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2 December 2021

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Submissions
Electricity Authority
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Wellington 6143

By email: TPM@ea.govt.nz

RE Consultation Paper – Proposed Transmission Pricing Methodology

Nova Energy (Nova) is making this submission on its own behalf as well as on behalf of its related company, Todd Generation Taranaki Limited, owner of the McKee Power Plant and Junction Road Power Plant, and as a part owner of the Whareroa co-generation plant.

Nova has around a 5% share of the electricity market by number of ICPs. Nova's retail business is supported by its portfolio of long-held co-generation assets, and more recently in its investments in gas fired peaking facilities at McKee and Junction Road. In addition to these generation assets, Nova supports its retail business through the purchase of electricity hedge contracts.

Nova is the owner of the largest co-generation portfolio in New Zealand that exports significant quantities of electricity to the Transpower Grid (Grid) in competition with the other generators such as Meridian Energy, Mercury, Contact Energy and Genesis. Although Nova's co-generation plants compete with other generators, there are significant differences between co-generation and other forms of electricity generation generally as well as between co-generation and embedded generation (see the characteristics of Nova's co-generation plants in Appendix A and the affidavits attached in Appendix C).

Given the comparatively small size of its retail electricity business compared to the major gentailers, Nova is sensitive to increases in unavoidable costs that cannot be recovered from the market including its customers. For a small gentailer like Nova, the costs under the TPM are inconsistent with the benefits that it gains from the Grid. The issues most directly impacting Nova are the way in which the residual charge is allocated to gross load, and the methodology being used to determine allocation of the benefit-based charge (BBC). The Authority's decisions with respect to the TPM benefits large gentailers at the expense of smaller players and this does not promote competition, one of the limbs of the Authority's statutory objectives.

By grossing up for "load" directly supplied by a co-generation plant to its industrial customer, the draft TPM proposes to impose charges for services that will never be rendered by the Grid. The "load" can only exist when the co-generation plant is producing steam. If the co-generation plant is not operating (i.e. producing steam and electricity) the load will not exist because of the independencies of the steam and electricity use within the customer's industrial manufacturing process. This distinguishes co-generation from ordinary embedded generation - a distinction apparently not appreciated by the Authority (see Appendices A and C for an explanation of Nova's co-generation plants).

Nova expects that as new wind farms and Grid scale solar PV projects are developed, electricity spot prices are going to become more variable with lower daytime prices and higher evening peak prices on average. As the market moves to greater renewable generation with lower marginal costs, the economics of operating the Whareroa co-generation plant as a base-load supplier of steam and electricity becomes more challenging. As a result, at some stage the co-generation plant servicing the Whareroa dairy factory will need to be substantially reconfigured. Adding an additional $1m p.a. cost[1] to Whareroa will bring forward the timing of such a decision.

This will have a major impact on the financial return of operating that co-generation plant. Nova detailed the effect of the grossing up of the residual charges on the Whareroa Joint Venture (which owns the Whareroa co-generation plant) in the affidavit of Charles Teichert[2] in the recent judicial review case brought by Trustpower, Nova and others against the Authority. For completeness and transparency, we **attach** (in Appendix C) that affidavit as well as the two affidavits of Babu Bahirathan to this submission (noting that the content of the affidavits reflect the TPM proposal at that time). Nova's comments contained in the affidavit are incorporated, and form part of, this submission, to the extent applicable.

With high gas and carbon emissions costs, the variable cost of running the peaker plants now exceeds the expected long run cost of new wind farms and Grid scale solar PV. As such, the expected levels of generation and gross profit margin are highly sensitive to model assumptions and in particular the expected balance between supply and demand. As for the co-generation plant, growth in wind and solar generation will likely result in the peakers running for considerably fewer hours than they have in the past. The TPM BBC is to be allocated entirely on the basis of modelling assumptions rather than being tied to actual generation output. The BBC, being a fixed charge, will add significantly to the uncertainty of net earnings from these power stations. As such, the higher costs and earnings volatility will lift the return required before Nova invests in any new generation at its fully consented site at Otorohanga and will also affect investment decisions when significant refurbishment maintenance is required on existing facilities. The impact of the new BBC is further aggravated by Transpower's proposal to split the costs of investments that are less than $20m equally between generation and load, when it is readily apparent that generators gain very little additional benefit from improvements in Grid reliability – noting also that Transpower's performance is measured by lost system minutes at demand Grid points and not loss of generation injection into the Grid!

Given the above issues, the review in five years of the assumptions underlying the TPM charges will potentially be quite significant for Nova, but it is unlikely to provide confidence that its costs will be reduced or may simply be too late.

Please note that aspects of the affidavit of Charles Teichert is commercially sensitive and therefor confidential. We have also **attached** a redacted version of that affidavit which can be published.

Yours sincerely

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Commercial & Regulatory Manager
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[1] Approximate only, based on the assumption that 1/3rd of the residual charge allocated remains because of the load that relies on the Grid when the co-generation plant is not operating.
[2] See paragraphs 27 and 28 of Charles Teichert's affidavit (marked commercially sensitive).

Nova submission

Consultation Paper: Inefficient price discrimination in the wholesale market – issues and options

Q No.	Question	Response
Chapter 4 Connection charges		
P23	Do you agree that the proposed TPM should specify that connection asset replacement values be regularly updated to promote cost-reflective charges and certainty?	Yes, Nova continues to support that as it should help avoid imbalances between customers. The TPM building blocks should also be updated to reflect changes in the Grid build standards. For example, Transpower now promotes and utilises disconnecting circuit breakers (DCBs) in the construction of switchyards and substations to avoid the need for isolating disconnectors to be employed each side of a traditional Disconnector - Circuit Breaker – Disconnector asset configuration. DCBs materially reduce the build infrastructure required and significantly reduce O&M costs over the life of the asset, compared with the legacy DIS-CB-DIS design standard. Though Transpower have not created a revised TPM building block for the DCB standard design configuration with the result that customers receive no benefit from a proportionate cost-reduction in transmission charges (e.g. connection charges) where the more cost-efficient DCBs have been employed. Nova estimates the current TPM building blocks used to represent DCBs overstates the value of actual assets employed by around 45%, translating to an approximate 25% over-recovery via current connection charges levied for a simple generator Grid connection.
Chapter 5 Benefit based charges: allocation		
P35	Do you have comments on the proposed standard and simple benefit-based allocation methods?	Nova agrees that the seven major investments specified in Schedule 1 of the Guidelines should be included in the benefit-based charge (BBC) calculation.

Q No.	Question	Response
	Do you have any comment or evidence on the proposed weighting of benefits between load and generation customers under the simple method, or the proposed review of the allocation?	The Authority's own evidence[3] points to a split of 75:25 load to generation being a more accurate reflection of the benefits accruing from 'low value' Grid upgrades. Nova appreciates the level of analysis provided, and as such is surprised that the 50:50 split is even being considered. Transpower 50:50 split is based on its analysis as set out in its "TPM Reasons Proposal" dated 30 June 2021 (in section 16.4) and its calculations of aggregate load vs aggregate generation volumes. In Nova's view: a) load is the primary beneficiary of the n-1 security standard. b) a high proportion of low value investments are associated with improving power quality and Grid reliability rather than capacity upgrades. Load is the primary beneficiary of such investments and therefore an equal allocation between load and generation cannot be an equitable or efficient allocation. These points are expanded further below. Nova also notes that the TPM is to be reviewed after five years. This is proposed in acknowledgement that if the 50:50 split is wrong, it can be corrected in five years' time. Even if the aggregate market impact of such an approach is not exceptionally large in the context of the overall expected benefits, it will have an impact on generation investment decisions in the meantime. It will also add a significant cost to the interconnection charges incurred by Todd Generation over that period. The difference between a 50% allocation and 25% allocation has an impact of $0.6m on the valuation of the power stations at McKee and Junction Road[4]. Nova asserts that the Authority must reject Transpower's proposed 50:50 split and recommend that a greater weighting must be given to load when applying the simple method to the BBC. **Impact of n-1 security requirement** In March 2020[5] Transpower provided the Security and Reliability Council with an outline to its approach to the Value of Lost Load (VoLL) when making investment

[3] 46. 24 May 2021 - Letter from EA (Transpower TPM Checkpoint 2B resubmission Appendix A-D).pdf
[4] Based on a discount rate of 7% p.a. over 5 years.
[5] https://www.ea.govt.nz/assets/dms-assets/27/2700612-Understanding-the-Value-of-Electricity-to-Consumers-Appendix-Combined.pdf

Q No.	Question	Response
		decisions. This illustrates in a very practical sense that the risk of non-supply relates to load and not generation. Transpower's proposed 50:50 split is inconsistent with this and implies that consumers and generators have the same benefit in the reliability and security of supply of the Grid, i.e. that under a straight commercial arrangement both parties would seek the same level of redundancy. This is not true. From the generators' perspective, a single circuit or N reliability Grid connection provides adequate security for the generator to inject electricity produced into the Grid. For example, both the McKee and Junction Road peaking facilities are constructed on the basis of a simple T-connection to a single Grid transmission circuit. The generation revenue lost from not being dispatched on the occasions that the circuit is disconnected did not justify the material additional capital investment required in building a full N-1 reliability connection, particularly as the plant is only expected to run around 30% of the time over the long run. The Code specifies a value for 'expected unserved energy' (or more commonly referred to as the value of lost load or VoLL) of \$20,000/MWh that is also stipulated to be applied under the Grid investment test and Capex IM in determining the net electricity market benefit required to support a Grid investment. Under the principle of n-1, the core Grid is built with roughly twice the capacity of that otherwise required to supply demand on N security criteria. We can value the relative benefits to generators and consumers of n-1 security by considering the impact of a loss of connection: • take a single circuit with generation 'G' supplying demand 'dd'. • under the principle of n-1 security, this simple model must include a second circuit between 'G' and 'dd'. • the benefit arising from the second circuit is directly related to the cost to each party of a loss of Grid connection: o the potential economic cost to G is the lost revenue, say \$100 /MWh per trading period. o the potential economic cost to dd is the VoLL, i.e. \$20,000 /MWh per trading period • given this relationship, the benefit of the second circuit providing n-1 security is in the ratio of \$100/\$20,000 G to dd; i.e. 0.5% to generation and 99.5% to demand. (The probability of an outage event being equal for both parties.)

Q No.	Question	Response
		Given this ratio and noting that that power flows only ever use up to 25% of the total Grid capacity, it is reasonable that at a minimum, the benefits should reflect a ratio of 1 circuit for generation, 2 circuits for demand, giving a ratio of 1:2, or 33%:67%. This result is consistent with the Authority's own findings in Appendix B in the Annex to the Authority's resubmission feedback letter[6]. A benefits allocation based on an even weighting between generation and load discriminates against generation if the cost-justification for the investment is based (in part) on the VoLL and the level of reliability provided by the investment exceeds that required by generation. The Grid investment test, CAPEX IM and supporting Integrated Transmission Plan all have a heavy bias towards the additional Grid reliability required by the demand-side, with ~82% of Grid points of service being provided N-1 security and Transpower's Grid performance measures and incentive revenue similarly demand centric[7]. An even benefits weighting does not reflect this materially uneven cost weighting on which the Grid is built. An example of a low value investment in the Taranaki region where there is negligible benefit to generation is included in Appendix B.
Chapter 6 Benefit based charges: covered costs		
P41	Do you have any comment on the proposed approach to covered costs, including on: • Whether overhead opex should be recovered through the BBC or residual charge, and any evidence to support your view? • The recovery of opex on fully depreciated assets through the residual charge?	In Nova's view this policy should rest on two key points: • Transpower's primary role is to provide continuity of electricity supply to consumers. • depreciated assets perform the same role in the network as new assets. Therefore a pro-rata allocation of overhead opex should be based on historical cost rather than depreciated value. Allocating 50% of overheads to generation via the BBC simple method is not appropriate. As stated in the discussion above on the allocation of costs using the 'simple method', the benefits of a reliable electricity transmission system are considerably less significant to generators than they are to consumers.

[6] 46. 24 May 2021 - Letter from EA (Transpower TPM Checkpoint 2B resubmission Appendix A-D).pdf
[7] ITP Grid Outputs Report 2021, Tables 3, 4 and 7

Q No.	Question	Response
		Adding additional fixed costs to generation, and in particular generation that has a stand-by role only, will have a marginal but still real impact on decisions relating to new investment in such plant. It is appropriate to recover overhead opex through the residual charge.
Chapter 7 Residual charges		
P64	Do you have any comment on how the proposed TPM implements the residual charge provided for in the Guidelines?	Nova considers that any formula that charges a directly connected co-generator an interconnection charge based on a load that is not and cannot be supplied by the Grid is contrary to the statutory objective of the Authority. By grossing up for "load" directly supplied by a co-generation plant to its industrial customer the TPM imposes charges for services that will never be rendered by the Grid. The "load" can only exist when the co-generation plant is producing steam. If the co-generation plant is not operating (i.e. not producing steam and electricity) the load does not exist. This distinguishes co-generation from ordinary embedded generation (see details in Appendix A) The problem could be overcome by deleting the last sentence of paragraph 5(1)(b) and replacing with the following: <u>For the purposes of this paragraph 5(1)(b),</u> the **embedded electricity** is referred to as the **supplying load customer's embedded electricity** "at" POC and the relevant **connection location** for the **trading period** <u>but excludes dependent load.</u> "Dependent load" is defined below. Please also refer to the note for Chapter 12 below.
	Do you agree with the application of the residual charge to generation with embedded load, or can you suggest a better way to mitigate charge avoidance incentives and risk of an uneven playing field?	In Nova's view, the residual charge provisions: • should be applied to load that is reliant on the Grid in absence of any embedded generation running and is not physically linked and dependent on the operation of the generating plant. Transpower should be able to estimate load based on reconciliation data to determine the gross load that would be present in the absence of embedded generation. • should ignore any load that can only exist when the generating plant is operating and is physically connected to the generating plant, such as the

Q No.	Question	Response
		parasitic load that occurs with running generation plant, or load that cannot exist in the absence steam being supplied from a co-generation plant (noting that such an exclusion should not apply to load incurred in starting up generation as that would require Grid support in most cases.) Such load could be defined as '**dependent load**' for the purposes of the TPM, i.e.: '**dependent load'** is load that: (a) can only exist when steam or other by-products of generating **electricity** being is supplied to a co-located **industrial process** directly from an **industrial co-generating station;** and (b) does not exist if the industrial co-generating plant is not operating; and (c) does not consume any **electricity** from the Grid. Given the potential difficulties for Transpower to identify "dependent load" this could be quantified and treated in a similar manner to the prudent discount policy, i.e. the applicant could be required to provide evidence of the relationship and data to enable Transpower to quantify the appropriate basis for the residual charge. For the avoidance of doubt, Nova does not object to residual charges being imposed on any residual electricity demand or load that exist when the generating plant is not operating which will need to be drawn from the Grid.
	Do you have any comment on the proposed approach to application of the residual charge to battery storage to avoid double-counting of load?	The proposed approach for batteries is consistent with the approach proposed for allocation of the residual charge above. In the case of batteries, if discharging the battery is equated with generation, then the load (charging) equivalent to the discharge quantity should be excluded for the purpose of the residual charge. In this way, the relationship between BESS and generation (embedded or otherwise) is kept neutral. Generators should be expected to pay for load that occurs when they are not generating, but not for electricity consumed in the process of generating electricity. Given that generators will pay the BBC on their output it seems paradoxical to simultaneously be expected to pay a residual charge on electricity consumed.
Chapter 8 Adjustments		

Q No.	Question	Response
P76	Do you agree with or have any other feedback on the proposed provisions for adjusting transmission charges?	
	• The plant disconnection provision should extend to plant de-rating	Yes. In the absence of this provision a marginally profitable operation could be disconnected early just to reduce ongoing transmission costs.
	• The relevant provision should be further extended to cover a substantial sustained decrease in Grid use not related to a plant disconnection or de-rating.	Yes. While it is harder for Transpower to form a view, market participants should have the opportunity to present to Transpower their justification for a lower charge as would be the case for a prudent discount arrangement. Transpower could include a claw-back provision should any claims by the applicant be proven to be inaccurate.
	• The proposed 'related entity' provisions' deal appropriately with avoidance concerns, and whether there is a case for a broader or more general related party provision to deal with other, potentially unforeseen avoidance opportunities.	
	• The residual charge for new entrant and an expanding customer should adjust with a lag and a gradual ramp-up as proposed	Yes, there needs to be an equivalence to minimise incentives for avoidance tactics. The sums involved for some parties are likely to be significant enough for them to seek alternative structures to avoid the immediate impost of the residual charge if they can.
	• The proposed TPM should include a specific provision for the adjustment of the residual charge of a large customer that close a plant (either to allow its adjustment immediately or in some other way), or should the standard lagged adjustment of the residual charge apply? If the former, should the provision be extended to deratings? If the latter, should it apply to embedded parties, and should there be any related entity provision?	In a commercial environment with counterparties on an equal footing, it is relatively common for long-term supply contracts to provide for the consumer to pay a termination fee payable in event it wishes to terminate the contract prior to the contract expiry. The early termination fee relates to parties' earning an economic return over the term of the contract. In this case however, Transpower's assets generally already exist prior to the commencement of the service, and the consumer has little influence in terms of the service being provided. The residual charge should therefore reduce if the connected party derates its plant. If the charges are to only reduce with a lagged adjustment, the consumer may well bring forward the derating or closure its plant prematurely in order to reduce the impact of the ongoing residual charge. That would not be economically efficient given that the allocation of the residual charge has no impact on Transpower's operating costs.

Q No.	Question	Response
Chapter 9 Prudent discounts (PD)		
P84	Do you have any comments on the proposed PDP provisions? The Authority welcomes comment on any aspect of the proposal, including whether:	
	• The proposed TPM adequately prescribes the fundamental aspects of the PDP?	
	• Transpower should have to prepare a PD practise manual, and if so, when, and should it be binding on Transpower	Transpower should be required to prepare a PD practise manual, even if it is at a reasonably high level in the first instance[8]. The preparation of the manual should also be subject to consultation which would help ensure it provides a useful purpose. The manual will help inform parties as to the level of detail expected in applications and should be updated following the processing of initial applications in order to better inform potential applicants.
	• 15 years should be the default maximum period with a longer term possible on proof	That term appears reasonable as it is a length of time that might be considered in evaluating the expected financial return from an investment in capital.
	• Prudent discounts should be funded via the residual charge and as appropriate the BBC.	Yes
	• Customers should be able to terminate a prudent discount agreement before the end date of the agreement?	Yes. Transpower's reasoning for the customer not having the right to terminate the agreement is weak. If the customer requires a comparatively small investment to by-pass the Grid, then it could just as easily reverse such an investment. As such, the PD agreement should equally be reversable. And if the investment required would have been very significant, then the presumption is that the level of discount would be commensurately smaller in any case. In such cases terminating the agreement would be unlikely to have an excessive impact.
Chapter 12 Indicative prices		

[8] Consistent with the processes described by Transpower under s2.2 of TPM Development Checkpoint 2 submission: Prudent Discount Policy

<table>
<tr><th>Q No.</th><th>Question</th><th>Response</th></tr>
<tr><td>P106</td><td>Do you have any comments on indicative pricing or the application of the transitional cap?</td><td> It appears that intermingled loads such as the co-generation “load” at Whareroa, are intended to be able to access the price cap.[9] Nova supports that approach although it considers that the effect is largely illusory once the inflation adjustment is made, i.e. from the base-line of 2019 and current inflation, the cap is expected to have a negligible effect by pricing year 2023/24.
Applying the formula and estimating the charges, if inflation averages 3% p.a. over 2019 – 2023, then the cap will provide zero benefit to Whareroa.
The impact on the customer’s energy costs is large and the cap should be amended to reflect the impact of the higher-than-expected inflation rate in addition to the increase in real costs. This can be achieved simply by indexing the cap from a 2021 base price rather than 2019.
Furthermore, Nova considers that under the current drafting, the price cap does not assist co-generators such as Nova. Even if interpreted by Transpower as doing so, it would be open to challenge by a customer dissatisfied with the extra cost burden. In particular, neither Nova nor its directly connected co-generation assets are (to use terms referred to in clause 114(2)):

a “distributor”. This term is defined in the Act to mean “a business engaged in distribution” i.e. lines company; or
“direct consumer”. This term is defined in the Code by reference to the term “consumer” which, in relation to a generator, applies only if “the generator” is supplied with electricity for its own consumption”. A co-generator supplies electricity for consumption by others.

The failure to accommodate its position here undermines the definition of “capped consumer”.
The problem could be overcome by inserting in sub-paragraph 114(2)(b) after “if the capped customer is a direct consumer” the words
“Including an industrial co-generating station”. </td></tr>
</table>

[9] See Transpower’s “TPM Proposal Reasons Paper” 30 June 2021 at paragraph 18 on page 12.8, specifically adopted by the Authority at paragraph 12.35 of its 8 October 2021 Consultation Paper

Q No.	Question	Response
Chapter 14 Regulatory statement		
P117	Do you have any comments on the regulatory statement or the assessment of wider factors?	The TPM largely meets its objectives, but it fails to be technology agnostic by penalising the co-generation of electricity and steam together. Cogeneration plants are optimised to meet a plant's steam requirements at minimal cost by co-producing electricity. Where that electricity is directly competitive with Grid supplied electricity there is a case for capturing it in the TPM pricing. However, where the consumption of electricity is directly tied to the use of the steam (in the sense that where there is no steam supplied by the co-generator, there will be no load and the plant will not run), the load is totally independent from and places no burden on, the Grid and therefore the residual charge should not be imposed. Putting aside the impact of rising CO_2 emissions costs on thermal generation, the additional charge will have a significant impact on the future economics of co-generation plants. Nova considers that this conflicts with section 32(1)(c) of the Act.
Chapter 15 Next steps		
P121	Do you agree that 1 April 2023 is an appropriate commencement date for the proposed TPM?	
	Do you agree with the proposed transitional measure for any standard method investments for which allocation is not completed?	Allowing for a delay in calculating the BBC for Grid investments still in the process of completion after July 2019 is acceptable so long as the charges are washed up in arrears once the more accurate BBCs have been determined. Nova would not favour the 'simple method' based charges being locked-in for 2023/24, particularly if the 50:50 split between generation and load is retained.
Appendix: Proposed TPM		
	Do you have any feedback that would improve the drafting of the proposed TPM?	Nova has provided some suggested drafting in the body of this submission.

APPENDIX A

ROLE OF CO-GENERATION

1 Co-generation has a unique role in the electricity industry that neatly promotes every limb of the Authority's statutory objective.

2 As such it should be encouraged rather than penalised.

3 Unfortunately, the grossing up of the residual charge penalises co-generation by charging it for a service it does not need and cannot use.

4 This is also a charge that is not borne by other generators.

5 This is likely to lead to pre-mature closure to the detriment of competition, reliability of supply and efficiency in the electricity industry.

6 The special characteristics of co-generation include:

a) the co-generation plant is built to service a particular industrial need. It does so in an efficient manner as it utilises a by-product needed by the industrial plant.

b) in Nova's case it provides steam. That is, the plants are specifically designed to provide steam for the related industrial use. This determines the size of the industrial plant.

c) because the steam is essential for the industrial process, the industrial process cannot operate unless the co-generation plant is operating and supplying steam and electricity.

d) this means that, other than a small amount of electricity for support services needs, the electricity supplied to the industrial plant will never create a demand on the Grid. The industrial process cannot operate without the steam and therefore does not require or consume electricity.

e) because the steam need is greater than the related electricity needs, the co-generation plant exports the surplus electricity into the Grid.

f) this means that, when the industrial plant is operating, the co-generation plant is actually exporting electricity in competition with other generators. There is no "load". Yet the grossing up of the residual charge creates a fictional load for which the generator is charged.

g) because the co-generation plant has been built to service the industrial load it is located immediately adjacent to the load it serves. This avoids line losses.

h) this does have the downside that, unlike other generation sites which are located close to their "fuel" (head of water, wind, geothermal field, gas field), it does have to pay for the transport of its fuel to its site.

7 The advantages of co-generation include:

a) efficient operation in that it makes very efficient use of its fuel by using the by product;

b) efficient operation as it avoids line losses;

c) reliability of supply as it is an additional source of supply and as it provides cover against outages on the Grid; and

d) extra competition;

e) being closely related to the dairy season it exports most electricity in the winter when dairy processing (and associated electrical load) is non-existent or minimal.

8 All this is to the long-term benefit of consumers.

9 Imposing the grossed up residual charge on co-generation plants that are directly connected to the industrial load is unfair as it is imposing a charge for a service it does not need and cannot use. It is also a charge that other generators do not bear. It is a double whammy as it charges for transport of electricity not actually used or required but fails to recognise that, instead of transporting that electricity, the co-generation plant has to pay for the transport of its fuel. This double whammy puts it at a disadvantage compared with other generators.

10 The extra charge is significant. This means that at some stage it will lead to the co-generation plant becoming economically uncompetitive and lead to its premature exit from the industry.

11 For example, the indicative (uncapped) residual charge for Whareroa Co-generation would increase the delivered electricity price to the dependent load customer (dairy factory) by approximately $10/MWh, materially eroding the transmission-alternative security and reliability benefits provided by the co-located generation plant and further threatening its viability under an increasing carbon cost.grid

12 The premature market exit of co-generation plant would add a significant step-increase in actual observable Grid demand, while also removing a significant volume of net-export generation from the market base-load merit order, eroding the consumer surplus.

Appendix B

Examples of listed Transpower project impacting Nova

Nova's gas fired peaking generation assets are connected to the "Central North Island low voltage network" (CNI_LV). Based on figures provided by Transpower, under the proposed TPM the Nova is expected to pay 14% of the covered cost of that part of the Grid.

(The extracts below are from the Transpower website – highlights by Nova)

1 North Taranaki Regional Supply Project[10]

a) 'We have several projects planned or underway in the Taranaki region to improve supply there. These include:

- decommissioning and removing our equipment from the existing New Plymouth substation (at Port Taranaki);
- constructing new 33 kV indoor switchgear at Carrington Street substation, enabling the connection of new 33 kV underground cables (owned by Powerco and connecting to their Moturoa zone substation);
- installing a new 220 kV/110 kV interconnecting transformer at Stratford substation and converting the existing 220 kV New Plymouth to Stratford transmission line to 110 kV operation.

b) Why we're doing it

The New Plymouth substation connects the Taranaki regional 110 kV network to the national grid via one 220/110 kV interconnecting transformer which provides approximately half of the supply to the Taranaki area. We are vacating this site as it is now required by Port Taranaki for its own purposes, and we have (together with Powerco) determined a suitable option (underground cabling from our Carrington Street substation to Powerco's Moturoa zone substation) to ensure supply is not at risk for consumers. Connecting the two lines servicing the Port together helps provide needed support to the one substation (Carrington St) that will be left supplying New Plymouth.'

2 Brunswick to Stratford Capacity Investigation[11]

c) This is a higher value project that will be covered by the more comprehensive method of determining the BBC than the allocation under the 'simple method'.

d) 'Transpower is carrying out an investigation into the capacity requirements between our Brunswick and Stratford substations in Taranaki. Depending on outcome, this may result in a major capex proposal to the Commerce Commission to replace conductor, remove or build a new line.

e) Why we're doing it

Two 220 kV lines, carrying three circuits in total connect our Brunswick and Stratford substations presently. Future likely maintenance costs for the older and smaller of these lines is bringing into question what future configuration would best suit New Zealand given future demand from the region.'

[10] North Taranaki Regional Supply Project | Transpower
[11] Brunswick to Stratford Capacity Investigation | Transpower

3 Southern Waikato Regional Network Investigation[12]

f) The impact on Nova of low value investments outside the CNI_LV network are small, but this illustrates the focus on load requirements in most of the planning.

g) ‘Transpower is commencing work to identify the need for investment on the southern Waikato 110 kV network (roughly between Hangatiki and Hamilton).

h) Why we're doing it

The southern Waikato 110 kV network is becoming more and more constrained due to the complex interplay between this and connecting regions and generation.

The nature of load growth in the region will make any future investments for either electricity distribution businesses or ourselves very challenging. However, as a prudent grid operator we need to work with our stakeholders on the need and possible options.’

[12] https://www.transpower.co.nz/southern-waikato-regional-network-investigation

APPENDIX C

AFFIDAVITS OF BABU BAHIRATHAN AND CHARLES TEICHERT

(see attached)

IN THE HIGH COURT OF NEW ZEALAND
WELLINGTON REGISTRY **CIV-2020-485-367**
I TE KOTI MATUA O AOTEAROA
TE WHANGANUI-Ā-TARA ROHE

UNDER	the Judicial Review Procedure Act 2016
IN THE MATTER OF	Judicial review of the proposed new Transmission Pricing Methodology
BETWEEN	**TRUSTPOWER LIMITED** Applicant
AND	**ELECTRICITY AUTHORITY and MERIDIAN ENERGY LIMITED** Respondents
AND	**NOVA ENERGY LIMITED and others** Interested Parties
AND	**TRANSPOWER NEW ZEALAND LIMITED** Intervenor

AFFIDAVIT OF CHARLES TEICHERT ON BEHALF OF NOVA ENERGY LIMITED 23 APRIL 2021

REDACTED

Solicitor:	Counsel:
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I, **Charles Allister Teichert** of Wellington, Manager, say:

A Background

1 My current role is General Manager Commercial and Strategy for the Downstream Energy Division at The Todd Corporation Limited ("**Todd**"). The Downstream Energy Division includes Nova Energy Limited ("**Nova**") and Todd Generation Limited ("**TGL**") which are both wholly-owned subsidiaries of Todd.

2 I have held various positions with Todd since joining the company in October 2000.

3 I started with Todd as an Energy Analyst with responsibilities for electricity spot trading, clearing and settlement and risk management. As Todd grew its electricity business, my role changed to take on additional responsibilities with respect gas trading activities, regulatory responsibilities and commercial negotiations and relationship management.

4 I have a degree in Accounting and Information Systems and was a member of the Society for Chartered Accountants (now retired as of approximately 2004/5).

5 Prior to joining Todd, after an initial career as a Chartered Accountant for Deloitte Touche, I joined Electricity Corporation of New Zealand in 1996 as a spot market trader until ECNZ was restructured in 1999.

6 My responsibilities within Todd that are relevant to this matter include:

a) Todd's wholesale electricity trading activities;

b) management and representation of Todd's interests in its cogeneration investments at Whareroa, Kapuni and Edgecumbe; and

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c) electricity industry regulatory affairs and consultation processes including the current and proposed Transmission Pricing Methodology change process.

7 By virtue of my role within Todd, I have personal knowledge of:

a) the Transmission Pricing Methodology process and the impacts it will have on market participants since its commencement;

b) transmission pricing matters prior to the commencement of the Transmission Pricing Methodology process; and

c) more generally, the Commerce Act Part 4 regime as it applies to gas and electricity line companies and Todd's participation in that regulatory process.

8 In the course of this affidavit, I will refer to:

a) a number of documents not already in the record. These are part of **Exhibit CT-A** to this affidavit. A reference to a Document by number is a reference to that Document in Exhibit CT-A; and

b) Todd and Nova interchangeability as they are related parties.

B Submission process

9 In relation to my responsibility for electricity industry regulatory matters for Todd, I wish to say that we have participated in the Transmission Pricing Methodology consultation process in an open and constructive manner for a good part of a decade.

10 From the outset of the Transmission Pricing Methodology review Todd has been sceptical of whether the Electricity Authority could devise a totally new pricing methodology that would provide sufficient benefit to consumers to be worth the effort given the market disruption and the winners and losers that is creates. At a fundamental level, it is Todd's view that the decision by the Electricity Authority to substantially move away

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from the current pricing methodology is a mistake and that it would have been better to take an incremental improvement approach to allocation of cost issues such as through a tilted postage stamp approach to cost recovery.

11 It is notable that despite the very extensive processes undertaken by the Authority, it has only arrived at a solution that allocates approximately 30% of Transpower interconnection charges on the basis of beneficiary pays, and the remainder is allocated in the manner of a tax (the Residual Charge that I am addressing in the affidavit). Despite these views, Todd has focussed its submissions on providing constructive feedback on the wide range of proposals put forward by the Authority in an attempt to get the best possible outcome rather than continue to relitigate past decisions. This will be apparent in the submissions listed below.

12 The written submissions we made, both in relation to the Transmission Pricing Methodology itself and related topics such as the avoided cost of transmission payment for distributed generation ("**ACOT**") are:

a) Nova's submission: 'Transmission Pricing Methodology' on 1 March 2013;[1]

b) Nova's response to unanswered questions: 'Transmission Pricing Methodology – response to questions' 24 June 2013;[2]

c) Nova's submission: 'Consultation Paper—Draft decision on exemption application – classification of NAaN assets under the TPM' on 30 September 2013 ("**Document CT1**");

d) Nova's submission: 'Working Paper – Transmission Pricing Methodology: Avoided cost of transmission payments for distributed generation' on 31 January 2014;[3]

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[1] EA record 213.05887 **[CB]**.
[2] EA record 216.07394 **[CB]**.
[3] EA record 218.08250 **[CB]**.

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e) Nova's submission: 'Consultation Paper – Use of LCE to offset transmission charges' on 4 March 2014;[4]

f) Nova's submission: 'Working Paper – TPM review: Beneficiaries-pay options' on 25 March 2014;[5]

g) Nova's submission: 'Transmission Pricing Methodology: Connection charges' 24 June 2014;[6]

h) Nova's submission: 'TPM Review – LRMC charges' on 23 September 2014;[7]

i) Nova's submission: 'Working Paper – TPM Options' on 11 August 2015;[8]

j) Nova's submission: 'Consultation Paper – Review of distributed generation pricing principles' on 26 July 2016 ("**Document CT2**");

k) Nova's submission: '2nd Issues Paper – TPM: Issues and proposal' on 26 July 2016;[9]

l) Nova's submission: 'TPM 2nd Issues Paper – supplementary consultation' 24 February 2017;[10] and

m) Nova's submission: 'Consultation Paper – Transmission pricing review' 1 October 2019.[11]

Paul Baker, who reports to me, prepared and submitted these on behalf of Nova with my oversight, review and assistance.

13 Often the time allowed for a response to what were very complex issues was very limited.

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[4] EA record 220.09208 **[CB]**.
[5] EA record 219.08950 **[CB]**.
[6] EA record 20.09437 **[CB]**.
[7] EA record 221.09598 **[CB]**.
[8] EA record 224.11051 **[CB]**.
[9] EA record 228.12856 **[CB]**.
[10] EA record 233.15139 **[CB]**.
[11] EA record 237.17362 **[CB]**.

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14 Over the last 10 years, the Transmission Pricing Methodology regulatory process has evolved from a high level analysis of options and alternatives to more specific and detailed analysis of the Electricity Authority's proposed option.

C The introduction of gross load

15 The Electricity Authority's position until 17 May 2016[12] was that the Residual Charges would be on a net load, not gross load, basis.

16 The possibility of a change in the Electricity Authority's position was first signalled in the 'Transmission Pricing Methodology: Second Issues Paper 17 May 2016.'[13] It was one of three possible alternative bases noting that the descriptions of those alternatives at the time was conceptual in nature with little specific detail as to how it might apply and what the financial implications might be. Nova submitted supporting at a conceptual level a residual charge for the recovery of overhead type costs but did not support moving away from a net demand basis for calculation purposes.

17 By the time of the 'Transmission Pricing Methodology: Second Issues Paper Supplementary Consultation 13 December 2016'[14] the Electricity Authority had dropped the other two alternative methods of allocating the Residual Charge in favour of Anytime Maximum Demand. There was some discussion as to whether that should be grossed up for distributed generation and demand response but that issue still appeared to be a matter for future decision. In Nova's view, the use of gross load would be a fundamental change. Nova submitted against it in its submission dated 24 February 2017.[15]

18 Post that consultation, the Electricity Authority had to address concerns over the Cost Benefit Analysis that it had conducted in support of the proposed TPM. The next substantive piece of work came out in July 2019 with the 'Consultation paper: Transmission pricing methodology: 2019

[12] EA record 01.0973 [CB].
[13] EA record 226.11692 [CB].
[14] EA record 230.13910 [CB].
[15] EA record 233.15139 [CB].

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issues paper'.[16] The question of net versus gross was again raised in the paper (paragraphs B210 – B.214).[17] We again submitted against that in our submission dated 1 October 2019[18].

19 We also considered that the Electricity Authority's justification for charging on the basis of gross load in that size equates to ability to pay is also wrong. This justification is not based on sound analysis or evidence specifically as it relates to cogeneration facilities. This is a significant point for us.

D Reasons given for the Residual Charge - introduction

20 The Electricity Authority discussed the reasons for its decision on the Residual Charge at Part 10 of its 'Transmission Pricing Methodology 2020 Guidelines and process for development of a proposed Transmission Pricing Methodology – Decision 10 June 2020' (**"the Decision"**).[19]

E Load customers not generators pay the Residual Charges and the impact of this

21 The Authority suggests that it is only load customers, and not generators who pay the Residual Charge. This, in this description, at least as far as cogeneration and embedded generation are concerned, is incorrect and distorts the competitive market.

22 In particular, at paragraph 10.7(b) the Authority stated:

> 10.7 Below we separately address feedback on the following aspects of the residual charge:
>
> ...
>
> (b) load customers pay the residual charge, because if generators paid the residual charge, consumers would ultimately pay higher wholesale prices.[20]

23 While it is correct that, as a general rule, generators do **not** pay the Residual Charge, the charge **is** proposed to be imposed on generators that have

[16] EA record 235.16259 **[CB]**.
[17] EA record 235.16259 at [B.210]-[B.214] **[CB]**.
[18] EA record 237.17362 **[CB]**.
[19] EA record 241.19119 **[CB]**.
[20] EA record 241.19119 at [10.7] **[CB]**.

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embedded load. This is particularly so for co-generators, whose primary purpose is to supply embedded customers' load before exporting any excess supply to a distribution network or the transmission grid.

24 The issue of generators not paying the Residual Charge was developed at paragraphs 10.15 to 10.20 of the Decision.[21] This included a reference to an argument by Rio Tinto that new generators should be exempt. That was responded to at 10.19.

> We understand this line of argument. However, we consider that making the distinction between future and existing generation as suggested by Rio Tinto would be problematic. Allocating a residual charge to existing generation only would, in effect, subsidise new generation, so distort competition in the generation market (e.g. it would cause existing generation to be less profitable and therefore risk premature exit). It would likely be seen as regulatory opportunism, heightening uncertainty and so indirectly increasing energy prices.[22]

25 The criticisms listed in paragraph 10.19 of the Decision apply equally here to generators with embedded load. The proposed Residual Charge subsidises non embedded load and risks premature exit of the relevant co-generator supplying the embedded load.

26 More specifically, there is a real risk that the imposition of the Residual Charge as currently proposed will render some of Nova's cogeneration plants uneconomic, meaning we will have to re-configure them at significant cost and loss of efficiency to the underlying factories. This includes potentially permanently disconnecting them from the grid or as a worst case close them entirely prematurely, particularly the Whareroa and Kapuni cogeneration facilities.

27 To illustrate my point about potential disconnection or permanent closure as being not an idle threat, I will use the Whareroa Cogeneration Joint Venture's (which owns the Whareroa cogeneration plant) average annual financial performance over a 4-year period between August 2016 and July 2020[23] as an example:

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[21] EA record 241.19119 at [10.15]-[10.20] **[CB]**.
[22] EA record 241.19119 at [10.19] **[CB]**.
[23] The Whareroa Cogeneration Joint Venture annual financial reporting period is for the 12 month period ending 31 July each year.

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a) The Whareroa Cogeneration Joint Venture:

   i) had an annual average revenue of [redacted]; and

   ii) annual average profit before interest, tax and depreciation, (i.e. the typical measure of profitability) of [redacted].

b) Note that the profitability has been abnormally high relative to the Whareroa Cogeneration Joint Venture's annual budget over that period due to higher than normal wholesale market spot prices that are not expected to continue in the long term. This will particularly so when Tiwai smelter closes. The annual budgeted EBITDA is [redacted] based on conservative expectations for wholesale electricity market spot prices for the export volumes to the national grid.

c) I understand that the proposed Residual Charge will impose an additional cost of ~$1.5m over and above what Whareroa Cogeneration Joint Venture currently pays and $1.1m more than calculated by the Electricity Authority in their analysis and as shown in Table 4 of the Decision.[24]

d) Therefore, this will have a material impact on the financial performance of the joint venture and so the threat of disconnection of the plant is not an impossibility.

e) As a minimum, the additional impost will accelerate the closure of the factory and/or the cogeneration plant supplying it, to the detriment of all consumers due to reduced efficient electricity production and resulting reduced competition in the wholesale electricity market.

28 If the Whareroa Cogeneration Joint Venture were to remain at the same level of profitability, it will simply have to pass the Residual Charge to Fonterra, its only customer for the Whareroa cogeneration plant and try to explain to it that it will incur this charge as it is seen as a party that has an ability to pay.

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[24] EA record 241.19119 at [16.14] **[CB]**.

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29 The use of gross load applied to embedded loads behind cogeneration plants will discourage the development and use of cogeneration plants despite the number of advantages cogeneration provides in supporting industry and economic growth of New Zealand.

F The Electricity Authority's "reasons" for using gross demand

30 At paragraphs 10.33 to 10.40 of the Decision, the Authority seeks to justify its argument that "gross demand, rather than net demand, is the better basis for allocating the residual".[25]

31 At paragraph 10.33 it summarises the submissions including an argument from IEGA that it was "difficult to understand why allocation of benefit-based charge is on a net basis and the residual is on a gross basis".[26]

32 The Authority then purports to give its reasons at paragraph 10.34 before dealing with some more specific issues at paragraphs 10.35 to 10.40.[27] Paragraph 10.34 reads:

> 10.34 We acknowledge the residual charge is set on a different basis to the benefit-based charge. This is because these two charges have different purposes which in turn have prompted different rules on allocating and updating them (to align with desired incentives):
>
> (a) the benefit-based charge reflects the benefit a customer gains from an investment. If a load customer has generation behind its point of connection, it is likely to receive a lower benefit from new grid investment and this is reflected in a net measure
>
> (b) the residual charge is not intended to reflect a customer's benefit from or burden on the transmission network. Rather, it is to recover remaining revenues in the least distorting manner. In the long-term, it will recover unallocated overheads and costs, for example, Transpower's Human Resources system costs: these costs are not related to grid use and not related to the benefits customers receive from particular grid investments. Residual charges are allocated on a proxy for customers' size and so their ability to pay (much like the way the tax system works). This is not reduced by the presence of generation behind the point of connection.
>
> (c) allocation of the residuary charge based on net demand would risk creating an artificial incentive for investment in distributed generation, in advance of the residual allocator being updated (and the shorter the lag with which updating occurs, the worse this inefficient incentive would be). This risk does not present itself in relation to the (largely fixed) benefit-

[25] EA record 241.19119 at [10.33]-[10.40] **[CB]**.
[26] EA record 241.19119 at [10.33] **[CB]**.
[27] EA record 241.19119 at [10.34]-[10.40] **[CB]**.

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based charge – parties face the cost and benefits of either the grid investment or of their decisions to avoid or minimise grid investment.[28]

33 That is, the Electricity Authority advances the following reasons for gross load:

a) it recognises that a load customer with generation behind its connection point receives a lower benefit from new grid investment, with the implication there is something unique about new investment;

b) implicitly, gross load is less distortionary;

c) in the long term the Residual Charge is recovering overheads;

d) the Residual Charge is based on ability to pay which is not reduced by having generation behind the connection point; and

e) to not include gross demand risks creating an artificial incentive for investment in distributed generation.

34 I consider that each of the Electricity Authority's reasons are incorrect. I will deal with each reason in turn.

G "Less benefit from existing and new investment"

35 As to subparagraph (a) of paragraph 10.34, a load customer that is embedded behind a co-generator equally receives a lower benefit from past grid investments as much as new investments. I see no reason to draw a distinction between the lack of benefit from new investments and the lack of benefit from existing investments.

H Residual Charge recovers more than just overheads

36 The Authority claims that in the long term the Residual Charge will recover unallocated overheads.

37 I fail to see why all overhead costs cannot be allocated across all the transmission assets such that these overheads can be recovered on a

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[28] EA record 241.19119 at [10.34] **[CB]**.

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benefit gained or burden imposed. This is what happens under the current Transmission Pricing Methodology.

38 In any event, in the long term, the Residual Charge may be intended to recover unallocated overheads and costs such as human resources, the fact is that for many years by far the largest part of the Residual Charge is to cover Transpower's capital costs for the existing grid (that is, depreciation and Transpower's cost of capital) as well as the operating expenses around that part of the grid. The Electricity Authority is wrong when it states that Residual Charges are not related to grid use and not related to the benefits customers receive from particular grid investments. There appears to be no exercise where they have even attempted to allocate overheads. Figure 6 on page 59 of the Decision shows that it is a long time, about 25 years, before the Residual Charge declines to a level that might equate to just overheads.[29]

39 At paragraph 10.10, the Authority estimated that the Residual Charges would, over an extended period of 25 or so years, decline from about 70% of the share of benefit-based and Residual Charges to 20%.[30] While some of that is as new investments are made, another part is as existing investments depreciate. This illustrates how the Residual Charge is more than just recovering human resource type overheads.

40 Expanding on that last point, I have reviewed Transpower's income and expenditure as set out in its Annual Report for 2019/2020 – (**"Document CT3"**).[31]

41 Transpower's income and expenditure for the year ended 30 June 2020 is at p34 with an expansion of operating revenue in note 2 (p41) and operating expenses in note 3 (p49) of its Annual Report.[32]

42 These are summarised in the table below. In relation to revenue I have broken this down between Interconnection Charges that in the future will

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[29] EA record 241.19119 at page 59 **[CB]**.
[30] EA record 241.19119 at [10.10] **[CB]**.
[31] Transpower *Annual Report 2019/20* (30 June 2020) (**"Document CT3"**).
[32] Transpower *Annual Report 2019/20* (30 June 2020) (**"Document CT3"**).

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be recovered by the Benefit-Based Charge and the Residual Charge and other charges that will be primarily recovered through Connection Charges.

Transpower Group ($M)	2020
HVAC interconnection	641.4
EV (rebate) charge – HVAC	(8.1)
HVDC	134.7
EV (rebate) charge – HVDC	(3.0)
Total interconnection charges	**765.0**
HVAC connection charges	124.6
Other regulated transmission	5.3
Customer investment contracts	30.6
Undergrounding and transmission realignment	4.3
Other transmission	2.0
Total transmission revenues	**931.8**
Other revenue	
System operator	41.9
Other	13.2
Total operating revenue	**986.9**
Operating expenses	
Grid maintenance	112.3
IST maintenance and operations	31.9
Other operating expenses	147.4
Total operating expenses	**291.6**
EBITDA[33]	**695.3**
Depreciation, amortisation, asset write-offs and impairment	284.5
Net interest expenses	159.2
Earnings before changes in the fair value of financial instruments and tax	**251.6**
Gain (loss) in the fair value of financial instruments	64.2
Earnings before tax	**315.8**
Income tax expense	84.7
Net profit	**231.1**

[33] Earnings before interest, tax, depreciation, amortisation, asset write-offs, impairment and changes in the fair value of financial instruments.

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43 As can be seen from the figures:

a) Transpower charged $987m for transmission and related services;

b) "Transmission services" include revenues with respect to its investment in the national grid and its System Operator services (including its market services contract/s with the Electricity Authority for $42m);

c) in 2020, Transpower's costs (other than depreciation and interest which would primarily be related to its investment in the grid) were $292m of which $112m are described as being related to grid maintenance activity leaving $180m which could be described as overheads including such things as personnel wages, industry levies, insurances, information technology and travel costs;

d) much of the $42m that is recovered from the Electricity Authority and in turn, are recovered from market participants via the electricity levy will be personnel, wages and information technology costs. Assuming a 16.7% return to Transpower on expenses, about $36m of the $42m will be available to meet overhead costs;

e) included in the remaining $144m is the $10.3m in industry levies. These will be related to the national grid; and

f) this leaves $133.7m of Transpower operating expenses that the Electricity Authority refers to as 'overheads' to be recovered ostensibly from the Residual Charge together with additional revenue for the parts of the grid that is not recovered through the Benefits-Based Charge. The $133.7m of overheads:

   i) represents 14% of Transpower's regulated revenue for their 2020 financial year ($133.7m divided by $931.8m) and ~21%

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of the Electricity Authority's assumed 2022 allowable revenue as per Table 4 in 16.14 ($133.7m divided by $636.8m);[34] and

ii) comprises a low proportion (about 29%) of the total Residual Charge of $462m, the bulk of which relates revenue associated with existing assets not covered by the Benefits Based Charge.

44 Those percentages are actually overstated. In particular, some of the overheads should be allocated to the Benefits-Based Charge and most of its insurance ($4.8m in 2019-20) would be related to its transmission business.

45 In short, the Residual Charge is estimated to collect about $462 million. While there is room for debate as to what the exact overhead figure should be it is clear that much of the Residual Charge goes to recover the cost of the existing grid.

46 What this analysis shows is that about 70% of the proposed Residual Charge is a charge recovering the cost of the transmission network assets and services. By adding in gross load into the base for allocation of the Residual Charge, the proposed Transmission Pricing Methodology burdens the embedded load with a very significant charge for assets that they do not use or get any benefit from.

47 But even if the whole Residual Charge just recovered overheads those overheads are still associated with Transpower's provision of transmission services. An embedded load that does not benefit from such services should not have to pay a contribution to the overheads related to that service.

48 None of this replicates what would happen in a workably competitive market as a customer would not pay if it was getting no benefit.

[34] EA record 241.19119 **[CB]**.

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I Ability to pay

49 The Electricity Authority states that Residual Charges are allocated on a proxy for the customers' size and so their ability to pay, which is not reduced by the presence of generation behind the point of connection – see paragraph 10.34(b).[35]

50 I would have thought that before advancing this as a major reason for its decision, a regulator would carry out all necessary investigations to confirm the basis of its assumptions, such as size equates to the ability to pay. But I cannot see anywhere in the Decision or the other papers provided for public consultation any attempt by the Authority to analyse that concept let alone support it with actual evidence.

51 The Electricity Authority's estimates of impact on affected parties of the proposed Transmission Pricing Methodology **are** shown in the Cost Benefit Analysis section of the Decision and in particular Table 4 in Para 16.14.[36] In that table the impact of the proposed Transmission Pricing Methodology on Nova and Whareroa Cogeneration Limited[37] are shown by separate entries.

52 Those figures have been calculated on a net basis. Our own calculation shows a much higher charge of $1.46m for Whareroa and $0.46m for Kapuni.

53 On 20 October 2020, Nova wrote to the lawyers acting for the Electricity Authority (**"Document CT4"**) seeking to understand how the Residual Charge in that table was calculated.[38] We specifically asked "can the Authority advise if it included an estimate for coincident embedded generation".[39]

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[35] EA record 241.19119 at [10.34(b)] **[CB]**.
[36] EA record 241.19119 at [16.14] **[CB]**.
[37] [redacted]

[38] Letter from Nova to Bell Gully (Electricity Authority) (20 October 2020) ("**Document CT4**").
[39] Letter from Nova to Bell Gully (Electricity Authority) (20 October 2020) ("**Document CT4**") at [4].

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54 Bell Gully replied on 30 October 2020 on behalf of the Electricity Authority, ("**Document CT5**").[40] They did not directly answer that question.

55 From my reading of that letter, it is apparent that the Electricity Authority did not allow for coincident embedded load of cogeneration plants.

56 That was logical as the Electricity Authority does not have ready access to the level of coincident generation or load reflecting the electricity demand of the cogeneration facility's customer(s) although it would have been aware of its existence due to the submissions of Nova and other co-generators. Moreover, Nova was never asked by the Electricity Authority to provide such information.

57 The result is that, in the accompanying analysis of impact on customer groups in paragraph 16.22, no assessment has been made of cogeneration facilities separately.[41] The impact of the Residual Charge is simply lumped in with:

a) North Island generators with respect to the Whareroa and Kapuni cogeneration plants; and

b) North Island distributors for the Edgecumbe cogeneration plant.

The impact of the Residual Charge, as estimated by the Electricity Authority on a net basis, is significantly understated and misleading.

58 In any event, the concept that a network with significant embedded generation has a greater ability to pay than a network with no or no significant embedded generation has no sound basis.

59 The locality of embedded generation reflects the availability of sources of generation or a suitable fuel for generation in that area and, in the case of cogeneration, the demand for process heat. This has nothing to do with ability to pay. The cogeneration plants that Todd has interests in are co-located with Fonterra owned dairy factories which require both process

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[40] Letter from Belly Gully (Electricity Authority) to Nova (30 October 2020) ("**Document CT5**").
[41] EA record 241.19119 at [16.22] **[CB].**

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heat and electricity. Fonterra's factories are typically located based on collection of milk from surrounding farms and are determined by Fonterra, not the cogeneration facility. The cogeneration plants either invest or pay to transport, typically gas, to fuel the plant. It is totally unsatisfactory for Todd that it must pay for natural gas transmission to its cogeneration facilities and now it seems it must also bear a charge for electricity transmission that it does not use.

60 Some of the poorest areas in New Zealand are the remote rural areas such as Upper Northland (line operator Top Energy), East Coast (Eastland Network), Eastern Bay of Plenty (Horizon) and Westland (Westpower). Being remote, these areas already have to pay a high price by way of transmission charges given the need to have lines reaching their area. They also pay a high price for electric power as line losses stem from having to convey electricity over extended distances.

61 Yet they can have geothermal steam or small rivers that are suitable for small scale geothermal or hydroelectricity schemes.

62 The 2018 Census lists the median income of residents in those areas which is a good indicator of ability to pay yet some of these regions will be significantly affected due to the combination of low incomes and the fewer number of households and businesses to spread the costs.

63 Some examples (including the bigger urban centres by way of contrast) are:

Region & Distributor	**ICP's[42]** (Customer connections)[i]	**Median Income[43]**	**Significant Embedded Generation (Capacity MW)[44]**
National		$31,800	n.a.
Eastern Bay of Plenty Whakatane Kawerau Opotiki (Horizon Energy)	25,255	 $25,900 $20,600 $22,400	Cogeneration: Edgecumbe Dairy Factory (10) Hydro: Wheao & Flaxy (26) Aniwhenua (25) Geothermal plants: Te Ahi O Maui (25) Geothermal development Ltd (8)

[42] Information is sourced from Energy News resource databased (paywalled) and can be provided on request
[43] https://www.stats.govt.nz/tools/2018-census-place-summaries
[44] Information is sourced from Energy News (paywalled) and can be provided on request

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Electricity supplied from distributed generation (288 GWh)			Tasman (Norske Skog) (13) Solar installations (1.2)
Northland (Northpower & Top Energy) Electricity supplied from distributed generation (217 GWh)	92,798	$24,800	Hydro: Wairua Falls (5) Geothermal plants: Ngawha geothermal (92) Diesel peaker: Taipa (3.6) Solar installations (9.5)
Gisborne (Eastland) Electricity supplied from distributed generation (12 GWh)	25,658	$25,900	Waihi Station (5) Solar installations (1.2)
Westland (Westpower) Electricity supplied from distributed generation (155 GWh)	13,812	$26,400	Small hydro stations: Amethyst (7.6) Arnold (3) Dillmans / Duffers / Kumara (11) Fox (0.9) Kaniere Forks / McKays Creek (1.5) Turnbull (0.9) Wahapo (3.1) Solar installations (0.2)
Auckland (Vector) Electricity supplied from distributed generation (136 GWh)	573,860	$34,500	Cogeneration: Auckland DHB (3.6) Small hydro stations: Mangatangi (0.6) Landfill biogas: Greenmount Landfill (3.6) Redvale Landfill & Energy Park (12) Rosedale (1) Whitford (3.2) Gas turbine peaker: Papakura (4.9) Solar installations (25.4)
Christchurch (Orion) Electricity supplied from distributed generation (11 GWh)	206,000	$32,900	Cogeneration: Chch Biosolids (8.4) Hornby - Ravensdown (3) Solar installations (12.7)

64 As can be seen from the table, urban areas have more connections available to spread the additional costs associated with the gross load methodology for allocation of Residual Charges and higher incomes than rural areas which have a demonstrably lower ability to bear those additional costs.

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J Alleged artificial incentives for investment in distributed generation

65 This reason overlooks both:

a) actual formula for imposing the Residual Charge as mandated by the Electricity Authority; and

b) commercial reality.

66 The mandated formula is set out at paragraphs 27-30 of the 2020 Guidelines.[45] Ignoring the adjustment in paragraph 29 the formula has 2 elements.

67 The first is the "$HAMD_0$" element in the formula. This is the one we object to. It takes the Anytime Maximum Demand and adds the concurrent generation. This is averaged over the 4 years of 2014 to 2018. This is measured in MW.

68 That is then multiplied by the formula U_1/U_0 being the product of **gross** energy used in the 4 year period immediately prior to the relevant pricing year divided by the yearly average of the **gross** energy used in the same base period of 2014 to 2018 used in Part A of the formula. This is measured in MWh. We do not object to the use of gross energy here.

69 If a new embedded generation plant is built, it does not alter the historic MW figure "$HAMD_0$" as that is still based on the 2014 to 2018 yearly average. Nor does it alter "U_1/U_0" as those elements are both based on gross load which will not be altered by embedded generation.

70 It could potentially only have an impact if there was to be a change in the peak demand base period 2014/2018. But the Transmission Pricing Methodology does not propose such change.

71 Further, the Residual Charge is paid by the local distribution network. By definition, the embedded generator is not directly connected to the national grid. It is only connected via the local distributor. It can only

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[45] EA record 241.19275 at [27]-[30] **[CB]**.

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benefit from any reduction in the Residual Charge that arises from its impact on an adjusted peak demand element (HAMD) **if** it is able to negotiate with the local distributor for the sharing of that benefit. One of the reasons for the introduction of the ACOT payments was because of the difficulty embedded generators had in negotiating with the local line monopoly in the sharing of that benefit.

72 It is unlikely that a potential investor would give much, if any, weight when making an investment decision, to the possibility both that:

a) the base period will change; and

b) they can then negotiate with the local distributor the sharing of any resulting benefit in a reduction of the Residual Charge.

73 The position is even stronger with cogeneration.

74 That is, the risk of artificial incentives for investment in distributed generation does not apply to existing generation let alone cogeneration plants. Nor does it apply to new cogeneration plants built to service new needs. Cogeneration plants are developed to meet the specific demands of factories, typically for process heat (often in the form of steam) and electricity and are not built to avoid transmission charges.

75 That is, cogeneration plants are developed to supply cost effective and efficient process heat and electricity to industrial users. Often the industrial customer of the cogeneration facility has industrial processes whereby its demand for electricity is inextricably linked to its requirements for process heat. This means that if the cogeneration plant has an unplanned outage this has the downstream effect on the industrial customer in that it reduces its demand for electricity as it does not need or cannot take the electricity for its processes as it also is not supplied with the process heat it requires.

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As such the industrial customer's load for the most part does not need and does not benefit from the transmission grid.

76 In its Decision the Authority goes on to say:

> 10.36 The Authority acknowledges that distributed generation has many benefits for consumers and plays a crucial role in energy markets, including as an alternative to transmission. Distributed generation can be rewarded in various ways (for example, through prices realised in the energy market or from entering a grid support contract with Transpower). In our view, however, it is generally appropriate for generation behind the customer's point of connection to reduce a load customer's liability for the benefit-based charge for future investments, but not for the residual charge (for the reasons explained above). We would observe that over time, we expect the share of total grid costs recovered through the benefit-based charge to materially increase as the share of the residual charge reduces ...
>
> 10.37 Some submitters argued for allocation based on net AMD on the basis that consumers with embedded co-generation and associated load never expose the grid to their full gross demand. One potential option would be to treat co-generation as a special case (that is, net off co-generation, but not other embedded generation). The Authority's view is that gross AMD is a proxy for customers' size and ability to pay. It is a better measure of size and ability to pay than net demand. In principle, the fact that some customers manage their use of the grid using embedded co-generation should not have the effect of reducing their allocation of the residual charge.[46]

77 As previously explained, although the share of total grid costs charged through the Residual Charge will reduce over time the process will be very gradual.

78 While an embedded generator may receive a higher price for electricity being close to its market so too do other generators who locate close to markets.

79 However, in cogeneration's case:

a) the plants are built to supply factories;

b) such factories are not in urban areas. There is no opportunity for the co-generator to receive any price benefit due to its location having within it or it being near a major demand centre such as a large urban city;

[46] EA record 241.19119 at [10.36]-[10.37] **[CB]**.

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c) the plants are built based on long term contractual arrangements with price of steam and electricity fixed for periods of 10 years or more; and

d) the surplus exported electricity is delivered to the national grid and traded just like any other generator.

80 As such, surplus electricity from cogeneration plants don't typically stand to earn higher prices because they are normally far from major demand centres such as a major city. Even if higher prices were able to be earned, they will not compensate for the charge for the extra cost of the Residual Charge for a service that it does not use.

81 The reasoning in paragraph 10.37 singularly fails to take into account cogeneration which is in a network that services only the beneficiary of the cogeneration the processing facility such as a dairy factory.

K Conclusion

82 In conclusion, the Electricity Authority's decision and the process it followed in arriving at that decision and specifically in relation to applying gross load to the calculation of the Residual Charge imposed on cogeneration plants and embedded generation are flawed and should be revisited.

Sworn at Wellington)
this 23rd day of April 2021)
before me:)

Charles Allister Teichert

Matthew John Dicken
Solicitor
Wellington

A Solicitor of the High Court of New Zealand

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"CT-A"

EXHIBIT NOTE

This is the exhibit marked "Document CT-A" referred to in the annexed affidavit of CHARLES ALLISTER TEICHERT sworn at Wellington this 23rd day of April 2021 before me:

....

A Solicitor of the High Court of New Zealand

Matthew John Dicken
Solicitor
Wellington

Index of documents annexed to the affidavit of Charles Allister Teichert

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Nova's submission: 'Consultation Paper – Review of distributed generation pricing principles' on 26 July 2016 **("Document CT2")**	2
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MJD

think differently

nova energy

30 September 2013

Submission
Electricity Authority
PO Box 10041
Wellington 6143

By email: submissions@ea.govt.nz

Dear Sirs

Re: Consultation Paper—Draft decision on exemption application – classification of NAaN assets under the TPM

Thank you for the opportunity to provide feedback on the consultation paper on the exemption application for the classification of NAaN assets under the TPM.

Nova Energy believes that the Electricity Authority's response to Transpower's application is substantially correct, although the points raised by Transpower do have some merit.

Nova believes that there is a middle ground, where Vector should pay for access to the NAaN assets as if these assets were designed and built solely to serve the long term Vector demand at HOB and WRD. That demand should be based on the demand growth assumptions at time of project approval.

The extent that the capital spent on the NAaN assets exceeds the anticipated requirements at HOB and WRD can reasonably be regarded as interconnection assets. While there is no benefit accruing from that expenditure until such time that the project is completed, the costs can be accrued and considered as part of the overall cost of developing the completed project.

The split in capital values and allocation of charges between connection and interconnection costs may be somewhat approximate, but they would still represent a more balanced allocation of charges than that promoted by Transpower or the Electricity Authority in its draft decision.

Yours sincerely

Paul Baker

Commercial & Regulatory Advisor

pbaker@novaenergy.co.nz

dd: 04 901 7338

great value energy

Electricity || Natural Gas || LPG

nova energy

Nova Energy Limited
PO Box 10141, Wellington 6143
www.novaenergy.co.nz

26 July 2016

Submission
Electricity Authority
PO Box 10041
Wellington 6143

By email: submissions@ea.govt.nz

Dear Sirs

Re: Consultation Paper – Review of distributed generation pricing principles

The Electricity Authority (Authority) states: "It is unclear why any single category of distribution network user should be favoured over others, as occurs under the DGPPs." In Nova Energy's experience distributed generators (DG) most definitely need unambiguous regulatory protection from the monopolistic practices of electricity distribution businesses (EDBs). Reasons for this are covered below:

Avoided Cost of Transmission (ACOT)

Nova acknowledges that ACOT payments have increased significantly in recent years as a result of:

- Increased Transpower charges,
- The focus of Transpower charges on a small number of load peaks, and
- The embedding of a number of significantly sized generation projects.

These are issues that need to be managed; but it is not sufficient cause for removing all protections for generators connected to EDB networks.

The Authority's argument against ACOT payments focuses on the gap between ACOT and the actual marginal cost of transmission, given that in many cases there is adequate transmission capacity and marginal costs of virtually zero. The underlying presumption is that a generator and consumer within the same GXP area shall have no rights for one to supply the other with electricity without the consumer also paying, via the EDB, the grid operator a transmission charge, i.e. a charge for a service that neither party is using.

With its proposal to abolish ACOTs, the Authority is, in effect, instituting a monopoly right to Transpower; enabling it to recover its regulated revenues from all parties, and in particular, in preference to embedded generators that provide an alternative service to consumers.

For example, if consumers were to contract directly with Transpower for transmission services, they will be in a position to choose between either paying Transpower's charges or choosing an alternative supplier, e.g. a DG operator. In a competitive market the DG would reduce the consumer's demand from the grid, and expect recompense for that. The current ACOTs arrangement provides this ability for the consumer; albeit inefficiently due to some EDBs extracting a disproportionate share of the benefit by being the intermediary for transmission charges. Removal of even this diluted benefit accruing to consumers under the current ACOT arrangement means that choice and competitive element is removed from consumers. We believe this is anti-competitive and a retrograde step.

In the absence of the EDB as the intermediary, the DG and connected consumer could be expected to jointly negotiate the benefits of the ACOT between them.

The logical response to the removal of the DG Regulations is for DG to by-pass the EDB and supply consumers directly. This can be achieved by connecting directly to networks that are not connected to the Transpower grid, i.e. embedded networks. The embedded network should only pay a share of the EDB's Transpower connection charges for the extent to which it draws electricity from the EDB's network. In some cases the embedded network net demand could be nil, or even a net exporter of electricity. In such cases, consumers on the embedded network can afford to pay the DG an amount up to the same amount saved in transmission charges that would have been passed on by the EDB, i.e. equivalent to an ACOT payment.

Such by-pass would be both rational and profitable in circumstances where the added lines costs are not excessive. It is not, however, an optimal solution economically.

The solution to that scenario is to rationalise the transmission pricing methodology such that interconnection charges are allocated appropriately to users of the grid (rather than basing charges entirely on small number of RCPD peaks). The TPM, as proposed, is largely expected to achieve that, in which case removing the distributed pricing principles from Part 6 of the Code is unnecessary as well as creating perverse incentives to directly connect DG to consumers, by-passing the EDBs.

Code amendment does not address market failure

The Authority uses an economic argument to justify the elimination of the DG protections under Part 6 of the Code. Its position, however, ignores the imbalance of negotiating power between generators and the EDB monopolies when it comes to connect DG to their networks.

The Authority recognises that there is justification for Transpower and EDB's to pay DG for:

- Avoided transmission cost, where this directly defers the need for additional investment in the Transpower Grid or reductions in load, and
- Avoided costs of distribution; where the DG enables the EDB to avoid the cost of additional network investment.

Where there is an LRMC charge applied to load (or in some cases generation), then Transpower should also be required to apply LRMC credits for DG generation where appropriate, reflecting the inverse of LRMC charges on load.

The primary issue for DG is that it is unlikely to receive such payments from EDBs without a mandated requirement under the Code. Furthermore, the Authority is opening up the opportunity for EDBs to allocate overheads to DG on whatever basis they may choose. The DG regulations were introduced specifically to address the way monopoly powers were being used to disadvantage DG owners.

Transpower is more likely to act appropriately than the EDBs in this respect, given its higher visibility and transparency, although the DG owners remain at a significant disadvantage in terms of access to information, analysis of data, and resources to negotiate a fair financial benefit from their generation.

The Authority has assessed the Code amendment against its Code amendment principles without considering the market's experience prior to the DG regulations.

The current DG regulations originated in an environment where DG proponents were having considerable difficulties engaging with EDBs. There are a number of reasons why this was the case, and these are not unique to the New Zealand situation. The UK energy regulator, OFGEM, acknowledges similar issues in the UK:

“Over recent years we have witnessed a dramatic growth in the number of distributed generators seeking to connect to the distribution network. Accompanying this surge in volume of connections have been concerns that customers are encountering a number of difficulties in navigating their way through the connection process.[1]”

The following study documents a range of barriers to connection in relation to grid connected generation, and includes case studies relevant to these. It explains why network operators are naturally inclined to be wary of DG and seek a higher proportion of costs from DG than consumers.

“The DECENT study (Decentralised Generation Technologies – Potential, Success Factors and impacts in the Liberalised Energy Markets (Joerss et al. 2002) was designed and carried out to identify the main barriers and success factors to the implementation of DG projects within the EU and Member State policy makers to enhance the feasibility of DG projects within the internal energy market.”

The following points are direct extracts from that work:

- Connection charges
    - “Shallow connection charges only bring into account the cost of line extension to the nearest connection point and the equipment needed to connect the line to the rest of the grid.
    - “Deep connection charges bring into account all the cost of integration of a generator into the network, including the cost of all adjustments beyond the point of connection to the network.
    - “However, determining the point of connection with deep connection charges is more complicated, because the location specific cost of grid adjustments will be taken into account both by the generator and the network operator.
    - The relative impact of deep connection charges are not straightforward and provide considerable scope for EDB’s to load costs onto DG.
- Safety and Liability Issues
    - “As they are often under pressure of price regulation they will often try to shift as many of the costs and risks of safety measures to the users of the grid, mainly to producers.
    - “The cost of safety measures related to network connections may entail special safety and contingency equipment in the connection to the grid and adjustments elsewhere (in the case of deeper connection charges), demands on the operation of the plant, etc.
    - “Necessary safety measures are generally determined by the grid operator taking a very risk adverse approach.
    - “The safety requirements on equipment and operation can compound the cost of connection. Moreover, the basis of establishing the necessary measures is not always transparent.”
- Lack of transparency
    - “When establishing the cost of connection to the grid it is important that both the procedures for requesting and negotiating connection and the cost assessment methodology are transparent and non-discriminatory.

[1] (https://www.ofgem.gov.uk/electricity/distribution-networks/connections-and-competition/distributed-generation)

- “In the absence of any standard conditions, new entrants will face uncertainty with regard to the cost of connection.
  - “On the other hand clear cost allocation rules between developer and (distribution) grid operator have proved to reduce uncertainty.

- Business practises
  - “It is not perceived to be the core business of grid operators to facilitate the integration of DG into their networks. The priority is the operation of the grid and maintenance of the assets.
  - “Furthermore, there is no incentive structure to stimulate the fast and efficient handling of connection procedures. Therefore connection requests by DG have a relatively low priority.

- Benefits of connection
  - “Benefits of connection of DG may arise from deferral of transmission and distribution network upgrades and expansion, decongestion, improved local reliability, and the provision of ancillary service to the grid.
  - “These benefits are usually not reflected in the connection charges, which only take into account the cost of connection.

- Lack of price signals
  - “DG operators seek to minimise the cost of connection to the network.
  - “Network operators also seek minimise the cost of connecting DG to their network and also seek to minimise the amount of effort involved in handling connection requests and in integrating DG in their grid planning.
  - “As described above the aims of both camps are often difficult to reconcile as a result of non-transparent procedures and cost assessment procedures.

- DSO (Distributed System Operators) incentives
  - “The incentives arising from price regulation on network companies determines the attitude of grid companies to the connection of DG.

- Co-ordination of spatial planning and network planning
  - “The location of DG projects is often constrained by spatial planning and resource availability.
  - “How to allocate these costs between the users of the network (shallow connection charges) and the DG operator (deep connection charges) will have to be discussed.

“Non-discriminatory access to the grid and transmission and distribution services is therefore fundamental to ensure that DG can compete with other sources of electricity on an equal basis[2].”

It is clear from the above that the issues are not unique to New Zealand and its 29 EDBs. Quite simply the issues are complex and the objectives and negotiating power are not aligned between the parties. However imperfect, the regulations under Part 6 of the Code have facilitated both DG operators and EDBs to resolve most of the above issues.

2 DECENT Final Report - https://www.izt.de/pdfs/decent/DECENT_Final_Report.pdf

If, on balance, it is deemed that the provision in the Code for ACOT payments must go, then it is still essential that the Code continues to regulate EDBs to:

- Act in a reasonable manner in terms of facilitating existing and new DG connections,
- Make provision for paying for avoided costs of distribution (ACOD), and
- Charge no more than the direct (shallow) connection costs associated with DG.

If EDBs are allowed to charge deeper connection costs plus overheads to DG, they are placing DG at a competitive disadvantage to grid connected generation. New EDB connection charges may therefore result, in some instances, in DB operators investing in lines and high voltage transformers that should otherwise be unnecessary.

While EDBs may incur deeper connection costs or overheads associated with DG, the EDBs also receive benefits that they are unlikely to credit back to the DG. By limiting the connection charges to the shallow costs, such regulation does, by effect, balance out at least some of those benefits.

LRMC charges

As per its submission to the Authority on the TPM Options Paper, Nova supports the application of the LRMC charging methodology as it focuses on future investment, and is complementary to the Area of Benefit charge.

Given the intent of the LRMC charge is to signal the increasing load on the grid and likelihood of future grid upgrades, it is also economically efficient to signal that to DG. Under the Authorities proposed Code change, it is unlikely that LRMC offsets will occur (unless the LRMC charge happens to be a net export charge).

Just as there is provision for Transpower to pay for DG directly for demand response, it should also be required under the Code to credit LRMC recoveries back to DG at the same rate as Transpower charges for load.

IEGA submission

Further to the points made in this submission, Nova supports the supports the submission made by the Independent Electricity Generators Association (IEGA), specifically:

- The point that the DG Regulations were primarily implemented to address barriers to entry for DG,
- The Authority has not fully evaluated the market impact of removing the incentive for DG to generate during peak demand periods, and potentially a wider shift of DG generation patterns, and
- The impact of EDB’s imposing lines charges, including overheads, on DG, whereas the Authority itself outlines very good reasons why grid connected generation should only pay for Interconnection charges to the extent that they can be shown to benefit from those.

Conclusion

ACOT payments have facilitated innovation in building DG projects throughout New Zealand, ranging from strategically located wind turbines, geothermal power stations of various sizes, co-generation plants, and landfill sites. Many of these would not have proceeded in the absence of the Part 6 regulations. However they are still economically efficient investments if all of the benefits are taken into account (which consist of more than just the revenues received by the DG owners).

Notwithstanding our view that mechanisms supporting recognition of DG, such as the ACOT payments structure, should be maintained, it is crucial that the Authority ensures that a level playing field with respect to connection costs is retained. That includes minimising transaction costs as well as preventing EDBs from subsidising consumers at the cost of the DG operators.

Part 6 of the Code should not be amended until the Authority is ready to address these wider issues.

Yours sincerely

Paul Baker
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Document CT3

TRANSPOWER

D.17

Annual Report

2019/20

Keeping the energy flowing

Contents

Corporate Governance Statement

For the year ended 30 June 2020

Introduction

As the operator of New Zealand's national electricity grid, Transpower has a unique responsibility to our nation. We are responsible for designing, building, operating and maintaining the national grid. At the same time, we operate and manage New Zealand's electricity market in real-time.

To achieve these dual roles, we are supported by an experienced group of New Zealanders who work across the country in our various departments.

We are headed by a Board of Directors and General Management Team who understand the electricity sector implicitly and who guide our business functions with robust corporate governance policies and practices.

Our Board and General Management Team are committed to creating and maintaining a high standard of corporate governance. Additional information on other activities of the Board this year and plans for next year can be found in the online **Annual Review**.

Our NZX commitments

Transpower is a limited liability company and a State-Owned Enterprise (SOE) with our shares held on behalf of the Crown by the Minister of Finance and the Minister for State-Owned Enterprises. Transpower has debt listed with the NZX and is, therefore, required to comply with debt listing obligations.

This corporate governance statement reports our activities against the NZX Corporate Governance Code (the NZX Code), updated in 2019. The NZX Code is the primary guidance on corporate governance for NZX-listed issuers, describing principles of corporate governance and the recommended action to demonstrate best practice.

There are certain parts of the NZX Code that do not apply to Transpower, such as those clauses related to director appointments, takeovers, directors' remuneration and shareholder rights. As an SOE, these governance arrangements are the responsibility of the Crown and are set out in the State-Owned Enterprises Act 1986 and Transpower's constitution. These are identified in the statement.

Transpower considers that, during the reporting period, the company materially complied with the NZX Code.

Principle 1:

Code of ethical behaviour

Recommendation 1.1

Code of conduct for Transpower's people and directors

"The board should document minimum standards of ethical behaviour to which the issuer's directors and employees are expected to adhere (a code of ethics)."

Transpower has a **Code of Ethics and Conduct Policy** that directors, employees, contractors and consultants must comply with. The policy is designed to promote and maintain high standards of ethical behaviour and provides advice on how to deal with ethical problems.

Transpower's Code of Ethics and Conduct Policy sets out explicit expectations:

- acting honestly and with high standards of personal and professional integrity;
- appropriately managing conflicts of interest;
- proper use of Transpower's property or information;
- not participating in any illegal or unethical activity, including safeguards against insider trading in the entity's securities (refer also to the **Insider Trading Policy and Guidelines**);
- fair dealing with shareholders, customers and other stakeholders;
- standards around giving and receiving gifts, koha, facilitation payments and bribes (refer also to the **Discretionary Expenditure, Gifts and Travel Policy**);
- compliance with relevant laws and regulations; and
- reporting of unethical decision-making and/or behaviour (refer also to the **Compliance Policy**).

New employees are required to acknowledge that they have read, understood and will comply with the Policy requirements. The induction process includes the completion of the 'Doing the right thing at Transpower' online e-learning module, which ensures people who join Transpower are familiar with the organisation and what is expected of them. This includes familiarisation with the Code of Ethics and Conduct Policy.

The Board reviews the Code of Ethics and Conduct Policy every five years. The Board is updated by the General Manager People and General Counsel & Company Secretary on any non-compliance with the policy.

As part of the recent external evaluation, the Board completed an extensive review of the Board Charter and embedded a code of ethics and conduct and minimum expectations for behaviour.

Recommendation 1.2

Financial dealing policy

"An issuer should have a financial product dealing policy which applies to employees and directors."

Transpower's **Insider Trading Policy and Guidelines** set out the requirements for all directors, officers, staff and contractors of Transpower and its subsidiaries who wish to deal in Transpower's securities. The Board reviews the Insider Trading Policy and Guidelines every five years, last reviewed and approved by the Board in June 2018.

> Directors should set high standards of ethical behaviour, model this behaviour and hold management accountable for these standards being followed throughout the organisation.

Principle 2:
Board composition and performance

Recommendation 2.1
Board charter

"The board of an issuer should operate under a written charter that sets out the roles and responsibilities of the board. The board charter should clearly distinguish and disclose the respective roles and responsibilities of the board and management."

The role and responsibilities of the Board are set out in Transpower's **Board Charter**. The Board reviews this every three years to ensure its relevance. As part of the recent external evaluation, the Board Charter was reviewed and a new version approved in June 2020.

The Board has a minimum of eight scheduled meetings each year and meets whenever necessary to discuss urgent business. The Chair, Chief Executive, and General Counsel & Company Secretary establish meeting agendas to ensure key issues are covered. Directors receive materials for Board meetings a minimum of seven days in advance except for urgent meetings called at short notice.

The Board appoints and delegates responsibility for Transpower's day-to-day management to the Chief Executive, who in turn may delegate authority to executive managers.

Transpower's **Delegated Authority Policy** describes the limits of delegated authority and prescribes the matters in respect of which the Board reserves its decision-making authority.

Recommendation 2.2
Nominating and appointing directors to the Board

"Every issuer should have a procedure for the nomination and appointment of directors to the board."

The shareholding Ministers and ultimately the Cabinet appoints Transpower directors on advice from The Treasury. Directors are independent and non-executive and are generally appointed for terms of up to three years, although they may be reappointed. Shareholding Ministers, in conjunction with the Board, seek to ensure there is a balance and diversity of skills, knowledge, experience and perspectives among directors.

Recommendation 2.3
Written agreements with each director

"An issuer should enter into written agreements with each newly appointed director establishing the terms of their appointment."

Transpower's directors hold office at the pleasure of shareholding Ministers and accept appointment on terms and conditions set out upon their appointment.

Recommendation 2.4
Information on directors

"Every issuer should disclose information about each director in its annual report or on its website, including a profile of experience, length of service, independence and ownership interests and director attendance at board meetings."

The members of the Board of Directors and their attendance at meetings during the 2019/20 financial year are listed below.

Profiles of each director can be found on Transpower's **website**. All directors are independent.

DIRECTOR	DATE COMMENCED IN OFFICE	MEETINGS HELD	MEETINGS ATTENDED
Pip Dunphy (Chair from 1 January 2019)	1-May-15	10	10
Dean Carroll (Deputy Chair from 1 January 2019)	1-Nov-16	10	10
Prof Jan Evans-Freeman (term ended 31 October 2019)	1-Nov-12	2	2
Bill Osborne	1-May-16	10	8
Sheridan Broadbent	1-May-18	10	9
Kathy Meads	1-Mar-19	10	10
Ilze Gotelli	1-Mar-19	10	10
Dr Tim Densem (term ended 4 October 2019)	1-Mar-19	2	2
Richard Aitken	1-Nov-19	8	8
Dr Roger Blakeley	1-Jun-20	1	1

No directors hold shares in Transpower, have loans from Transpower or have made any request to use company information received in their capacity as directors that would not otherwise have been available to them.

Transpower's **Directors' Interests Policy** governs how Transpower resolves and manages the way directors' individual interests are disclosed.

The following directors have made general disclosures of interest with certain external organisations based on them being a Chair, director, Board member, trustee, council member, member, employee or consultant of those organisations or holding material securities or shares of those organisations. The disclosures of interest cover the period up to the end of the financial year, on 30 June 2020.

DIRECTOR	POSITION	ORGANISATION
Pip Dunphy	Chair**	First Gas Holdings TopCo Limited and subsidiary companies
	Chair**	Gas Services NZ Limited and subsidiary companies
	Chair	Abano Healthcare Limited
	Director	Fonterra Shareholders Fund
	Director*	DGC Limited
Dean Carroll	Nil	Nil
Prof Jan Evans-Freeman**	Pro Vice-Chancellor	College of Engineering, University of Canterbury
	Director	Wireless Research Institute
	Director	Electric Power Engineering Centre (EPE Centre)
	Director	University of Canterbury Quake Centre
	Director	QuakeCore
	Member	Engineering NZ Governing Board
Bill Osborne	Chair**	PlantTech Research Institute Limited
	Chair	Page Macrae Engineering
	President	New Zealand Rugby Union Incorporated
	Director	Rangitira Services Limited
	Director	Ports of Auckland Limited
Sheridan Broadbent	Shareholder	Figured Limited
	Shareholder	Invivo Wines Limited
	Director	Business Leaders' Health and Safety Forum
	Director	Breach Consulting Limited
	Director	Kordia Group limited
	Director	Spruce Goose Aerospace Limited
	Director	Timberlands Limited
	Director**	NZ Transport Agency
Kathy Meads	Director	Shipowners Mutual Protection and Indemnity Association
	Director	Enable Services Limited
	Director	Enable Networks Limited
	Director	Port Taranaki Limited
	Director	NZPM Group Limited
	Trustee	Christchurch Symphony Orchestra
	Director*	Magic Memories Group Holdings Ltd
Ilze Gotelli	Employee	Head of Major Developments, Watercare Services Limited

* Appointed during the year ** Resigned during the year

DIRECTOR	POSITION	ORGANISATION
Dr Tim Densem**	Director	South West Consulting Group
	Director	Pukeko Rentals
Richard Aitken*	Director	BGCF Trustee Limited
	Director	BGL Custodian Limited
	Director	Pitt Vincent Limited
	Director	BGLIR Trustee Limited
	Director	BGL Management Share Trustee Limited
	Director	Albert Pitt Limited
	Director	BGS Trustee Limited
	Director	Derceto Trustee Limited
	Director	John Scotts Investment Limited
	Trustee	Beca Indemnity Fund Custodian Trust
	Trustee	BGLIR Custodian Trust
	Trustee	BGL Custodian Trust
	Trustee	BGS Custodian Trust
	Member**	Building Advisory Panel at Ministry of Business, Innovation and Employment
	Member	National Asset Management Plan Reference Group for the Ministry of Health
	Chair	Te Punaha Matatini Advisory Board
	Chair**	Waterview Project Alliance Board
Dr Roger Blakely*	Director	Greater Wellington Regional Council and subsidiaries
	Director	Capital and Coast District Health Board
	Trustee	Harkness Fellowships Trust Board
	Trustee	Wesley Community Action Trust

The Transpower Group has directors' and officers' liability insurance policies. An indemnity is also permitted by Transpower's constitution and separate deeds of indemnity have been entered into between Transpower and individual directors. These ensure that, generally, directors will incur no financial loss as a result of actions undertaken by them as directors. Certain actions are specifically excluded, for example, the incurring of penalties and fines that may be imposed in respect of breaches of the law.

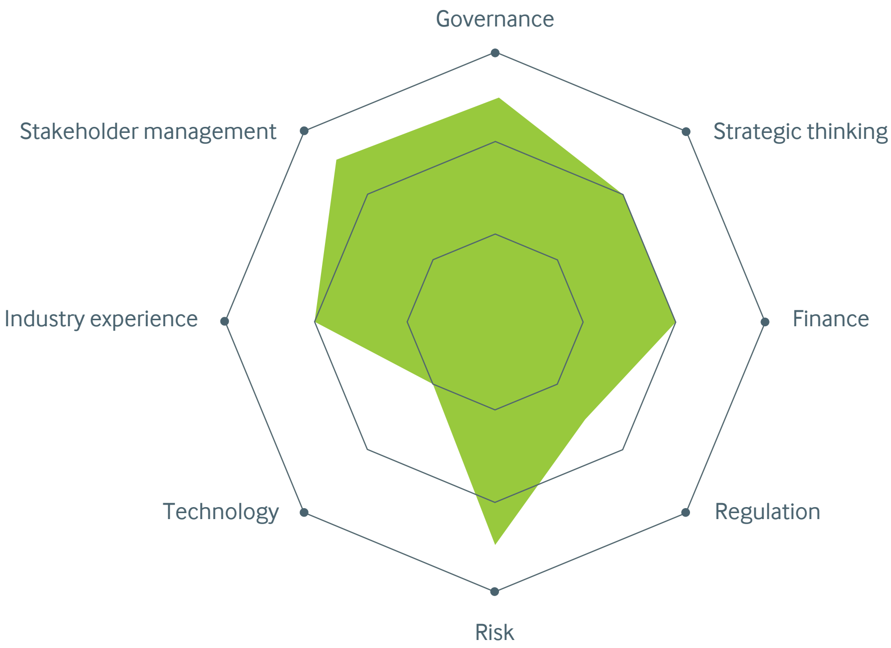
Diversity of skills and experience

Transpower's Board of Directors comprises individuals with a broad and diverse set of skills and experience that collectively benefit our company and the electricity sector. The board is a collective unit directing and guiding Transpower's direction and business activities. Complementing the Board's over-arching view of the business, each board member spends time with our General Management Team, extending their knowledge base in the day-to-day operations and understanding what happens at every layer of the organisation.

> To ensure an effective board, there should be a balance of independence, skills, knowledge, experience and perspectives.

* Appointed during the year ** Resigned during the year

Director skills matrix



Information on directors of subsidiary companies
as at 30 June 2020

TB AND T LIMITED	RISK REINSURANCE LIMITED
Christopher Sutherland	David Knight (Chair)
David Knight	John Clarke
	Gordon Davidson

HALFWAY BUSH FINANCE LIMITED	emsTRADEPOINT LIMITED
Christopher Sutherland	John Clarke (Chair)
David Knight	David Knight
	Gordon Davidson

The directors of the subsidiary companies are all Transpower employees. Employees do not receive any additional remuneration for their role as a director of a subsidiary company.

Directors declare any interests they have after they are appointed to the Board, and interests are updated at every meeting. The Chair and General Counsel & Company Secretary together decide whether the interests present any conflicts and manage those accordingly, including not allowing directors to vote or be present during discussions where there may be a conflict.

Recommendation 2.5
Diversity policy

"An issuer should have a written diversity policy that includes requirements for the board or a relevant committee of the board to set measurable objectives for achieving diversity (which, at a minimum, should address gender diversity) and to assess annually both the objectives and the entity's progress in achieving them. The issuer should disclose the policy or a summary of it."

Transpower has a **Diversity and Inclusion Policy**. Created in November 2017, the policy defines Transpower's commitment to building a culture that promotes diversity and inclusiveness, pay parity and attracting, recruiting, developing, promoting and retaining a diverse group of talented individuals over a three-year period. The policy prescribes the responsibilities of the Board, the General Management Team and other employee groups and outlines Transpower's approach to the measurement and reporting of gender and ethnic diversity and inclusiveness of culture.

The policy identifies five priorities that Transpower is focused on:

- make diversity and inclusion a core part of Transpower's corporate policy framework;
- attracting and retaining more women with the objective of achieving a 40/40/20 gender target in teams over time (40% men, 40% women and 20% unallocated);
- attracting and retaining more Māori;
- eliminating the gender pay gap in Transpower; and
- making diversity and inclusion a core part of Transpower's employee value proposition.

Guided by our Chief Executive, Alison Andrew, who is part of the Champions for Change initiative in New Zealand, Transpower has made considerable progress during the 2019/20 year to support greater diversity and an inclusive culture across the organisation including:

- **Young Professional Community:** We have a strong focus on mentorship within Transpower. In the 2019/20 year, our Young Professional Community established a calendar of regular meetings, both online and in person, focused on professional development and mentoring.
- **Establishment of a hearing-impaired group:** More than 200,000 New Zealanders have a hearing impairment. This year we established an online group for our staff affected by hearing loss, providing a safe forum for members to share stories and provide guidance for the organisation.
- **Whanaungatanga:** We saw increased numbers attending the regular Noho Marae around New Zealand, immersing Transpower staff and local service providers in Māori culture.
- **Flexible work arrangements:** Transpower has always had flexible working arrangements and this came to the fore during the COVID-19 lockdown and the subsequent return to the office (with many staff juggling increased stress levels, school closures and 'business as usual').

MEASURE	DESCRIPTION	AS AT JUNE 2020		AS AT JUNE 2019	
AGE PROFILE	Median age		45 years		45 years
GENDER IDENTITY BY ROLE*	Role groupings by gender identity	Female (%)	Male (%)	Female (%)	Male (%)
	All	33	66	33	66
	People leaders	32	66	34	64
	General Management	30	70	33	67
	Board	57	43	62.5	37.5
ETHNICITY**			(%)		(%)
	% of staff providing ethnicity data		59		52
	European (incl NZer)		80		87
	Māori		4		5
	Middle Eastern/Latin American/African		7		7
	Asian		18		18
	Pacific		2		2
	Other Ethnicity		7		5
PART-TIME WORKING ARRANGEMENTS	Percentage of staff working part-time hours		5.6		5.5
NEW EMPLOYEES	The previous year's intake by age and gender		Median age 38.4 years Gender Identity: Female 39.7%; Male 59.5%		Median age 38 years Gender Identity: Female 39.5%; Male 60.5%
	Ethnicity		(%)		(%)
	% of staff providing ethnicity data		98		98
	European (incl NZer)		66		65
	Māori		1		4
	Middle Eastern/Latin American/African		7		7
	Asian		15		13
	Pacific		3		0
	Other Ethnicity		9		10

* Note: data as at 30 March 2020. Data may not add up to 100% if staff chose not to state their gender or state 'gender diverse' in the survey.
** Note: data as at 30 March 2020. Data is based on 59% of all staff who submitted ethnicity data when surveyed.
Totals may be greater than 100% due to staff being able to identify with up-to three ethnicities.

MEASURE	DESCRIPTION	AS AT JUNE 2020	AS AT JUNE 2019
INTERNAL HIRE RATE	The previous year's appointments identifying internal versus external hires	30.5% of all appointments have been internal.	41% of all appointments have been internal.
EMPLOYEE SATISFACTION	Response to the diversity statement: "I feel Transpower values diversity (e.g. age, gender, ethnicity, language, education qualifications, ideas and perspectives)."	Question not posed in 2020 survey.	82%
	Response to the diversity statement: "People from all backgrounds are treated fairly at Transpower."	8.6 (out of a possible 10)	Question not posed previously

Recommendation 2.6

Director training

"Directors should undertake appropriate training to remain current on how to best perform their duties as directors of an issuer."

From the outset of their tenure, Transpower directors participate in a comprehensive induction programme that includes one-on-one meetings with the Chief Executive and the General Management Team and site visits to key locations.

At least once a year, the Board holds strategic and professional development workshops. These provide opportunities for management to update the Board on key issues. Outside of these workshops, directors are regularly updated on relevant industry and company issues through an education programme agreed with the Chair. There is an ongoing programme of presentations to the Board by all parts of the business. Transpower's directors ensure that they are independently familiar with the company's operations through continuous education to appropriately and effectively perform their duties. This includes participating in an ongoing site visits programme.

Directors have ongoing Continuing Professional Development (CPD) objectives through their professional and director organisations which they are individually responsible for.

Recommendation 2.7

Performance

"The board should have a procedure to regularly assess director, board and committee performance."

Transpower's Board is accountable to shareholding Ministers for company performance. The Treasury monitors and advises shareholding Ministers on the Board's performance. Each director's performance is evaluated by the Chair, and the Board also evaluates its overall performance annually through external evaluations, which are provided to shareholders. The most recent evaluation was undertaken in 2019/20.

Recommendation 2.8

Independent Directors

"A majority of the board should be independent directors."

All directors are independent directors.

Recommendation 2.9

Chair and CEO

"The Chair and the CEO should be different people."

Transpower's **Board Charter** states that the Chair is separate from the Chief Executive. Pip Dunphy is the Chair of the Board of Transpower. Alison Andrew is Transpower's Chief Executive.

Principle 3:
Board committees

Transpower has five regular Board committees:

- Risk Committee;
- Audit and Finance Committee;
- People and Performance Committee;
- System Operator Committee (established during the 2019/20 year); and
- Transmission Pricing Methodology Committee (established during the 2019/20 year)

Each Board committee has terms of reference that outline the role, rights, responsibilities and membership requirements for that committee.

Other committees may be established from time-to-time to consider matters of special importance or to exercise the Board's delegated authority. The Board is responsible for appointing committee members according to the skills, experience and other qualities they bring to the committee.

A minimum of two directors are required to sit on each committee, although typically three or more do so. The General Counsel & Company Secretary attends all meetings as Secretary at the invitation of the Board. Each committee is chaired by a director who is not the Board Chair. The agenda, papers and minutes of each committee meeting are provided to all directors. The Board is also given a verbal or written report by the committee Chair on the outcomes of each Committee meeting.

The committees attend meetings each year scheduled to coincide with the timing of that committee's responsibilities. Each committee reviews its activities annually to ensure it is adequately covering its roles and responsibilities. The external evaluation of the Board also evaluates how each Board committee is functioning.

Recommendation 3.1
Audit committee

"An issuer's audit committee should operate under a written charter. Membership on the audit committee should be majority independent and comprise solely of non-executive directors of the issuer. The Chair of the audit committee should be an independent director and not the Chair of the board."

Transpower's Audit and Finance Committee is responsible for monitoring the financial performance and reporting of Transpower and its subsidiaries. It also reviews the appointment of external auditors (subject to the authority of the Auditor-General) and manages the external audit process, including reviewing and monitoring external audit and management reports.

> The board should use committees where this will enhance its effectiveness in key areas, while still retaining board responsibility.

Meetings of the Audit and Finance Committee

MEMBERS	MEETINGS HELD	MEETINGS ATTENDED
Kathy Meads	4	4
Pip Dunphy	4	4
Dean Carroll**	3	3
Sheridan Broadbent**	3	3
Bill Osborne*	1	1
Ilze Gotelli*	1	1

The external auditor is subject to the independence rules of the Auditor-General. These rules require the audit partner to be rotated after a maximum of six years. Transpower discloses fees paid to external auditors in its Annual Report and differentiates between audit fees and fees for individually identified non-audit work.

The Auditor-General has appointed Grant Taylor of Ernst & Young to carry out the audit on his behalf.

The Audit and Finance Committee also manages the internal audit process for financial matters, including reviewing, monitoring and approving internal audit reviews, annual audit plans and internal audit and management reports. All members of the Audit and Finance Committee are independent directors.

Recommendation 3.2
Employee attendance at audit committee meetings

"Employees should only attend audit committee meetings at the invitation of the audit committee."

The Audit and Finance Committee terms of reference set out that the Chief Executive and Chief Financial Officer are included as attendees at committee meetings at the request of the Chair of the committee. The General Counsel & Company Secretary attends all meetings as Secretary. All other attendees are only at the invitation or request of the Chair or Chief Executive.

Recommendation 3.3
Remuneration Committee

"An issuer should have a remuneration committee which operates under a written charter (unless this is carried out by the whole board). At least a majority of the remuneration committee should be independent directors. Management should only attend remuneration committee meetings at the invitation of the remuneration committee."

Transpower's People and Performance Committee performs the functions of a remuneration committee. This committee oversees Transpower's culture and performance and approves recruitment, remuneration, retention and termination decisions, and policies and procedures regarding executive management. It reviews and recommends to the Board the Chief Executive's remuneration, terms, annual key performance indicators and performance recommendations.

* Appointed to the Committee during the year ** Left the Committee during the year

Meetings of the People and Performance Committee

MEMBERS	MEETINGS HELD	MEETINGS ATTENDED
Prof Jan Evans-Freeman**	1	1
Pip Dunphy	2	2
Bill Osborne	2	1
Ilze Gotelli**	1	1
Dean Carroll*	1	1
Kathy Meads*	1	1

The People and Performance Committee terms of reference set out that the Chief Executive and the General Manager People are included as attendees at committee meetings. The General Counsel & Company Secretary attends all meetings as Secretary. All other attendees are only at the invitation or request of the Chair of the committee or Chief Executive.

Recommendation 3.4
Nomination committee

"An issuer should establish a nomination committee to recommend director appointments to the board (unless this is carried out by the whole board), which should operate under a written charter. At least a majority of the nomination committee should be independent directors."

The shareholding Ministers and ultimately the Cabinet appoints Transpower's directors on advice from The Treasury. The Board discusses potential candidates and makes recommendations to The Treasury. The Chair and Deputy Chair participate in interviews for potential candidates.

Recommendation 3.5
Other committees

"An issuer should consider whether it is appropriate to have any other board committees as standing board committees. All committees should operate under written charters. An issuer should identify the members of each of its committees, and periodically report member attendance."

Risk Committee

Transpower's Risk Committee has responsibility for reviewing health and safety matters on the Board's behalf and is responsible for ensuring that management has established a risk management framework that includes policy, procedures and assessment methodologies that enable Transpower to effectively manage and monitor business risks.

The Risk Committee also recommends the appointment of internal auditors and manages the internal audit process, including reviewing, monitoring and approving internal audit reviews, annual audit plans and internal audit and management reports. The Risk Committee will direct internal audit functions or material to either the Audit and Finance Committee or the People and Performance Committee where the subject matter is within the expertise of the respective committee. The primary objective of these internal audits is to assist the Board and the executive team in exercising good governance by providing independent assurance.

These recommendations came into play in earnest in the 2019/20 year with the COVID-19 lockdown. Strategic, external and operational risks were reviewed and updated as part of our ongoing efforts to manage our risks in the COVID-19 pandemic environment.

Meetings of the Risk Committee

MEMBERS	MEETINGS HELD	MEETINGS ATTENDED
Dean Carroll	4	4
Sheridan Broadbent	4	3
Pip Dunphy*	2	2
Prof Jan Evans-Freeman**	1	1
Dr Tim Densem**	1	1
Richard Aitken*	2	2

System Operator Committee

The System Operator Committee was formed during the 2019/20 year to oversee and provide guidance on all business activities related to Transpower's role as System Operator and reporting requirements to the Electricity Authority.

During the 2019/20 year the System Operator Committee provided recommendations to the business on system operator business assurance audits, software audits and major project assurance, real time pricing management and risk, and structure.

Meetings of the System Operator Committee

MEMBERS	MEETINGS HELD	MEETINGS ATTENDED
Dean Carroll	2	2
Pip Dunphy	2	2
Sheridan Broadbent	2	2
Richard Aitken	2	2

Transmission Pricing Methodology Committee

The Transmission Pricing Methodology Committee was formed on 30 June 2020 to oversee and provide guidance on Transpower's activities on the new pricing system, which is responsible for 90% of Transpower's revenue. The Committee met in the first quarter of the 2020/21 financial year.

* Appointed to the Committee during the year ** Left the Committee during the year

Principle 4:
Reporting and disclosure

Recommendation 4.1
Continuous disclosure

"An issuer's board should have a written continuous disclosure policy."

Transpower's External Communications Policy contains the Board approved policy on continuous disclosure.

Transpower has debt listed on the NZX Debt Market quoted under the ticker codes TRP030, TRP040, TRP050, TRP060 and TRR070 (together, bonds) and debt listed on the Swiss Stock Exchange (SIX). As a listed issuer, Transpower is subject to certain requirements and obligations under the NZSX/NZDX and SIX Listing Rules, including a continuous disclosure obligation.

The Board has appointed the General Counsel & Company Secretary as the Disclosure Officer and, with the Disclosure Officer, examines continuous disclosure at the end of every meeting, including whether anything discussed at the meeting warrants disclosure, and reviews any disclosures made the previous month. The General Management Team also evaluates disclosure at its two-weekly meetings.

Other disclosures

Based on the register of bondholders, Transpower has at least the following number of bondholders as at 30 June 2020:

BONDHOLDER NUMBERS	TRP030		TRP040		TRP050		TRP060		TRP070	
	No. of bond holders	No. of bonds (000)	No. of bond holders	No. of bonds (000)	No. of bond holders	No. of bonds (000)	No. of bond holders	No. of bonds (000)	No. of bond holders	No. of bonds (000)
1,001–5,000	9	45	5	25	1	5	3	15	3	15
5,001-10,000	34	320	22	204	17	156	2	18	9	83
10,001–100,000	103	3,673	44	1,594	56	2,033	9	387	78	3,194
>100,001	67	145,962	36	98,177	28	122,806	30	149,580	28	146,708
TOTAL	**213**	**150,000**	**107**	**100,000**	**102**	**125,000**	**44**	**150,000**	**118**	**150,000**

Top twenty largest listed bondholders	Holdings
BNP Paribas Nominees NZ	86,800,000
Cogent Nominees Limited	79,039,000
HSBC Nominees (New Zealand)	68,804,000
ASB Bank Limited	55,000,000
Citibank Nominees (NZ) Ltd	53,564,000
Tea Custodians Limited	47,416,000
JP Morgan Chase Bank	44,645,000
Premier Nominees Ltd	29,650,000
TSB Bank Ltd (Associate)	28,900,000
Investment Custodial Services	28,081,000
National Nominees New Zealand	22,725,000
Custodial Services Limited	22,241,000
FNZ Custodians Limited	21,682,000
Forsyth Barr Custodians	20,415,000
Lynette Therese Erceg	7,400,000
The Co-Operative Bank Limited	7,000,000
JBWere (NZ) Nominees Limited	6,345,000
NZ Permanent Trustees Ltd	5,750,000
PT (Booster Investments)	5,400,000
Southland Building Society	3,000,000

The **Insider Trading Policy and Guidelines Policy** has clear rules for when directors, officers and staff are dealing in listed Transpower securities.

Recommendation 4.2
Make key documents available

"An issuer should make its code of ethics, board and committee charters and the policies recommended in the NZX Code, together with any other key governance documents, available on its website."

Transpower's Code of Ethics and Conduct Policy, Board Charter and Terms of Reference for board committees recommended in the NZX Code, together with other governance documents, are available on Transpower's **website.**

Recommendation 4.3
Financial reporting

"Financial reporting should be balanced, clear and objective. An issuer should provide non-financial disclosure at least annually, including considering environmental, economic and social sustainability factors and practices. It should explain how it plans to manage those risks and how operational or non-financial targets are measured. Non-financial reporting should be informative, include forward-looking assessments, and align with key strategies and metrics monitored by the Board."

Transpower's Audit and Finance Committee is responsible for monitoring the financial performance and reporting of Transpower and its operating subsidiaries, emsTradepoint Limited and Risk Reinsurance Limited.

Transpower measures performance against a range of safety, operational, financial and non-financial performance targets. The 2019/20 targets are set out in the **2019/20 Statement of Corporate Intent**.

Each year, Transpower also agrees a set of system operation service targets with the Electricity Authority. There is a financial incentive to meet or outperform these targets.

Financial reporting

The Board requires, and the Audit and Finance Committee monitors and ensures, that Transpower's General Management Team implements and maintains best practice and fit-for-purpose financial reporting principles, policies and internal controls designed to comply with accounting standards and applicable laws and regulations.

Transpower develops targets for, and reports against, five key financial metrics. These are focused on sustaining Transpower's credit rating, balance sheet strength and returns.

Non-financial reporting

Transpower is committed to transparency at all levels of the organisation. Transpower reports on several non-financial performance measures to ensure transparency across the organisation. The Audit and Finance Committee ensures the Board is well informed about best practice reporting, including the **International Integrated Reporting Council Framework** and the **NZX Environmental, Social and Governance Guidance Note** issued on 11 December 2017.

Other non-financial performance measures relate to the health of Transpower's long-life assets – availability of the transmission grid and the length of outages on the transmission grid – as well as measures relating to safety and the environment.

The following tables compare the performance targets and measures for the 2019/20 year set out in the Statement of Corporate Intent (SCI) with those set out in the previous SCI. Further information on these targets and activities can be found in the online **Annual Review**.

> The board should demand integrity in financial and non-financial reporting, and in the timeliness and balance of corporate disclosures.

Statement of Corporate Intent Measures

Year-end performance	30 JUNE		SCI / PLAN
	2020	2019	TARGET
Safety and People Performance Targets			
Number of fatalities or injuries causing permanent disability	0	0	0
Total recordable injury frequency rate (TRIFR)[1]	6.34	6.89	≤ 6
High potential incident frequency rate (HPIFR)[1]	2.11	2.48	≤ 2.5
Staff Engagement	65%[2]	69%	>72%
Sustainability Targets			
Publish a carbon emissions report yearly to show our overall carbon footprint	Achieved	Achieved	Achieve Target
Hold SF_6 emissions at or below 0.8% of installed nameplate capacity	0.47	0.35	≤ 0.8
% of CommunityCare funding to Māori organisations	22%	31%	≥ 15
% of CommunityCare applications meeting strategic criteria submitted to the CommunityCare Fund Panel	78%	52%	≥ 75
Operational Performance Targets[3]			
Grid interruptions:[4]			
Achieve targets for occurrence	Achieved	Achieved	Achieve Target
Achieve targets for duration	Achieved	Achieved	Achieve Target
Grid availability:			
HVDC energy availability[5]	88.26%	99.1%	98.5%
Key HVAC circuits availability[5]	99.10%	98.7%	*5
Achieve system operations target	Achieved	Achieved	Achieve Target
Financial Targets			
Free funds from operations interest coverage (# of times)	3.9	3.6	3.7
Free funds from operations / Debt (%)	15.7	15.8	15.8
Debt/(Net Debt +Equity)	65.5	66.6	65.5
Return on equity (%)	10.1	11.9	10.1
Return on capital employed (%)	5.6	6.5	5.8

1: Safety Performance results at 30 June are rolling 12 months. All reported injuries were minor in nature. We are continuing to work closely with our service providers to maintain a focus on the contributing low-level incidents and deliver appropriate intervention programmes to address this trend.

2: Our employee engagement score result is a derived score as we are transitioning to a new survey platform. The result, from the new survey undertaken in May, was 8.0 out of a possible score of 10. This places Transpower in the top 10% of benchmark, global Energy and Utilities sector organisations. Participation was at 94%.

3: The Commerce Commission sets the price-quality standards for our network performance – a range of upper and lower limits within which we are expected to perform. Standards are set for outages and for asset health with financial penalties possible should standards be breached. These standards are not contained in the Statement of Corporate Intent (SCI) and differ from the targets listed in the SCI. Instead, they are listed on our website under RCP2 updates. For each year of RCP2, we have breached some of these standards resulting in investigations from the Commerce Commission.

4: Grid Interruptions
Transpower's performance against network service targets is measured at an aggregate level through a financial incentive framework to meet or outperform these targets. Our SCI target across grid interruptions and HVDC availability is to achieve a revenue-neutral outcome.

Grid Interruptions, as a performance category, includes targets for frequency (occurrence) and duration of interruptions. There are different targets, collars and caps for high priority, important, standard, N-security and generator connection locations.

5: Grid Availability
We breached our targets for the HVAC and HVDC availability due to the scheduled work programme necessary to maintain the grid.

6: No SCI target was set for the 2019/20 year.

The Task Force on Climate-related Financial Disclosures

Established in the 2019/20 financial year, the Task Force on Climate-related Financial Disclosures (TCFD) created a framework for New Zealand organisations to manage risks, identify and seize climate-related business opportunities, and disclose reliable information about the risks and opportunities to investors.

Transpower has a keen interest in climate-related financial disclosures for several reasons. We are a debt issuer under the NZX and have a number of subsidiaries and carry out group reporting. We are a signatory to the Climate Leaders Coalition and have committed to voluntarily measuring and reporting greenhouse gas emissions, setting a public emissions reduction target and working with our suppliers to reduce their emissions. We accept that the effects of climate change present risks to our assets. We are also a reporting organisation under the Climate Change Response (Zero Carbon) Amendment Act 2019 (Zero Carbon Act).

We have developed a staged approach for enhancing and integrating our identification and assessment of climate-related risks and opportunities across the organisation. Our TCFD roadmap to the 2022/23 financial year provides an outline of the key steps we will take to manage climate-related transition, physical risks and liability risks and opportunities and effectively disclose any material information.

This report includes full disclosure against six of the recommended 11 disclosures in the four key areas: Governance, Strategy, Risk management and Metrics and Targets.

Transpower TCFD roadmap

KEY: Complete In progress Planned

	FY2019-20	FY2020-21	FY2021-22	FY2022-23
Governance	Board approval of TCFD approach	Describe management's role and Board oversight of climate-related risks and opportunities		Review management's role and Board oversight of climate-related risks and opportunities
	Establish a project team to define scope, approach and roadmap for TCFD			
Strategy	Conduct initial climate change risk analysis and assessment	Conduct a gap analysis between current disclosures and TCFD recommendations	Review climate metrics and targets	Review results of scenario analysis and management of related risks and opportunities and fully integrate into strategic planning and decision making
		Undertake detailed assessment of climate-related transition risks, physical risks and liability risks	Develop range of scenarios and assess impact and risks/opportunities associated with selected scenarios using risk bowties	
Risk Management	Describe current approach to identifying, assessing and managing climate-related risks	Develop climate change resilience targets to flag potential climate change adaptation.	Integrate management of climate-related risks and opportunities into the enterprise risk management framework and associated processes	Principles on how an investment programme for adaptation can operate is developed with input from the regulator
Metrics and targets	Disclose Scope 1 – 3 GHG emissions	Report Scope 1 – 3 GHG emissions and carbon intensity of grid electricity	Report stage 2 baseline and targets for identified metrics	
Assurance	Board approval of GHG emission target	Undertake assurance of GHG emissions	Prepare for assurance over climate-related disclosures	Undertake assurance over climate-related disclosures

TCFD Disclosures FY2019/20

KEY ● Complete disclosure ● Partial disclosure ○ Planned

DISCLOSURE	INFORMATION
GOVERNANCE	Disclose the actual and potential impact of climate-related risks and opportunities on the organisation's business, strategy and financial planning where such information is material
● Describe the Board's oversight of climate-related risks and opportunities.	The Transpower Board is committed to responding to the challenges posed by climate change and has approved the updated sustainability strategy. A core function of the Board is to provide oversight of Transpower's enterprise risk management framework, including monitoring of Transpower's strategic, external and key operational risks and opportunities. Monitoring of risks and controls is performed by Board sub-committees, specifically the Risk Committee.
● Describe management's role in assessing and managing climate-related risks and opportunities.	In March 2020 management released its *Whakamana i Te Mauri Hiko* report, an update to the 2018 paper highlighting the opportunity that New Zealand has to decarbonise its economy. *Whakamana i Te Mauri Hiko* was completed after a great deal of work with a range of stakeholders and underlines the commitment of management to respond to the challenges of climate change. The Chief Executive has overall responsibility for the management of Transpower. Day-to-day management is delegated to respective General Managers who together make up the General Management Team (GMT). General Managers are responsible for assessing and managing risks in their Divisions. GMT is responsible for directing and providing assurance over Transpower's enterprise Risk Management Framework. Transpower's Chief Finance Officer is the responsible business owner of the framework. On a quarterly basis GMT reviews all strategic, external and key operational risks. The risk related to climate change is a key external risk to Transpower. In addition, the impact of a changing climate is reflected in other strategic and external risks such as the risk of serious harm to the environment, the risk of geopolitical instability and the risk of a significant fire or bushfire.
STRATEGY	Disclose the actual and potential impact of climate-related risks and opportunities on the organisation's business, strategy and financial planning where such information is material
● Describe the climate-related risks and opportunities the organisation has identified overt the short-term, medium-term and long-term.	Transpower has modelled a range of future scenarios as part of the development of *Whakamana i Te Mauri Hiko*. Relevant key points underpinning New Zealand's energy future for 2035 (medium-term) and 2050 (long-term) are: • Our electricity system provides economic advantages and risks • Electrification will drive decarbonisation • Electricity demand will increase by 68% by 2050 • The electrification of transport and process heat must be priorities • Renewables will dominate • A renewable future is the most affordable • The grid lies at the heart of the decarbonisation opportunity • Delivering this opportunity will require substantial investment • Our workforce is inadequate for the future Using the *Whakamana i Te Mauri Hiko* scenarios as a basis, Transpower has completed an initial assessment of climate-related risks and opportunities. The following categories have been identified:

Transition risks	Technology risks Market risks Reputation risks	• Substitution of current products and services • Changing customer preferences • Uncertainty in market signals • Shift to decentralised energy generation • Increased cost of materials • Increased stakeholder concerns

	Physical risks	Acute physical risks Chronic physical risks	• Increased frequency and severity of extreme weather events • Changes in precipitation patterns and extreme variability in weather patterns • Rising mean temperatures • Rising sea levels
	Liability risks	Regulatory risks Litigation risks	• Mandates on and regulation of existing products and services • Exposure to litigation
	Opportunities	More favourable physical conditions Resource efficiency Products and services	• Climate conditions in some parts of New Zealand become more favourable • Use of more efficient distribution processes • Waste minimalisation • Development and expansion of products and services

Describe the impact of climate-related risks and opportunities on the organisation's businesses, strategy and financial planning.	Climate-related risks impact on Transpower in a range of areas. Our financial position might be impacted by write-offs and early retirement of existing assets, additional costs to adopt and deploy new technologies, higher material and transport prices, reduced revenue and fines for grid interruptions and increased insurance premiums. We might also see an impact on our service performance, caused by an increasing number of unplanned grid interruptions and longer restoration times. Our reputation might be impacted by public and stakeholder dissatisfaction caused by more frequent and longer grid interruptions, as well as longer restoration times. Conversely, climate-related opportunities could help reduce our operating costs, increase the value of our fixed assets and increase our revenue through new products and services.
Describe the resilience of the organisation's strategy, taken into consideration different climate-related scenarios, including a 2-degrees or lower scenario.	Transpower uses the scenarios developed for *Whakamana i Te Mauri Hiko* to inform the organisation's strategies, taking into account the impacts of climate change. *Whakamana i Te Mauri Hiko* does not specifically include a 2-degrees or lower scenario. The development of these scenarios is planned for completion in FY2021/22.

RISK MANAGEMENT	Disclose how the organisation identifies, assesses and manages climate-related risks
Describe the organisation's processes for identifying and assessing climate-related risks.	Transpower carries out the identification and assessment process for climate-related risks in accordance with its enterprise risk management framework. Risks and opportunities are identified both bottom-up and top-down. For example, our acute and chronic physical risks consider climate-related threats to our fixed assets and our operating processes. Examples of a top-down or enterprise-wide risk are changes in customer preferences and Transpower's ability to adequately respond. Transpower is using risk workshops with subject matter experts, bowtie risk analysis and semi-quantitative risk assessment to get a deeper understanding of its climate-related risk. A comprehensive assessment of climate-related risk is planned for FY2020/21.
Describe the organisation's processes for managing climate-related risks.	Transpower recognises that risk management is an integral element of good management practice and governance. Risk management is the responsibility of line managers. Managers at each level are responsible for evaluating their risk environment, identifying and assessing risks to the achievement of their objectives and putting controls in place to prevent these risks from occurring or, once they have eventuated, to mitigate the impact. Risks are assessed against the enterprise risk rating framework which is derived from the Board's risk appetite statement. Transpower's risk and assurance function conducts an annual internal audit programme to provide assurance to management and the Board that controls are well-designed and working effectively.

Describe how processes for identifying, assessing and managing climate-related risks are integrated into the organisation's overall risk management.	A further integration of climate-related risks and opportunities into Transpower's enterprise risk and assurance framework and associated processes is planned for FY2021/22.
METRICS AND TARGETS	Disclose the metrics and targets used to assess climate-related risks and opportunities where such information is material
Disclose the metrics used by the organisation to assess climate related risks and opportunities in line with its strategy and risk management process.	Climate change metrics include Transpower's greenhouse gas emissions and our absolute carbon reduction target. Our sustainability framework dashboard includes qualitative KPIs addressing climate resilience, planning grid networks, enabling renewable and electrification connections and reporting the carbon impact of grid electricity delivered. KPIs are subject to review. This is published on our website and in our Annual Review.
Disclose Scope 1, Scope 2 and, if appropriate, Scope 3 greenhouse gas (GHG) emissions and the related risks.	Greenhouse gas emissions are disclosed according to Scope 1,2 and 3 of the GHG Protocol Corporate Standard. This will be disclosed in a separate GHG reporting section of the Annual Review and published on our website.
Describe the targets used by the organisation to manage climate related risks and opportunities and performance against targets.	Transpower is targeting a 60% reduction in emissions below 2005 levels by 2030, on track to achieve a net zero grid by 2050. This target applies to Scope 1 and 2 emissions. Our focus is on emissions we can control therefore the target excludes emissions due to transmission losses reported in Scope 2 emissions.

Principle 5:
Remuneration

Recommendation 5.1
Director remuneration

"An issuer should recommend director remuneration to shareholders for approval in a transparent manner. Actual director remuneration should be clearly disclosed in the issuer's annual report."

Remuneration and benefits payable to directors for services as a director are determined by shareholding Ministers. As a consequence of COVID-19, the Board agreed to take a 20% reduction in board fees for a six-month period. Remuneration paid to Transpower's directors during the 2019/20 financial year is detailed in the following table.

DIRECTOR	DATE COMMENCED IN OFFICE	DATE CEASED IN OFFICE	2019/20 $000	2018/19 $000
Pip Dunphy (Chair from 1 January 2019)	1 May 2015		112	101
Dean Carroll (Deputy Chair from 1 January 2019)	1 November 2016		69	71
Prof Jan Evans-Freeman	1 November 2012	31 October 2019	19	65
Bill Osborne	1 May 2016		54	65
Sheridan Broadbent	1 May 2018		54	65
Kathy Meads	1 March 2019		54	22
Ilze Gotelli	1 March 2019		54	22
Dr Tim Densem	1 March 2019	4 October 2019	13	22
Richard Aitken	1 November 2019		35	-
Dr Robert Blakeley	1 June 2020		-	-
Total			**464**	**511***

* Total includes directors who ceased in office in 2018/19.

During the 2019/20 year, no director of Transpower or the Transpower Group has received or become entitled to receive any benefit other than that disclosed above.

Recommendation 5.2
Remuneration policy for directors and officers

"An issuer should have a remuneration policy for remuneration of directors and officers, which outlines the relative weightings of remuneration components and relevant performance criteria."

Transpower's **Directors' Fees and Expenses Policy** sets out the directors' fees policy and how expenses incurred by directors are managed.

Transpower's Remuneration Policy and framework for officers is managed by the People and Performance Committee in line with the **committee's terms of reference**. Members of the executive team can earn incentive payments, subject to company and individual targets being met, such payments being at the absolute discretion of the Board. Any changes to executive management salaries are subject to consultation with the Chair and reviewed by the People and Performance Committee annually. Executives have performance objectives with line of sight to the company and Chief Executive objectives. Their salaries are informed by performance assessment by the Chief Executive, and incentives can be 20-25% of their salary. In relation to their 2019/20 objectives, the General Management Team received an average of 99% of their available incentives.

Remuneration of Transpower employees including executives

The remuneration model is designed to provide line of sight between the company objectives and individual objectives. It aims to attract, maintain and motivate employees.

All employees have fixed remuneration, reviewed each year within a budget agreed by the Board on recommendation from the People and Performance Committee. Any increase is informed by data from independent remuneration specialists. Employee remuneration is calculated based on a combination of their performance and how their salary compares to the market of a comparable position.

Transpower's employee remuneration tables for remuneration greater than $100,000

Aside from the Chief Executive, Transpower employees who received total remuneration of greater than $100,000 were in the following bands:

	2019/20	2018/19
550-559	1	-
540-549	1	-
530-539	-	1
520-529	-	1
450-459	4	2
440-449	1	1
390-399	1	-
370-379	-	1
330-339	-	1
320-329	1	1
310-319	1	2*
300-309	2	2
290-299	1	4*
280-289	1	-
270-279	2	2
260-269	6*	5
250-259	11	9*
240-249	8	9
230-239	9	13*
220-229	8*	6
210-219	7	11
200-209	7	11
190-199	23	19*
180-189	13*	17*
170-179	19	21
160-169	39*	31*
150-159	67	56
140-149	84*	77
130-139	74	66
120-129	77	81*
110-119	73	85*
100-109	60*	65*
	601	**600**

The bands above include all remuneration paid to or on behalf of employees, including base salary, performance payment, KiwiSaver, medical insurance, death and disability insurance, income protection insurance and severance or redundancy payments.

* The asterisk indicates those remuneration bands that include at least one former employee who received a severance or redundancy payment, without which they would not have been in that band.

Recommendation 5.3

CEO remuneration

"An issuer should disclose the remuneration arrangements in place for the CEO in its annual report. This should include disclosure of the base salary, short-term incentives and long-term incentives and the performance criteria used to determine performance-based payments."

> The remuneration of directors and executives should be transparent, fair and reasonable.

The Chief Executive can earn incentive payments, subject to company and individual targets being met and at the discretion of the Board. Any changes to Chief Executive salary is subject to approval by the Board following a review by the People and Performance Committee. As a consequence of COVID-19, the Chief Executive has taken a 20% reduction in her salary for a six-month period.

The Chief Executive objectives for 2019/20 related to the following:

70% **COMPANY COMPONENT**

WEIGHTING	PERFORMANCE OUTCOME AREA	PERFORMANCE DRIVER	INDICATOR	TARGET
15%	Safety	Zero Fatalities	Number of fatalities or injuries causing permanent disability	0
		Severe Harm & Injury Frequency	Severity Index (% of actual and potential serious harm)	≤2%
			Total recordable frequency rate (TRIFR)	≤6%
10%	Our People	Organisational Health	Engagement	≥76%
		Diversity & Inclusion	Gender balance 40/40/20[1]	Progress toward 40/40/20
		Establishment	Establishment FTE	836 Budget Full Time Equivalent (FTE)
15%	Customers	Grid Reliability	Grid Interruptions	Achieve targets for occurrence
		Grid Availability	Grid HVDC Energy Availability	Achieve ComCom target for HVDC of 98.5%
			Key HVAC circuits Availability	Achieve Transpower target for key HVAC of 98.7%
		Service Restoration	Customer Restoration	Achieve targets for duration
20%	Financial	Operating Profit	EBITDA	Achieve plan EBITDA (+/-2%)
		Works Delivery	Deliver 2019/20 base capex plan (Spend basis)	Deliver ≥95% of 2019/20 base capex plan (Spend basis)
		Works Planning	RCP3 Planning	Submit RCP3 Plan to ComCom
		Business Optimisation	Transformation Benefits	2019/20 Transformation Benefits Realised
5%	Relationships	Stakeholder Relationships	System Operator Service Targets	Achieve targets under SOSPA
5%	Sustainability	Environmental	Annual Carbon Emissions Report showing our overall carbon footprint	Publish Carbon Emissions report
			SF_6 emissions	Hold SF_6 emissions ≤0.8% of installed nameplate capacity
		Community	Percentage of CommunityCare applications meeting strategic criteria being approved	≥75%
			Percentage of CommunityCare funding to Māori organisations	≥15%

[1] 40/40/20 is explained under Principle 2.5.

30% STRATEGIC COMPONENT

WEIGHTING	COMPANY FOCUS AREA	STRATEGIC INITIATIVE	KEY PERFORMANCE INDICATORS
7.5%	Competitive costs and services	Deliver first year of Service Excellence programme	Stage one Service Excellence milestones achieved as planned
7.5%	Shape industry future	Constructively engage stakeholders in Te Mauri Hiko; engage key government and related organisations in conversations	Feedback to Chairman's satisfaction from stakeholders (Treasury, Electricity Networks Association, Climate Commission, Electricity Price Review, and Mercury Energy) as assessed by the Board Chair
7.5%	Setting direction for RCP3	Proposed service targets and expenditure benchmarks for RCP3 planned and agreed	Achieve RCP3 outcome from the Commerce Commission against base case +/- 10%
7.5%	Organisational effectiveness	Implement second year of transformation programme. Deliver year one of people strategy activities to achieve cultural transformation	Progress against diversity targets 40/40/20 Improve assessment against four behaviours by increase of 5% points or greater on 2018/19 results

The details of the Chief Executive remuneration are set out below. Figures include KiwiSaver. Incentives are based on company and individual objectives.

YEAR	FIXED REMUNERATION ($000)	AMOUNT OF INCENTIVE ($000*)	TOTAL REMUNERATION
2019/20	1,052	292	1,344
2018/19	1,017	288	1,305
2017/18	1,002	271	1,273
2016/17	994	271	1,245
2015/16	945	237	1,182

* Performance incentive paid during the financial year but relates to the prior year's performance as they were paid after balance date. It includes Kiwisaver paid on the incentive.

The details of the Chief Financial Officer remuneration are set out below. Figures include Kiwisaver. Incentives are based on company and individual objectives.

YEAR	FIXED REMUNERATION ($000)	AMOUNT OF INCENTIVE ($000)	TOTAL REMUNERATION
FY20[1]	444.5	-	444.5
FY19[2]	499.6	114.6	614.2
FY18	499.6	114.7	614.3
FY17	494.8	109.0	604.0
FY16	488.6	70.3	558.9

[1] Gordon Davidson started 29 April 2019 so was not eligible for incentive payment in the 2019/20 year.
[2] Alex Ball left 17 December 2018.

Principle 6:
Risk management

Recommendation 6.1:
Risk Management Framework

"An issuer should have a risk management framework for its business and the issuer's board should receive and review regular reports. An issuer should report the material risks facing the business and how these are being managed."

Transpower recognises that risk management is an integral element of good management practice and governance. The Board requires rigorous processes for risk management, supported by internal controls, to ensure that Transpower meets strategic objectives and the organisation is protected from adverse events.

Transpower's risk management covers the enterprise's entire perspective, including strategic, operational, commercial and financial aspects. The risk management policy is consistent with the internationally recognised standard AS/NZS ISO 31000:2009[1] and reflects the same risk management principles. Transpower's risk management methodologies include bowtie risk analysis and semi-quantitative risk assessment.

These methodologies enable Transpower to have a more comprehensive understanding of the risks faced and the control environment used to manage those risks. An independent review of Transpower's risk and assurance framework confirmed that the organisation has good risk and assurance practices in place, enabled by a culture that understands the value of risk management. The auditors reported that Transpower's risk and assurance performance is one of the stronger examples they had recently seen relative to their other clients.

Transpower's Risk Committee has responsibility for ensuring that management has established a risk management framework that includes policy, procedures and assessment methodologies that enable us to effectively manage and monitor organisational risks.

Management report on the status of key risks and the control environment to the Risk Committee on a quarterly basis.

The following pages are a summary of our strategic priorities and the key risks that relate to them.

> Directors should have a sound understanding of the material risks faced by the issuer and how to manage them. The Board should regularly verify that the issuer has appropriate processes that identify and manage potential and material risks.

[1] This standard has since been superseded by AS/NZS ISO 31000:2018. Transpower is in the process of aligning its risk policy and framework to the new standard. This will be completed in FY2020/21

KEY RISKS AND RELATED STRATEGIC PRIORITIES	EXPLANATION AND MITIGATION
Risk of a serious workplace injury or death at a Transpower site or involving Transpower assets • Sustain our social licence to operate	Our work relates to the development, operation and maintenance of assets where there is a risk of serious personal injury. We have sound, documented work processes in place to identify and manage hazards and risks throughout the lifecycle of our assets including project and maintenance work. We collaborate closely with our service providers in the planning and delivery of work in the field and support this with robust assurance processes to ensure works are completed to a high standard and without placing the health, safety and wellbeing of our people and members of the public at risk. Transpower continuously seeks to learn from others both within and external to our industry sector in order to share knowledge and drive improvements in safety. In response to the unfolding threat of COVID-19 we put additional measures in place to manage the risk of a workplace transmission of the virus, including development of COVID-19 site-specific management plans, physical separation of critical functions and protocols for office work and illness reporting.
Risk of serious harm to the environment • Sustain our social licence to operate	Our sustainability strategy seeks to position Transpower to support New Zealand's transition to a sustainable energy future. We do this through our focus on four challenges. The first is on enabling renewable and electrification connections while also reducing our own carbon footprint. The second relates to restoring the natural environment and reducing the impacts of materials and resources used. The third challenge is ensuring that our regulatory, governance and decision frameworks include full consideration of social and environmental impact while our reporting transparently describes our impacts, goals and progress. Lastly, we acknowledge mana whenua's connection to the land and partner with iwi to remediate the natural environment. We also work with landowners to minimise the impact of our work on their land and seek to reduce our footprint.
Risk of significant power supply interruptions • Sustain our social licence to operate	A core part of our role is to plan, build, operate and maintain the national grid, with the objective of 'keeping the energy flowing' for New Zealand electricity consumers. In the unlikely event that 'the lights do go off', we need to ensure there is sufficient resilience in the grid to reconnect people to their power supply as soon as possible. Those events could be related to asset failure, operations error or external circumstances, such as severe adverse weather or a national catastrophe. An important risk-reduction measure is our investment in the replacement and refurbishment of assets as their health and condition deteriorates. Ongoing measures include reliability-informed maintenance reviews, emergency preparedness and a collaborative approach to contingency planning with our customers. Following the outbreak of COVID-19 we have increased our stock of spare parts and materials in critical areas. We have also increased our level of coordination with our service providers to ensure critical works could continue as planned.
Risks in system operations • Sustain our social licence to operate • Accelerate our organisational effectiveness	Another core part of our role is that of system operator, in which we manage and coordinate electricity generation and operation of the electricity market minute-by-minute, 24/7, 365 days per year to provide an efficient and reliable power system. There is a constant risk that an event on the power system could impact our ability to ensure delivery of electricity around the country or maintain operation of the market. Key risk controls include having the people, systems and processes with which we plan for and manage any event in real-time and having the flexibility to respond and adapt to whatever event arises.
Risk of a cybersecurity breach • Sustain our social licence to operate • Evolve services to meet customers' needs • Play an active role in enabling New Zealand's energy future	We use a number of information, communications and technology systems that are critical for the supply of power and for system operations. To protect our systems and information against this sophisticated and ever-changing threat, continuous and systematic work aligned to international best-practice standards is ongoing to ensure information security. To achieve this, we are working closely with other stakeholders in the sector and with national authorities. We are also investing appropriately to increase our capabilities to better understand and respond to cybersecurity events.

KEY RISKS AND RELATED STRATEGIC PRIORITIES	EXPLANATION AND MITIGATION
Risk of not being able to find the skilled resources we need to effectively deliver our services • Accelerate our organisational effectiveness • Play an active role in enabling New Zealand's energy future	Engineers (electrical, civil and mechanical) and IT professionals with transmission and/ or power systems experience have always been a skills shortage in New Zealand. The skills shortage will increase as our population ages and as market demand for skilled people to build and connect generation increases globally, as electric vehicles grow their share for transport and as renewable energy increasingly substitutes for fossil fuels. As markets for skilled people are internationally connected, New Zealand will continue to recruit from a global talent pool, subject to New Zealand Immigration settings for acquiring skilled migrants. Equally, New Zealand may become a source of workforce supply for other countries, thus further reducing the skilled workforce required nationally to operate and maintain the grid. In response, we have developed a people strategy and we are focused on building a diverse and inclusive workforce, having a strong employment brand and employee value proposition that will enable us to attract and retain talent. We continue to build awareness of the sector and attractiveness of science, technology, engineering and maths (STEM) jobs at a national level. Transpower is engaging with stakeholders in the energy sector to increase domestic training of electricity workers.
Risk of not being able to adequately respond to exponential growth of emerging technologies such as batteries or in transport • Evolve services to meet customers' needs • Match our infrastructure to need over time	Potential changes in electricity consumption, generation and customer response technologies bring with them greater uncertainty about future grid usage. Our challenge is to sustain a cost-effective transmission service that continues to provide an appropriate level of reliability while adapting to changing demands. We foster dialogue and develop forecasts to help us understand trends that will impact the grid and invest in asset management improvements and innovation so we can anticipate and respond to changes.
Reputational risk • Sustain our social licence to operate • Play an active role in enabling New Zealand's energy future	Transpower provides a lifeline utility service for New Zealand and grid reliability is highly valued by our customers and electricity consumers. Our biggest reputational risk is associated with our ability to deliver on our mission 24/7, through all seasons and unaffected by weather conditions and other events. Furthermore, through our investments and operations, we have a physical presence throughout the country. This means that we need to continuously seek acceptance for our plans and ongoing activities. To establish and maintain good relations with the outside world, we proactively reach out to communities and stakeholders in specific cases.
Financial risk • Evolve services to meet customers' needs	Transpower's activities expose it to a variety of financial risks. We have a strong framework for financial risk management and treasury policies that include guidelines and limits related to liquidity risk, interest rate risk, currency risk, credit risk, commodity risk and insurance risk. Further details for each of these categories is provided in the notes to the financial section of this report. A specific financial risk relates to the fact that Transpower, as a natural monopoly, is regulated by the Commerce Commission. The Commerce Commission determines what rate of return applies to our assets, as well as the incentives for meeting and exceeding operating expenditure, capital expenditure and meeting certain deliverables and outage targets.
Supply Chain risk • Sustain our social licence to operate • Evolve services to meet customers' needs • Play an active role in enabling New Zealand's energy future	The unfolding outbreak of COVID-19 has elevated the risk to Transpower's international and domestic supply chain. In response, we have increased stock levels of supplies and materials for critical projects, identified alternative supply arrangements and ramped up our engagement with our international and domestic suppliers. We have also advanced the planning of materials and resources for our upcoming projects to enable early ordering of components.

Recommendation 6.2
Health and safety risks

"An issuer should disclose how it manages its health and safety risks and should report on their health and safety risks, performance and management."

Transpower strives to provide a working environment in which there are no fatalities or injuries causing permanent disability. The company also seeks to reduce the rate at which activities cause injury through continuously focusing on safety and making improvements to processes. The Board focuses on reducing the target for injuries in each year. The target for fatalities is always zero.

The Board closely monitors health and safety, and it is a standing agenda item at the commencement of every meeting. The Risk Committee also undertakes deep dives into matters of interest relevant to health and safety at the Board's direction. Reporting to the Board and the business on relevant metrics is crucial in understanding health and safety risks and trends. As well as the Total Recordable Injury Frequency Rate (TRIFR), Transpower also uses a severity index to measure and track the severity of health and safety incidents, including near misses, to provide us with more information about our more serious incidents.

The staff who work for Transpower's service provider organisations – Broadspectrum, Electrix, ElectroNet and Northpower – are the most exposed to health and safety risks inherent in carrying out high voltage work, often at height in remote parts of New Zealand. Transpower works with these organisations on health and safety issues, and a health and safety leadership team, comprising the Transpower Chief Executive and Chief Executive Officers of the four service providers, meets three times a year to ensure a national focus for an ongoing safe healthy working environment. The objective of these meetings is to implement major change programmes to improve safety performance, with a strong focus on behavioural safety management.

Principle 7:
Auditors

Recommendation 7.1
Establish a framework

"The board should establish a framework for the issuer's relationship with its external auditors."

Transpower's Audit and Finance Committee reviews the appointment of external auditors (subject to the authority of the Auditor-General) and manages the external audit process, including reviewing and monitoring external audit and management reports. There is regular dialogue between the Board and Board committees with both the internal and external auditors.

The external auditor is subject to the independence rules of the Auditor-General. These rules require the audit partner to be rotated after a maximum of six years. Transpower discloses fees paid to external auditors in our Annual Report and differentiates between audit fees and fees for individually identified non-audit work.

Recommendation 7.2
External auditor attendance at annual meeting

"The external auditor should attend the issuer's Annual Meeting to answer questions from shareholders in relation to the audit."

Transpower meets with shareholding Ministers or their representatives annually to examine the company's performance and review the strategic direction. Shareholding Ministers or their representatives can place items on the agenda for the annual meeting (including any governance or strategy items) and request other meetings throughout the year, if required. Transpower's Board, Chief Executive, General Counsel & Company Secretary and other executives by invitation, attend the annual shareholders' meeting and are available to answer any questions the shareholding Ministers have.

Transpower also attends the Transport and Infrastructure Select Committee annually to discuss the company's performance during the year. The Transport and Infrastructure Select Committee also meets separately with Transpower's external auditors.

Recommendation 7.3
Internal audit

"Internal audit functions should be disclosed."

The Risk Committee recommends the appointment of internal auditors and provides governance oversight of the internal audit process for all audits including any financial audits. This includes reviewing, monitoring and approving internal audit reviews, annual audit plans and internal audit and management reports. Any financial audits are also shared with the Audit and Finance Committee. The primary objective of these internal audits is to assist the Board and the General Management Team in exercising good governance by providing independent assurance. All Board members have access to these reports.

Transpower predominantly delivers its internal audit function using external resources (mostly Deloitte) to carry out a range of compliance and improvement audits. Deloitte's internal audit partner attends the Risk Committee on request.

> The board should ensure the quality and independence of the external audit process.

Principle 8:
Shareholder rights and relations

Recommendation 8.1
Website

"An issuer should have a website where investors and interested stakeholders can access financial and operational information and key corporate governance information about the issuer."

Financial disclosures and information for investors can be found in the **investor section** of Transpower's website.

Recommendation 8.2
Investor communications

"An issuer should allow investors the ability to easily communicate with the issuer, including providing the option to receive communications from the issuer electronically."

Transpower communicates with investors via multiple channels throughout the year: continuous market disclosure, half-year and full-year reporting of financial and non-financial performance and half-year and full-year investor briefings. Numerous stakeholder events are held throughout the year. The Board has hosted and attended a number of these events, and directors have also undertaken several customer visits to better understand customer needs.

Transpower's Board has a clear policy for engagement and regular communication with significant stakeholders, in particular, customers and regulators. The Board regularly assesses its stakeholder engagement and ensures that conduct towards stakeholders complies with ethical obligations and the law, and is within broadly accepted social, environmental and ethical norms.

Transpower has debt securities listed on the NZX. Its bond holders are set out in Principle 4. Transpower regularly updates bond holders with information relevant to their investment and takes the opportunity to meet with them and their representatives regularly.

Investors can contact the executive or the Board by entering their query details on Transpower's **website**.

> The board should respect the rights of shareholders and foster constructive relationships with shareholders that encourage them to engage with the issuer.

Financial Statements

For the year ended 30 June 2020

Statement of comprehensive income

For the year ended 30 June 2020

	NOTES	2020 Group ($M)	2019 Group ($M)
Operating revenue	**2**	**986.9**	**1,029.9**
Operating expenses	**3**	**291.6**	**297.0**
Earnings before interest, tax, depreciation, amortisation, asset write-offs, impairment and changes in the fair value of financial instruments	**1**	**695.3**	**732.9**
Depreciation, amortisation, asset write-offs and impairment	5, 6	284.5	263.8
Net interest expenses	4, 6	159.2	181.3
Earnings before changes in the fair value of financial instruments and tax		**251.6**	**287.8**
Gain (loss) in the fair value of financial instruments	16	64.2	71.0
Earnings before tax		**315.8**	**358.8**
Income tax expense	17	84.7	100.4
Net profit		**231.1**	**258.4**
Attributable to:			
Non-controlling interest		(1.0)	0.3
Owners of the parent		232.1	258.1
Other comprehensive income (expense)*	**16**	**(83.2)**	**(8.6)**
Attributable to:			
Non-controlling interest		-	-
Owners of the parent		(83.2)	(8.6)
Total comprehensive income (expense)		**147.9**	**249.8**
Attributable to:			
Non-controlling interest		(1.0)	0.3
Owners of the parent		148.9	249.5

Reconciliation of net profit specifying the net impact of fair value movements

Earnings before changes in the fair value of financial instruments and tax		**251.6**	**287.8**
Income tax expense excluding changes in the fair value of financial instruments		66.7	80.5
Earnings before net changes in the fair value of financial instruments	1	**184.9**	**207.3**
Gain (loss) in the fair value of financial instruments		64.2	71.0
Income tax expense on changes in the fair value of financial instruments		18.0	19.9
Net profit		**231.1**	**258.4**

* During the year, the Group has designated certain interest rate swaps into the cash flow hedge accounting relationships, which align interest rate exposures to the Regulatory Control Period (RCP).

These statements are to be read in conjunction with the accompanying notes.

Statement of financial position

As at 30 June 2020

	NOTES	2020 Group ($M)	2019 Group ($M)
Assets Employed			
Cash and cash equivalents		13.4	156.5
Investments	10	100.6	99.9
Trade receivables and other assets	11	100.7	136.1
Derivatives and hedge commitment in gain	8	423.1	321.2
NZPCL investment	9	98.1	85.7
Property, plant and equipment	5	4,732.2	4,621.8
Intangibles	5	374.1	372.9
Right-of-use asset	6	122.0	-
Capital work in progress	5	151.7	138.3
Total assets employed		**6,115.9**	**5,932.4**
Funds Employed			
Liabilities			
Cash and cash equivalents		-	0.3
Trade and other payables	12	60.4	97.2
Current tax liability		12.8	24.0
Deferred income	2	166.0	129.8
Derivatives and hedge commitment in loss	8	232.4	213.4
Provisions	13	56.7	63.5
Debt	7	3,311.0	3,227.4
NZPCL debt	9	100.5	86.7
Lease liabilities	6	99.7	-
Deferred tax	17	453.0	449.6
Total liabilities		**4,492.5**	**4,291.9**
Equity			
Capital	14	1,200.0	1,200.0
Accumulated surplus		500.0	441.3
Cash flow hedge reserve		(74.8)	-
Non-controlling interest	9	(1.8)	(0.8)
Total equity		**1,623.4**	**1,640.5**
Total funds employed		**6,115.9**	**5,932.4**

The Board of Directors of Transpower New Zealand Limited authorised these financial statements for issue on 20 August 2020.

For, and on behalf of, the Board

Pip Dunphy | Chair   **Kathy Meads** | Chair Audit and Finance Committee

These statements are to be read in conjunction with the accompanying notes.

Statement of changes in equity

For the year ended 30 June 2020

2019/20 Group	NOTES	ORDINARY SHARES	RETAINED EARNINGS	CASH FLOW HEDGE RESERVE	OWNERS OF THE PARENT	NON CONTROLLING INTEREST	TOTAL
		($M)	($M)	($M)	($M)	($M)	($M)
Equity at 1 July 2019		1,200.0	441.3	-	1,641.3	(0.8)	1,640.5
Profit for the year		-	232.1	-	232.1	(1.0)	231.1
Other comprehensive income		-	(8.4)	(74.8)	(83.2)	-	(83.2)
Total comprehensive income		-	**223.7**	**(74.8)**	**148.9**	**(1.0)**	**147.9**
Dividends paid	14	-	(165.0)	-	(165.0)	-	(165.0)
Total equity at 30 June 2020		**1,200.0**	**500.0**	**(74.8)**	**1,625.2**	**(1.8)**	**1,623.4**

2018/19 Group	NOTES	ORDINARY SHARES	RETAINED EARNINGS	CASH FLOW HEDGE RESERVE	OWNERS OF THE PARENT	NON CONTROLLING INTEREST	TOTAL
		($M)	($M)	($M)	($M)	($M)	($M)
Equity at 1 July 2018		1,200.0	356.8	-	1,556.8	(1.1)	1,555.7
Profit for the year		-	258.1	-	258.1	0.3	258.4
Other comprehensive income		-	(8.6)	-	(8.6)	-	(8.6)
Total comprehensive income		**-**	**249.5**	**-**	**249.5**	**0.3**	**249.8**
Dividends paid	14	-	(165.0)	-	(165.0)	-	(165.0)
Total equity at 30 June 2019		**1,200.0**	**441.3**	-	**1,641.3**	**(0.8)**	**1,640.5**

Non controlling interest - refer to Note 9 for detailed description.

These statements are to be read in conjunction with the accompanying notes.

Cash flow statement

For the year ended 30 June 2020

	2020 Group ($M)	2019 Group ($M)
Cash flow from operations		
Receipts from customers	1,025.1	1,054.2
Interest received	6.0	5.9
Payments to suppliers and employees	(303.0)	(292.6)
Tax payments	(60.2)	(64.3)
Interest paid	(184.4)	(189.4)
Net cash inflows from operations	**483.5**	**513.8**
Cash flow from investments		
Sale of property, plant and equipment	2.1	9.5
Sale of short-term investments	61.0	130.4
Purchase of property, plant and equipment and intangibles	(425.5)	(328.8)
Purchase of short-term investments	(60.5)	(78.6)
Net cash (outflows) from investments	**(422.9)**	**(267.5)**
Cash flow from financing		
Proceeds from bonds, term debt and commercial paper	1,495.5	707.4
Dividends paid	(165.0)	(165.0)
Payment of principal portion of lease liabilities	(8.6)	-
Repayment of bonds, term debt and commercial paper	(1,525.3)	(707.5)
Net cash (outflows) from financing	**(203.4)**	**(165.1)**
Net increase/(decrease) in cash held	(142.8)	81.2
Opening balance brought forward	156.2	75.0
Closing net cash carried forward	**13.4**	**156.2**
Closing net cash carried forward comprises:		
Cash and on-call deposits	13.4	81.1
Short-term deposits with original maturity less than three months	-	75.1

These statements are to be read in conjunction with the accompanying notes.

Cash flow statement reconciliation

Reconciliation of net profit (loss) with net cash flow from operations

	2020	2019
	Group ($M)	Group ($M)
Net profit	**231.1**	**258.4**
Add (deduct) non-cash items:		
Change in the fair value of financial instruments	(63.8)	(70.7)
Depreciation, amortisation and write-offs	284.5	263.8
Deferred tax	35.7	39.2
Capitalised interest	(8.5)	(8.1)
Movements in working capital items:		
(Increase)/decrease in trade and other receivables	(11.1)	(0.5)
(Increase)/decrease in prepayments	21.8	3.2
(Decrease)/increase in trade and other payables, interest payable and deferred income	4.8	27.2
(Decrease)/increase in taxation payable	(11.2)	(3.1)
(Decrease)/increase in provisions	0.2	4.4
Net cash flow from operations	**483.5**	**513.8**

1. Transpower Group information

Reporting entity and statutory base

Transpower New Zealand Limited (Transpower) is a state-owned enterprise registered in New Zealand under the Companies Act 1993. The financial statements are in New Zealand dollars and comprise of Transpower and its subsidiaries (together the Group).

The Group is the owner and operator of New Zealand's national electricity grid. The Group is a for-profit entity in accordance with XRB A1 Accounting Standards Framework.

Basis of preparation

The financial statements have been presented in accordance with the State-Owned Enterprise Act 1986 and are prepared in accordance with the Financial Markets Conduct Act 2013. The financial statements have been prepared and comply with generally accepted accounting practice (GAAP) in New Zealand and the Financial Reporting Act 2013.

The financial statements comply with New Zealand Equivalents to International Financial Reporting Standards (NZ IFRS). The financial statements comply with International Financial Reporting Standards (IFRS).

The statement of comprehensive income and the cash flow statement are prepared so that all components are stated exclusive of GST. All items in the statement of financial position are stated exclusive of GST with the exception of receivables and payables, which include GST.

The financial statements of the Group's subsidiaries are prepared in the functional currency of that entity, being New Zealand dollars. The exception to this is New Zealand Power Cayman 2003-1 Limited which has a functional currency of US dollars and a presentational currency of New Zealand dollars.

Where necessary, certain comparative information has been reclassified to conform to changes in presentation in the current period.

COVID-19 Pandemic

On 11 March 2020, the World Health Organisation declared the outbreak of COVID-19 a pandemic and two weeks later the New Zealand Government declared a State of National Emergency. From this, the country was in lockdown at Alert Level 4 for the period 26 March to 27 April and remained in lockdown at Alert Level 3 until 13 May inclusive.

During Alert Levels 3 and 4 Transpower had the majority of staff working from home with the exception of those unable to complete their tasks outside of the offices such as our Control Centres and warehouse staff. Under Alert Level 4 we suspended our non-essential routine maintenance programme, and our capital works and on 13 May 2020, we resumed all our operations. There was no unplanned interruptions or significant impact on supply on the grid over this period.

The impacts on our maintenance and capex programmes as a result of COVID-19 are being rescheduled with our service providers over the Regulatory Control Period 3. These delays are not expected to impact negatively on reliability of supply.

Due to concerns about the COVID-19 virus' impact on the global economy and resultant significant financial market volatility, Transpower delayed its plans to issue Term Debt on 16 March 2020. Instead Transpower improved short-term liquidity by way of issuing a bank facility of $50 million maturing May 2022 and commercial paper of $98.8 million maturing April 2021. Transpower used these funds to help fund our customers and suppliers impacted by COVID-19. We continue to monitor market conditions with a view to return to the bond market.

The Directors have considered the effects on the business and financial statements caused either directly or indirectly by COVID-19. The effect on the overall results was not material due to the majority of Transpower's revenue being regulated, the period of the lockdown within this financial year and continuation of essential services during the lockdown period. An assessment of the impact of COVID-19 on Transpower's balance sheet is set out below, based on information available at the time of preparing these financial statements:

STATEMENT OF FINANCIAL POSITION ITEMS	COVID-19 ASSESSMENT	NOTE
Cash	No impact to the carrying value of cash on hand.	
Trade receivables and other assets	The majority of Transpower's revenue is covered by the Input Methodologies, which ultimately provides credit protection. Transpower has no evidence that there is any expected credit loss at balance date due to COVID-19. There was no impact on the net realisable value of inventory on hand at balance date.	11
Capital assets and commitment	Transpower uses the cost model for all capital assets, including capital work in progress. There was no impact on the carrying value of capital assets at balance date.	5
Right-of-use assets	Transpower is not currently seeking any rent relief from landlords and has not considered any changes to or extension of leases within its lease portfolio resulting from COVID-19.	6
Derivatives Financial instruments	COVID-19 has impacted financial markets. Derivatives are valued and recorded at fair value, the carrying value reflects the movements of underlying market rates at balance date.	7
Trade and other payables	To assist the cash flows to New Zealand businesses, Transpower increased payment frequency to domestic suppliers, which resulted in lower payable balance at balance date.	12
Income tax	There was no material impact on profitability driven by COVID-19 as such provisional tax payment level remained unchanged.	17
Provisions	To assist the cash flow of Transpower's key service providers, Transpower has reviewed and was able to release some retentions on certain projects, where the risk is anticipated to be low. This has reduced the balance of contractor provisions at balance date.	13

The Directors are continuing to closely monitor the COVID-19 situation. The Company has not identified any going-concern issues and is working closely with customers and contractors to ensure that appropriate actions are taken, with people's safety and wellbeing as the priority.

New standards adopted during the year

During the period, Transpower adopted NZ IFRS 16 Leases.

NZ IFRS 16 supersedes NZ IAS 17 Leases and sets out the principles for the recognition, measurement, presentation and disclosure of leases. It requires lessees to recognise most leases on the balance sheet. Accordingly, the profit or loss impact is a decrease in operating lease and rental expenditures and an increase in depreciation expense and imputed interest.

Transpower adopted NZ IFRS 16 using the modified retrospective method of adoption with the date of initial application of 1 July 2019. Under this method, the cumulative effect will flow through retained earnings at the date of initial application.

Upon adoption of NZ IFRS 16, Transpower applied a single recognition and measurement approach for all leases except for short-term leases and leases of low-value assets. Transpower applies the short-term lease recognition exemption to its short-term leases (i.e. those leases that have a lease term of 12 months or less from the commencement date and do not contain a purchase option). Transpower also applies the lease of low-value assets recognition exemption to leases of office equipment that are considered to be low value. Lease payments for these leases are recognised as an expense on a straight-line basis over the lease term.

The effect of adopting NZ IFRS 16 as at 1 July 2019 (increase/(decrease)) is, as follows:

Assets

($M)	
Right-of-use assets	129.1
Property, plant and equipment	-
Prepayments	(23.0)
Total assets	**106.1**

Liabilities

($M)	
Lease liabilities	106.1
Deferred tax liabilities	-
Trade and other payables	-
Total liabilities	**106.1**

Total adjustment on equity

($M)	
Retained earnings	-
Non-controlling interest	-
Total equity	**-**

The lease liabilities as at 1 July 2019 can be reconciled to the operating lease commitments as of 30 June 2019, as follow:

($M)	
Operating lease commitments as at 30 June 2019	112.2
Weighted average incremental borrowing rate as at 1 July 2019	3.48%
Discounted operating lease commitments as at 1 July 2019	**83.9**
Less:	
Commitments relating to short-term leases	-
Commitment relating to leases not containing an asset	(20.8)
Commitments relating to leases of low-value assets	-
Add:	
Lease payments relating to extensions deemed reasonably certain	43.0
Lease liabilities as at 1 July 2019	**106.1**

Measurement basis

The measurement basis adopted in the preparation of these financial statements is historical cost except as modified for certain investments, held for sale assets, financial assets and financial liabilities.

Additionally, Transpower discloses an alternative measure of profit, which is earnings before net changes in fair values of financial instruments. Transpower discloses this information as it provides a different measure of underlying performance to the IFRS-mandated profit measures, which are also disclosed. The Directors consider that this additional profit measure is useful additional information for users of the financial statements and is a measure that Directors consider when setting the level of dividend payments to the shareholder. Transpower has consistently reported an alternative profit on this basis since the adoption of IFRS.

Significant accounting policies

a) The Group financial statements consolidate the financial statements of subsidiaries as at and for the year ended 30 June 2020. Subsidiaries are those entities controlled, directly or indirectly, by Transpower. All significant intercompany balances and transactions are eliminated on consolidation. The Group discloses a non-controlling interest (NCI) relating to New Zealand Power Cayman 2003-1 Limited. NCI is measured at the NCI's share of net assets.

b) Accounting policies, and information about judgements that have had a significant effect on the amounts recognised in the financial statements are disclosed in the relevant notes as follows:

   i. Operating revenue and deferred income — Note 2
   ii. Capital assets and commitments — Note 5
   iii. Debt, financial instruments and risk management — Note 7

New standards not yet adopted

There are no new accounting standards issued but not yet effective which materially impact Transpower.

2. Operating revenue and deferred income

Transmission revenue

Group ($M)	2020	2019
HVAC interconnection	641.4	673.9
HVAC connection	124.6	129.6
EV (rebate) charge – HVAC	(8.1)	(16.6)
HVDC	134.7	150.6
EV (rebate) charge – HVDC	(3.0)	(0.2)
Other regulated transmission	5.3	4.5
Customer investment contracts	30.6	27.8
Undergrounding and transmission realignment	4.3	4.4
Other transmission	2.0	1.7
	931.8	**975.7**

Other revenue

System operator	41.9	41.1
Other	13.2	13.1
	55.1	**54.2**
Total operating revenue	**986.9**	**1,029.9**

Description

Transmission revenue

Transmission revenue consists of charges for the transmission of electricity from the point of generation to the point of supply, being high voltage alternating current (HVAC) interconnection, connection and high voltage direct current (HVDC).

Customer investment contracts are contracts entered into with customers to build grid connection assets. Transpower recognises this revenue over the life of the asset.

Undergrounding and transmission realignment contracts are contracts entered into with third parties to underground and/or realign certain transmission line assets. The revenue is recognised based on the revenue source.

Other revenue

System operator income relates to payments received to operate the electricity market to dispatch generation to ensure the short-term security of the New Zealand electricity system.

Included in the above numbers is revenue subject to the telecommunications development levy of $2.5 million in the year to 30 June 2020 (2019: $2.5 million).

Accounting policies

Transmission revenue with customers, excluding customer investment contracts and transmission realignment contracts, are recognised on a monthly basis as Transpower delivers the service and customers consume the benefit. The transmission revenue performance obligation is the provision of access to the network.

The money received from customer investment contracts can be received over different contract periods varying between all up-front to over 40 years. The assets built for the customers are owned by Transpower, however, Transpower is providing a service to the customers over the life of the asset. The service is the monthly delivery of electricity and the customers' consumption of that benefit. Therefore, the revenue is grossed up for an imputed interest expense and recognised over the estimated life of the related assets. The performance obligation is the provision of access to the network.

Agreements between Transpower and third parties to underground and/or realign certain transmission line assets are recognised based on the revenue source. If the revenue is received from central or local government, or their agencies, then the revenue is recognised according to the government grants standard (NZ IAS 20) with revenue grossed up for an imputed interest expense and recognised over the life of the related transmission assets. If revenue is received from non-government parties, then it is recognised at a point in time, once the transmission assets are commissioned. The decommissioned transmission assets are then immediately written off for the same value. In contracts with non-government customers, the performance obligation is the shifting of the transmission line.

Summary of revenue recognition

	Recognised monthly as customers use service	Recognised over life of relevant asset	Recognised in year of commissioning asset
Transmission revenue	●		
Customer investment contracts		●	
Undergrounding and transmission realignment – Government		●	
Undergrounding and transmission realignment – non-Government			●

Certain transactions relating to the operation of the electricity market, specifically wholesale market-related ancillary services and losses and constraint payments, are passed through and are, therefore, not recorded in profit or loss. This pass-through occurs because Transpower is deemed to act only as an agent. Similarly, Transpower acts as an agent relating to its natural gas market operation.

Related disclosures

Group ($M)	2020	2019
Deferred income		
Customer investment contracts	71.2	53.2
Undergrounding and transmission realignment	90.0	73.2
Other	4.8	3.4
Total deferred income	**166.0**	**129.8**
Current portion	34.1	16.9
Non-current portion	131.9	112.9
Total deferred income	**166.0**	**129.8**

A reconciliation of deferred income as it relates to revenue is shown below for the two major categories:

2020 ($M)	Customer investment contracts	Undergrounding and transmission realignment
Opening balance 1 July 2019	53.2	73.2
Advance payments received from customers	44.6	17.1
Net revenue recognised in the year from		
Amounts included in the contract liability at the beginning of the year	(0.2)	(0.3)
Advance payments applied to current year	(26.4)	-
Closing balance 30 June 2020	**71.2**	**90.0**

2019 ($M)	Customer investment contracts	Undergrounding and transmission realignment
Opening balance 1 July 2018	35.4	58.8
Advance payments received from customers	42.4	14.6
Net revenue recognised in the year from		
Amounts included in the contract liability at the beginning of the year	(0.1)	(0.2)
Advance payments applied to current year	(24.5)	-
Closing balance 30 June 2019	**53.2**	**73.2**

3. Operating expenses

Group ($M)	2020	2019
Grid maintenance		
HVAC substations maintenance	44.4	46.5
HVDC substations and cables maintenance	11.4	10.3
HVAC lines maintenance	41.5	39.1
HVDC lines maintenance	1.9	1.9
Transmission-related rates	6.5	6.4
Other	6.6	6.9
	112.3	**111.1**
IST maintenance and operations		
Support and maintenance	9.0	9.0
Outsourced services	11.2	15.6
Licences	9.2	9.2
Other IST	2.5	7.5
	31.9	**41.3**
Other operating expenses		
Investigations	18.3	15.3
Ancillary service costs	3.2	4.6
Employee benefits	117.0	112.7
Capitalised salary costs	(26.7)	(24.6)
Salary transferred to investigations	(6.0)	(6.2)
Contractors and consultants	11.7	9.5
Operating lease and rental costs	0.3	5.0
Industry levies	10.3	10.8
Insurance	4.8	4.3
Travel and vehicle costs	1.9	2.6
Other business support costs	12.6	10.6
	147.4	**144.6**
Total operating expenses	**291.6**	**297.0**

Description

Maintenance includes inspection, servicing and repair costs.

Other grid maintenance expenses include maintenance support, communication systems costs and training for service providers and third parties.

Information Service Technology (IST) maintenance and operations expenses include system and software support, software license fees and service lease charges.

Investigations includes work that the Group conducts prior to the commencement of a capital project, updates to maintenance standards and demand response costs.

Other business support costs include such items as lease expenses relating to short-term leases and low-value assets, legal fees, office equipment and communications.

In the June 2019 comparatives, the Group had total lease payments of $12.6 million in Other IST and Other business support costs.

Related disclosures

Fees paid to external auditor

Group ($000)	2020	2019
Audit of financial statements		
Audit and reviews of financial statements [1]	474	472
Other services		
Other assurance [2]	18	8
Independent review of economic modelling and demand forecasting	64	34
Training courses	49	54
Trust deed requirements [3]	11	11
Remuneration benchmarking report	9	8
	151	**115**
Total fees paid to external auditor	**625**	**587**

1. This includes an annual audit and a six-monthly review.
2. This includes an assurance of the Group's Carbon footprint report in 2020.
3. Trust deed requirements include fees to review Directors' certificates in relation to debt held against two trust deeds.

4. Net interest expenses

Group ($M)	2020	2019
Interest revenue		
Interest received	6.0	5.9
	6.0	**5.9**
Interest expenses		
Interest expenses and associated fees	161.5	187.8
Capitalised interest	(8.5)	(8.1)
Imputed interest	12.2	7.5
	165.2	**187.2**
Total net interest expenses	**159.2**	**181.3**

Description

Capitalised interest is based on Transpower's forecast weighted average cost of borrowing. For 2020, capitalised interest was 5.83% (2019: 6.59%).

Imputed interest arises on deferred income, the unwinding of the discount of future cash flows related to provisions, and the interest on lease liabilities.

5. Capital assets and commitments

This note includes property, plant and equipment, intangible assets, non-current assets held for sale, capital work in progress and capital commitments.

Group ($M)	HVAC TRANSMISSION LINES	HVDC TRANSMISSION LINES	HVAC SUBSTATIONS	HVDC SUBSTATIONS AND SUBMARINE CABLES
At 30 June 2020				
Cost	2,768.7	167.3	2,728.5	876.9
Accumulated depreciation/amortisation	(771.6)	(60.3)	(844.0)	(398.7)
Net book value/carrying value	**1,997.1**	**107.0**	**1,884.5**	**478.2**
30 June 2020 reconciliation				
Opening net book value/carrying value (1 July 2019)	1,981.5	91.8	1,790.3	510.8
Additions/transfers	89.5	19.5	169.4	4.9
Disposals/transfers	(3.0)	(0.2)	(3.5)	(0.5)
Depreciation/amortisation	(70.9)	(4.1)	(71.7)	(37.0)
Closing net book value/carrying value	**1,997.1**	**107.0**	**1,884.5**	**478.2**
At 30 June 2019				
Cost	2,683.9	148.2	2,583.1	873.0
Accumulated depreciation/amortisation	(702.4)	(56.4)	(792.8)	(362.2)
Net book value/carrying value	**1,981.5**	**91.8**	**1,790.3**	**510.8**
30 June 2019 reconciliation				
Opening net book value/carrying value (1 July 2018)	1,958.8	96.7	1,765.1	542.4
Additions/transfers	95.1	1.9	102.0	5.0
Disposals/transfers	(4.3)	(2.9)	(5.3)	-
Depreciation/amortisation	(68.1)	(3.9)	(71.5)	(36.6)
Closing net book value/carrying value	**1,981.5**	**91.8**	**1,790.3**	**510.8**

Depreciation, amortisation, write-offs and dismantling

Group ($M)	2020	2019
Total depreciation	225.6	220.4
Total amortisation	30.0	29.1
Impairment	(0.9)	1.5
Write-offs on disposal	9.2	12.2
Dismantling expense	9.2	4.0
(Gain) loss on disposals	1.3	(3.4)
	274.4	**263.8**

The 2020 dismantling expense includes an asbestos provision movement of $4.4 million (2019: $1.3 million).

COMMUNICATIONS	ADMINISTRATION ASSETS	TOTAL PROPERTY, PLANT AND EQUIPMENT	EASEMENTS AND RIGHT OF ACCESS	SOFTWARE	TOTAL INTANGIBLE ASSETS	CAPITAL WORK IN PROGRESS
429.2	204.8	7,175.4	310.3	376.6	686.9	151.7
(234.6)	(134.0)	(2,443.2)	(5.3)	(307.5)	(312.8)	-
194.6	**70.8**	**4,732.2**	**305.0**	**69.1**	**374.1**	**151.7**
175.5	71.9	4,621.8	305.6	67.3	372.9	138.3
48.8	11.8	343.9	-	31.6	31.6	387.4
(0.6)	(0.1)	(7.9)	-	(0.4)	(0.4)	(374.0)
(29.1)	(12.8)	(225.6)	(0.6)	(29.4)	(30.0)	-
194.6	**70.8**	**4,732.2**	**305.0**	**69.1**	**374.1**	**151.7**
382.5	193.6	6,864.3	310.4	348.9	659.3	138.3
(207.0)	(121.7)	(2,242.5)	(4.8)	(281.6)	(286.4)	-
175.5	**71.9**	**4,621.8**	**305.6**	**67.3**	**372.9**	**138.3**
177.6	74.4	4,615.0	304.4	73.0	377.4	75.0
27.2	9.2	240.4	1.8	23.3	25.1	328.9
(0.6)	(0.1)	(13.2)	-	(0.5)	(0.5)	(265.6)
(28.7)	(11.6)	(220.4)	(0.6)	(28.5)	(29.1)	-
175.5	**71.9**	**4,621.8**	**305.6**	**67.3**	**372.9**	**138.3**

Capital work in progress is split into the following classes:

Group ($M)	2020	2019
HVAC transmission lines	51.4	34.9
HVAC substations	78.1	80.8
Communications	2.0	5.7
Other	20.2	16.9
	151.7	**138.3**

Description

Administration assets include computer hardware, plant, equipment, furniture and motor vehicles.

The most significant right-to-access asset relates to the 2011 purchase of access rights to the Vector Tunnel in Auckland for $50 million. The Vector Tunnel right-to-access asset is being amortised over the contract life, which is 90 years.

Accounting policies

Transpower uses the cost model for all capital assets. Capital work in progress is recorded at cost. Cost is determined by including all costs directly associated with bringing the assets to their location and condition for use. Finance costs incurred during the period of time that is required to complete and prepare the asset for its intended use are capitalised as part of the total cost for capital work in progress.

Assets are transferred from capital work in progress at cost to property, plant and equipment, or intangible assets as they become operational and available for use.

At each reporting date, Transpower reviews the carrying amounts of its tangible and intangible assets and exercises judgement to determine whether there is any indication that those assets have suffered an impairment loss. This is based on allocating the assets to cash generating units. If any such indication exists, the recoverable amount of the asset or cash generating unit is estimated in order to determine the extent of the impairment loss (if any). The recoverable amount for regulated assets is generally equal to the regulatory book value for revenue recovery purposes. In 2020, there has been no impairment to the regulatory asset base (2019: nil).

For unregulated assets, Transpower tests for indicators of impairment, such as deterioration in the credit worthiness of the customer, and any indicated factors in pricing the future cash flows Transpower expects to derive from the assets are reflected in the calculation of the asset's value in use. In 2020, there was an impairment movement of $(0.9) million (2019: $1.5 million).

Depreciation

Depreciation of property, plant and equipment is calculated using the straight line method to write down the cost of property, plant and equipment to its estimated residual value over its estimated useful life.

Transpower has a variety of different assets with different lives. The estimated weighted average of useful lives by asset category is as follows:

HVAC transmission lines	58 years
HVAC transmission high voltage cables	45 years
HVAC transmission lines (tower painting)	15 years
HVAC substations	43 years
HVDC substations (incl submarine cables)	28 years
HVDC transmission lines	55 years
Communication assets	15 years
Administration assets	16 years

Non-current assets held for sale

Non-current assets (and disposal groups) classified as held for sale are measured at the lower of carrying amount and fair value less costs to sell.

Intangibles

The cost of acquiring a finite-life intangible asset is amortised from the date the underlying asset is held ready for use on a straight line basis over the period of its expected benefit, which is as follows:

Software	5-8 years
Right-to-access asset	90 years

Easements are deemed to have an indefinite useful life and are tested for impairment annually.

Certain easements have been donated by the Crown. These are recognised at cost (nil) plus any direct costs associated with putting the easement in place.

Key judgements and estimates

Transpower has exercised judgement in the following four areas:

1) Determining the useful life of property, plant and equipment and finite-life intangible assets. Transpower uses assistance from independent engineers. For transmission line assets, a determining factor in the life assumption is proximity to the coast.
2) Whether or not an item is capital in nature and the appropriate component level of asset at which to depreciate.
3) Determining the appropriate time to commission an asset and commence depreciation.
4) Whether there are any regulated assets that ought to be impaired.

Related disclosures

Land and buildings are contained within the above classes and have a net book value of $305.4 million (2019: $260.6 million).

Held-for-sale non-current assets are contained within the above classes and have a net book value of $0.2 million (2019: $0.2 million).

Capital commitments in respect of contracts for property, plant and equipment:

Group ($M)	2020	2019
Property, plant and equipment	103.7	175.4
	103.7	**175.4**

Capital commitments in respect of contracts for intangible assets:

Easements and right to access assets	-	-
Software	-	-
Total capital commitments	**103.7**	**175.4**

6. Leases

Right-of-use assets

Group ($M)	PROPERTY AND IT DATA CENTRES	FIBRE COMMUNICATION NETWORK	GROUP TOTAL
30 June 2020 reconciliation			
Opening net book value (1 July 2019)	-	-	-
Effect of adoption of IFRS 16	67.0	62.1	129.1
Additions	0.2	4.2	4.4
Depreciation	(5.1)	(4.9)	(10.0)
Impairment/Retirement	(0.3)	(1.2)	(1.5)
Closing net book value	**61.8**	**60.2**	**122.0**

Lease liabilities

30 June 2020 reconciliation

Group ($M)	
Opening balance (1 July 2019)	-
Effect of adoption of IFRS 16	106.1
Additions	4.0
Accretion of interest	3.4
Payments	(12.4)
Remeasurement/Write-off	(1.4)
Closing balance	**99.7**
Current	7.0
Non-current	92.7

Description

The Group's leases primarily relate to the leasing of fibre optic cables for Transpower's communication network and property leases for office buildings and IT data centres.

Accounting Policies

Lease liabilities

Lease liabilities are recognised based on the present value of the remaining lease payments, including lease renewals that are deemed reasonably certain to be exercised. The Group uses the incremental borrowing rate at the lease commencement date to calculate the present value of lease payments.

Lease liabilities will decrease over time as lease payments are made and increase with an imputed interest expense being recognised. In addition, the carrying amount of lease liabilities is remeasured if there is a modification, a change in the lease term or a change in the in-substance fixed lease payments.

Right-of-use assets

The Group recognises right-of-use assets at the commencement date of the lease (i.e. the date the underlying asset is available for use) except for short-term leases and leases of low-value assets.

The Group applies the recognition exemptions to its short-term leases with less than 12 months remaining and for low-value leases. Lease payments for these leases are recognised as an expenses on a straight-line basis over the lease term.

Right-of-use assets are measured at cost, less any accumulated depreciation and impairment losses, and adjusted for any remeasurements of lease liabilities. The cost of right-of-use assets includes the amount of lease liabilities recognised, adjusted for any remaining prepaid lease payments. The right-of-use assets are depreciated on a straight-line basis over the shorter of their estimated useful life and the lease term. The Group assesses the right-of-use asset for impairment when such indicators exist.

Key judgements

Transpower has exercised judgement in the following areas:

1) Determination of whether or not a lease exists through assessment of contractual arrangements;
2) Where the contract contains options to extend or terminate the lease, consideration of the likelihood of exercising the options based on past practice; and
3) Use of a single discount rate to a portfolio of leases with reasonably similar characteristics.

Related Disclosure

The following are the amounts recognised in profit or loss:

Group ($M)	2020
Depreciation expense of right-of-use assets	10.0
Interest expenses on lease liabilities	3.4
Expense relating to short-term leases (included in operating expenses)	2.9
Total amount recognised in profit or loss	**16.3**

The group had total cash outflow for lease payments of $12.1 million in 2020.

7. Debt, financial instruments and risk management

(a) Summary

Debt is issued by the Group in both New Zealand dollars (NZD) and foreign currencies. Derivatives are used to manage currency risk and interest rate risk by converting foreign borrowings to NZD and by converting floating interest rates to fixed interest rates. The use of derivatives means that Transpower effectively has borrowings denominated in NZD, predominantly at fixed interest rates.

Debt and associated derivatives are designated as fair value through profit or loss on the basis of preventing an accounting mismatch, unless the derivatives are designated in an effective hedge accounting relationship. For these derivatives that are effectively hedged, the resulting gain or loss is recognised in other comprehensive income. Group's debt and derivatives are managed as one integrated portfolio.

The Group also uses derivatives (foreign exchange forward contracts) in its purchase of goods and services.

The Group is subject to a number of financial risks that arise as a result of its business activities, including having a debt portfolio that is denominated in both NZD and foreign currencies, holding an investment portfolio and from purchases in certain foreign currencies.

Financial risk management is carried out by a central treasury function, which operates under policies approved by the Board of Directors.

Key judgements

The fair values of debt and derivatives are determined by converting currency exposures and discounting cash flows based on the relevant yield curve. The yield curve is adjusted to reflect the credit risk of the counterparty to the transaction or the credit risk of Transpower. These valuations are considered level two in the IFRS three-level valuation hierarchy. There has been no movement between levels during the year.

(b) Financial risks

i. Liquidity risk

Liquidity risk is the risk of the Group being unable to access sufficient funds to meet its financial obligations in an orderly manner. This might result from the Group not maintaining adequate funding facilities or being unable to replace existing debt maturities.

To smooth the Group's refinancing requirements and exposures to adverse market rate movement in future periods, the Group's policy is that debt, net of cash, maturing in any 12-month period is not to exceed NZD750 million, or up to NZD1 billion with prior approval of the Board.

The Group's liquidity policy requires the Group to have access to committed funding facilities to cover the sum of all debt that matures over the next six months, plus peak cumulative anticipated operating cash flow requirements over the next six months. To meet this policy requirement Transpower has committed standby facilities split into two tranches of NZD250 million each, maturing 7 December 2020 and 7 December 2021, which supports the commercial paper programmes and liquidity. The facilities have been undrawn since inception.

Debt Facilities

The Group has four debt facilities. The aggregate principal amount of the debt outstanding may not exceed the following:

($M)	CURRENCY	FOREIGN CURRENCY EQUIVALENT	NZD	UTILISED NZD
Domestic medium term note programme	NZD	-	No set limit	825
Australian medium term note programme	AUD	750	802	507
European commercial paper programme (ECP)	USD	500	775	-
Domestic commercial paper programme (CP)	NZD	500	500	345

ii. Interest rate risk

Interest rate risk is the risk of an adverse impact on the present and future finance costs of the Group arising from an increase in interest rates. Transpower uses various financial instruments to fix interest rates to mitigate interest rate risk.

The Group generally seeks to fix interest rates with interest rate derivatives to provide certainty of interest rates and costs during Regulatory Control Periods (RCP). This means that, prima facie, a decrease in market interest rates will result in the Group sustaining fair value losses, and conversely an increase in market interest rates will result in fair value gains.

The Group's policy sets minimum and maximum hedging parameters expressed as a percentage of forecast debt. Interest rate swaps and options are used to change the interest rate profile on existing and forecast debt and cross-currency interest rate swaps entered into.

iii. Currency risk

Currency risk on debt is the risk of adverse impact of exchange rate movements, which determine the NZD cost of debt (principal and interest) issued in foreign currencies.

Foreign currency borrowings are converted into a NZD-denominated exposure at the time of commitment to drawdown. Currency risk on foreign currency-denominated borrowings is managed using cross-currency interest rate swaps and basis swaps.

Cross-currency interest rate swaps eliminate foreign currency risk on the underlying debt by determining the NZD equivalent of the interest payments and final principal exchange at the time of entering into the swap.

Basis swaps are used to eliminate currency basis risk when the Group issues bonds in a foreign currency. In a basis swap, the Group receives the offshore currency floating interest rate and pays the NZD floating interest rate.

Currency risk on foreign currency-denominated purchases is the risk of adverse impact of exchange rate movements which determine the NZD cost of foreign currency-denominated purchases. It is the Group's policy to hedge committed foreign currency-denominated payments greater than NZD200,000 (NZD equivalent) by using forward foreign exchange contracts to fix or offset the NZD cost. For committed payments below NZD200,000 the Group has discretion on whether or not to hedge.

Debt and related derivatives - interest rate, currency and liquidity risk

The following tables detail Transpower's debt and associated derivatives. The result after derivatives is that Transpower effectively has a debt portfolio in New Zealand dollars at predominantly fixed interest rates matching Transpower's Regulatory Control Periods.

The derivatives in the table below are interest rate swaps and cross-currency interest rate swaps that relate directly to the particular debt issue. The effective interest rate on debt including the effect of all derivative financial instruments was 5.4% (2019: 6.4%).

2020 Group	DEBT CURRENCY	DEBT AND DERIVATIVE MATURITY DATE	DEBT FACE VALUE	DEBT FAIR VALUE	DERIVATIVE FAIR VALUE	TOTAL DEBT + DERIVATIVES FAIR VALUE
			($M)	NZ ($M)	NZ ($M)	NZ ($M)
Bank Term						
Bank Term 2021	NZD	17-Jun-21	100.0	100.0	-	100.0
Bank Term 2022	NZD	4-May-22	50.0	50.9	-	50.9
Domestic Commercial Paper						
NZ Issue	NZD	3-Jul-20	13.0	13.0	-	13.0
NZ Issue	NZD	6-Jul-20	24.9	25.0	-	25.0
NZ Issue	NZD	11-Aug-20	32.9	33.0	-	33.0
NZ Issue	NZD	19-Aug-20	25.0	25.0	-	25.0
NZ Issue	NZD	26-Aug-20	25.0	25.0	-	25.0
NZ Issue	NZD	3-Sep-20	30.0	30.0	-	30.0
NZ Issue	NZD	9-Sep-20	30.0	30.0	-	30.0
NZ Issue	NZD	16-Sep-20	35.0	34.9	-	34.9
NZ Issue	NZD	23-Sep-20	30.0	29.9	-	29.9
NZ Issue	NZD	14-Apr-21	98.8	99.5	-	99.5
Domestic Bonds						
Bonds 2022	NZD	30-Jun-22	75.0	80.5	(5.2)	75.3
Bonds 2022	NZD	30-Jun-22	75.0	80.5	(4.9)	75.6
Bonds 2022	NZD	16-Sep-22	100.0	108.9	(7.6)	101.3
Bonds 2023	NZD	15-Mar-23	50.0	57.2	(6.0)	51.2
Bonds 2024	NZD	14-Mar-24	150.0	161.6	(10.5)	151.1
Bonds 2025	NZD	6-Mar-25	125.0	142.7	(16.5)	126.2
Bonds 2025	NZD	4-Sep-25	150.0	155.7	(5.5)	150.2
Bonds 2028	NZD	15-Mar-28	100.0	134.5	(29.4)	105.1
Australian Medium Term Notes						
AUD MTN 2021	AUD	6-Aug-21	150.0	169.8	(3.1)	166.7
AUD MTN 2023	AUD	28-Aug-23	300.0	376.3	(24.4)	351.9
Swiss Bonds						
CHF MTN 2027	CHF	16-Dec-27	125.0	200.1	(5.0)	195.1
US Private Placement						
USPP 2021	USD	13-Oct-21	232.0	376.3	(84.1)	292.2
USPP 2022	USD	15-Dec-22	150.0	250.2	(39.9)	210.3
USPP 2023	USD	13-Oct-23	78.0	133.6	(33.0)	100.6
USPP 2026	USD	28-Jun-26	75.0	128.4	(13.6)	114.8
USPP 2026	USD	13-Oct-26	70.0	127.8	(35.1)	92.7
USPP 2028	USD	28-Jun-28	75.0	130.7	(15.7)	115.0
				3,311.0	**(339.5)**	**2,971.5**

Debt short term	345.3
Current portion of long-term debt	100.0
Debt short term	**445.3**
Debt long term	**2,865.7**
Total debt as per statement of financial position	**3,311.0**

Debt face value (as per above)	
New Zealand dollar debt	1,319.6
Foreign debt after adjusting for related cross-currency interest rate swaps	1,593.5
	2,913.1

The notional amount of the cross-currency interest rate swaps is NZD1,593.5 million.
Group debt, net of cash, maturing in the 12 month period is $432.6 million, within the $750 million policy threshold.

Interest rate swaps (IRS) are used to fix interest payments as per the Group's treasury policy. The table below shows the notional IRS that are not directly related to underlying debt. The table includes forward starting and offsetting IRS. The IRS are net settled. The table below reflects the net cash outflows comprising both IRS assets and liabilities. IRS with unrealised gains are assets and IRS with unrealised losses are liabilities.

($M)	DERIVATIVE NOTIONAL VALUE	DERIVATIVE FAIR VALUE
Value of interest rate swaps – liabilities	3,140.0	232.1
Value of interest rate swaps – (assets)	660.0	(83.3)
Total fair value of interest rate swaps		**148.8**
Total fair value of debt-related derivatives as shown above		**(339.5)**
Total debt derivatives fair value (assets) / liabilities (refer to note 8 for further derivatives breakdown)		**(190.7)**

Effective net payable contractual cash flow maturity profile

The effective net cash flows on floating rate payments are determined by applying the applicable swap curve to determine the expected future cash flows.

($M)	WITHIN ONE YEAR	ONE TO TWO YEARS	TWO TO THREE YEARS	THREE TO FOUR YEARS	FOUR TO FIVE YEARS	GREATER THAN FIVE YEARS	TOTAL
Debt	539.1	802.8	442.3	631.3	149.1	834.2	3,398.8
Debt-related derivatives	(53.5)	(120.7)	(62.6)	(25.2)	(7.9)	(48.4)	(318.3)
Interest rate swap (portfolio) – liabilities	44.8	52.5	49.3	43.4	38.2	8.4	236.6
Interest rate swap (portfolio) – assets	(14.7)	(17.5)	(16.9)	(15.4)	(14.6)	(5.9)	(85.0)
Trade and other payables	59.8	0.2	0.1	0.1	0.1	0.1	60.4
Leases	10.3	10.1	9.9	9.7	9.8	75.9	125.7
Total contractual cash flows	**585.8**	**727.4**	**422.1**	**643.9**	**174.7**	**864.3**	**3,418.2**

These interest rate swaps (portfolio) have an average contracted fixed interest rate of 1.36% (2019: 3.68%)

Reconciliation of liabilities arising from financing activities

($M)	BALANCE 30 JUNE 2019	CASH FLOWS	FAIR VALUE CHANGES IN P&L	FAIR VALUE CHANGES IN OCI	OTHER	BALANCE 30 JUNE 2020
Short-term borrowing	74.8	270.0	0.7	(0.4)	0.2	345.3
Long-term borrowing	3,152.6	(293.2)	103.1	12.0	(8.8)	2,965.7
Total liabilities from financing activities	**3,227.4**	**(23.2)**	**103.8**	**11.6**	**(8.6)**	**3,311.0**

Fair value changes in the table above include foreign exchange movements

Debt and related derivatives - interest rate, currency and liquidity risk

The following tables detail Transpower's debt and associated derivatives. The result after derivatives is that Transpower effectively has a debt portfolio in New Zealand dollars at predominantly fixed interest rates matching Transpower's Regulatory Control Periods.

The derivatives in the table below are interest rate swaps and cross-currency interest rate swaps that relate directly to the particular debt issue. The effective interest rate on debt including the effect of all derivative financial instruments was 6.4% (2018: 6.8%).

2019 Group	DEBT CURRENCY	DEBT AND DERIVATIVE MATURITY DATE	DEBT FACE VALUE	DEBT FAIR VALUE	DERIVATIVE FAIR VALUE	TOTAL DEBT + DERIVATIVES FAIR VALUE
			($M)	NZ ($M)	NZ ($M)	NZ ($M)
Bank Term						
Bank Term 2021	NZD	17-Jun-21	100	100.1	-	100.1
Domestic Commercial Paper						
NZ Issue	NZD	2-Jul-19	19.9	20.0	-	20.0
NZ Issue	NZD	7-Aug-19	29.9	29.9	-	29.9
NZ Issue	NZD	28-Aug-19	24.9	24.9	-	24.9
Domestic Bonds						
Bonds 2019	NZD	6-Sep-19	200.0	204.0	(3.1)	200.9
Bonds 2019	NZD	12-Nov-19	50.0	51.4	(1.2)	50.2
FRN CPI linked 2020	NZD	15-May-20	100.0	117.7	(16.8)	100.9
Bonds 2020	NZD	10-Jun-20	150.0	157.6	(7.9)	149.7
Bonds 2022	NZD	30-Jun-22	150.0	163.0	(9.6)	153.4
Bonds 2022	NZD	16-Sep-22	100.0	107.2	(6.6)	100.6
Bonds 2023	NZD	15-Mar-23	50.0	56.5	(5.6)	50.9
Bonds 2024	NZD	14-Mar-24	150.0	153.5	(4.6)	148.9
Bonds 2025	NZD	6-Mar-25	125.0	135.0	(10.9)	124.1
Bonds 2028	NZD	15-Mar-28	100.0	123.4	(22.1)	101.3
European Medium Term Notes						
HKD EMTN 2020	HKD	24-Mar-20	400.0	78.0	(4.7)	73.3
AUD EMTN 2021	AUD	6-Aug-21	150.0	167.8	(0.4)	167.4
AUD EMTN 2023	AUD	28-Aug-23	300.0	368.7	(16.9)	351.8
US Private Placement						
USPP 2019	USD	27-Sep-19	75.0	114.2	9.2	123.4
USPP 2021	USD	13-Oct-21	232.0	357.1	(62.8)	294.3
USPP 2022	USD	15-Dec-22	150.0	233.7	(29.2)	204.5
USPP 2023	USD	13-Oct-23	78.0	123.1	(23.1)	100.0
USPP 2026	USD	28-Jun-26	75.0	113.7	(0.6)	113.1
USPP 2026	USD	13-Oct-26	70.0	113.5	(24.1)	89.4
USPP 2028	USD	28-Jun-28	75.0	113.4	(1.4)	112.0
				3,227.4	**(242.4)**	**2,985.0**

Debt short term	74.8
Current portion of long-term debt	722.9
Debt short term	**797.7**
Debt long term	**2,429.7**
Total debt as per statement of financial position	**3,227.4**

Debt face value (as per above)	
New Zealand dollar debt	1,349.7
Foreign debt after adjusting for related cross-currency interest rate swaps	1,593.2
	2,942.9

The notional amount of the cross-currency interest rate swaps is NZD1,593.2 million.
Group debt, net of cash, maturing in the 12 month period is $614 million, within the $750 million policy threshold.

Interest rate swaps (IRS) are used to fix interest payments as per the Group's treasury policy. The table below shows the notional IRS that are not directly related to underlying debt. The table includes forward starting and offsetting IRS. The IRS are net settled. The table below reflects the net cash outflows comprising both IRS assets and liabilities. IRS with unrealised gains are assets and IRS with unrealised losses are liabilities.

($M)	DERIVATIVE NOTIONAL VALUE	DERIVATIVE FAIR VALUE
Value of interest rate swaps – liabilities	3,905.0	202.5
Value of interest rate swaps – (assets)	905.0	(67.9)
Total fair value of interest rate swaps		**134.6**
Total fair value of debt-related derivatives as shown above		**(242.4)**
Total debt derivatives fair value (assets) / liabilities (refer to note 8 for further derivatives breakdown)		**(107.8)**

Effective net payable contractual cash flow maturity profile

The effective net cash flows on floating rate payments are determined by applying the applicable swap curve to determine the expected future cash flows.

($M)	WITHIN ONE YEAR	ONE TO TWO YEARS	TWO TO THREE YEARS	THREE TO FOUR YEARS	FOUR TO FIVE YEARS	GREATER THAN FIVE YEARS	TOTAL
Debt	996.6	87.3	729.7	429.4	616.0	610.3	3,469.3
Debt-related derivatives	(52.6)	(31.6)	(80.3)	(38.4)	(5.0)	(30.0)	(237.9)
Interest rate swap (portfolio) – liabilities	110.3	19.3	21.1	19.9	17.6	22.3	210.5
Interest rate swap (portfolio) – assets	(13.2)	(10.3)	(12.0)	(11.7)	(10.8)	(14.3)	(72.3)
Trade and other payables	96.6	0.1	0.1	0.1	0.1	0.2	97.2
Total contractual cash flows	**1,137.7**	**64.8**	**658.6**	**399.3**	**617.9**	**588.5**	**3,466.8**

These interest rate swaps (portfolio) have an average contracted fixed interest rate of 3.68% (2018: 3.88%)

Reconciliation of liabilities arising from financing activities

($M)	BALANCE 1 JULY 2018	CASH FLOWS	FAIR VALUE CHANGES IN P&L	FAIR VALUE CHANGES IN OCI	OTHER	BALANCE 30 JUNE 2019
Short-term borrowing	-	74.6	-	-	0.2	74.8
Long-term borrowing	3,152.9	(75.0)	63.1	12.0	(0.4)	3,152.6
Total liabilities from financing activities	**3,152.9**	**(0.4)**	**63.1**	**12.0**	**(0.2)**	**3,227.4**

Fair value changes in the table above include foreign exchange movements

iv. Credit risk

Credit risk is the risk of adverse impact on the Group through the failure of a counterparty bank, financial institution or customer to meet its financial obligations. Transpower's credit risk arises from financial assets. These include investments, derivatives and accounts receivable.

Transpower has not recognised an expected credit loss impairment on its financial assets. No loss is expected due to Transpower maintaining a high quality credit policy as explained below.

Treasury credit risk

The Group's policy is to buy high quality credit and establish credit limits with counterparties that are either a bank, a financial institution, a special-purpose derivative products company, or a New Zealand corporate. These net credit limits are not to exceed 20% of Shareholder Funds of Transpower as shown in the most current audited annual report. In addition, if the counterparty is a New Zealand corporate, the credit limit for investments is not to exceed $40 million.

Counterparties must have a minimum long-term Standard & Poor's credit rating of A or above (or Fitch or Moody's equivalent). For minimum credit ratings for Risk Reinsurance Limited (RRL) investments, please refer to Note 10 Investment disclosure.

For those counterparties with which the Group has a collateral support agreement (CSA), the counterparty credit limit for derivatives is defined as the maximum exposure threshold dictated by the CSA.

The maximum credit exposure in respect of non-derivative assets is best represented by their carrying value.

The credit risk arising from the use of derivative products is minimised by the netting and set-off provisions contained in the Group's International Swaps and Derivatives Association (ISDA) agreement. Under these agreements, transactions are net settled. Therefore, the maximum credit exposure is best represented by the net mark-to-market valuation by counterparty where the net valuation is positive as follows:

Group ($M)	2020	2019
Cross-currency interest rate swaps (CCIRS)	253.9	153.9
Interest rate swaps (IRS)	56.7	26.9
Foreign exchange forward contracts	-	0.1
Total	**310.6**	**180.9**

The net movement in value of CCIRS is primarily driven by a movement lower in both US interest rates and the New Zealand dollar against the CCIRS derivatives used to hedge foreign currency debt.

The breakdown of the CCIRS by counterparty is as follows:

Group ($M)	2020	2019
ANZ Bank New Zealand Limited	68.9	48.8
Bank of New Zealand	24.4	16.9
Citibank N.A.	39.9	20.0
Commonwealth Bank of Australia	45.6	34.4
Westpac Banking Corporation	75.1	33.8
	253.9	**153.9**

Customer credit risk

Regulated customers

Transpower recovers the value of its transmission assets over their useful lives in accordance with Commerce Commission input methodology regulations. The effect of these regulations is that for the majority of assets, a customer default would result in Transpower recovering any revenue shortfall from all other transmission customers.

Transpower's customers comprise predominantly electricity generators, distribution companies and some large industrial users. There is a high concentration of credit risk with respect to trade receivables due to the small number of significant customers from which the majority of revenue is received. It is the Group's policy to perform credit evaluations on customers requiring credit, and the Group may, in some circumstances, require collateral. Collateral held at 30 June 2020 was $0.2 million (2019: $0.2 million).

The entities below have receivables balances greater than 10% of the total trade receivables of $86.9 million at 30 June 2020 (2019: $99.4 million).

Group ($M)	2020	2019
Vector Limited	18.6	19.9
Meridian Energy Limited	9.1	11.6
Powerco Limited	8.7	10.4

Unregulated customers

The Group holds bank guarantees to protect itself in the event private developers are unable to pay any outstanding balances owing on transmission realignment projects performed on their behalf. The bank guarantee may reduce as payments are made by the developers.

There is a specific credit risk in relation to customer default on customer investment contracts where revenue is recovered from individual customers over time for specific assets already in use. Transpower has performed a credit risk assessment on its customers with investment contracts. The assessment is based on the latest financial and non-financial information available from the customer, and Transpower's understanding and experience with the customer. The majority of this credit exposure is to Electricity Lines companies and Electricity Generators, most of whom remain financially stable. Transpower anticipates minimal impact from these customers due to COVID-19. Transpower believes the majority of credit risk relates to certain large industrial users. Transpower monitors the creditworthiness of these organisations. The largest credit risk in this category relates to an organisation with future receivables out to 2046 of $7.8 million on a net present value basis. Transpower has no evidence that there will be any default risk associated with this customer due to COVID-19 as at balance date.

There have been no customer defaults in 2020 (2019: nil).

v. Sensitivity analysis

Currency risk - debt

All foreign currency debt is converted back to NZD, eliminating foreign currency exposure. Therefore, no sensitivity analysis has been performed for foreign currency debt.

Interest rate risk

The Group has issued fixed and floating rate debt and is exposed to interest rate risk. The Group manages the exposure through the use of interest rate swaps with the net exposure being predominantly fixed rate and aligned to Regulatory Control Periods. A portion of the portfolio is left at floating interest rates which will result in a reduction to finance costs should interest rates fall and an increase in finance costs should interest rates rise.

Group ($M)	2020	2020	2019	2019
Yield curve interest rate change and impact on pre-tax profit/(loss)/equity	+100bp	-100bp	+100bp	-100bp
Net interest expenses (annual impact)	(4.1)	4.1	(1.0)	1.0

Fair value risk

The Group is subject to fair value gains or losses. Fair value gains and losses are measured by discounting cash flows on debt and derivatives using market interest rates or yield curves. A move upwards of interest rates and yield curves results in fair value gains and a move downwards results in fair value losses.

A parallel shift in the yield curve by 1% (100 basis points) or the same movement due to a change in credit spreads would create the following fair value movements based on debt, investments and derivatives held at balance date:

Group ($M)	2020	2020	2019	2019
Yield curve interest rate change and impact on pre-tax profit/(loss)/equity	+100bp	-100bp	+100bp	-100bp
Fair Value	123.3	(129.6)	55.1	(57.7)

vi. Commodity risk

Commodity risk is the risk of an adverse impact in commodity prices such as prices for aluminium and copper. These are some of the raw materials used in the construction of the electricity transmission network. Generally, Transpower has contracts in which commodity risk is borne by the supplier.

vii. Insurance risk

Transpower operates a captive insurance company through its subsidiary Risk Reinsurance Limited (RRL) and also has external insurance. RRL maintains an investment portfolio to meet insurance claims.

The more significant insurance policies are outlined in the table below. These policies are renewed annually in September.

INSURANCE POLICY ($M)	AMOUNT INSURED	DEDUCTIBLE	RRL RETAINED RISK	EXTERNALLY INSURED RISK	TOTAL INSURED
HVDC submarine cables	0-15	-	15.0	-	90.0
	15-40	-	8.7	16.3	-
	40-90	-	-	50.0	-
Other grid assets (excluding transmission lines)	0-10	0.1	9.9	-	750.0
	10-750	-	-	740.0	-
Transmission lines	0-10	0.1	9.9	-	10.0

For the HVDC cables above, RRL would pay up to the first $15m of any claim and 35% of the layer between $15 - $40m, with the remaining 65% covered by external insurance providers on a pro-rata basis. The remaining layer between $40 - $90m is covered entirely by external insurance providers.

viii. Regulatory risk

Transpower is a natural monopoly and is regulated by the Commerce Commission and the Electricity Authority. The Commerce Commission determines what rate of return applies to Transpower's assets and approves large capital projects. It also determines the incentives that apply to Transpower which covers operating expenditure, capital expenditure, and meeting certain deliverables and outage targets. The Electricity Authority governs the running of the electricity market.

There is a risk that Transpower's rate of return may be set at too low a level to compensate Transpower for undertaking investments in grid assets. There is also a risk that Transpower does not meet some or all of the performance targets set by the Commerce Commission. Financial penalties would apply and The Commerce Commission can further penalise Transpower for failing to meet targets for which quality standards have been set. The network performance incentive is +/- $11 million per annum. The operating expenditure and base capex incentive is one quarter of the overspend or underspend.

8. Derivatives and hedge commitment

This note shows the short-term (ST) and long-term (LT) breakdown of the derivatives and hedge commitments.

	ASSET			(LIABILITY)			ASSET (LIABILITY)
2020 Group ($M)	ST	LT	TOTAL	ST	LT	TOTAL	NET ASSET
Debt-related derivatives							
Cross-currency interest rate swaps	-	253.9	253.9	-	-	-	253.9
Interest rate swaps	35.2	133.7	168.9	(45.3)	(186.8)	(232.1)	(63.2)
Purchasing related derivatives and hedge commitment							
Foreign exchange forward contracts	0.1	-	0.1	(0.2)	-	(0.2)	(0.1)
Commitment on fair value hedges	0.2	-	0.2	(0.1)	-	(0.1)	0.1
Total derivatives and hedge commitment	**35.5**	**387.6**	**423.1**	**(45.6)**	**(186.8)**	**(232.4)**	**190.7**
2019 Group ($M)	ST	LT	TOTAL	ST	LT	TOTAL	NET ASSET
Debt-related derivatives							
Cross-currency interest rate swaps	4.6	158.4	163.0	(9.1)	-	(9.1)	153.9
Interest rate swaps	52.4	104.4	156.8	(109.1)	(93.8)	(202.9)	(46.1)
Purchasing related derivatives and hedge commitment							
Foreign exchange forward contracts	0.4	-	0.4	(0.8)	(0.2)	(1.0)	(0.6)
Commitment on fair value hedges	0.8	0.2	1.0	(0.4)	-	(0.4)	0.6
Total derivatives and hedge commitment	**58.2**	**263.0**	**321.2**	**(119.4)**	**(94.0)**	**(213.4)**	**107.8**

Description

Derivatives are used to manage financial risk. The gain or loss on derivatives represents the unrealised gain or loss at balance date. The Group anticipates that the derivatives will be held until maturity, and it is unlikely that settlement at the reported fair values will occur.

Accounting policies

Derivative financial instruments

The Group uses derivative financial instruments to reduce its exposures to fluctuations in foreign currency exchange rates and interest rates. All derivatives are classified as fair value through profit and loss except:

i. Those derivatives that are designated into cash flow hedge accounting relationships, where the effective portion of the hedge is included in the Cash Flow Hedge Reserve; and

ii. Those derivatives used to reduce foreign currency exposure on asset purchases, that are designated into fair value hedge accounting relationships. For fair value hedging relationships, gains or losses on hedging instruments are included in profit or loss together with any change in the fair value of the hedged purchase commitment attributable to the foreign currency risk.

The valuation technique and key inputs used to value the derivatives are disclosed in note 7 Debt, financial instruments and risk management.

9. NZPCL debt and investment

Group ($M)	2020	2019
Investment		
Current	-	-
Non-current	98.1	85.7
	98.1	**85.7**
Debt		
Current	-	-
Non-current	100.5	86.7
	100.5	**86.7**
Net investment (debt)	(2.4)	(1.0)
Non-controlling interest net of tax	(1.8)	(0.8)

Description

In November 2009, the Group partially terminated the 2003 cross-border lease in respect of the majority of the HVAC transmission assets in the South Island. As a result of the partial termination, Transpower has consolidated a special-purpose vehicle, New Zealand Power Cayman 2003-1 Limited (NZPCL). NZPCL has a USD deposit with a financial institution and a USD loan from another financial institution. The cash flows from the deposit and loan offset. No consideration was transferred. The loan to NZPCL is guaranteed by Transpower.

As Transpower has no legal ownership interest in NZPCL, the net liabilities and any movements in net liabilities are recognised as a non-controlling interest. The substance of the transaction is such that Transpower rather than the non-controlling interest would be responsible for any shortfall between the value of the asset and the liability.

Accounting policies

The loan and the deposit are recognised at fair value in the Group financial statements based on discounted cash flows. These financial instruments are designated as fair value through profit or loss.

The difference between the asset and liability is due to the yield curves that have been applied to the cash flows. These valuations are considered level two in the IFRS three-level valuation hierarchy.

10. Investments

Group ($M)	2020	2019
Risk Reinsurance Limited investments		
Deposits	37.1	45.0
Corporate bonds	63.5	54.9
	100.6	**99.9**
Transpower investments		
Deposits	-	-
Total investments	**100.6**	**99.9**

Description

Transpower has a captive insurance company called Risk Reinsurance Limited (RRL). RRL invests premiums received from Transpower. RRL reinsures externally and maintains sufficient investments to meet expected claims. RRL does not offer insurance to any external parties.

For RRL cash and bond holdings, the counterparties have maximum limits depending on their ratings. Investments in deposits, floating rate notes and corporate bonds were made in financial instruments issued by organisations with credit ratings of BBB or above.

RRL counterparty exposures are limited to $4 million or less, by individual counterparty, and exposures are monitored on a daily basis.

Accounting policies

If the market for a financial asset is not active, fair value is established by using discounted cash flow analysis based on the relevant yield curve. The yield curve is adjusted to reflect the credit risk of the counterparty to the transaction. Deposits, floating rate notes and corporate bonds are considered level two in the NZ IFRS 13 three-level valuation hierarchy.

RRL investments are classified as fair value through profit or loss. This classification is on the basis that RRL has an active investment programme (held for trading) and as such investments are classified as current assets.

11. Trade receivables and other assets

Group ($M)	2020	2019
Current		
Trade receivables	86.9	99.4
Prepayments	7.9	10.3
Inventory	**2.7**	**3.8**
	97.5	**113.5**
Non-current		
Prepayments	3.2	22.6
Total trade and other receivables	**100.7**	**136.1**
Ageing of trade receivables		
Current	85.0	99.4
Past 31 days	1.9	-
	86.9	**99.4**

Description

The prepayments in 2019 predominantly related to telecommunication lease connection fees.

During COVID-19, Transpower offered deferral payment terms for transmission charges to its customers who themselves are providing financial relief to businesses impacted by the New Zealand Government's Alert Level 4 lockdown. Transpower also provided payment deferral relief to industrial customers directly connected to the National Grid that are closed or have limited operation.

The payment deferral will be offered for up to three months to qualifying customers. The deferred payment will be recovered over the remaining nine months of the payment year. The total payment deferral from customers is $2.8 million at 30 June 2020.

There was no expected credit loss realised during the year (2019: nil).

Accounting policies

Trade receivables are measured initially at fair value and subsequently at amortised cost. Due to the short-term nature of the receivables, no discounting is applied and the fair value is materially similar to amortised cost.

For trade receivables, the Group applies a simplified approach in calculating expected credit loss. Therefore, the Group does not track changes in credit risk, but instead recognises a loss allowance based on lifetime expected credit loss at each reporting date.

12. Trade and other payables

Group ($M)	2020	2019
Current		
Trade creditors and accruals	46.8	86.3
Employee entitlements	13.0	10.3
	59.8	**96.6**
Non-current		
Other non-current payables	0.6	0.6
Total trade and other payables	**60.4**	**97.2**

Description

During COVID-19, Transpower increased the frequency of New Zealand Domestic supplier payments to a weekly basis and changed the payment terms to Pay Now which pays suppliers when all approvals and receipts are complete. These changes provided more frequent cash flow assistance to New Zealand businesses during the pandemic and was also in line with best practice.

Accounting policies

Trade and other payables are measured initially at fair value and subsequently at amortised cost. Due to the short-term nature of the payables, no discounting is applied and the fair value is materially similar to amortised cost.

13. Provisions

Group ($M)	CONTRACTOR PROVISION	DISMANTLING & ENVIRONMENTAL HAZARDS	TOWER AND LINE SAFETY	OTHER	TOTAL
Balance at 1 July 2019	15.4	32.7	12.4	3.0	63.5
Provisions made during the year	2.2	8.8	1.0	5.0	17.0
Provisions used during the year	(13.8)	(4.5)	(3.5)	(1.5)	(23.3)
Provisions reversed during the year	-	-	-	(0.5)	(0.5)
Balance at 30 June 2020	**3.8**	**37.0**	**9.9**	**6.0**	**56.7**
Current portion of provisions	3.8	6.9	5.1	3.8	19.6
Non-current portion of provisions	-	30.1	4.8	2.2	37.1
Balance at 30 June 2020	**3.8**	**37.0**	**9.9**	**6.0**	**56.7**

Description

Contractor provision

Transpower has determined that a future payment to a contractor should be recognised as a provision. Accordingly, the future cash flow has been present-valued and recognised as a provision and also capitalised as property, plant and equipment. The present value is amortised as the interest is incurred and the provision is used each year. The future payment will occur if certain assets are free from defects and have met prescribed service levels.

During COVID-19, to assist with cash flows for service providers, Transpower has early released $0.5 million to service providers on projects where the defect and performance risks are considered to be low.

Dismantling and environmental hazards

Transpower recognises dismantling and environmental hazard costs where it believes a reliably measurable obligation exists. Transpower has estimated these costs based on engineering advice. Actual costs may vary from the figures indicated.

Tower and line safety

Transpower has provided for two work programmes which are to remedy high priority lines underclearance issues and high priority earth potential rise issues on towers.

Other

This may include provisions such as performance incentive scheme, redundancy, onerous contract provision and regulatory provisions, where the amounts can be reliably estimated.

Accounting policies

Provisions are liabilities of uncertain timing or amount. They are measured at the amounts expected to be paid when the liabilities are settled.

14. Equity

Capital

Transpower has 1,200,000,000 issued and fully paid $1 ordinary shares. Transpower's authorised capital is $1,200,000,000 (2019: $1,200,000,000). The shares confer on the holders the right to vote at any annual general meeting of Transpower. All shares rank equally.

The Group manages capital to maintain its strong credit rating and to have sufficient capital available to meet its financing and operating requirements. Surplus equity is returned by way of dividends to shareholders.

Credit rating

Transpower's investment grade credit rating is Standard & Poor's AA- (2019: AA-) and Moody's Aa3 (2019: Aa3).

Net tangible assets per share

Group ($M)	2020	2019
Net assets (equity)	1,623.4	1,640.5
Less intangibles (note 5)	(374.1)	(372.9)
Total net tangible assets	**1,249.3**	**1,267.6**
Net tangible assets per share ($)	1.04	1.06

Net assets (equity) include both Right-of-use assets and Lease liabilities.

Dividends

Dividends declared and provided by Transpower are as follows:

	2020 ($M)	2020 (¢ per share)	2019 ($M)	2019 (¢ per share)
Previous year final dividend paid	99.0	8	99.0	8
Interim dividend paid	66.0	6	66.0	6
	165.0	**14**	**165.0**	**14**
Final dividend declared subsequent to balance date (refer note 20)	99.0	8	99.0	8

Group entities

All subsidiaries are wholly owned, are incorporated in New Zealand (except where specified otherwise) and have a balance date of 30 June 2020.

Transpower has no ownership interest in NZPCL. NZPCL is a special-purpose vehicle registered in the Cayman Islands and is consolidated for financial reporting, indicated by the dotted line in the diagram below. Refer to note 9 NZPCL debt and investment for more detail. Risk Reinsurance Limited is registered and incorporated in the Cayman Islands and was established to provide insurance for the Transpower Group.

As at balance date, the group entities are as follows:

Party to a cross-border lease over the majority of the South Island HVAC Assets

15. Segment reporting

The Group has two segments - transmission and system operator.

- **Transmission** - the transmission of electricity from the point of generation to the point of connection.
- **System operator** - operates the electricity market to dispatch generation to ensure the short term security of the New Zealand electricity system.

Both segments have external revenue derived from New Zealand customers and assets based in New Zealand. The Group has no other reportable segments. The material portion of **Other** is made up of Risk Reinsurance Limited, which provides insurance services to the Group.

Segment results are determined based on information provided to the Chief operating Decision Maker, which include only External revenue and Capex. They are calculated using the avoidable cost allocation methodology (ACAM).

Major customers

External customers that contribute 10% or more of total Group revenue are:

CUSTOMER	% OF GROUP REVENUE	SEGMENT
Vector Limited	18.8 (2019: 20.5)	Transmission

	TRANSMISSION		SYSTEM OPERATOR		OTHER		ADJUSTMENTS		TOTAL	
Group ($M)	2020	2019	2020	2019	2020	2019	2020	2019	2020	2019
External revenue	932.1	968.7	42.1	41.1	12.7	12.6	-	7.5	986.9	1,029.9
Capex	355.3	305.4	13.5	10.4	-	-	18.6	13.0	387.4	328.8

The adjustment is:

Group ($M)	2020	2019	EXPLANATION
External revenue	-	7.5	Prior to July 2019, Financial statements include imputed interest in non-operating expenses, net interest expenses (note 4) rather than revenue
Capex	18.6	13.0	Financial statements include capital work on a customer funded transmission line undergrounding project

16. Change in fair value of financial instruments

Group ($M)	2020	2019
Fair Value through profit or loss		
Accounting hedges		
Foreign exchange forward contracts – hedge accounted	0.4	(2.1)
Hedge commitment	**(0.4)**	**2.1**
	-	-
Other		
Foreign debt	(104.9)	(32.0)
Cross-currency interest rate swaps	93.2	34.0
NZD interest rate swaps	74.8	97.6
Investments	1.6	2.0
NZD debt	(0.5)	(30.6)
	64.2	**71.0**
Total fair value gain (loss)	**64.2**	**71.0**
Fair value through other comprehensive income		
Credit spread on debt		
Foreign debt	(1.7)	(7.2)
NZD debt	(9.9)	(4.8)
Gross fair value gain (loss)	**(11.6)**	**(12.0)**
Less income tax credit (expense)	3.2	3.4
	(8.4)	**(8.6)**
Cash flow hedging		
Interest risk	(103.9)	-
Gross fair value gain (loss)	**(103.9)**	**-**
Less income tax credit (expense)	29.1	-
	(74.8)	-
Total other comprehensive income (expenses)	**(83.2)**	**(8.6)**

Description

The Group experiences changes in fair value through movements in underlying interest rates, exchange rates and credit spread on debt and derivatives. The Group generally seeks to fix interest rates to provide certainty of interest rate costs during regulatory control periods. This means that, prima facie, a decrease in market interest rates will result in the Group sustaining fair value losses, and conversely, an increase in market interest rates will result in fair value gains.

The fair value of debt and derivatives is determined by converting currency exposures and discounting cash flows based on the relevant yield curve. The yield curve is adjusted to reflect the credit risk of the counterparty to the transaction or the credit risk of Transpower. These valuations are considered level two in the IFRS three-level valuation hierarchy. There have been no movements between levels during the period.

Changes in fair value of financial instruments are separately disclosed as fair value changes through profit and loss, or through other comprehensive income. The fair value change through other comprehensive income comprises fair value changes resulting from credit spread changes on the Group's issued debt and the effective portion of fair value changes on derivatives designated as cash flow hedges for accounting.

Credit spreads are an estimate of the additional premium over the relevant yield curve that would be required by market participants to compensate them for the perceived credit risk inherent in the counterparty and transaction. For derivative transactions, the impact of credit spreads is substantially lower than for debt and investment transactions due to the offsetting nature of the cash flows.

Cash flow hedges

During the year, the Group has designated certain interest rate swaps into the cash flow hedge accounting relationships, which align interest rate exposures to the RCP. The Group uses the hypothetical derivative method to measure hedge accounting effectiveness and compares the changes in the fair value of the hedging instruments against the changes in fair value of the hedged item attributable to hedged risk. To the extent these hedges are effective, the change in fair value of the hedging instrument is recognised in other comprehensive income in the Cash Flow Hedge Reserve within Equity, while the change in fair value on the ineffective portion is recognised immediately in the statement of profit or loss. The cash flow hedge reserve is adjusted to the lower of the cumulative gain or loss on the hedging instrument and the cumulative change in fair value of the hedged item. Hedge ineffectiveness in the cash flow hedge accounting relationship can arise from movements in credit risk on hedging instrument counterparties.

Fair values in statement of financial position

For cash and cash equivalents, accounts payable and receivables, fair values are materially similar to their cost due to the short-term nature of these items.

Related disclosures

The following table shows the impact of credit spread movements on fair value:

Group ($M)	2020	2019
Current year fair value profit/(loss) movement included above		
Fair value movement in debt due to credit spread movement	(11.7)	(12.0)
Fair value movement in asset due to credit spread movement	(0.2)	(0.7)
Fair value movement in derivatives due to credit spread movement	(17.1)	(9.0)
Statement of financial position balance – decrease in debt due to credit spread	63.1	74.8
Statement of financial position balance – (decrease) in investment due to credit spread	(2.9)	(2.7)
Statement of financial position balance – (increase)/decrease in derivatives due to credit spread	(6.5)	10.6

17. Taxation

Income tax expenses

Group ($M)	2020	2019
Current tax expense		
Current period	50.5	63.8
Adjustment for prior periods	(1.5)	(2.6)
	49.0	**61.2**
Deferred tax expense		
Origination and reversal of temporary differences	33.5	36.9
Adjustment for prior periods	2.2	2.3
	35.7	**39.2**
Total income tax expense (credit)	**84.7**	**100.4**
Reconciliation of effective tax		
Operating surplus before tax	315.8	358.8
Income tax at 28%	88.4	100.5
Tax effect of:		
Net non-deductible expenses and non-assessable items	0.7	0.2
Under/(over) provided in prior periods	0.7	(0.3)
Reinstatement of depreciation on buildings	(5.1)	-
Total income tax expense (credit)	**84.7**	**100.4**

Description

There are no unrecognised deferred tax balances (2019: nil).

For property, plant and equipment, deferred tax typically arises from the accounting book including capitalised interest, differences in depreciation rates between tax and accounting and the capital contribution rules.

In March 2020, the Government re-introduced the deductibility of depreciation on building for tax purpose, for buildings not primarily used for residential accommodation. This amendment applies from 1 April 2020 and the depreciation rate is 2% diminishing value. The impact of this change increases the tax base for these assets, giving rise to a reduced difference between the carrying cost and tax base and results in a reduction in deferred tax liability and reduction in tax expense of $5.1 million.

Accounting policies

Deferred tax arises from differences between the accounting and tax values of assets and liabilities, except where the initial recognition exemption applies.

Deferred tax is shown as a net liability for the Group. This disclosure reflects that the deferred tax balances relate to companies in the Transpower Consolidated Tax Group and are in the same jurisdiction, being New Zealand.

Imputation credits

The imputation credit balance at 30 June 2020 is $66.8 million (2019: $80.4 million). This balance includes the tax payable outstanding at 30 June 2020.

Deferred tax

Group ($M)	BALANCE 1 JULY 2018	RECOGNISED IN PROFIT OR LOSS	RECOGNISED IN OCI	BALANCE 30 JUNE 2019	RECOGNISED IN PROFIT OR LOSS	RECOGNISED IN OCI	BALANCE 30 JUNE 2020
Property, plant and equipment temporary differences	490.3	22.1	-	512.4	19.1	-	531.5
Fair value of net debt and derivatives	(56.8)	19.2	(3.4)	(41.0)	17.5	(32.3)	(55.8)
Revenue deferral	(5.6)	(0.6)	-	(6.2)	(0.4)	-	(6.6)
Dismantling provision	(6.3)	(0.2)	-	(6.5)	(1.1)	-	(7.6)
Other	(7.8)	(1.3)	-	(9.1)	0.6	-	(8.5)
Total deferred tax	**413.8**	**39.2**	**(3.4)**	**449.6**	**35.7**	**(32.3)**	**453.0**

18. Related parties

Transactions with key management personnel

The Group did not conduct any business with key management personnel aside from the compensation payments below.

Key management personnel compensation

Key management personnel received the following compensation for their services to the Group:

Group ($M)	2020	2019
Directors' fees	0.5	0.5
Other key management personnel	5.2	4.6
Short-term employee remuneration	**5.7**	**5.1**
Defined contribution schemes	0.2	0.2

There were no termination payments to key management personnel in 2020 (2019: nil). There was no long-term compensation paid to key management personnel (2019: nil).

Government-related transactions

Transpower, being a State-owned enterprise, transacts with other government-related entities. The most significant transactions and balances (greater than $15 million) are as follows:

Group ($M)	2020	2019
Meridian Energy Limited – revenue	90.8	118.5
Electricity Authority – revenue	42.4	41.8

Meridian Energy Limited (Meridian) is a majority state owned company and is an electricity generator and retailer. Meridian pays Transpower primarily for the transportation of electricity across the national electricity grid.

The Electricity Authority is an independent Crown entity responsible for regulating the New Zealand electricity market. The Electricity Authority pays Transpower a contracted fee for its role as system operator.

Transpower also settles its income and indirect tax obligations with Inland Revenue.

Some Directors of the company may be Directors or officers of other companies or organisations with which Transpower may transact.

All related party transactions are carried out at on an arm's length and independent commercial basis.

19. Contingencies

(i) Guarantees

NZPCL

In November 2009, the Group partially terminated the 2003 cross-border lease in respect of the majority of the HVAC transmission assets in the South Island. As a result of the partial termination, Transpower has consolidated a special-purpose vehicle, NZPCL.

NZPCL has a USD deposit with a financial institution and a USD loan from another financial institution. The cash flows from the deposit and loan offset. No consideration was transferred. The loan to NZPCL is guaranteed by Transpower.

The substance of the transaction is such that Transpower rather than the non-controlling interest would be responsible for any shortfall between the value of the asset and the liability. The likelihood of losses in respect of these matters is considered to be remote.

Debt

Transpower has given a negative pledge covenant to certain debt holders that, while any debt issued remains outstanding, we will not, subject to certain exceptions, create or permit to exist, any charge or lien over any of our assets.

(ii) Economic gain (loss) account

Transpower operates its revenue-setting methodology within an economic value (EV) framework that analyses economic gains and losses between those attributable to shareholders and those attributable to customers. Under Commerce Commission regulations, Transpower is required to pass onto, or claim from, customers the customer balance at the end of RCP2 (30 June 2020). These balances are spread evenly over the 5 years of RCP3 from 1 April 2020 to 31 March 2025. This results in an NPV equivalent reduction in revenue per annum of $18 million for each year of RCP3.

The economic gain (loss) account is considered a contingency rather than a provision because Transpower is able to change the future conduct of its business in a way that avoids the future expenditure.

($M)	HVAC	HVDC	TOTAL
EV balance to be recovered (paid) 1 April 2020 to 31 March 2025	(77.5)	(2.0)	(79.5)

(iii) Environmental hazards

Transpower has a programme of identifying, mitigating and removing environmental hazards such as asbestos at its sites. The cost of mitigating and/or removing identified hazards will vary, depending on the particular circumstances at the site. Where a reasonable estimate of the cost of mitigating or removal of a hazard can be made, a provision has been established.

(iv) Various lawsuits, claims and investigations

Various other lawsuits, claims and investigations have been brought or are pending against the Group. The directors of Transpower cannot reasonably estimate the adverse effect (if any) on the Group if any of the foregoing claims are ultimately resolved against the Group's interests.

20. Subsequent events

On 20 August 2020, the Directors approved the payment of a dividend of $99.0 million. The dividend will be fully imputed and is expected to be paid on 20 September 2020.

On 17 August 2020, Transpower announced it is considering an offer of unsecured unsubordinated fixed rate bonds to New Zealand retail investors and institutional investors.

On 20 August 2020, the Directors approved the extension of the $250 million committed standby facility, due to mature 7 December 2020, by a further two years to 7 December 2022.

Rio Tinto has given notice to Meridian Energy Limited to terminate their electricity supply contract by end of August 2021. Under current regulation, Transpower's revenue is not reduced but the closure will result in an excess of generation in the lower South Island of New Zealand. Transpower has already committed to continue with the Clutha Upper Waitaki capital work to reduce transmission constraints and is considering ways to accelerate this work and manage service performance impacts.

The Directors are not aware of any other matter or circumstance since the end of the financial year that has significantly or may significantly affect the operations of Transpower or the Group.

Building a better working world

INDEPENDENT AUDITOR'S REPORT

TO THE READERS OF TRANSPOWER NEW ZEALAND LIMITED'S GROUP FINANCIAL STATEMENTS FOR THE YEAR ENDED 30 JUNE 2020

The Auditor-General is the auditor of Transpower New Zealand Limited and its subsidiaries (the Group). The Auditor-General has appointed me, Grant Taylor, using the staff and resources of Ernst & Young, to carry out the audit of the consolidated financial statements of the Group on his behalf.

Opinion

We have audited the consolidated financial statements of the Group on pages 34 to 71, that comprise the consolidated statement of financial position as at 30 June 2020, the consolidated statement of comprehensive income, consolidated statement of changes in equity and consolidated statement of cash flows for the year then ended, and the notes to the consolidated financial statements, including a summary of significant accounting policies.

In our opinion, the consolidated financial statements present fairly, in all material respects, the consolidated financial position of the Group as at 30 June 2020, and its consolidated financial performance and its consolidated cash flows for the year then ended in accordance with New Zealand equivalents to International Financial Reporting Standards and International Financial Reporting Standards.

Basis for our opinion

We conducted our audit in accordance with the Auditor-General's Auditing Standards, which incorporate the Professional and Ethical Standards and the International Standards on Auditing (New Zealand) issued by the New Zealand Auditing and Assurance Standards Board. Our responsibilities under those standards are further described in the *Auditor's responsibilities for the audit of the consolidated financial statements* section of our report. We are independent of the Group in accordance with the Auditor-General's Auditing Standards, which incorporate Professional and Ethical Standard 1: *International Code of Ethics for Assurance Practitioners* issued by the New Zealand Auditing and Assurance Standards Board, and we have fulfilled our other ethical responsibilities in accordance with these requirements.

We believe that the audit evidence we have obtained is sufficient and appropriate to provide a basis for our opinion.

In addition to the audit we have carried out assignments in the areas of other assurance services, training and remuneration benchmarking, which are compatible with those independence requirements. Other than in our capacity as auditor and these assignments, we have no relationship with, or interests in, Transpower New Zealand Limited or any of its subsidiaries.

Key audit matters

Key audit matters are those matters that, in our professional judgement, were of most significance in our audit of the consolidated financial statements of the current period. These matters were addressed in the context of our audit of the consolidated financial statements as a whole, and in forming our opinion thereon, and we do not provide a separate opinion on these matters.

We have fulfilled the responsibilities described in the *Auditor's responsibilities for the audit of the consolidated financial statements* section of the audit report, including in relation to these matters. Accordingly, our audit included the performance of procedures designed to respond to our assessment of the risks of the material misstatement of the consolidated financial statements. The results of our audit procedures, including the procedures performed to address the matters below, provide the basis for our audit opinion on the accompanying consolidated financial statements.

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Regulated assets

Why significant	How our audit addressed the key audit matter
The Group's regulated assets (consisting of property, plant and equipment, intangible assets and associated capital work in progress) described in Note 5 represent 86% of total assets at 30 June 2020. Judgements required to be made by management in relation to regulated assets include: - Determining what costs ought to be capitalised; - Determining the appropriate time to commission an asset and commence depreciation; - The period over which regulated assets should be depreciated; and - Whether there are any regulated assets that ought to be impaired and if so the amount of that impairment. Transpower reviews regulated assets for indicators of impairment at each reporting date. As described in Note 5 the recoverable amount for regulated assets is generally their regulatory book value. Regulatory book value is the amount Transpower is able to recover from customers through future revenue under the terms of the regulations per Part 4 of the Commerce Act 1986. Transpower allocates its regulated assets between cash generating units and compares the carrying amount against the regulated book value to identify possible indicators of impairment. Disclosures regarding regulated assets are included in Note 5 to the consolidated financial statements and in relation to the impact of COVID-19 on the Group's assessment of possible indicators of impairment are included in Note 1 to the consolidated financial statements.	In obtaining sufficient appropriate audit evidence we: - Assessed the appropriateness of a sample of capitalised costs against the criteria contained in NZ IAS 16 *Property, Plant and Equipment*. - Reviewed a sample of assets commissioned in the period to consider whether depreciation was charged from the appropriate date. - Reviewed a sample of large capital work-in-progress project balances to determine whether they ought to have been commissioned and depreciated as at 30 June 2020. - Considered how Transpower has assessed the assumed asset useful lives that are the basis on which depreciation has been charged. - Assessed cash generating units identified against the requirements of NZ IAS 36 *Impairment of Assets* and the allocation of regulated assets between cash generating units. - Tested management's identification of differences between the financial statement carrying amounts and regulatory book values at 30 June 2020 and considered the reasons for such differences. - Independently considered the completeness of management's assessment of indicators of impairment with reference to NZ IAS 36 *Impairment of Assets*, particularly in the context of the COVID-19 pandemic. - Assessed whether the Group's disclosures in Notes 1 and 5 of the consolidated financial statements in relation to regulated assets comply with NZ IAS 16 *Property, Plant and Equipment* and NZ IAS 36 *Impairment of Assets* and describe the impact of COVID-19 pandemic on the Group's consolidated financial statements appropriately.

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Debt and derivatives

Why significant	How our audit addressed the key audit matter
Transpower has significant debt and derivative financial instruments. The total debt and derivative portfolio at 30 June 2020 was a net liability position of $3.1b and is detailed in Note 7 to the consolidated financial statements. Disclosures relating to the impact of COVID-19 on the debt and derivative portfolio are included in Note 1 to the consolidated financial statements. During the financial year Transpower entered into derivatives that were designated as hedges of the Group's interest rate exposure. This was a change for Transpower as derivatives had not historically been designated into hedge relationships in accordance with the requirements of NZ IFRS 9 *Financial Instruments*. Debt and derivatives are both recorded at fair value. Movements in fair value of debt and related derivative financial instruments impact profit or loss, or the cash flow hedge reserve where the derivative is in a designated hedge relationship. The valuation of these instruments involves the application of valuation techniques which require the exercise of judgement and the use of estimates as described in Note 7 to the consolidated financial statements.	In obtaining sufficient appropriate audit evidence we: - Obtained counterparty confirmations for all debt and derivatives at 30 June 2020. - Assessed, in conjunction with our valuation specialists, the appropriateness of the valuation models and significant inputs. - Compared observable inputs used against independent sources and externally available market data. - Performed our own independent valuations for a sample of instruments. - Assessed the Group's documentation of hedging relationships against the requirements of NZ IFRS 9 *Financial Instruments*. - Assessed the Group's analysis of the effectiveness of its hedging relationships in achieving offsetting changes in the fair values of the hedging instrument and the hedged item. - Assessed whether the Group's disclosures in the consolidated financial statements in relation to the valuation of investments comply with NZ IFRS 7 *Financial Instruments: Disclosure* and NZ IFRS 13 *Fair Value Measurement*. - Evaluated the appropriateness of the disclosures made in Note 1 to the consolidated financial statements in respect of the impact of the COVID-19 pandemic on the fair value of the debt and derivative portfolio.

Other information

The Directors are responsible on behalf of the Group for the other information. The other information comprises the information included on pages 6 to 31, but does not include the consolidated financial statements and our auditor's report thereon.

Our opinion on the consolidated financial statements does not cover the other information and we do not express any form of audit opinion or assurance conclusion thereon.

In connection with our audit of the consolidated financial statements, our responsibility is to read the other information and, in doing so, consider whether the other information is materially inconsistent with the consolidated financial statements or our knowledge obtained in the audit or otherwise appears to be materially misstated. If, based on the work we have performed, we conclude that there is a material misstatement of this other information, we are required to report that fact. We have nothing to report in this regard.

Directors' responsibilities for the consolidated financial statements

The Directors are responsible on behalf of the Group for the preparation and fair presentation of the consolidated financial statements in accordance with New Zealand equivalents to International Financial Reporting Standards and International Financial Reporting Standards, and for such internal control as

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the Directors determine is necessary to enable the preparation of consolidated financial statements that are free from material misstatement, whether due to fraud or error.

In preparing the consolidated financial statements, the Directors are responsible on behalf of the Group for assessing the Group's ability to continue as a going concern, disclosing, as applicable, matters related to going concern and using the going concern basis of accounting unless the Directors either intend to liquidate the Group or to cease operations, or have no realistic alternative but to do so.

The Directors' responsibilities arise from the Financial Markets Conduct Act 2013.

Auditor's responsibilities for the audit of the consolidated financial statements

Our objectives are to obtain reasonable assurance about whether the consolidated financial statements as a whole are free from material misstatement, whether due to fraud or error, and to issue an auditor's report that includes our opinion.

Reasonable assurance is a high level of assurance, but is not a guarantee that an audit conducted in accordance with the Auditor-General's Auditing Standards will always detect a material misstatement when it exists. Misstatements can arise from fraud or error and are considered material if, individually or in the aggregate, they could reasonably be expected to influence the economic decisions of readers taken on the basis of these consolidated financial statements.

As part of an audit in accordance with the Auditor-General's Auditing Standards, we exercise professional judgement and maintain professional scepticism throughout the audit. We also:

- Identify and assess the risks of material misstatement of the consolidated financial statements, whether due to fraud or error, design and perform audit procedures responsive to those risks, and obtain audit evidence that is sufficient and appropriate to provide a basis for our opinion. The risk of not detecting a material misstatement resulting from fraud is higher than for one resulting from error, as fraud may involve collusion, forgery, intentional omissions, misrepresentations, or the override of internal control.
- Obtain an understanding of internal control relevant to the audit in order to design audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of the Group's internal control.
- Evaluate the appropriateness of accounting policies used and the reasonableness of accounting estimates and related disclosures made by management.
- Conclude on the appropriateness of the use of the going concern basis of accounting by the directors and, based on the audit evidence obtained, whether a material uncertainty exists related to events or conditions that may cast significant doubt on the Group's ability to continue as a going concern. If we conclude that a material uncertainty exists, we are required to draw attention in our auditor's report to the related disclosures in the consolidated financial statements or, if such disclosures are inadequate, to modify our opinion. Our conclusions are based on the audit evidence obtained up to the date of our auditor's report. However, future events or conditions may cause the Group to cease to continue as a going concern.
- Evaluate the overall presentation, structure and content of the consolidated financial statements, including the disclosures, and whether the consolidated financial statements represent the underlying transactions and events in a manner that achieves fair presentation.
- Obtain sufficient appropriate audit evidence regarding the financial information of the entities or business activities within the Group to express an opinion on the consolidated financial statements. We are responsible for the direction, supervision and performance of the group audit. We remain solely responsible for our audit opinion.

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We communicate with the Directors regarding, among other matters, the planned scope and timing of the audit and significant audit findings, including any significant deficiencies in internal control that we identify during our audit.

We also provide the Directors with a statement that we have complied with relevant ethical requirements regarding independence, and to communicate with them all relationships and other matters that may reasonably be thought to bear on our independence, and where applicable, actions taken to eliminate threats or safeguards applied.

From the matters communicated with the Directors, we determine those matters that were of most significance in the audit of the consolidated financial statements of the current period and are therefore the key audit matters. We describe these matters in our auditor's report unless law or regulation precludes public disclosure about the matter or when, in extremely rare circumstances, we determine that a matter should not be communicated in our report because the adverse consequences of doing so would reasonably be expected to outweigh the public interest benefits of such communication.

Our responsibilities arise from the Public Audit Act 2001.

Grant Taylor
Ernst & Young
On behalf of the Auditor-General
Wellington, New Zealand
20 August 2020

Directory

Board of Directors

Pip Dunphy – *Chair*
Dean Carroll – *Deputy Chair*
Bill Osborne
Sheridan Broadbent
Ilze Gotelli
Kathy Meads
Richard Aitken
Dr Roger Blakeley

General Management Team

Alison Andrew
Chief Executive

Gordon Davidson
Chief Financial Officer

John Clarke
General Manager
Grid Development

Stephen Jay
General Manager
Operations

Brighid Kelly
General Manager People

David Knight
General Counsel &
Company Secretary

Raewyn Moss
General Manager
External Affairs

Cobus Nel
General Manager Information
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General Manager Grid
Grid Delivery

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0800 668 236
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info@novaenergy.co.nz

20 October 2020

Laura Hardcastle
Bell Gully
WELLINGTON

Dear Laura

TRUSTPOWER v ELECTRICITY AUTHORITY AND NOVA (AN INTERESTED PARTY)

1 You will have seen that Nova, in its Memorandum for Wednesday's teleconference, states at paragraph 4.

> Nova, at this stage, does not seek discovery. There is a possibility it may need to seek some assistance from either the Authority or Transpower as to the calculation of the Residual Charge at particular sites relevant to it but this can probably be done without needing the intervention of the Court. However, it would be desirable to reserve leave for Nova to apply.

2 The 2020 Decision Paper in Table 4 at pp 103/104, sets out the Authority's estimate of the "2022 charges by $M, by customer".

3 This includes an estimate of the amount payable by way of the Residual Charge.

4 Can the Authority please advise how it derived the data used in the calculation of the residual charge.

5 Separately, can the Authority advise if it included an estimate for coincident embedded generation.

6 Can the Authority provide the specific calculations for each of:

- Eastland Network
- Horizon Energy
- Orion
- Top Energy
- Vector
- Wellington Electricity
- West Power
- Nova Energy
- Todd Generation Taranaki
- Whareroa Cogeneration Facility (located at Fonterra's Whareroa dairy factory site near Hawera, Taranaki)

7 We note that Trustpower and the Electricity Authority are in agreement that any application for discovery is required by 6 November 2020 if agreement is not reached by 30 October with other parties to apply by 13 November.

8 If necessary, Nova will apply formally for discovery of the information sought as above. However, it hopes that we can agree on a more informal process so long as Nova can then incorporate such of that information as it wishes into an affidavit.

9 Can you please advise by at least 30 October if the Authority is willing to voluntarily provide the requested information.

Yours sincerely

Liesbeth Koomen / Joycelyn Raffills

General Counsel / Special Counsel

BELL GULLY

By email jraffills@toddcorporation.com

Nova Energy Limited
95 Customhouse Quay
Wellington 6011

Attention Liesbeth Koomen / Joycelyn Raffills

FROM **Jenny Stevens / Laura Hardcastle**
DDI +64 4 915 6849 / +64 4 915 6870
MOBILE +64 21 190 2973 / -
EMAIL jenny.stevens@bellgully.com
EMAIL laura.hardcastle@bellgully.com
MATTER NO. 404-0953
DATE 30 October 2020

CIV 2020-485-367: Trustpower Limited v Electricity Authority

1. We refer to your letter dated 20 October 2020, in addition to your Memorandum of Counsel dated 17 October 2020, outlining Nova's position on discovery.

2. Your letter contained queries relating to the calculation of indicative residual charges in the TPM Decision Paper 2020 ("**Decision Paper**"). Specifically, you have referred to Table 4 at pages 103-104 of the Decision Paper which sets out the Authority's estimate of the "2022 charges by $M, by customer". You have asked:

   (a) can the Authority advise how it derived the data used in the calculation of the residual charge;

   (b) can the Authority advise if it included an estimate for coincident embedded generation; and

   (c) can the Authority provide the specific calculations for each of: Eastland Network, Horizon Energy, Orion, Top Energy, Vector, Wellington Electricity, Westpower, Nova Energy, Todd Generation Taranaki and Whareroa Cogeneration Facility?

3. Given your questions are asked in the context of discussing discovery, we take it they are directed toward understanding whether the answers to your questions will be located in the formal record (that the Authority is currently compiling) or if Nova needs to consider a separate discovery application. For the reasons set out below, the short answer to your queries is that these matters were addressed in, and are apparent from, the formal published record. They will therefore be covered by the formal record the Authority is currently compiling (albeit we are still considering how best to cross reference the underlying data packs the Authority made available as part of the formal record).

4. To further explain the position:

   (a) The data used in the calculation of the information presented in Table 4 of the Decision Paper, including the calculation of the residual charge, is explained in Appendix A of the Decision Paper entitled "Modelling of indicative transmission charges".

   (b) The Authority publicly released the modelling underpinning that data at the link given in footnote 288 of the Decision Paper i.e. on the Github repository. The Github repository includes the code for the Authority's TPM impacts model.

   (c) An earlier Excel version of the model called '2019 Proposal impacts modelling', and an accompanying 'Residual charge options module', were originally released as part of the 2019 Issues Paper. The original Excel version of the model is still available via EMI, along with the data files used to generate the inputs to the model. Appendix H of the 2019 Issues Paper provides a description of the methods and assumptions used in this earlier calculation of the indicative residual charge.

(d) The Authority's treatment of each of the matters you have raised can be ascertained from the data that was made available and Nova is able to use and interrogate that data, just as parties could (and did) at the time of release of the 2019 Issues Paper.

(e) But, to further assist Nova in understanding what is available, the Authority comments further that:

(i) In relation to Nova's two questions around how the indicative residual charges were calculated:

The Authority used revenue forecasts provided by Transpower, along with its estimates of the other transmission charges provided for in the Guidelines, to calculate the total amount to be recovered via the residual charge. It then used data provided by the Reconciliation Manager (the GR010 data) to calculate participants' gross Anytime Maximum Demand (AMD) for each pricing year for the period 1 July 2014 to 30 June 2018. These were then averaged to generate an average annual gross AMD for each participant for that period and the indicative charges were allocated to each participant in proportion with that average annual gross AMD. For more detail on this process, please see paragraphs H.20 to H.28 of Appendix H to the 2019 Issues Paper.

In terms of the GR010 data, the Reconciliation Manager's Functional Specification (available on the Authority's website at https://www.ea.govt.nz/operations/market-operation-service-providers/reconciliation-manager/) sets out how this data is generated, including its treatment of embedded generation.

The raw data used to calculate the indicative residual charge for each participant can be found at Github/ElectricityAuthority/tpm-impacts-model/inputs/demand and Github/ElectricityAuthority/tpm-impacts-model/inputs/revenue.

(ii) In relation to specific customer calculations:

The final calculations used to produce the indicative residual charges in the Decision Paper were completed using the code from Github. The section of the code that calculates the indicative residual charges is available on Github titled 'calculate_residual_options.R'. By running through the calculation script, it is possible to see how participants' indicative residual charges were calculated, including the adjustments which were made after the Authority's consultation process. The output file which contains the results of all the indicative charge calculations, including the indicative residual charges, is also available on Github and is titled "indicative_charges.csv". Alternatively, individual participant calculations can be viewed in the Excel version of the model, which was released on EMI to accompany the 2019 Issues Paper (referred to at paragraph 4(c)) above. This Excel version does not contain the adjustments described in Appendix A to the 2020 Decision Paper; however, the underlying approach is the same as was taken in the later code.

(f) The Authority notes that, as set out in both the 2019 Issues Paper and the Decision Paper, the residual charges presented in those papers are indicative only, and are subject to:

(i) the limitations inherent in the data that has been used for the purpose of calculating the indicative charges, as described above; and

(ii) the precise formulation of a final TPM that is consistent with the 2020 guidelines.

Final charges would be calculated by Transpower in the event that a new TPM was incorporated into the Electricity Industry Participation Code 2010.

Please let us know if you wish to discuss this further.

Yours sincerely

Jenny Stevens / Laura Hardcastle
Partner / Senior Solicitor

IN THE HIGH COURT OF NEW ZEALAND
WELLINGTON REGISTRY
I TE KOTI MATUA O AOTEAROA
TE WHANGANUI-Ā-TARA ROHE

CIV-2020-485-367

UNDER	the Judicial Review Procedure Act 2016
IN THE MATTER OF	Judicial review of the proposed new Transmission Pricing Methodology
BETWEEN	**TRUSTPOWER LIMITED** Applicant
AND	**ELECTRICITY AUTHORITY and MERIDIAN ENERGY LIMITED** Respondents
AND	**NOVA ENERGY LIMITED and others** Interested Parties
AND	**TRANSPOWER NEW ZEALAND LIMITED** Intervenor

AFFIDAVIT OF MAHADEVAN BAHIRATHAN ON BEHALF OF NOVA ENERGY LIMITED
23 APRIL 2021

Solicitor:	Counsel:
Liesbeth Koomen	Ian Millard QC
Nova Energy Limited	Barrister
Level 15, the Todd Building	Thorndon Chambers
95 Customhouse Quay	P O Box 1530
Wellington	Wellington 6140
Telephone: 027 7343149	(04) 499 6040

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I, **Mahadevan Bahirathan** of Wellington, Manager, say:

A Personal background

1 My name is Mahadevan Bahirathan (I am generally known as Babu Bahirathan).

2 I am the Vice President Downstream Energy Division, and a member of the Senior Management Team, at The Todd Corporation Limited ("**Todd**"). That role encompasses the following roles / responsibilities:

a) Chief Executive Officer of Nova Energy Limited ("**Nova**"); and

b) Managing Director of Todd Generation Limited ("**TGL**");

both of which are wholly owned subsidiaries of Todd.

3 As such, I have responsibilities for:

a) the Kapuni co-generation plant, which was first commissioned in 1998 and was a 50:50 joint venture between Nova and Vector, until Nova acquired Vector's interest in 2020;

b) the Edgecumbe co-generation plant, which was first commissioned in 1996 and is connected to Horizon Energy Distribution Limited's ("**Horizon**") network near Whakatane; and

c) Todd's participation in the Whareroa Co-generation Joint Venture with Whareroa Co-generation Limited, a subsidiary of Fonterra, which entered production in 1996. I was Todd's representative on the joint venture for over 10 years.

4 I joined Todd on 29 March 1999 as a Business Analyst. I subsequently held the positions of Strategic Asset Manager, Commercial Operations Manager and Group Electricity Manager. I have held my current role since 2011.

5 From 1990 to 1999, I worked at Transpower New Zealand Ltd ("**Transpower**"). I started there as an Assistant Planning Engineer, working as a field officer for two years, before working in design and

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planning. I then worked on various development projects as Development Engineer before moving into transmission pricing. I left Transpower after working as the Team Leader of the pricing division for nearly two years.

6 I have personal knowledge of the existing Transmission Pricing Methodology as I was a key member of a team that developed it in 1998 when I was employed by Transpower.

7 I have a good understanding of the proposed Transmission Pricing Methodology and have followed its development since a new methodology was mooted over 10 years ago.

8 I have an engineering degree (First Class Honours) in electrical and electronics from the University of Canterbury and a Postgraduate Diploma in finance from Massey University.

9 In this statement, I address:

Section B: Nova's concerns with the proposed Transmission Pricing Methodology.
Section C: Cogeneration plants generally.
Section D: Nova's cogeneration plants.
Section E: Todd's other generation plants.
Section F: New Zealand electricity industry and the Electricity Authority
Section G: The impact of the proposed amendment to the charging regime.
Section H: Water analogy.
Section I: Price cap
Section J: Potential consequences.
Section K: Comparative position of net versus gross demand.
Section L: Residual Charges an amendment from what went before.
Section M: Inconsistencies in the proposal.
Section N: Other reasons given by the Electricity Authority
Section O: Failure on all three limbs of the statutory objective.
Section P: Closing comments.

10 In the course of this affidavit I will refer to:

MJD

a) a number of documents not already in the record; they are part of **Exhibit BB-A** to this affidavit; a reference to a Document by number is a reference to that Document in Exhibit BB-A; and

b) Todd, Nova and TGL interchangeably, as they are all part of Todd's Downstream Energy Division and ultimately owned by Todd.

B Nova's concern with the proposed Transmission Pricing Methodology

11 Nova is a generator and retailer of electricity and is a registered industry participant in the wholesale electricity market. As a generator, it is connected to the national grid both directly and, in some cases, indirectly through a local distribution network.

12 Nova's primary objection to the proposed Transmission Pricing Methodology relates to the proposed Residual Charge. In particular, Nova objects to including demand that will never be supplied by electricity from the national grid. This the Transmission Pricing Methodology does by grossing up the deciding factor, Anytime Maximum Demand, for concurrent demand behind the point of connection. I explain this in detail in Section G.

13 Nova has made extensive investments in embedded cogeneration plants that will be caught by this charge. Nova in fact owns the largest cogeneration portfolio in NZ. I describe the relevant plants in Section D below and the impact of the Residual Charge in Section G. To give some context, I also describe Todd's other generation plants, in Section E.

14 From Nova's perspective, the proposed Transmission Pricing Methodology fails to deliver on all three limbs of the Electricity Authority's statutory objective when it is applied to cogeneration plants.

15 The Authority has failed to correctly classify grid connected cogeneration plants. At times it appears to treat them as a pure generator, and on other occasions as a distributor or directly connected load. A cogeneration plant is different to the other two even after taking into account any rationalisation in ownership. E.g. connected transmission customer versus customer of underlying demand.

MJP

C Cogeneration plants generally

16 Cogeneration plants are generally built for the following reasons and have a number of advantages over conventional generation:

a) the plants are built primarily to meet demand for two or more forms of energy, typically steam, hot water and electricity to a factory or industrial processing facility. For example, the Whareroa co-generation plant exists primarily to supply electricity and steam to Fonterra's adjacent dairy factory;

b) they enable conversion of primary energy such as gas or coal to be converted to steam and electricity significantly more efficiently than if they were to be generated separately;

c) plant size and design are determined by the main energy requirement of the site, so as to optimise the cost and operation of the plant. In most New Zealand cogeneration plants, demand for steam and hot water determines the size of the plant;

d) typically, and certainly in all of Nova's cogeneration plants:

   i. site electricity demand is intrinsically linked to the steam demand, i.e. the majority of the electricity demand at the factory will only exist if /when there is steam demand; and

   ii. more electricity than is required by the demand is generated by the cogeneration plant, and excess electricity is exported to the national grid or local distribution network for sale.

e) Cogeneration plants:

   i. avoid the inefficiency and expenses of line losses, because the load is close to the demand;

   ii. create greater reliability of supply, because they avoid the risk of transmission outages;

MJD

iii. avoid altogether, or at least defer, the need for investment in peak transmission capacity;

iv. provide long term energy price certainty and stability to its primary customer without the vagaries of varying third-party costs and charges;

v. increase competition in the wholesale electricity market and thus enable a reduction in price by making available all surplus generation for sale; and

vi. increase security of supply of the electricity system because they diversify the sources of generation and supply.

17 Cogeneration plants are not the same as embedded generation plants:

a) embedded generation plants generally exist near their fuel source and where the demand is not dependent on the amount of generation. For example, a generation plant at a landfill site in Wellington uses the methane released from the landfill and does not influence the level of demand in Wellington. In a cogeneration plant, the majority of the electricity demand is inextricably linked to the level of steam generation: if the cogeneration plant is not operating and delivering steam to the customer, then it will have low or no electricity demand;

b) most, if not all, embedded generation is built after the demand has been established at a Transpower Grid Exit Point (**"GXP"**). Conversely, a cogeneration plant is built at the same time as the demand is first established. It is not built to reduce demand from the grid, because the primary objective of the cogeneration plant is to meet the entire needs of the demand from the underlying processing operation e.g. a factory;

c) often the cogeneration owner is the connected party. This is the case for Nova and Whareroa Co-generation Limited (a subsidiary of Fonterra) as the joint venture parties at Whareroa and Nova at Kapuni.

MJD

18 Cogeneration plants are also different from most other generating plants.

19 Most other plants are situated at or close to the site of the "fuel" used to generate the electricity:

a) a hydro generation plant has to be situated on a river that provides sufficient water flow and vertical drop (head) to produce the kinetic energy needed to drive the hydro electric turbines;

b) a geothermal generation plant needs to be situated on a geothermal reservoir capable of delivering the required steam;

c) a wind farm has to be situated in places where there is a strong and reasonably reliable supply of wind;

d) even most gas fired generation plants are situated near gas fields. The exception is Huntly but that was originally coal fired and was situated near the coal fields at Huntly. It then developed the dual capacity of using either gas or coal before adding an exclusively gas fired combined cycle turbine.

20 In contrast, cogeneration plants are situated near to the demand for steam. Unlike their competitors, such plants face the cost of having their fuel delivered to their site - in the case of the 3 Nova sites, the cost of gas transmission.

21 This makes the basis of the proposed Residual Charge even more discriminatory as, on top of paying for the transmission of the gas Nova uses, it is having to pay for the notional transmission to Nova's customer of electricity it does not receive or use.

D Nova's cogeneration plants

Whareroa

22 The Whareroa plant is near Hawera and is located at one of the largest dairy factories in the world. It has four 10.5 MW gas turbines and a 28 MW steam

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turbine. It provides steam and electricity to the dairy factory, with surplus electricity exported to the national grid. The site is directly connected to the national grid via a dedicated line, which has no other users. The connected party is the joint venture, namely Whareroa Co-generation Limited and Nova.

23 Nova committed to build Whareroa with Fonterra's predecessor Kiwi Co-operative Dairy Company in 1995. At the time it was considered that the existing distribution network was inadequate to reliably meet the expected load of the dairy factory. Accordingly, it was decided to build a cogeneration plant. This entailed constructing 20 kilometres of dedicated gas pipeline from Kapuni to Whareroa and then 6 kilometres of 110 kilo Volts high voltage lines from Whareroa to the national grid at Transpower's Hawera substation so that the excess electricity could be exported.

24 The first stage with 2 gas turbines and heat recovery steam generators ("**HRSG**") was commissioned in mid-1996 and a further 2 turbines, associated HRSGs and the steam turbine were commissioned and connected to the national grid in 1997/8.

25 At the time the plant was constructed and connected to the transmission grid, the peak demand at Transpower's Hawera substation was around 30 MW. Egmont Electricity (at the time the local network company) owned the nearby Patea generation with a capacity of 32MW and was considered an embedded generation for transmission charges to Egmont Electricity by Transpower. This goes to confirm that cogeneration was not designed or located to avoid transmission charges.

26 The plant primarily runs when there is demand for steam and electricity from Fonterra's dairy factory. In doing so, by design, it will always generate excess electricity and thus export the surplus to the national grid.

27 I will explain the demand profile of the dairy factory and the operation of the cogeneration plant.

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28 The dairy season typically starts in late July, with milk supply arriving at the factory for processing. Milk supply peaks in October / November and gradually stops in mid to late May the following year. Peak electricity demand at the dairy factory is around 28 MW. During the season, at least one gas turbine and associated HRSG will operate to meet the dairy factory demand for steam and electricity. Even with only one turbine operating, some electricity will be exported to the national grid.

29 During the milk season, the dairy factory takes steam at different pressures, 40 bar, 10 bar and 6 bar. The cogeneration plant has a condensing and extracting steam turbine that enables the high-pressure steam to be reduced to lower pressures suitable for the factory and, in doing so, generate more electricity. The design is a feature to improve energy efficiency. The steam turbine operates during the dairy season subject to steam availability and requirements of the site.

30 There is no significant milk processing in June / early July and that period is when the factory and the cogeneration plant undergo major maintenance. In early June there is a complete 10-day shut down of all steam systems. During that time there is no steam demand, and the cogeneration plant is also shut down for maintenance if required. If the cogeneration plant is completely shut down, electricity is imported from the national grid - about 5 MW during this period. This represents the electricity demand of the offices and cool stores associated with the dairy factory and is the highest demand imposed by the cogeneration plant on the transmission grid.

31 While Nova does not like it, it does not object to the joint venture being charged a Residual Charge for that demand if / when it is met by the grid, despite it only occurring for a maximum of 10 days in a year. However, the joint venture had a $0 Interconnection Charge from Transpower for the calendar year 2020 because the circa 5MW was not coincident with the 100 peak half hours when the transmission grid had the highest demand.

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32 Otherwise in that mid-June to mid-July period, the cogeneration plant operates predominantly as a generation plant when wholesale electricity prices are sufficiently high. In that mode, the steam that is generated is condensed through the steam turbine to generate electricity.

33 The Whareroa cogeneration plant is operated by Fonterra staff under a contract with the joint venture, as its operation is intrinsically linked to the dairy factory's needs.

34 I can categorically state that the plant is not run simply to avoid peak demand charges. Rather, it is run when there is a need for steam at the dairy factory.

Kapuni

35 The Kapuni cogeneration plant is located within the Kapuni gas treatment plant near Kaponga, South Taranaki. It has two 10 MW gas turbines, a 2 MW steam turbine and a 1.5 MW steam turbine. The steam and electricity are provided to the Kapuni gas treatment plant and a Fonterra lactose factory. A meat rendering and by-products facility is also supplied with electricity from the plant, with surplus electricity exported to the national grid. This site is also directly connected to the national grid via a dedicated line which has no other users. The connected party is the generator (Nova).

36 One of Nova's predecessors, Bay of Plenty Electricity, committed to build the Kapuni cogeneration plant in 1996, in a 50:50 joint venture with Vector (previously Natural Gas Corporation Energy Limited). Vector sold the gas treatment plant to Todd Energy in April 2020 and, at the same time, Nova acquired Vector's 50% interest in the cogeneration plant making it the 100% owner. The plant was completed in 1998 by the original joint venture parties. Due to its experience in the electricity sector, Bay of Plenty Electricity (Nova) was responsible for the connection to the national grid and remains the connected party.

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37 Again, this plant primarily runs when there is customer demand for steam and, like Whareroa, it generates more electricity than needed by the customers and thus exports surplus electricity to the national grid.

38 The maximum demand supplied by the Kapuni cogeneration plant is about 9 MW, with maximum electricity imported from the grid about 6 MW. However, as Kapuni's maintenance is done during spring and autumn months, the import is not when the transmission network is at high use, resulting in $0 Interconnection Charges from Transpower for the year 2020.

39 The Kapuni cogeneration plant is operated like the Whareroa cogeneration plant, but with the following notable differences:

a) peak steam demand is set by the requirements of the Kapuni gas treatment plant, which occurs in the winter months. The lactose dairy factory demand for steam and electricity is about one-third the size of the gas treatment plant and peaks in spring. Thus, major maintenance is normally scheduled for the shoulder seasons of the two demands from January to April;

b) the cogeneration plant can generate steam independent of the gas turbines operating. This is to ensure that both major customers can be supplied from the plant during planned maintenance work.

c) the cogeneration plant is operated by Todd Energy (previously Vector) as the owner/operator of the Kapuni gas treatment plant, as it is intrinsically linked to that plant's operations.

40 I can categorically state that the Kapuni cogeneration plant is not run simply to avoid peak demand charges. It is run when its customers have a need for steam.

Edgecumbe

41 Nova's predecessor, Bay of Plenty Electricity commissioned the Edgecumbe plant in 1996. It is located within Fonterra's Edgecumbe dairy

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factory and has two 5 MW gas turbines, associated HRSGs and a standalone steam boiler. The Edgecumbe cogeneration plant supplies steam and electricity to the dairy factory, with all surplus electricity exported to the Horizon distribution network in which it is embedded.

42 This plant is run very similar to the Whareroa cogeneration plant as its only customer is the dairy factory with the same seasonal demand profile. The plant is operated by Fonterra under a contract with Nova.

43 Again, I can categorically state that the plant is not run simply to avoid peak demand charges. Rather it is run when there is a need for steam and electricity at the dairy factory.

44 Interestingly, since this plant is connected to Horizon's network and is not directly connected to the national grid, if the cogeneration plant was run to reduce peak demand as seen by Transpower i.e. run to avoid/minimise transmission charges imposed on Horizon by Transpower, then it would have to have a different operating regime than to reducing peak demand as seen by Horizon. However, the plant does neither, and operates to meet steam and electricity needs of Fonterra. In doing so, Horizon stands to gain from any resulting demand reduction reflected on Transpower's grid due to excess generation being supplied by the cogeneration plant.

E Other Todd generation plants

45 Todd (either through Nova or TGL) owns and operates several other power generation stations. Unlike the cogeneration plants, they (other than the solar plants) are purely operated to wholesale electricity price:

a) 100MW McKee Peaker Plant (Taranaki);

b) 100MW Junction Road Peaker Plant (Taranaki);

c) 9MW Mangahewa power plant (Taranaki);

d) 2MW McKee power plant (Taranaki);

e) 1MW Happy Valley landfill power plant (Wellington);

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f) interests in a number of solar installations totalling ~10MW and a further 8MW ground mounted solar currently under construction in NZ and the Pacific Islands.

46 The two large plants are directly connected to the transmission grid whilst the other three are connected to local distribution networks. The proposed Transpower Pricing Methodology will impose new and additional charges on all of these generation assets. While this is something Nova has submitted against, at least they will all be treated like other similar generators or embedded generators on a level playing field. That is not the case with the cogeneration plants Nova owns where Nova and its customers are being forced to pay for a service that they never need nor receive.

F New Zealand electricity market and the Electricity Authority

47 Participants in the New Zealand wholesale electricity industry can be classified into four broad categories:

a) generators – e.g. Meridian, Contact, Nova, Pioneer etc

b) transmission grid owner - Transpower

c) distribution line companies – e.g. Vector, Powerco, Westpower etc

d) retailers – who are often generators but also include others

48 The price and volume of electricity generated and supplied are determined by competitive bids and offers in the wholesale electricity market. The market is operated in real time by the System Operator (Transpower) and closely regulated and monitored by the Electricity Authority.

49 Generators offer their generation with volume and price they are willing to sell for often in tranches. The volume could be as small as 1 MW. The market operator requests, in order from lowest to highest cost, the generation required to meet the demand at any point in time. The market is settled in 30-minute intervals.

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50 All generators receive the price offered by the marginal generator required to meet the demand.

51 Therefore, price set by the last 1 MW of generation required to meet the demand sets the price for the entire market.

52 Electricity demand in NZ peaks in winter months and consequently, demand on the national grid also peaks. The wholesale electricity prices are usually higher during these months because higher priced marginal generators are required to meet the increased demand.

53 At all of Nova's cogeneration plants, the excess generation is offered into the market at 1 cent per MW as what is exported to the market is not a function of the wholesale price, rather a function of what the factory demand is for steam. At times Nova has to offer its excess generation at a price of zero to ensure it is dispatched.

54 Thus, even removing say 12 MW of excess electricity injected by the cogeneration plant could result in a generator with a higher marginal price being dispatched, resulting in all electricity generated for that period to be higher priced. This is even more so in the winter months of peak national demand when the cogeneration generates around 50MW of excess electricity to the grid.

55 Most generation in New Zealand is located far away from the main demand centres. Laws of physics means in transporting the generation to the demand there will be losses, typically around 6 to 7%. The longer distance you transport electricity, the higher the losses.

56 The cogeneration plant by generating and supplying its customers has nearly zero transmission losses.

57 Further, if 10 MW of excess generation from the cogeneration plant is not made available to the market in Taranaki, and if the shortfall has to be made up from a marginal generator in the South Island, nearly 6 or 7% more electricity needs to be generated to meet the demand.

58 The Electricity Industry Act 2010 ("**Code**") sets out the duties and responsibilities that apply to industry participants and the Electricity Authority.

59 The Electricity Authority is the regulator responsible for the electricity market and has the objective to promote competition in, reliable supply by, and the efficient operation of, the New Zealand electricity industry for the long-term benefit of consumers.

G Impact of the proposed amendment to the charging regime

60 Every party connected to the national transmission grid pays connection charges for Transpower assets dedicated to that connection, in the old Transmission Pricing Methodology "connection assets". In addition, it contributes to the cost of common good transmission assets, in the old Transmission Pricing Methodology "interconnection assets" and "HVDC". References in this affidavit to transmission charges are references to the charges to recover the costs of providing and maintaining those common good assets.

61 The current regime for allocating those costs is based on Regional Coincident Peak Demand **("RCPD")**. The RCPD is the average of the highest 100 half hourly peak demands supplied in the region over a defined measurement period in the prior year. [1]

62 A customer's allocated transmission charges are based on its maximum peak demand in the 100 half hour periods of the RCPD – this therefore reflects the amount of transmission capacity demanded by the customer at times of peak grid utilisation.

63 Thus, under the existing methodology, if the Whareroa cogeneration plant imports ~5 MW from the national grid for 10 days in June and if any of those half hour periods coincides with the regional peak demand used to calculate the RCPD, then Whareroa cogeneration will be charged its

[1] In 1999, when the original version of the current pricing methodology commenced, the RCPD was based on the average of the highest 12 half hour periods for the year. That was subsequently increased to 100 half hours.

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[illegible]

proportion of transmission charges based on the 5 MW demand it puts on the transmission grid. While Nova does not like it, it does not object to such charge.

64 The proposed methodology for the Residual Charge is to calculate the charge by combining 2 elements:

a) the designated transmission customer's Anytime Maximum Demand in a year but averaged over 4 years (ie. the load demand placed by that customer on the transmission system); PLUS

b) the concurrent generation behind the point of connection even although that places NO demand on the transmission system.

65 Applying that to Whareroa there will be a short period of time in June each year when the cogeneration plant will be importing up to 5 MW of electricity – its Anytime Maximum Demand. While Nova does not like it, it does not object to such charge.

66 But for most of the time Nova will be generating electricity (up to 50 MW) and, therefore will not be a load customer. Rather it will be like an ordinary generator except that most of its electricity (usually in the range of 5 to 28 MW) is used by its sole customer, Fonterra, with only the balance (usually in the range from 10 to 40 MW) being exported to the grid. But, unlike its competitors in the electricity market, it will have to pay the Residual Charge. It is understood this will be based on the 28 MW being used by Fonterra.

67 That is, although Nova is not then using the grid to draw off electricity and is, instead, exporting electricity such that it has a zero Anytime Maximum Demand, it is treated as being a load customer with a 28 MW notional demand on the grid and charged accordingly. This seems to be the upshot of the paper published by Transpower in January this year "TPM Development Checkpoint 2 resubmission: Residual Charge and Transitional Cap" ("**Document BB1**") and also the Electricity Authority's response to Transpower in its letter of 4 February 2021 ("**Document BB2**").

68 Nova objects to that because neither the factory nor the cogeneration plant imposes a demand anywhere close to that on the transmission grid at any time, let alone at peak grid demand times. That is, the difference between 5 MW and 28 MW ~23 MW is never ever a contributor to any demand on Transpower's network.

69 Because Whareroa, Kapuni and Edgecumbe cogeneration plants primarily exist to service their connected customer demand when those customers' demands are supplied by the cogeneration plants, there will be no demand supplied from the grid. If cogeneration plants were to be treated on a level playing field as other generators that inject electricity into the transmission system, then they would not be forced to incur Residual Charges on cogeneration's customer peak demand that is never supplied from the grid.

70 Nova's cogeneration plants not only reduce the burden on the grid, but they also inject significant generation into the grid that increases the supply, reliability and competition in the wholesale electricity market whilst reducing transmission losses.

71 This can be seen from the electricity generated and demand each co-generation plant places on the national grid, as I explain further below.

Whareroa

72 When Whareroa cogeneration first connected to the transmission grid, it paid to Transpower a total of about $60,000 per annum in Connection and New Investment Charges. In Transpower's 2020 financial year, Nova paid (a) a Connection Charge of $160,000 - due to Transpower cost increases and allocation of more connection charges; and (b) the RPCD charge was zero – reflecting that the cogeneration plant did not receive any electricity from the grid during the RCPD measurement periods.

73 Electricity generation and demand at Whareroa over the calendar year 2020 was as follows:

Single highest anytime peak import	4.9 MW
Peak on-site demand	27.4 MW
Total generation	320 GWh

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Annual on-site electricity consumption	142 GWh
Total generation exported to grid	178 GWh
Annual electricity imported	0.1 GWh

74 From those figures it can be seen that, if peak on-site demand is used for calculating the Residual Charge, then Nova's cost will be 5.6 times higher than if the charge is based on actual use of the grid (27.4 ÷ 4.9), noting that even the 4.9 MW was not drawn during the 100 highest peak grid demand periods. The Residual Charge (over and above Connection Charges) would rise to $1.46 million per annum (based on an estimated Residual Charge of $106,660/MWh[2]). If, instead, this was to be based on average anytime imports the charge would be close to $0.26 million based on the same assumption.

75 Simply put, Nova strongly objects to the proposed $1.2 million per annum increase in transmission charges for a service premised on demand that is in fact not met by the national grid and which is to be allocated purely on an arbitrary assumption of ability to pay.

Kapuni

76 When the Kapuni cogeneration plant was first connected to the transmission grid, Nova funded all of the required connection assets and work and accordingly paid zero Connection Charges. Subsequently, Transpower changed its definition of connection assets with the result that, in Transpower's 2020 financial year, Nova paid $258,000 in Connection Charges (and zero Interconnection Charge).

77 Electricity generation and demand at Kapuni over the calendar year 2020 was as follows:

Single highest anytime peak import averaged over 4 years	2.8 MW
Peak on-site demand	8.7 MW
Total generation	175 GWh
Annual on-site electricity consumption	56 GWh
Total generation exported to grid	120 GWh

[2] Equivalent to $53,330/MW given the measurement occurs over a half hour period. Based on the figures supplied in supporting links to the Electricity Authority *Transmission pricing methodology 2020 Guidelines and process for development of a proposed TPM: Decision* (10 June 2020) – EA record 241.19119 **[CB]**.

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Annual electricity imported	0.1 GWh

78 Under the proposed methodology, using peak on-site demand for 2020 for calculating the Residual Charge for the Kapuni cogeneration plant, Nova estimates the Residual Charge to be $464,000 per annum and not the $150,000 estimate provided by the Electricity Authority, which is based on actual electricity imports in 2014-18. If, instead, this was to be based on average anytime imports the charge would increase by $314,000 based on the same assumptions. Again, Nova strongly objects to an incremental annual charge for a service not in fact provided and to be allocated purely on an arbitrary assumption of ability to pay.

Edgecumbe

79 The position of Edgecumbe is slightly different because it is embedded in the Horizon network. Because it is not directly connected to the national grid it will not incur the Residual Charge. However, under the proposed Transmission Pricing Methodology, it is anticipated that Horizon will seek to pass through those Residual Charges attributable to the factory. The following calculations assume full recovery by Horizon.

80 Electricity generation and demand at Edgecumbe over the calendar year 2020 was as follows (noting these were as calculated to the Horizon network, not Transpower's):

Single highest anytime peak import	3.3 MW
Average annual peak on-site demand	7.9 MW
Total generation	54 GWh
Average annual on-site electricity consumption	42 GWh
Total generation exported to grid	12 GWh
Annual electricity imported	2.5 GWh

81 Based on similar assumptions to Whareroa and Kapuni, if Horizon was to pass through the transmission charge it incurs, I estimate it will seek to charge Edgecumbe cogeneration $421,000 per annum in Residual Charges. If, instead, this was to be based on average anytime imports the charge would be close to $176,000 based on the same assumptions.

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82 The effect will be to impose on Nova (in this case, a non-connected party) a charge for a service not in fact provided and to be allocated purely on an arbitrary assumption of ability to pay.

Calculations may be understated

83 My calculation of the incremental charges on the cogeneration plant use the Electricity Authority's figures. These are based on an assumption by the Electricity Authority of a near 20% reduction[3] in transmission charges between 2019/20 and when the new Transmission Pricing Methodology is expected to come into effect in 2023. There is no guarantee the charges will be reduced by 20%. Therefore, the additional cost impost on the cogeneration plants is significant and could remain significant.

H Water analogy

84 An analogy to Council water supply will illustrate my point. In the analogy, a Council builds and maintains a water pipe connection to the house. However, the householder has installed a rainwater collection system, which meets the majority of household needs for watering the garden. The householder pays a connection charge as well as any usage charge for water delivered through the council pipes, to which it does not object.

85 What it does object to is a proposal by the Council to apply a residual charge based on:

a) the household's entire water demand for the garden, even though that demand is met by the household's own system and not through the council owned connection; and

b) a premise that a household which can afford its own rain water collection system to meet most of its needs, has an ability to pay increased charges for a service it does not need.

[3] Transpower's non Inter Connection and HVDC Charges for the 2019/20 year was $797 million. The calculations done in the Authority's Decision is based on the equivalent charges totalling $636 million. See Transpower 'Transmission Pricing Data for 2020/21 Pricing Year' ("**Document BB3**").

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I Price cap

86 Although the proposed Transmission Pricing Methodology does have a price cap this does not appear to apply to Nova.

87 This is even though, if the new pricing methodology is implemented, Whareroa Co-generation Joint Venture will face an increase in total transmission charges of 1040% at the Whareroa cogeneration plant. Yet, despite such a huge increase in charges the Authority's own calculations in Table 4 in section 16 of the Decision show no benefit accruing to Nova or Whareroa Co-generation Limited from the transitional cap.

88 This goes to show the design of the cap is ineffective or totally inappropriate as applied to Nova's assets. One explanation may be because the Authority cannot determine whether a cogeneration plant such as Nova's is a generation or distribution or an industrial demand customer. Another explanation may be the Electricity Authority doesn't have the necessary data (nor did it ask Nova) and has wrongly assumed the impact the proposal will have on the business.

J Potential consequences

89 If materially increased charges are imposed on the cogeneration plants and its customers, it will no doubt incentivise Nova and its customers to assess the viability of those plants and consider all alternative operating modes including but not limited to:

a) disconnecting from the transmission grid and operating in an islanded mode whereby the plant's output is moderated to only supply the factory demand;

b) disconnecting from the transmission grid and connecting to the local distribution network;

c) investing in other types of plant to raise steam and electricity at different amounts to solely meet the factory demand;

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d) Nova building an electricity transmission line between Whareroa and Kapuni (note, Todd Energy another subsidiary of Todd owns a gas pipeline between the two sites already with easements) and disconnecting from Transpower entirely or at one of the grid exit points thereby creating diversity in demand;

e) Fonterra, as a customer of the cogeneration plant, moving or reducing some of its operations to another facility.

90 All of these would result in inefficient economic outcomes, exactly the issue the Authority assumes will not occur.

K Comparative position of net versus gross demand

91 One of the core assumptions of the Electricity Authority is that using gross load for allocating Residual Charges would minimise the risk of distortion to customer investment or demand response – see the Paper for the Electricity Authority's Board meeting of 9 May 2019 "TPM: net versus gross load for allocation of Residual and Benefit Based Charges"[4]. This paper was not one of the papers available to us during the consultation period and was only obtained as part of the discovery process.

92 However, in the same paper, the Authority states

> *A gross approach to the default residual allocator would materially increase transmission charges for distributors with substantial distributed generation and grid-connected industrials with cogeneration (compared to a net approach for the residual only) and slightly decrease charges for other load customers."*[5]

93 Therefore, contrary to Electricity Authority's own assertion elsewhere that using net demand will put undue burden on other users, this confirms that what is being proposed will have minimal impact on other users.

94 The Ministry for Business, Innovation and Employment's ("**MBIE**") statistics on embedded generation show that in 2019 the total onsite annual demand of all such plants was 294 GWh, out of total national

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[4] EA record 01.0973 [**CB**].
[5] EA record 01.0973 at [7.9] [**CB**].

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demand of 39,954 GWh i.e. total onsite demand met by cogeneration plants was just 0.73% of total NZ electricity demand[6].

95 By way of comparison, in Wellington for example Nova has a 1 MW landfill generation plant within Wellington Electricity's network. The electricity consumed in the operation of that generation plant is immaterial to Wellington Electricity's total load, which is about 575 MW at peak.

96 What is being proposed is simply a significant cost burden on cogeneration plants because it is assumed they are able to pay and will not disconnect from the grid. This is for minimal reduction of the burden on other customers.

97 At least when I was at Transpower, when planning and designing the grid and the need for upgrades it took into account of embedded generation in the local network rather than gross load. I have no reason to believe that Transpower will have changed that practice.

98 The proposed Transmission Pricing Methodology forces Transpower to charge on the basis of gross load even though it plans, designs and operates the national grid on the basis of only having to meet net load. So the cogeneration plant has to pay for a service it does not require and which Transpower does not plan to deliver.

99 In the Electricity Authority's board paper on 9 May 2019[7], the Authority recommends a number of items in relation to allocating charges based on net and gross loads.

100 It defines net load as demand measured at the grid exit point in the recommendations in 1.1 (a) of the same paper.[8] It further states in 1.1 (c) that

[6] See https://www.mbie.govt.nz/building-and-energy/energy-and-natural-resources/energy-statistics-and-modelling/energy-statistics/electricity-statistics/
[7] EA record 01.0973 **[CB]**.
[8] EA record 01.0973 at [1.1(a)] **[CB]**.

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"TPM guidelines require Transpower to determine the residual charge based on gross load (according to anytime maximum demand measured at the GXP plus injection by embedded generation)".[9]

101 The Authority also states:

> ***2 Rationale***
>
> *2.1 The Board deferred a decision on this policy issue at its October 2018 meeting pending a cost-benefit analysis (CBA) of the relative effects of the various approaches to measuring demand. However, the different ways of measuring demand do not impact CBA results significantly. So we have relied on other relevant factors for this recommendation.*
>
> *2.2 We should allocate the costs of the seven benefit-based historical investments on the basis of net load as this is a better measure of a load customer's benefit from the grid.*
>
> *2.3 Transpower should have flexibility as to whether it allocates the costs of post-2019 grid investments on a net load or a gross load basis as:*
>
> *(a) net load is generally a better measure of a load customer's benefit from the grid*
> *(b) there may be some circumstances in which use of gross load would discourage inefficient investment for charge avoidance purposes*
>
> *2.4 The residual charge should be calculated on a gross load basis for all load customers as this better reflects customer size and provides better assurance that load customers will not be encouraged to invest in distributed generation or batteries just to avoid charges. A gross load approach would mean higher charges for customers with embedded generation.*[10]

102 Significantly, the Authority admits that the use of net or gross load does not impact the Cost Benefit Analysis ("**CBA**") of the Transmission Pricing Methodology. Further at paragraph 2.4 of that Paper it promotes Residual Charges being allocated on gross load based on it better reflecting customer size and it would not encourage investment in distribution generation or batteries, just to avoid charges. [11]

103 It is clear from the material I have presented, Nova's cogeneration plants were not built to avoid charges. They were built to provide energy supply to vital industries in New Zealand. Since being connected in the late 1990s, although the definition of connection assets has changed, the same basic

[9] EA record 01.0973 at [1.1(c)] **[CB]**.
[10] EA record 01.0973 at [2] **[CB]**.
[11] EA record 01.0973 at [2.4] **[CB]**.

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concepts for allocating the cost of interconnection assets have been used consistently.

104 Now, the Electricity Authority is proposing to impose a charge on a radically different and completely arbitrary, theoretical notion of not encouraging distribution generation being built to avoid charges.

105 In my view, the Electricity Authority is completely void of any practical understanding of how investment decisions are made in the real world. What it is proposing to do will have the effect of encouraging parties, such as Nova, to contemplate disconnection from the transmission grid, thereby resulting in not supplying any excess generation to the market and not sharing some of the costs of the transmission grid.

106 Note, all three of Nova's cogeneration plants are capable of operating in complete isolation of the transmission grid on a permanent basis. Whilst it is less efficient to do so, imposing such unreasonable charges for services not rendered will force the owners to consider how the plants will be operated in the future.

107 It is also evident from the analysis that the Electricity Authority starts with the premise that in all circumstances the demand connected to the transmission grid at a grid exit point is greater than the generation, thus all of the analysis is premised on the assumption parties are investing in embedded or distributed generation to avoid transmission charges. As explained previously, Nova's cogeneration plants are **not** built to avoid a pre-existing demand. Rather they were developed to supply steam and electricity to industrial processes and as a function generate excess electricity than is needed by the processes and export that to the transmission grid.

108 Nova's cogeneration plants are generation plants that on at least 355 days in each year generate electricity to export to the transmission grid. This is likely to be more regular than conventional generation plants.

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109 The Authority is unclear as to how it would treat the cogeneration plants. It lists them as generators in some of its papers[12], but imposes charges on embedded demand as if they are a distribution customer.

110 In simple terms, the Authority is proposing to impose unreasonable charges on some transmission customers on the basis it can, despite its own Cost Benefit Analysis clearly showing the differentiation between charging based on gross versus net load is not determinative. It is simply based on the assumption that gross load represents a party's ability to pay.

L Residual Charges an amendment from what went before

111 As noted above:

a) Whareroa cogeneration plant was completed in 1997/8
b) Kapuni cogeneration plant was completed in 1998; and
c) Edgecumbe cogeneration plant was completed in 1996.

112 At that time, the charging regime for common good assets was a Transport and Access Charge. Transport Charge which collected 50% of the charges was based on customer's use of the relevant Transpower grid assets based on complex power flow models calculated over hundreds of generation scenarios that occurred in the previous year. The Access Charge that collected the remaining 50% was based on coincident peak demand a customer imposed on Transpower's grid.

113 On 1 April 1999, those charges were replaced by a single Interconnection Charge as it was considered transmission charges should not be avoidable and should be entirely allocated on a postage stamp type allocation with minimal distortion. The Interconnection Charge was allocated on the average of customer's half hour peak demand that was coincident at the 12 highest half hour peak demand periods in New Zealand in the previous year (note measurement periods were from 1 October to 30 September in the prior year, whereas the charges were from 1 April to 31 March). All demand

[12] See EA record 241.19233 at [16.14] [**CB**].

customers connected to Transpower's grid who imposed a demand on the transmission system in the 12 highest peak periods in the country were allocated transmission charges in proportion to their contribution to the national peak. Thus, if a demand customer did not have any demand in the 12 half hours when New Zealand had the highest demand, they did not get any Interconnection charge allocated as they were seen as not imposing a burden on the transmission system.

114 The 12 half hour peaks were subsequently changed to only apply to the upper North Island demand whilst the rest of the country was measured on the average of the top 100 half hour peak demand periods.

115 Further, in the case of the Edgecumbe cogeneration plant, since it is embedded within the local distribution company's network, Transpower didn't deal with Edgecumbe as a generation or demand customer as it was not directly connected to the national grid.

116 However, the local distribution company derived a benefit from the fact that Edgecumbe generation injected electricity into its network, thus reducing the electricity imported from the national grid. This benefit was based on Edgecumbe cogeneration plant's coincident export of electricity into Horizon's network during the 12 half hour periods when the Interconnection Charge was calculated (i.e. the RCPD).

117 The local distribution company shared the benefit with the Edgecumbe cogeneration plant to incentivise it to export electricity whenever possible. This benefit sharing was in existence since mid-1990s. This was eventually termed as the Avoided Cost of Transmission ("**ACOT**") by Transpower.

118 This benefit was removed with effect in 2018 when the Electricity Authority considered that ACOT payments were providing signals for uneconomic investment in embedded generation and putting a burden on parties that could not reduce their demand.

119 It can be seen that there has already been a major change in the manner in which embedded generation has been treated.

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120 In the above cases, the connected party to the transmission grid was primarily a demand customer that may have had embedded generation.

121 The proposed change is now seeking to impose a transmission tariff on connected parties who are primarily generation customers, based on embedded demand that is never supplied by the grid, purely on the basis on an assumption of ability to pay.

122 Such major changes are not conducive to innovative investment decision-making. One cannot be certain as to what the future charging regime will be. Note para 10.19 of the Decision.[13]

123 I note that in its defence the Electricity Authority at para 96(b) admits:

> *That its 2020 Revised CBA did not include quantitative analysis specifically addressing the issue of whether to adopt a gross load calculation for the Residual Charge or whether this best reflects a customer's ability to pay but denies that such analysis was required under the Act or Code and further says that it conducted qualitative analysis of its approach to the matters listed in paragraphs 20 and 24 of Nova's SoC, including advantages and disadvantages of its approach, in the 2019 Issues Paper and Decision.*[14]

124 Just to make clear, it is my understanding of the various papers released by the Authority no quantitative cost benefit analysis was ever done by the Authority on this issue, not in 2020 or 2019 or earlier.

M Inconsistencies in the proposal

Batteries

125 In March of this year, Transpower published an options paper "TPM Development Residual Charges and the Treatment of Batteries" (**Document "BB4"**)[15]. This was in response to Contact Energy writing to the Electricity Authority seeking more favourable treatment for grid connected batteries than the proposed Transmission Pricing Methodology would allow. The concept underlying the request is that batteries can be charged when the delivered electricity price is low and then discharged

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[13] See EA record 241.19119 at [10.19] [**CB**].
[14] Electricity Authority *Statement of Defence*, 2 October 2020 at [96(b)].
[15] Transpower *TPM Development Residual Charges and the Treatment of Batteries Options Consultation* (March 2021) ("**Document BB4**").

when the price is high arbitraging on the differential in such price. This could be used to lower a network's Anytime Maximum Demand.

126 Shortly before that the Electricity Authority (**Document "BB5")** sought to clarify comments it had made in relation to batteries in its Transmission Pricing Methodology papers.[16]

127 Having stated in that letter that Residual Charges should be based on gross load so parties will not be encouraged to invest in distributed generation or batteries just to avoid charges, the Authority states:

> *The Authority considers that it would most likely be inconsistent with its statutory objective (and it would certainly not be the Authority's intent) for the new TPM to discourage efficient investment in grid-connected batteries.*[17]

This letter clearly points Transpower to its freedom, subject to the Electricity Authority's final discretion, to provide batteries with a favoured status in terms of an exemption of some form from Residual Charges.

128 A number of submissions to Transpower, including Nova's, on the topic highlight the fact that batteries are not unique in being able to provide demand response or peak electricity injection in the national grid.

129 The Electricity Authority justifies providing this favourable position for batteries on the basis of promoting competition under its statutory objectives. But applying a new charge on existing cogeneration plants and providing an exception for new technologies is not in fact beneficial to consumers over the long term as it discriminates between generators.

130 Interestingly, it also conveniently ignores a party's ability to pay when it comes to batteries.

131 It is widely recognised that by increasing investment risk this ultimately leads to higher hurdle rates of return being required by investors; this in turn will ultimately lead to higher electricity prices.

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[16] Letter from Electricity Authority to Transpower regarding clarification of Transpower's comments on batteries in its TPM paper (18 March 2021) ("**Document BB5**").

[17] Letter from Electricity Authority to Transpower regarding clarification of Transpower's comments on batteries in its TPM paper (18 March 2021) ("**Document BB5**") at page 3.

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132 At paragraph 10.34 (b) of the Decision the Authority states:

> *Residual charges are allocated on a proxy for customers' size and so their ability to pay (much like the way the tax system works). This is not reduced by the presence of generation behind the point of connection*[18]

133 Earlier in time the issue of net load or gross load was dealt with at paragraphs B.210 to B.216 of the 2019 Issues Paper.[19] At paragraph B.213 the Authority gives its reasons for preferring gross load. It states:

> *B.213 Our current preferred option is that the residual should be allocated based on a gross load approach, as gross demand is a better proxy for customers' size (and so their willingness and ability to pay) than net demand.*[20]

134 As previously stated in this affidavit, generation is normally based near the "fuel" source for generating electricity. This will normally be in rural areas where the connected party is the local lines distributor. Being a rural area the number of customers that such distributor will have per kilometres of lines will be much lower than city areas. That is the local line distributor has to recover the high cost of reticulating electricity to dispersed rural communities over a relatively small base of customers.

135 Westpower, which serves the West Coast is an example of a distributor which has significant embedded generation, mainly small hydro schemes, yet has a very extensive network of lines.

136 The Authority's Decision paper in section 16.14, Table 4 shows that the Residual Charge will increase Westpower's transmission charges by $1.5million per annum, a near 93% increase.[21]

137 Westpower has around 13,800 customers on its network. The proposed change in charges will mean an increase of around $137 per customer per year, plus GST i.e. $158 per annum in their power bills each year. If the Residual Charges were to be calculated on a net load basis, the increase would be $133 on their bill.

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[18] EA record 241.19119 at [10.34(b)] [**CB**].
[19] EA record 235.16423 [**CB**].
[20] EA record 235.16423 at [B.213] [**CB**].
[21] EA record 241.19119 at [16.14] [**CB**].

138 Westpower customers face a huge increase from the proposed changes anyway. The use of gross load will add a further $25 impost per annum on the basis of allocating Residual Charges on gross demand which is not served by the transmission grid due to a number of embedded generation in the network. However, the Authority's assertion that due to embedded generation in the network, Westpower, and by inference its customers, are demonstrating their increased ability to pay more charges. It is impossible to ascertain how Westpower's customers could be considered as being able to pay the increased charges because of embedded generation in the network.

N Other reasons given by the Electricity Authority

139 The Authority does, in its defence, refer back to and relies on its 2019 Issues Paper. I note that it does not cross-refer to that 2019 Issues Paper at paragraphs 10.33 to 10.40 of the 2020 Decision when justifying the use of gross load **other** than to reject an argument advanced on behalf of Trustpower that the Ramsay pricing principle should be used.[22] However it does say at paragraphs 3.11 and 3.12 that the Decision builds on earlier papers and should be read with the 2019 Issues Paper and the 2020 Supplementary Consultation Paper.[23]

140 The only Residual Charge issue the 2020 Supplementary Consultation Paper dealt with was the annual adjustment to that charge.[24] That is not the main issue that Nova is concerned with.

141 The issue of net load or gross load was dealt with at paragraphs B.210 to B.216 of the 2019 Issues Paper.[25] At paragraph B.213 the Authority gives its reasons for preferring gross load. It states:

> *B.213* *Our current preferred option is that the residual should be allocated based on a gross load approach, as gross demand is a better proxy for customers' size (and so their willingness and ability to pay) than net demand. As is discussed in appendix D: decision making framework, allocation of common costs based on this is consistent with what would occur in a workably*

[22] EA record 241.19192 at [10.33]-[10.40] **[CB]**.
[23] EA record 241.19192 at [3.11]-[3.12] **[CB]**.
[24] See EA record 240.18644 **[CB]**.
[25] EA record 235.16259 at [B.210]-[B.216] **[CB]**.

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> *competitive market. If the operation of distributed generation reduced the residual charge, the allocation would no longer be based on customer size or ability-to-pay. It would also risk creating an artificial incentive for investment in distributed generation over time, in advance of the residual allocator being updated (particularly if updating occurred frequently.)*[26]

142 However Appendix D does not explain why a customer in a workably competitive market would pay for a service that does not benefit it.[27] Rather, as Appendix D acknowledges, price rations demand for services to those users who value it most. Efficient markets can only charge customers who benefit from the service and in proportion to the benefits they receive.[28]

143 It is also entirely consistent with a workably competitive market for a user to limit use of a high cost service in order to minimise cost if the cost of not doing so outweighs the benefit.

144 The Residual Charge covers the cost of existing grid investments other than 7 recent major investments. The Authority at paragraph D.66 favoured applying Benefit Based Charges to existing investments.[29] At paragraph D.67 it states:

> *D.67 The discussion of workably competitive markets above indicates that where users are indifferent about the age of the investment providing a service, charges for the services of old investments will likely be the same as if the investment was new. This means that the principle for charges for existing grid investments discussed above should also apply to existing investments.*[30]

145 Nova and, I believe, most if not all transmission customers are indifferent about the age of the investment providing the service.

146 Appendix D does go on at paragraph D.79 to deal with Transpower's other costs, that is its overheads and unallocated operating costs.[31] It notes at paragraph D.80 that in workably competitive markets costs that are additional to short run marginal costs are recovered by having higher

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[26] EA record 235.16259 at [B.213] **[CB]**.
[27] EA record 235.16259 at [I.50]-[I.53] **[CB]**.
[28] EA record 235.16259 at [I.50]-[I.53] **[CB]**.
[29] EA record 235.16259 at [D.66] **[CB]**.
[30] EA record 235.16259 at [D.67] **[CB]**.
[31] EA record 235.16259 at [D.79] **[CB]**.

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charges for those customers who are prepared to pay more than short run marginal cost.[32] However, at paragraph D.81 the Authority asserts:

> *However, given the practical difficulties involved, such charges are typically levied on the basis of some measure of size and/or ability to pay.*[33]

147 I disagree with that statement. Such costs, in a workably competitive market, are added to the price charged to those who are prepared to pay it.

148 In any event, the discussion in Appendix D would suggest that there are 2 charges in relation to Transpower's existing costs:

1. a charge for use of the existing grid based on benefit;

2. a residual charge for other costs that are unrelated to the asset (i.e. the grid) that is charges such as audit fees, human resources costs.

149 However, the Residual Charge is a single charge which covers both and is primarily used to recover Transpower's costs associated with the existing grid rather than the other costs.

O Failure on all three limbs of the statutory objective

150 The Authority's statutory objective is to promote competition in, reliable supply by, and the efficient operation of, the electricity industry for the long-term benefit of consumers.

151 What is proposed under the Transmission Pricing Methodology fails on all three of these limbs as far as how grid connected cogeneration plants are proposed to be charged. I explain below.

152 Competition – the proposed methodology fails to provide a level playing field for generators regardless of location and enhancing competition between grid and non-grid alternatives. The proposal encourages Nova's cogeneration plants to seek to embed within distribution networks or worse still, completely disconnect from the network.

[32] EA record 235.16259 at [D.80] **[CB]**.
[33] EA record 235.16259 at [D.81] **[CB]**.

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153 Reliability – In encouraging the cogeneration plants to disconnect or alter its operations, the diversity in generation supply provided by such cogeneration plants which as previously explained operate for over 355 days in each year will be lost to the system.

154 Efficient operation – by encouraging the cogeneration plant to embed within a distribution network where losses are higher or to operate in an island mode the plant will be operated less efficiently, and thus will cost more to operate.

155 Long term impact on consumers –a rational response of the cogeneration plant to a significant increase in transmission costs would be to look to disconnect from the grid. This deprives the wholesale market of the very low-priced excess electricity generation supplied by the cogeneration plant. That, in turn, will lead to a higher priced generator being dispatched to fill the gap including the additional line losses. Consumers will ultimately pay the cost of the higher priced generation in their retail tariff.

156 The Authority in paragraphs 7.11 to 7.13 in its Board paper of 9 May 2019[34] states that *"we see no evidence to support the view that it would be material enough to alter a decision to exit one way or the other (particularly in the early years while the price cap is in effect)"*.[35] This statement seems to accept that but for the cap, there may be sufficient incentives for parties to exit Transpower's transmission service. This is consistent with my own analysis that the proposed increase in charges will provide sufficient incentives for Nova to seriously consider alternative options, including disconnecting from the national grid.

157 The Authority has also failed, in Section 16 of its Decision, to properly consider the impact on Nova's assets namely Kapuni and Whareroa cogeneration.[36] I say this because it said in the response[37] to a question put forward by Nova[38] that the increase in charges were calculated based on

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[34] EA record 01.0973 at [7.11]-[7.13] **[CB]**.
[35] EA record 01.0973 at [7.12] **[CB]**.
[36] EA record 241.19192 at [16] **[CB]**.
[37] Letter from Bell Gully (Electricity Authority) to Nova (30 October 2020) ("**Document BB6**").
[38] Letter from Nova to Bell Gully (Electricity Authority) (20 October 2020) ("**Document BB7**").

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the current Anytime Maximum Demand. The Authority is not in possession of the factory demand supplied by the cogeneration plants as that is not a market traded volume. Thus the Authority's calculations are flawed and grossly underestimate the increase in charges to Nova's cogeneration plants.

P Closing comments

158 The proposed Transmission Pricing Methodology if implemented will, at least as far as Nova's cogeneration plants are concerned, encourage Nova to take action that will likely result in outcomes that are against the statutory objectives of the Electricity Authority.

159 It is most likely to manifest itself in the form of reduced supply of generation resulting in reduction in reliability and inefficient operation of the plant or investment to reduce the proposed charges.

160 This arises primarily because the Authority:

a) has failed to recognise the cogeneration plants such as plants owned by Nova are different to typical embedded generation plants in that they are not operating to avoid or minimise transmission charges;

b) is proposing to charge for a service that will not be taken or delivered; and

c) has mistakenly assumed a transmission customer's (in this case a cogeneration plant) ability of to pay a substantial increase in costs is represented by the size of its downstream customer's demand.

161 The Authority in its most recent correspondence to Transpower in relation to charging methodology for batteries has sought to vary the very principles it espoused in its Decision by seeking a different treatment of batteries that are no different to a load behind a cogeneration plant, confirming that the Transmission Pricing Methodology over its 12-year gestation period is not fit for purpose and does not cater for new technologies such as batteries.

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162 From the beginning of the Transmission Pricing Methodology review, Nova has been highly sceptical of benefits to consumers of a complete overhaul of the existing Transmission Pricing Methodology. Nova has submitted against a major change and has been supportive of modifying the existing Transmission Pricing Methodology to deal with matters of concern, e.g. allocation of HVDC charges and recovery of new common grid investments.

163 I have personally given these views directly to the Electricity Authority's previous CEO and Chair to no avail.

164 Despite having had no traction, Nova has continued to constructively submit on the consultation process. That should not be mistaken as Nova's support of the proposed complete overhauling of the existing Transmission Pricing Methodology.

165 It is notable that despite the very extensive processes undertaken by the Authority, it has only arrived at a solution that allocates less than half of the transmission charges on the basis of beneficiary pays, either through the Benefit Based Charge or the Connection Charge. The remainder is allocated in the manner of a tax - the Residual Charge - which I have addressed in the affidavit.

166 Investments in the generation, transmission and distribution assets in the electricity industry are of a long-term nature and require significant capital. Thus, investors require long term stability and certainty.

167 For all its faults, the existing Transmission Pricing Methodology has provided significant stability and certainty to participants as to their transmission charges over the past 20 plus years.

168 Nova's position firmly remains that the existing Transmission Pricing Methodology should be modified slightly to deal with the key issues rather than create significant uncertainty and instability by completely overhauling it.

169 Further, the proposed Transmission Pricing Methodology particularly in how Residual Charges are applied to cogeneration plants and the process followed to reach those decisions were flawed, do not meet the Authority's statutory objective, will be detrimental to consumers in the long term and thus should be rejected. The Authority should be asked to consider modifying the exiting Transmission Pricing Methodology to deal with the HVDC charges, recovery of new investments and provision for new technology such as batteries.

Affirmed at Wellington)
this 23rd day of April 2021)
before me:)

Mahadevan Bahirathan

Matthew John Dicken
Solicitor
Wellington

A Solicitor of the High Court of New Zealand

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"BB-A"

EXHIBIT NOTE
This is the exhibit marked "Document BB-A" referred to in the annexed affidavit of MAHADEVAN BAHIRATHAN sworn at Wellington ~~this 23~~rd day of April 2021 before me:

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A Solicitor of the High Court of New Zealand

Matthew John Dicke
Solicitor
Wellington

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Document BB1

TRANSPOWER

TPM Development

Checkpoint 2 resubmission: Residual Charge and Transitional Cap

January 2021

Contents

1 Purpose of this paper

1. This paper is our Checkpoint 2 resubmission containing our preliminary proposals for the residual charge and transitional cap provisions of the new TPM, which have been updated in response to feedback received from the Electricity Authority (**Authority**).[1] We have included revised preliminary TPM drafting for the residual charge and transitional cap in the Appendix.
2. The Authority considered most of the drafting for the residual charge and transitional cap in our Checkpoint 2 submission is appropriate and largely consistent with the Guidelines but provided feedback on some "primary concerns" and other "secondary matters". This paper responds to those primary concerns and secondary matters.
3. As previously noted, given time constraints, we may not be able to provide preliminary TPM drafting for other aspects of the TPM with our later Checkpoint 2 submission. It has been possible to do so for this Checkpoint 2 submission and resubmission because of the level of prescription in the Guidelines for the residual charge and transitional cap.

[1] Authority letter from James Stevenson-Wallace to Alison Andrew, "Transpower's TPM Checkpoint 2a submission", dated 7 December 2020.

2 Our response to Authority's feedback: residual charge

4. The Authority's feedback on our preliminary proposal for the residual charge comprises three "primary concerns", each of which we address below.

2.1 Generators with embedded load

Authority feedback

A.6 Transpower appears to be proposing that the residual charge only be paid by customers that draw energy directly from the grid.[2] However, such an approach risks omitting a category of customers: generation customers with embedded load. This omission could encourage customers to structure their connection arrangements in order to avoid paying transmission charges.

A.7 In some cases a large industrial load is embedded behind a generator's point of connection to the grid. The load customer may draw some or all of its energy from the generator and potentially also some from the grid. The guidelines require a generation customer to pay a residual charge in respect of any embedded load connected behind its point of connection, as the guidelines provide that:

(a) generation customers pay a residual charge to the extent that they have load

(b) the use of electricity by an embedded load customer is a characteristic of, or other matter relating to, that party and must be considered as part of any assessment of the transmission customer's characteristics etc, by virtue of clause 7. The effect of this is to impute that use of electricity by the embedded load customer to the transmission customer (ie, generator) into whose network it is embedded

(c) load is measured on a gross basis for residual charge purposes (that is, for residual charge purposes, it does not matter whether the electricity is drawn from the grid, or directly from a generator: the customer is charged based on its usage, regardless).

A.8 As set out in the TPM Guidelines Decision Paper, the reason for the gross load approach is that the residual charge is intended to recover remaining revenue without distorting grid use or investment decisions.

A.9 In order to calculate gross load for residual charge allocation purposes, Transpower will require data on electricity flows behind the transmission customer's point of connection.[3] The Reconciliation Manager's dataset does not include all the required information on such electricity flows. So, to properly calculate gross load, Transpower would need to seek further data outside the Reconciliation Manager's dataset.

A.10 We understand from Transpower staff that Transpower does not currently have access to all the required data.[4] However, we consider that the Authority could seek a Code amendment to address this data limitation issue, eg, requiring participants to provide to the Reconciliation Manager or to Transpower the data required to calculate gross load for the purposes of allocating the residual charge. We envisage that a Code change proposal to address this issue could potentially be advanced in parallel with a Code change proposal to incorporate the draft proposed TPM into the Code.[5]

2 Clause 1(1). Definition of offtake customer

3 This data issue relates to the calculation of gross load generally, not only in relation to generation with embedded load. For example, it is also relevant to load customers with embedded generation. In order to determine gross load for such a customer, the guidelines require Transpower to make a reasonable estimate of concurrent generation behind the transmission customer's point of connection.

4 We note the matter of data limitations was not highlighted in Transpower's 2a submission. However this matter has been covered with Transpower staff in discussions on the Checkpoint 2a material, and so feedback is included here.

5 This might occur, for example, in the third quarter of 2021 (calendar year).

6 This is explained in more detail in Transpower's adjustments options paper. As the proposal is also referenced in section 2.3 of the Checkpoint 2a submission (para 16), we also provide comment in this Checkpoint 2a feedback.

5. We acknowledge the issue raised by the Authority is consistent with its policy decision to allocate the residual charge on a gross load basis.

6. The revised preliminary TPM drafting shows a way in which the TPM could apply the residual charge to generators in relation to load embedded behind their generating plant. Refer to the definition of "supplying load customer" and clause A.

7. However, in our view, we would need to depart from the detail of the Guidelines using clause 2 in order to apply the residual charge to generators with embedded load.[2] This is because:

   7.1. Clause 27 of the Guidelines says designated transmission customers (**DTCs**) pay residual charges "to the extent that they are load customers", not "to the extent that they have load" (the words the Authority used in paragraph A.7(a) of its feedback).[3] This is an important difference because "load customer" is defined in the Guidelines in a way that does not capture generators with embedded load (the generator is not drawing electricity from the grid or from other generation behind the point of connection, and the party with the embedded load is not a DTC).[4]

   7.2. Similarly, the HAMD calculation in clause 28(a) of the Guidelines does not capture the embedded load being supplied by the generator.[5]

8. There is a lack of clarity about the intent of the Guidelines on this issue in the Guidelines themselves and in the Authority documents released at the same time as, or before, the Guidelines. In particular:

   8.1. The intent of the residual charge recorded in the Guidelines themselves (clause (v)) provides no specific guidance on this issue.[6]

   8.2. Clause 1(c) perhaps provides some implicit support for this approach, to the extent it might "avoid creating incentives for existing and potential DTCs to avoid transmission charges in ways that cause economic inefficiency."[7] However, it is

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[2] Clause 2: We may propose a TPM that "differ[s] in its details from the particular requirements in these **Guidelines** (but not their intent … if [we consider, in our] reasonable opinion, that doing so would better meet the Authority's statutory objective than complying with these **Guidelines** in their entirety."

[3] Clause 27: "The **TPM** must provide for a **residual charge** to apply to all designated transmission customers, to the extent that they are **load customers**, to allow Transpower to recover any remaining **recoverable revenue** not recovered through other **transmission charges**."

[4] Clause 69: "**load customer** means a designated transmission customer whose equipment draws electricity from the grid or from any generation behind the designated transmission customer's point or points of connection (including distributed generation and behind-the-meter generation)."

[5] Clause 28(a): The residual charge "is to be calculated by:
(a) taking, in a year from 1 July to 30 June, the customer's anytime maximum demand for that year, which is calculated by:
  i. for each one of the customer's points of connection, taking the highest value in any trading period in that year of gross load, being the sum of:
    1. the net quantity of electricity flow from the grid at that point of connection; and
    2. Transpower's reasonable estimate of concurrent generation behind the designated transmission customer's point of connection; and
  ii. aggregating each of those sums across all the customer's points of connection;"

[6] Clause (v): "The purpose of the **residual charge** is to provide a mechanism to ensure that Transpower can recover up to its **recoverable revenue** in any **pricing year** in a way which is designed to minimise any effect on designated transmission customers' decision-making."

[7] Clause 1(c): "in developing the **TPM** … **Transpower** must, as far as reasonably practicable, use the following [principle], including in selecting between options which otherwise comply with these **Guidelines**: … (c) avoid creating incentives for existing and potential designated transmission customers to avoid **transmission charges** in ways that cause economic inefficiency;"

most likely to be the party with the embedded load who has the incentive to avoid the residual charge, and that party is not a DTC with respect to the embedded load.

8.3. Clause 7 also does not provide clear intent because it is about equipment connected through "the designated transmission customer's network". A generating station is not a network, and the lines that connect a generating station to the grid are not a network (as defined in the Code) either.[8] In any event, we do not consider clause 7 can override otherwise unambiguous definitions in the TPM, including because clause 7 is not relevant to overall interpretation under clause 3 of the Guidelines.[9]

8.4. The definition of "gross" in the Guidelines does not capture the embedded load being supplied by the generator.[10]

8.5. We are not aware of any clear intent on this issue explicitly recorded in the Authority's Final Decision, 2019 Issues Paper, or other published consultation or information papers. If the Authority can point to any relevant explicit statements of intent with respect to load embedded behind generation in its documents, that may be helpful.

9. Although the Guidelines, Final Decision and 2019 Issues Paper do not appear to assist, the Authority's feedback on our Checkpoint 2 submission does express an explicit intent for the residual charge to be applied to generators with embedded load, which (as noted above) we consider is consistent with the Authority's policy decision to apply the residual on the basis of gross load. On this basis, in our reasonable opinion, there is sufficient Authority-expressed intent to support departure from the detail of the Guidelines by applying the residual charge to generators with embedded load. We are still considering whether the departure would better meet the Authority's statutory objective than complying with the Guidelines in their entirety.

10. We would support a Code change that compels participants to provide Transpower (as grid owner) on request with all information the participants may have access to that is relevant to setting transmission charges (including, but not limited to, the inputs to gross load).

11. However, the Code change will not assist Transpower to obtain information the relevant participant does not have. We recommend the Authority consider including in the Code change a requirement for participants to collect and retain the relevant information to a level of accuracy appropriate for the purpose. We recognise in some

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8 Clause 7: "The **TPM** must provide that, where it is necessary to consider the characteristics of, benefits or costs accruing to, incentives on, or other matters related to a designated transmission customer under the **TPM**, that assessment must also consider the characteristics of, benefits or costs accruing to, incentives on, or other matters related to any party whose equipment is directly or indirectly electrically connected through that designated transmission customer's network to the grid."

9 Clause 3: "All subsequent provisions in these Guidelines are to be interpreted and applied subject to clauses 1 and 2 above."

10 Clause 69: "**gross**, in relation to a **load customer**'s energy usage means total energy usage on the **load customer's** network, being the sum of:
1. the customer's off-take from the grid;
2. Transpower's reasonable estimate of concurrent generation behind the designated transmission customer's point of connection."

cases this may require a participant to invest in appropriately accurate metering systems specifically so the residual charge can be applied to their gross load.

2.2 Step changes to the residual charge

Authority feedback

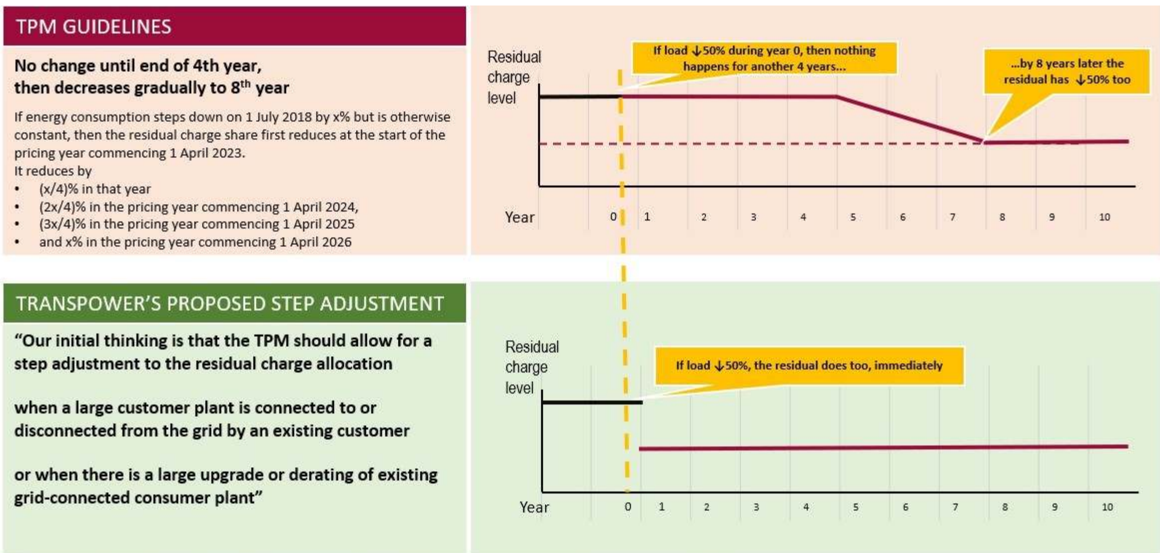
A.11 Transpower is proposing that the residual charge would immediately change when a large customer plant is connected to or disconnected from the grid by an existing customer or when there is a large upgrade or derating of existing grid-connected consumer plant.[6]

A.12 In our view this proposal does not reflect the correct interpretation of the guidelines, which provide that such a change would occur gradually, after a lag. The guidelines provide for regular updates to the allocation of the residual charge based on lagged changes in usage. The initial allocation of the residual charge (which is based on historical gross AMD) is to be adjusted annually based on changes in the four-year rolling average of gross annual energy usage, with a lag.

A.13 Clause 33(e), which deals with the connection, disconnection or increase in use/generation by embedded plant, provides that where this occurs the transmission customer's residual charge is to be adjusted by the amount that the party would have paid if the plant had been separately connected to the grid. If a transmission customer opened or closed a plant, or changed its use of electricity, those changes would be accommodated after the lag in the residual charge (by the ordinary operation of the residual charge clauses or because of the absence of a reference to the residual charge in clause 33(a)(ii)). We consider the guidelines require the same approach for embedded plant.

A.14 The figure below illustrates our understanding of the difference between Transpower's proposal for a step adjustment in the residual charge and the guidelines.

Figure: Adjustment to the residual charge



6 This is explained in more detail in Transpower's adjustments options paper. As the proposal is also referenced in section 2.3 of the Checkpoint 2a submission (para 16), we also provide comment in this Checkpoint 2a feedback.

12. We will consider the Authority's interpretation for our Checkpoint 2 submission on Adjustments.

13. One matter we are considering is how the Authority's interpretation sits with the principles in clause 1 of the Guidelines and impacts on competitive neutrality.[11] For example, the Authority's interpretation (as also discussed with the Authority in the context of our work on Adjustments generally) appears to mean:

    13.1. an existing DTC connecting new load to the grid would not immediately incur an increased residual charge, whereas a new DTC connecting the same load would; and

    13.2. an existing DTC connecting new load to the grid would not immediately incur an increased residual charge, whereas the DTC would (through the relevant distributor) if it instead embedded the load in the distributor's network (at least if the DTC were not an existing customer of the distributor).

2.3 Competitive neutrality in the application of the residual charge to batteries

14. In its feedback the Authority has identified a further matter potentially relevant to the residual charge and not directly addressed in the Guidelines or its Final Decision. We have been asked to consider how batteries should be treated for the purposes of residual charge allocation, including how best to avoid distortion of production and investment decisions and preserve competitive neutrality in the wholesale generation market. We are considering this matter, and discussing it with the Authority outside the current Checkpoint 2 process. Whether a battery owner meets the definition of

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[11] Clause 1: "In developing the **TPM** in accordance with these **Guidelines**, Transpower must, as far as reasonably practicable, use the following principles, including in selecting between options which otherwise comply with these **Guidelines**:

a. set charges in a way that:
   (i) reflects the cost of providing designated transmission customers with:
      A. new **investment** in the grid;
      B. access to the parts of the grid relevant to them; and
      C. use of the grid to transport energy;
   (ii) reflects the share of **positive net private benefits** those designated transmission customers are expected to derive from the matters referred to in (A) to (C) above;
   (iii) takes into account, and does not seek to replicate the effect of, other means of controlling demand, including nodal prices;
b. balance the economic benefits and costs of precision of the **TPM** with the economic benefits and costs of practical considerations including:
   (i) robustness;
   (ii) simplicity;
   (iii) certainty, including through limiting the need for Transpower to exercise discretion; and
   (iv) costs associated with developing, administering and complying with the **TPM**;
c. avoid creating incentives for existing and potential designated transmission customers to avoid **transmission charges** in ways that cause economic inefficiency;
d. avoid creating incentives for distributed generators to seek avoided cost of transmission payments, except to the extent that the payments reflect a saving in the costs of transmission (not just a saving in **transmission charges** to the relevant designated transmission customer);
e. avoid discriminating between designated transmission customers, except to the extent allowed by these **Guidelines** or otherwise necessary to achieve the Authority's statutory objective; and
f. allow Transpower to recover up to, but no more than, its **recoverable revenue**, should it wish to do so."

"load customer" in the Guidelines when the battery is charging is one of the issues being considered.[12]

2.4 Secondary matters

15. The Authority also provided feedback on several "secondary matters", which we have taken into account in revising the preliminary TPM drafting. The following table provides a summary of our response to these matters.

12 Refer to footnote 4 above.

<table>
<tr><th>Authority feedback</th><th>Transpower response</th></tr>
<tr><td>Transpower’s identified departures from the guidelines
A.21 Transpower has identified two areas where it considers it is proposing a departure from the guidelines. The two areas relate to:
(a) a proposal for Transpower to have some flexibility in determining an initial residual charge for new customers,[9] to avoid providing inefficient incentives for customers to change their grid use to avoid charges. Our view is that overall the proposal is consistent with the guidelines, (ie, is not a departure), given that cl 33(c) of the guidelines gives Transpower some flexibility regarding the residual charge for new customers, providing that, in the long run, the charges ultimately result in the customer paying residual charges equivalent to those they would have received if they had been fully operational from 1 July 2014
(b) a proposal to adjust measured volumes for Exceptional Operating Circumstances (where a customer’s load measurement is unusual only because of some action taken by Transpower in managing its network).[10] The Authority has no substantive concerns with either of these proposals.
9 Section 2.2 of the Checkpoint 2a submission.
10 Section 2.4 of the Checkpoint 2a submission.</td><td>Thank you for the clarity that the Authority has no substantive concerns with either of these proposals.</td></tr>
<tr><td>Definition of offtake customer
A.22 The Authority queries why Transpower has defined an offtake customer as a customer who has or controls assets into which electricity flowed or may flow from the grid at that connection location. However, we recognise this may make little difference in practice if the customer does not in fact take electricity from the grid, as the formulae for the residual charge and cap</td><td>We have removed the “may flow” language from the definition of “offtake customer” in the revised preliminary TPM drafting (and intend to do likewise for “injection customer”).

We have also included a new definition of “load customer” in the revised preliminary TPM drafting (of which an offtake customer is one</td></tr>
</table>

(which depend on electricity usage) would not result in charges being imposed.	type). We consider the new definition, together with clause A, now fully captures the types of load that will (or may) attract a residual charge. As noted above, an issue being considered outside the Checkpoint 2 process is whether this definition should capture a battery when it is charging.
Definition of reduction event A.23 We note that Transpower has added the criterion that change be sustained, in addition to the criteria in clause 29 of the guidelines for modifying customers' initial allocations of the residual charge. In our view, such an addition is consistent with the Authority's intention here, (ie, to capture circumstances such as the closure of the Holcim plant). We support this approach.	Thank you for the clarity that the Authority supports our approach.
Setting a new customer's demand baseline A.24 As we understand it, Transpower's drafting allows it flexibility in initially setting a new customer's AMDR baseline.[11] Transpower has then also provided itself with the ability to re-determine that baseline AMDR, but we understand this to be possible only once and only between years five and eight of operation (since clause 5(3) requires at least four complete financial years, but also that any assessment be undertaken before RCAF is first applied, which clause 4(1)(a)(iii) provides occurs after eight years). A.25 We query whether this is sufficient to meet the Authority's intention in clause 33(c) of the guidelines. That clause provides that adjustment processes must "ultimately result in an annual residual charge equivalent to the charge that would, in Transpower's reasonable opinion" have been payable if the customer was fully operational at 1 July 2014. We would be happy to discuss the details of this issue with Transpower staff. 11 Clause 3(3).	We will consider this point as we progress towards our final proposal. We note the Authority confirmed in paragraph A.21(a) of its feedback that, overall, our proposal for determining the initial residual charge for a new customer is consistent with the Guidelines (see above). Our current thinking is having a limited ability to reset a new customer's AMDR baseline, if we have materially over or under-estimated the customer's gross load, should not affect that assessment.

3 Our response to Authority's feedback: transitional cap

16. The Authority's feedback on our preliminary proposal for the transitional cap comprises two "primary concerns", each of which we address below.

3.1 Definition of capped charges: the cap should be limited to historical investments

Authority feedback
A.28 Under Transpower's preliminary drafting of its proposed TPM, the transitional cap would extend across all benefit-based charges.[12] This is inconsistent with the guidelines, which intend for the cap to cover only charges (both residual and benefit-based charges) that relate to pre-2019 transmission investments, not charges for post-2019 investments, so as to reduce the impact of charges relating to the existing grid.
12 Sub-paragraph (a), proposed definition of capped charges.

17. This was a drafting error, which we have corrected in the definitions of "capped charges" and "cap surcharge-relevant charges" in the revised preliminary TPM drafting.

3.2 Definition of capped offtake customer: generators that are also load customers

Authority feedback
A.29 Transpower proposes the cap apply only to distributors and direct connects and does not propose the cap extends to generators that are also load customers, with respect to charges relating to that load. Transpower's proposed draft TPM explicitly defines a capped offtake customer as "not a generator".[13]
A.30 However, some generators are also load customers to the extent they also draw electricity from the grid and to the extent that there is load embedded behind their grid connection point. Transpower's proposal does not specify how generators with load would be treated with respect to the price cap, nor how the load attributed to such a generator would be calculated.
A.31 There therefore seems to be a risk that any party who owns generating units would be excluded from having the cap apply to them, even if the guidelines suggest they should receive the benefit of the cap (and, moreover, were subject to the residual charge and therefore to much the same charges as those parties that would have the advantage of the cap). This includes both parties who are generators that sometimes draw electricity from the grid, as well as generators with load embedded behind their grid connection point.
A.32 We request that Transpower considers this issue and that the resubmission provides more detail on how the price cap would apply to generators with load.
13 Sub-paragraph (a)(iv), proposed definition of capped offtake customer.

18. In our view, we would need to depart from the detail of the Guidelines using clause 2[13] in order to extend eligibility for the cap to generators to the extent they draw electricity from the grid or there is load embedded behind their grid connection point.

    18.1. We agree a generator will be a load customer (as an offtake customer/direct consumer) when it is taking electricity from the grid because it is a DTC drawing electricity from the grid for consumption. However, as explained in section 2.1 above, a generator is not otherwise a load customer as defined in the Guidelines.[14]

    18.2. Clause 50 of the Guidelines does not contain a formula for calculating the difference cap for a generator that is not a direct consumer.[15] Further, if we were to calculate the difference cap based only on the trading periods during which the generator was a direct consumer, the generator's difference cap would be artificially low.[16]

19. We note that, in its Final Decision:

    19.1. the Authority expressly decided not to cap generators' transmission charges (paragraphs 13.21 and 13.22);[17] and

    19.2. the Authority's indicative pricing did not apply the cap to generators or to any load customers who are not distributors or direct consumers (paragraphs 16.23-16.28 and Figure 13).

20. In view of the above, we do not consider we should depart from the detail of the Guidelines by applying the cap to generators. We do not consider there is any basis for concluding that applying the cap to generators would be consistent with the Authority's intent when the Guidelines were made, and doing so would require us to develop a cap calculation tailored for generators (as there is not one in the Guidelines, or at least one that would yield a sensible result).

21. Further, if we applied the direct consumer cap in the Guidelines to generators, producing an artificially low difference cap, the effect would likely be to redistribute significant generator charges to other customers and distort the pricing signals intended to be provided by the TPM. We do not consider doing that would advance the Authority's statutory objective.

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[13] Refer to footnote 2 above.

[14] Refer to footnote 4 above. In any event, there is no current configuration where we treat a connected generator as having embedded load. There are some "intermingled" load and generation configurations (such as the dairy factory and co-generation plant at Whareroa) but those are all treated as connected load with embedded generation.

[15] Clause 50 specifies the formulae and parameters the TPM must use in setting a cap.

[16] The generator's notional electricity bill, and therefore difference cap, would be calculated from a small number of trading periods, as would its 2019 transmission charges used in the cap condition.

[17] Final Decision, page 96: "**Guidelines do not extend the cap to generators**

13.21 Contact and Nova support the price cap being limited to load customers. Conversely, some submissions thought the price cap should also apply to generators, either as a matter of principle, or because it would ease the transition for smaller North Island generation that currently pay no interconnection charges (e.g. Ngā Awa Purua, Tuaropaki Power and Whareroa Cogen).

13.22 The Authority decided not to adopt this approach because generators already are exempt from residual charges (except to the extent they have load). Their charges are thus linked to benefits from transmission services, suggesting the risks are thus not to the same extent as those set out in paragraph 13.5. "

22. Accordingly, we have retained the exclusion of generators from the cap in the revised preliminary TPM drafting.

3.3 Secondary matters

23. The Authority also provided feedback on several "secondary matters". The following table provides a summary of our response to date to these matters.

Authority feedback	Transpower response
Whether the cap addresses the requirement that customers have been fully operational in the 2019/20 pricing year A.33 The Authority queries whether the proposed guidelines' definition of capped offtake customer captures the "fully operational requirement" contained in the guidelines' definition of existing load customer.[14] A.34 The guidelines define an existing load customer, for the purposes of clause 49 (transitional cap provision), as a load customer which, in Transpower's reasonable opinion, was fully operational prior to the beginning of the 2019/20 pricing year. Our understanding is that Transpower's paragraph (a)(iii) may be intending to capture this, providing that a capped offtake customer must be an "offtake customer who was an offtake customer during pricing year 2019 and pricing year preceding pricing year 2019". Thus, a participant would be caught by Transpower's definition if they merely started operations in 2018 and are still continuing to increase their operations in pricing year 2019/20. This would seem to be inconsistent with the guidelines and risk that participant's charges improperly being capped at a rate which does not reflect their full operations. 14 Sub-paragraph (a)(iii)), proposed definition of capped offtake customer.	The requirement to have been a load customer prior to 2019 comes from the definition of "existing load customer" in the Guidelines. The requirement to have been a load customer during 2019 comes from the need for the customer to have been a load customer, and to have paid transmission charges, in 2019 for the cap logic in clause 50 of the Guidelines to work.[18] The "fully operational" criterion would be difficult to apply objectively, in our view. In the revised preliminary TPM drafting we have suggested a requirement that the customer has been a load customer for at least two years prior to 2019 (definition of "capped load customer"). We consider this to be a reasonable objective proxy for full operation.
Definition of surcharge-relevant charges A.35 As with the reference to not including generators in the definition of "capped offtake customer", Transpower may need to consider whether the eventual definition of "injection customer" as referenced in the definition of "surcharge-relevant charges" is sufficiently wide in scope to capture	We have revised the definition of "cap surcharge-relevant charges" in the revised preliminary TPM drafting. This has removed the reference to injection customers and made the definition clearer generally.

18 Refer to footnote 14 above.

customers who may in some places be injection customers but elsewhere might be load customers.	
Data source for transitional cap A.36 We note that in calculating the transitional cap, Transpower is intending to use some information from sources other than those specified in the guidelines. For example, it is proposing to use disclosure information in calculating the cap, instead of information provided by the Reconciliation Manager.[15] A.37 We note that cl 28 of the guidelines refers to each customer's historical AMD "which may be calculated using data supplied by the Reconciliation Manager"; the use of "may" here suggests that Transpower is able to deviate from this provision if it wishes. However, the definitions around the transitional cap in cl 50 do not have that permissive "may", so using different data here may be a deviation from the guidelines. A.38 Similarly, the guidelines refer to the CPI, (ie, the final CPI issued by Statistics NZ), however, the CPI values used in Transpower's proposal are the average of the most recent quarterly forecasts by RBNZ. Using different data here may also be a deviation from the guidelines. A.39 However, such deviations may be possible and appropriate under clause 2 of the guidelines. We would invite Transpower to consider whether any proposed deviation from the guidelines would satisfy the requirements of clause 2. In doing so, it could consider whether any differences between the relevant datasets are material and appropriate. 15 Clause 8.	We will consider this point as we progress towards our final proposal.

Appendix 1 Preliminary TPM drafting

The revised preliminary TPM drafting provided in this Appendix includes explanatory comments and tracked changes in response to the Authority's feedback on our Checkpoint 2 submission.

Definitions relevant to residual charge and transitional price cap

anytime maximum demand (residual) or **AMDR** means, for a~~n~~ ~~**offtake customer**~~**load customer** and **pricing year**, the amount calculated in accordance with clause 2 for the ~~**offtake customer**~~**load customer** and **pricing year**

cap condition means the condition specified in clause 7(2)

cap surcharge means, for a **customer** and **pricing year**, the amount calculated in accordance with clause 9 for the **customer** and **pricing year**

cap surcharge-relevant charges means, for a **customer** and **pricing year**, the **customer's**:

(a) **annual benefit-based charges** for **Schedule A BBIs** for the **pricing year**; plus

(b) **annual residual charge** for the **pricing year**

~~(a) if the **customer** is an **offtake customer**, the **customer's capped charges** for the **pricing year**; or~~

~~(b) if the **customer** is an **injection customer**, the sum of the **customer's annual benefit-based charges** for the **pricing year**~~

capacity measurement period or **CMP** means a period over which a calculation under this **transmission pricing methodology** is to be made, being either:

CMP A for **pricing year** n, the period from the first **trading period** of 1 September during **pricing year** n-2 to the last **trading period** of 31 August during **pricing year** n-1. **CMP A** is relevant to **connection charges**

CMP B the period from the first **trading period** of **financial year** 2014 to the last **trading period** of **financial year** 2017. **CMP B** is relevant to **residual charges**

CMP C the period from the first **trading period** of **pricing year** 2015 to the last **trading period** of **pricing year** 2019. **CMP C** is relevant to the transitional price cap

capped charges means, for a~~n~~ ~~**offtake customer**~~**capped load customer** and **pricing year**, the **capped load customer's**:

(a) ~~the **offtake customer's**~~ **annual benefit-based charges** for **Schedule A BBIs** for the **pricing year**; plus

(b) ~~the **offtake customer's**~~ **annual residual charge** for the **pricing year**; plus

(c) ~~the **offtake customer's**~~**cap surcharge** for the **pricing year**

capped ~~**offtake customer**~~**load customer** means:

(a) for:

(i) the **first pricing year**; and

Commented [SG1]: We have made this definition clearer and excluded the cap surcharge itself.

Commented [SG2]: Schedule A BBIs will be defined as the seven benefit-based investments in Schedule 1 of the guidelines.

(ii) each **pricing year** after the **first pricing year** up to and including the **pricing year** during which there is a **benefit-based charge** for a **low-value benefit-based investment**,

~~an **offtake customer** who:~~

~~(iii)~~ a **customer**, other than a **generator**, who was an **offtake customer** during **pricing year** 2019 and at least two **pricing years** preceding **pricing year** 2019; and

~~(iv) is not a **generator**; and~~

(b) for each subsequent **pricing year**, any such ~~**offtake**~~ **customer** whose **capped charges** for the previous **pricing year** were reduced in accordance with clause 7(1)

consumer plant means equipment that consumes **electricity**. In the definition of **supplying load customer**, **consumer plant** does not include equipment that is part of the **generating plant** that is connected at the **connection location** or directly related to its operation

CPI means the consumers price index (all groups)

EDB ID determination means the *Electricity Distribution Information Disclosure Determination 2012* [2012] NZCC 22 (as amended)

embedded electricity means the **electricity** referred to in the definitions of **consuming customer** and **supplying customer**

financial year means a period of 12 months beginning on 1 July of a year and ending on 30 June of the following year, and **financial year** n means the **financial year** beginning in year n

first pricing year means the **first pricing year** this **transmission pricing methodology** applies

load customer means a **customer** who, at a **connection location** during **trading period**, is or was (as the context requires) one or more of the following:

(a) an **offtake customer**:

(b) a **supplied load customer**:

(c) a **supplying load customer**.

new ~~**offtake customer**~~**load customer** means a~~n~~ ~~**offtake customer**~~**load customer** who is not a **pre-existing** ~~**offtake customer**~~**load customer**

non-grid network means a system of **lines**, substations and other **works**, used primarily for the conveyance of **electricity**, that is not part of the **grid** or directly connected to the **grid**

Commented [SG3]: We consider the generator exclusion should to be retained. See comment on clause 8 about calculating the difference cap for generators.

Commented [SG4]: In order to qualify for the cap, a load customer must have been a load customer before pricing year 2019 and must also have been "fully operational" before then. Extending the pre-2019 period of operation to at least two pricing years could be a reasonable proxy for full operation.

Commented [SG5]: We do not consider electricity required to operate the generating plant of a supplying load customer (so called "parasitic load") should count as embedded electricity of the supplying load customer.

Commented [SG6]: Embedded electricity is electricity that flows directly to or from a supplied or supplying load customer. Embedded electricity is factored into the calculation of gross energy under clause A(3).

Commented [SG7]: This new definition of load customer more clearly captures the type of customer expected to pay residual charges (i.e. need not be an offtake customer). We have added some explanatory diagrams in clause A(1).

Commented [SG8]: This definition captures networks directly connected to grid-connected generating plant for the purposes of the definition of supplying load customer. This type of network is not an "embedded network" because it is not indirectly connected to the grid "through 1 or more other networks".

offtake customer means, for a **connection location** and **trading period**, a **customer** who owns~~has~~ or controls **assets** connected at the **connection location** into which **electricity** flowed ~~or may flow~~ from the **grid** during the **trading period** ~~at that **connection location**~~

Commented [SG9]: We have reverted to the actual flow type wording of the current TPM.

pre-existing ~~**offtake customer**~~**load customer** means a~~n~~ ~~**offtake customer**~~**load customer** who was a~~n~~ **load customer**~~**offtake customer**~~ during **CMP B**

previous transmission pricing methodology means, as applicable, the transmission pricing methodology—
(a) added to the Electricity Governance Rules 2003 on 1 September 2007, as subsequently amended; or
(b) comprised in this Code when it came into force, as subsequently amended up to the date this **transmission pricing methodology** came into force

pricing year has the meaning given to that term in the **Transpower IMs**~~Commerce Commission determinations for **Transpower's** price-quality regulation under Part 4 of the Commerce Act 1986~~. At the date of this **transmission pricing methodology**, ~~the relevant determination is the *Transpower Input Methodologies Determination 2010* [2012] NZCC 17 (as amended) and the~~a **pricing year** is a period of 12 months beginning on 1 April ~~of a year~~ and ending on 31 March ~~of the following year~~. **Pricing year** n means the **pricing year** beginning in year n

reduction event means, for a **pre-existing** ~~**offtake customer**~~**load customer**, a reduction in the **pre-existing** ~~**offtake customer**~~**load customer's maximum gross demand** or **total gross energy** that—
(a) occurred after the start of **financial year** 2014 and before the start of the **first pricing year**; and
(b) **Transpower** determines was—
  (i) substantial and sustained; and
  (ii) due to an event or circumstance beyond the **pre-existing** ~~**offtake customer**~~**load customer's** reasonable control, not being:
    (A) a change in the basis for calculating future transmission charges; or
    (B) a change in the market for the **pre-existing** ~~**offtake customer**~~**load customer's** products or services; or
    (C) any of the events set out in paragraph (d) of the definition of **force majeure event**; or
    (D) an event that could have been prevented by the **customer** by the exercise of a reasonable standard of care

residual charge adjustment factor or **RCAF** means, for a~~n~~ ~~**offtake customer**~~**load customer** and **pricing year**, the factor calculated or determined in accordance with clause~~s~~ 4 ~~and 5(2)~~ for the ~~**offtake customer**~~**load customer** and **pricing year**

residual charge allocation adjustment event means an event that occurs after the start of the **first pricing year** and triggers a reallocation of **residual charges** under clause [ ]

residual revenue means, for a **pricing year**, **recoverable revenue** for the **pricing year** less **connection charges** and **benefit-based charges**~~the sum of all **transmission charges** other than **residual charges**~~ for the **pricing year**. The minimum value of **residual revenue** for a **pricing year** is 0

supplied load customer means, for a **connection location** and **trading period**—

(a) a **distributor** who owns or controls a **local network** connected at the **connection location** into which **electricity** flowed directly from **generating plant** during the **trading period**; or

(b) a **direct consumer** who owns or controls **consumer plant** connected at the **connection location** into which **electricity** flowed directly from **generating plant** during the **trading period**

supplying load customer means, for a **connection location** and **trading period**, a **generator** who owns or controls **generating plant** connected at the **connection location** from which **electricity** flowed directly to **consumer plant** or a **non-grid network** during the **trading period**

Commented [SG10]: Supplied load customers are distributors or direct consumers with embedded generation, who may or may not be offtake customers also.

Commented [SG11]: Supplying load customers are generators with embedded load, who may or may not be offtake customers also.

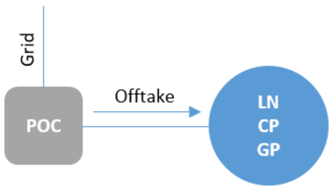
Including supplying load customers as load customers would require a departure under clause 2 of the guidelines. A non-offtake generator is not within the definition of "load customer" in the guidelines and its embedded electricity is not captured by the AMD calculation in paragraph 28 of the guidelines.

General provisions relevant to residual charge

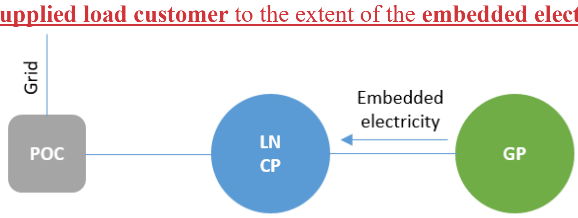
A Load Customers, Gross Energy and Maximum Gross Demand

(1) The different types of **load customer** are shown in the following diagrams. In these diagrams, "LN" means **local network**, "CP" means **consumer plant**, "GP" means **generating plant**, "NGN" means **non-grid network** and "POC" means **point of connection** to the **grid**:

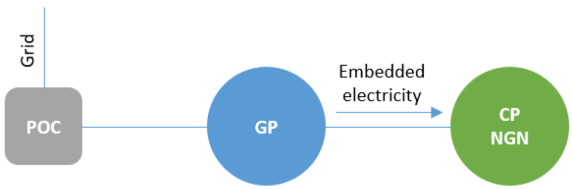
(a) In the following diagram, a **customer** owning or controlling LN, CP or GP is an **offtake customer** to the extent of the **offtake**:



(b) In the following diagram, a **customer** owning or controlling LN or CP is a **supplied load customer** to the extent of the **embedded electricity**:



(c) In the following diagram, a **customer** owning or controlling GP is a **supplying load customer** to the extent of the **embedded electricity**:



(2) If a configuration of **consumer plant** and **generating plant** is such that the **customer** may be treated as either a **supplied load customer** or **supplying load customer**, the **customer's** status as a **supplied load customer** or **supplying load customer** must be determined by **Transpower**.

(3) **Gross energy** (measured in kWh) means, for a~~n~~ ~~**offtake customer**~~**load customer**, **connection location** and **trading period**:

(a) the ~~**offtake customer**~~**load customer**'s **offtake** at the **connection location** during the **trading period**; plus

(b) the ~~contribution of non-**grid**-connected generation to the **offtake customer**~~**load customer**'s **embedded electricity** at~~consumption behind~~ the **connection location** during the **trading period**.

Commented [SG12]: Some consumer plant/generating plant configurations may be such that it is not clear which plant is directly connected to the grid (e.g. the dairy factory and co-generation plant at Whareroa). This subclause allows Transpower to determine the treatment in those cases.

(~~4~~2) **Maximum gross demand** (measured in kW) means, for a~~n~~ ~~**offtake customer**~~**load customer**, **connection location** and period, the ~~**offtake customer**~~**load customer's** maximum per-**trading period gross energy** at the **connection location** during the period multiplied by 2.

(~~5~~3) **Total gross energy** (measured in kWh) for ~~**offtake customer**~~**load customer** c and period p (TGE_{cp}) is calculated as follows:

$$TGE_{cp} = \sum_{l} \sum_{t} GE_{ctlp}$$

where GE_{ctlp} is ~~**offtake customer**~~**load customer** c's **gross energy** for **trading period** t at **connection location** l during period p.

B Exceptional Operating Circumstances

If **Transpower** reasonably considers—

(a) **Transpower's** requirements (as a **grid owner**) have caused exceptional operating circumstances in the power system during a **capacity measurement period**; and

(b) those circumstances have resulted in a distortion to any **metering information** for the **capacity measurement period**,

Transpower may—

(a) adjust the **metering information** to mitigate or eliminate the distortion, as determined by **Transpower**; and

(b) use the adjusted **metering information** to calculate **transmission charges**.

C Substantial Change

Where **Transpower** is required under this **transmission pricing methodology** to assess whether a change in a quantity is "substantial", that assessment must be made relative to the quantity after the change.

Residual charge provisions

Residual Charges

1 Calculation of Residual Charges

(1) Only ~~**offtake customer**~~**load customer**s pay **residual charges**.

(2) ~~**Offtake customer**~~**Load customer** c's **annual residual charge** for ~~a~~ **pricing year** n (ARC_{cn}) is calculated as follows:

$$ARC_{cn} = AMDR_{cn} \times RCR_n$$

where

$AMDR_{cn}$	is ~~**offtake customer**~~**load customer** c's **AMDR** for **pricing year** n
RCR_n	is the **residual charge** rate for **pricing year** n calculated in accordance with clause 6.

(3) ~~**Offtake customer**~~**Load customer** c's **monthly residual charge** for **pricing year** n (MRC_{cn}) is calculated as follows:

$$MRC_{cn} = \frac{ARC_{cn}}{12}$$

(4) Each **residual charge** is recalculated for each **pricing year**.

2 Anytime Maximum Demand (Residual)

~~**Offtake customer**~~**Load customer** c's **AMDR** for **pricing year** n ($AMDR_{cn}$) is calculated as follows:

$$AMDR_{cn} = AMDR_{c\ baseline} \times RCAF_{cn}$$

where

$AMDR_{c\ baseline}$	is ~~**offtake customer**~~**load customer** c's **AMDR** baseline calculated or determined in accordance with clause~~s~~ 3~~, 5(1) and 5(3)~~
$RCAF_{cn}$	is ~~**offtake customer**~~**load customer** c's **RCAF** for **pricing year** n.

3 Anytime Maximum Demand (Residual) Baseline

(1) Subject to clause 5~~(1)~~, **pre-existing** ~~**offtake customer**~~**load customer** c's **AMDR** baseline ($AMDR_{c\ baseline}$) is calculated as follows:

$$AMDR_{c\ baseline} = \frac{\sum_{n=2014}^{2017} \sum_{l} MGD_{cln}}{N}$$

where

MGD_{cln}	i~~I~~s **pre-existing** ~~**offtake customer**~~**load customer** c's **maximum gross demand** for **connection location** l for **financial year** n
N	is the number of **financial years** (rounded up to the nearest whole **financial year**) during **CMP B** for which **pre-existing** ~~**offtake customer**~~**load customer** c was a~~n~~ ~~**offtake customer**~~**load customer**.

(2) A **pre-existing** ~~**offtake customer**~~**load customer's AMDR** baseline is not re-calculated or re-determined after it is initially calculated or determined in accordance with subclause~~s 3~~(1)~~ and 5(1)~~.

(3) A **new** ~~**offtake customer**~~**load customer's AMDR** baseline—

(a) is determined by **Transpower**, taking into account:

(i) the rated capacity of the **new** ~~**offtake customer**~~**load customer's assets**; and

(ii) any available historical information about the **new** ~~**offtake customer**~~**load customer's maximum gross demand**; and

(b) may only be re-determined by **Transpower** in accordance with clause 5A~~5(3)~~.

4 Residual Charge Adjustment Factor

(1) ~~Subject to clause 5(2), **offtake customer**~~**Load customer** c's **RCAF** for **pricing year** n ($RCAF_{cn}$) is—

(a) 1 if:

(i) **pricing year** n is the **first pricing year**; or

(ii) **pricing year** n is **pricing year** 2022 or earlier; or

(iii) ~~**offtake customer**~~**load customer** c became a~~n~~ ~~**offtake customer**~~**load customer** after the start of **financial year** n-8; or

(b) otherwise, calculated as follows:

$$RCAF_{cn} = \frac{\overline{LTGE}_{cn}}{\overline{TGE}_{c\ baseline}}$$

where

$\overline{\text{LTGE}}_{cn}$	is ~~**offtake customer**~~**load customer** c's lagged average **total gross energy** for **pricing year** n calculated in accordance with subclause (2)
$\overline{\text{TGE}}_{c\ baseline}$	is ~~**offtake customer**~~**load customer** c's average **total gross energy** baseline calculated or determined in accordance with subclause~~s~~ (3) or~~and~~ (4)~~ and clause 5(1)~~.

(2) ~~**Offtake customer**~~**Load customer** c's lagged average **total gross energy** for **pricing year** n ($\overline{\text{LTGE}}_{cn}$) is calculated as follows:

$$\overline{LTGE}_{cn} = \frac{\sum_{i=n-8}^{n-5} TGE_{ci}}{4}$$

where TGE_{ci} is ~~offtake customer~~load customer c's **total gross energy** for **financial year** i.

(3) Subject to clause 5~~(1)~~, **pre-existing** ~~**offtake customer**~~**load customer** c's average **total gross energy** baseline ($\overline{TGE}_{c\ baseline}$) is calculated as follows:

$$\overline{TGE}_{c\ baseline} = \frac{\sum_{n=2014}^{2017} TGE_{cn}}{N}$$

where

TGE_{cn} is **pre-existing** ~~**offtake customer**~~**load customer** c's **total gross energy** for **financial year** n

N is the number of **financial years** (including part **financial years** expressed as a decimal) during **CMP B** for which **pre-existing** ~~**offtake customer**~~**load customer** c was a~~n~~ ~~**offtake customer**~~**load customer**.

(4) A **new** ~~**offtake customer**~~**load customer's** average **total gross energy** baseline is equal to the **new** ~~**offtake customer**~~**load customer's** lagged average **total gross energy** for the first **pricing year** the **new** ~~**offtake customer**~~**load customer's** **RCAF** is calculated under clause 4(1)(b). For the avoidance of doubt, this means the **new** ~~**offtake customer**~~**load customer's** **RCAF** for that **pricing year** will be 1~~, subject to clause 5(2)~~.

(5) A~~n~~ ~~**offtake customer**~~**load customer's** average **total gross energy** baseline is not re-calculated or re-determined after it is initially calculated or determined in accordance with subclause~~s~~ (3) or~~and~~ (4)~~ and clause 5(1)~~.

5 Adjustments

(1) **Transpower** may reduce either or both of a **pre-existing** ~~**offtake customer**~~**load customer's** **AMDR** baseline or average **total gross energy** baseline by an amount determined by **Transpower**—

(a) if a **reduction event** for the **pre-existing** ~~**offtake customer**~~**load customer** has occurred; and

(b) to the extent the impact of the **reduction event** is not fully captured in the calculation of the **pre-existing** ~~**offtake customer**~~**load customer's** **AMDR** baseline or average **total gross energy** baseline (as the case may be) under clause 3(1) or 4(3).

(2) **Transpower** may adjust a~~n~~ **load**~~**offtake**~~ **customer's RCAF** for a **pricing year** by an amount determined by **Transpower**—

(a) if a **residual charge allocation adjustment event** for the load~~offtake~~ **customer** has occurred; and

(b) to the extent the impact of the **residual charge allocation adjustment event** is not fully captured in the calculation of the load~~offtake~~ **customer's RCAF** for the **pricing year** under clause 4(1).

Commented [SG13]: We have retained this subclause for now, pending further consideration of the circumstances that should result in a step adjustment to residual charge allocation.

(3) **Transpower** may re-determine a **new** ~~**offtake customer**~~**load customer's AMDR** baseline when historical information about the **new** ~~**offtake customer**~~**load customer's maximum gross demand** and **total gross energy** for at least 4 complete **financial years** is available, but—

(a) may only do so once; and

(b) may only do so before the first **pricing year** the **new** ~~**offtake customer**~~**load customer's RCAF** is calculated under clause 4(1)(b).

(4) For the avoidance of doubt—

(a) the purpose of an adjustment under subclause (1) or (2) is to ensure the impact of a **reduction event** or **residual charge allocation adjustment event** is captured in the allocation of **residual charges** without double-counting; and

(b) the purpose of a re-determination under subclause (3) is to correct any material under- or over-estimation in **Transpower's** initial determination of a **new** ~~**offtake customer**~~**load customer's AMDR** baseline.

6 Residual Charge Rate

The **residual charge rate** for **pricing year** n (RCR_n) is calculated as follows:

$$RCR_n = \frac{RR_n}{\sum_c AMDR_{cn}}$$

where

RR_n is the **residual revenue** for **pricing year** n

$AMDR_{cn}$ is ~~**offtake customer**~~**load customer** c's **AMDR** for **pricing year** n.

Transitional price cap provisions

Transitional Price Cap

7 Cap and cap condition

(1) A **capped** ~~**offtake customer**~~**load customer's capped charges** for each **pricing year** preceding **pricing year** 2038 are to be reduced by the minimum amount necessary (if any) to ensure the **cap condition** is not violated for the **capped** ~~**offtake customer**~~**load customer** for the **pricing year**.

(2) The **cap condition** is:

$$CC_{cn} - IC_{c19} \leq DC_{cn}$$

where

CC_{cn}	is capped ~~offtake customer~~load customer c's **capped charges** for **pricing year** n
IC_{c19}	is capped ~~offtake customer~~load customer c's annual interconnection charge for **pricing year** 2019 under the **previous transmission pricing methodology**
DC_{cn}	is capped ~~offtake customer~~load customer c's difference cap for **pricing year** n calculated in accordance with clause 8.

(3) A **capped** ~~**offtake customer**~~**load customer's capped charges** include the **capped** ~~**offtake customer**~~**load customer's** cap **surcharge**. It is therefore possible the **cap condition** will be violated for the **capped** ~~**offtake customer**~~**load customer** when a cap **surcharge** is allocated to the **capped** ~~**offtake customer**~~**load customer**. Accordingly, for each **pricing year**, subclause (1) is to be applied iteratively until the **cap condition** does not result in a reduction in any **capped** ~~**offtake customer**~~**load customer's capped charges** for the **pricing year**. The cap **surcharge** component of **capped charges** is 0 for the first iteration.

(4) Despite anything else in this clause 7, the **cap condition** must not result in **Transpower** recovering less than **recoverable revenue** for a **pricing year**.

8 Difference Cap

(1) **Capped** ~~**offtake customer**~~**load customer** c's difference cap for **pricing year** n (DC_{cn}) is calculated as follows:

$$DC_{cn} = NEB_{c19} \times (0.035 + (0.02 \times N) + \Delta CPI_n + \Delta TGE_{cn})$$

where

Commented [SG14]: EA4: The Guidelines do not contain a difference cap for generators who do not draw electricity from the grid (i.e. are not direct consumers). Clause 50 of the Guidelines contains difference cap formulae for distributors and direct consumers only. If we calculated difference caps for generators based only on the trading periods during which they were direct consumers, their difference caps would be artificially low.

Applying the cap to generators would require a departure under clause 2 of the Guidelines, specifically by developing a cap that is not provided for in the Guidelines.

In any event, in this case a clause 2 departure does not appear to be available for the reasons discussion in our Checkpoint 2 resubmission.

NEB_{c19}	is **capped** ~~**offtake customer**~~**load customer** c's notional **electricity** bill for **pricing year** 2019 calculated in accordance with subclause (2)
N	is: (a) if **capped** ~~**offtake customer**~~**load customer** c is a **distributor**, 0; or (b) if **capped** ~~**offtake customer**~~**load customer** c is a **direct consumer**, the greater of 0 and n-2024
ΔCPI_n	is the proportionate change in **CPI** for **pricing year** n calculated in accordance with subclause (3)
ΔTGE_{cn}	is the proportionate increase (if any) in **capped** ~~**offtake customer**~~**load customer** c's **total gross energy** for **pricing year** n calculated in accordance with subclause (5).

(2) **Capped** ~~**offtake customer**~~**load customer** c's notional **electricity** bill for **pricing year** 2019 (NEB_{c19}) is calculated as follows:

$$NEB_{c19} = LC_{c19} + (P_{c19} \times TGE_{c19})$$

where

LC_{c19}	is: (a) if **capped** ~~**offtake customer**~~**load customer** c is a **distributor**, **capped** ~~**offtake customer**~~**load customer** c's "total line charge revenue" for **pricing year** 2019, as disclosed in **capped** ~~**offtake customer**~~**load customer** c's Report on Billed Quantities and Line Charge Revenues (Schedule 8) under the **EDB ID determination** for its disclosure year ended 31 March 2020; or (b) if **capped** ~~**offtake customer**~~**load customer** c is a **direct consumer**, **capped** ~~**offtake customer**~~**load customer** c's total annual transmission charges for **pricing year** 2019 under the **previous transmission pricing methodology**
P_{c19}	is the volume weighted average of **final prices** at **capped** ~~**offtake customer**~~**load customer** c's **connection locations** during **CMP C**, using **gross energy** per **trading period** for weighting
TGE_{c19}	is **capped** ~~**offtake customer**~~**load customer** c's **total gross energy** for **pricing year** 2019, being: (a) ~~,~~ if **capped** ~~**offtake customer**~~**load customer** c is a **distributor**, **capped** ~~**offtake customer**~~**load customer** c's "electricity entering system for supply to consumers' connection points" for **pricing year** 2019, as disclosed in **capped** ~~**offtake customer**~~**load customer** c's Report on Network Demand (Schedule 9e) under the **EDB ID determination** for its disclosure year ended 31 March 2020; or (b) if **capped load customer** c is a **direct consumer**, as determined by **Transpower**.

(3) Subject to subclause (4), the proportionate change in **CPI** for **pricing year** n (ΔCPI_n) is calculated as follows:

$$\Delta CPI_n = \frac{CPI_n}{CPI_{19}} - 1$$

where

CPI_n is the average of the quarterly forecast **CPIs** for **pricing year** n most recently published by the Reserve Bank of New Zealand at the time the calculation is made

CPI_{19} is 1041.75, being the average of the quarterly **CPIs** for **pricing year** 2019.

(4) If there is a base adjustment to **CPI**, the calculation in subclause (3) is to include an equivalency adjustment to eliminate the impact of the base adjustment.

(5) The proportionate increase (if any) in **capped** ~~**offtake customer**~~**load customer** c's **total gross energy** for **pricing year** n (ΔTGE_{cn}) is calculated as follows:

$$\Delta TGE_{cn} = \frac{TGE_{cn}}{TGE_{c19}} - 1$$

where

TGE_{cn} is **capped** ~~**offtake customer**~~**load customer** c's **total gross energy** for **pricing year** n-2, being:

(a) ~~,~~ if **capped** ~~**offtake customer**~~**load customer** c is a **distributor**, **capped** ~~**offtake customer**~~**load customer** c's "electricity entering system for supply to consumers' connection points" for **pricing year** n-2, as disclosed in **capped** ~~**offtake customer**~~**load customer** c's Report on Network Demand (Schedule 9e) under the **EDB ID determination** for its disclosure year ended 31 March of year n-1; or

(b) if **capped load customer** c is a **direct consumer**, as determined by **Transpower**~~.~~

TGE_{c19} is as defined in clause 8(2) for **capped** ~~**offtake customer**~~**load customer** c.

9 Cap Surcharge

Customer c's **cap surcharge** for **pricing year** n (S_{cn}) is calculated as follows:

$$S_{cn} = TCR_{cn} \times \frac{SRC_{cn}}{\sum_i SRC_{in}}$$

where

TCR_{cn} the sum of all reductions to **capped** ~~**offtake customer**~~**load customers'** **capped charges** made under clause 7(1) for **pricing year** n

SRC_{cn} is **customer** c's cap **surcharge-relevant charges** for **pricing year** n

SRC_{in} is **customer** i's (including **customer** c's) cap **surcharge-relevant charges** for **pricing year** n.

Document BB2

ELECTRICITY AUTHORITY
TE MANA HIKO

4 February 2021

Alison Andrew
Chief Executive
Transpower New Zealand
WELLINGTON

Dear Alison

Transpower's TPM Checkpoint 2a resubmission

Thank you for your letter of 22 January, and Transpower's Checkpoint 2a resubmission covering the residual charge and transitional cap provisions of a proposed new TPM.

I acknowledge the further progress that has been made in the resubmission (including revised preliminary drafting for the proposed TPM) with respect to the residual charge and the cap.

The Authority's feedback on each of the main issues is set out below.

Residual charge: generation with embedded load

The Authority welcomes Transpower's constructive response to our feedback on this matter, in particular Transpower's:

- Acknowledgement that the Authority's feedback is consistent with its policy decision to allocate the residual charge on a gross load basis
- Provision of revised preliminary drafting for the proposed TPM that shows how the TPM could apply the residual charge to generators in relation to load embedded behind their generating plant
- Support for a Code change to ensure Transpower can obtain the information it requires to set residual charges on a gross load basis.

The Authority does not, however, share Transpower's view that it would be necessary to depart from the detail of the 2020 TPM guidelines using clause 2 in order to apply the residual charge to generators with embedded load. We remain of the view that the guidelines do require the application of the residual charge to load behind generation, by virtue of clause 7.[1]

On this basis, the Authority's view is that Transpower's proposed TPM should therefore provide for generation with embedded load to be allocated a share of the residual charge.

In any case though, the Authority's view is that allocating a share of the residual charge to generators with embedded load would avoid distorting location decisions by load, which might otherwise be encouraged to inefficiently locate behind generation in order to avoid the residual

[1] Clause 7 was not intended to apply only to distribution networks but was also intended to apply more broadly. This intent is apparent from paragraph B.19 of the 2019 Issues Paper, which highlights the broader intention behind clause 7, while also signalling that distributors are only one example of the types of participants it may apply to.

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charge. As such, we consider the proposed approach is necessary to satisfy the principle included at clause 1(c) of the Guidelines.

Residual charge: step changes

Transpower has indicated that it will consider the Authority's feedback on this issue as part of the Adjustments provisions of the proposed TPM (to be included in its Checkpoint 2b submission in March 2021). The Authority is happy to defer discussion of this issue to Checkpoint 2b.

Residual charge: application to batteries

Transpower has stated that it requires further time to fully consider how the residual charge could be applied for batteries and storage more broadly. We look forward to you proposing an approach and timeline for this piece of work in the coming weeks.

Transitional cap: limited to historical investments

Transpower's drafting now indicates that the cap would not apply to charges for post-2019 investment (noting that applying the cap to these investments in Transpower's Checkpoint 2a submission was a drafting error). The Authority is pleased to accept the corrected drafting.

Transitional cap: generators that are also load customers

I note that Transpower does not intend to provide for the transitional cap to apply to generators that are also load customers in its drafting of the proposed TPM. The Authority accepts this outcome at this point given that the Authority's main concern appears not to arise in practice:

- Transpower has stated that there are no current instances where it treats a connected generator as having embedded load, as all "intermingled" load and generation configurations are treated as connected load with embedded generation (footnote 14 of the resubmission)
- Connected load is eligible for the transitional cap.

That said, the Authority will likely test this outcome through its consultation on the proposed TPM in late 2021 to confirm that there are no current instances where connected generators are treated as having embedded load.

I note that the Authority does not share Transpower's view that it would be necessary to depart from the detail of the Guidelines using clause 2 in order to extend eligibility for the cap to generators that are also load customers. As discussed above, a generator with embedded load is a load customer, based on the Authority's interpretation of clause 7.

Minor points

The appendix to this letter notes a small number of minor points in response to the Checkpoint 2a resubmission for your consideration.

Next steps

I am happy to confirm that the Checkpoint 2a process in relation to the price cap and residual charge is now complete and look forward to receiving the remaining Checkpoint 2 material[2] by 1 March 2021. I also look forward to receiving the work relating to storage, noting the approach and timeline are to be established shortly.

---

2 Including material on adjustments to the residual charge.

Thank you again for the Transpower team's ongoing dialogue and constructive interaction with the Authority on these matters. We are grateful for your team's ongoing diligence in developing the proposed new TPM.

Yours faithfully

James Stevenson-Wallace
Chief Executive

Appendix: Minor points

We note the following more minor points for Transpower's consideration:

(a) The definition of "residual revenue" refers to this being Transpower's recoverable revenue minus connection and benefit-based charges. While this may work at the present, it would cease to do so if Transpower later proposed one of the additional components (e.g. the transitional congestion charge or kvar charge) as part of an operational review.

(b) We are not sure that clause 3(2) (which says a pre-existing load customer's baseline AMDR can never change) and paragraph 13 of Transpower's submission are correct. In particular, our reading of clause 33(e)(i) of the guidelines is a new embedded customer connecting plant would cause a readjustment of the residual allocator for the associated DTC so its baseline might change.

(c) The proposed TPM provisions provide Transpower with discretion to determine a direct consumer's total gross energy for the purposes of the cap (clauses 8(2) and (5)). However, the Guidelines provide for it to use information provided by the reconciliation manager so this would seem on the face of it to be inconsistent with the guidelines.

We have also noted the following typos and similar:

(a) The definition of "embedded electricity" needs to be updated to reflect the new defined terms "supplying load customer" and "supplied load customer".

(b) There is also a missing "a" in the first line of the definition of "load customer".

(c) The deletion of the reference to clause 5(1) in clause 4(5) does not seem to make sense since clause 4(5) provides for average total gross energy baseline not to be recalculated, while clause 5(1) seems to provide for this precise event to occur.

Document BB3

TRANSPOWER

Transmission Pricing Data for 2020/21 Pricing Year

Pricing Year 1 April 2021 to 31 March 2022

Capacity measurement period 1 September 2019 to 31 August 2020

Capacity Data	2015/16	2016/17	2017/18	2018/19	2019/20	2020/21	2021/22
South Island Mean Injection (GWh)	-	-	17,900	16,931	16,921	17,211	17,278
Historical Anytime Maximum Injection (MW)*	3,225	3,223	3,221	3,215	3,174	-	-
Total Regional Coincident Peak Demand (MW)	5,729	5,775	5,768	5,791	5,963	5,894	5,952
RCPD – Upper North Island (UNI)	1,904	1,904	1,934	1,960	2,034	1,969	1,970
RCPD – Lower North Island (LNI)	1,890	1,897	1,877	1,871	1,935	1,905	1,957
RCPD – Upper South Island (USI)	966	980	964	975	983	1,001	1,004
RCPD – Lower South Island (LSI)	968	994	993	986	1,012	1,020	1,021

Revenue and Rates		2015/16	2016/17	2017/18	2018/19	2019/20	2020/21	2021/21
Pre-tax WACC (%)		8.94	8.94	8.94	8.94	8.94	5.88	5.88
Asset Return Rate (%)		7.80	7.97	8.26	8.68	8.83	7.01	7.81
Maintenance Recovery Rates	Substations (%)	2.00	1.87	1.83	1.76	1.74	1.74	1.80
	220kV tower lines ($/km)	5,381	5,242	5,225	5,342	5,345	5,330	5,710
	All other tower lines ($/km)	7,269	5,326	4,980	3,928	3,629	3,054	3,940
	Pole lines ($/km)	8,387	4,301	3,683	3,455	3,056	3,127	3,055
Injection Overhead Rate (%)		4.42	5.03	4.69	4.54	4.14	4.41	4.16
Operating Recovery Rate ($/switch)		1,016	1,107	1,207	1,384	1,217	1,645	1,602
Total Connection Charge Revenue ($m)		127.68	128.57	126.95	130.68	129.62	113.56	119.97
Total Interconnection Revenue ($m)		632.19	662.09	715.16	658.81	652.22	579.98	583.68
Interconnection Rate ($/kW)		110.35	114.64	123.98	113.77	109.38	98.39	98.07
Total HVDC Revenue ($m)		149.93	152.27	149.24	152.36	144.87	92.13	92.13
SIMI Rate ($/MWh)		-	-	2.08	4.50	6.42	5.35	5.33
HAMI Rate ($/kW)*		46.49	47.24	34.75	23.69	11.41	-	-

* Historical Anytime Maximum Injection (HAMI) was replaced by South Island Mean Injection (SIMI) as the allocator for HVDC revenue. The transition occurred over the four years to 2020/21

Document BB4

TRANSPOWER

TPM Development
Residual Charges and the Treatment of Batteries Options Consultation

March 2021

Contents

Front cover photo credit: Tesla

1 Overview

1. The purpose of this consultation is to explore potential issues in relation to the application of the residual charge to grid-connected batteries under the new transmission pricing methodology (**TPM**) and potential options for addressing these issues within the TPM development framework.
2. The Electricity Authority (**Authority**) released its final decision on its transmission pricing review and published new TPM Guidelines (**Guidelines**) on 10 June 2020.[1]
3. One of the issues that has come up since the Guidelines were issued, which the Authority has invited us to consider, is the application of the residual charge to grid-connected batteries.
4. This follows from Contact Energy Limited (**Contact**) writing to the Authority expressing concern that "the Electricity Authority's benefit-based and residual charges may unintentionally undermine investment in new technologies, notably grid-connected batteries".[2] In response, the Authority advised:[3]

    > the matters raised in your letter may be considered by Transpower in its development of a proposed TPM. In our view the TPM guidelines provide Transpower with flexibility around various aspects of its design of a proposed TPM. Transpower may choose to consider the matters raised in your letter. The Authority encourages you to continue to engage with Transpower on these matters.

5. The Authority also commissioned a report from Sense Partners on electricity storage and the residual charge, which has informed some of our thinking on this matter.[4]
6. While Contact's letter refers to grid-connected batteries only, we consider the issues identified by Contact are relevant to any grid-connected device that stores energy (in any form) for later use, including a solid-state battery and pumped hydro scheme. We consider the issues identified by Contact are also relevant to embedded utility-scale storage devices. Throughout this consultation paper, we use the generic term grid-connected battery to refer to any type of grid-connected storage device or embedded utility-scale storage device.

2 Consultation Process

7. We welcome any feedback on whether, and the extent to which:
    - 7.1 there are potential problems with the application of the residual charge to grid-connected batteries under the new TPM; and
    - 7.2 the TPM could or should provide for different treatment of grid-connected batteries with respect to the residual charge, e.g. through an exemption for grid-connected batteries when they are charging for storage.
8. If you consider there are problems, we would be grateful if you could identify whether you consider the problems can be resolved in compliance with the requirements of the

[1] Transmission pricing methodology: 2020 Guidelines and process for development of a proposed TPM: Decision, 10 June 2020 (**Final Decision**). The Guidelines are in a separate document.

[2] Contact letter to Authority, TPM impacts on grid-connected battery investment, 16 November 2020.

[3] Authority letter to Contact, Transmission charges and grid-connected battery investment, 9 December 2020.

[4] Sense Partners, Electricity storage and residual transmission charges, 4 February 2021.

Guidelines or Transpower would need to depart from the requirements of the Guidelines under clause 2.[5]

9. We have developed specific questions for the main Sections of this consultation paper, which are throughout the consultation paper and consolidated in the Appendix. Please provide reasons for your answers to those questions, should you choose to answer them.
10. The consultation period is three weeks commencing Monday, 22 March 2021. Submissions are due by 5pm on Monday, 12 April 2021. This is followed by a one-week period for cross-submissions. Cross-submissions are due by 5pm on Monday, 19 April 2021.
11. Please send submissions and cross-submissions to tpm@transpower.co.nz.
12. We will acknowledge receipt of all submissions and cross-submissions. Submissions and cross-submissions will be published on our website at https://www.transpower.co.nz/industry/transmission-pricing-methodology-tpm.
13. If your submission or cross-submission contains confidential material, please ensure this is clearly identified and provide a version of your submission or cross-submission that can be published. Please note that all information provided to Transpower is subject to potential disclosure under the Official Information Act 1982.

3 Requirements of the Guidelines

14. Clause (v) of the Guidelines states the intent of the residual charge:

> The purpose of the **residual charge** is to provide a mechanism to ensure that Transpower can recover up to its **recoverable revenue** in any **pricing year** in a way which is designed to minimise any effect on designated transmission customers' decision-making.

15. Clauses 27 to 30 of the Guidelines contain the requirements for the residual charge:

> **Main component 3: residual charge**
>
> 27. The **TPM** must provide for a **residual charge** to apply to all designated transmission customers, to the extent that they are **load customers,** to allow Transpower to recover any remaining **recoverable revenue** not recovered through other **transmission charges**.
>
> 28. The **TPM** must provide for the **residual charge** to be initially allocated in proportion to each designated transmission customer's historical anytime maximum demand, which may be calculated using data supplied by the reconciliation manager, and is to be calculated by:
>
>   a. taking**,** in a year from 1 July to 30 June, the customer's anytime maximum demand for that year, which is calculated by:
>
>   i. for each one of the customer's points of connection, taking the highest value in any trading period in that year of gross load, being the sum of:
>
>   1. the net quantity of electricity flow from the grid at that point of connection; and
>
>   2. Transpower's reasonable estimate of concurrent generation behind the designated transmission customer's point of connection; and
>
>   ii. aggregating each of those sums across all the customer's points of connection;

[5] Clause 2 of the Guidelines allows us to depart from the requirements of the Guidelines in some circumstances. See paragraph 60.

b. taking the average of the customer's anytime maximum demand over the four years from 1 July 2014 to 30 June 2018.

29. The **TPM** must provide that, in initially allocating the **residual charge** under clause 28, Transpower may adjust the allocation where necessary to accommodate circumstances in which, in Transpower's reasonable opinion, a designated transmission customer has experienced a substantial reduction in anytime maximum demand, due to factors that are largely beyond the customer's control or influence. For the purposes of this clause, a substantial reduction in demand is to be assessed relative to the designated transmission customer's remaining demand.

30. The **TPM** must provide that for each **pricing year**, from and including the **pricing year** commencing on 1 April 2023, the **residual charge** is to be allocated in proportion to each designated transmission customer's adjusted historical anytime maximum demand, calculated as:

$$AHAMD_t = HAMD_0 \times U_t / U_0$$

where:

$AHAMD_t$ is the designated transmission customer's adjusted historical anytime maximum demand

$HAMD_0$ is the designated transmission customer's historical anytime maximum demand calculated as described in clauses 28 and 29.

U_t is the designated transmission customer's average total **gross** annual energy usage (measured in MWh) across the year commencing on 1 July four years and nine months prior to the start of the **pricing year** in which the adjustment applies and the three preceding years commencing on 1 July

U_0 is the designated transmission customer's average total **gross** annual energy usage (measured in MWh) across the four years from 1 July 2014 to 30 June 2018, reduced as necessary to be consistent with the reduction in anytime maximum demand under clause 29.

3.1 Load customers and residual charges

16. Clause 27 of the Guidelines says all designated transmission customers must pay a residual charge "*to the extent that they are load customers*". The Guidelines define "load customer" as:

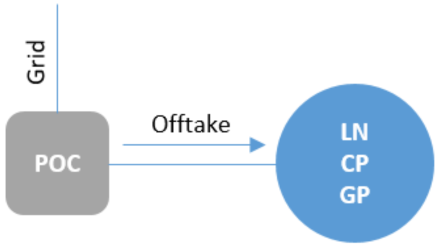
> a designated transmission customer whose equipment draws electricity from the grid or from any generation behind the designated transmission customer's point or points of connection (including distributed generation and behind-the-meter generation).

17. As part of our preliminary TPM drafting task, we have been considering the situations where a customer will be a load customer. The following diagrams show what we currently consider to be the different types of load customer (offtake customer, supplied load customer and supplying load customer):[6]

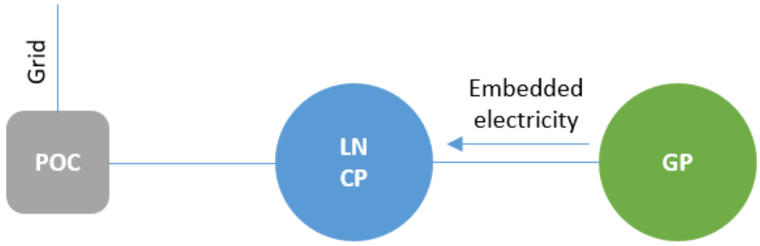
[6] The third situation (supplying load customer) is not within the definition of load customer in the Guidelines because the generating plant (GP) is not drawing electricity from the grid or from any generation behind the point of connection. However, the Authority intends supplying load customers to be captured as load customers (Authority letter to Transpower, Transpower's TPM Checkpoint 2a submission, 7 December 2020, paragraphs A.6 to A.10). If Transpower proposes this, it will likely need to be by way of a departure under clause 2 of the Guidelines.

The different types of **load customer** are shown in the following diagrams. In these diagrams, "LN" means **local network**, "CP" means **consuming plant**, "GP" means **generating plant**, "NGN" means **non-grid network** and "POC" means **point of connection** to the **grid**:

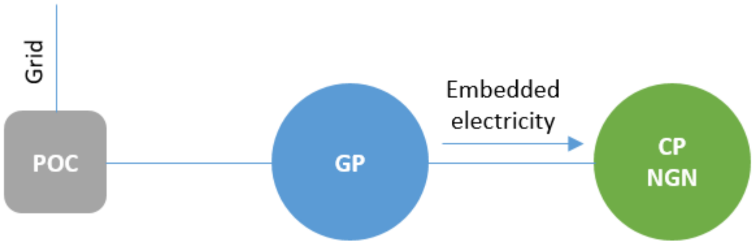
(a) In the following diagram, a **customer** owning or controlling LN, CP or GP is an **offtake customer** to the extent of the **offtake**:



(b) In the following diagram, a **customer** owning or controlling LN or CP is a **supplied load customer** to the extent of the **embedded electricity**. The **embedded electricity** is referred to as the **supplied load customer's embedded electricity** "at" the POC and relevant **connection location**:



(c) In the following diagram, a **customer** owning or controlling GP is a **supplying load customer** to the extent of the **embedded electricity**. The **embedded electricity** is referred to as the **supplying load customer's embedded electricity** "at" the POC and relevant **connection location**:



18. The Authority has previously stated that:[7]

> A party providing energy storage services using a battery, for example, would be a load customer when charging the battery and a generation customer when discharging its battery.

19. This would mean that a grid-connected battery would constitute a load customer whether the battery is charging from the grid (as an offtake customer) or from generation behind the point of connection (as a supplied load customer). The grid-connected battery would also be a load customer (as a supplying load customer) when it is discharging behind the point of connection.

[7] Authority, 2019 issues paper, Transmission pricing review, Consultation paper, 23 July 2019, footnote 180.

20. A load customer's allocation of the residual charge is based on its average historical (2014-2018) anytime maximum demand (**AMD**).[8] AMD is a measure of peak per-trading period gross demand (in MW) during a year, gross demand being the sum of the load customer's offtake and embedded electricity, i.e. the electricity flows shown in the diagrams above.[9] The higher the load customer's average historical AMD, relative to other load customers, the higher its residual charge.
21. A load customer's baseline historical average AMD is adjusted annually based on changes in the load customer's average annual gross energy (in MWh). However, the underlying allocator remains AMD and the demand peaks inherent in it.

4 The role of grid-connected batteries

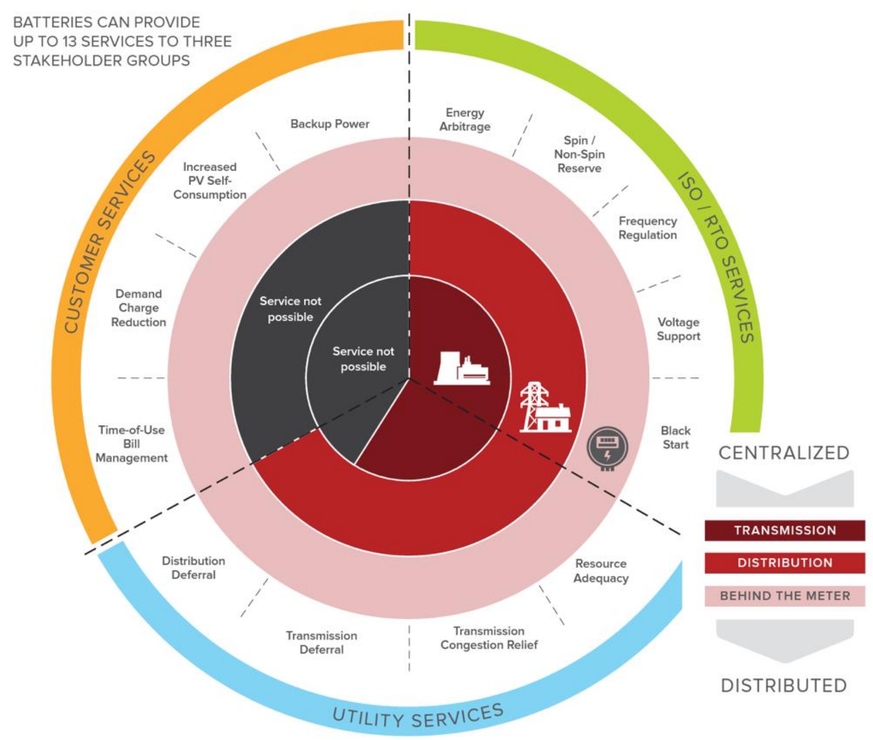
22. This Section provides an overview of the current views of key stakeholders on the role of grid-connected batteries in New Zealand's energy sector.

4.1 Transpower's views

23. In 2020 Transpower released Whakamana i Te Mauri Hiko, a report which lays out the role that electricity will play in enabling New Zealand's decarbonisation.[10] The report considers how New Zealand's electricity sector will need to evolve to support this transition, with a focus on how we will plan and develop the transmission system as the transport and process heat sectors are electrified, demand for electricity increases and as new renewable generation is added to the system.
24. Whakamana i Te Mauri Hiko identifies the adoption of batteries as a key opportunity which will allow New Zealand to achieve its decarbonisation targets at minimum cost.
25. While there are significant opportunities to use batteries to optimise network utilisation, their benefits are wide ranging and there is an opportunity for battery owners to provide a range of services, as shown in the following diagram:[11]

[8] For new grid-connected batteries (as they all would be) Transpower has to estimate a value for average historical AMD as if the battery had existed at the relevant time.
[9] In contrast, the current interconnection charge is based on offtake only, and only during peak periods.
[10] Transpower, Whakamana I Te Mauri Hiko, Empowering our Energy Future, March 2020
[11] Published in Transpower, Transmission Tomorrow – Our Strategy, December 2018, page 39.

Figure 13: **The Rocky Mountain Institute view on the services batteries can provide**



26. As an example, Contact has pointed out that grid-connected batteries are beneficial due to their ability to, effectively, shift generation from times when it is less valuable/more available to times when it is more valuable/less available. This could become an important function if the removal of the peak-pricing signal from transmission charges results in higher peak demand.[12]

4.2 Authority's views

27. In a 2018 Market Commentary about Mercury's plans for grid-connected batteries, the Authority made the following comments regarding the ability of grid-connected batteries to contribute to the efficiency of New Zealand's electricity industry:[13]

> The Authority encourages Transpower and distributors to adopt approaches that allow those providing innovative services from devices such as batteries, to access their networks on a non-discriminatory basis.
>
> In the future, consumers will have greater opportunities and choices to enjoy the benefits of the new technologies becoming available.
>
> Removing barriers to different forms of generating technologies in the wholesale market will improve supply side competition, contribute to reliability and potentially improve the operational efficiency of the electricity industry.
>
> …

[12] See Section 5.

[13] Authority, Market Commentary: Participation of Battery Storage Units in the Wholesale Market, 17 August 2018.

[The Authority's Senior Advisor Wholesale Markets says] "The battery will also have benefits for the consumer by helping to meet peak demand and will complement New Zealand's existing storage in hydro lakes as well as enhancing security of supply to Auckland."

28. In response to Contact's letter, the Authority commented that *"the Authority understands the potential for grid-connected batteries, like many other technologies, to contribute to New Zealand's transition to a low-emissions economy."*[14]

4.3 Climate Change Commission's views

29. The Climate Change Commission (**CCC**) has identified grid-connected batteries, and batteries more generally, as *"important in the transition to a low emissions economy"*[15] and for the efficient operation of the electricity industry.

30. The comments the CCC has made closely align with the Authority's views:

[Draft Supporting Evidence for Consultation][16]

Adding storage to the electricity system makes renewable generation more useful by providing a back-up for times when the renewable resource is insufficient (daily peaks). Transpower estimates that peak demand could increase from 7.3 GW in 2020 to 8.9 GW by 2035 and 10 GW by 2050. Batteries can be large 'grid-scale' installations or distributed units in buildings and electric vehicles (EVs). Batteries can help to smooth peaks and troughs in demand. A battery charged over the course of the day using renewable generation can be rapidly discharged to meet a short period of peak demand which would otherwise be provided by a fossil fuelled power station. For example, Transpower estimates that by 2035, about 1.2GW of battery storage capacity could be deployed to support periods of peak demand.

...

The results of the ICCC's modelling show that, instead of pursuing 100% renewable electricity by 2035, more emissions savings could be achieved through accelerated electrification of transport and process heat. However, while using natural gas in the electricity system may be an effective mechanism to minimise emissions and achieve security of supply until 2035, eventually all fossil fuel generation would need to be eliminated and the dry year issue addressed to contribute to efforts to limit the global average temperature increase to 1.5^{o}C above pre-industrial levels.

Options to address dry year risk that the ICCC examined included, overbuilding renewables, using biomass or hydrogen for generation, long-term battery storage, indicative large-scale demand interruption and pumped hydro storage.

[Draft Advice for Consultation][17]

The Government needs to plan to manage the risk around affordability and security of supply as a result of moving to a low emissions energy system. It is currently investigating options for managing dry year risk under the NZ Battery project, including the proposed Lake Onslow pumped hydro scheme and alternative storage options. The aim is to provide a large amount of storage capacity to manage the risk of dry years where hydro lake levels are low. This project could displace the requirement for thermal generation and achieve an

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14 See footnote 3.

15 CCC, Draft Advice for Consultation, 31 January 2021, page 100.

16 CCC, Draft Supporting Evidence for Consultation, Chapter 4a: Reducing emissions – opportunities and challenges across sectors – Heat, industry and power, 1 February 2021, pages 21 and 23.

17 See footnote 15, page 90.

> abrupt decarbonisation of the electricity sector. Any solution for managing the dry year risk could be expensive.
>
> Other actions to increase resilience of the electricity grid and the system include building new generation in the North Island, reinforcing the transmission infrastructure, deploying new technologies such as batteries, and diversifying into new fuels such as biofuels and hydrogen that boost energy security.

31. The CCC mentions the Government's target of achieving 100% renewable generation by 2035 (now 2030). Grid-connected batteries may help achieve this target by reducing New Zealand's reliance on thermal peaking generation. The Government has committed to the investigation stage of the "NZ Battery Project", a large pumped hydro scheme at Lake Onslow.[18]

4.4 Specific questions

4.4.1 Do you agree grid-connected batteries have a potential role in the efficient operation of the electricity industry?

4.4.2 Do you agree grid-connected batteries have a potential role in achieving carbon emissions reductions in New Zealand's energy system?

5 Contact's concerns

32. Contact outlined the following concerns specific to the Guidelines' requirements that all load customers pay the residual charge and the allocation of the residual charge be on the basis of AMD:[19]

> These concerns have come to light as we investigate investment in a 100 MW grid-connected battery. Its purpose would be to provide peaking generation, instantaneous reserve and voltage support. A key benefit of the additional instantaneous reserve is that greater utilisation of the existing capacity of the HVDC will be possible and therefore additional transmission investment (e.g. the fourth submarine cable) can be deferred.
>
> We have proposed the voltage support role to Transpower who has been highly supportive of the concept. Collectively, these services will benefit all consumers and are strongly aligned with the Authority's purpose statement, and potentially reduce the market's reliance on thermal generation and support the Government's wider decarbonisation goals.
>
> To perform these services, the battery will need to be frequently charged and discharged. The intention is to charge during off-peak periods when there is a surplus of electricity and transmission capacity and then discharge the battery during periods when demand is high or other generation is scarce. The Authority has confirmed that under the current TPM a grid-connected battery is treated as a "Load Customer" rather than a "Generator". Based on the existing Regional Coincident Peak Demand (RCPD) charge, this approach does not lead to a material transmission charge as there is no effect on peak demand and no additional transmission costs are incurred
>
> However, by replacing the existing RCPD charge with the unavoidable Anytime Maximum Demand (AMD) charge, a grid-connected battery will incur a charge regardless of whether it is charged during periods when there is an abundance of transmission capacity.

[18] https://www.mbie.govt.nz/building-and-energy/energy-and-natural-resources/low-emissions-economy/nz-battery/.

[19] See footnote 2.

> In addition, the removal of the existing RCPD charge has the potential to materially increase peak demand. Grid-connected batteries are likely to be the most cost-effective way of meeting this higher peak demand (and without the carbon emissions of a gas-fired peaker). But the same set of policy changes that create the need for grid-connected batteries also actively discourages them.

33. Contact's point is that treating grid-connected batteries as load customers will discourage investment in them (including its own investment) because the residual charge incurred as a load customer cannot be avoided, even if the battery charges from the grid at times when there is excess grid capacity. Its concern is that this may put grid-connected batteries at a competitive disadvantage relative to other types of grid-connected generator, who largely do not incur residual charges.

34. The Authority has noted in response to Contact that:[20]

 34.1 *"a grid-connected battery owner meets the definition of a load customer under the Guidelines, and on that basis would contribute to the residual charge"*; and

 34.2 as part of the development of the TPM, consideration could be given to whether, in allocating the residual charge, there is justification for treating batteries differently to other load customers *"for the purpose of preserving competitive neutrality between batteries and generation in the wholesale market."*

35. The Authority made similar comments about batteries in its feedback on Transpower's Checkpoint 2A submission.[21]

5.1 Specific questions

5.1.1 Do you have any comments about the concerns Contact has raised about grid-connected batteries?

6 Assessment of the potential problems

6.1 Distortion of wholesale electricity market

36. Grid-connected batteries can compete with more traditional forms of generation in a number of different markets, including the wholesale markets for electricity and ancillary services. In our view, the TPM should, as far as practicable, achieve competitive neutrality between participants and technologies in those markets. In particular, the TPM should not be written in a way that advantages current technologies relative to emerging ones, if that can be avoided.

37. The concept of competitive neutrality overlaps with the TPM development principle in clause (1)(e) of the Guidelines:

> Transpower must, as far as reasonably practicable,... avoid discriminating between designated transmission customers, except to the extent allowed by these Guidelines or otherwise necessary to achieve the Authority's statutory objective...

38. One of the aims of this consultation is to assess whether a problem could arise if the new TPM creates barriers to entry for grid-connected batteries by imposing (non-cost related)

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20 See footnote 3.

21 See footnote 6, paragraphs A.15 to A.20.

charges that electricity generators who also offer electricity into the wholesale electricity market do not face.[22]

39. This is consistent with correspondence we received from the Authority following Contact's letter:[23]

> The guidelines provide that the residual charge would apply to load customers, which would include batteries, whereas other generation is largely exempt from the residual charge since it would typically draw little electricity from the grid.
>
> However, reflecting on Contact Energy's letter, a question logically follows about whether a battery (or similar asset) should be treated in the same manner as other generators in order to ensure competitive neutrality in the wholesale market.

40. The Authority identified a similar problem with the current HVDC charge, which will not exist in the new TPM:[24]

> The HVDC charge is … problematic. South Island generators are currently required to pay for all costs of this link between the South and North Islands despite North Island generators benefitting from the HVDC link as well as New Zealand electricity consumers.
>
> In effect, the HVDC charge acts like a tax on South Island generation. It inefficiently discourages investment in South Island generation. Dampening investment in generation pushes electricity prices higher than they need to be. The Authority considers the new guidelines will contribute to unlocking renewable generation in the South Island and lower generation costs for the long-term benefit of New Zealand consumers.

41. Similarly, Sense Partners have expressed the following view:[25]

> Imposing residual charges on electricity storage could inefficiently inhibit investment in such technologies. This could be a significant problem, judging from experiences elsewhere in the world where investment in storage – such as grid-scale batteries – have significantly reduced costs of ancillary services and provided alternatives to investment in transmission and distribution networks.
>
> …
>
> **Residual charges add costs to storage not faced by most other producers of electricity services**
>
> The current approach to allocating residual charges is likely to reduce investment in energy storage in favour of investment in technologies that do not use electricity as an input. The effect will vary depending on the size and location of the investment.

42. It is relevant that the Authority deliberately exempted generators in general from the residual charge when it made the Guidelines.[26] As the Authority has confirmed recently, *"the purpose of this exemption [is] to avoid distortions in the wholesale market (including increases in the wholesale energy price)."*[27] In the short term, residual charges imposed on generators are likely to be passed through in wholesale prices (ultimately to consumers), and in the long-term may put upward pressure on wholesale prices by deterring new entrants.

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22 A difference in costs is not a problem/is competitively neutral if it is cost-based, i.e. if the cost difference reflects that different designated transmission customers have different connection costs or if location results in higher transmission costs more generally.

23 See footnote 6.

24 Final Decision, Executive Summary, page ii. In the Guidelines, the HVDC link is one of the historical benefit-based investments in Schedule 1, meaning its costs will be recovered from all beneficiaries through the benefit-based charge.

25 See footnote 4, pages 1 and 2.

26 Except for the relatively rare occasions when a generator is supplied with electricity for its own consumption.

27 See footnote 6, paragraph A.17.

43. The Sense Partners report demonstrates that in other jurisdictions regulators are considering various approaches to address the potential inefficiencies that arise from treating grid-connected batteries as both generation and load customers.[28]

6.2 Residual charge inconsistent with mode of operation for batteries

44. The underlying allocator for the residual charge is AMD. As described in Section 3.1, AMD is a measure of peak demand, in MW. If a load customer had zero demand for all trading periods in a year but one, the load customer's demand during that one trading period would be its AMD for the year and contribute to its underlying allocator for the residual charge.

45. The basis for allocation of the residual charge required under the Guidelines may be conceptually inconsistent with how grid-connected batteries operate in practice. Consistent with Contact's comments,[29] we expect grid-connected batteries to be charged when spot prices are lowest and discharged when spot prices are highest and/or there are transmission constraints or outages. Accordingly, the demand profile for a grid-connected battery is likely to be relatively "peaky" compared to non-battery load sources. We are interested in stakeholders' views on whether this may result in batteries being further disadvantaged by the imposition of the residual charge, potentially exacerbating the competitive neutrality problem and impacting negatively on overall efficiency.

46. Separately, we are interested in stakeholders' views as to whether the application of the residual charge to grid-connected batteries in accordance with the Guidelines may incentivise grid-connected batteries to operate in an inefficient manner. Of relevance here is the TPM development principle in clause 1(c) of the Guidelines:

> Transpower must, as far as reasonably practicable,… avoid creating incentives for existing and potential designated transmission customers to avoid transmission charges in ways that cause economic inefficiency…

47. For example, it is possible a grid-connected battery operator would be incentivised to implement physical limits on its battery's ability to take electricity from the grid in order to reduce its AMD. We consider this is likely to be inefficient - the residual charge would have incentivised the battery operator to design its battery in a way that is contrary to the battery's most efficient mode of operation.[30]

48. Another possibility is that the annual adjustment to the residual charge allocator based on historical average gross energy will incentivise the battery operator to limit charging of the battery generally, in a way that may be inefficient. This decision would likely come down to the operator's assessment of whether it had more to gain from avoiding the residual charge than from selling additional electricity.

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[28] See footnote 4, pages 9 to 11.

[29] See paragraph 32.

[30] This type of efficiency distortion led to the allocator for the current HVDC charge being changed from half-hour anytime maximum injection (HAMI) to South Island mean injection (SIMI) as part of Transpower's 2014/15 operational review of the TPM (https://www.transpower.co.nz/industry/transmission-pricing-methodology-tpm/operational-review-1-2014).

6.3 Specific questions

6.3.1 Do you agree with this assessment of potential problems with applying the residual charge to grid-connected batteries?

6.3.2 Are there any other potential problems we have not identified, and that should be considered as part of TPM development?

6.3.3 Do you consider the potential problems are material?

7 Options for the treatment of grid-connected batteries

49. Our options for the design of the residual charge for grid-connected batteries are constrained by the legal framework in which we must develop the TPM, including the Guidelines.

50. We have identified three options for the application of the residual charge to grid-connected batteries:

    50.1 *Option 1*: Grid-connected batteries are treated as load customers for their entire offtake and embedded electricity under the new TPM.

    50.2 *Option 2*: Grid-connected batteries are exempted from the residual charge with respect to offtake and embedded electricity while charging, except as to losses.

    50.3 *Option 3*: Grid-connected batteries are fully exempted from the residual charge with respect to offtake and embedded electricity while charging.

51. An alternative to these options would be for the Authority to amend the Guidelines to clarify how grid-connected batteries are to be treated for the purposes of the residual charge. This is not our option to propose, and in any event the Authority recently confirmed it is not open to amending the Guidelines to address this issue.[31]

52. The three options we have identified are:

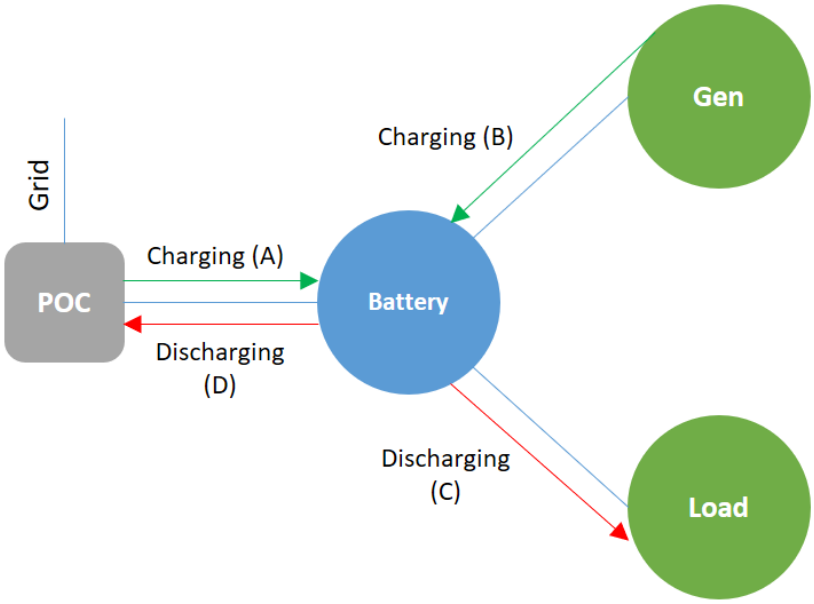
7.1 Option 1: No exemption

53. We consider this is the best interpretation of the relevant clauses of the Guidelines. It is also the interpretation of those clauses favoured by the Authority. We consider there are some potential problems with this option, as discussed in Section 6.

7.2 Option 2: Exemption while charging except as to losses

54. The following diagram illustrates the different ways a grid-connected battery may charge and discharge:

[31] Authority letter to Transpower, Proposed TPM residual charges and the treatment of batteries, 18 March 2021.



55. A potential treatment we have identified for grid-connected batteries is as follows:

55.1 Exclude A+B from the battery's gross energy for the purpose of calculating its residual charge.

55.2 Add back in battery losses, either using:

- loss factor x (A+B), with the loss factor derived from manufacturer's specifications and potentially commissioning tests; or
- (A+B) – (C+D).

The first approach may be best so that timing issues are avoided.

55.3 Count C as part of the battery's gross energy for the purpose of calculating its residual charge (assuming Transpower adopts the Authority's approach to defining gross energy) so that the supplied load is not incentivised to avoid a residual charge by embedding behind the battery.

55.4 For plant that is a hybrid battery/normal load source, Transpower could nominate some part of A+B as "normal" load and count it towards the plant's gross energy.

56. Battery losses are added back in this option because they are analogous to the electricity a non-battery generator uses to run itself, which will attract a residual charge.

57. A consequence of this option is that the part of the residual charge not allocated to grid-connected batteries would be spread to other load customers through a proportionate increase in their allocated residual charges.

7.3 Option 3: Full exemption while charging

58. This option is the same as option 2 except battery losses would not be added back in.

7.4 Implementing option 2 or option 3

59. Our current view is that option 2 or option 3 would need to be implemented by way of a departure from the requirements of the Guidelines under clause 2 (by fully or partially exempting grid-connected batteries from the residual charge while charging).[32]

60. Clause 2 of the Guidelines permits Transpower to depart from the requirements of the Guidelines if:

    60.1 the departure is not inconsistent with the intent of the Guidelines; and

    60.2 Transpower considers departing from the requirements of the Guidelines would better meet the Authority's statutory objective than not departing from them.

61. As noted above, clause (v) of the Guidelines says the residual charge should be "designed to minimise any effect on designated transmission customers' decision-making". One of the key issues on which we are seeking feedback in this consultation paper is the extent to which the application of the residual charge to grid-connected batteries would deter efficient investment in grid-connected batteries and/or inefficiently distort usage decisions. If this is the case, then the application of the residual charge to grid-connected batteries is arguably inconsistent with the intent of the Guidelines as recorded in clause (v).

62. While the Authority has previously stated that its preferred interpretation of the clauses of the Guidelines is that batteries are load customers (and would therefore attract the full residual charge), the Authority has also previously indicated there may be scope for Transpower to take a different approach in the TPM. For example:[33]

    > Transpower may wish to further consider…whether or not a different approach for grid-connected batteries might better promote the Authority's statutory objective (noting the flexibility afforded by clause 2 of the guidelines). To be clear, the Authority does not currently have a view on this question.

63. Transpower has recently received a letter from the Authority clarifying the intent of the Guidelines in relation to the residual charge for grid-connected batteries:[34]

    > [The Authority's Chief Executive] can confirm it is the Authority's view that this issue is capable of being satisfactorily addressed within the 2020 guidelines. The guidelines cannot, and do not, provide for all matters which might need to be considered to ensure the proposed TPM is consistent with the Authority's statutory objective. Instead, they provide Transpower with some flexibility including through the operation of clause 2, which provides for the proposed TPM to differ in matters of detail from particular requirements in the Guidelines (but not to depart from the Authority's intent).
    >
    > …
    >
    > As the Decision paper makes clear, the Authority intends for any final TPM to be consistent with its statutory objective, ie, it should promote competition, reliability and efficient operation of the industry. In line with its statutory objective the Authority intends that any new TPM would not compromise competitive neutrality in te wholesale market, and that batteries/storage should be able to operate efficiently and contribute to the reliability of the grid. The Authority considers that it would most likely be inconsistent with its statutory

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32 We have explored whether there is an alternative interpretation of the existing definitions in the Code that would permit Transpower to exempt grid-connected batteries from the residual charge, without the need for Transpower to rely on a departure under clause 2 of the Guidelines. We have not been able to identify a robust interpretative option.

33 See footnote 6.

34 See footnote 31.

> objective (and it would certainly not be the Authority's intent) for the new TPM to discourage efficient investment in grid-connected batteries.
>
> …
>
> It would therefore be reading too much into [the Authority's comment quoted in paragraph 18 above] to construe it as a broader indication of the Authority's intent with respect to the residual charge's application to batteries.

64. Based on clause (v) of the Guidelines and our correspondence with the Authority, we consider a departure from the requirements of the Guidelines to fully or partially exempt grid-connected batteries from the residual charge while charging would not be inconsistent with the intent of the Guidelines. We also consider such a departure would be likely to support all three limbs of the Authority's statutory objective (competition, reliability and efficiency) for the reasons discussed in Sections 4 and 6. We welcome stakeholder feedback on these matters.

7.5 Specific questions

7.5.1 Are there any other options we have not identified, and that should be considered as part of TPM development?

7.5.2 Which option do you prefer?

7.5.3 If you consider option 2 or option 3 is appropriate, what threshold would be appropriate for determining whether an embedded battery is "utility-scale", i.e. treated the same as a grid-connected battery?

Appendix Specific questions

65. We have developed specific questions for each of the main Sections of this consultation paper, which are throughout the consultation paper and consolidated below. Please provide reasons for your answers to these questions, should you choose to answer them.

The role of grid-connected batteries	
Question 4.4.1	Do you agree grid-connected batteries have a potential role in the efficient operation of the electricity industry?
Question 4.4.2	Do you agree grid-connected batteries have a potential role in achieving carbon emissions reductions in New Zealand's energy system?
Contact's concerns	
Question 5.1.1	Do you have any comments about the concerns Contact has raised about grid-connected batteries?
Assessment of the potential problems	
Question 6.3.1	Do you agree with this assessment of potential problems with applying the residual charge to grid-connected batteries?
Question 6.3.2	Are there any other potential problems we have not identified, and that should be considered as part of TPM development?
Question 6.3.3	Do you consider the potential problems are material?
Options for the treatment of grid-connected batteries	
Question 7.5.1	Are there any other options we have not identified, and that should be considered as part of TPM development?
Question 7.5.3	Which option do you prefer?
Question 7.5.4	If you consider option 2 or option 3 is appropriate, what threshold would be appropriate for determining whether an embedded battery is "utility-scale", i.e. treated the same as a grid-connected battery?

Document BB5

ELECTRICITY AUTHORITY
TE MANA HIKO

18 March 2021

Alison Andrew
Chief Executive
Transpower New Zealand
WELLINGTON

By email: Alison.Andrew@transpower.co.nz

Dear Alison

Proposed TPM residual charges and the treatment of batteries

I am writing to you regarding the application of the proposed TPM's provisions relating to the residual charge to grid-connected batteries and similar storage.[1] Our respective teams have been discussing this issue since mid-November 2020, when Contact Energy wrote to the Authority outlining its concerns, and particularly following the Authority's response to Transpower's Checkpoint 2A submission on 7 December 2020. We appreciate your team's constructive approach to this matter.

During discussions between Transpower and Authority staff on 12 March 2021, your team asked the Authority to provide

- a statement explaining the Authority's view that the batteries issue can be accommodated within the 2020 TPM guidelines and that the guidelines do not need to be amended
- clarification of the Authority's intent on the application of the residual charge to batteries, in the context of the options paper Transpower will shortly be publishing. That clarification will help Transpower in its consideration of whether it is able to apply greater flexibility in the TPM it proposes by relying on clause 2 of the 2020 TPM guidelines[2]

This letter responds to those requests.

Context

By way of background, the proposed residual charge allows Transpower to recover its revenue (that is not recovered through other charges) in a way that does not distort its customers' decision-making. As a starting point, this charge reflects the principle of spreading these costs widely.

However, in the 2020 TPM guidelines the Authority decided to carve generation out from this principle because we recognised residual charges on generation would largely be passed on to

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1 The issues under consideration are relevant to grid-connected solid-state batteries and also any grid-connected device that stores energy (in any form) for later use, eg, a pumped hydro scheme or any other energy storage installation. The issues are also relevant to embedded utility-scale storage devices. For simplicity, this letter uses the generic term 'grid-connected battery' to refer to any type of grid-connected storage device or embedded utility-scale storage device.

2 Clause 2 provides that "The TPM may differ in its details from the particular requirements in these Guidelines (but not their intent, including as set out in the Authority's intent section of these Guidelines), if Transpower considers, in its reasonable opinion, that doing so would better meet the Authority's statutory objective than complying with these Guidelines in their entirety."

load in the form of higher energy prices (by delaying generators' entry). Based on this reasoning, under the guidelines generation does not pay the residual charge except to the extent it has load.[3]

During the TPM review process the Authority previously recognised that batteries operate as both load and generation, but the specific role (now contemplated by Contact) that could be played by grid-connected batteries was not subject to significant discussion or debate during the Authority's consultation process in respect of the TPM guidelines.

In our view Contact's letter, received after the 2020 TPM guidelines were published, raises a potential problem of competitive neutrality between generation exempted from the residual charge and batteries (which are not currently exempted).

The Authority noted this competitive neutrality problem in its 9 December 2020 response to Contact's 16 November 2020 letter, as follows:

> *The Authority considers that battery owners, like all other transmission customers, should in principle contribute to the cost of transmission investments from which they benefit. Battery owners gain substantial benefit from connection to the grid and should pay for that.*
>
> *A grid-connected battery owner meets the definition of a load customer under the TPM guidelines, and on that basis would contribute to the residual charge. However, we note that there may be reasonable further discussion to be had – between Contact and Transpower, as part of its development of the proposed TPM, in the first instance – about whether, in allocating the residual charge, there is justification for treating batteries differently to other load for the purpose of preserving competitive neutrality between batteries and generation in the wholesale market.*

This was the basis upon which we referred this issue to Transpower as part of Checkpoint 2A.

The 2020 guidelines provide sufficient flexibility

I can confirm it is the Authority's view that this issue is capable of being satisfactorily addressed within the 2020 guidelines. The guidelines cannot, and do not, provide for all matters which might need to be considered to ensure the proposed TPM is consistent with the Authority's statutory objective. Instead, they provide Transpower with some flexibility including through the operation of clause 2, which provides for the proposed TPM to differ in matters of detail from particular requirements in the Guidelines (but not to depart from the Authority's intent).

The Authority's view is that it is appropriate for Transpower to consider issues relating to batteries as part of its development of the proposed TPM (which will subsequently be reviewed and consulted on by the Authority), including through the use of clause 2 if Transpower considers the criteria for its use are met. So, as matters stand, the Authority does not intend to re-open the guidelines in respect of this issue.

Intent

As the Decision Paper makes clear, the Authority intends for any final TPM to be consistent with its statutory objective, ie, it should promote competition, reliability and efficient operation of the industry.[4] In line with its statutory objective the Authority intends that any new TPM would not compromise competitive neutrality in the wholesale market,[5] and that batteries/storage should

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3 See paragraphs 10.4 and 10.15 - 10.20 in the Authority's 2020 TPM guidelines decision paper.

4 Section 15 of the Electricity Industry Act 2010: *The objective of the Authority is to promote competition in, reliable supply by, and the efficient operation of, the electricity industry for the long-term benefit of consumers.*

5 This intent is demonstrated in, for example, the 2019 Issues paper, para 2.15: *An efficient price signal avoids inadvertently promoting or discouraging any particular technology, and instead promotes competition by providing electricity services on an even footing. That is, efficient network prices would level the playing field for new solutions,*

be able to operate efficiently and contribute to the reliability of the grid.[6] The Authority considers that it would most likely be inconsistent with its statutory objective (and it would certainly not be the Authority's intent) for the new TPM to discourage efficient investment in grid-connected batteries.

Transpower staff have noted that we stated in a footnote to the 2019 Issues paper that batteries would be a load customer while charging.[7] This statement, however:

- was made in the context of discussion around the benefit-based charge and particularly the idea that parties might be both importers and exporters of electricity (and may therefore benefit from investments in different ways)
- is consistent with the principles behind the benefit-based charge, ie, that parties should be charged in proportion to the benefits they receive, since battery owners/operators will benefit from investments as other load customers do
- does not indicate that batteries and similar storage must be allocated a portion of the *residual* charge on the same basis as other load,[8] irrespective of competition concerns (or other matters relevant to the Authority's statutory objective)
- does not prevent Transpower from utilising clause 2 in this regard.

In addition, the competitive neutrality issue for grid-connected batteries had not been raised by Contact or others, and was not in contemplation, when this statement was made.

It would therefore be reading too much into that footnote to construe it as a broader indication of the Authority's intent with respect to the residual charge's application to batteries.

Noting that the proposed closure of the Tiwai Point aluminium smelter in 2021 (now delayed to 2024) has brought this issue of the residual charge's application to batteries into sharp focus, we agree that Transpower should now explore this issue with stakeholders, to better form its own view of whether clause 2 of the 2020 guidelines should be applied.

Next steps

I look forward to Transpower publishing its options paper on this topic. If your team wishes to discuss the Authority's intent further, please contact Rob Bernau, Director TPM, in the first instance.

Yours faithfully

James Stevenson-Wallace
Chief Executive

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for the benefit of consumers. See also 2020 decision paper on the TPM guidelines, para 2.14: *The HVDC charge [....] inefficiently discourages investment in South Island generation relative to North Island generation....*

6 Note also that the Authority is currently considering wider matters relating to batteries, to enable new generation technologies to participate in the wholesale electricity market. We are currently considering updates to the Code provisions to provide a means for offering energy and reserve from batteries as instantaneous reserve into the ancillary services market.

7 See footnote 180 of the 2019 Issues paper.

8 Note that the residual charge is founded on different principles to the benefit-based charge.

Document BB6

BELL GULLY

By email jraffills@toddcorporation.com

Nova Energy Limited
95 Customhouse Quay
Wellington 6011

Attention Liesbeth Koomen / Joycelyn Raffills

FROM **Jenny Stevens / Laura Hardcastle**
DDI +64 4 915 6849 / +64 4 915 6870
MOBILE +64 21 190 2973 / -
EMAIL jenny.stevens@bellgully.com
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MATTER NO. 404-0953
DATE 30 October 2020

CIV 2020-485-367: Trustpower Limited v Electricity Authority

1. We refer to your letter dated 20 October 2020, in addition to your Memorandum of Counsel dated 17 October 2020, outlining Nova's position on discovery.

2. Your letter contained queries relating to the calculation of indicative residual charges in the TPM Decision Paper 2020 ("**Decision Paper**"). Specifically, you have referred to Table 4 at pages 103-104 of the Decision Paper which sets out the Authority's estimate of the "2022 charges by $M, by customer". You have asked:

   (a) can the Authority advise how it derived the data used in the calculation of the residual charge;

   (b) can the Authority advise if it included an estimate for coincident embedded generation; and

   (c) can the Authority provide the specific calculations for each of: Eastland Network, Horizon Energy, Orion, Top Energy, Vector, Wellington Electricity, Westpower, Nova Energy, Todd Generation Taranaki and Whareroa Cogeneration Facility?

3. Given your questions are asked in the context of discussing discovery, we take it they are directed toward understanding whether the answers to your questions will be located in the formal record (that the Authority is currently compiling) or if Nova needs to consider a separate discovery application. For the reasons set out below, the short answer to your queries is that these matters were addressed in, and are apparent from, the formal published record. They will therefore be covered by the formal record the Authority is currently compiling (albeit we are still considering how best to cross reference the underlying data packs the Authority made available as part of the formal record).

4. To further explain the position:

   (a) The data used in the calculation of the information presented in Table 4 of the Decision Paper, including the calculation of the residual charge, is explained in Appendix A of the Decision Paper entitled "Modelling of indicative transmission charges".

   (b) The Authority publicly released the modelling underpinning that data at the link given in footnote 288 of the Decision Paper i.e. on the Github repository. The Github repository includes the code for the Authority's TPM impacts model.

   (c) An earlier Excel version of the model called '2019 Proposal impacts modelling', and an accompanying 'Residual charge options module', were originally released as part of the 2019 Issues Paper. The original Excel version of the model is still available via EMI, along with the data files used to generate the inputs to the model. Appendix H of the 2019 Issues Paper provides a description of the methods and assumptions used in this earlier calculation of the indicative residual charge.

(d) The Authority's treatment of each of the matters you have raised can be ascertained from the data that was made available and Nova is able to use and interrogate that data, just as parties could (and did) at the time of release of the 2019 Issues Paper.

(e) But, to further assist Nova in understanding what is available, the Authority comments further that:

(i) In relation to Nova's two questions around how the indicative residual charges were calculated:

The Authority used revenue forecasts provided by Transpower, along with its estimates of the other transmission charges provided for in the Guidelines, to calculate the total amount to be recovered via the residual charge. It then used data provided by the Reconciliation Manager (the GR010 data) to calculate participants' gross Anytime Maximum Demand (AMD) for each pricing year for the period 1 July 2014 to 30 June 2018. These were then averaged to generate an average annual gross AMD for each participant for that period and the indicative charges were allocated to each participant in proportion with that average annual gross AMD. For more detail on this process, please see paragraphs H.20 to H.28 of Appendix H to the 2019 Issues Paper.

In terms of the GR010 data, the Reconciliation Manager's Functional Specification (available on the Authority's website at https://www.ea.govt.nz/operations/market-operation-service-providers/reconciliation-manager/) sets out how this data is generated, including its treatment of embedded generation.

The raw data used to calculate the indicative residual charge for each participant can be found at Github/ElectricityAuthority/tpm-impacts-model/inputs/demand and Github/ElectricityAuthority/tpm-impacts-model/inputs/revenue.

(ii) In relation to specific customer calculations:

The final calculations used to produce the indicative residual charges in the Decision Paper were completed using the code from Github. The section of the code that calculates the indicative residual charges is available on Github titled 'calculate_residual_options.R'. By running through the calculation script, it is possible to see how participants' indicative residual charges were calculated, including the adjustments which were made after the Authority's consultation process. The output file which contains the results of all the indicative charge calculations, including the indicative residual charges, is also available on Github and is titled "indicative_charges.csv". Alternatively, individual participant calculations can be viewed in the Excel version of the model, which was released on EMI to accompany the 2019 Issues Paper (referred to at paragraph 4(c)) above. This Excel version does not contain the adjustments described in Appendix A to the 2020 Decision Paper; however, the underlying approach is the same as was taken in the later code.

(f) The Authority notes that, as set out in both the 2019 Issues Paper and the Decision Paper, the residual charges presented in those papers are indicative only, and are subject to:

(i) the limitations inherent in the data that has been used for the purpose of calculating the indicative charges, as described above; and

(ii) the precise formulation of a final TPM that is consistent with the 2020 guidelines.

Final charges would be calculated by Transpower in the event that a new TPM was incorporated into the Electricity Industry Participation Code 2010.

Please let us know if you wish to discuss this further.

Yours sincerely

Jenny Stevens / Laura Hardcastle
Partner / Senior Solicitor

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info@novaenergy.co.nz

20 October 2020

Laura Hardcastle
Bell Gully
WELLINGTON

Dear Laura

TRUSTPOWER v ELECTRICITY AUTHORITY AND NOVA (AN INTERESTED PARTY)

1 You will have seen that Nova, in its Memorandum for Wednesday's teleconference, states at paragraph 4.

> Nova, at this stage, does not seek discovery. There is a possibility it may need to seek some assistance from either the Authority or Transpower as to the calculation of the Residual Charge at particular sites relevant to it but this can probably be done without needing the intervention of the Court. However, it would be desirable to reserve leave for Nova to apply.

2 The 2020 Decision Paper in Table 4 at pp 103/104, sets out the Authority's estimate of the "2022 charges by $M, by customer".

3 This includes an estimate of the amount payable by way of the Residual Charge.

4 Can the Authority please advise how it derived the data used in the calculation of the residual charge.

5 Separately, can the Authority advise if it included an estimate for coincident embedded generation.

6 Can the Authority provide the specific calculations for each of:

- Eastland Network
- Horizon Energy
- Orion
- Top Energy
- Vector
- Wellington Electricity
- West Power
- Nova Energy
- Todd Generation Taranaki
- Whareroa Cogeneration Facility (located at Fonterra's Whareroa dairy factory site near Hawera, Taranaki)

7 We note that Trustpower and the Electricity Authority are in agreement that any application for discovery is required by 6 November 2020 if agreement is not reached by 30 October with other parties to apply by 13 November.

8 If necessary, Nova will apply formally for discovery of the information sought as above. However, it hopes that we can agree on a more informal process so long as Nova can then incorporate such of that information as it wishes into an affidavit.

9 Can you please advise by at least 30 October if the Authority is willing to voluntarily provide the requested information.

Yours sincerely

Liesbeth Koomen / Joycelyn Raffills

General Counsel / Special Counsel

IN THE HIGH COURT OF NEW ZEALAND
WELLINGTON REGISTRY **CIV-2020-485-367**
I TE KOTI MATUA O AOTEAROA
TE WHANGANUI-Ā-TARA ROHE

UNDER	the Judicial Review Procedure Act 2016
IN THE MATTER OF	Judicial review of the proposed new Transmission Pricing Methodology
BETWEEN	**TRUSTPOWER LIMITED** Applicant
AND	**ELECTRICITY AUTHORITY and MERIDIAN ENERGY LIMITED** Respondents
AND	**NOVA ENERGY LIMITED and others** Interested Parties
AND	**TRANSPOWER NEW ZEALAND LIMITED** Intervenor

REPLY AFFIDAVIT OF MAHADEVAN BAHIRATHAN ON BEHALF OF NOVA ENERGY LIMITED
9 July 2021

Solicitor:	Counsel:
Liesbeth Koomen	Ian Millard QC
Nova Energy Limited	Barrister
Level 15, the Todd Building	Thorndon Chambers
95 Customhouse Quay	P O Box 1530
Wellington	Wellington 6140
Telephone: 027 7343149	(04) 499 6040

I, **Mahadevan Bahirathan** of Wellington, Manager, say:

1 My name is Mahadevan Bahirathan (I am generally known as Babu Bahirathan).

2 I affirmed an affidavit on 23 April 2021. This affidavit is in reply to the affidavits filed on behalf of the Electricity Authority. Meridian also filed an affidavit, that of Mr Mellsop. He acknowledged that he had read my earlier affidavit and that of Charles Teichert on behalf of Nova but he does not record any disagreement with what we said.

3 In the case of the Electricity Authority, it is only Lana Maree Stockman in her affidavit of 9 June 2021 ("**Ms Stockman**") who comments on our affidavits (directly or by implication) in any detail. I will deal with those comments.

4 In light of the memorandum on behalf of the Electricity Authority of 11 June 2021 objecting to some of the evidence filed on behalf of Nova in part on the grounds that it is new evidence I will also explain how Nova was taken by surprise by the final decision. I will deal with that first.

Inclusion of a gross up for co-generation not signalled

5 As will be apparent from the evidence already filed on behalf of Nova, while Nova was not happy with the general thrust of the Benefit-Based Charge and the Residual Charge, it would have accepted these.

6 Its objection is the late inclusion, as part of the method of calculation of the Residual Charge, of what it, as a co-generator, supplies to the plant that was the very reason for its construction in the first place. This is even though such electricity is not transmitted by the grid, gets no benefit from the grid and imposes no burden on the grid.

7 This was NOT signalled by the Authority in the prior consultation documents.

8 The last major consultation round pre-decision was triggered by the "2019 Issues Paper – Transmission Pricing Review Consultation Paper", 23 July 2019.[1]

9 How the then proposed Residual Charge was to be calculated was set out in draft guidelines at page 95.[2] At least as they apply to Nova, these were significantly different to the final decision. I set out a comparison in an appendix to this affidavit.

10 Importantly, neither at Whareroa nor at Kapuni was Nova caught by even the primary provision, clause 40(a)(i)B.

11 Neither plant is a "distributed generator" nor is their generation indirectly connected to the grid through a designated transmission customer. It is directly connected.

12 Further, the 2019 draft guidelines allowed Transpower to come up with an alternative method of allocation should Transpower consider the alternative better meets the Authority's statutory objective. As set out by me in my earlier affidavit[3] it is the case for Nova that the final decision on this point results in a method of allocation that is diametrically opposite to the Authority's statutory objective. What was in the draft guidelines was consistent with how we thought we should be charged. That is, we thought that the Authority had recognised the position of co-generators and had excluded them from the gross up.

13 The indicative impact on each customer of what was proposed in 2019 is set out in Table 12 of the 23 July 2019 Issues Paper.[4] Unsurprisingly, Nova (i.e., at Kapuni) and Whareroa Cogen Ltd (i.e., at Whareroa) are there listed as generators rather than distributors. Their respective Residual Charges were shown as $0.2m and $0.4m. We looked at those figures. Although they would be a significant new impost on the business, the business could tolerate that amount of charge. They were consistent with our

[1] EA record 235.16259 **[CB]**.
[2] EA record 235.16259 at page 95 **[CB]**.
[3] Bahirathan affidavit at paras 151–155. Incidentally, the Authority also seeks to exclude this evidence.
[4] EA record 235.16259 at pages 61–62 **[CB]**.

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interpretation of the draft rule in that they did not allow for grossing up for our dedicated load.

14 Nor is it apparent that such electricity demand was provided for in the financial modelling included in the CBA Technical Paper of 23 July 2019.[5]

15 Had the true position been disclosed we would have looked much more closely at the figures and have made more comprehensive submissions challenging the logic and providing supporting information as to the significant adverse impact of the proposal.

16 Reinforcing the impression that Nova's co-generation was not caught by what was proposed is Table 2 on page 14 which says:

> "Transpower's load customers (including generators to the extent that they are also load customers) would pay the residual charge".[6]

Nova is a generator, but is not a load customer of Transpower in relation to the electricity supplies to the facility it was built to serve – Fonterra at Whareroa, and Edgecumbe, and the Kapuni gas treatment plant and related uses there. But it is now being charged way beyond the extent to which it is also a load customer.

17 A Supplementary Consultation paper was published on 11 February 2020, submissions closing on 3 March 2020.[7] That did refer to the Residual Charge but only dealt with the method for updating the basic allocation data. Even at this stage it did not signal the changes that were to catch and penalise Nova.

18 Nor did the April 2020 "Response to feedback on the 2019 cost benefit analysis".[8]

19 It, therefore, came as a surprise that the primary formula had been changed to capture co-generation, made worse by the removal of the possibility of

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[5] EA record 236.16565 **[CB]**.
[6] EA record 235.16259 at page 14 **[CB]**.
[7] EA record 240.18644 **[CB]**.
[8] EA record 241.18883 **[CB]**.

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Transpower coming up with another methodology that actually complied with the Authority's statutory objectives.

20 Ms Stockman at paragraph 11.13 refers to papers presented to the Board at its respective meetings of 3 October 2018 and 9 May 2019.[9] Neither papers were made available to Nova until this litigation began.

21 Ms Stockman appears to place reliance on the staff view in the paper for the May 2019 meeting that :

> Staff have now estimated the differences in charges between the net and gross load approaches, and saw no evidence to support the view that it would be material enough to alter a decision by a load customer to exit one way or the other (particularly in the early years while the price cap is in effect).[10]

22 Nova was not consulted on this at all and was unaware of this conclusion until after this litigation began. Assuming the figures the staff were looking at were the same as in the 2019 Issues Paper, as already explained, it is obvious the Authority has made significant and material errors in calculating the financial impact on Nova and Whareroa Co-generation. Further, as explained below, the Price Cap is of no or little benefit.

23 Most of the evidence being objected to seeks to address this issue.

Details of Embedded Generation

24 The details of embedded generation in the objection to paragraph 63 of Charles Teichert's affidavit are on the Authority's website.[11]

Ms Stockman Affidavit

25 Ms Stockman's affidavit para 8.9 says that the Authority's board considered the principles it developed to be consistent with:

> how things were done in workably competitive markets (which are considered to be reasonably efficient) and looked to set up principles as to how this would apply to transmission pricing.[12]

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[9] Stockman affidavit at para 11.13.
[10] Stockman affidavit at para 11.13(b)(i).
[11] Teichert affidavit at para 63;
see https://www.emi.ea.govt.nz/Wholesale/Datasets/Generation/Generation_fleet/Existing .
[12] Stockman affidavit at para 8.9.

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In a workably competitive market there is no way a supplier would be able to charge a customer for a service it never delivers. This is what the gross demand approach to co-generation plants attempts to do/achieve.

26 At para 11.5 Ms Stockman says that the Residual Charge may be reduced if Transpower exercises the discretion given to them under Additional Component E to include in the Benefit-Based Charges some additional historic investments.[13] This is over and above the seven such investments already included by the Authority.

27 While that may be desirable, I doubt if it will happen to any significant extent. Transpower, for a long period up to the early 2000s, did very little by way of upgrades to the grid. It was concerned that its assets could become stranded by new generation. I believe that the Authority has considered all significant investment upgrades made since then with a view to including them in the Benefit-Based Charge. I note that at para 11.4 Ms Stockman states that:

> In relation to some large, recent historical investments for which we had thought costs might be recovered via the benefit-based charge, the estimated benefit of those investments did not exceed the costs and therefore we included them in the residual charge.[14]

The Authority consulted on which historic investments should be included and which should not.

28 For the Additional Component E to be used, Transpower would have to come to a different conclusion to that of the Authority as to the cost benefit and also do that notwithstanding the consultation that has occurred.

29 There is a table at paragraph A.34 (page 125) of the 2020 Decision Paper setting out the estimates of year 1 Benefit-Based Charges for the historic assets.[15] That shows at least some of the investments that were considered but rejected. If they were reintroduced the reduction in the Residual Charge would not be significant especially after allowance for additional depreciation in the meantime.

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[13] Stockman affidavit at para 11.5.
[14] Stockman affidavit at para 11.4.
[15] EA record 241.19119 at para A.34.

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30 At para 11.6 Ms Stockman concludes that they decided that the Residual Charge should only apply to the load and not the generator.[16] But their final outcome, as far as Nova's co-generation is concerned, does exactly the opposite. It seeks to impose a Residual Charge on the connected customer based on a non-Transpower customer's demand that is not delivered by the grid. Therefore, the co-generation business (the generator) is now forced to pass on the increased charges to its customer. This is inefficient as Ms Stockman says.

31 In para 11.7 Ms Stockman says "residual charge was not intended to influence grid use and investment".[17] But it should at least be linked to grid use, even if only historic use, and should take into account historic investment made in reliance on the then charging regime.

32 Then in para 11.10 (b) Ms Stockman says:

> a gross load approach essentially measures the load customer's total electricity consumption during the relevant period (such that it makes no difference whether the electricity is supplied by distributed generator or via the grid).[18]

The charge is on Nova as the connected party or "load customer" but it is the supplier and not the user of the electricity. Gross load does not reflect its consumption of electricity from the grid. Nor can its dedicated load take the equivalent electricity from the grid because its demand for electricity is intimately linked to its demand for steam which the grid cannot supply.

33 In para 11.11 Ms Stockman states:

> the intention is to levy the charge *on the load customer* in such a way that the presence or absence of distributed generation makes no difference to the measure of demand.[19]

To the extent she uses this to justify including co-generation loads this shows a fundamental misunderstanding. The absence of generation at our co-generation plants means that the demand is affected. A lack of generation means no steam. No steam means no production at the dairy

[16] Stockman affidavit at para 11.6.
[17] Stockman Affidavit at para 11.7.
[18] Stockman Affidavit at para 11.10(b).
[19] Stockman Affidavit at para 11.11.

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factory or gas treatment plant etc., so electricity demand largely disappears.

34 The trading rules that apply to generators offering their generation to the wholesale electricity market already recognise that co-generation plants like those that Nova operates are different to all other forms of generators. There are specific rules for Type-B co-generator under the Code. These clearly recognise the co-generation's output and the downstream customer demand are intrinsically linked and interdependent. Unfortunately, the Authority has failed to appreciate that difference when it comes to the Residual Charge.

35 The lack of initial response by Nova when gross load was first raised in the 2016 Second Issues Paper (but only as one of 3 possibilities), as referred to at para 11.12 of Ms Stockman's affidavit, has been covered by Charles Teichert at para 16 of his affidavit.[20] Nova certainly submitted against it thereafter with an extensive submission in relation to co-generation in its response of 24 February 2017.[21] Obviously, as gross load was just 1 of 3 options, no indicative charges were shown in the initial Second Issues Paper.

36 From the discussion at para 11.13 of Ms Stockman's affidavit,[22] it appears that the Authority was focussed on direct connect industrial load customers. Nova's co-generation assets are not direct-connect load customers. I have already commented on the problem in para 11.13(b)(i) [23]– see paras 32 and 33 above.

37 At para 11.16 Ms Stockman states:

> Overall, however, it [the Authority] thought that the Authority's proposal as a whole more accurately reflected the cost of delivered energy to end consumers over time.[24]

38 However nowhere in her affidavit or in the decision of the Authority is there any recognition that co-generation plants have to bear the cost of

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[20] Stockman affidavit at para 11.12; Teichert affidavit at para 16.
[21] EA record 233.15139 **[CB]**.
[22] Stockman affidavit at para 11.13.
[23] Stockman affidavit at para 11.13(b)(i).
[24] Stockman affidavit at para 11.16.

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getting the fuel (gas) to the site of the co-generation plant. This, of course, is part of the cost of delivered energy to Fonterra and the Kapuni gas treatment plant etc. A distinctive feature of co-generation is that it has to co-locate near the load rather than near any particular source of energy used to generate the electricity. Other generators do not bear the same level of costs in getting the fuel they use to their generation plant.

39 For the avoidance of doubt, I should say in relation to the reference to Nova's submissions in that para 11.16,[25] Nova was working on the basis that the gross up did not apply to it. This was for the reasons already set out. Nova's submission responded to what was then in front of it and, in doing that, tried to be constructive. The Authority published a definition and numbers consistent with that definition and Nova responded appropriately. It now transpires that the Authority used the incorrect numbers for Nova and had a different intention to what it stated and to what Nova had understood.

40 At para 11.17 Ms Stockman continues to fail to see the difference between co-generation and embedded generation generally and, in particular, if the co-generation is not running and producing steam then the load supplied by the co-generation largely disappears.[26] Then, when looking at the alleged advantages of co-generation, there is no allowance for the cost of delivering the fuel to the co-generation site. As to the reduced Benefit-Based Charge no other type of generator suffers a higher Residual Charge because it has a lower Benefit-Based Charge.

41 In relation to para 11.18,[27] the imposition of a charge on co-generation for a service it never uses, which charge is not imposed on other generators, and which reduces the charges of others who do use the service, imposes a penalty on co-generation vis a vis other generators and thereby distorts the competitive process.

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[25] Stockman affidavit at para 11.16.
[26] Stockman affidavit at para 11.17.
[27] Stockman affidavit at para 11.18.

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42 Further, the apparent mischief the Authority appears to be obsessed with is only a potential future issue, but the remedy they use applies equally to existing arrangements entered into in good faith and for good commercial reasons unconnected with the potential problem identified by the Authority. Even if load customers were encouraged to connect behind generators and this was inefficient, all such customers who would then move would have demand that is truly independent of generation. That is, their demand will exist even if the generation is off. Our customer's demand doesn't exist when the co-generation is not on. For the demand that is truly independent, we are prepared to be charged – which is the 4-5MW we take from the grid during the ten days p.a. the plant is shut.

43 At para 11.19 Ms Stockman suggests that the cap could mitigate the outcome.[28] The relevant formulae for the cap are set out in clause 50 of the 2020 Guidelines. There are two different caps. The first is for a "distributor" and the second is for a "direct consumer". Nova is neither so, at least as it currently stands, cannot access the cap. Ms Stockman appears to partially recognise that at the end of that para 11.19 by saying that:

> In practice, if a customer is connected through another (e.g., a distributor), it would be the connected customer who had access to the cap (and would need to determine/negotiate how to apportion costs).[29]

44 But that customer in Nova's co-generation plants is not a direct consumer so does not have access to the cap. Further, if that customer has an existing contract with the co-generation plant giving it long term price stability for delivered electricity, it does not wear the price increase. The co-generator does.

45 Given that the Authority used the wrong numbers for Nova and its co-generation plants it cannot have accurately modelled whether or not the cap did limit the increase in transmission charges to co-generation. Ms Stockman's comments are just hopeful speculation on the part of the Authority.

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[28] Stockman affidavit at para 11.19.
[29] Stockman affidavit at para 11.19.

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46 In fact, even if the co-generation plant can access the cap it provides little or no protection to it:

a) Although the cap is, at least initially, 3.5%, it is increased by inflation from the 2019/20 pricing year. As the new regime will only apply from 2023/24 pricing year, there has to be added to it four years of inflation. With inflation at around 2% p.a. the cap is increased by about 8.2% to 11.7% total by the beginning of the new regime.

b) For all caps, the cap limits the increase in interconnection charges by reference to the total energy cost. Currently interconnection charges only make up around 10% of the average consumer's total delivered energy cost.[30] The cap of 3.5% on the delivered energy cost therefore equates to an increase of 35% on the interconnection charges (before accounting for inflation). And with 2% p.a. inflation, the cap becomes 117% – a very large increase.

c) As a matter of definition, the co-generation plant would only access the direct-connect consumer cap. The basic cap of 3.5% cap increases in steps of 2% each year after the first year of the new regime i.e., to 5.5% for the 2025/26 pricing year before the further impact of inflation.

47 The following calculations show how ineffective the cap is for Nova. I use the example of Whareroa:

a) Whareroa consumes ~150GWh of electricity per annum (note, only about 1 to 2GWh is ever supplied from the transmission grid);

b) the current connection charge is ~$300,000 p.a., and interconnection charge zero (the limited demand that does occur has not been coincident with regional peak demand);

[30] The Authority has a website which shows how the average consumer's electricity bill is made up - <https://www.ea.govt.nz/consumers/my-electricity-bill/>. That shows that transmission comprises 10.5% of the bill and GST 13%. The cap is calculated net of GST. Looking at the cost net of GST transmission rises to 12%. However, that includes connection charges which are excluded from the application of the cap. Based on the figures in Table 3-1 in the report of Jason Man for the Authority, connection charges in 2020/21 pricing year were $114m out of a total of $786m in transmission charges or 14.5% meaning interconnection charges are 85.5% of the total transmission charges and 10.2% of the total bill net of GST (12*.0.855).

c) assuming an average electricity price of \$80/MWh,[31] total delivered cost to the customer could be estimated to be ~\$80 x 150,000 + \$300,000 = \$12.3m p.a.;

d) therefore, the interconnection transmission charge must increase by more than \$430,500 before the cap applies even before adjustment for inflation;

e) given the TPM commences in 2023/24, allowing for ~2% inflation from the base year of 2019/20, the cap increases to \$1.4m in 2023, i.e. the cap is expected to have little impact at Whareroa in year one of the new TPM, and no effect thereafter.

48 Ms Stockman addresses the changing approach of the Authority to batteries at paras 12.19 to 12.22.[32] It appears this more detailed consideration has been spurred by the possibility of a grid connected battery being built in the upper North Island to participate in offering reserves as well as energy trading. The Authority appears to be thinking that batteries are generators. She states:

> If batteries incurred a residual charge, there was an argument that this could affect the competitive neutrality between them and other generators.[33]

The imposition of the Residual Charge on co-generation does exactly that.

49 At para 12.22 Ms Stockman states:

> It seems to me that there may be a difference between batteries, which do not actually consume the electricity they take from the grid, and load supplied by co-generation where the electricity is actually consumed.[34]

Not a kWh of the electricity supplied by the co-generation plant to the connected demand comes from the grid, but Ms Stockman is happy to charge for it anyway, but not charge for the battery that actually takes energy from the grid. Moreover, batteries are not 100% efficient but more

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[31] The unweighted average wholesale electricity price for the 5 years to and including the 2019/20 pricing year was \$89/MWh. To get a weighted average requires detailed work across each half hour. Using \$80/MWh will be conservative.
[32] Stockman affidavit at paras 12.19–12.22.
[33] Stockman affidavit at para 12.20.
[34] Stockman affidavit at para 12.22.

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like 70-90% depending on the technology being deployed.[35] There is therefore a net usage by them of electricity supplied from the grid.

50 Ms Stockman, in her affidavit para 12.48, dismisses my calculations as being incorrect by stating the Authority's figures exclude connection charges.[36] My calculations were outlined in my original affidavit in a footnote 3 in para 83.[37] I stand by my statement that the Authority has assumed a ~20% reduction in the equivalent charges between 2019/20 and the 2022 year. For completeness, my statement is made on the basis the interconnection plus HVDC revenues in 2019/2020 year of ~$797m (interconnection charges $652.22m plus HVDC charge of $144.87m as per document BB3 of my first affidavit)[38] will reduce to ~$636.8m in 2022 as per para 16.14 of the Authority's decision.[39] Both those figures exclude connection charges.

51 In relation to para 12.49 of Ms Stockman the numbers were consistent with the definition the Authority was using, which did not include co-generation in the grossing up.[40]

52 In relation to para 12.50 the removal of the ACOT payments was outside the new Transmission Pricing Methodology.[41] This was a decision made by the Authority in December 2016.

Affirmed at Wellington)
this 9th day of July 2021)
before me:)

Mahadevan Bahirathan

A Solicitor of the High Court of New Zealand

Matthew John Dicken
Solicitor
Wellington

[35] There are a wide range of emerging and existing technologies, each with different advantages and disadvantages.
[36] Stockman affidavit at para 12.48.
[37] Bahirathan affidavit at para 83.
[38] Bahirathan affidavit at [BB3].
[39] EA record 241.19119 **[CB]**.
[40] Stockman affidavit at para 12.49.
[41] Stockman affidavit at para 12.50.

Appendix A

Draft Guidelines

Main component 3: residual charge

	2019 Issue Paper, 23 July 2019		2020 Guidelines, 20 June 2020
39.	The **TPM** must provide for a **residual charge** to apply to all designated transmission customers to the extent that they are load to recover any remaining **forecast MAR** not recovered through other **transmission charges**.	27.	The **TPM** must provide for a **residual charge** to apply to all designated transmission customers, to the extent that they are **load customers**, to allow Transpower to recover any remaining **recoverable revenue** not recovered through other **transmission charges**.
40.	The **TPM** must provide for the **residual charge** to be allocated: (a) In proportion to each designated transmission customer's historical anytime maximum demand, which is to be calculated using data supplied by the reconciliation manager and by: (i) taking, in a **pricing year**, the highest value for any trading period which represents the sum of: A. the highest net quantity of electricity flow from the grid at the designated transmission customer's grid exit point; and B. Transpower's estimate of any concurrent generation by distributed generators or behind-the-meter generation that is indirectly connected to the grid through the designated transmission customer; and (ii) taking the average of that value over at least two years ending prior to either 1 July 2019 or the date 10 years prior to the date on which the **residual charge** is to be assessed, whichever is the later; or (b) By an alternative method of allocating the charge to designated transmission customers to the extent that they are load, should Transpower consider that the alternative method would better meet the Authority's statutory objective than the method set out in paragraph (a) above.	28.	The **TPM** must provide for the **residual charge** to be initially allocated in proportion to each designated transmission customer's historical anytime maximum demand, which may be calculated using data supplied by the reconciliation manager, and is to be calculated by: a. taking, in a year from 1 July to 30 June, the customer's anytime maximum demand for that year, which is calculated by: i. for each one of the customer's points of connection, taking the highest value in any trading period in that year of gross load, being the sum of: 1. the net quantity of electricity flow from the grid at that point of connection; and 2. Transpower's reasonable estimate of concurrent generation behind the designated transmission customer's point of connection; and ii. aggregating each of those sums across all the customer's points of connection; b. taking the average of the customer's anytime maximum demand over the four years from 1 July 2014 to 30 June 2018.
41.	The **TPM** must provide that, in initially allocating the **residual charge** under clause 40, Transpower may adjust the allocation where necessary to accommodate circumstances in which a designated transmission customer has experienced a substantial change in demand due to factors beyond their control or influence. For the purposes of this clause, a substantial change in demand is to be assessed relative to the designated transmission customer's remaining demand.	29.	The **TPM** must provide that, in initially allocating the **residual charge** under clause 28, Transpower may adjust the allocation where necessary to accommodate circumstances in which, in Transpower's reasonable opinion, a designated transmission customer has experienced a substantial reduction in anytime maximum demand, due to factors that are largely beyond the customer's control or

influence. For the purposes of this clause, a substantial reduction in demand is to be assessed relative to the designated transmission customer's remaining demand.

30. The **TPM** must provide that for each **pricing year**, from and including the **pricing year** commencing on 1 April 2023, the **residual charge** is to be allocated in proportion to each designated transmission customer's adjusted historical anytime maximum demand, calculated as:

$$AHAMD_t = HAMD_0 \times U_t / U_0$$

Where:

$AHAMD_t$ is the designated transmission customer's adjusted historical anytime maximum demand

$HAMD_0$ is the designated transmission customer's historical anytime maximum demand calculated as described in clauses 28 and 29

U_t is the designated transmission customer's average total **gross** annual energy usage (measured in MWh) across the year commencing on 1 July four years and nine months prior to the start of the **pricing year** in which the adjustment applies and the three preceding years commencing on 1 July

U_0 is the designated transmission customer's average total **gross** annual energy usage (measured in MWh) across the four years on 1 July 2014 to 30 June 2018, reduced as necessary to be consistent with the reduction in anytime maximum demand under clause 29.