Transmission pricing

Regional Workshops

19 August - 2 September 2019

COMPETITION • RELIABILITY • EFFICIENCY

Agenda

1 Introduction
Problems with the current TPM
Proposals and reasons
Long term benefits for consumers
2 Possible topics for discussion / Q&As
Topic: Using nodal prices to signal cost of grid use and distribution pricing
Topic: allocators for remaining cost of 7 historical grid investments
Topic: the residual charge
Topic: application of the price cap
Case study: explaining indicative charges for Upper North Island
Case study: entry or exit of participants
3 Final questions and next steps

Problems

with the current

Transmission Pricing Methodology

TPM reform is necessary and increasingly urgent

- Consistent and long term pressure for TPM reform - no single option will deliver a consensus.
- If we don’t act now, consumers get less benefit from the electricity system, and pay more for it, in the long-run.
- Consultation underway - feedback and suggestions for improvements are welcome

Getting ahead of future challenges and opportunities

Electrification and lowering emission

A large amount of investment in renewable energy and a potential doubling of electricity demand by 2050. (Te Mauro Hiko – Energy Futures)

Efficient transmission pricing can support this transition at least cost

Rapid-changing technology

New and increasingly affordable technologies will give consumers far greater choice about how to engage with electricity markets

Efficient transmission pricing can ensure investments in micro-grids, batteries, solar and EVs are made for the right reasons, not to avoid and shift distorted transmission charges

Key issues with the current pricing methodology

Around 70% of Transpower's revenue is recovered through a peak demand charge (RCPD). This charge is concentrated on 100 of the 17,520 trading periods in a year.

This is a very strong – and volatile – signal that unnecessarily:

- discourages electricity use at peak times when it is valued most
- encourages investments to avoid the charge and shift it to others

Majority of costs of an investment spread over all customers (postage stamp) – makes grid investments appear artificially cheap to the customer who benefits

Around 15% of Transpower's revenue is recovered through a charge on South Island generators (HVDC), creating a North Island generation investment bias.

Proposals,

reasons, and

the long term benefits to consumers

TRANSMISSION PRICING GUIDELINE PROPOSALS

Charge	Comment
Connection charge	Retain. Market-like. Close loophole
	Nodal prices to signal marginal cost, and/or a transitional demand control charge (possibly)
Benefit-based charge	Benefit-based charge for generation and load customers, to recover asset cost over economic life Apply to new and some existing investments
Residual charge	Balance of Transpower’s recoverable revenue Includes overheads and common costs that cannot be attributed Charge to transmission customers based on measure of size/capacity, without distorting use or investment
Prudent discount	Expand to address off-grid bypass risk

Major changes from 2016 proposal

- More discretion for Transpower in implementation (practicality v precision)
- High-value investment definition raised from $5m to $20m
- Authority's Guidelines set specific allocators for the seven (down from 10) pre-2019 'historic' investments. Transpower will not have to do this
- Peak charge as a non-mandatory component, and transitional only
- Asset valuation, cost profile, benefit definition aligned with Commerce Commission
- An even simpler method for benefit-based allocation for low-value investment
- Provides for adjustment of charges (eg if a large party exits or enters)
- Specific guidance on data and formulas to use in calculating the price cap.

Significant long-term benefits for consumers

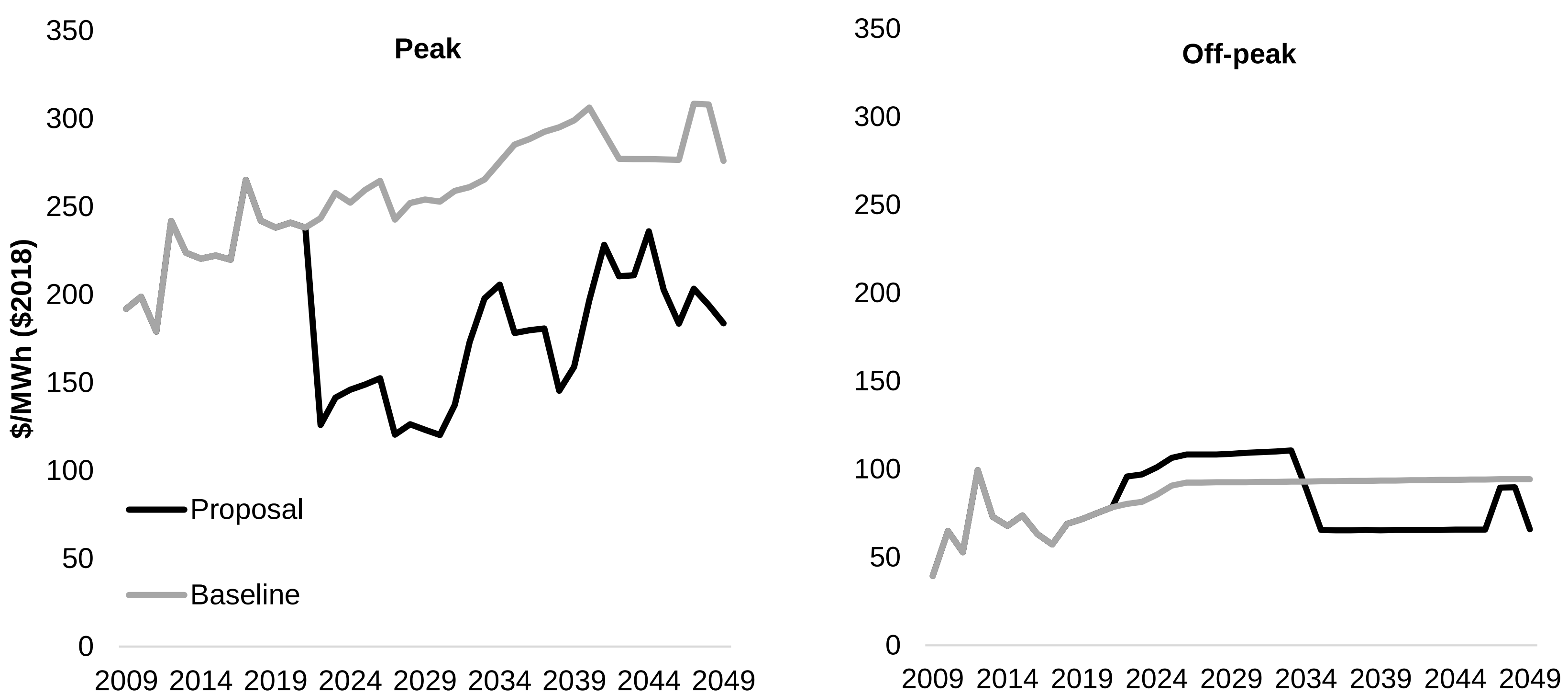
Proposal would deliver a net benefit of over $2.7b:

- $2.36b: grid use efficiencies (net off increased costs)
- $200m: investment efficiencies (batteries)
- $145m: investment efficiencies
  - signals to generation and large load, scrutiny of transmission proposals, certainty

Quantified range: $0.2b – $6.4b

Some benefits not quantified, eg mass-market battery investment

Key driver of grid use benefits



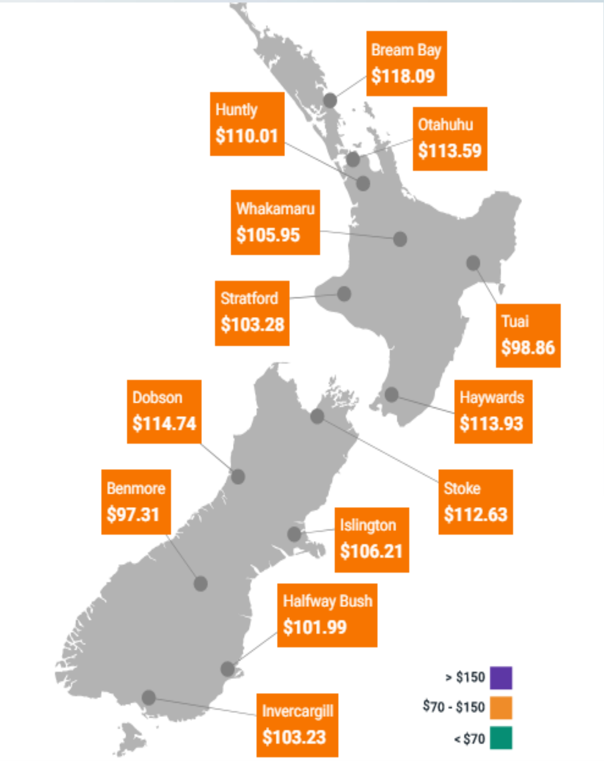
Topics

Using nodal prices to signal economic cost of grid use
Fit with distribution pricing
Allocators for remaining cost of 7 historic investments
Residual charge
Price cap
Case study: explaining indicative charges for Upper North Island
Case study: entry or exit of participants
Final questions and next steps

Signalling economic cost of grid use

Advantages of nodal prices to signal cost of grid use

- Established system
- Targeted to where congestion emerges
- Price rises at time there is congestion
- Only as long as there is congestion
- Variety of participants can respond to price signal
- Market based signal of cost of congestion (or how consumers value grid investment)



"*A trading arrangement based on [locational marginal pricing] takes all relevant generation and transmission costs appropriately into account and hence supports optimal investments.*" **International Energy Agency**

A transitional peak charge to manage uncertainty

Near term uncertainty: what is distributors' reaction to removal of RCPD?

- Transpower's '*Role of peak pricing for transmission*' report
- Could bid load control into market eg. reserves, or to retailer/aggregator

Uncertainty will reduce over time as demand becomes more responsive:

- emerging technology and business models
- real-time pricing stimulates more efficient demand response

Features of transitional peak charge

Additional component

Application to be limited:

- only where otherwise congested
- phased out gradually

Transpower would have some flexibility to:

- alter level of charge
- extend phase-out period / re-introduce later

Could result in ACOT payments:

- cost-reflective charge (cf: kvar charge)

Benefit-based charge

Allocation based on benefit

Benefit-based charge:

- allocation: positive net private benefits
- measure of demand net of distributed generation (in most circumstances)

For future grid investments, Transpower to determine method:

- "electricity market benefits"
- standard method – for high-value investments
- Simple method – for low-value investments

Reason for a benefit-based charge

Efficient cost allocation:

- customers that benefit from an investment pay for it
- similar to approach for connection assets
- removes cross-subsidies
- supports Transpower and Commerce Commission in identifying investments

Residual charge

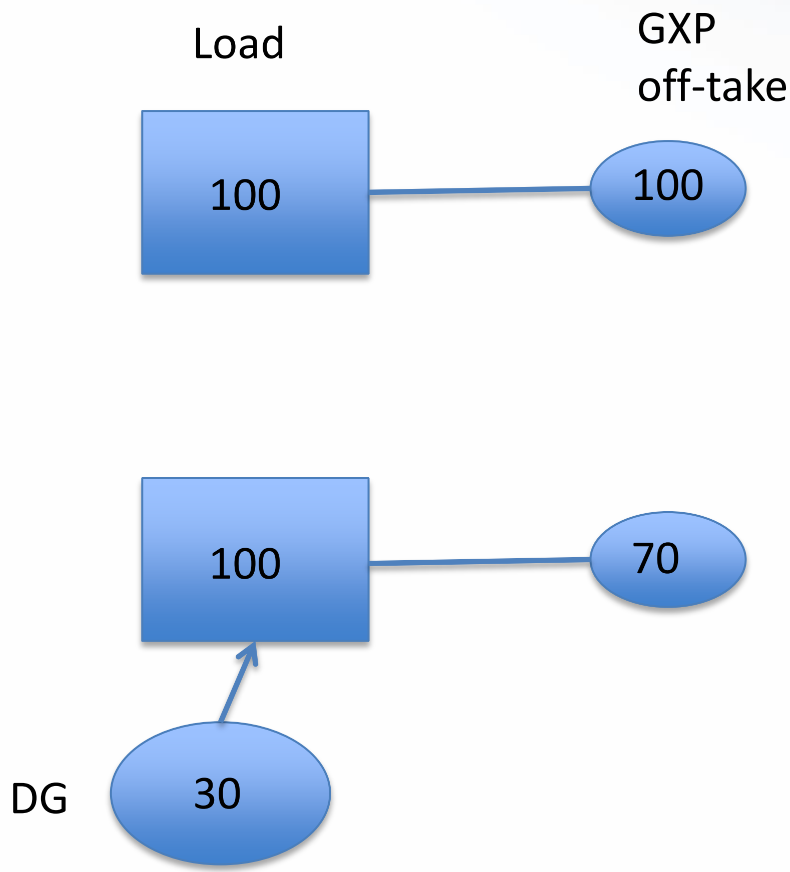
Residual charge for unallocated transmission costs

- A residual charge for costs not directly attributable to investments
- At the start, includes bulk of historical investments
- No price signal
- Designed to:
  - be hard to avoid
  - least distort use and investment
  - reduce administrative burden

Calculating the residual charge

- Allocated in proportion to historical anytime maximum demand (AMD)
- Gross measure proposed
- Applies to load customers only
- Shares based on average AMD over:
  - at least two years prior to July 2019
  - or at least 10 years prior to date assessed
- Indicative charges: average of four years

Measuring demand under net vs gross approach



Net	Gross
100	100
70	100

Fit with distribution pricing

Fit with distribution pricing

Same principles: signal economic cost, recover remaining cost in least-distorting way

Application different:

- principles-based vs setting guidelines to be followed
- no wholesale nodal prices to signal economic cost of local lines use.

Implications:

- reflect fixed-like transmission charges in distribution tariffs
- distribution pricing can reflect own cost drivers and capacity issues.

Proposed cost recovery for historic grid investments

The trouble with a future-only benefit-based charge

Proposal: benefit based charge for remaining costs of some historical investments:

- ensures consumers in some regions do not end up paying twice - once for grid investments built for their benefit, and also for those they never benefited from.

We consider this makes proposal more durable. Future-only might not be enduring:

- New switching station and transmission line into Islington: $283 million
- Christchurch consumers would pay most of that through benefit-based charge
- If current cost allocation remained for historical investments, Christchurch consumers would also continue to pay 9 percent of the costs of (for example) the $876 million North Island Grid Upgrade

Durability important to achieve efficiency benefits, and eliminate uncertainty.

Recent major investments largely in upper North Island

Customers have:

- paid for investments they or their customers don't benefit from significantly
- not fully paid for investments they or their customers benefit from

Region	Post-2004 investment*	Impact on Transpower revenue requirement	Actual increase in interconnection charges from 2008/9 to 2015/16	Actual tariff increase as a % of impact on revenue requirement
UNI	$1,342m	$201m	$87m	43%
LNI	$237m	$36m	$80m	225%
USI	$77m	$12m	$40m	343%
LSI	$81m	$12m	$40m	327%

*does not include HVDC or connection investment

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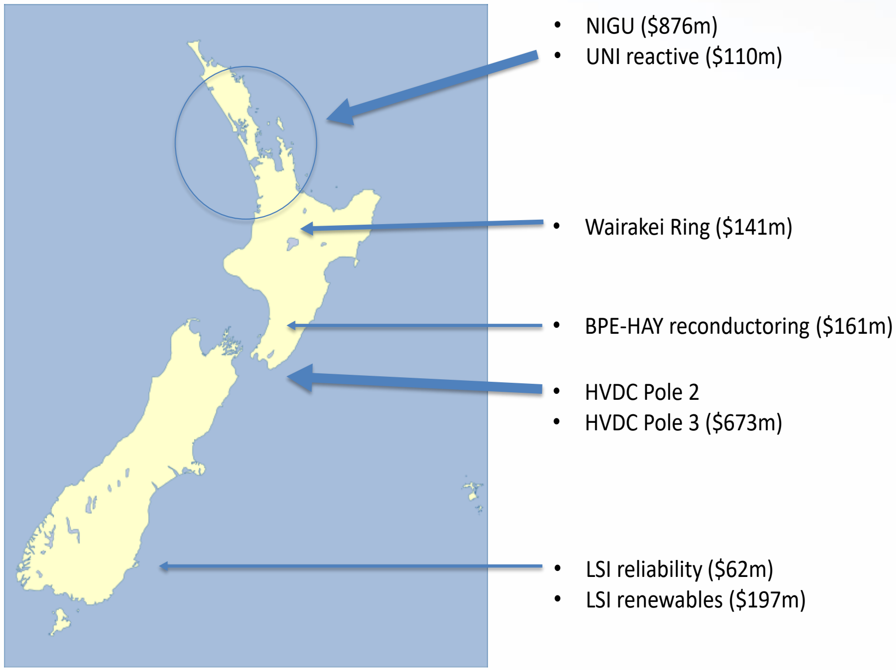
Benefit-based charge for seven historical investments



These investments:

- were approved after May 2004 (other than HVDC Pole 2, which is older)
- had an approved value over $50 million at the time the investment was approved
- have estimated benefits exceeding their cost.

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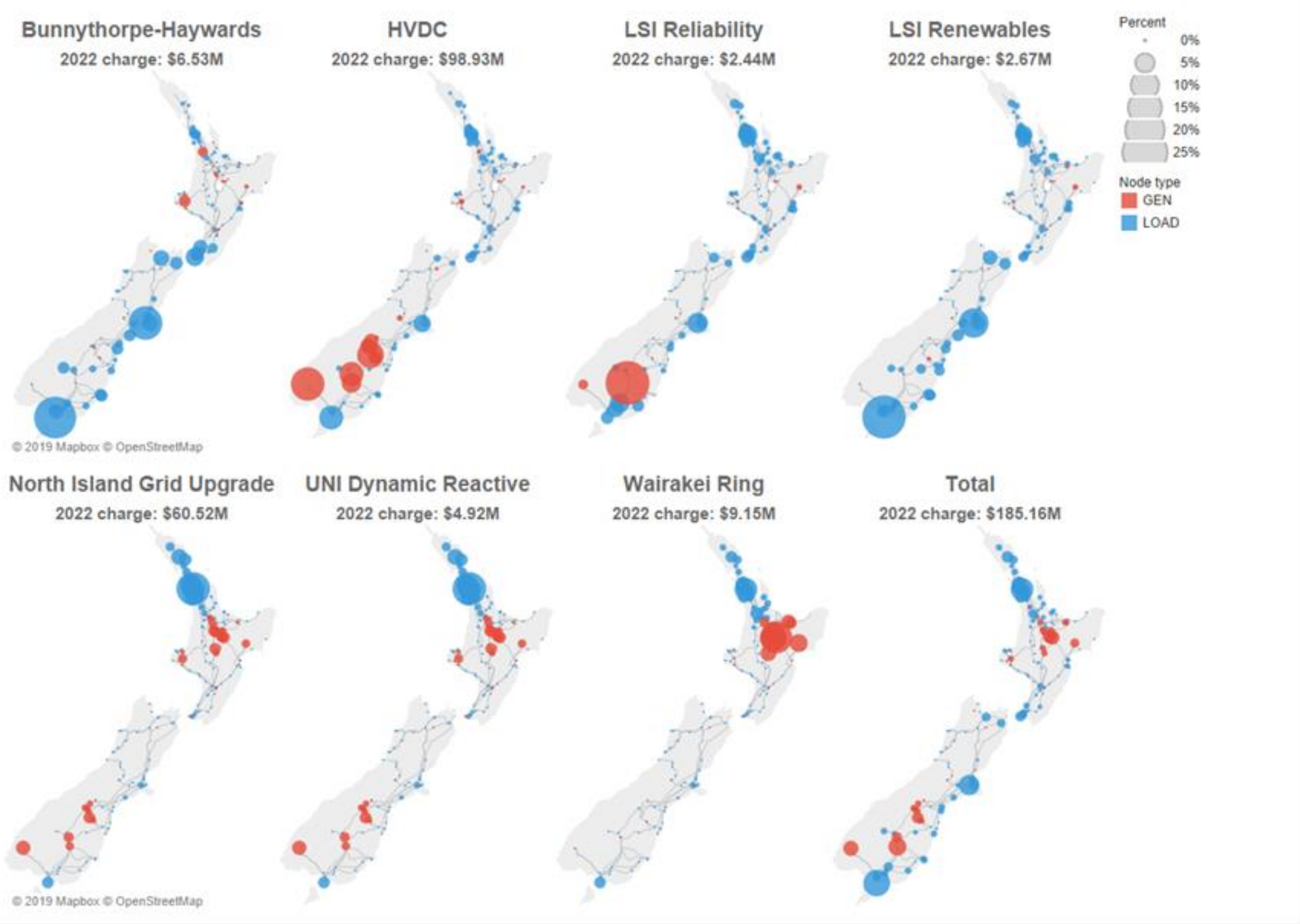


We used vSPD to estimate who benefits from each of seven recent major investments

Proposed indicative charges

Indicative charges

Detail covered in technical workshop: Wellington 10 September

High level:

- benefit-based charge: $185m – the seven historical investments
- remaining $494m allocated via residual charge
- status quo charges are based on latest available (19/20) and scaled
- estimated status quo charges may be atypical for some

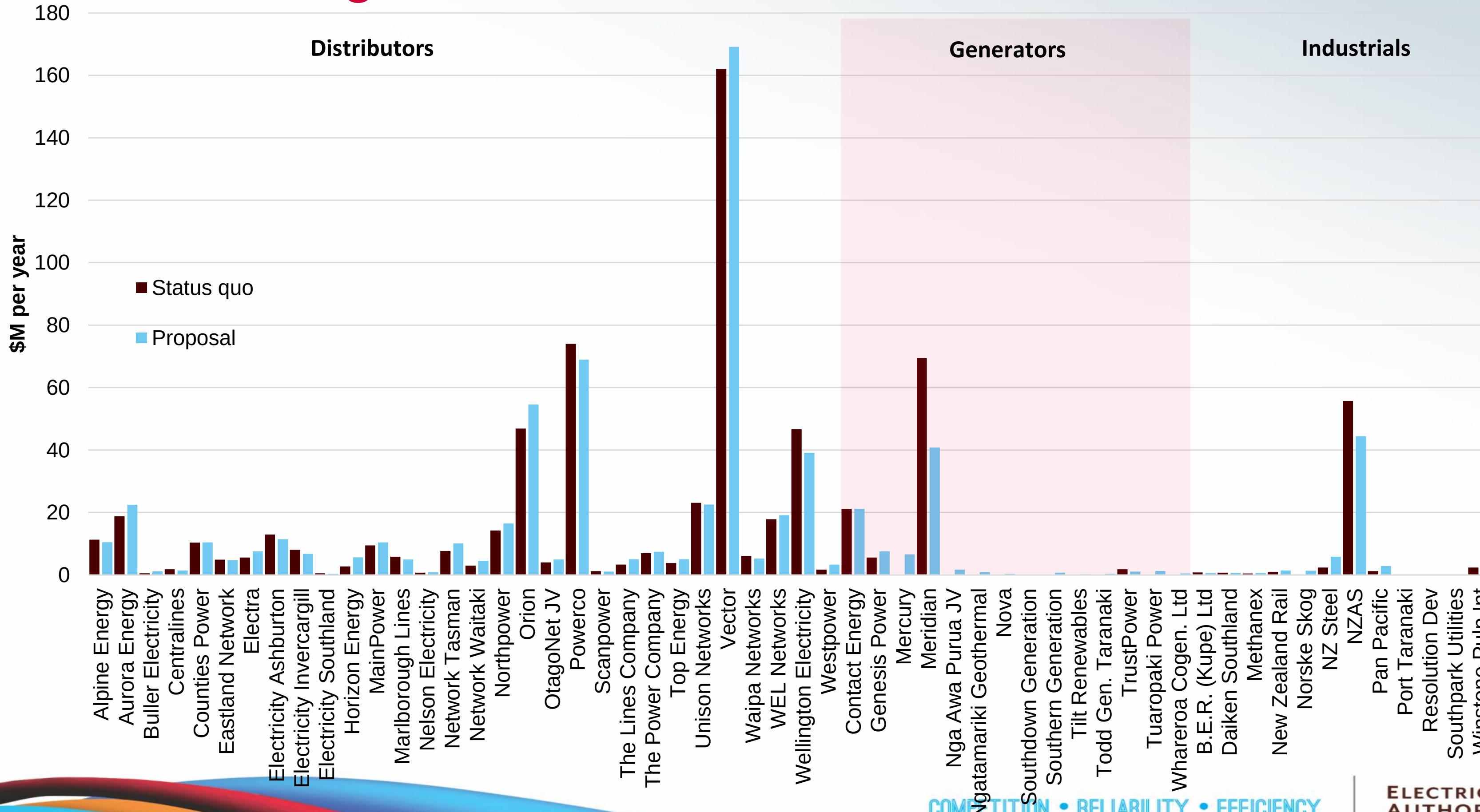
Indicative charges at implementation

TPM Revenue Draft determination 21/22	$848m
Less connection charge	-$111m
Less PDP	-$3m
Less LCE revenues	-$55m
Recover via benefit-based and residual charge	**$679m**

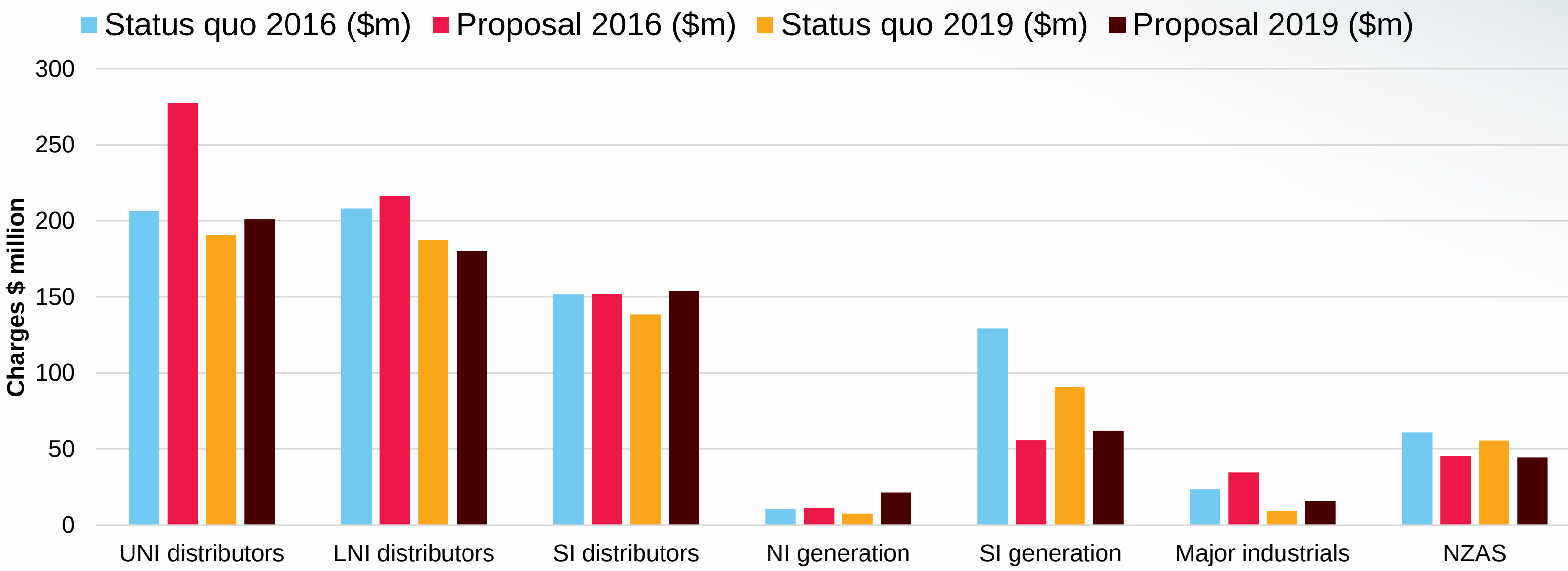
Status quo charges: based on latest available (19/20)

- scaled down: 21/22
- atypical for some customers

Indicative charges

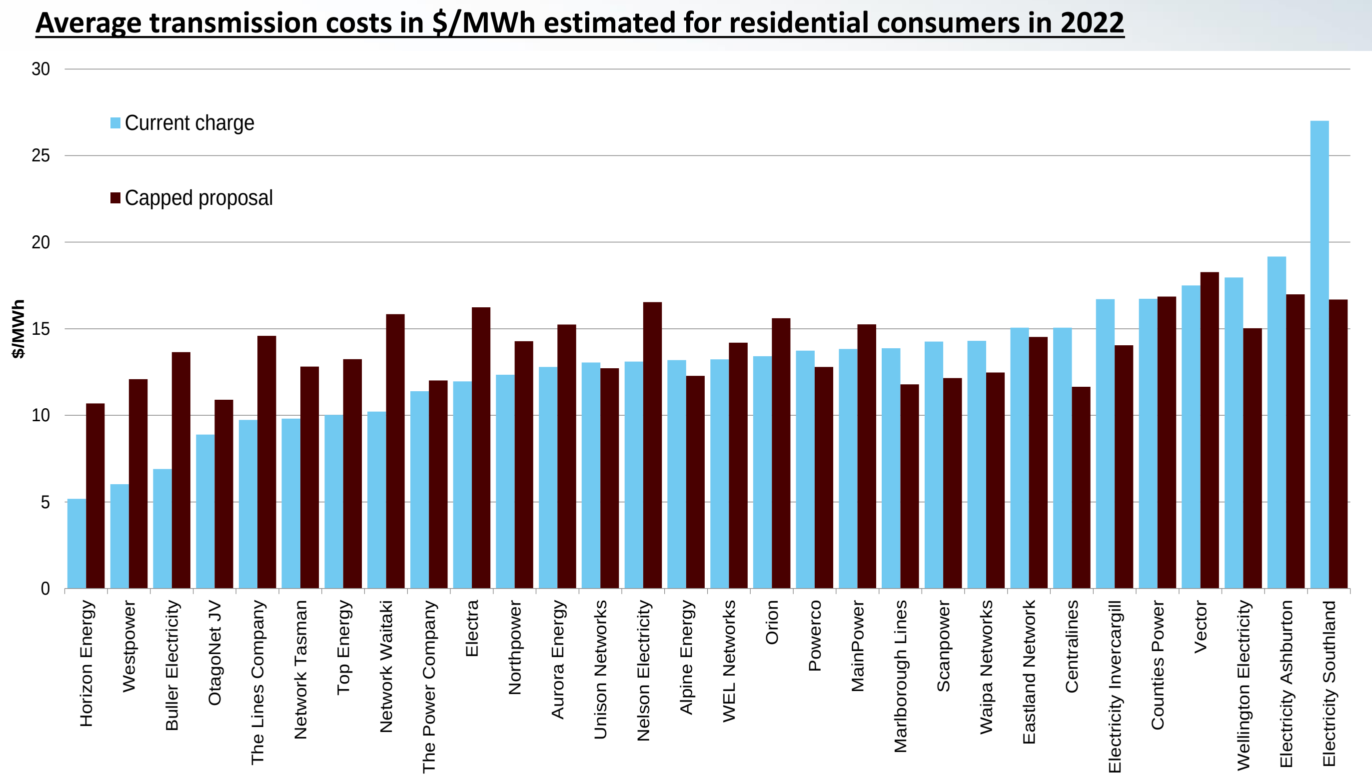


Comparison of indicative charges: 2016 and 2019 proposals



[See appendix for region-specific slides]

Comparison with other distributors



Impact on charges: generators and direct connects

Generators	Status quo $m	Proposal pre cap $m	Change due to cap $m	Proposal post cap $m
Contact Energy	21.1	20.7	0.5	21.2
Genesis Power	5.6	7.4	0.2	7.6
Mercury	0.0	6.4	0.2	6.6
Meridian	69.5	39.9	1.0	40.8
TrustPower	1.8	1.0	0.0	1.1
Other	0.0	6.0	0.1	6.1
Total	**98.0**	**81.4**	**2.0**	**83.3**

Industrial customers	Status quo $m	Proposal pre cap $m	Change due to cap $m	Proposal post cap $m
New Zealand Rail	1.0	2.7	-1.2	1.4
Norske Skog	0.0	6.8	-5.4	1.4
NZ Steel	2.4	11.9	-6.1	5.8
NZAS	55.7	43.4	1.0	44.4
Pan Pacific	1.2	5.0	-2.2	2.9
Port Taranaki	0.0	0.0	0.0	0.0
Winstone Pulp Int	2.3	2.4	0.1	2.5
Other	2.0	1.9	0.0	1.9
Total	**64.7**	**74.1**	**-13.8**	**60.3**

Price cap

A price cap to avoid price shocks

Rise in transmission charges capped at 3.5% of electricity bill

Reassures consumers there will not be price shocks due to proposal

Cap helps industrials to adjust:

- they currently pay little, but will pay more
- phases out for direct connects

New investments not covered

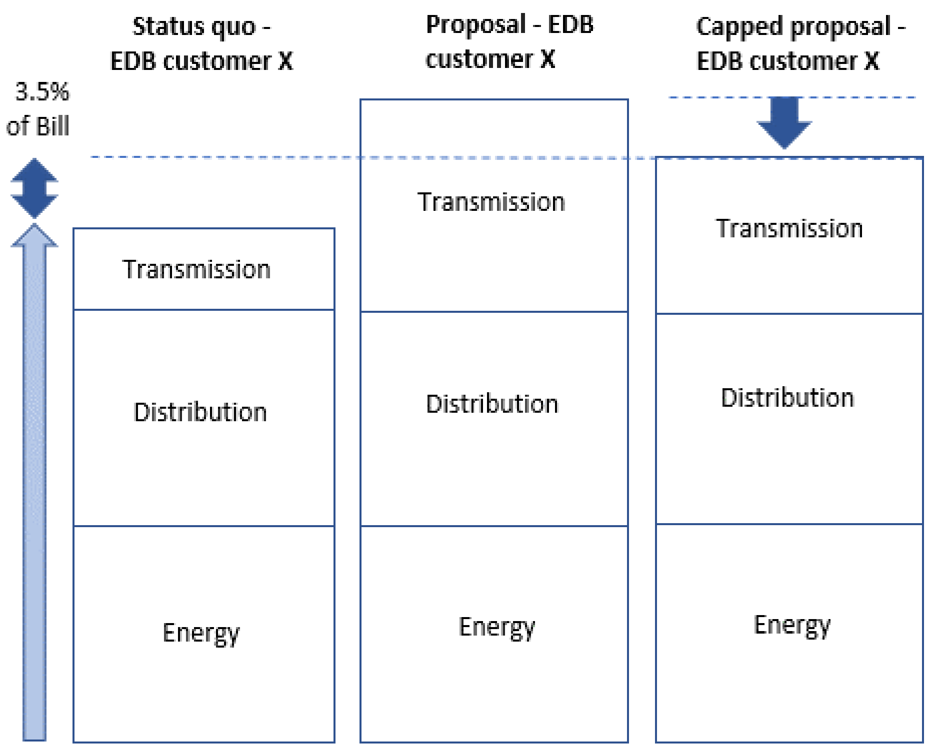
How the proposed cap works

- Distributors: 3.5% of estimated consumer electricity bills (2019/20)
  - capped amount increases annually by inflation and load growth

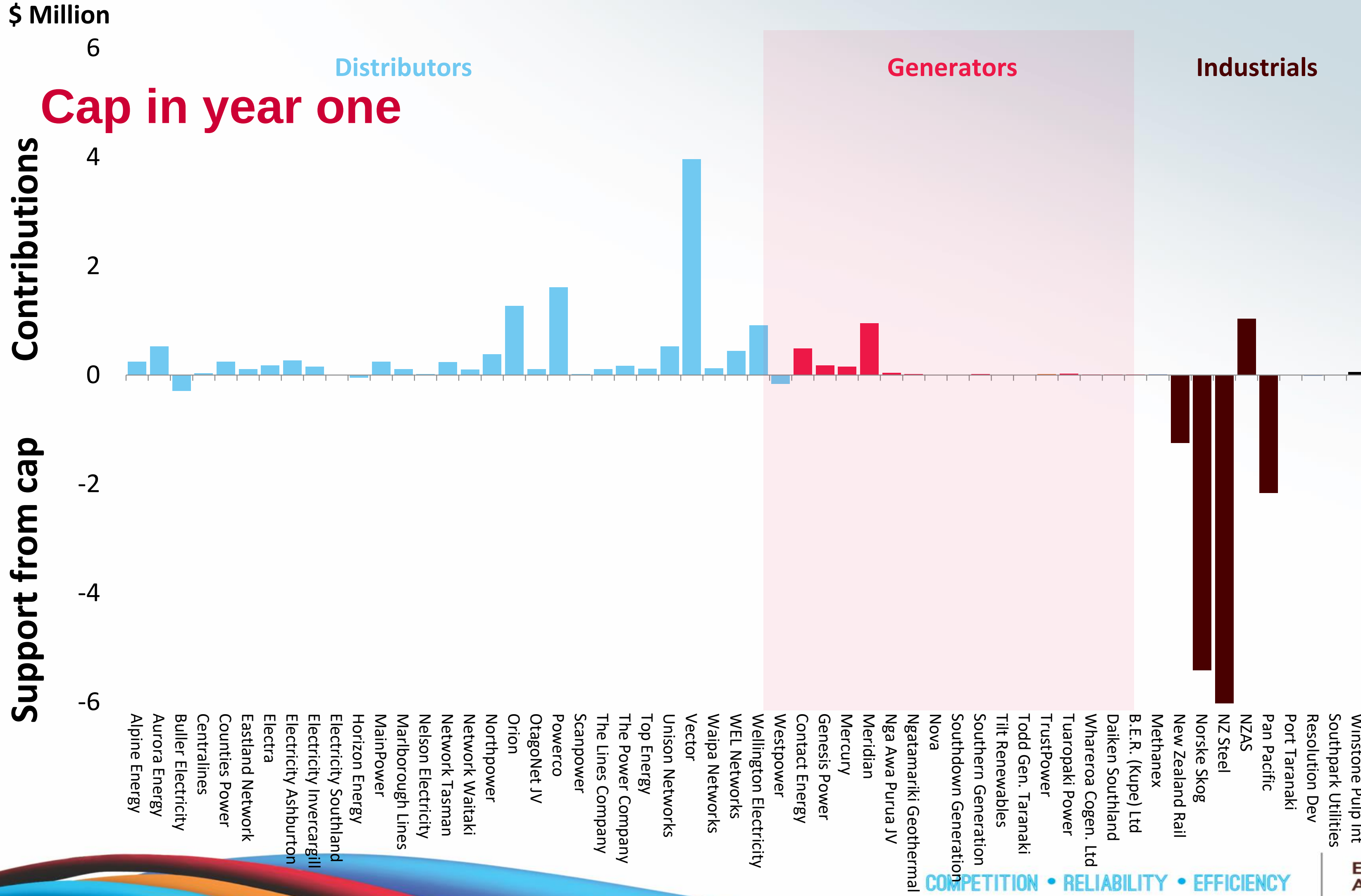
- Industrials: 3.5% cap rises by 2 percentage points per year, after first five years

- Guidelines give formula and data sources

How the proposed cap works



Cap in year one



Case study – price shocks under current TPM: Electricity Ashburton

- Transmission charges rose $10 million
  - $6.5 million in 2018-19
  - $16.7 million in 2019-20.
- Caused by changes in top 100 peaks
- Distribution charges unexpectedly higher:
  - irrigators, major users: almost 40%
  - general consumers: 10%
- Irrigators asked to reduce demand by 35%
  - effects on production?

Case study:

Entry and exit of new customers

Entries and Exits

- Detailed methodology in TPM
- Proposed guidelines:
  - TPM must include a method
  - Substantial and sustained change in grid use
  - Reassignment

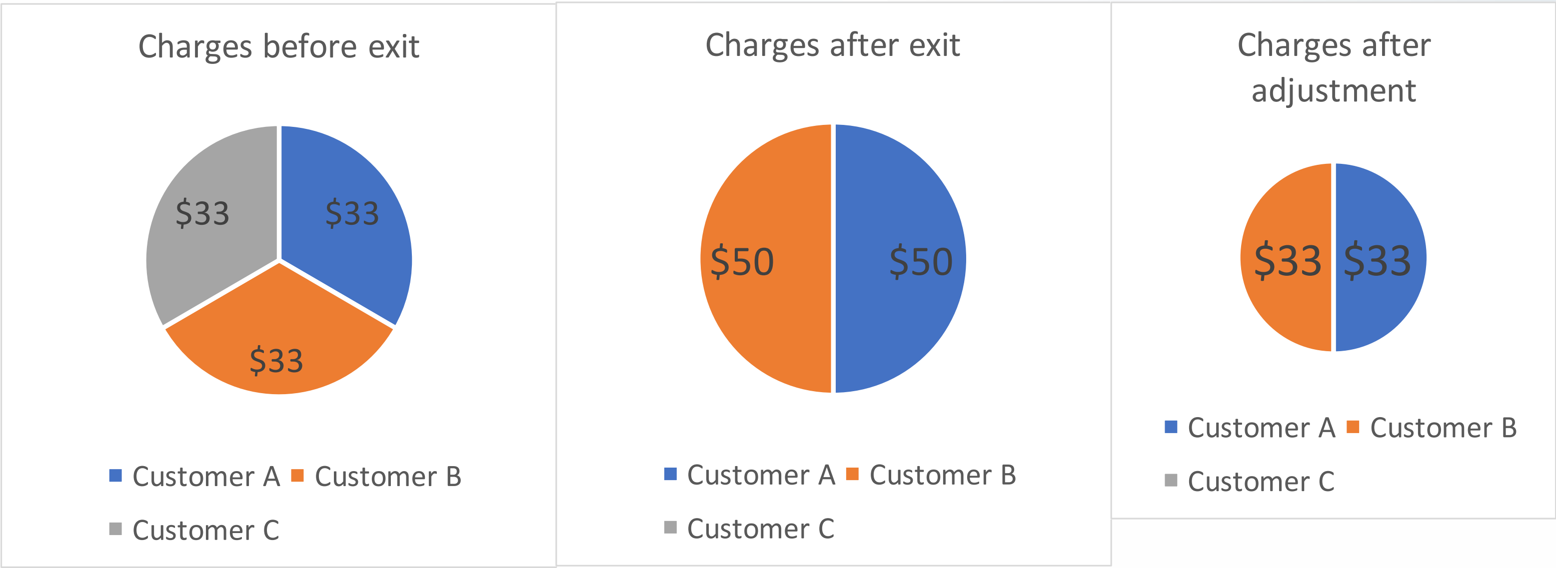
Example – entry – Junction road

- New grid-connected 100MW Taranaki thermal generator (mid-2020)
  - similar locational characteristics to McKee (illustrative assessment)
  - likely similar pattern and scale of benefits as McKee
- Illustrative conclusion: Junction Road charge to be the same as McKee
  - Residual: 0.002% of residual – based on offtake
  - Benefit-based charge – informed by McKee benefits:

BPE HAY	HVDC	LSI Reliability	LSI Renw	NIGU	Wairakei	UNI Dynamic
0.2%	0.1%	0.001%	0.013%	0.3%	0.001%	0.3%

Example: Exit (+ reopening of benefit-based charge)

Reassignment



Prudent discount policy

- To discourage inefficient disconnection from the grid
- Available where privately beneficial to disconnect – but inefficient

- Proposed guidelines:
  - extend to situations where load customer sources alternative supply
  - apply for life of asset (unless otherwise agreed)

Next steps

Transmission pricing methodology

www.ea.govt.nz

https://www.ea.govt.nz/development/work-programme/pricing-cost-allocation/transmission-pricing-review/

Submissions close 1 October 2019

tpm@ea.govt.nz

Appendix

Additional components (#1)

Transpower would need to propose additional components if that would better meet the Authority's statutory objective.

Their implementation must be deferred (except for the transitional peak charge) if it would expedite the implementation of benefit-based charge.

1. Charging methods to support staged commissioning (allow Transpower to make adjustments so that charges better reflect benefit provided at each stage)
2. Charging for assets that are principally a connection asset: should be charged as such (to avoid investments made to reclassify as interconnection assets)
3. Charging method for connection services can be aligned with that for benefit-based charge (to avoid poor incentives from differences in basis of charges)

Additional components (#2)

4. Transitional peak charge would phase out over five years, with option to extend or reintroduce (to support the transition to state where only nodal pricing signals grid congestion)
5. Other pre-2019 investments could be included in the benefit-based charge as Transpower proposed in 2016 (this could have efficiency benefits, but transaction costs may be too high)
6. Operating and maintenance costs attributed to asset it is spent on (rather than broad cost allocation rule)
7. Kvar charge to recover cost of static reactive investments from exacerbators

Fit with Electricity Price Review

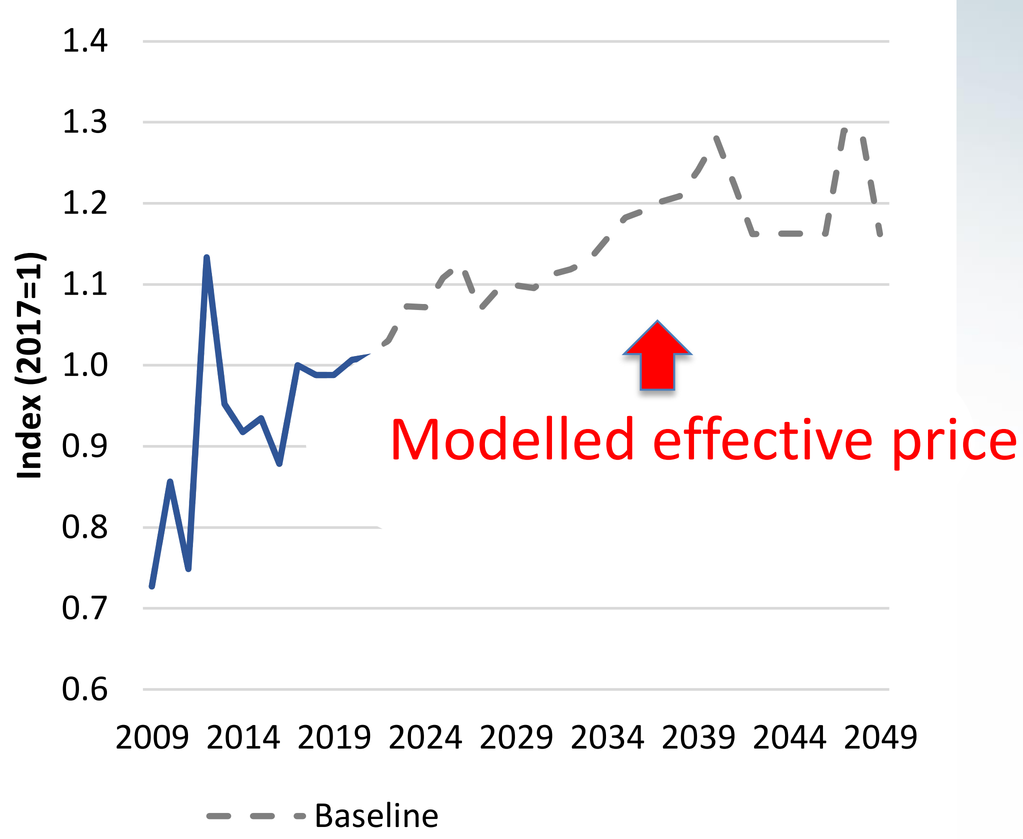
We anticipate the EPR recommends a Government Policy Statement

The topics likely to be included in a possible GPS are part of the proposal we are consulting on:

- recovering cost of grid investments from those who benefit from it
- recovering remaining costs of seven major pre-2019 grid investments to ensure durability of the regime
- a price cap, to avoid bill shock for consumers and industrial firms

The RCPD charge could spiral upwards

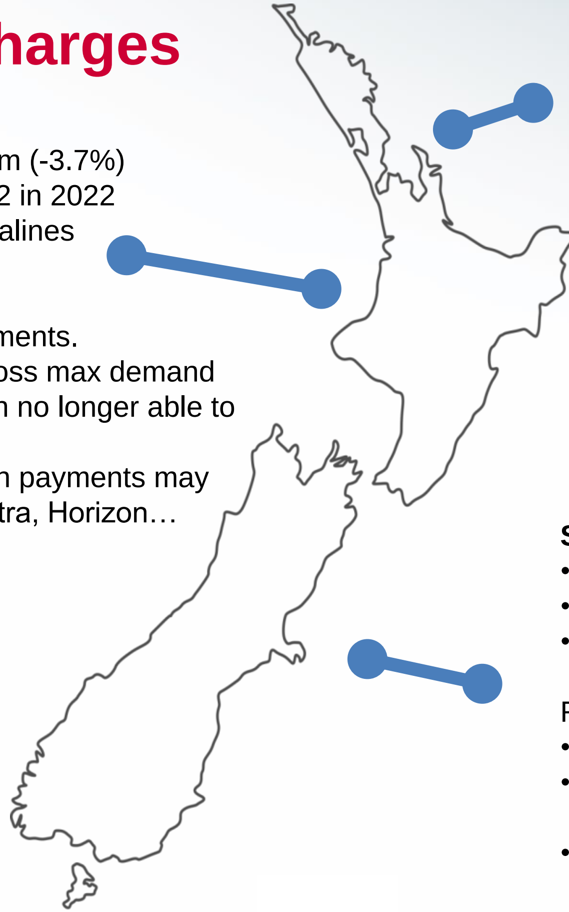
Cost of electricity use at peak: wholesale energy and interconnection charges (index: $/MWh)



Initial impact on charges

Lower North Island distributors
- Charges from $187m to $180m, -$7m (-3.7%)
- Average consumer electricity bill +$2 in 2022
- High = +$30 TLC, Low = -$24 Centralines

Reflects:
- Limited benefits from historic investments.
- Large residual charge as highest gross max demand
- Locations with distributed generation no longer able to avoid peak charges
- Lower Avoided Cost of Transmission payments may reduce consumer bills for TLC, Electra, Horizon…



Upper North Island distributors
- Charges from $190m to $201m, +10.6m, (+5.6%)
- Consumer bills per year +$10
- High = +$20 Top, Low = +$1 Counties

Reflects:
- Benefit-based charges for historic investments (benefits: cheaper and more reliable power)

South Island distributors
- Charges from $139m to $154m, +15m (+11%)
- Consumer bills per year +$5
- High = +$43 Waitaki, Low = -$23 Invercargill

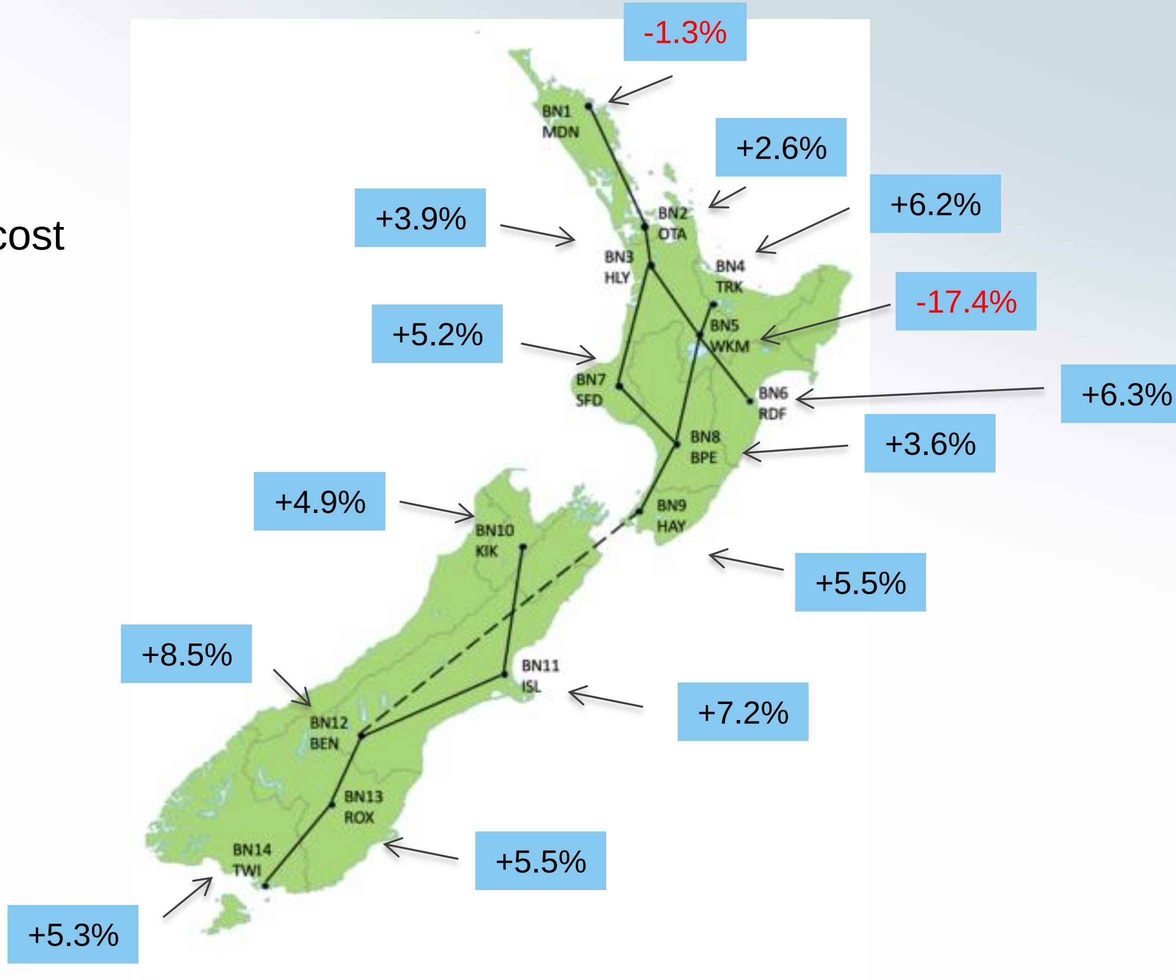
Reflects:
- Gross max demand high (winters, irrigation)
- Waitaki high as charge no longer net of Blackpoint generation.
- Inability to offset distributed generation also affects Buller, Westpower, Network Tasman, Otago…
- Consumers may save ACOT costs

Long term benefits

Net benefits as % of baseline cost (wholesale + transmission)

Overall net benefits:

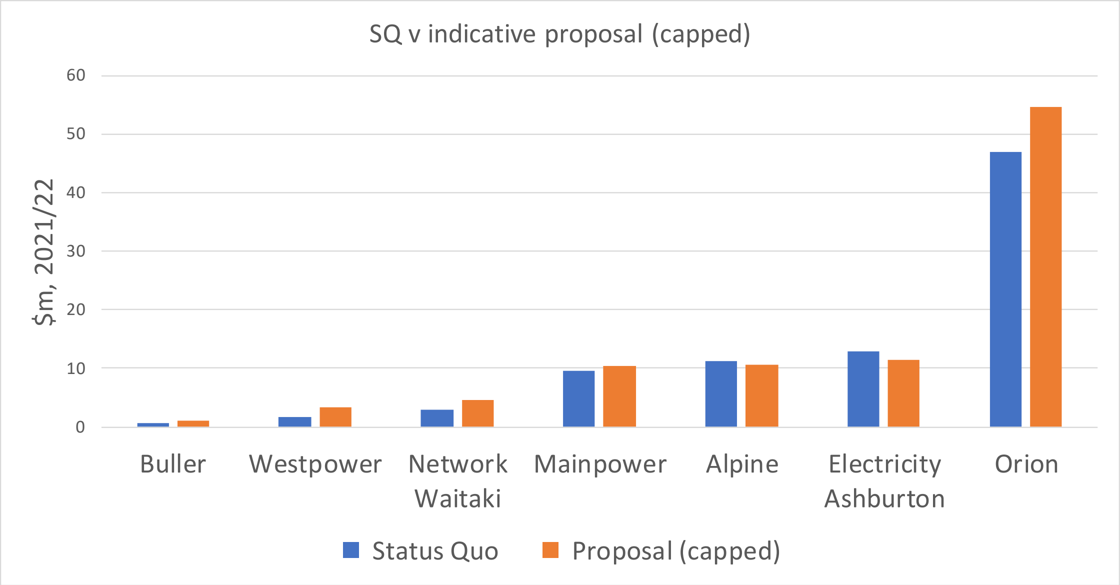
- **4.4% ($2.7b)**



Region specific slides

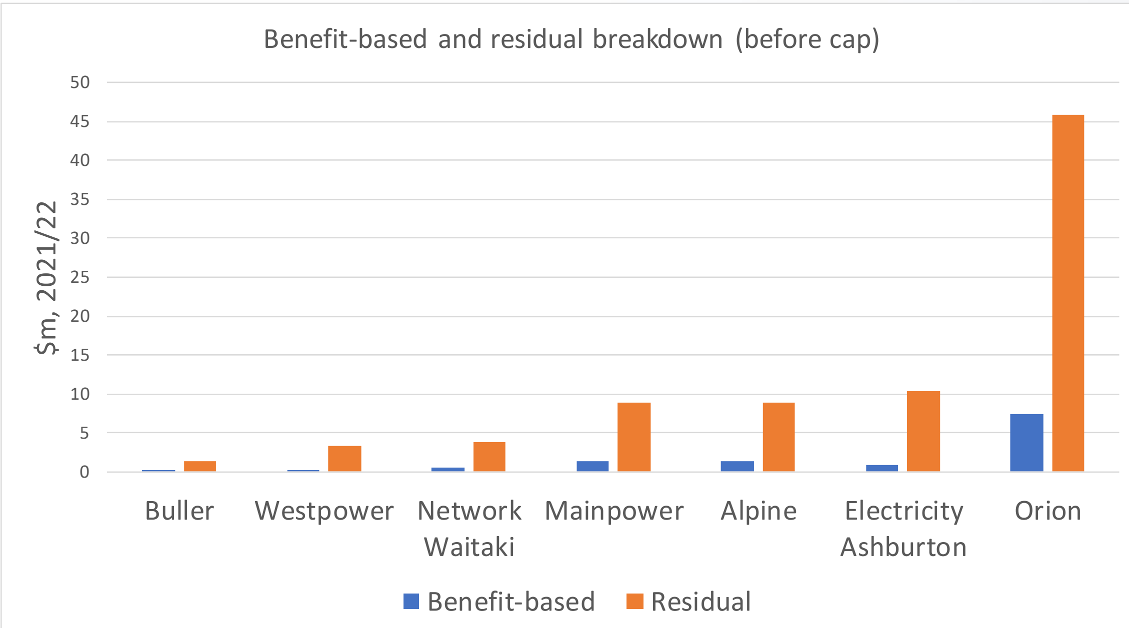
Examples of indicative charges and drivers

Indicative charges under proposal [Christchurch workshop]



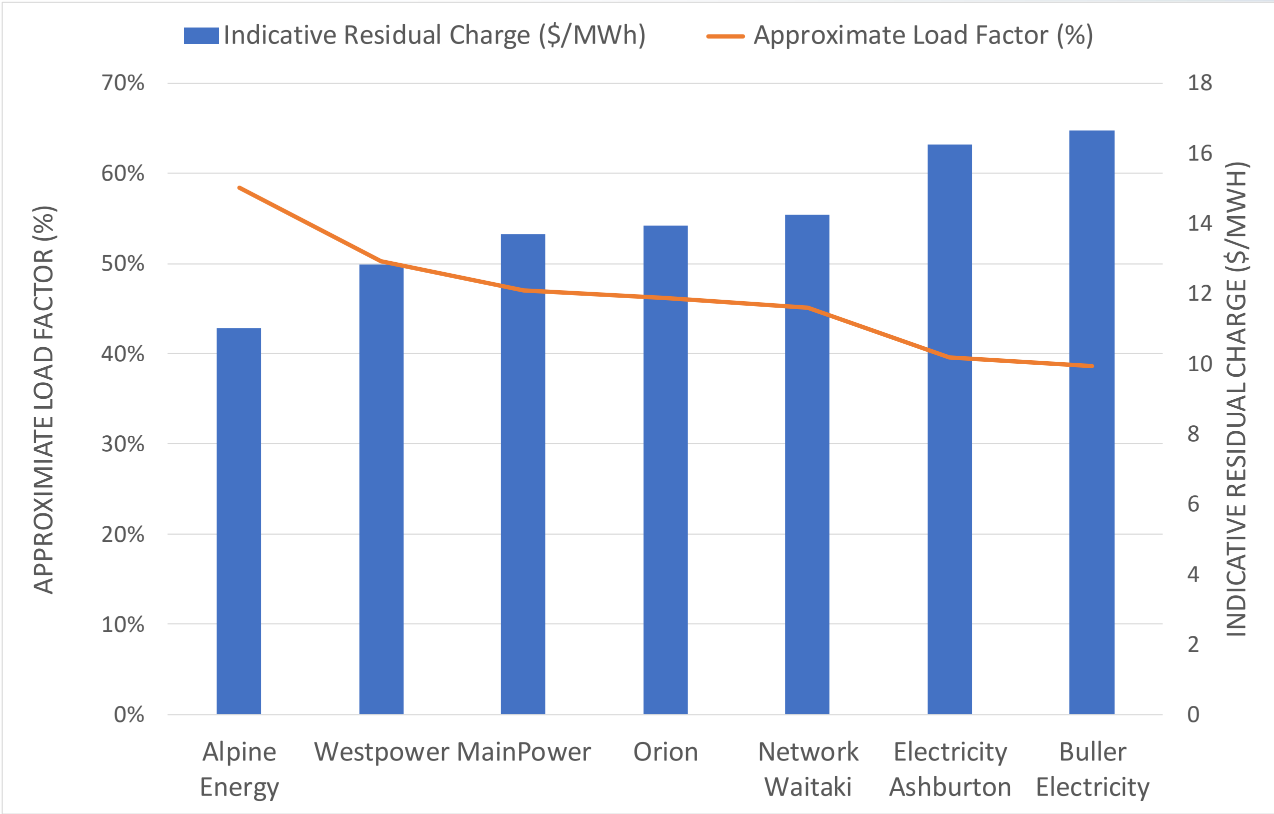
$m 2021/22	Status Quo	Proposal (capped)	%
Buller	0.6	1.1	98%
Westpower	1.7	3.4	101%
Network Waitaki	3.0	4.6	55%
Mainpower	9.5	10.4	10%
Alpine	11.3	10.5	-7%
Electricity Ashburton	12.9	11.5	-11%
Orion	46.9	54.5	16%

Residual charge dominates



$m 2021/22	Benefit-based	Residual
Buller	0.1	1.3
Westpower	0.2	3.4
Network Waitaki	0.6	3.9
Mainpower	1.4	8.8
Alpine	1.4	8.9
Electricity Ashburtoı	0.9	10.3
Orion	7.4	45.8

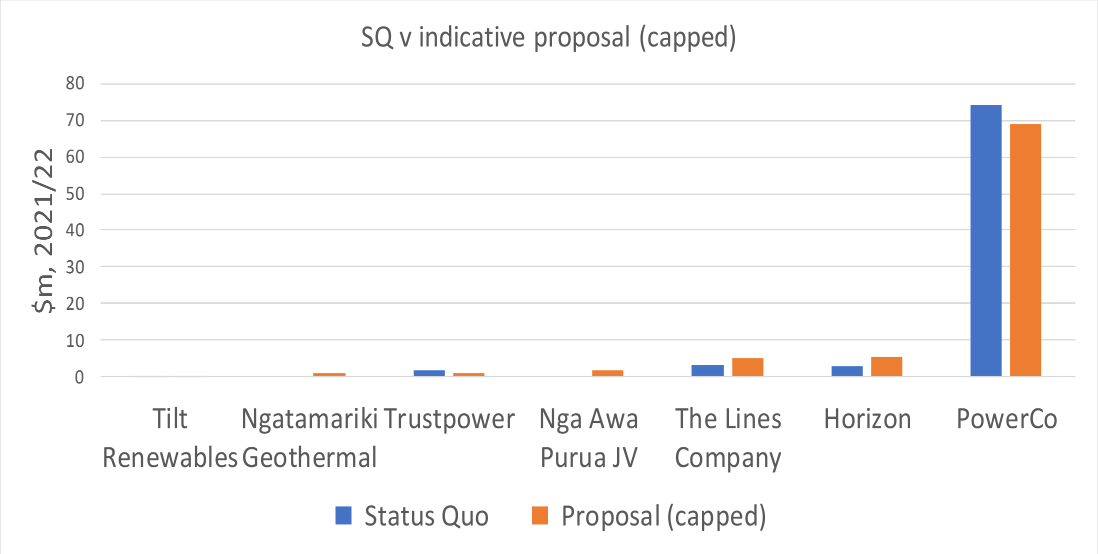
Peakier load customers get a higher residual charge



Indicative impacts – benefit-based charge breakdown

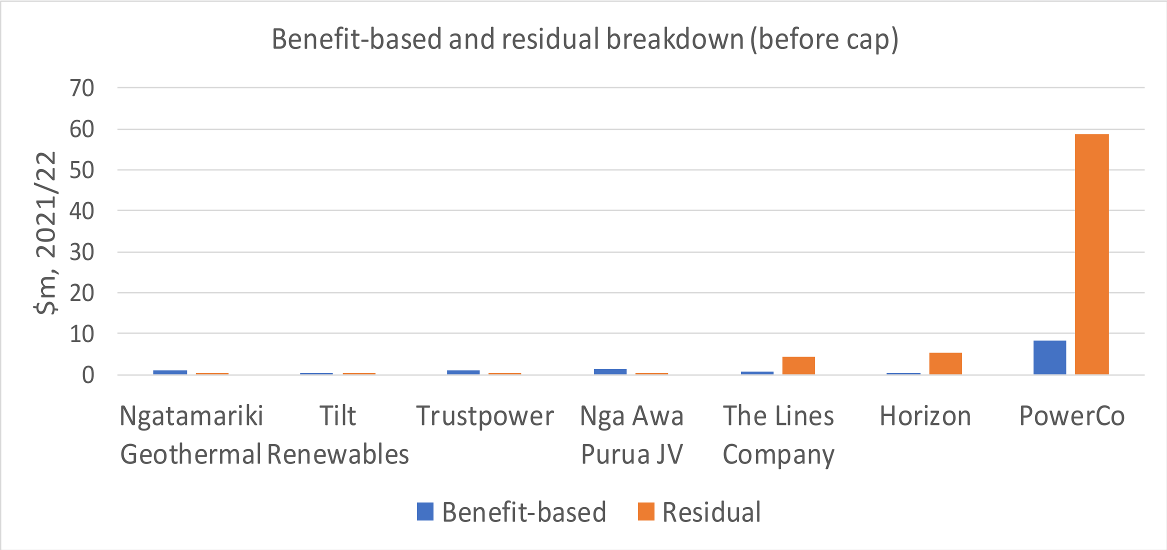
	Bunnythorpe-Haywards	HVDC	LSI Reliability	LSI Renewables	North Island grid upgrade	Wairakei Ring	UNI dynamic reactive	Total
Alpine Energy	203,082	843,626	36,413	79,677	181,360	22,263	14,730	1,381,150
Buller Electricity	17,421	74,599	2,959	5,419	20,104	1,676	1,633	123,810
Electricity Ashburton	111,054	503,269	18,535	45,642	156,425	13,456	12,705	861,085
MainPower	209,387	867,281	31,167	78,836	145,996	17,879	11,858	1,362,405
Meridian	15,256	33,343,465	26,843	1,297	4,447,324	427	361,214	38,195,826
Network Waitaki	73,786	352,958	12,753	57,773	79,569	7,705	6,463	591,006
Orion	1,189,306	4,831,626	174,599	392,926	693,201	91,095	56,302	7,429,055
Westpower	26,215	86,222	5,035	12,257	32,158	3,119	2,612	167,617
Total cost	**6,526,412**	**98,930,000**	**2,438,734**	**2,674,728**	**60,521,008**	**9,154,513**	**4,915,553**	**185,160,948**

Indicative charges under proposal [Tauranga workshop]



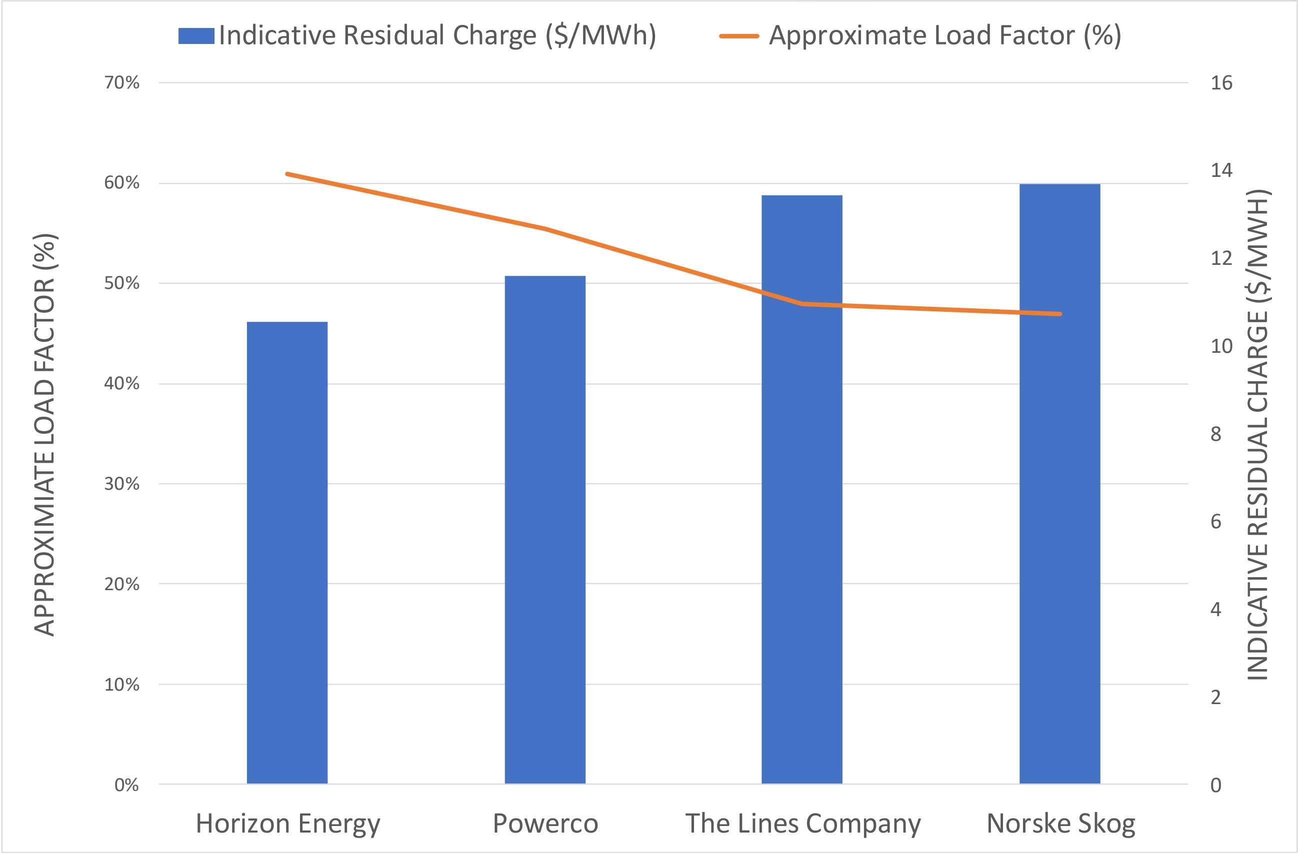
$m 2021/22	Status Quo	Proposal (capped)	%
Tilt Renewables	0.0	0.2	
Ngatamariki Geotherm	-	0.9	
Trustpower	1.8	1.1	-42%
Nga Awa Purua JV	-	1.7	
The Lines Company	3.3	5.0	50%
Horizon	2.7	5.7	107%
PowerCo	74.0	68.9	-7%

Residual charge dominates



$m 2021/22	Benefit-based	Residual
Ngatamariki Geothe	0.8	0.1
Tilt Renewables	0.1	0.1
Trustpower	0.9	0.1
Nga Awa Purua JV	1.4	0.3
The Lines Company	0.5	4.3
Horizon	0.4	5.3
PowerCo	8.4	58.9

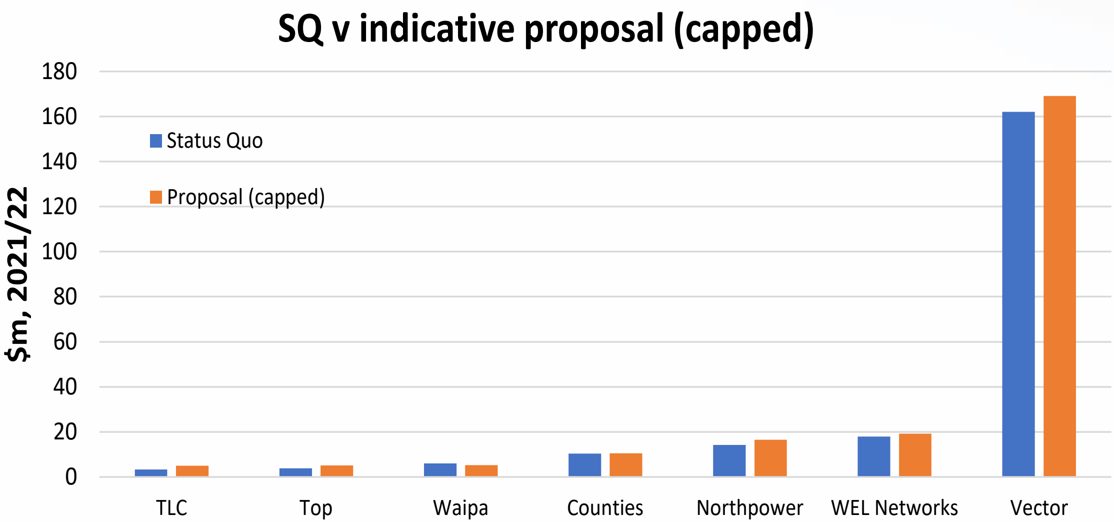
Peakier load customers get a higher residual charge



Indicative impacts – benefit-based charge breakdown

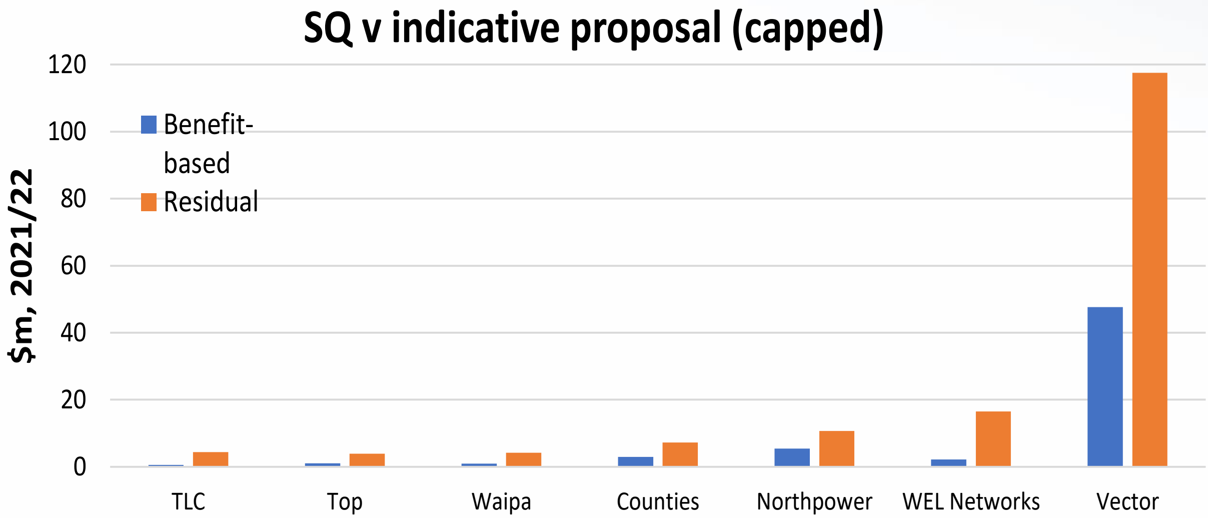
	Bunnythorpe-Haywards	HVDC	LSI Reliability	LSI Renewables	North Island grid upgrade	Wairakei Ring	UNI dynamic reactive	Total
Horizon Energy	19,970	360,443	14,456	17,699	30,433	-	2,472	445,472
Nga Awa Purua JV	108	165	6	6	589,672	732,624	47,894	1,370,474
Ngatamariki Geothermal	764	11	1	0	356,012	444,939	28,915	830,643
Powerco	262,440	6,184,114	208,575	179,146	1,155,967	327,895	93,888	8,412,024
The Lines Company	10,336	353,613	11,408	9,941	109,580	44,623	8,900	548,402
Tilt Renewables	17,117	6,094	19	20	97,959	17	7,956	129,183
TrustPower	673	738,502	17	145	97,374	104,576	7,909	949,196
Total cost	**6,526,412**	**98,930,000**	**2,438,734**	**2,674,728**	**60,521,008**	**9,154,513**	**4,915,553**	**185,160,948**

Indicative charges under the proposal [Auckland Workshop]



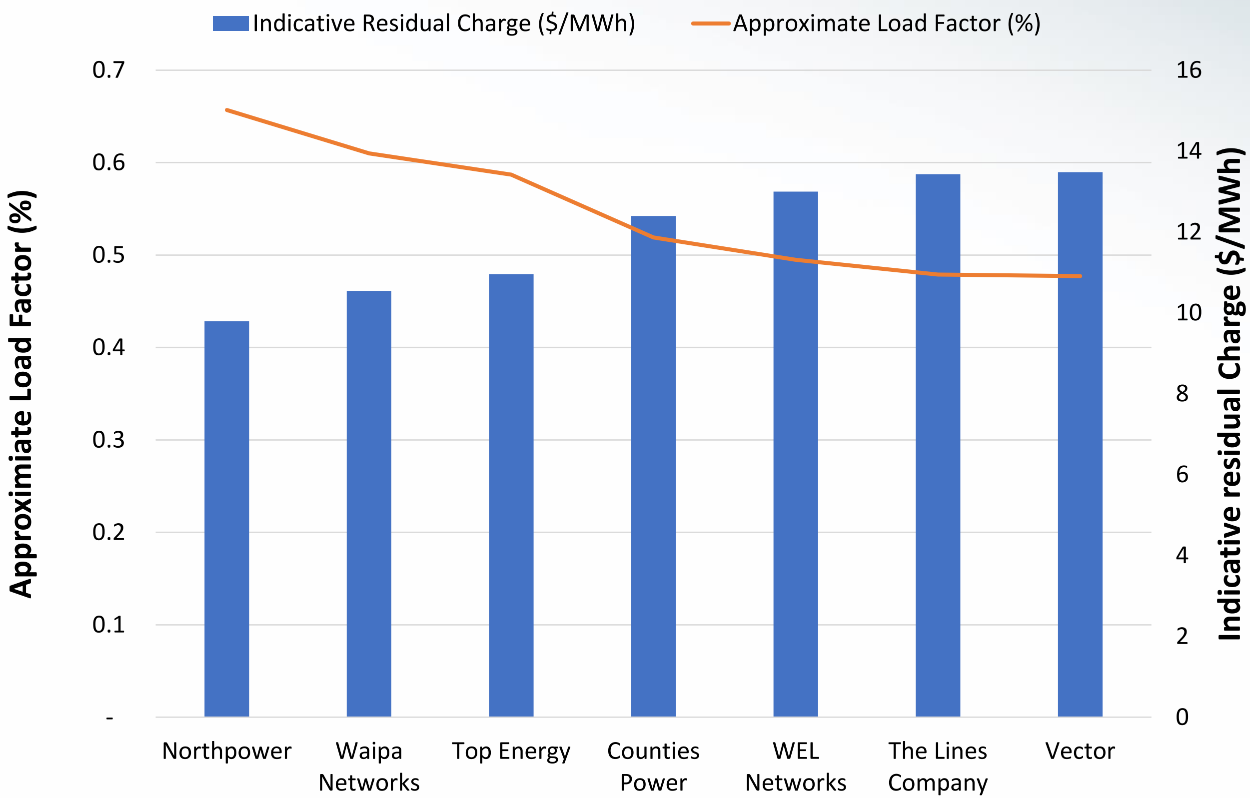
$m 2021/22	Status Quo	Proposal (capped)
TLC	3.3	5.0
Top	3.8	5.0
Waipa	6.0	5.3
Counties	10.4	10.4
Northpower	14.2	16.5
WEL Networks	17.9	19.2
Vector	162.0	169.1

Residual charge dominates



$m 2021/22	Benefit-based	Residual
TLC	0.5	4.3
Top	1.0	3.9
Waipa	0.9	4.2
Counties	3.0	7.2
Northpower	5.4	10.6
WEL Networks	2.2	16.5
Vector	47.6	117.5

Peakier load means a higher residual $/MWh charge

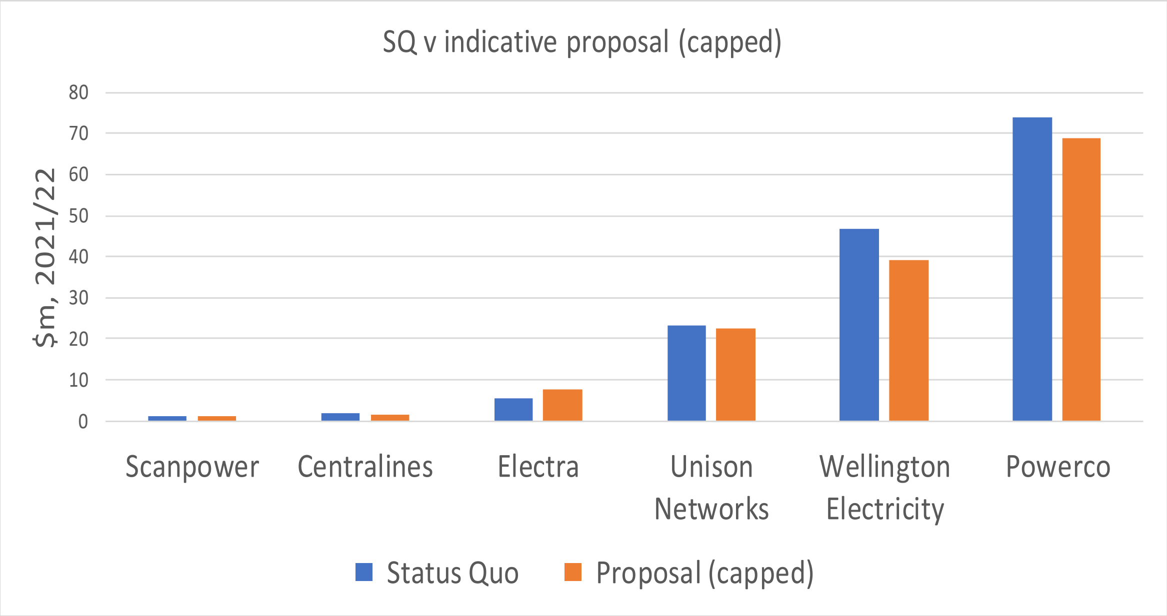


Indicative impacts – benefit-based charge breakdown

	Bunnythorpe-Haywards	HVDC	LSI Reliability	LSI Renewables	North Island grid upgrade	Wairakei Ring	UNI dynamic reactive
TLC	0.16%	0.36%	0.47%	0.37%	0.18%	0.49%	0.18%
Top	0.00%	0.24%	0.00%	0.00%	1.09%	0.51%	1.09%
Waipa	0.25%	0.59%	0.81%	0.64%	0.33%	1.01%	0.33%
Counties	0.32%	1.06%	1.08%	0.85%	2.62%	1.41%	2.62%
Northpower	0.67%	1.13%	2.16%	1.78%	5.98%	2.90%	5.98%
WEL Networks	0.52%	1.13%	1.81%	1.41%	1.13%	2.36%	1.13%
Vector	5.51%	10.76%	18.95%	14.37%	51.26%	24.41%	51.26%

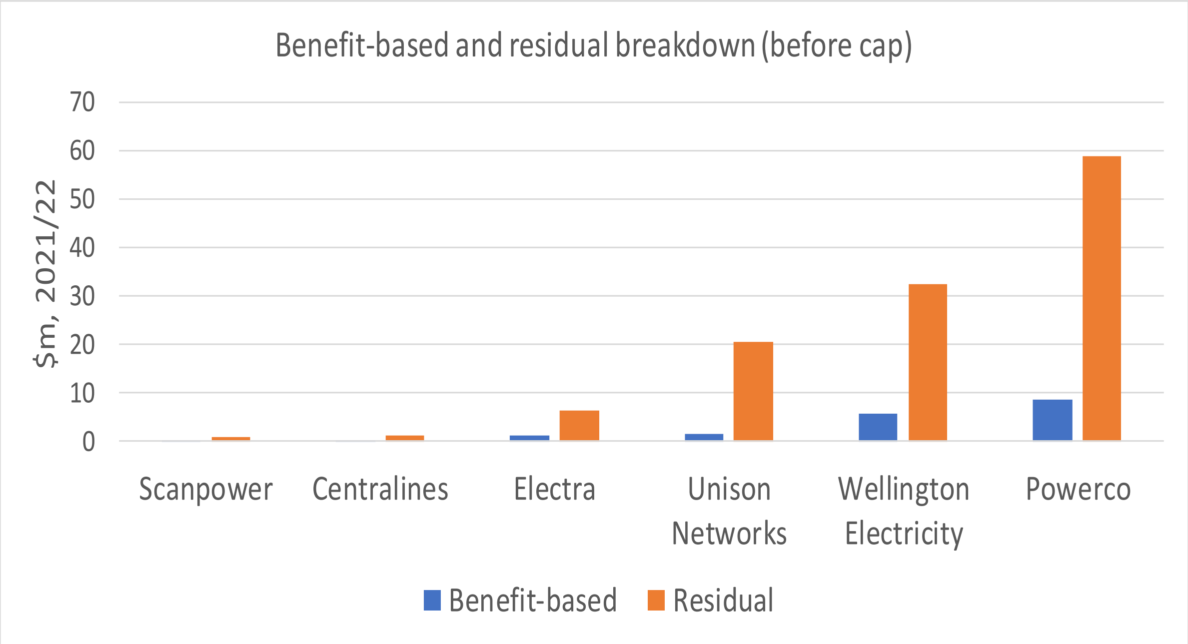
	Bunnythorpe-Haywards	HVDC	LSI Reliability	LSI Renewables	North Island grid upgrade	Wairakei Ring	UNI dynamic reactive	Total
TLC	0.01	0.35	0.01	0.01	0.11	0.04	0.01	0.5
Top	-	0.24	-	-	0.66	0.05	0.05	1.0
Waipa	0.02	0.59	0.02	0.02	0.20	0.09	0.02	0.9
Counties	0.02	1.05	0.03	0.02	1.59	0.13	0.13	3.0
Northpower	0.04	1.12	0.05	0.05	3.62	0.27	0.29	5.4
WEL Networks	0.03	1.11	0.04	0.04	0.68	0.22	0.06	2.2
Vector	0.36	10.64	0.46	0.38	31.02	2.23	2.52	47.6

Indicative charges under the proposal [Wellington workshop]



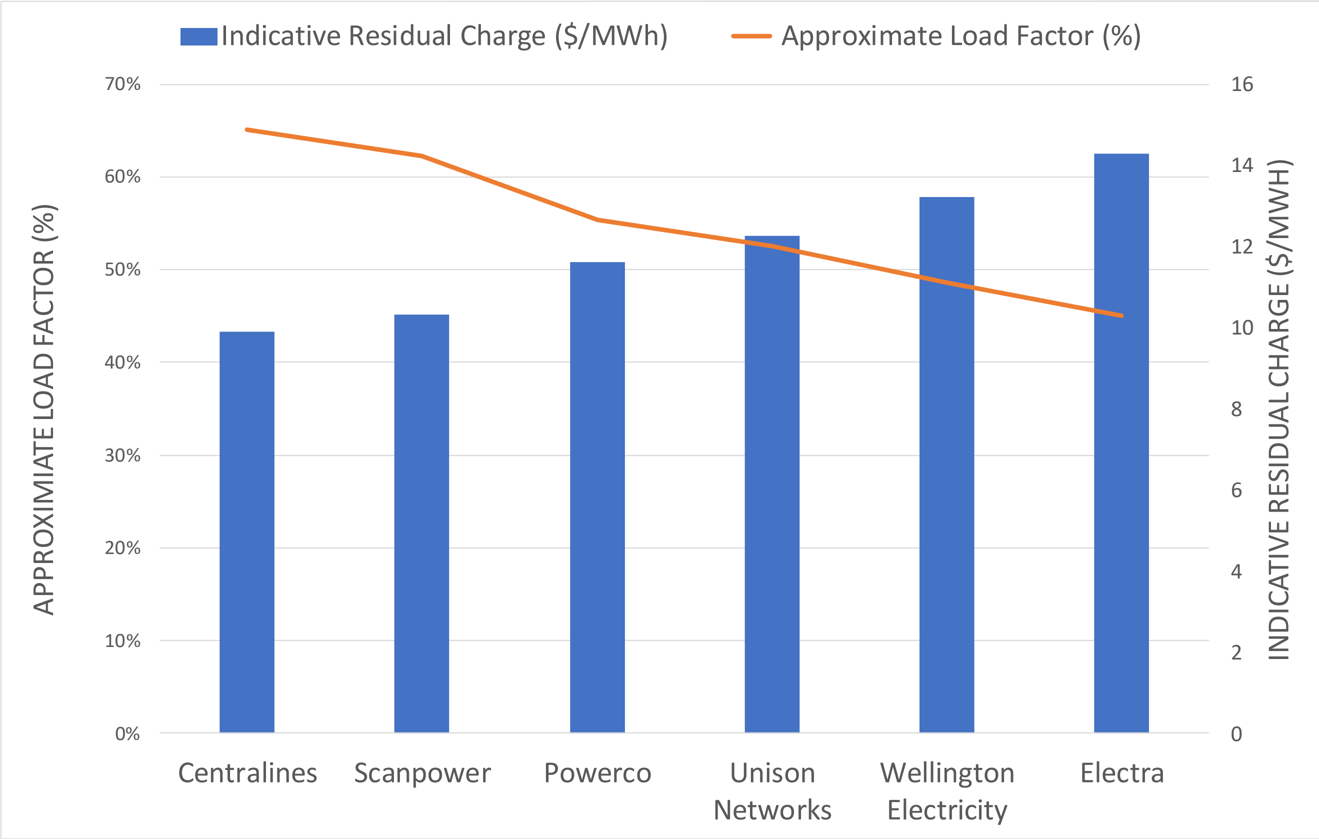
	Status Quo	Proposal (capped)	%
Scanpower	1.25	1.07	-15%
Centralines	1.86	1.43	-23%
Electra	5.57	7.57	36%
Unison Networks	23.12	22.53	-3%
Wellington Electricity	46.69	39.09	-16%
Powerco	74.03	68.95	-7%

Residual charge dominates



$m 2021/22	Benefit-based	Residual
Scanpower	0.19	0.85
Centralines	0.25	1.15
Electra	1.12	6.27
Unison Networks	1.56	20.44
Wellington Electricity	5.77	32.40
Powerco	8.41	58.92

Peakier load means a higher $/MWh residual charge



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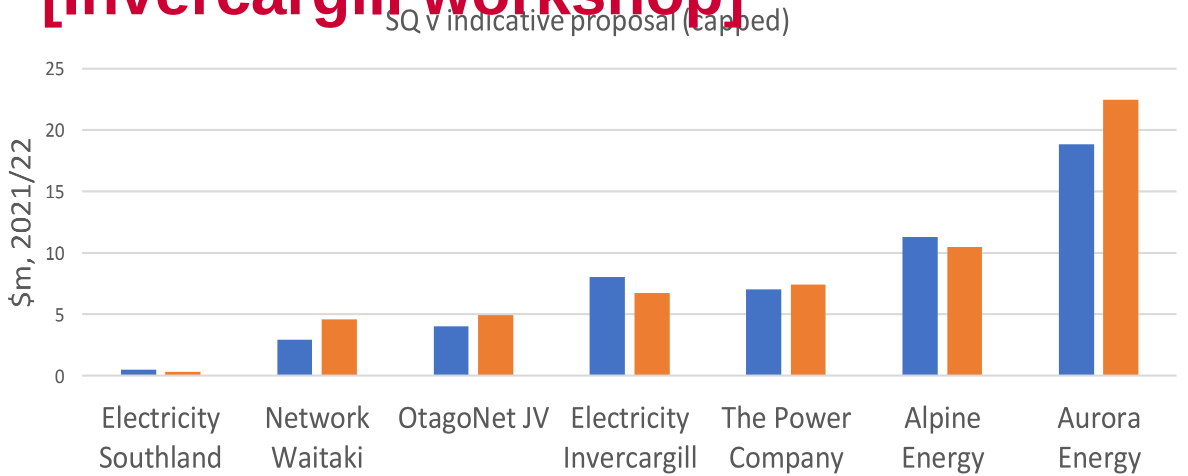
Indicative impacts – benefit-based charge breakdown

	Bunnythorpe-Haywards	HVDC	LSI Reliability	LSI Renewables	North Island grid upgrade	Wairakei Ring	UNI dynamic reactive
Centralines	0.07%	0.21%	0.24%	0.17%	0.05%	0.01%	0.05%
Electra	2.70%	0.79%	0.95%	0.67%	0.16%	0.14%	0.16%
Powerco	4.02%	6.25%	8.55%	6.70%	1.91%	3.58%	1.91%
Scanpower	0.05%	0.15%	0.17%	0.12%	0.03%	0.03%	0.03%
Unison Networks	0.63%	1.34%	2.19%	1.60%	0.16%	0.00%	0.16%
Wellington Electricity	11.83%	4.24%	4.90%	3.21%	0.83%	0.65%	0.83%

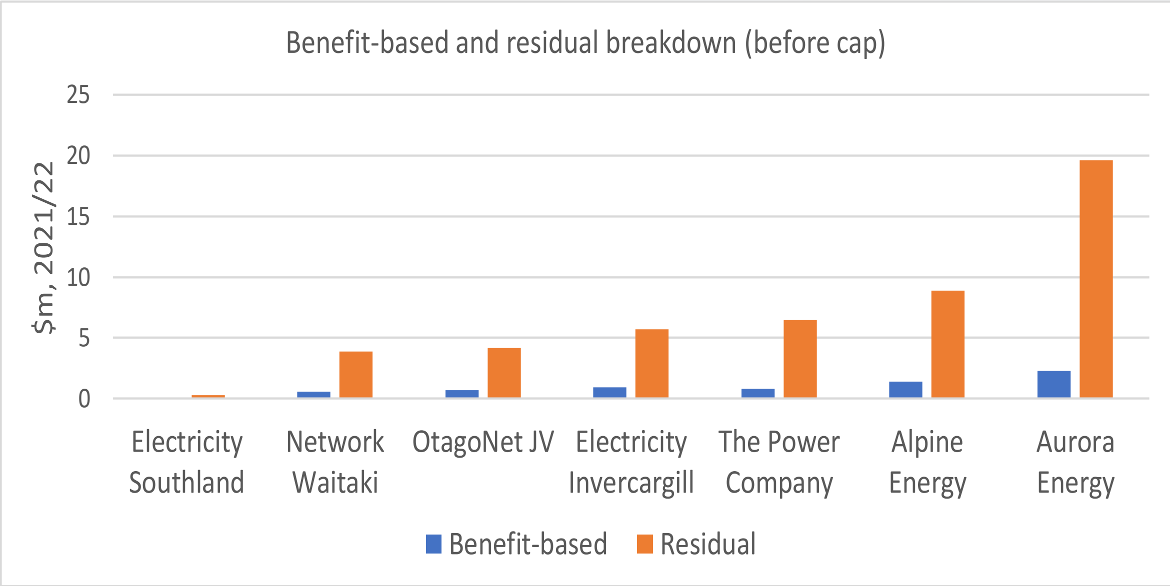
	Bunnythorpe-Haywards	HVDC	LSI Reliability	LSI Renewables	North Island grid upgrade	Wairakei Ring	UNI dynamic reactive	Total
Centralines	4,401	206,290	5,818	4,602	28,754	1,146	2,335	253,346
Electra	176,036	781,801	23,194	17,907	99,731	13,251	8,100	1,120,020
Powerco	262,440	6,184,114	208,575	179,146	1,155,967	327,895	93,888	8,412,024
Scanpower	2,965	151,464	4,164	3,215	20,837	2,787	1,692	187,125
Unison Networks	41,364	1,321,015	53,462	42,731	95,872	0	7,787	1,562,232
Wellington Electricity	772,173	4,193,954	119,438	85,873	502,098	59,605	40,781	5,773,921

Indicative charges under the proposal [Invercargill workshop]



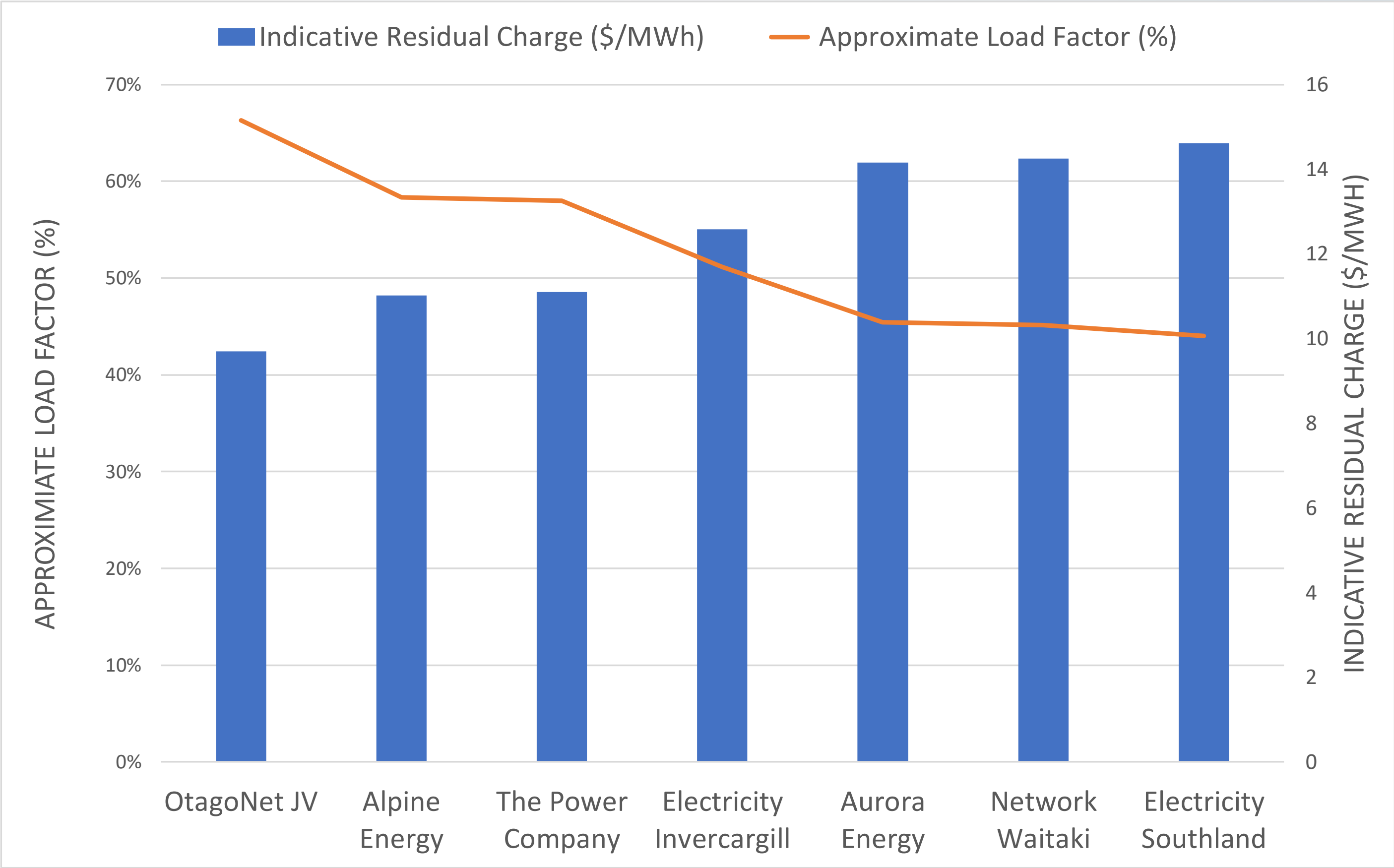
	Status quo $m	Proposal (capped) $m	% change	Impact household bill $ pa	If no ACOT payments $ pa
Electricity Southland	0.5	0.3	-38%	(85)	(85)
Network Waitaki	3.0	4.6	55%	43	43
OtagoNet JV	4.0	5.0	23%	14	(6)
Electricity Invercargill	8.1	6.8	-16%	(23)	(23)
The Power Company	7.0	7.4	5%	5	4
Alpine Energy	11.3	10.5	-7%	(8)	(8)
Aurora Energy	18.8	22.5	19%	20	(17)

Residual charge dominates



$m 2021/22	Benefit-based	Residual
Electricity Southland	0.0	0.3
Network Waitaki	0.6	3.9
OtagoNet JV	0.7	4.2
Electricity Invercargill	0.9	5.7
The Power Company	0.8	6.5
Alpine Energy	1.4	8.9
Aurora Energy	2.3	19.6

Peakier load means a higher $/MWh residual charge

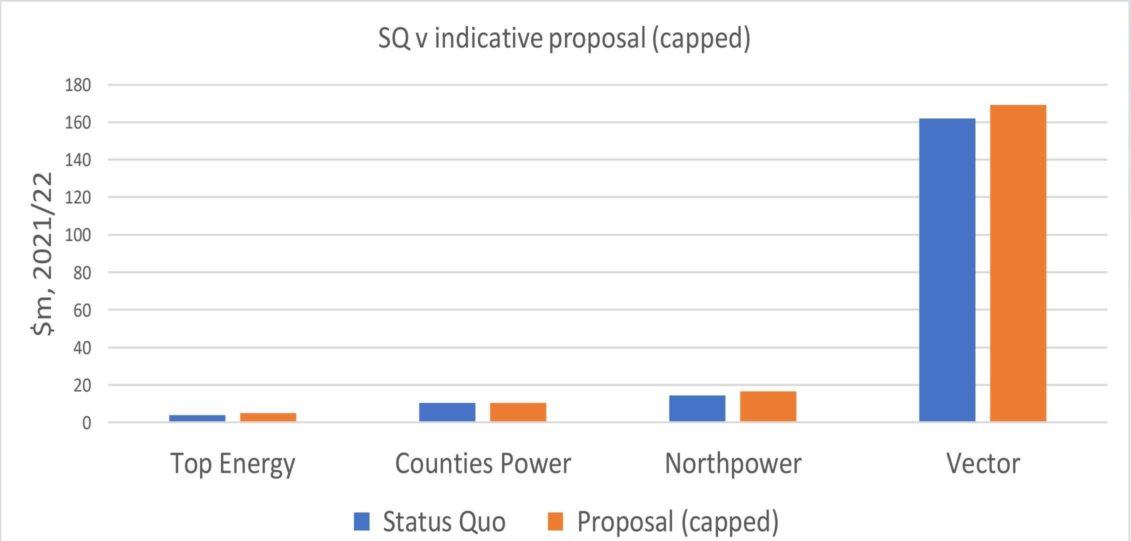


Indicative impacts – benefit-based charge breakdown

	Bunnythorpe-Haywards	HVDC	LSI Reliability	LSI Renewables	North Island grid upgrade	Wairakei Ring	UNI dynamic reactive
Electricity Southland	0.12%	0.04%	0.05%	0.07%	0.01%	0.01%	0.01%
Network Waitaki	1.13%	0.36%	0.52%	2.16%	0.13%	0.08%	0.13%
OtagoNet JV	1.46%	0.41%	2.01%	2.03%	0.11%	0.11%	0.11%
Electricity Invercargill	2.26%	0.59%	0.27%	2.19%	0.14%	0.12%	0.14%
The Power Company	1.54%	0.34%	8.22%	2.04%	0.13%	0.12%	0.13%
Alpine Energy	3.11%	0.85%	1.49%	2.98%	0.30%	0.24%	0.30%
Aurora Energy	5.71%	1.57%	0.90%	4.48%	0.30%	0.27%	0.30%

	Bunnythorpe-Haywards	HVDC	LSI Reliability	LSI Renewables	North Island grid upgrade	Wairakei Ring	UNI dynamic reactive	Total
Electricity Southland	7,766	34,686	1,105	1,771	3,087	482	251	49,146
Network Waitaki	73,786	352,958	12,753	57,773	79,569	7,705	6,463	591,006
OtagoNet JV	95,094	403,375	49,019	54,231	68,858	9,676	5,593	685,845
Electricity Invercargill	147,762	583,888	6,598	58,499	83,313	11,347	6,767	898,174
The Power Company	100,396	339,188	200,375	54,641	77,755	10,737	6,315	789,409
Alpine Energy	203,082	843,626	36,413	79,677	181,360	22,263	14,730	1,381,150
Aurora Energy	372,415	1,552,757	21,960	119,767	181,259	24,845	14,722	2,287,725

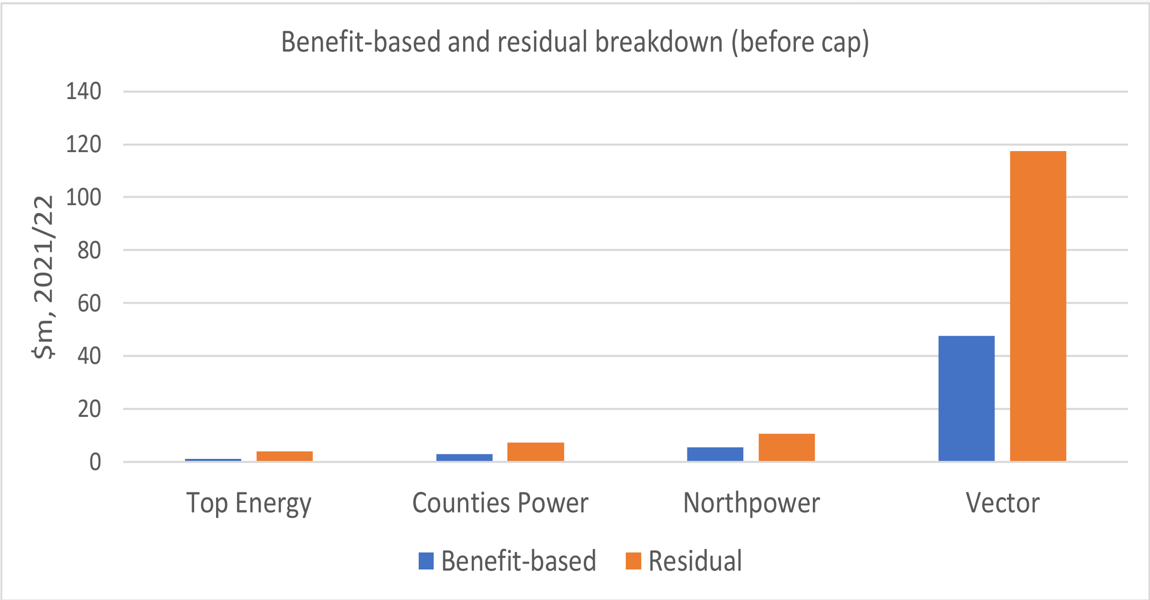
Indicative charges - Upper North Island distributors



Distributor	Status quo (Estimated $M in 2022)	Benefit based charge	Residual	Proposed Total (capped $M)	Potential impact on average household bill for first year $	Potential impact on average household bill if no ACOT
Top Energy	3.8	1.0	3.9	5.0	20	-24
Counties Power	10.4	3.0	7.2	10.4	1	-5
Northpower	14.2	5.4	10.6	16.5	12	5
Vector	162.0	47.6	117.5	169.1	5	5

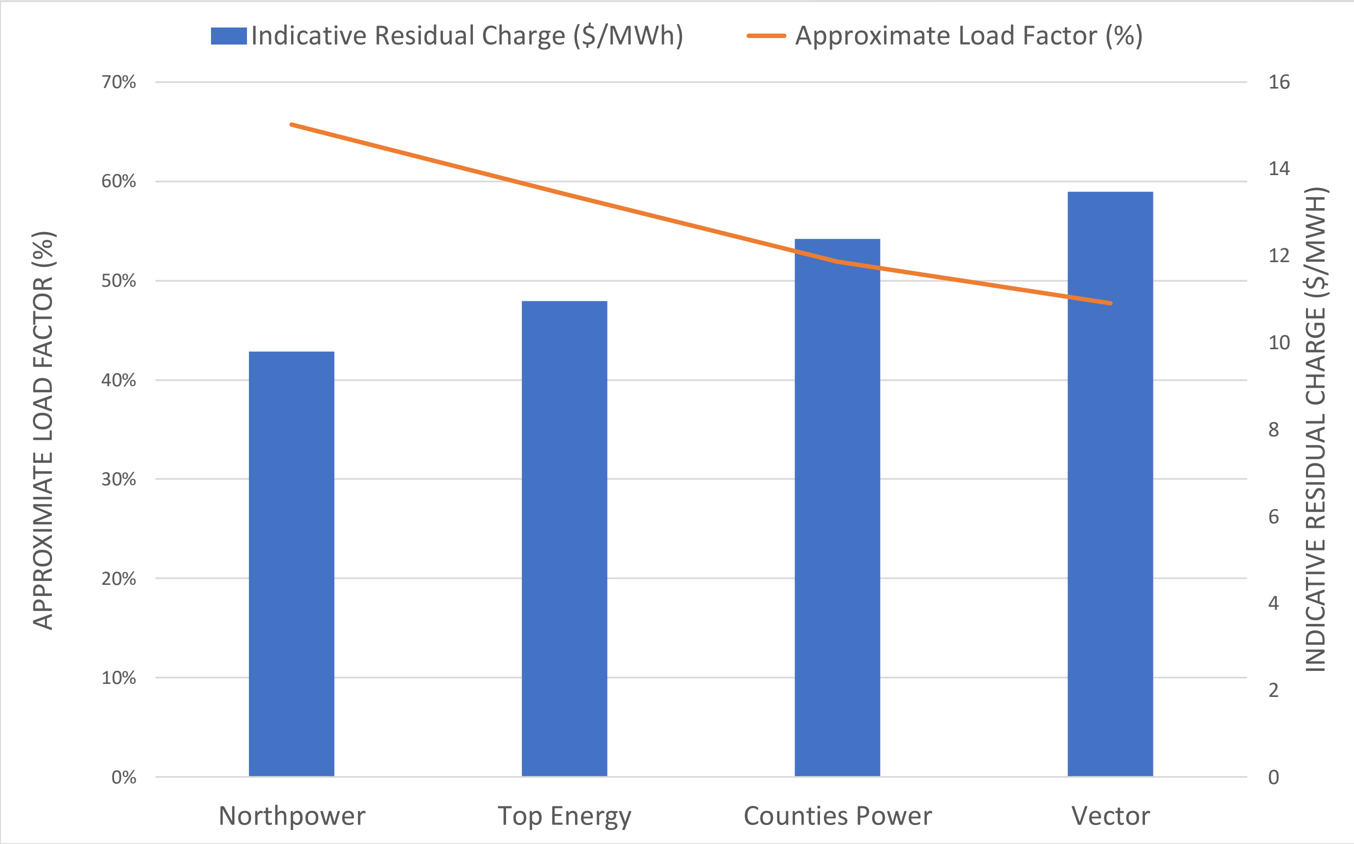
Note: Correction 9/9/19 in ACOT column to match paper--transposed #

Residual charge dominates



$m 2021/22	Benefit-based	Residual
Top Energy	1.0	3.9
Counties Power	3.0	7.2
Northpower	5.4	10.6
Vector	47.6	117.5

Peakier load means a higher $/MWh residual charge



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Indicative impacts – benefit-based charge breakdown

	Bunnythorpe-Haywards	HVDC	LSI Reliability	LSI Renewables	North Island grid upgrade	Wairakei Ring	UNI dynamic reactive
Counties Power	0.32%	1.06%	1.08%	0	2.62%	1.41%	2.62%
Northpower	0.67%	1.13%	2.16%	0	5.98%	2.90%	5.98%
Top Energy	0.00%	0.24%	0.00%	-	1.09%	0.51%	1.09%
Vector	5.51%	10.76%	18.95%	0	51.26%	24.41%	51.26%

	Bunnythorpe-Haywards	HVDC	LSI Reliability	LSI Renewables	North Island grid upgrade	Wairakei Ring	UNI dynamic reactive	Total
Counties Power	20,667	1,047,082	26,329	22,619	1,588,308	128,868	129,003	2,962,876
Northpower	43,645	1,119,405	52,669	47,628	3,620,562	265,395	294,064	5,443,368
Top Energy	-	236,405	-	-	658,413	46,895	53,477	995,190
Vector	359,477	10,643,248	462,176	384,433	31,023,653	2,234,539	2,519,760	47,627,284