2020 Full Year Results Presentation

Twelve months ended 30 June 2020

Putting our energy where it matters

Disclaimer and important information

This presentation may contain projections or forward-looking statements regarding a variety of items. Such forward-looking statements are based upon assumptions at a point in time, and carry significant risks if relied upon.

Actual results may differ materially from those stated in any forward-looking statement based on a number of important factors and risks.

Although management may indicate and believe that the assumptions underlying the forward-looking statements are reasonable, any of the assumptions could prove inaccurate or incorrect and, therefore, there can be no assurance that the results contemplated in the forward-looking statements will be realised.

EBITDAF, underlying profit, free cash flow and operating free cash flow are non-GAAP (generally accepted accounting practice) measures. Information regarding the usefulness, calculation and reconciliation of these measures is provided in the supporting material.

Furthermore, while all reasonable care has been taken in compiling this presentation, Contact accepts no responsibility for any errors or omissions.

This presentation does not constitute investment advice.

Numbers in the presentation have not all been rounded and might not appear to add.

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All references to $ are New Zealand dollar.

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FY20 highlights and progress on strategy

Mike Fuge, CEO

Financial performance down on a very strong comparative period, cash flow supported by controllable cost and capital discipline

	Twelve months ended 30 June 2020 (FY20)	Comparison against continuing operations[3] FY19		Twelve months ended 30 June 2019 (FY19)	
EBITDAF[1]	$451m	↓	-11% from $505m	↓	-13% from $518m
Profit	$125m	↓	-26% from $170m	↓	-64% from $345m
Underlying profit[1]	$129m	↓	-22% from $166m	↓	-27% from $176m
Dividend per share	39.0 cps			-	39.0 cps
Operating free cash flow[2]	$290m	↓	-13% from $334m	↓	-15% from $341m
Operating free cash flow per share[2]	40.4 cps	↓	-13% from 46.5 cps	↓	-15% from 47.5 cps
Stay-in-business (SIB) capital expenditure (cash)	$51m	-	-12% from $58m	↓	15% from $60m

[1] Refer to slides 54-55 for a definition and reconciliation of EBITDAF and underlying profit
[2] Refer to slides 29 for a reconciliation of operating free cash flow
[3] Continuing operations excludes the discontinued Rockgas LPG business sold on 30 November 2018

Operating earnings (EBITDAF) were down by $54m when compared to continuing operations in FY19, a period which included:

- **Stronger hydro generation**
- **Higher wholesale prices**

The operating conditions in FY20 were characterised by:

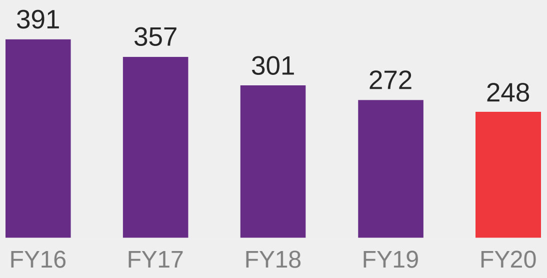
- Rising costs of thermal generation which include gas, carbon and gas storage.
- Disciplined and active commodity risk management and a reduction in fixed priced sales.
- Transmission constraints during planned HVDC outage impacting market making.
- Global pandemic.

Despite the difficult operating conditions, Contact delivered **strong cost control with other operating costs from continuing operations down by $9m (4%) and SIB capital spend down by $7m (12%).** Our high quality renewable generation assets and portfolio structure deliver strong cash flows.

Economics of baseload thermal generation are looking challenged long-term; The Taranaki Combined Cycle (TCC) plant asset useful life has been reassessed with depreciation accelerated, reducing profit in FY20 vs prior comparative period.

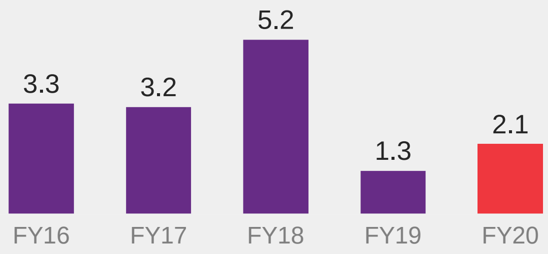
An efficient and focused business, delivering on the controllables and building capability

Maintaining financial discipline
Other operating costs and SIB capex ($m)

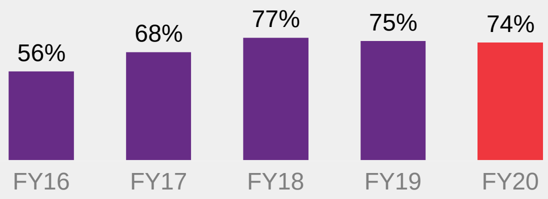


Building customer advocacy
Net promoter score - NPS (Promoters less detractors)

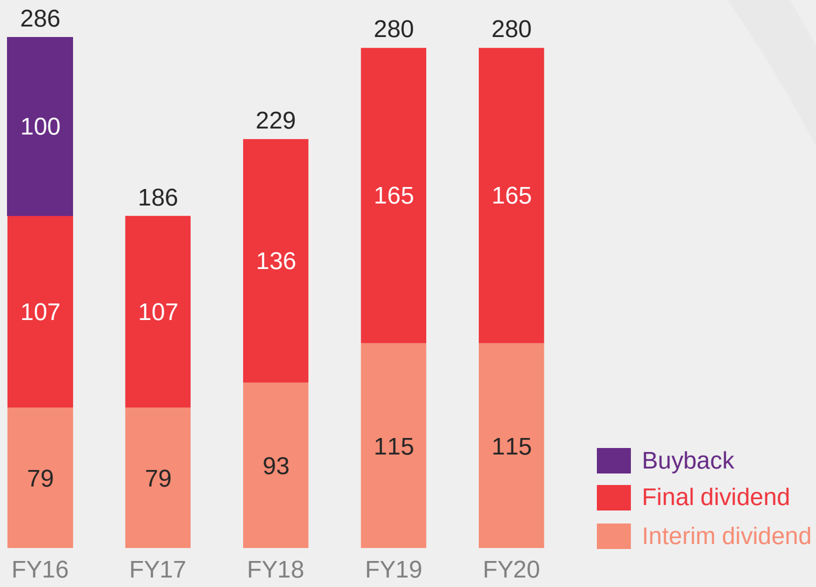
Safe and engaged employees
Total recordable injury frequency rate
(Recordable injuries per million hours worked)



Employee engagement (%)

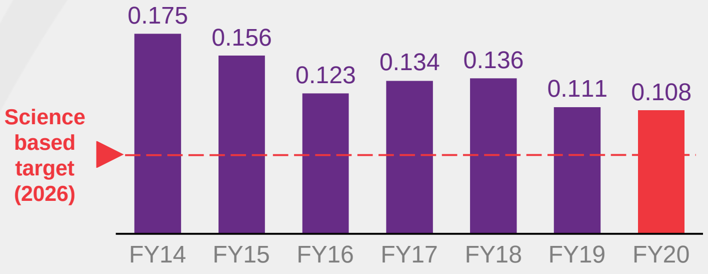


Rewarding shareholders
Distributions ($m)

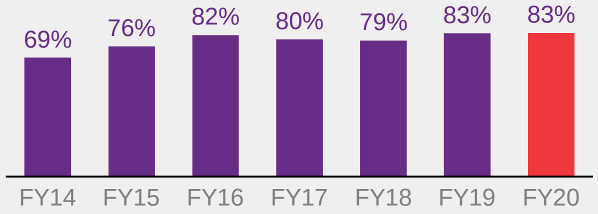


We take a holistic view on our operations to benefit all stakeholders

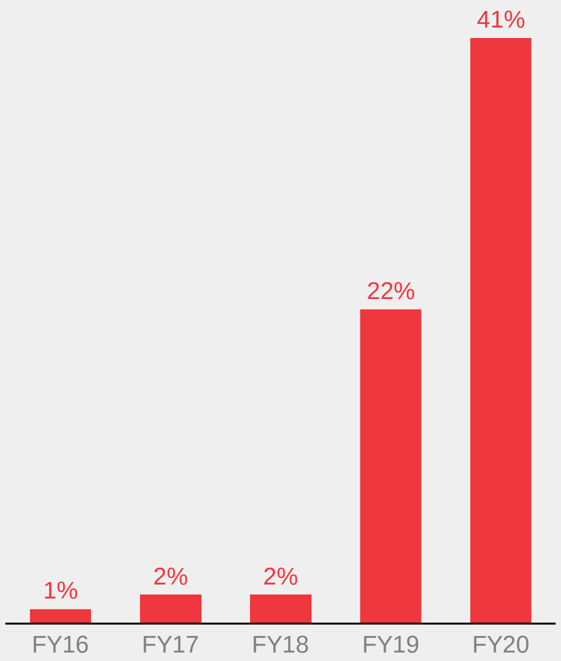
Total generation emissions intensity
tCO2-e / MWh



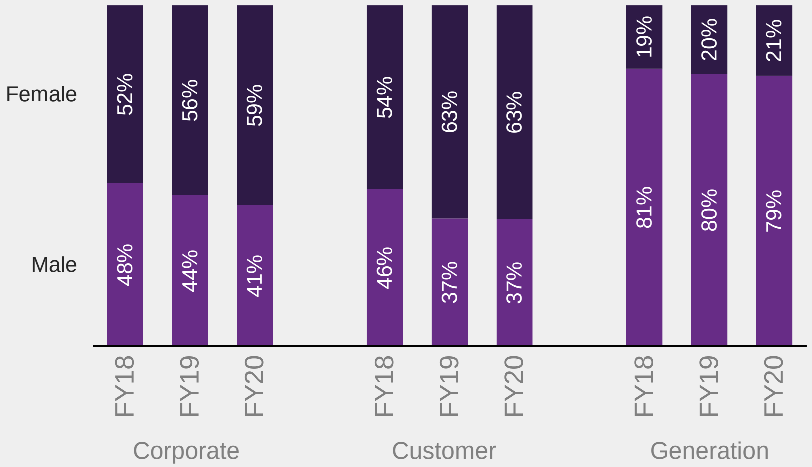
Renewable generation
% of total generation

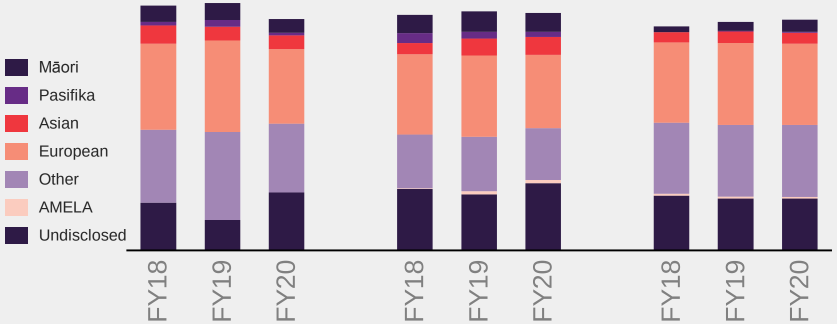


Customers with impaired credit now accepted
% of impaired credit customers accepted



Gender diverse workforce
% of total workforce





NB. Individuals can choose to identify multiple ethnicities

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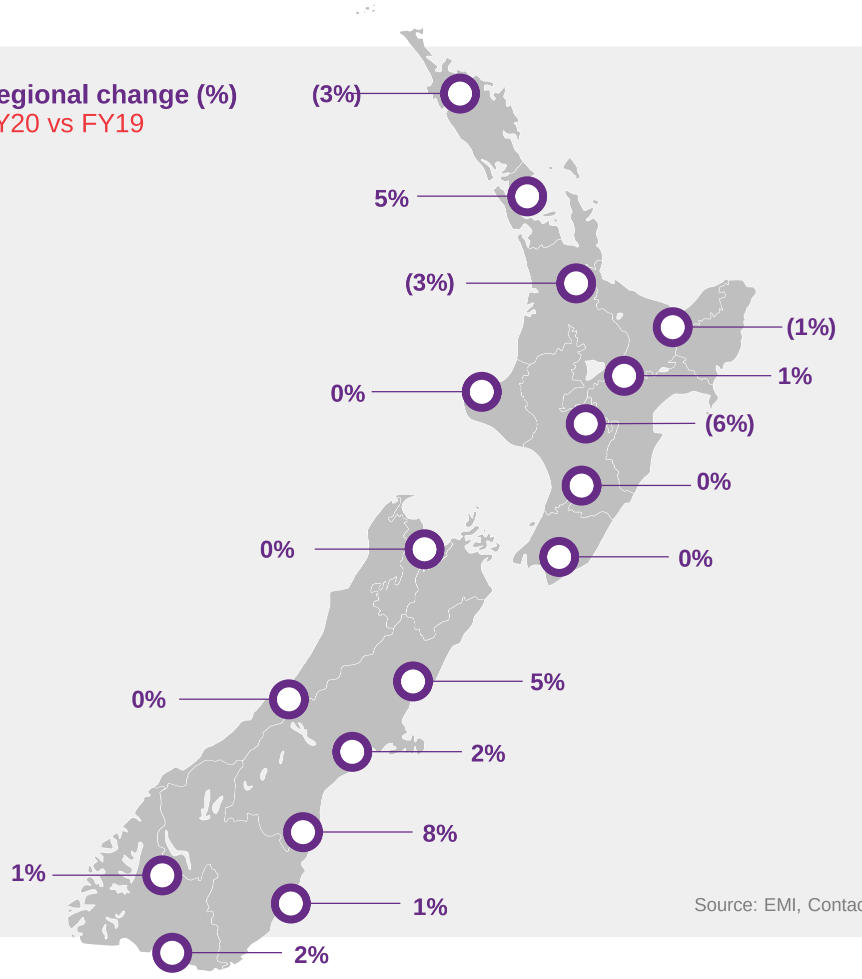
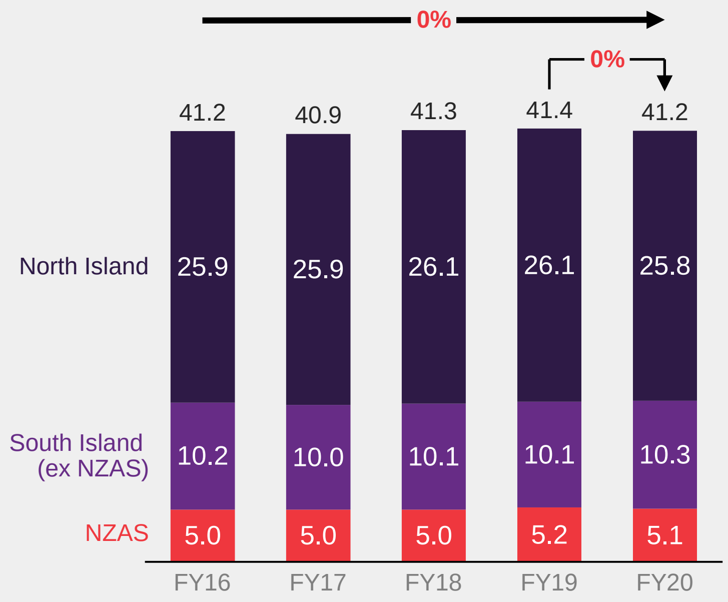
National electricity demand

Regional change (%)
FY20 vs FY19



Source: EMI, Contact

National electricity demand (TWh)



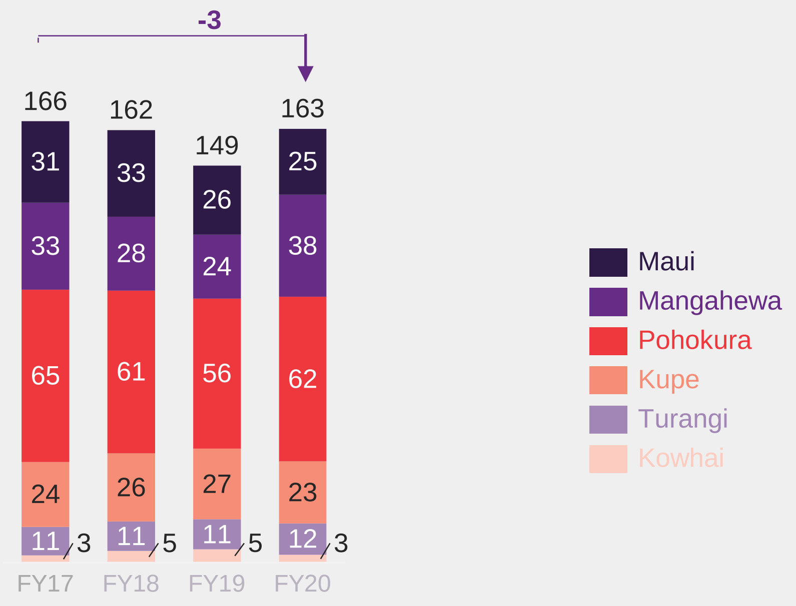
Demand flat. Indicates underlying demand growth once the impact of COVID is included

NZAS curtailed the production from the 4th potline (50MW) from 3 April 2020. NZAS have given notice of termination of their remaining electricity contract (572MW), with closure expected on 31 August 2021.

Source: EMI, Contact

Natural gas production recovered after two years of impaired deliverability

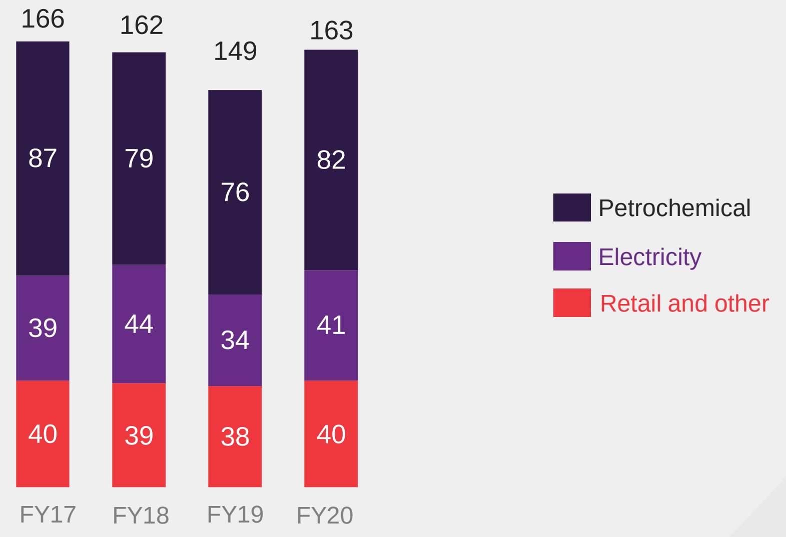
Production from the major fields (PJ)



Source: OATIS

Total production has recovered with increases from McKee Mangahewa, and Maui. Pohokura performing well.

Demand from key sectors (PJ)



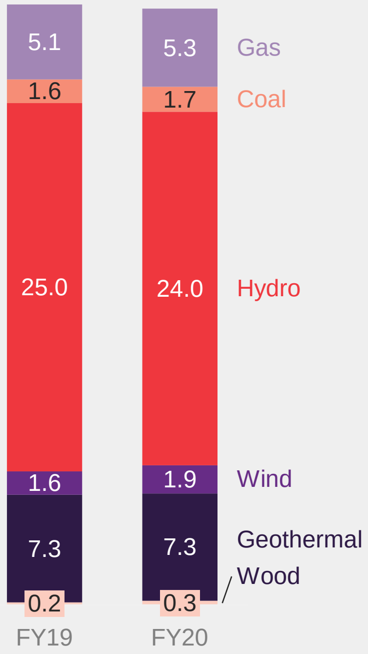
Source: OATIS, EMI, Contact estimate

Gas used in electricity generation in line with the last two years. Concerns around future delivery have resulted in cautious management of hydro storage.

Hydrology and impact on generation mix

Generation by type (TWh)

Generation from generator retailers



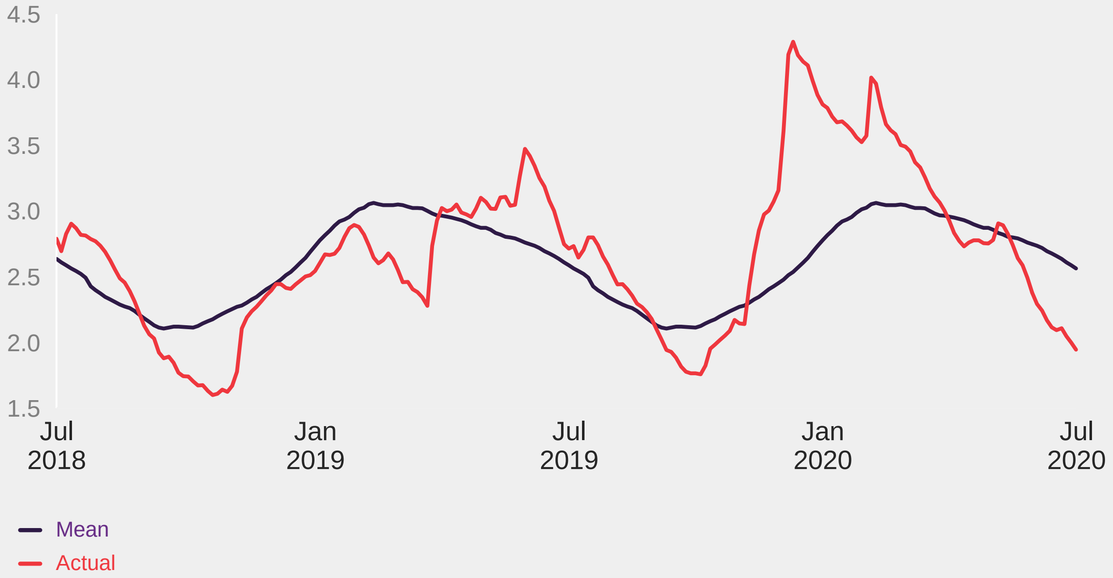
Despite high inflows in November and December 2019, hydro generation was slightly down compared with FY19 following a 3-month HVDC outage limiting the ability to generate from South Island hydro catchments.

The increase in gas fired generation reflects a recovery in gas volumes from the Pohokura field following an extended outage in late 2018. Production from the Maui and Pohokura fields are still below historical levels.

Source: EMI

National hydro storage against mean storage (TWh)

Mean storage 1927 – 2020



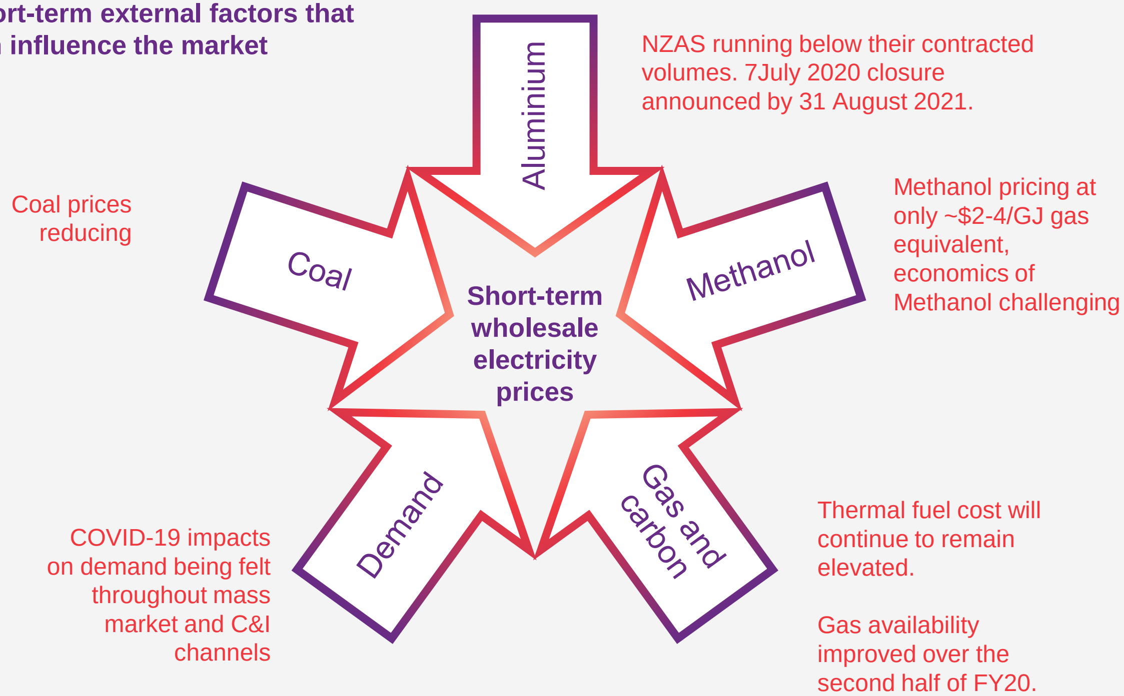
Hydro generators stored more water than historically seen to cover potential 2020 winter exposure in an uncertain gas supply environment, while the HVDC outage limited South Island hydro during the first quarter of calendar 2020.

Source: NZX

In addition to hydrology, wholesale electricity prices are influenced by multiple factors

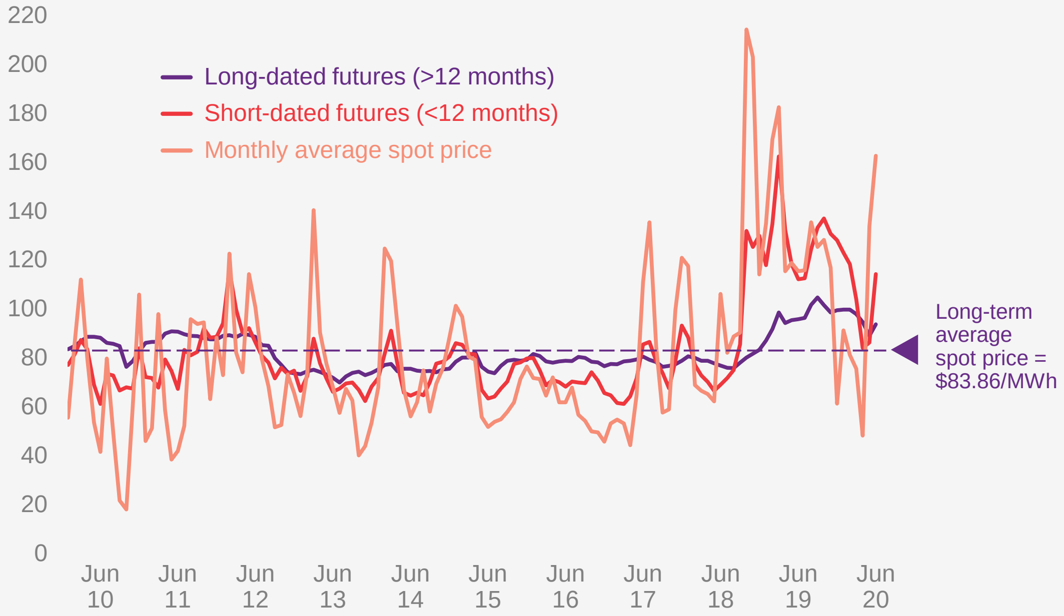
The market quickly responds to key market inputs by sending price signals.

Short-term external factors that can influence the market



Long-term pricing is linked to the **long-run marginal costs of new renewable projects** to meet demand plus costs associated with **firming renewable intermittency**

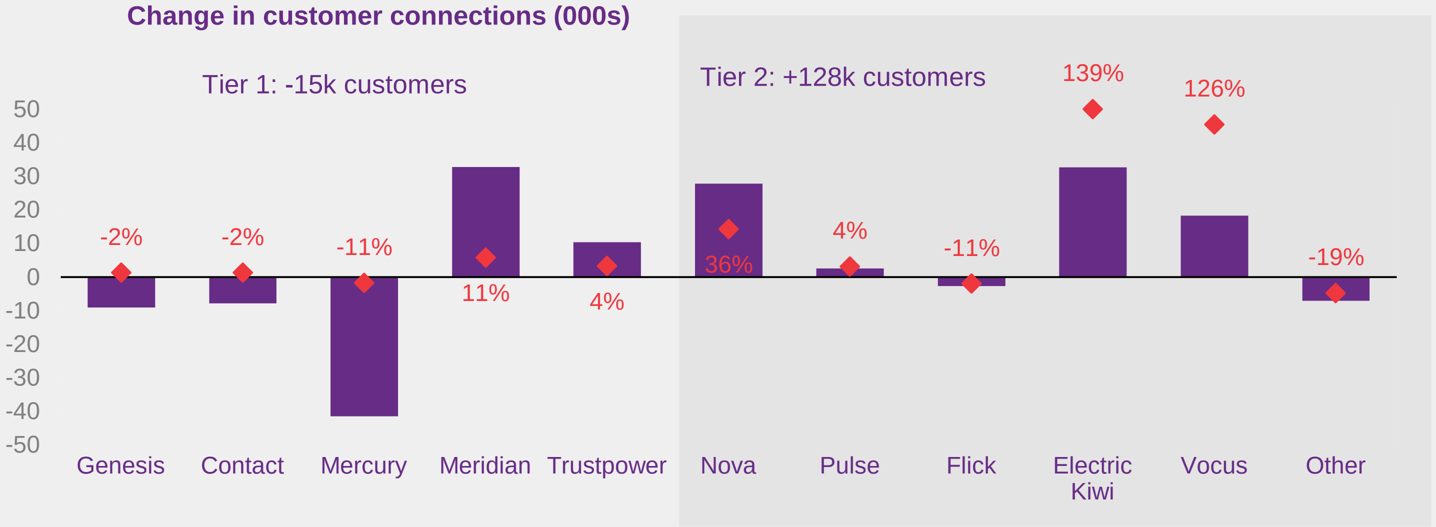
Wholesale and futures electricity pricing ($/MWh)



Both long-dated and short-dated prices remain well above long-term averages, reflecting higher thermal fuel costs.

Source: EMI wholesale pricing

Retail competition remains intense

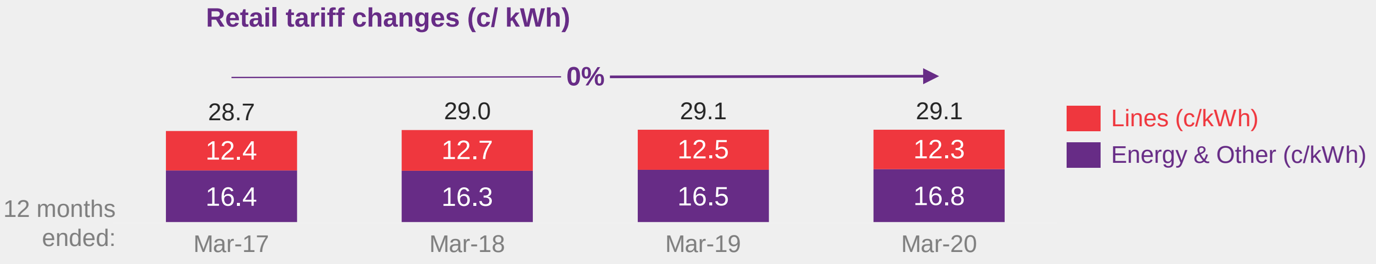


Source: EMI

Retail competition remains intense.

Divergent views on the value of a customer:

- Tier 1: Mercury reducing customer numbers, Meridian growing market share
- Electric Kiwi continuing growth trajectory
- Reducing market share of main players continues, Tier 2 market share now at 15% (from 12% June 2018).
- New connections in line with prior year



Source: MBIE

Despite sharply higher wholesale prices over the last two years, tariffs flat reflecting intense competition and diverging views of long-term wholesale prices.

Regulatory reset of Electricity Distributors WACC, has led to network cost reductions since 1 April 2020.

Topical regulatory matters

Preliminary undesirable trading situation (UTS) findings

The Electricity Authority (EA) reached a preliminary conclusion that a UTS occurred in December 2019 during significant flooding in the lower South Island.

While Contact was not found responsible, Contact disagrees with the EA's initial assessment of market conditions and generators offer behavior.

Plant was appropriately operated

Safety first

Safety of our assets, people and the communities in which we operate is paramount. Contact sought to limit marginal running during the flood event to maintain stable lake levels and ensure steady flows to avoid flooding downstream of Roxburgh. Marginal running can exacerbate changes in lake levels and river flow.

Economically rational

Generators need to offer their generation to be able to recover the economic cost

Submissions close on 18 August, with cross submissions due on 9 September.

Market making

The cost of providing market making services needs to be borne by all beneficiaries including generators, purchasers and financial participants. Contact welcomes the EA's Hedge Market Enhancement workstream and believe a Commercial scheme that is sized appropriately through a competitive process will be the most sustainable and beneficial to consumers.

In January, Contact agreed new ASX trading arrangements that increased market making volume and maintain narrow bid/offer spreads. This was consistent with the EA's request for Contact and other large gentailers to voluntarily provide market making to ensure market liquidity.

The EA is also continuing consultation on enduring market making measures.

A Better New Zealand

We put our energy where it matters

Optimise

the Customer and Wholesale businesses to deliver strong cash flows.

Customer

Wholesale

Disciplined and transparent approach

to operating and capital expenditure. Continuing to investigate ways to optimise our portfolio of assets.

A service and value focused retailer, connecting customers and communities to smart solutions that make living easier for them now, and in the future.

Technology

Leverage advances in technology to drive efficiency with automated customer experiences.

Brand

Brand and reputation repositioned from a strong operational retailer to a smart customer solutions provider.

Operating model

Simple and lean operating model centred on the customer experience, reinventing key customer experiences and processes. Capable employees identifying and driving performance initiatives with ownership and accountability.

DELIVERING CUSTOMER STRATEGY: UPDATE

Technology

Optimisation through ‘clouding’ and digital collaboration

Top rated energy app

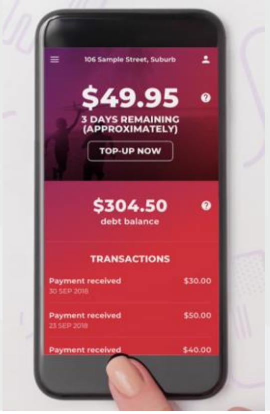
in New Zealand, with usage increasing 90% on prior year

Cloud based systems and software enabling seamless remote working

for all staff through the Covid-19 lockdown

Digital self service interactions up 450%

Through bill and consumption views, payments, account management & support.



Operating model

Targeting reductions in cost to serve

Robotic Process Automation (RPA) implementation

across 26 key processes

130k customers now on zero Prompt Payment Discount (PPD) plans,

following the launch of our Simplicity plans

Cost reductions

with $4m reduction in ICT opex from ongoing platform improvements

Lower customer complaints than market

12% share of all market deadlock complaints relative to our connection market share of ~19%

Net bad debt write offs reduced

by 25% on prior year

Brand

Winning brand recognition and awareness

>26,000 broadband connections

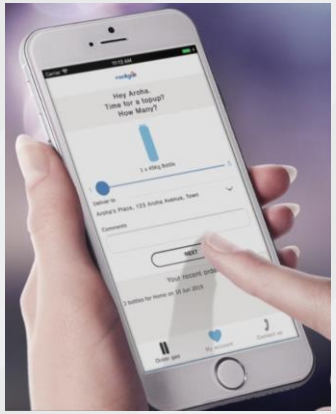
With >19% of customers now taking more than one product or service

Award winning Brand

Charge Energy Global Awards: Best Established Brand, and Readers Digest Quality Service Awards: sector Gold Award

Strong NPS growth

Q4 NPS increased from +26 in FY19 to +36 in FY20



An innovative, safe and efficient generator, working with business customers, and partners to decarbonise New Zealand.

Strong operational performance and options to grow earnings being developed.

Thermal generation

Develop options to enable the economic substitution of Contact's thermal generation assets with renewables.

Improve the economic return on our flexible thermal assets in a volatile market.

Customer solutions

Leveraging capability to expand C&I products and services; underpinned by our investment in Simply Energy.

Partner with customers on mutually beneficial decarbonisation opportunities.

Renewable development

Potential to develop Tauhara, New Zealand's lowest-cost firmed scale renewable generation option:

Prepare a range of development strategies to accommodate the project in a changing market.

Resource proven, project ready for execution as soon as market conditions allow.

Tauhara remains New Zealand's pre-eminent scale renewable development

However, market conditions do not currently support the development of this resource

Recently completed
$40m
appraisal of Tauhara
geothermal field
near Taupo

Secured
the equivalent of
90MW
of high-temperature
production
fluid

150MW
power station
development
with Sumitomo Corporation
as preferred construction
partner

Additional
cash investment
in the order of
$600m
excluding capitalised interest

**The Tauhara development is ready
for execution when market conditions allow.**

Contact successfully adapted to the challenges from COVID-19

Catalyst to accelerate transformation of the operating model

A resilient business with strong systems and capability

- Enterprise-wide programme management office set up identifying opportunities to improve performance
  - Reduced controllable operating and capital costs
- Increased liquidity by $200m for 18 months at short notice to pre-emptively protect against a potential credit market closure

- Support provided to employees
- Support provided to the community

- Credit collection well managed in line with Nga Tikanga, our moral compass
- Customer advocacy improved, with NPS higher

- New ways of working programme accelerated
  - Enabled by technology investment and move to cloud-based applications

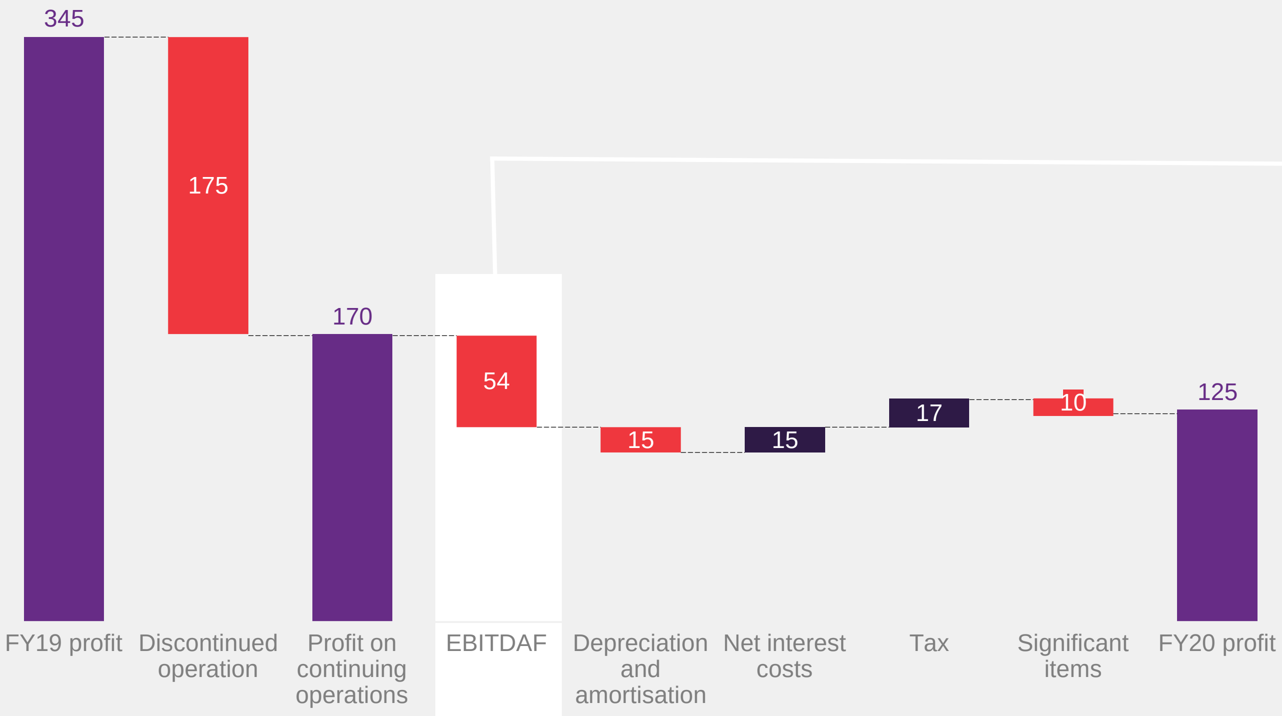
Operational performance and financial results

Dorian Devers, CFO

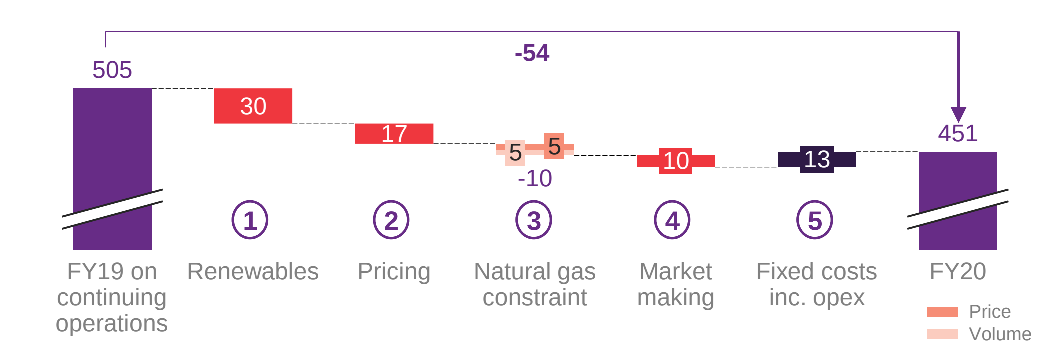
Profit of $125m

EBITDAF from continuing operations down by $54m, reflecting strong prior period and lower hydro generation

Profit ($m)



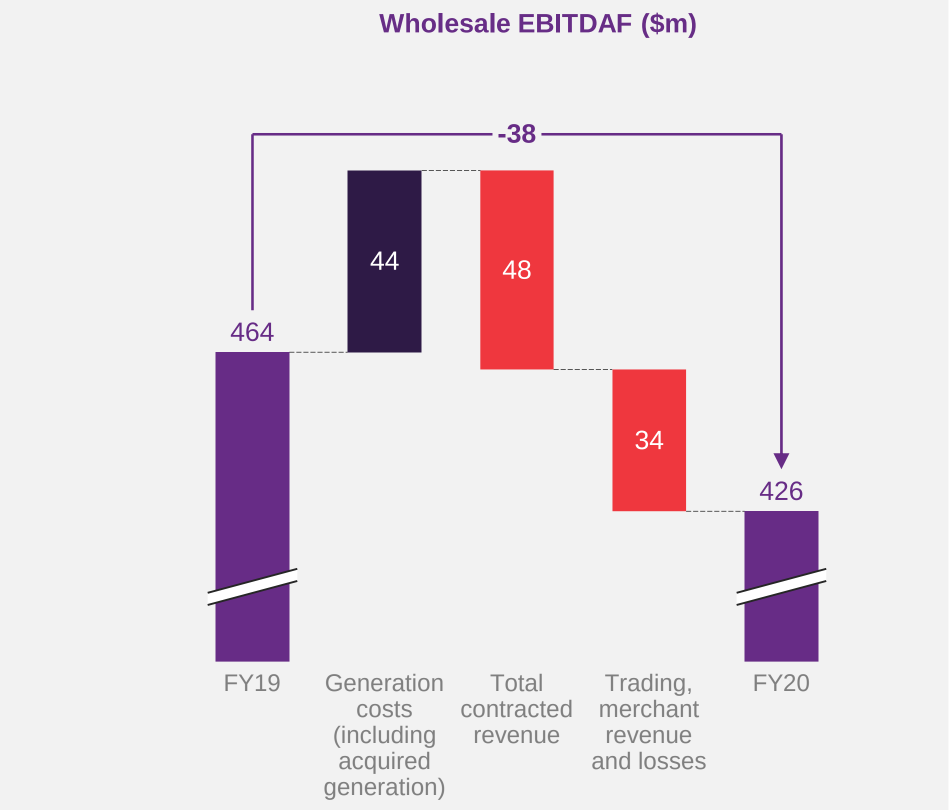
EBITDAF ($m)



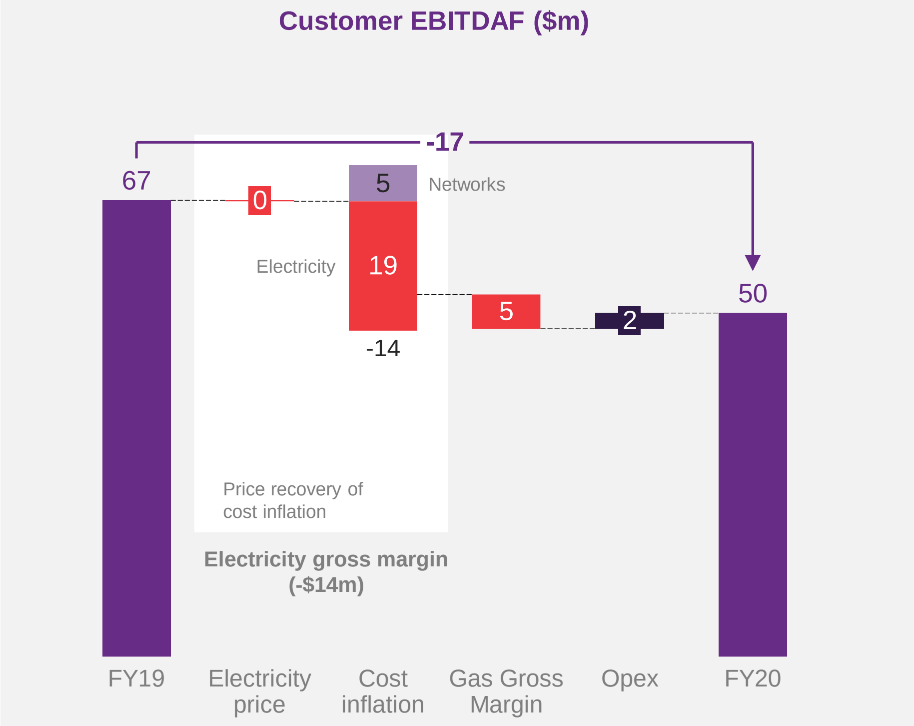
1. Lower hydro year on year (impacted by transmission constraints) partially offset by strong geothermal generation
2. FY19 supported stressed market during unplanned gas field outage.
3. Gas availability issues in 1H20, lower electricity sales volumes.
4. Market makers forced into positions, driving earnings volatility
5. Strong operating cost control and lower transmission costs.

EBITDAF from continuing operations down by $54m

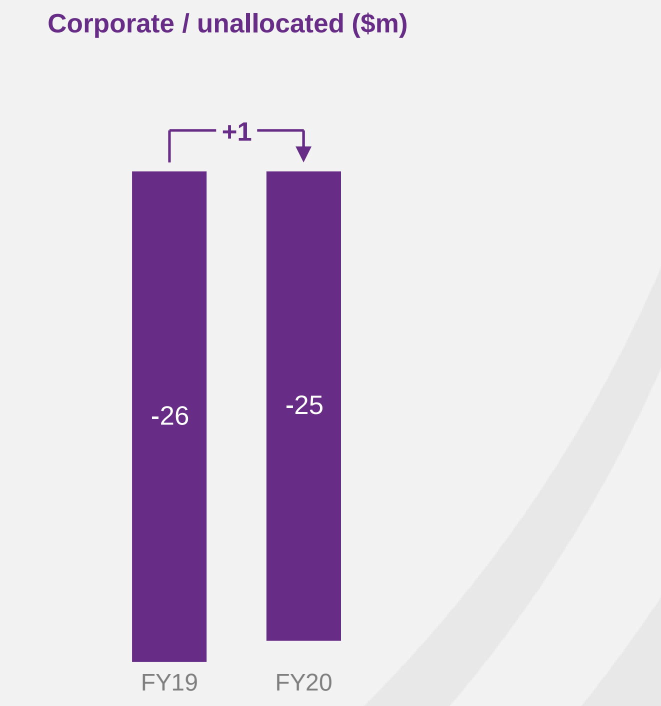
Continuing business performance by segment.



Refer to slides 23 - 25



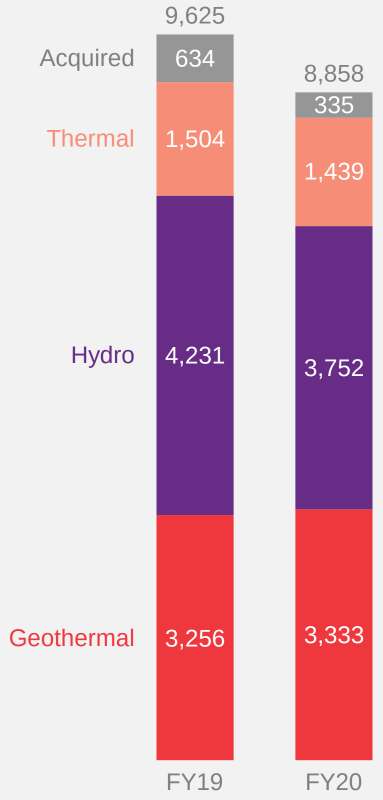
Refer to slide 26



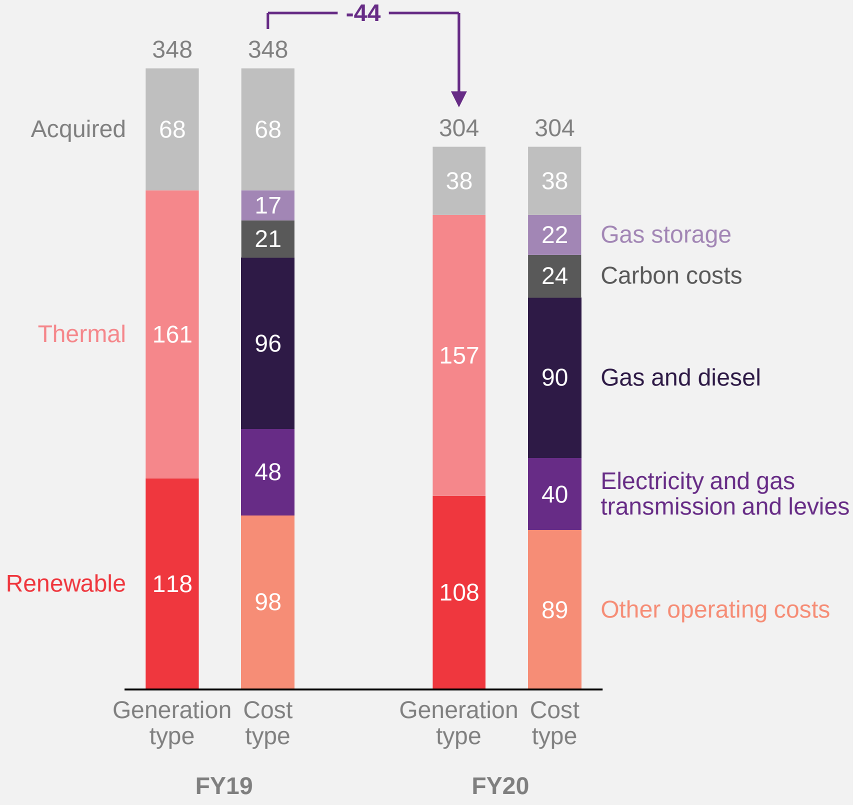
Generation costs

Hydro down 11%. Costs down $44m ($2/MWh) on lower acquired generation, transmission costs and deliberate cost control.

Electricity generated or acquired (GWh)



Electricity generated or acquired costs ($m)



Hydro generation down 479GWh on FY19 (-11%), 4% below that expected in a mean year. Geothermal volumes were 77GWh up on prior year and 33GWh on an average year as Contact processed more fluid in advance of FY21 outages.

- Renewable generation costs were down by $10m. Transmission costs down by $6m, other operating costs down $5m. Geothermal carbon costs were up $1m.

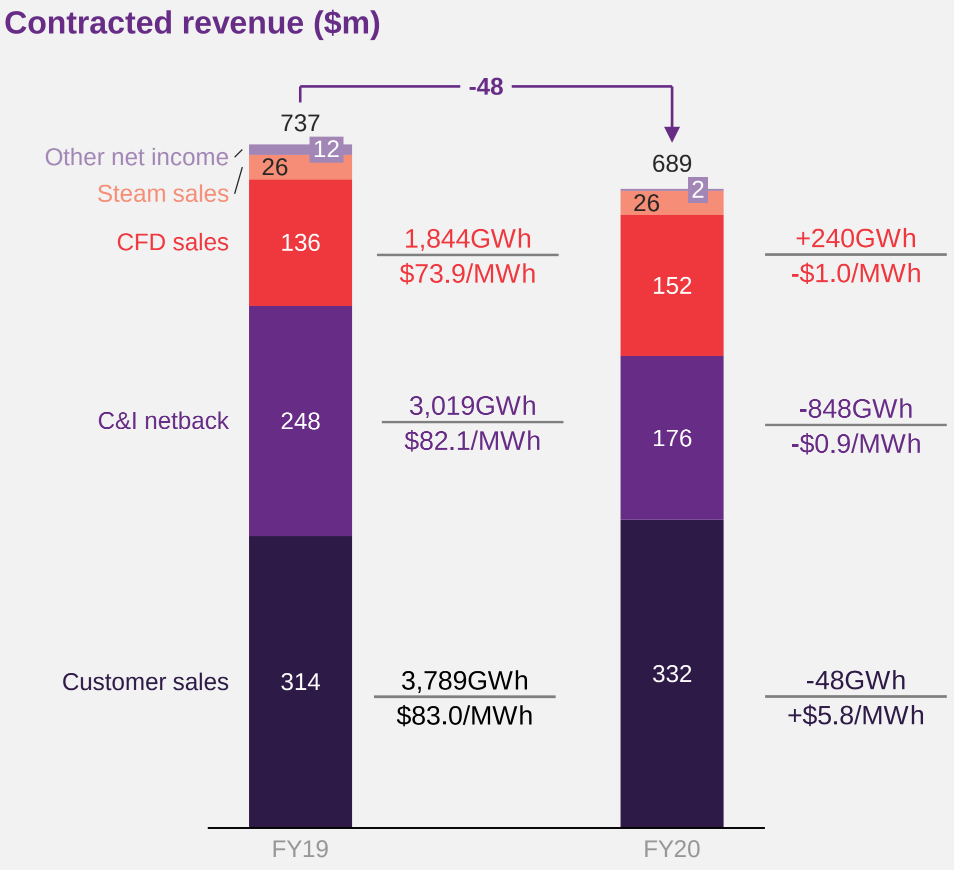
Thermal generation costs were down due to lower thermal generation in the year.

- Gas and carbon unit costs up from $75/MWh in FY19 to $76/MWh (+1%).
- Fixed costs, led by the new gas storage contract (since October 18), were up by $6m on the prior comparative period (net of other operating costs).

An easing of gas supply restrictions over FY20 saw risk management costs significantly lower (down $30m) with acquired generation volume down by 53%.

Wholesale contracted revenue

Sales mix adjusted to manage commodity risk; fuel now contracted to recover fixed price sales

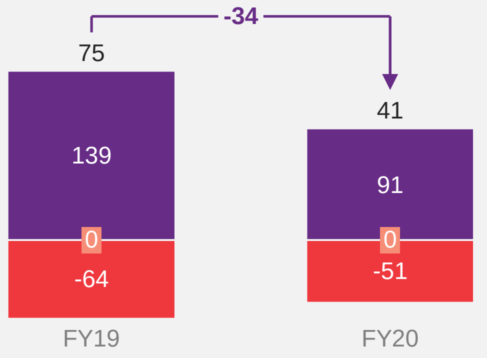


- Fixed price variable volume electricity sales to the Customer segment and C&I customers ended 896GWh lower than FY19 (-$75m), this was partially offset by higher prices (+$22m) to the Customer business, reflecting higher wholesale prices over the three preceding years.
- CFD sales were up by 240GWh with increased sales to support NZAS, which was up by 23GWh on FY19, electricity sales from gas tolling (gas price, not market linked) and CFD sales committed to part way through 1H19 before forward prices rose. Only 274GWh of CFD sales have been committed since October 2018.
- Steam revenue was in line with FY19 with a reduction in volume but increased tariffs on rising carbon costs.
- Other income down by $10m as volatile wholesale markets reduced market making revenue ($9m)

Wholesale trading and merchant revenue

In the prior period we supported the stressed market during the unplanned Pohokura outage by selling 'merchant'. Contact enjoyed favourable hydro generation during this period.

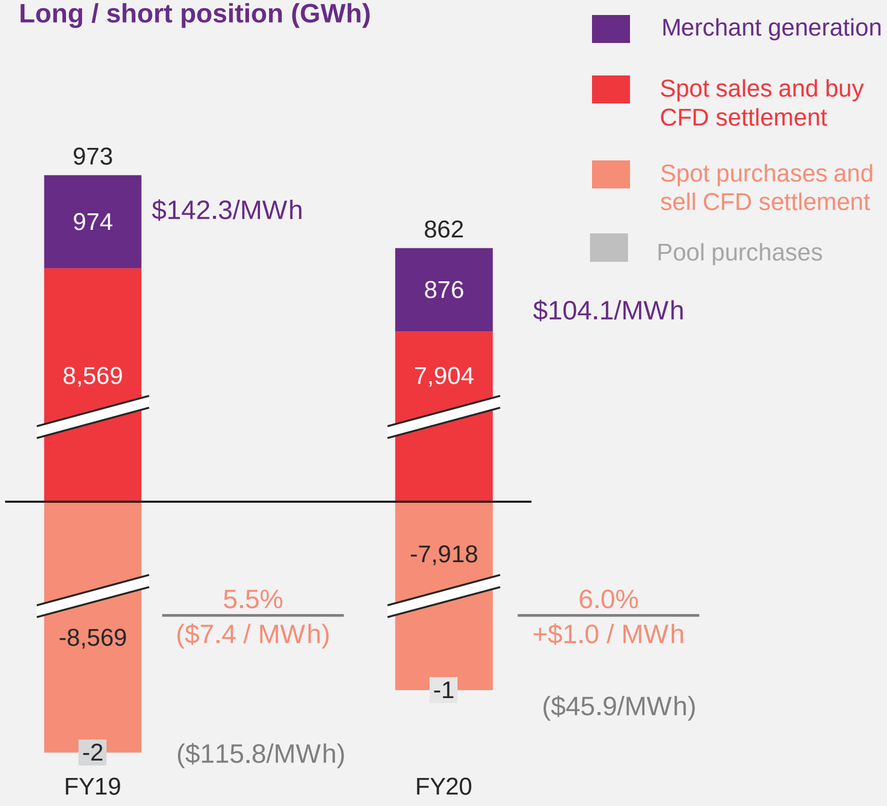
Trading EBITDAF ($m)



Trading revenue

- **Merchant sales:** short-term sales channel available when the spot prices exceed the opportunity cost of Contact generation.
- **Pool purchase:** short-term opportunistic purchases from the spot electricity market when better value than alternatives (adjusted for volatility and volume).
- **LWAP / GWAP losses:** locational price differences between where electricity is generated and purchased.

Long / short position (GWh)



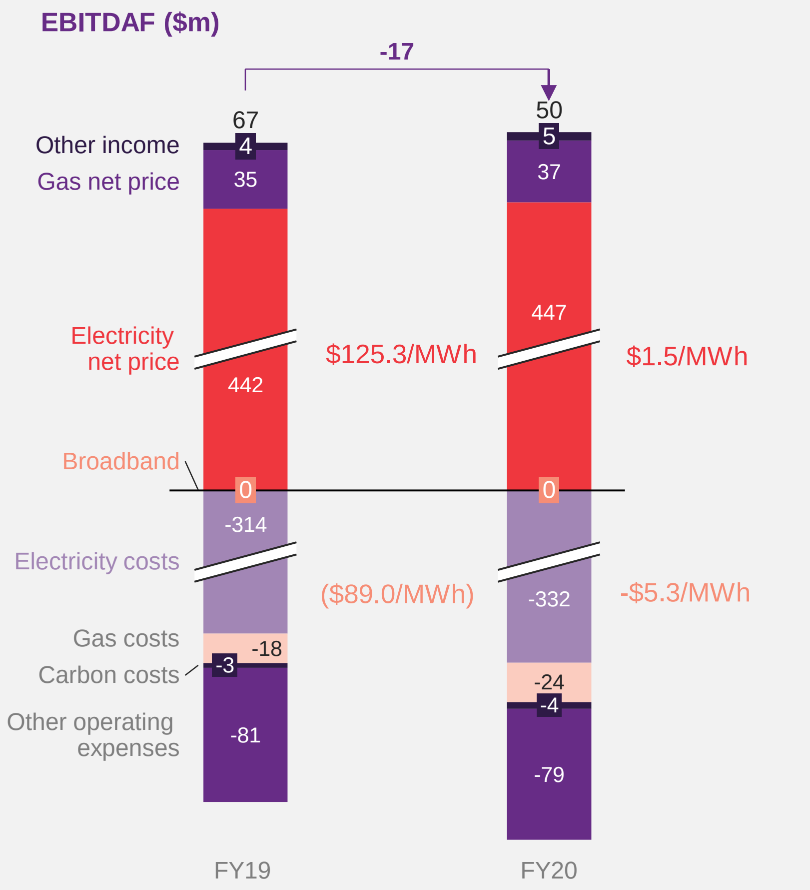
- 98GWh decrease in merchant sales volumes (-$10m). The price received for this "long" generation was down by $38.2/MWh (-$37m).
- Strong risk management saw limited price exposure to unhedged spot market purchases during higher wholesale price periods.
- The relative reduction fixed price sales and lower wholesale prices saw absolute LWAP/GWAP improve by $13m.

Customer business performance

Government's regulatory review completed.

Revenue & Tariff[1] ($m)	FY19	FY20		Variance	
	$m	$m	*Tariff*	$m	*Tariff*
Electricity gross revenue	858	859	*243.7*	1	0.8
PPD not taken	12	10			
Incentives paid	(7)	(6)			
Net revenue (cash)	**863**	**862**	***244.8***	**(1)**	**0.7**
Capitalised incentives	9	7			
Amortised incentives	(8)	(8)			
Net revenue (P&L)	**864**	**861**	***244.5***	**(3)**	**0.0**
Gas revenue	73	74	*88.8*	1	3.8
Broadband revenue	7	17	*70.1*	10	(27.5)
Other income	4	5		1	
Total revenue	**948**	**957**		**9**	
Contract Asset (closing)	16	13		(3)	

1. Tariff is $/MWh for electricity, Gas $/GJ and $ per month per customer connection for broadband



Net price is Revenue less Networks, Meters and Levies. $/MWh is at the ICP

Electricity tariff changes reflect the regulatory pressures and the competitive environment:

- 16k customers migrated to fit-for-purpose plans.
- End to further Prompt Payment Discounts - 19% reduction in PPD not taken.
- Free electricity to charities during COVID ($0.7m).
- Only ~20% of customers received a price increase in FY19, resulting in limited flow through.

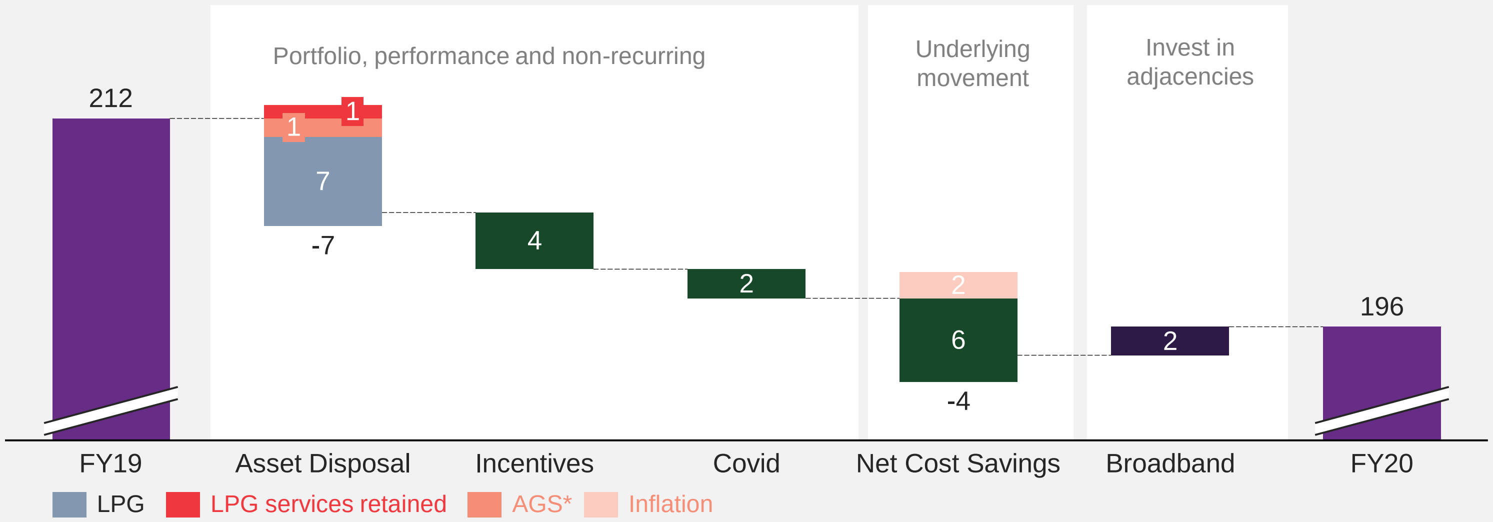
Smooth the impact of higher electricity costs for customers, which are up by 6% on FY19.

- Combination of targeted retail price rises and a reduction in network costs from 1 April 2020 has seen gross margins recover.

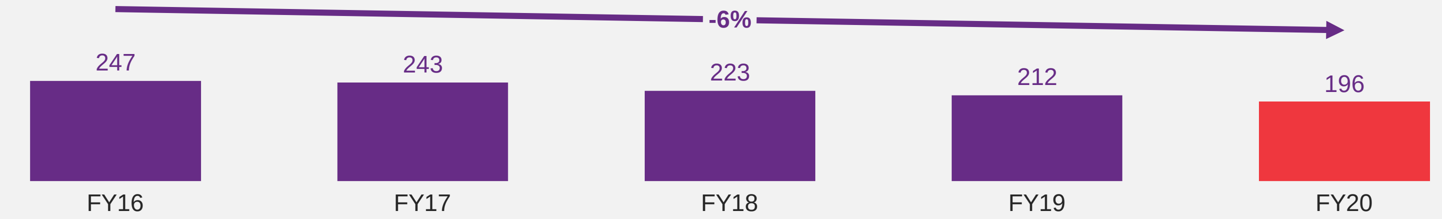
Retail gas tariffs will need to rise to reflect rising gas and carbon costs.

Controllable operational expenditure continues to fall

Other operating cost movement ($m)



Other operating cost ($m)



*Ahuroa Gas Storage

Underlying movement

$5m from procurement savings with ICT delivering reductions from insourcing activity and relocation of servers into the cloud.

$1m change in meter read provider.

COVID

$2m from reduced marketing

- Reassessed the tone of customer engagement during COVID.

$1m from reduced field services and travel.

($1m) from an increase in provision for bad debts.

Other operating cost trajectory

Reduction of 6% CAGR since FY16.

Delivered $6m of underlying operating cost improvement exceeding our FY20 target of between $200m – $205m.

.

Normalised and expected EBITDAF assumptions

With reconciliation to actual performance.

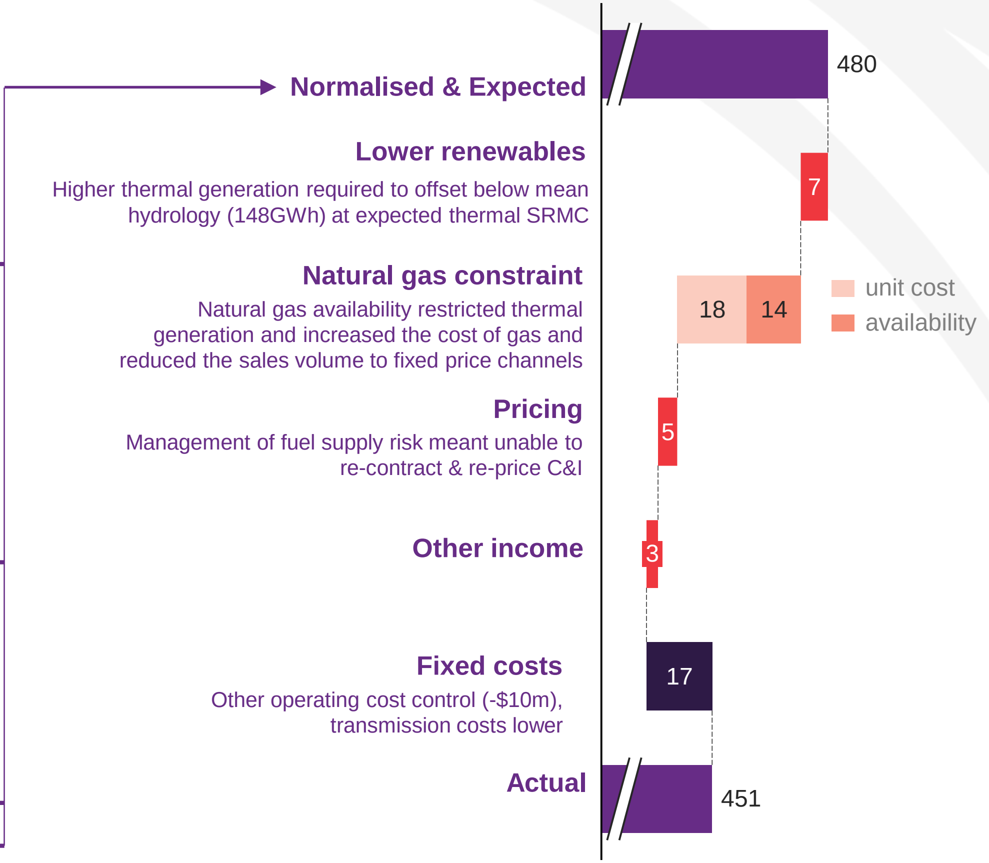
FY assumptions that deliver expected & normalised EBITDAF of $480m

1 Channel choices maximise long term value[1]		X	2 Net price[2] driven by best commercial practices	=	Total
CFDs	1,450GWh	x	$64/MWh	=	$93m
C&I	3,350GWh	x	$83/MWh	=	$278m
Retail	3,800GWh	x	$117/MWh	=	$445m
Other income[3]					$50m
					$866m

3 Hydrology & Asset availability optimise generation		X	4 Access to and price of fuel* drives financials & risk position	=	Total
Hydro mean	3,900GWh	x	$0/MWh	=	-$0m
Geothermal average	3,300GWh	x	$1/MWh	=	-$3m
Thermal	1,800GWh	x	$66/MWh[4]	=	-$119m
Acquired	100GWh	x	$100/MWh	=	-$10m
					-$132m

5 Trading delivers value to more than offset locational losses		6 Digitalisation & continuous improvement optimise fixed costs	
Length[5]	$55m	Transmission/Storage	-$70m
Location losses[6]	-$36m	Operating expenses	-$203m
Total	**$19m**	**Total**	**-$273m**

EBITDAF reconciliation to FY20



1. All volumes are at the Grid Exit Point (GXP)
2. Net price is equal to tariff less pass-through costs (network, meters and levies) /MWh
3. Steam sales, retail gas gross margin, other income
4. Gas price of $6/GJ, carbon price of $20/unit and thermal portfolio heat rate (9.25GJ/MWh)
5. Length of 500GWh p.a. assumed
6. Locational losses of 5.6% on spot purchases and settlement of CFDs sold at a wholesale price of $75/MWh

* Fuel is natural gas and carbon costs

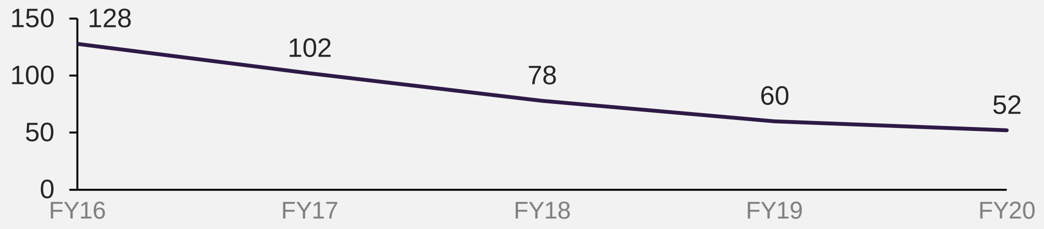
Cash flow and capital expenditure

Underlying cash conversion remains strong.

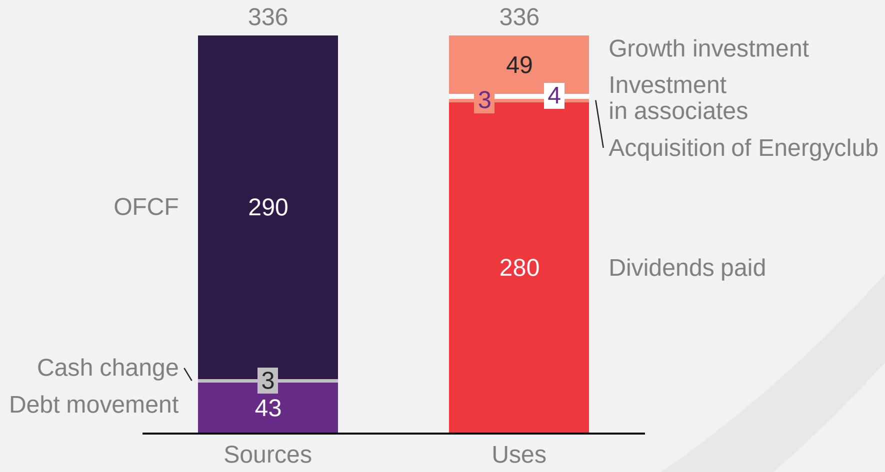
	12 months ended 30 June 2020	12 months ended 30 June 2019	Comparison against FY19	
EBITDAF	**$451m**	$518m	↓	($67m)
Working capital changes	**$7m**	($7m)	↑	$14m
Tax paid	**($70m)**	($47m)	↓	($23m)
Interest paid, net of interest capitalised	**($49m)**	($65m)	↑	$16m
SIB capital expenditure	**($51m)**	($60m)	↑	$9m
Non-cash items included in EBITDAF	**$2m**	$4m	↑	$2m
Significant items	**-**	($2m)	↑	$2m
Operating free cash flow	**$290m**	$341m	↓	($51m)
Operating free cash flow per share	**40.4 cps**	47.5 cps	↓	(7.1 cps)
Proceeds from sale of assets/operations	**-**	$390m	↓	($390m)
Free cash flow	**$290m**	$731m	↓	($441m)

- EBITDAF down $67m with continuing operations down $54m with $13m from Rockgas (discontinued)
- Working capital changes $14m favourable as debtors balance reduced in line with fixed-priced sales
- Capital expenditure (cash) on continuing operations of $51m in FY20, $9m less than FY19

SIB capital expenditure – accounting ($m)



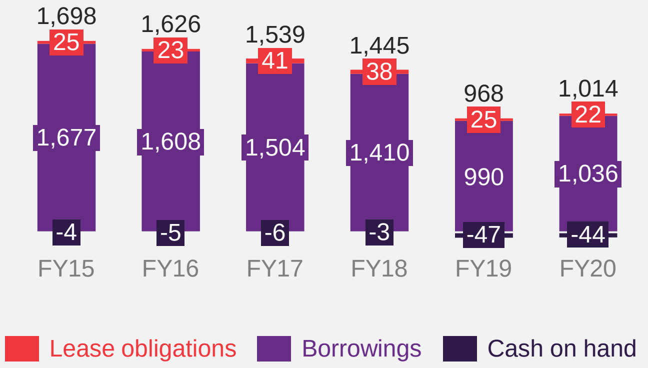
Sources and uses of cash ($m) FY20



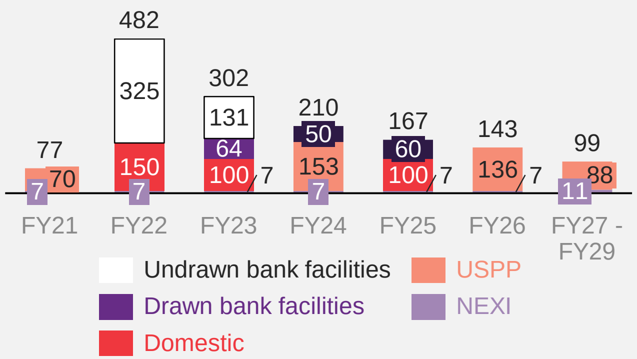
Robust balance sheet

Well-managed, diversified portfolio with green certification. Capacity to withstand uncertain operating conditions.

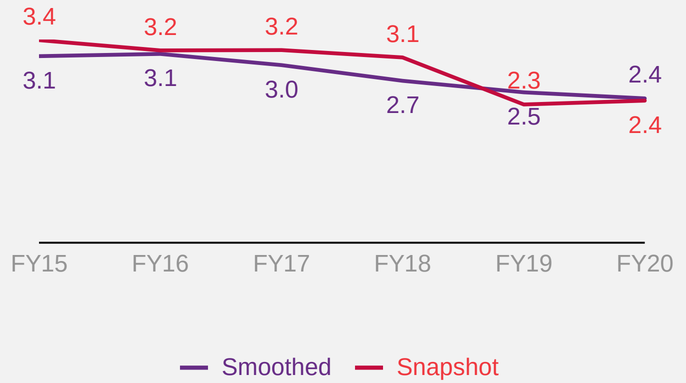
Closing net debt ($m)
Face value of borrowings less cash



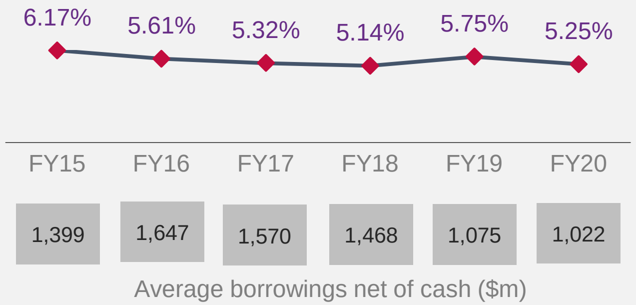
Borrowing maturities ($m)
Average tenor of 3.0 years as at 30 June 2020



Net debt to EBITDAF (x)
Includes S&P adjustments (prior to FY20 AGS was treated as a lease)



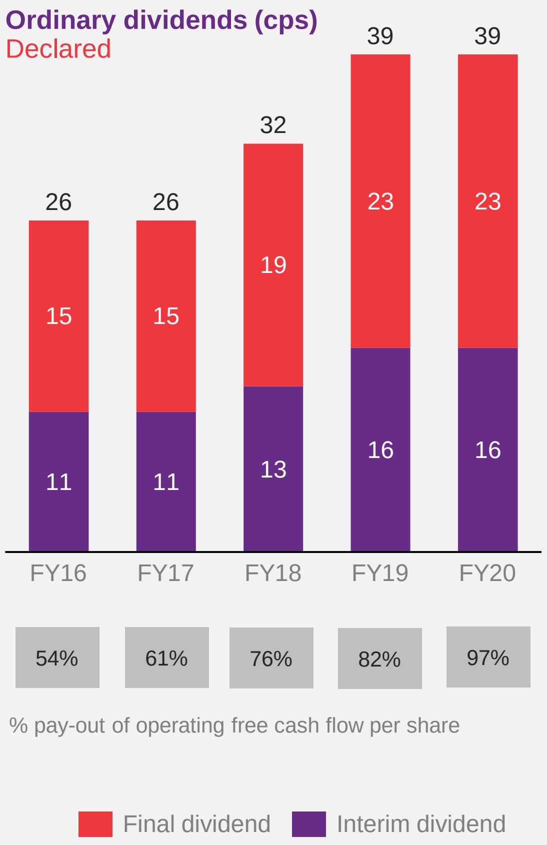
Interest rate (%)
Weighted average net interest[1] on average borrowings net of cash



- Face value borrowings net of cash (excl. leases) increased by $46m to $1,036m from 30 June 2019. This was due to investments in associates and growth capex exceeding operating free cash flow.
- Net debt has reduced by $684m since the end of FY15. Gearing was 31.4% at 30 June 2020, up from 28.3% at 30 June 2019.
- $70m USPP maturity in December 2020 is expected to be funded through existing facilities.
- Weighted average interest rate reduced by 50bp compared to FY19. A greater portion of funding was financed at low floating rate debt in FY20.
- Contact continues to target a credit rating of BBB (net debt / EBITDAF <2.8x).
- New sustainability linked loan was executed in December 2019, aligning capital structure with strategic ESG ambitions.
- $200m syndicated loan was established in April 2019 to provide additional liquidity buffer during COVID-19.

1. Net interest includes all interest on borrowings, bank commitment fees and deferred financing costs. Unwind of leases and provisions not included.

Dividend for FY20 in line with target



Dividend for FY20 of 39 cents per share

- Final dividend of 23 cents per share (Final FY19 23 cents per share) is imputed to 65% or 15 cents per share for qualifying shareholders. This represents a pay-out of 97% of FY20 operating free cash flow per share.
- Record date of 27 August 2020; payment date of 15 September 2020.
- The NZD/AUD exchange rate used for the payment of Australian dollar dividends will be set on 1 September 2020.

Market update and outlook

Mike Fuge, CEO & Dorian Devers, CFO

A disorderly exit impacts multiple stakeholders

Suppliers

- Reduced return on thermal assets and lower natural gas demand
- Heavy industry
- Premature decline of the oil and gas sector

Government

- Impact on the Southland and Taranaki economy, loss of regional jobs
- Carbon leakage from low carbon aluminum
- Inefficient capital investment decisions
- Loss of tax revenue; current account impact

Communities & employees

- Large closing costs with uncertain remediation timeline
- Uncertainty from 14 month termination
- Infrastructure and supply chain to support NZAS
- Retooling and reskilling – time and investment

Joined up thinking is required:

1. Risk of a disorderly exit needs to be fully understood
2. Competitive short-term electricity contract negotiated to facilitate a staged exit
3. Fair transmission pricing
4. Working with the Southland community to understand the terms of a just transition

South Island renewable supply to the North Island increases

Transmission investment underway, Transpower evaluating acceleration options

What we know

NZAS consumes 13% of national demand, 572MW baseload contract, located in the lower South Island.

Transmission constrained at times until May 2022 leading up to 0.6 TWh of spill p.a. for Contact.

HVDC currently runs at an average of ~275MW over a year:
- Physical capacity 1,200MW, practical capacity with current reserve arrangements 950MW
- Post LSI* upgrade and with effective lake management there is HVDC capacity for all of Tiwai linked generation to flow North
- Base load thermal will limit South Island generation and lead to unnecessary spill

Currently ~$1bn being invested in wind in the NI which will further limit SI hydro coming across the HVDC.

The key bottleneck is caused by the actual NI demand less must run NI renewables and the reserves.

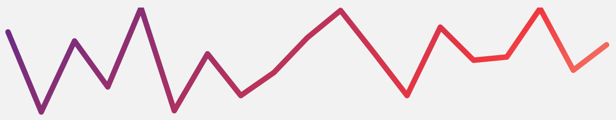
*Lower South Island

South Island renewable supply to the North Island increases

Actual HVDC flows will be determined by a range of volatile factors

Hydrology

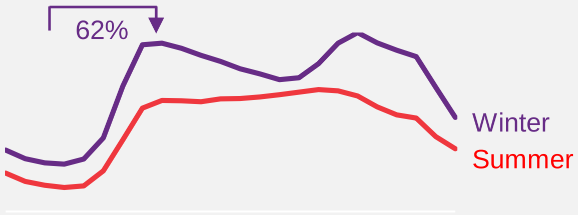
Annual Hydrology (2000 - 2019)



Min **22.7 TWh** | Mean **25.3 TWh** | Max **27.7 TWh**

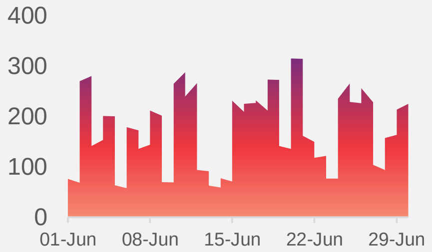
Daily demand shape

Daily demand (MWh)



Wind generation

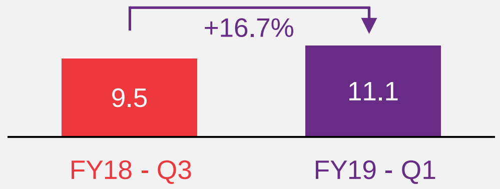
Wind generation
(MW by trading period June 2020)



Multiple variables will impact actual HVDC South to North Flow up +950MW

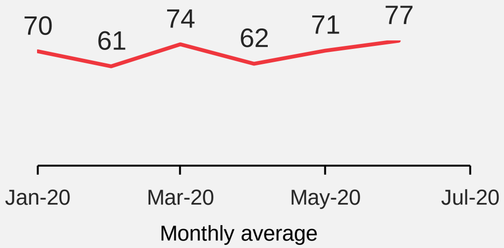
Seasonal demand

Seasonal demand (TWh)



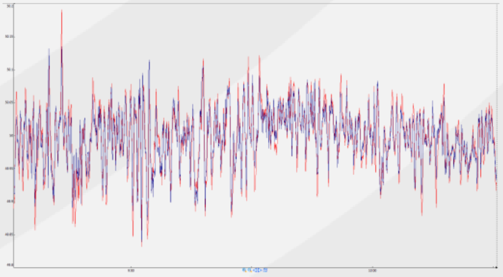
Take-or-pay gas contracts

Kupe delivered energy (TJ/day)



North Island reserves

Increase reserves will increase HVDC capacity beyond 950MW



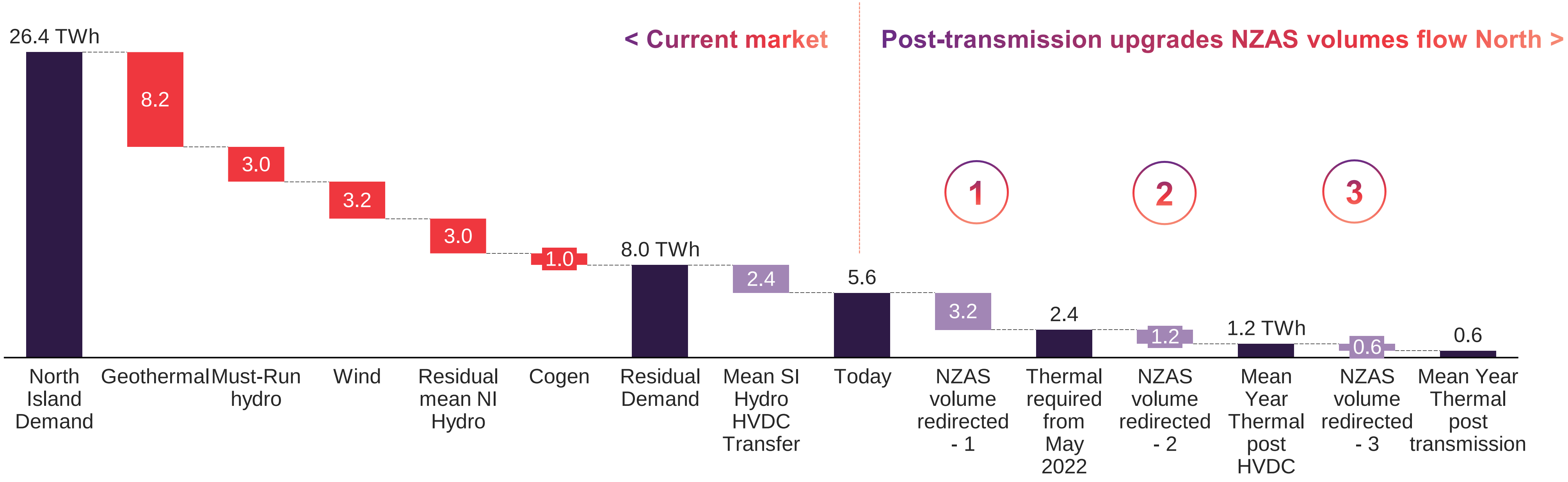
*at time North Island demand less than must run NI generation

North Island position

Thermal generation has a limited role after the HVDC investment

North Island energy market

- Thermal generation will become increasingly volatile and therefore require flexible gas and/or coal.
- On a national level 5.6 TWh of thermal generation is currently required. This would reduce to ~0.6 TWh under mean hydrological conditions once the HVDC is invested in.
- Additional North Island generation is not required without demand.

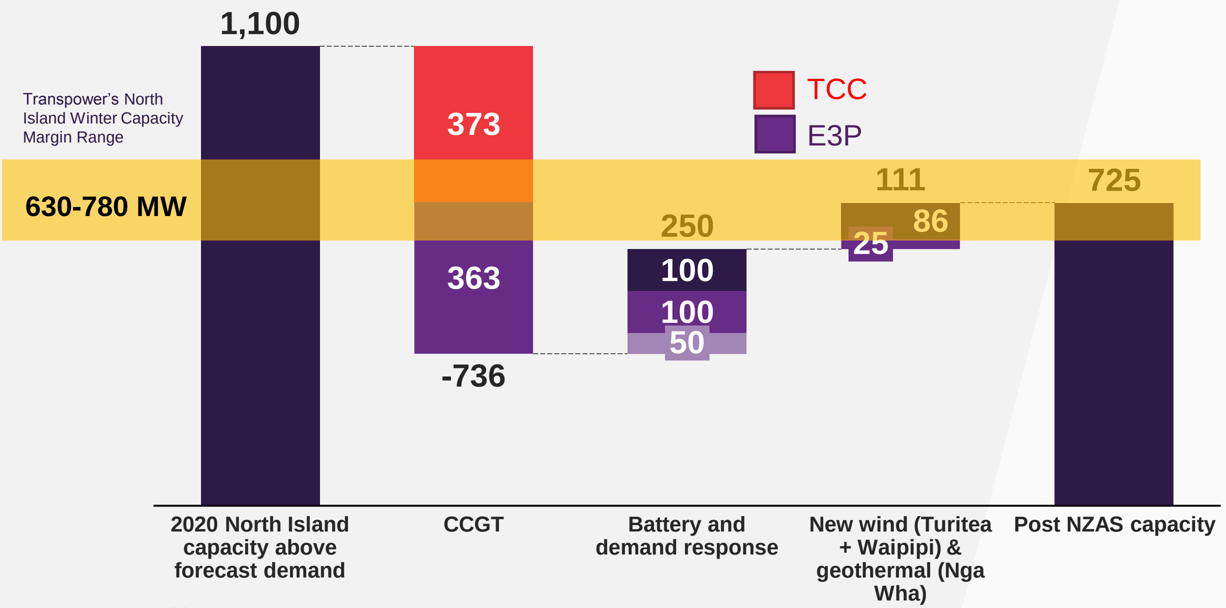


North Island capacity

Limited requirement for thermal generation except to cover outages, North Island hydro risk and peak demand growth.

North Island Winter Capacity Margin (MW)

Transpower's North Island Winter Capacity Margin (WCM) Security Standard (April 2020) is still exceeded post NZAS without any CCGTs.

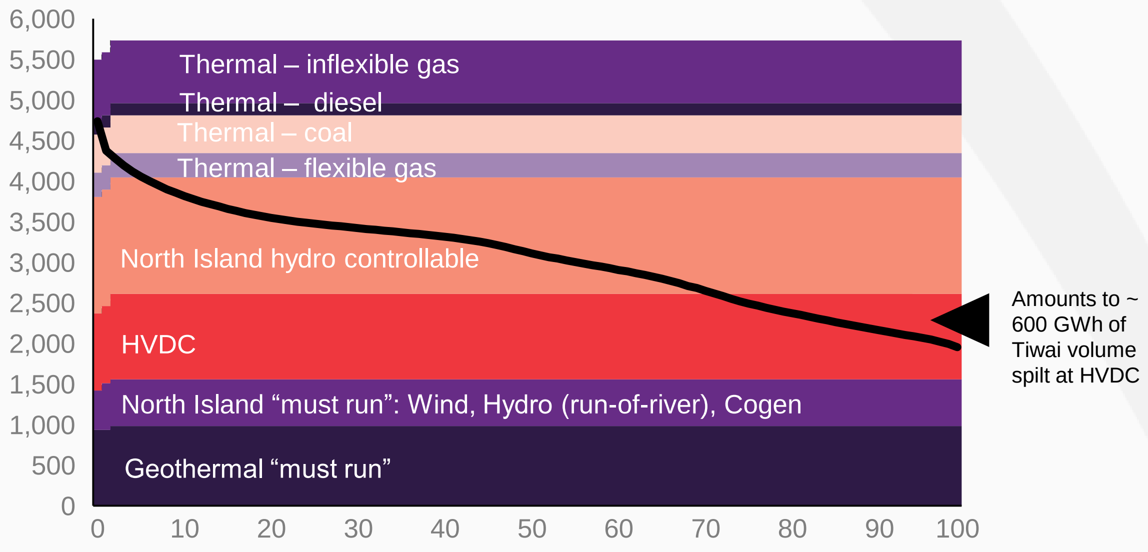


Notes

1. Based on Low Demand growth scenario
2. Wind: 25% of the installed capacity
3. North Island WCM Security Standard is 630-780 MW

North Island demand duration curve (MW)

Generation capacity to meet the market.



Using Transpower's contribution to winter capacity margin calculations.

There appears no role for any baseload thermal generation post NZAS exit.

Required thermal generation

TCC faces the same challenge as all thermal plant, with the advantage of flexible fuel through gas storage.

Plant type	Fuel type	Fuel flexibility/ economic dispatch	Efficiency / operating costs	Dry year / seasonal	Daily shape	Reserves	Assessment of value post NZAS exit
Open cycle	Diesel	+++	---	-	+++	+++	More important role
Peaker	Gas with storage	+++	+	++	+++	++	Critical in managing volatility
	Gas with take-or-pay/inflexible/integrated	--	++	+	-	+	Baseload thermal not required
Rankine cycle	Coal	++	--	+++	++	++	Value of flexibility diminished by coal stigma and age of plant
	Gas with take-or-pay/inflexible/integrated	--	-	+	-	++	Baseload thermal not required
Combined cycle plant	Gas with storage	+	+++	++	+	--	Dry year cover and supports market outages
	Gas with take-or-pay/inflexible/integrated	--	+++	-	++	+	Baseload thermal not required

There appears no role for baseload thermal generation post NZAS exit.

Contact strengths and mitigations

Well-positioned emerge in a stronger competitive position longer-term

Strengths

Organisational capability to deliver competitive advantage.

	Strength	Mitigation
1	Contract position with limited short-term price exposure	**Fixed prices sales contracts** Limits near-term exposure to lower near-term prices.
2	Unique expertise to drive decarbonisation	**Alternative electricity demand growth** Dairy electrification real. Increase holding in. Simply Energy to 100%.
3	Strong customer proposition	**Leverage customer propositions** Broadband bundle is valued by customers and increases loyalty.
4	Flexible thermal fuel, with asset optionality for TCC to support control of wholesale outcomes	**Thermal portfolio optionality** Short gas book. Access to flexible fuel – gas storage, includes first right to further expansion. Whirinaki well placed to offer reserves.
5	Flexible portfolio	**Control NI reserves to increase HVDC flow** Virtual peaker – grow DemandFlex business from 7MW to >50MW. Battery investment.
6	Low-cost renewable assets	**Optimise assets** Low capex extension of the Wairakei geothermal field. Reviewing the merits of bringing forward hydro refurbishment programme. Optimising geothermal fuelling spend.
7	Track-record of delivering operational cost improvement	**Cost and capital reduction programme** Will continue to support Contact's strong balance sheet.

Refer to slide 40

Refer to slide 41

Mitigations

Transpower proceeding with transmission upgrades at pace.

The value of flexibility will increase post Tiwai

Unique sources of portfolio flexibility

Hawea

286 GWh storage,
~500 GWh p.a. throughput

AGS contract and gas peakers

0-200 MW

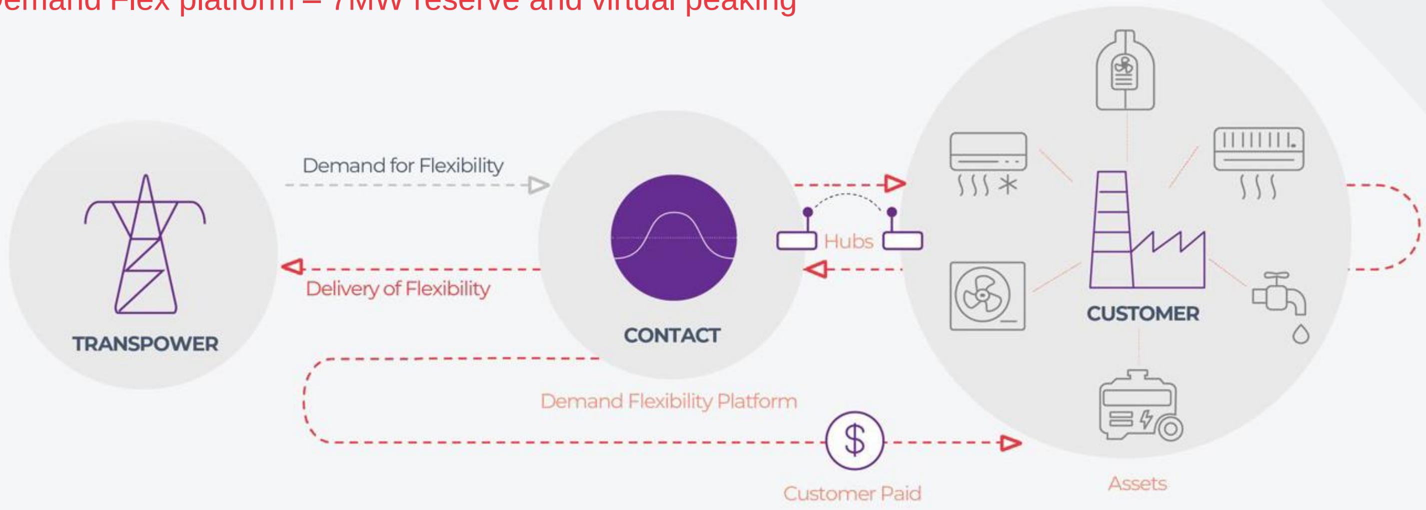
First rights on further AGS expansion

Whirinaki peaker plant

155 MW peaker

Virtual generator I

Demand Flex platform – 7MW reserve and virtual peaking



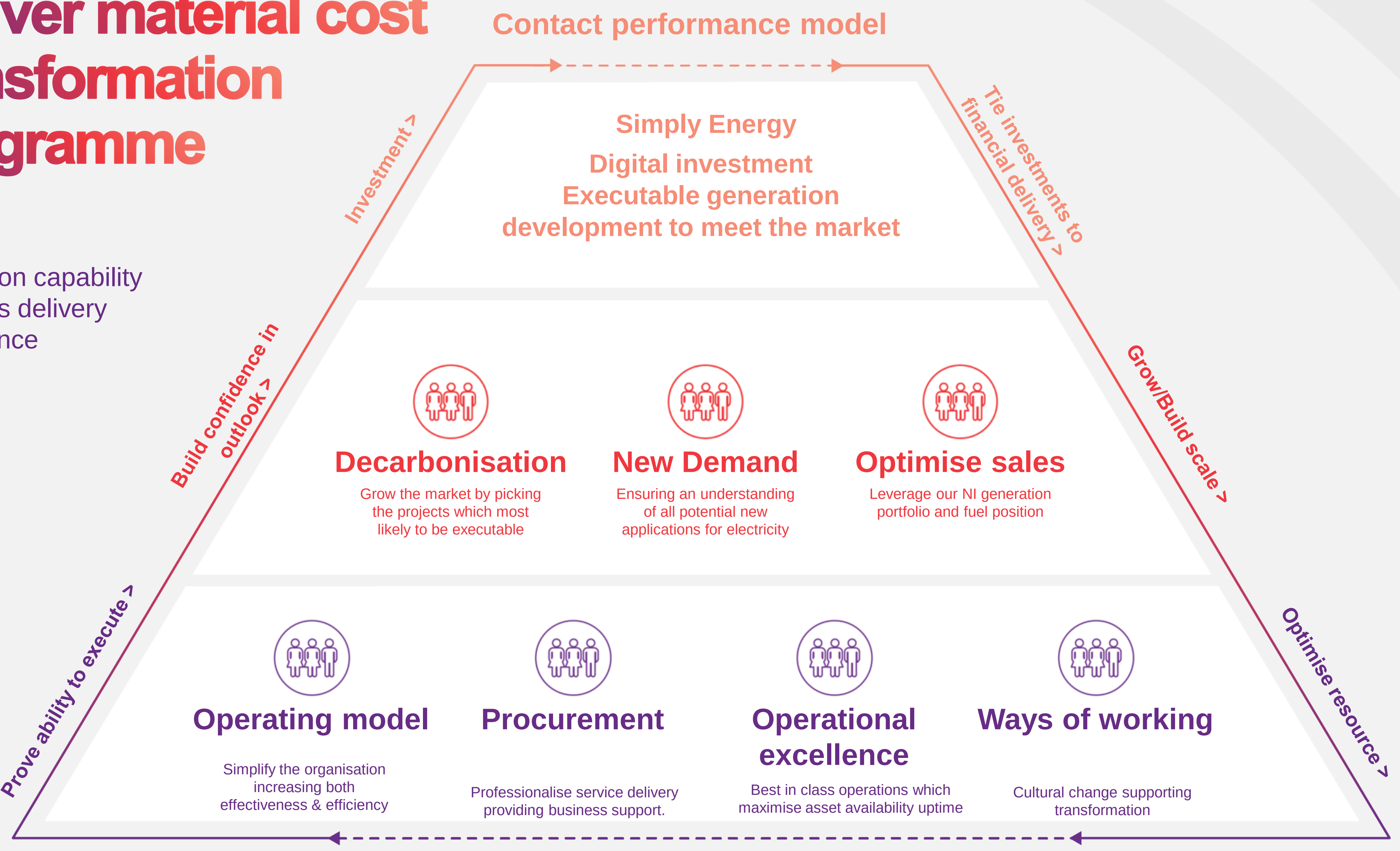
Virtual generator II

Huntly swaption – 100 MW

Investigating the benefits of and the optimal approach to invest in a North Island battery

Deliver material cost transformation programme

Execution capability provides delivery confidence



Priority areas

Near term

NZAS
Constructive engagement to promote an orderly exit

Manage wholesale market volatility
Effective risk management. Monetise flexible thermal advantage.
Gas contracts will allows for greater participation in contracting fixed price sales.

Delivering value
Recover rising wholesale input costs.
Investment in digital and data to further reduce costs and develop new, innovative propositions.
Continued focus on controllable cost reduction.

Post NZAS recovery
Implement mitigations to compete hard post NZAS exit

Transformation programme
Optimise operating model, drive procurement, embed the benefits from transformative ways of working

Medium term

Capture scale efficiencies
Redesign customer journeys to capture multi-product scale efficiencies.
Maintain the optionality to develop Tauhara as soon as appropriate
Investigate low capital options to extend Wairakei generation

Decarbonisation
Partner with customers on mutually beneficial decarbonisation opportunities.

Distribution policy under review.

Dividend policy needs to endure a period of potentially significant market disruption.

Current dividend policy is predicated on a stable environment – this is no longer appropriate

Forward expected earnings >

- Forecast uncertainty reduces confidence in the expected earnings over the medium term
- Mitigation options need to be fully developed

Forward stay-in-business capex >

- Decisions around the optimal asset portfolio need to be made including geothermal life extension (Wairakei re-consenting) and TCC refurbishment

Forward balance sheet strength >

- Maintaining balance sheet strength is an important mitigation (maintenance of BBB credit rating)
  - Means net debt/EBITDA ratio below 2.8x.

Financial framework principles are unchanged

Disciplined management and application of cash flows to maximise the returns for shareholders.

- This includes an evaluation of the capital required to pursue mitigation/growth opportunities and ongoing investment in the business
- The maintenance of an appropriate gearing level and distribution of profit and excess capital to investors in an efficient manner

FY21 dividend guidance to be provided as soon as appropriate

This provides time to refine expectations to include:

- Potential changes to the current NZAS exit timeline
- Shorter term impacts on market pricing
- Capital risk management linked to increased uncertainty
- Value of mitigations and implementation costs

Strong delivery in FY20. Further performance improvements targeted

	FY20 Guidance	Result	FY21 Guidance	Guidance commentary
Other operating costs	$200 – 205m	✓ $196m	$190 – 205m*	Targeting further reduction in controllable costs
Stay in business capital expenditure	$55 – 60m	✓ $51m	$55 – 60m	
Cash spend ('Totex')	**$255 – 265m**	✓ **$247m**	**$250 – 265m**	
Depreciation and amortisation	$213 – 223m	✓ $220m	$250 – 260m	TCC likely to be fully depreciated by 2022.
Net interest (accounting)	$55 – 60m	✓ $55m	$55 – 60m	Interest on Tauhara spend no longer capitalised to PP&E
Cash interest (in operating cash flow)	$50 – 55m	✓ $49m	$50 – 55m	
Cash taxation	$70 – 75m	✓ $70m	$75 – 85m	
Target ordinary dividend per share	39 cps	✓ 39 cps	No guidance issued	FY21 dividend target updated as soon as appropriate
Geothermal volumes	3,300GWh	✓ 3,333GWh	3,050GWh	Statutory 4-yearly Te Mihi outage in 1H21

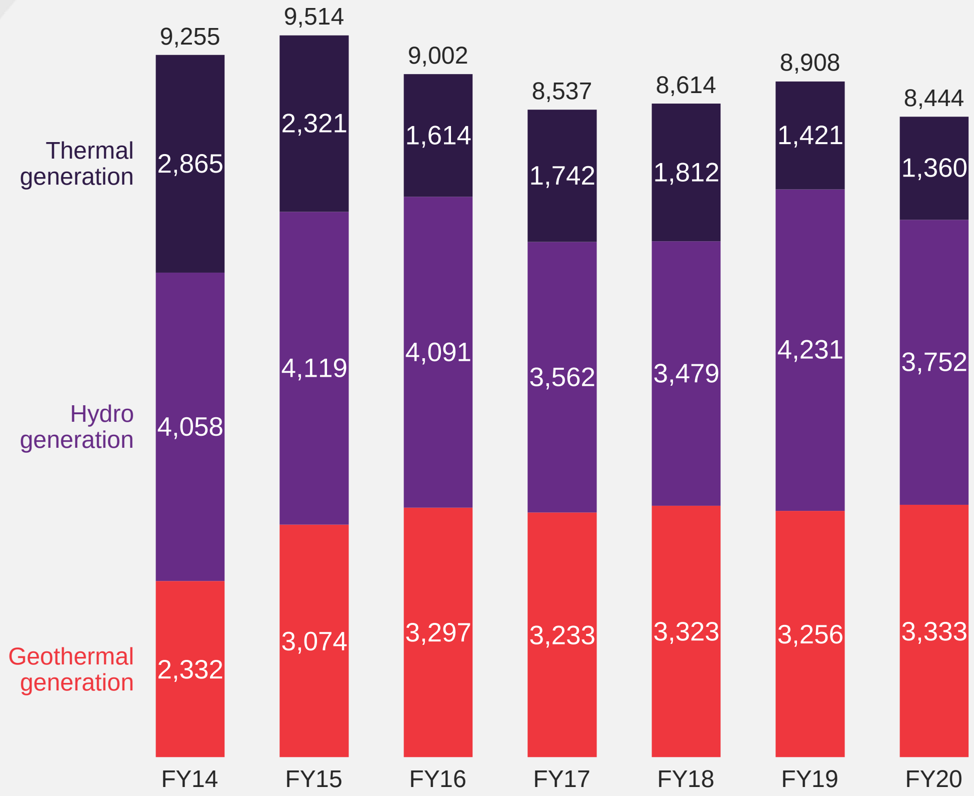
* Excludes any additional abnormal impacts due to COVID-19

Questions

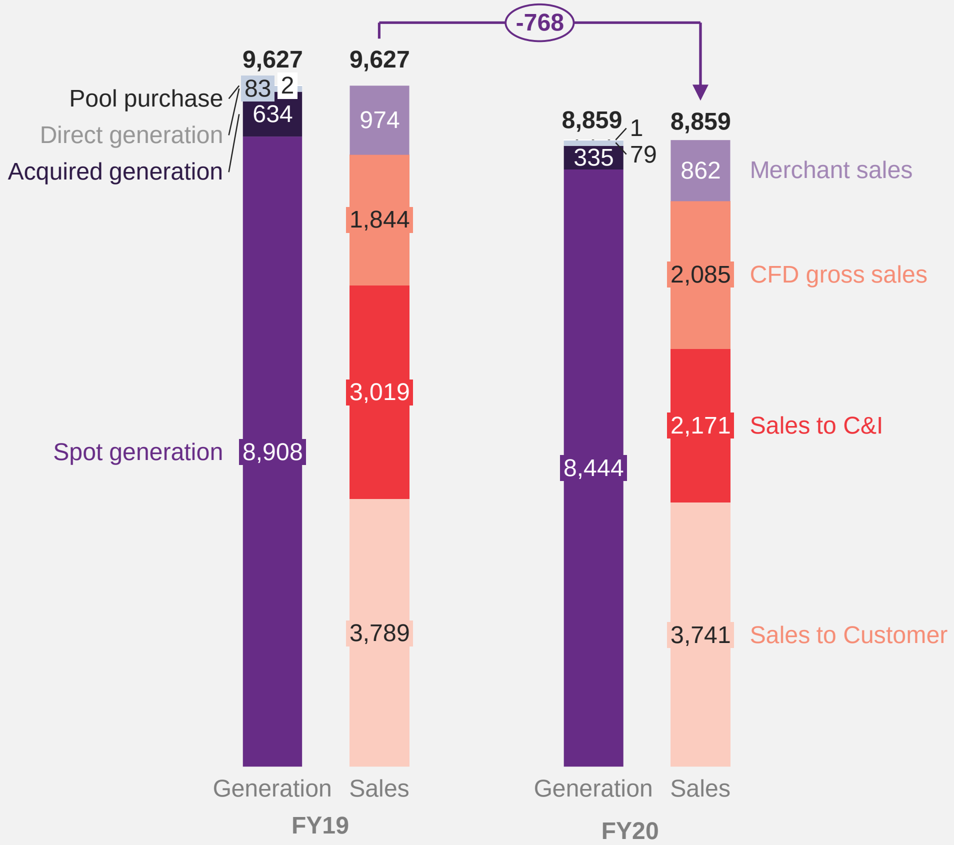
Supporting materials

Generation and sales position

Contact generation output sold to the national grid (GWh)

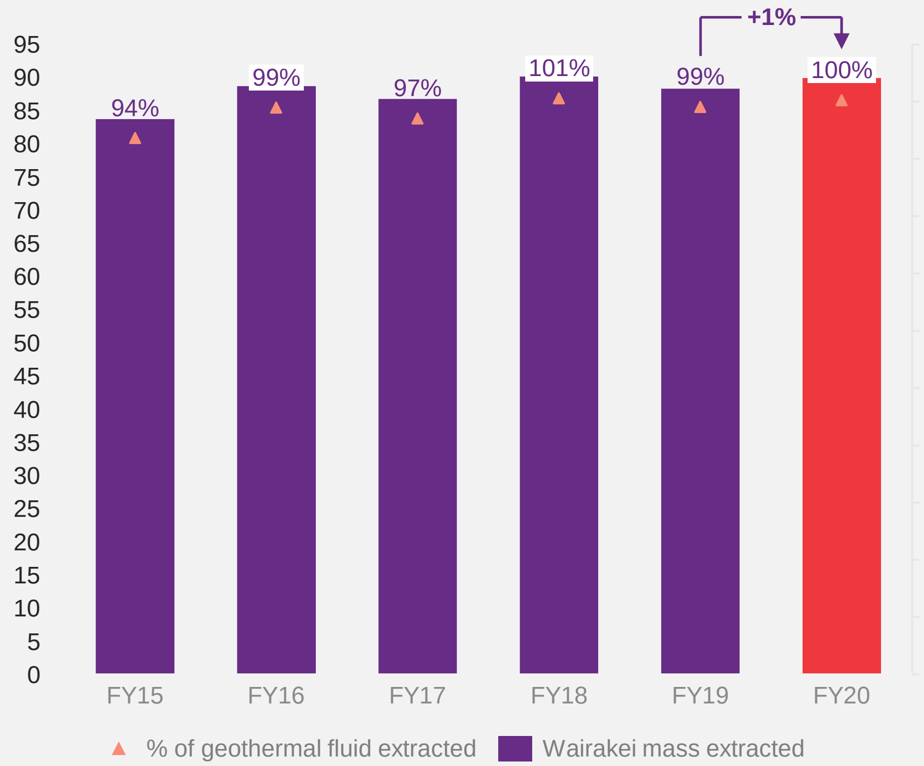


Electricity and generation sales position (GWh)

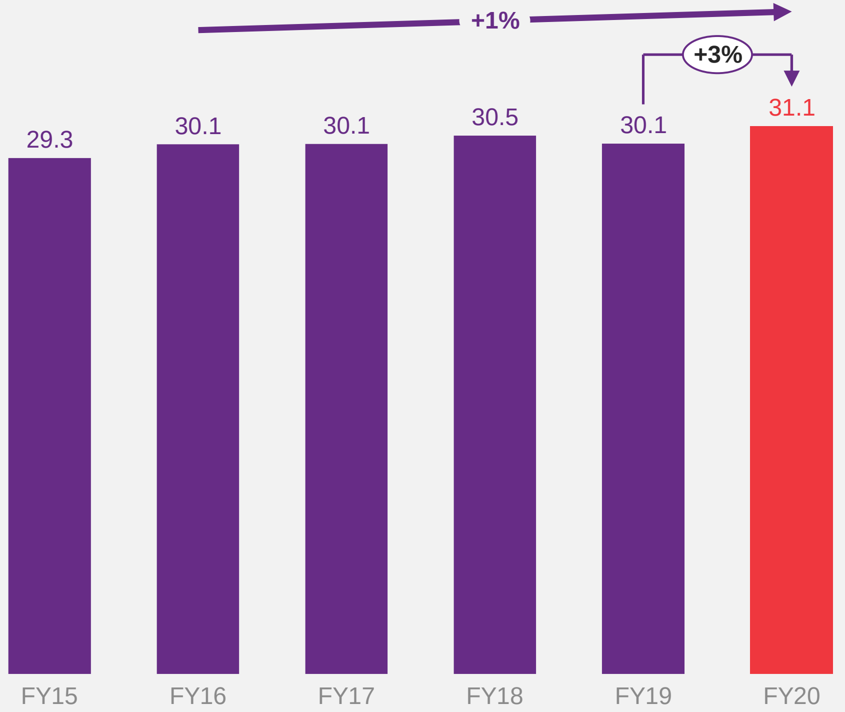


Wairakei geothermal field mass take and efficiency

Geothermal fuel extracted at Wairakei vs consented (GWh)

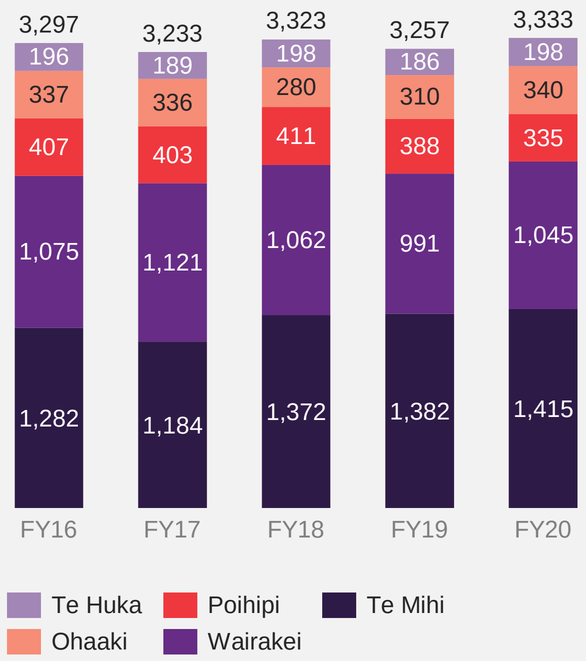


Wairakei, Poihipi and Te Mihi conversion effectiveness (MWh per kT extracted)



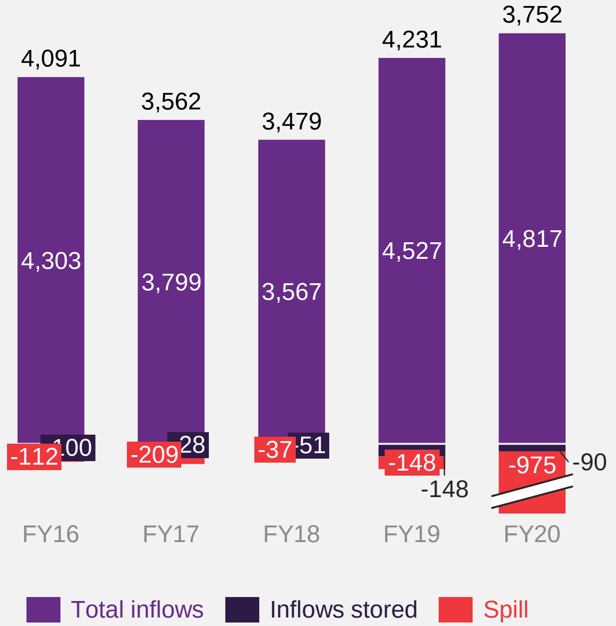
Generation volumes: renewable generation down by 5% on FY19

Geothermal generation (GWh)



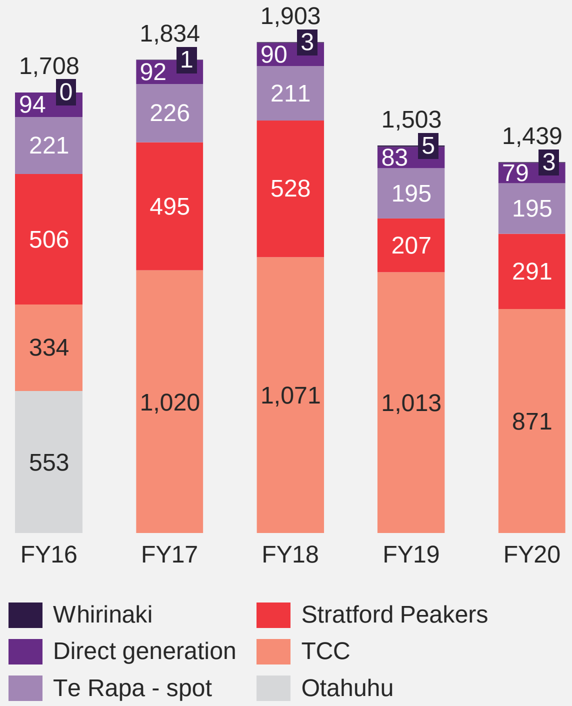
Geothermal generation was 76GWh higher than FY19 as an increase in Te Mihi and Wairakei generation to extract consented geothermal take in advance of the FY21 statutory Te Mihi outage

Hydro generation (GWh)



Hydro generation was 148GWh below mean (FY 3,900GWh) in FY20, 756GWh below FY19 but 245GWh higher than a dry FY18. During December the Clutha catchment was in flood conditions throughout the period. We could not process all of the water through our hydro stations and had to spill it.

Thermal generation (GWh)



Thermal generation volumes were 64GWh lower in FY20 on lower sales and restricted availability of gas in H1 of this year, which reduced the ability to run baseload thermal at TCC with the Stratford peakers. Gas availability in H2 allowed for TCC to run more and flexibility with Stratford peakers.

Plant availability

Hydro

	Net capacity (MW)	Availability (%)	Capacity factor (%)	Electricity output (GWh)	Pool revenue ($/MWh)	Pool revenue ($m)
FY17	784	92%	52%	3,562	47	169
FY18	784	95%	51%	3,479	78	271
FY19	784	97%	62%	4,231	123	521
FY20	784	92%	54%	3,752	90	338

Geothermal

	Net capacity (MW)	Availability (%)	Capacity factor (%)	Electricity output (GWh)	Pool revenue ($/MWh)	Pool revenue ($m)
FY17	429	91%	86%	3,233	55	177
FY18	425	96%	89%	3,323	80	267
FY19	425	92%	87%	3,256	133	434
FY20	425	95%	89%	3,333	99	330

Taranaki combined cycle (TCC)

	Net capacity (MW)	Availability (%)	Capacity factor (%)	Electricity output (GWh)	Pool revenue ($/MWh)	Pool revenue ($m)
FY17	377	90%	31%	1,021	64	65
FY18	377	68%	32%	1,071	102	110
FY19	377	63%	31%	1,031	115	117
FY20	377	88%	26%	870	120	104

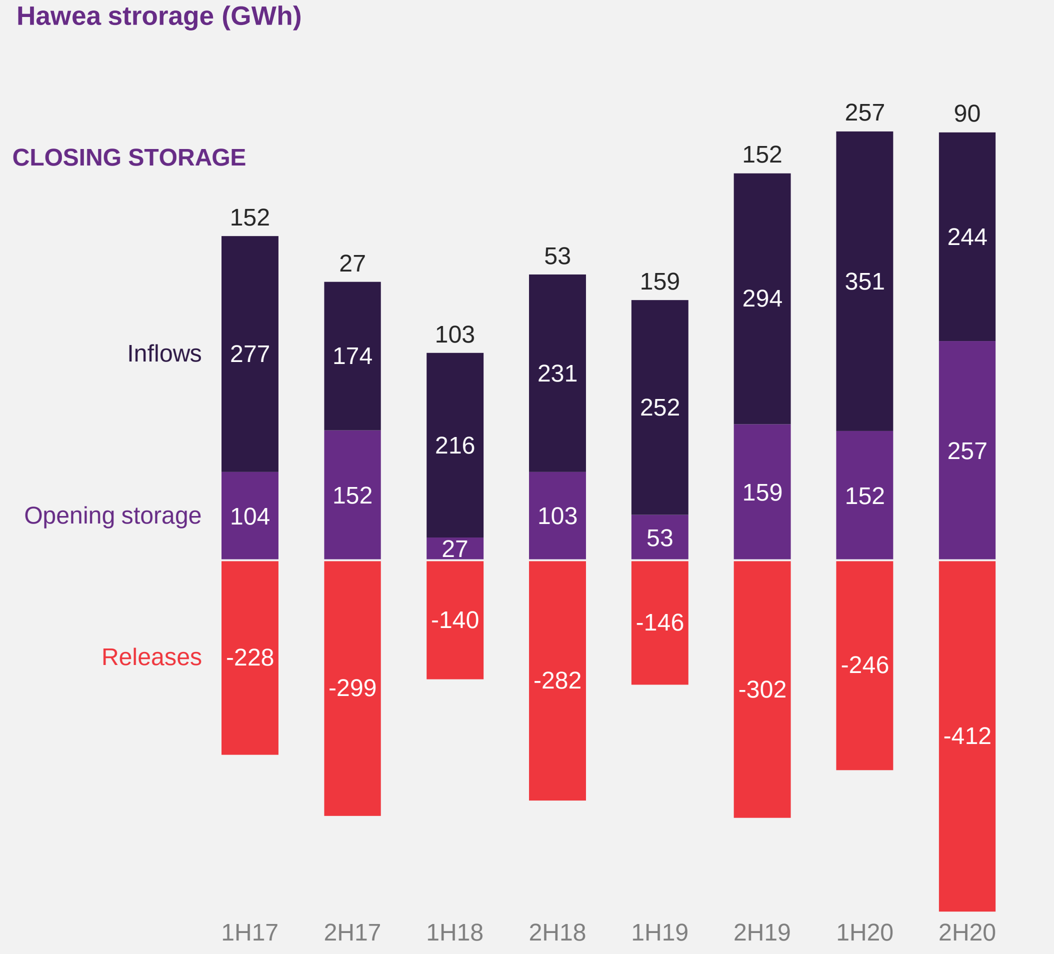
Peakers (including Whirinaki)

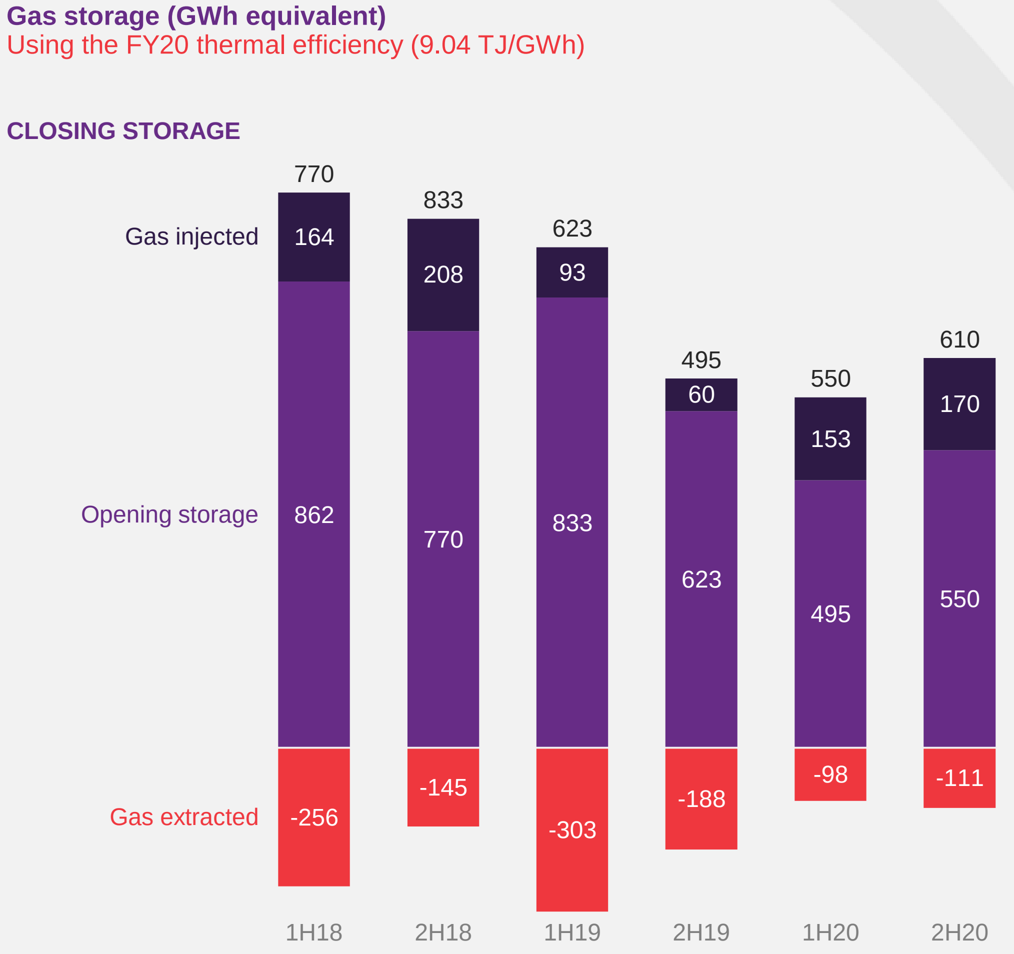
	Net capacity (MW)	Availability (%)	Capacity factor (%)	Electricity output (GWh)	Pool revenue ($/MWh)	Pool revenue ($m)
FY17	360	95%	16%	495	73	36
FY18	360	87%	17%	530	116	62
FY19	360	79%	7%	212	192	41
FY20	360	88%	9%	295	162	48

Te Rapa (spot generation only)

	Net capacity (MW)	Availability (%)	Capacity factor (%)	Electricity output (GWh)	Pool revenue ($/MWh)	Pool revenue ($m)
FY17	41	98%	63%	226	58	13
FY18	41	87%	59%	211	94	20
FY19	41	96%	54%	195	160	31
FY20	41	98%	73%	184	106	21

Fuel storage movements

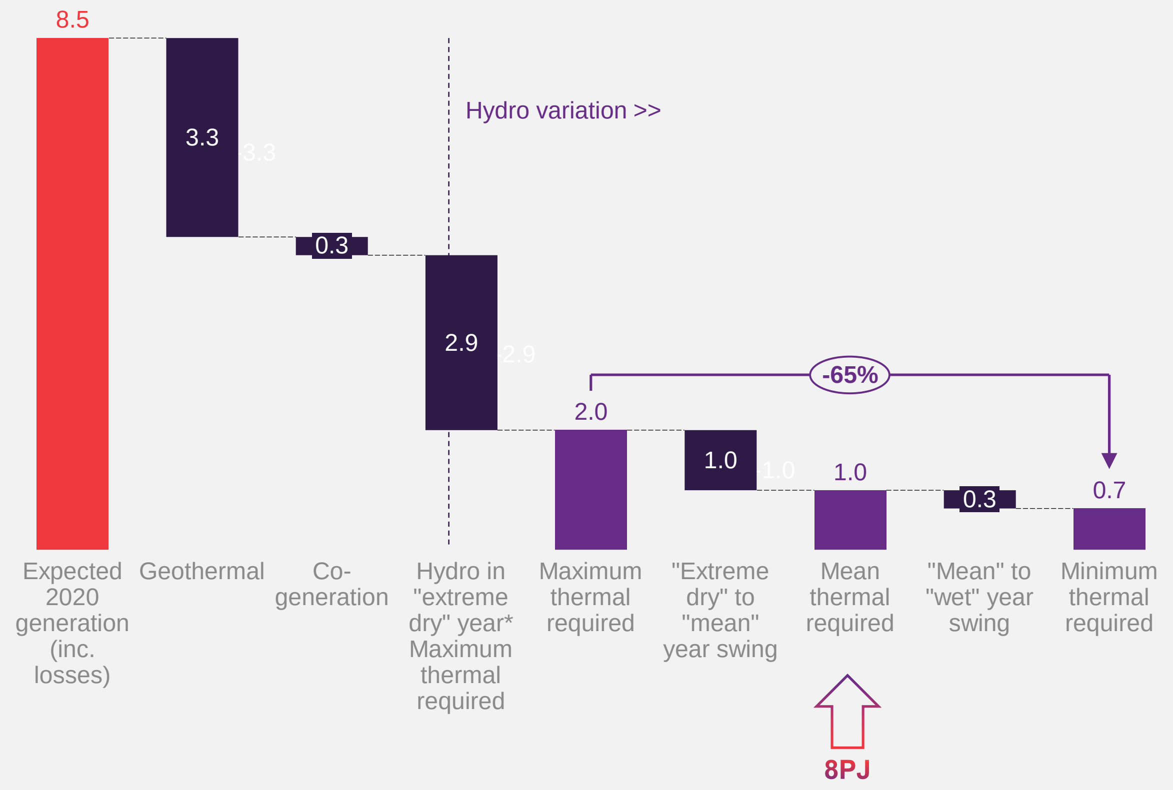




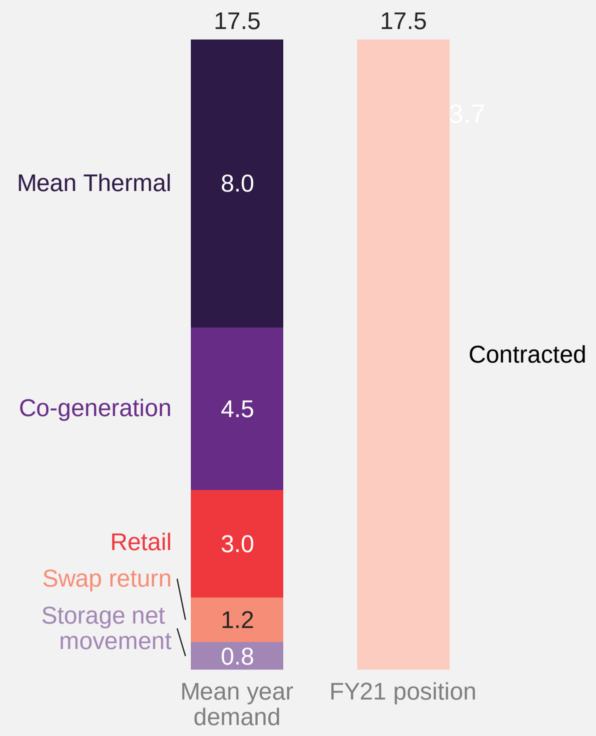
Source: NZX hydro

Contractual fuel position in line with firming requirements

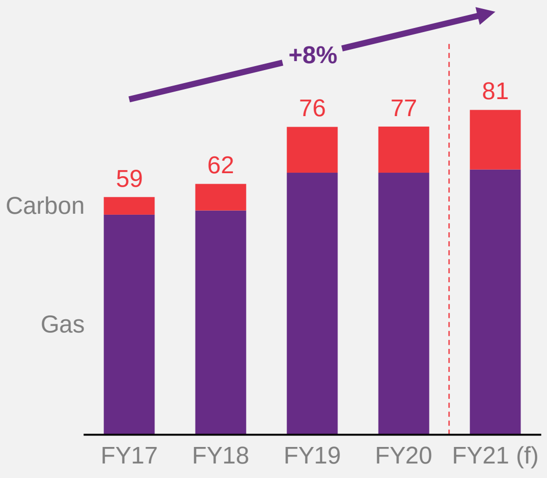
Portfolio requirements for thermal generation (TWh)



Gas supply and demand FY21 (PJ)



Thermal plant fuel cost ($/MWh)

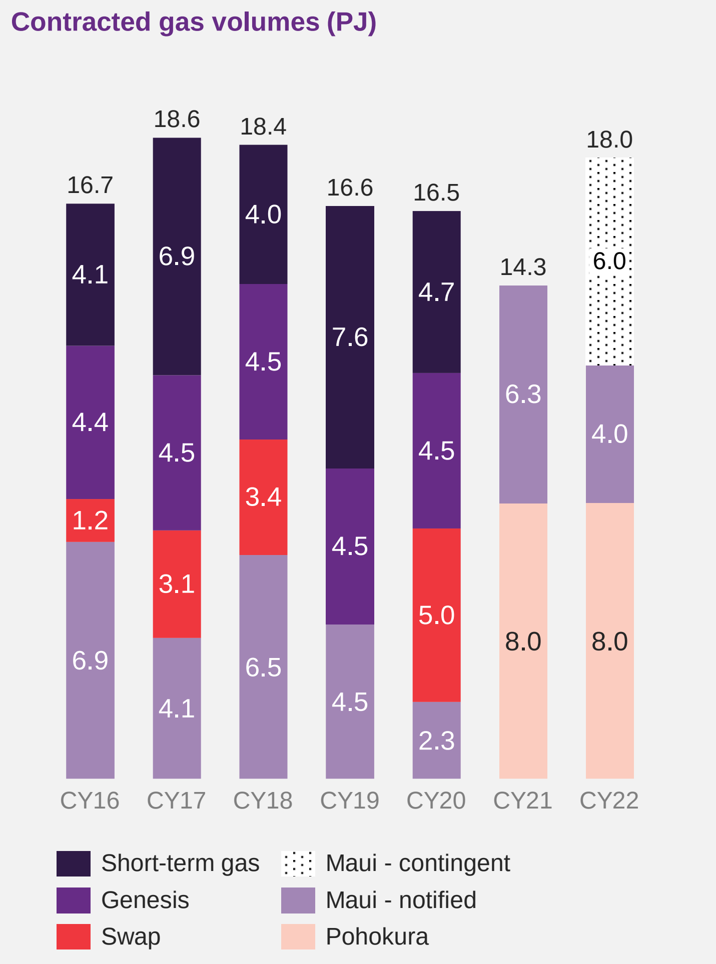


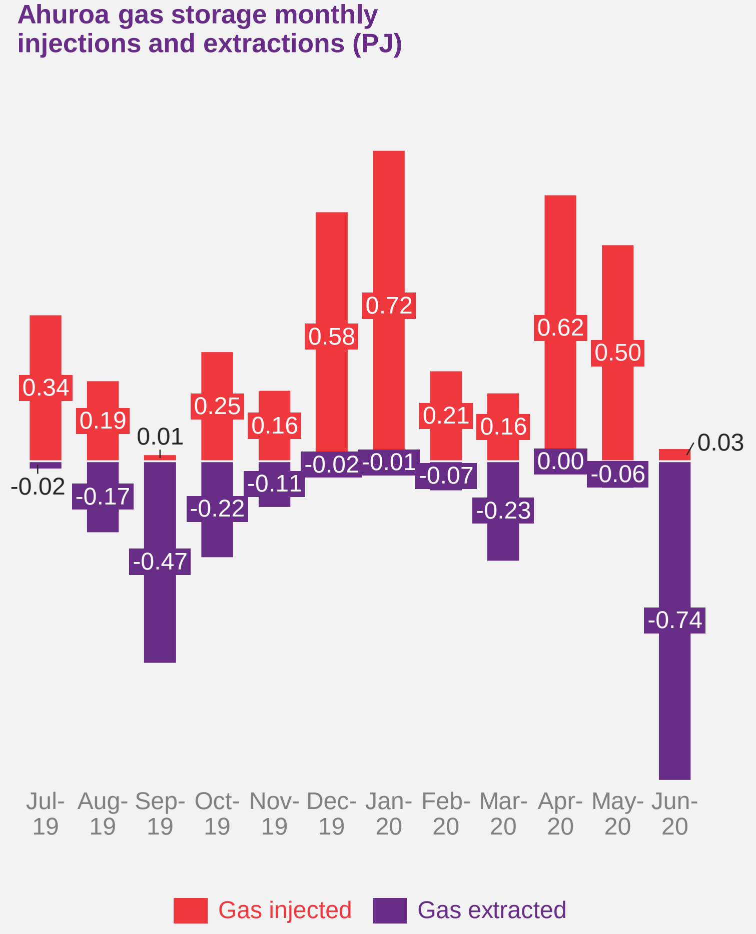
The increasing price of natural gas and carbon will support wholesale prices in the medium term.

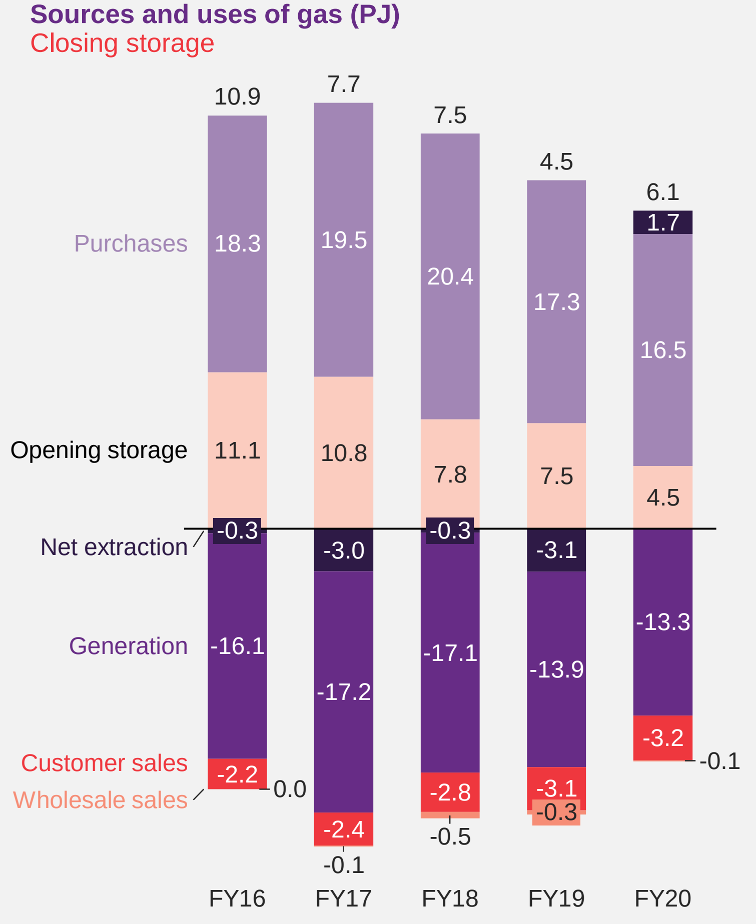
- Access to gas storage and flexible gas contracting means Contact is well positioned post NZAS exit

* Hydro generation in FY12

Contracted and stored gas







Storage balance at 30 June 2020 was 6.1PJ

Reconciliation between Profit and EBITDAF

- EBITDAF is Contact's earnings before net interest expense, tax, depreciation, amortisation, change in fair value of financial instruments and other significant items.
- EBITDAF is commonly used in the electricity industry so provides a comparable measure of Contact's performance.
- Reconciliation of statutory profit back to EBITDAF:

	12 months ended 30 June 2020	12 months ended 30 June 2019	Variance on prior year	
			$m	%
Profit	**125**	**345**	**(220)**	**(64%)**
Depreciation and amortisation	220	205	15	7%
Significant items (gross of tax)	5	(174)	179	(103)%
Net interest expense	55	70	(15)	(21%)
Tax expense	46	72	(26)	(36%)
EBITDAF	**451**	**518**	**(67)**	**(13%)**

- Depreciation and amortisation, change in fair value of financial instruments, net interest and tax expense are explained in the following slide

The adjustments from EBITDAF to reported profit and movements on FY19 are as follows:

- **Depreciation and amortisation:** Increased by $15m (7%) on FY19 primarily resulting from the change in estimate for the expected useful life of TCC to 2022 (previously 2028) which has resulted in accelerated depreciation from 1 July 2019.
- **Net interest expense:** Reduced by $15m (21%) over FY20 on reduced average borrowings and a lower interest rate as well as the capitalisation of interest relating to the Tauhara geothermal project ($6m).
- **Tax expense** for the period was $26m down following operating earnings and higher depreciation partially offset by lower net interest expense. Tax expense for FY20 represents an effective tax rate of 27%. The effective tax rate for FY19 was 17% on total earnings as the gain on the sale of Rockgas was not subject to income tax.
- **Other significant items** are detailed on the following page.

Reconciliation between Profit and Underlying profit

	12 months ended 30 June 2020	12 months ended 30 June 2019	Variance on prior year	
			$m	%
Profit	**125**	**345**	**(220)**	**(64%)**
Change in fair value of financial instruments	-	(2)	2	(100%)
Gain on sale of Rockgas Limited (LPG)	-	(165)	165	(100%)
Gain on sale of Ahuroa gas storage	-	(5)	5	(100%)
Remediation for Holidays Act non-compliance	(5)	(2)	(3)	150%
Tax on items excluded from underlying profit	1	5	(4)	(80%)
Underlying profit	**129**	**176**	**(47)**	**(27%)**

- Underlying profit provides a consistent measure of Contact's ongoing performance.
- Underlying profit excludes the effect of significant items from profit. Significant items are determined based on principles approved by the Board of Directors.
- Other significant items are determined in accordance with the principles of consistency, relevance and clarity. Items considered for classification as other significant items include impairment or reversal of impairment of assets; business integration, restructure, acquisition and disposal costs; and transactions or events outside of Contact's ongoing operations that have a significant impact on reported profit.
- Reconciliation of statutory profit for the year to underlying profit.

The only adjustment from profit to underlying profit for FY20 was:

- Increase in Holiday Act provision to reflect the recent High Court ruling following the Metro Glass vs MBIE case and estimated impact (net of tax).
- Final tax payment relating to the sale of the Otahuhu Power Station in FY16.

Historical financial information

	Unit	FY16	FY17	FY18	FY19	FY20
Revenue	$m	2,163	2,079	2,275	2,519	2,073
Expenses	$m	1,640	1,578	1,794	2,001	1,622
EBITDAF	$m	523	501	481	518	451
Profit/(loss)	$m	-66	151	132	345	125
Underlying profit	$m	157	142	130	176	129
Underlying profit per share	cps	21.7	19.9	18.1	24.6	18.0
Operating free cash flow	$m	352	305	301	341	290
Operating free cash flow per share	cps	48.5	42.6	42	47.5	40.4
Dividends declared[1]	cps	26	26	32	39	39
Total assets	$m	5,652	5,455	5,311	4,954	4,896
Total liabilities	$m	2,829	2,677	2,584	2,172	2,275
Total equity	$m	2,823	2,778	2,727	2,782	2,621
Gearing ratio	%	38	36	35	28	31

1 On 10 August 2020, the Board resolved to pay a 65% imputed final dividend of 23 cents per share on 15 September 2020. On 7 August 2020, Contact had $7 million of imputation credits available for use in future periods.

1. Figures have been restated for the adoption of NZ IFRS 15 *Revenue from Contracts with Customers* and NZ IFRS 16 *Leases*
2. Figures above reflect the combined result and position for continuing and discontinued operations and certain 2018 amounts have been reclassified to conform to the current year's presentation

Wholesale segment

Note: this table has not been rounded and might not add	FY20 Twelve months ended 30 June 2020 Volume GWh	GWAP $/MWh	$m	FY19 Twelve months ended 30 June 2019 Volume GWh	GWAP $/MWh	$m	Reference number for Wholesale segment note (see following page)
Electricity sales to Customer	**3,741**	**88.8**	**332**	**3,789**	**83.0**	**314**	1
Electricity sales to Fixed C&I (netback)	2,092	80.3	168	2,936	81.6	240	
Electricity sales – Direct	79	105.1	8	83	99.2	8	2
Electricity sales to C&I	**2,171**	**81.2**	**176**	**3,019**	**82.1**	**248**	
CfDs – Tiwai support	828			805			
CfDs - Long term sales	581			569			
CfDs - Short term sales	676			471			3
Electricity sales - CFDs	**2,085**	**72.9**	**152**	**1,844**	**73.9**	**136**	
Total contracted electricity sales	**7,997**	**82.6**	**661**	**8,652**	**80.7**	**699**	
Steam sales	**544**	**47.6**	**26**	**558**	**47.3**	**26**	4
Other income			0			10	5
Net income on gas sales			1			1	6
Net income on electricity related services			2			0	7
Net other income			**2**			**12**	
Total contracted revenue (1)	**8,540**	**80.6**	**689**	**9,210**	**80.0**	**737**	
Generation costs	8,523	(31.2)	(266)	8,991	(31.1)	(279)	8
Acquired generation cost	335	(113.9)	(38)	634	(107.7)	(68)	9
Generation costs (including acquired generation) (2)	**8,858**	**(34.3)**	**(304)**	**9,625**	**(36.1)**	**(348)**	
Spot electricity revenue	8,444	99.7	842	8,908	128.6	1,146	10
Settlement on acquired generation	335	115.4	39	634	146.1	93	11
Spot revenue and settlement on acquired generation (GWAP)	**8,779**	**100.3**	**880**	**9,542**	**129.8**	**1,238**	
Spot electricity cost	(5,833)	(109.0)	(636)	(6,725)	(137.6)	(925)	12
Settlement on CFDs sold	(2,085)	(97.8)	(204)	(1,844)	(129.2)	(238)	13
Spot purchases and settlement on CFDs sold (LWAP)	**(7,918)**	**(106.0)**	**(840)**	**(8,569)**	**(135.8)**	**(1,163)**	
Trading, merchant revenue and losses (3)			**41**			**75**	
Wholesale EBITDAF (1+2+3)			**426**			**464**	

Wholesale segment key

	Wholesale segment	Reference to detailed operating segment performance	Comment
Revenue	C&I electricity – Fixed Price	2	
	C&I electricity – Spot	2-spot	Spot sales are regarded as a pass-through and not reflected in performance reporting, any margin included in C&I netback
	Wholesale electricity, net of hedging	3 + 10 + 13	
	Electricity related services revenue	7	
	Inter-segment electricity sales	1	
	Gas	6	Revenue from wholesale gas sales, purchase cost in gas and diesel purchases
	Steam	4	
	Other income	5	
Costs	Electricity purchases, net of hedging	9 + 11 + 12	
	Electricity purchases – Spot	2-spot	Spot sales are regarded as a pass-through
	Electricity related services cost	7	
	Gas and diesel purchases	8 (less costs identified relating to 6)	Includes wholesale gas sales purchases (if any)
	Gas storage costs	8	
	Carbon emissions	8	
	Generation transmission and reserve costs	8	
	Gas networks, transmission and meter costs – Fixed Price	2	
	Gas networks, transmission and meter costs – Spot	2-spot	Spot sales are regarded as a pass-through
	Gas networks, transmission and meter costs	8	
	Other operating expenses	8 (less costs identified relating to 2)	C&I operating costs are included in the calculation of netback (2) and are excluded from generation operating costs

Customer segment

Residential electricity	unit	FY17	FY18	FY19	FY20
Average connections	#	362,570	359,171	353,105	355,073
Sales volumes	GWh	2,628	2,549	2,491	2,532
Average usage	per ICP	7.2	7.1	7.1	7.1
Tariff	$/MWh	248	250.1	251.7	250.4
Network, meters and levies	$/MWh	-119.8	-122.4	-122.1	-118.8
Energy costs	$/MWh	-85.7	-86.7	-89.5	-94.8
Gross margin	**$/MWh**	**42.5**	**41**	**40.2**	**36.8**
Gross margin	$ per ICP	308	291	283	262
Gross margin	$m	112	104	100	93

Residential gas	unit	FY17	FY18	FY19	FY20
Average connections	#	59,809	60,905	61,711	61,591
Sales volumes	TJ	1,581	1,600	1,605	1,577
Average usage	per ICP	26.4	26.3	26	25.6
Tariff	$/GJ	32	31.6	31.5	33.1
Network, meters and levies	$/GJ	-19.5	-19.6	-18.4	-17.9
Energy costs	$/GJ	-5.8	-5.6	-5.9	-7.9
Carbon costs	$/GJ	-0.3	-0.7	-1	-1.4
Gross margin	**$/GJ**	**6.4**	**5.8**	**6.3**	**5.9**
Gross margin	$ per ICP	168	152	165	151
Gross margin	$m	10	9	10	9

SME electricity	unit	FY17	FY18	FY19	FY20
Average connections	#	56,292	57,309	55,020	55,033
Sales volumes	GWh	1,074	1,099	1,042	991
Average usage	per ICP	19.1	19.2	18.9	18.0
Tariff	$/MWh	224.1	224.1	226.8	229.3
Network, meters and levies	$/MWh	-106.6	-108	-111.9	-114.5
Energy costs	$/MWh	-83.8	-84.8	-87.7	-93.0
Gross margin	**$/MWh**	**33.7**	**31.3**	**27.2**	**21.8**
Gross margin	$ per ICP	643	599	516	392
Gross margin	$m	36	34	28	22

SME gas	unit	FY17	FY18	FY19	FY20
Average connections	#	2,981	3,677	3,901	3,947
Sales volumes	TJ	883	1,300	1,492	1,425
Average usage	per ICP	296.3	353.5	382.6	360.9
Tariff	$/GJ	17.5	15.5	15.1	15.5
Network, meters and levies	$/GJ	-5.3	-4.5	-5.5	-6.0
Energy costs	$/GJ	-5.8	-5.6	-5.9	-7.9
Carbon costs	$/GJ	-0.3	-0.7	-1	-1.4
Gross margin	**$/GJ**	**6.1**	**4.8**	**2.8**	**0.2**
Gross margin	$ per ICP	1,817	1,689	1,068	72
Gross margin	$m	5	6	4	0

Customer EBITDAF					
Electricity Gross margin	$m	148	139	128	115
Gas Gross Margin	$m	15	15	14	9
Broadband Gross Margin	$m	-	0	1	0
Total Gross Margin	**$m**	**163**	**154**	**144**	**125**
Other income	$m	4	4	4	5
Other operating costs	$m	-105	-82	-82	-79
Customer EBITDAF	**$m**	**62**	**76**	**67**	**50**
Corporate allocation (50%)[1]	$m		-12	-13	-12
Retailing EBITDAF	**$m**	**62**	**64**	**54**	**38**
EBITDAF margins (% of revenue)	%	6%	7%	5%	4%

1. Prior to FY18, corporate costs were fully allocated to the reporting segments.