards, Unmetered Lights with 1 lamp	0.5010		-	
		UMLDH		Unmetered supply consisting of 1 pole with 2 lamps	1.0031		-	
		UMLTH		Unmetered supply consisting of 1 pole with 3 lamps	1.5028		-	
		UMLSHLPMC		Unmetered supply consisting of 1 lamp mounted on a Top Energy Pole e.g. Pedestrian Crossing, Streetlights, Bollards	0.6180		-	
		UMDECL		Unmetered supply consisting of String lighting of Incandescent light bulbs	0.5010		-	
		UMGL		Unmetered supply consisting of Community Lighting, Convenience Lighting, Jetty Lights, Under Verandah Lighting	0.1679		-	
		UMCON500		Unmetered continuous supply less than 500 watts e.g. Battery Chargers, Electric Fences, Irrigation, PCM Cabinets, Phone Booths, Radio Repeaters, TV Boosters	0.4840		-	
		UMINT		Unmetered intermittent supply consisting of Fire Sirens, Railway Crossing Lights, Traffic Counters	0.2679		-	

Consumer Group	Category Code	Price Code	Register Code	Description	Daily Fixed Charge ($/Day/Lamp Equivalent)	($/kWh)		
New Unmetered (UM)								
	Open From 1.4.2016 No. of users 57							
		UMLF		UM streetlight (STL)	0.5010		-	
		UML		UM streetlight (STL)		-		
		UMGF		UM General connection (UM)	0.5010		-	
		UMG		UM General connection (UM)		-		
		NIL		Tsunami Warning Alarms	-		-	