Interim results presentation

Six months ended 31 December 2019

contact

Putting our energy where it matters

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This presentation may contain projections or forward-looking statements regarding a variety of items. Such forward-looking statements are based upon current expectations and involve risks and uncertainties.

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1H20 highlights and progress on strategy

Dennis Barnes, CEO

Financial performance down on a very strong comparative period, disciplined and active risk management.

	Six months ended 31 December 2019 (1H20)	Comparison against continuing operations[3] 1H19		Six months ended 31 December 2018 (1H19)	
EBITDAF[1]	$221m	↓	21% from $278m	↓	24% from $291m
Profit	$59m	↓	40% from $99m	↓	79% from $276m
Underlying profit[1]	$58m	↓	40% from $97m	↓	46% from $107m
Interim dividend per share	16.0 cps			-	16.0 cps
Operating free cash flow[2]	$120m	↓	38% from $196m	↓	41% from $203m
Operating free cash flow per share[2]	16.8 cps	↓	38% from 27.3 cps	↓	41% from 28.3 cps
SIB capital expenditure (cash)	$27m	-	$27m	↓	7% from $29m

[1] Refer to slides 48-49 for a definition and reconciliation of EBITDAF and underlying profit

[2] Refer to slides 28,40 for a reconciliation of operating free cash flow

[3] Sale of Rockgas LPG which completed on 30 November 2018

Operating earnings (EBITDAF) were down by $57m when compared to continuing operations in 1H19, a period which included:

- Stronger hydro generation
- Higher wholesale prices
- Gas available in storage for 'merchant generation' to support the market.

The operating conditions in 1H20 were characterised by:

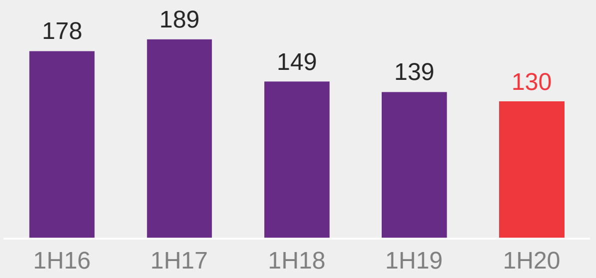
- Constrained natural gas supply
- Rising costs of thermal generation which include gas, carbon and gas storage
- Disciplined and active commodity risk management and a reduction in fixed priced sales.

Despite the difficult operating conditions, our high quality renewable generation assets continue to support the dividend.

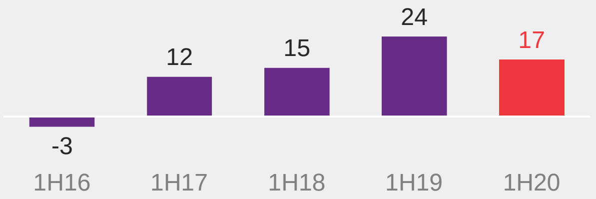
Economics of baseload generation at TCC is looking challenged long-term; asset useful life has been reassessed with depreciation accelerated, reducing profit in 1H20 vs prior comparative period

An efficient and focused business, building capability.

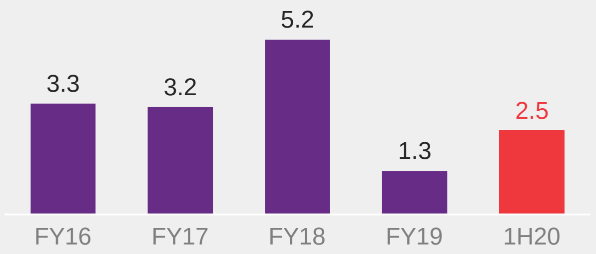
Maintaining financial discipline
Controllable opex and capex costs ($m)



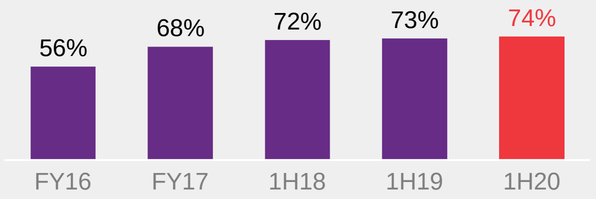
Building customer advocacy
Net promoter score (Promoters less detractors)



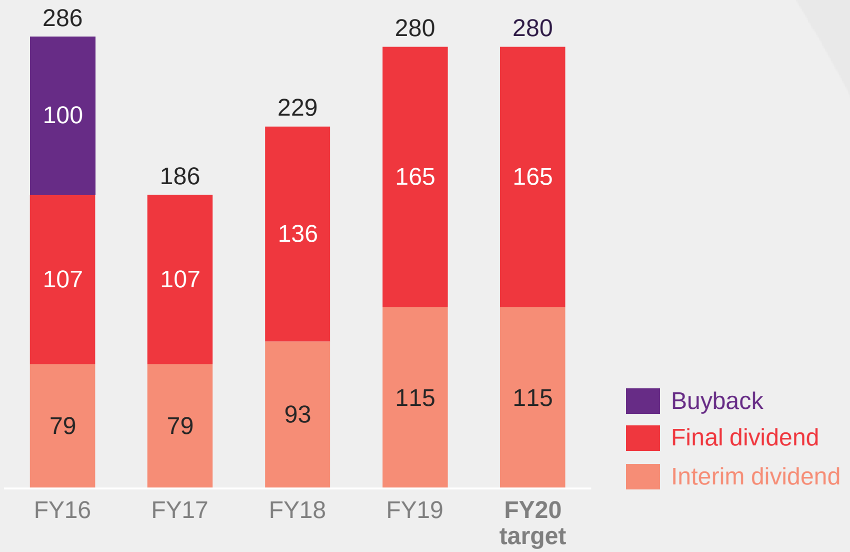
Safe and engaged employees
Total recordable injury frequency rate
(Recordable injuries per million hours worked)



Employee engagement (%)

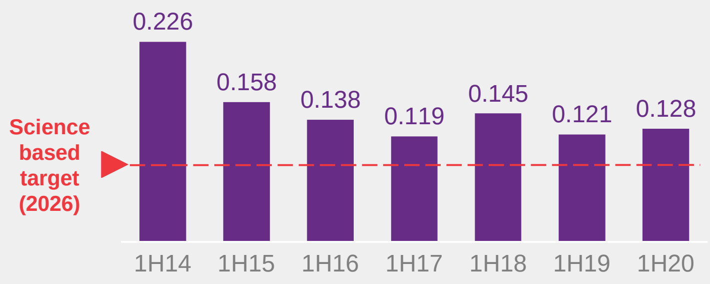


Rewarding shareholders
Distributions ($m)

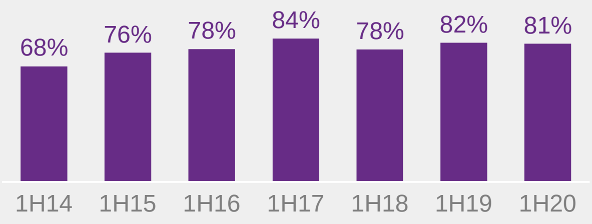


We take a holistic view on performance for all stakeholders.

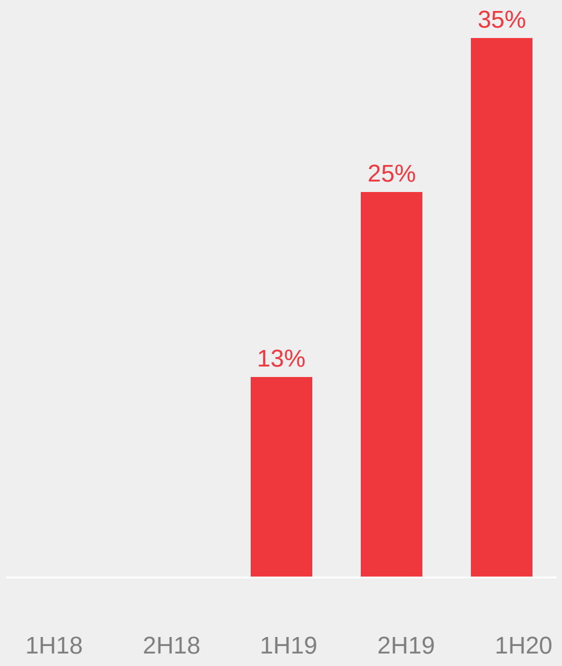
Total generation emissions intensity
tCO2-e / MWh



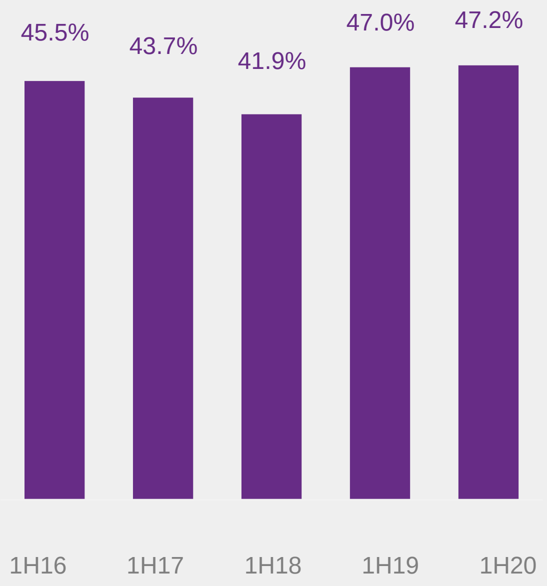
Renewable generation
% of total generation



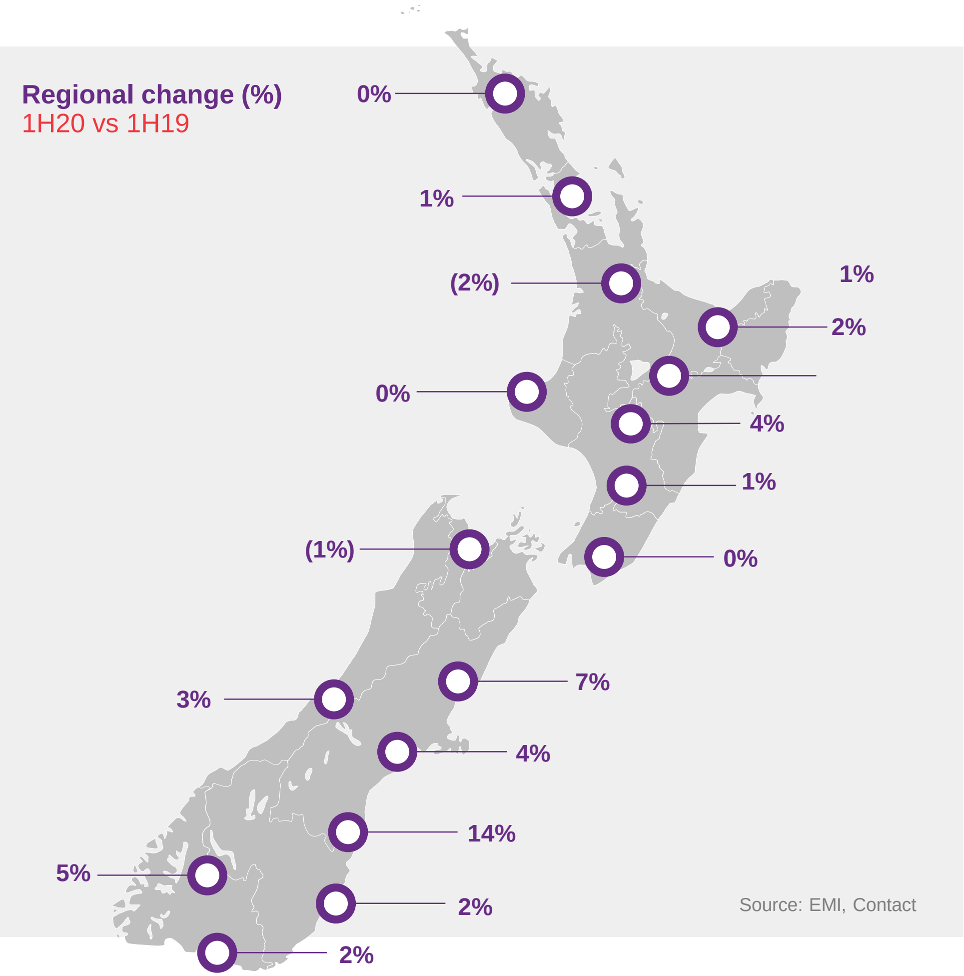
Customers with impaired credit now accepted
% of impaired credit customers accepted

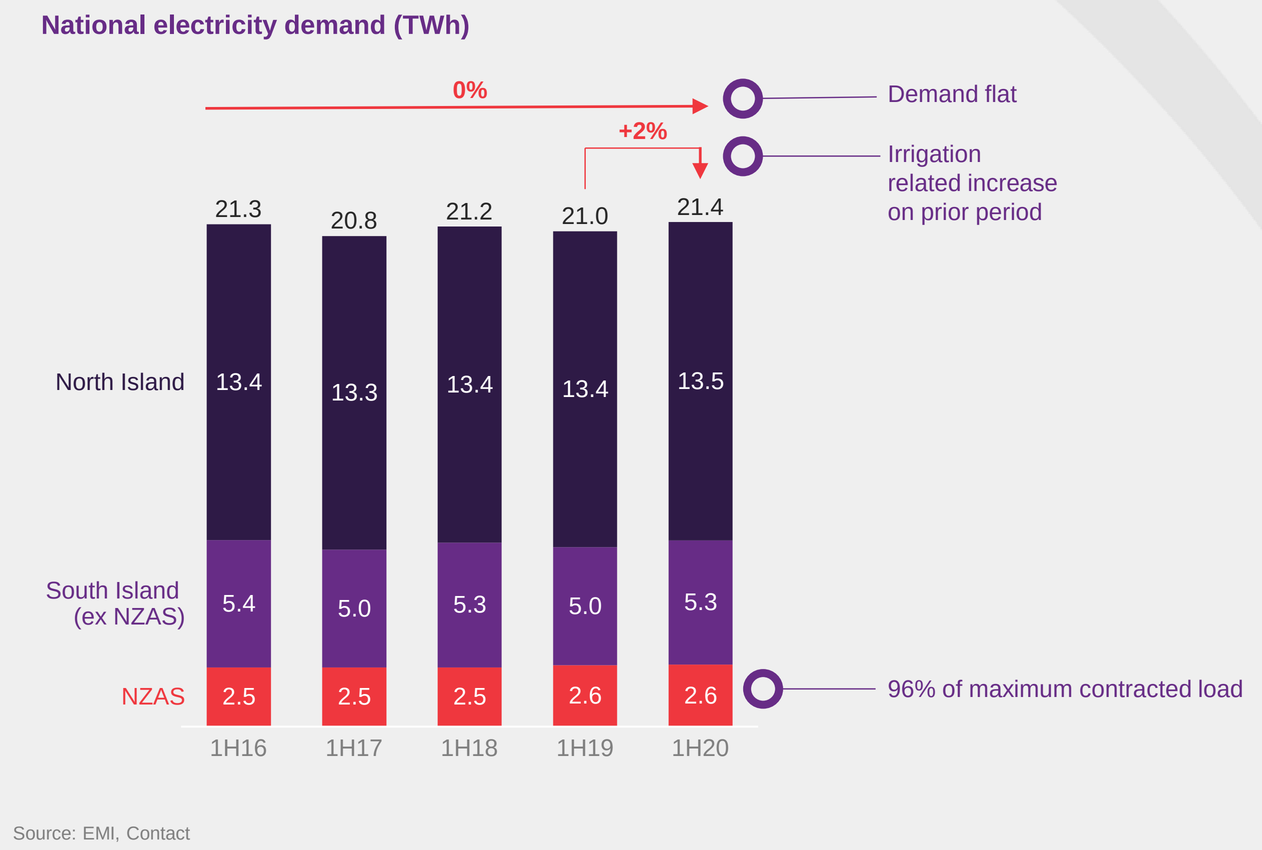


Gender diverse workforce
% of total workforce that is female



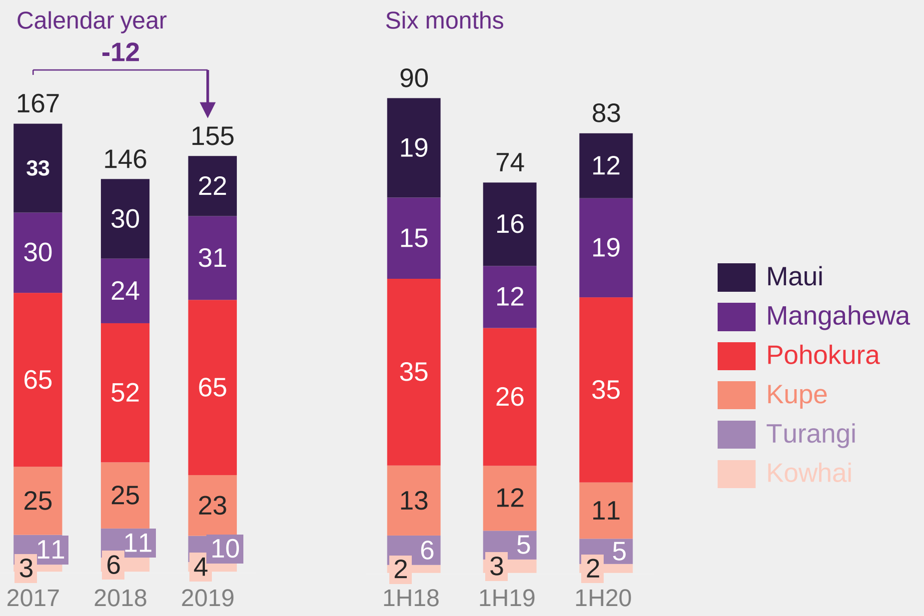
National electricity demand.





Natural gas production up on 1H19, continued improvements expected.

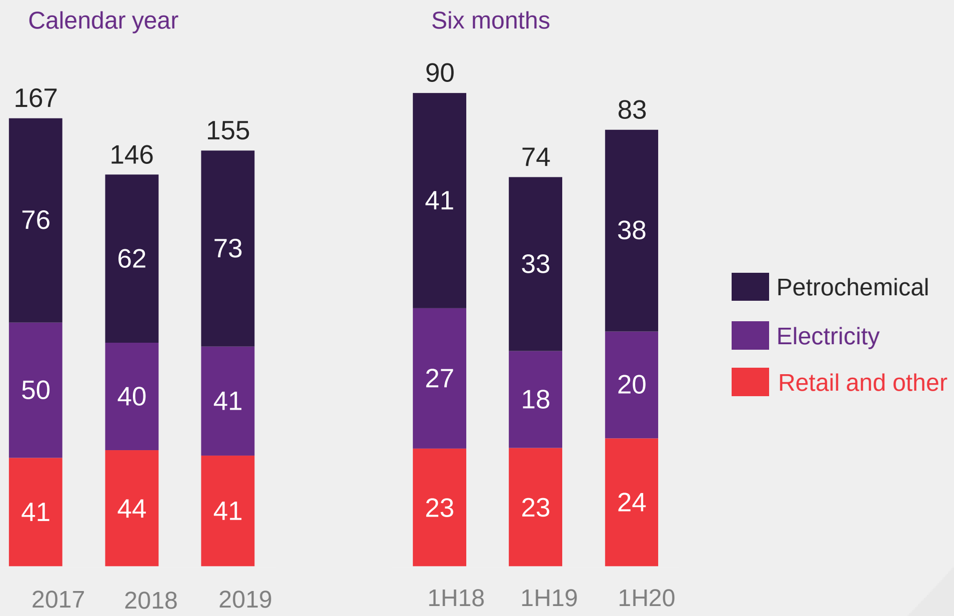
Production from the major fields (PJ)



Source: OATIS

Total production has recovered since 1H19 with large increases from Pohokura and McKee Mangahewa.

Demand from key sectors (PJ)



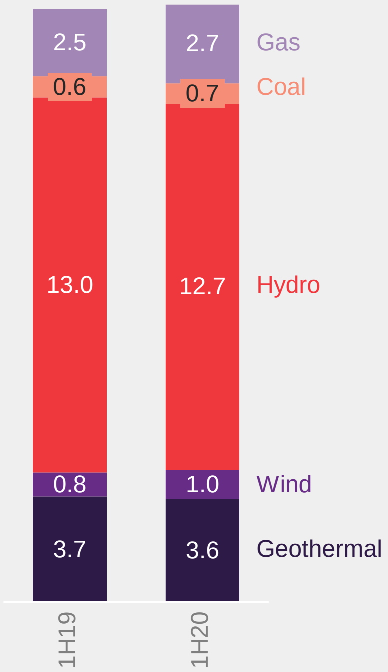
Source: OATIS, EMI

Gas used in electricity generation down 7PJ p.a. from 2017. This has resulted in lower levels of gas storage and cautious management of hydro storage

Fuel - hydro and sources of generation.

Generation by type (TWh)

Generation from generator retailers (source: company reports)



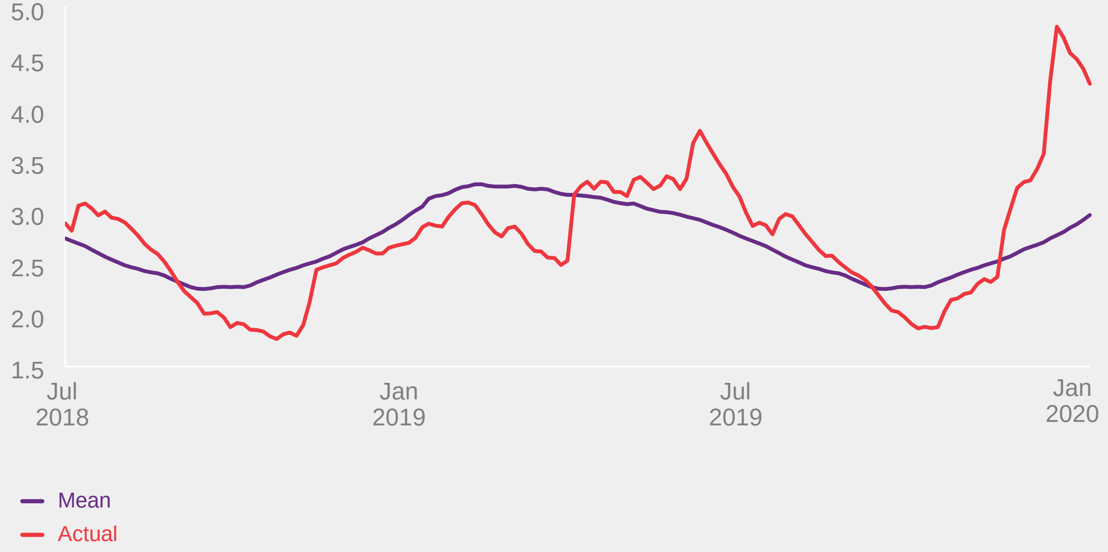
Despite high inflows in November and December 2019, hydro generation was slightly down compared with 1H19. This reduction was offset by a small increase in wind generation and an increase in gas fired generation.

The increase in gas fired generation reflects a recovery in gas volumes from the Pohokura field following an extended outage in late 2018. However production from the Maui and Pohokura fields are still down when compared with historical levels.

Source: EMI, Genesis

National hydro storage against mean storage (TWh)

Mean storage 1926 – 2019 (source: NZX hydro)



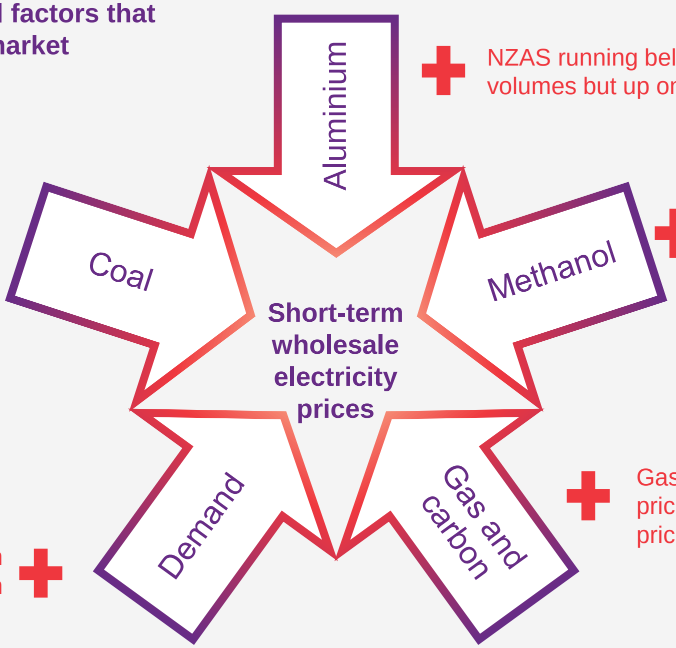
Hydro generators stored more water to cover potential winter exposure if gas is constrained.

Source: NZX

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

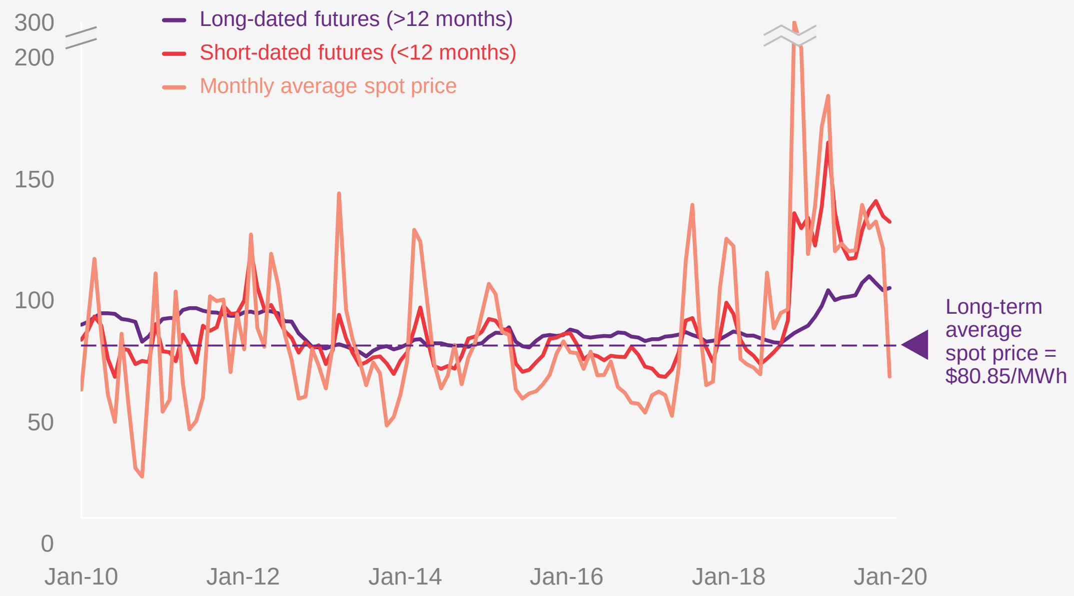
The market quickly responds to changes by sending price signals.

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)



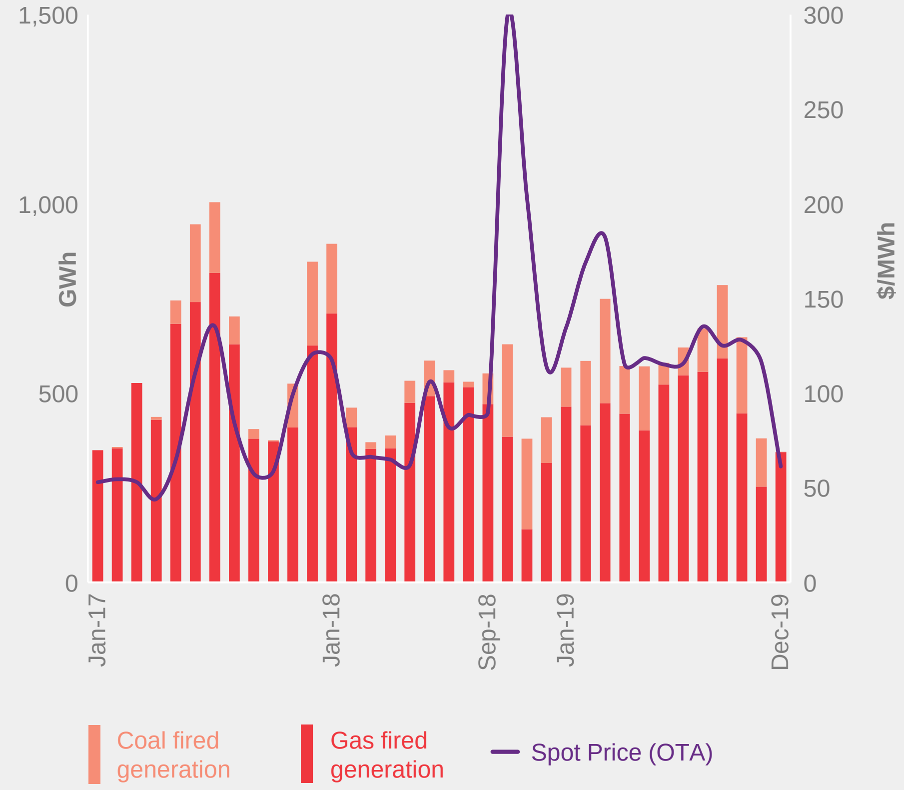
Long-dated futures have jumped +30% in last 12 months.
Average spot prices remain well above long-term average.

Source: EMI wholesale pricing

ASX forward price now trading at thermal SRMC.

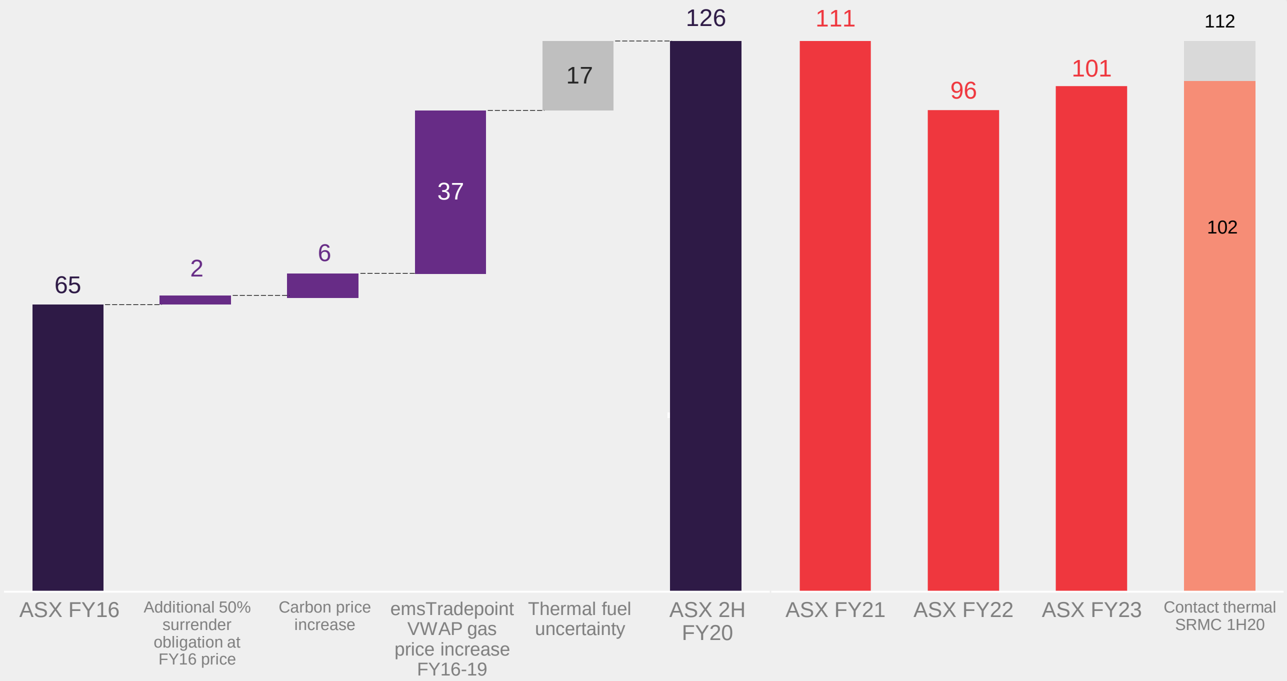
Unreliable natural gas makes coal marginal fuel source

Thermal generation and spot price



Source: EMI

ASX electricity futures prices ($/MWh)

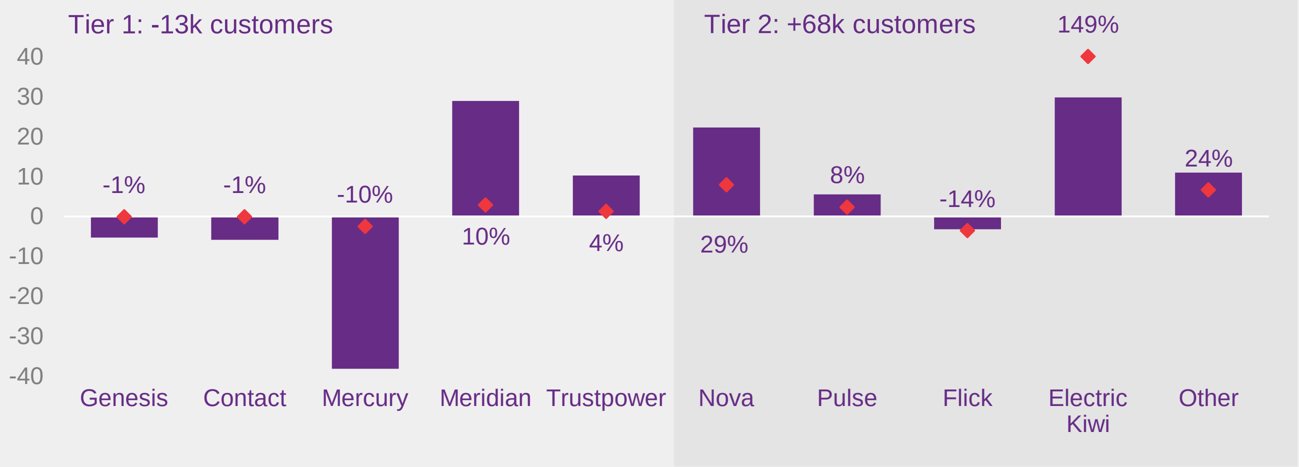


Limited thermal capital recovery included in the ASX price.

The recent increase in NZU prices (carbon) resulting from the proposed ETS amendments and rising gas costs have not been included.

Retail competition remains intense.

Change in customer connections (000s)



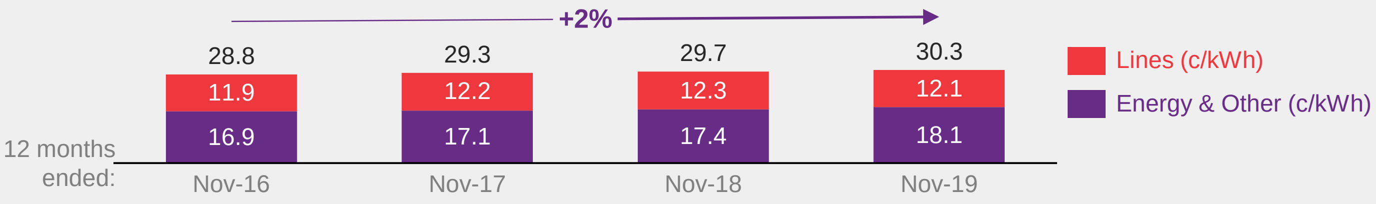
Source: EMI

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 14% (from 11% Dec. 2018).
- New connections up by 1% p.a

Retail tariff changes (c/ kWh)



Source: MBIE

Despite sharply higher wholesale prices over the last two years, tariffs only rising in line with inflation. Expect this to continue.

Creating sustainable value for New Zealanders by putting 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.

Technology

Optimisation through 'clouding' and digital collaboration

New app
downloaded 65k times

Digital sales channel share improved
by 9% to 28%. 40% of customers interacting digitally

Digital sales NPS improved
from 23% to 26%, after new join journey release in June 2019

Operating model

Targeting reductions in cost to serve

Robotic Process Automation (RPA) implementation
across 14 key processes

60k customers now on zero PPD plans,
following the launch of our Simplicity plans

Cost reductions
from build-out of new Application Programming Interface (API) and data platform on Cloud

Deadlock complaint levels at
11% share of all market complaints,
relative to our market share of ~19%

Net bad debt write offs reduced
by 33% on 1H19

Brand

Winning brand recognition and awareness

20,000 broadband connections

Winner of Charge Energy Global Awards
for Best Established Brand

CHARGE AWARDS 2019

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.

Renewable development

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

Prepare a range of development options for a final investment decision (FID).

Deploy capital to enabling works, including pre-FID drilling.

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.

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

Pre-FID drilling of first four wells scheduled to continue until April.

Excellent progress being made with the rig, substantial improvements in drilling rates compared with previous campaigns.

Consent variation given to allow build of Binary or Steam.
JULY 2019

Tender process competitive, multiple bids received with ongoing discussions with multiple parties. A clear interest in the project. Tendered output has exceeded initial expectations.

Well 1
DECEMBER 2019

Well 2
JANUARY 2020
Drilled on the land of our project partner the Tauhara Moana Trust.

Well 3
MARCH 2020
(estimated)

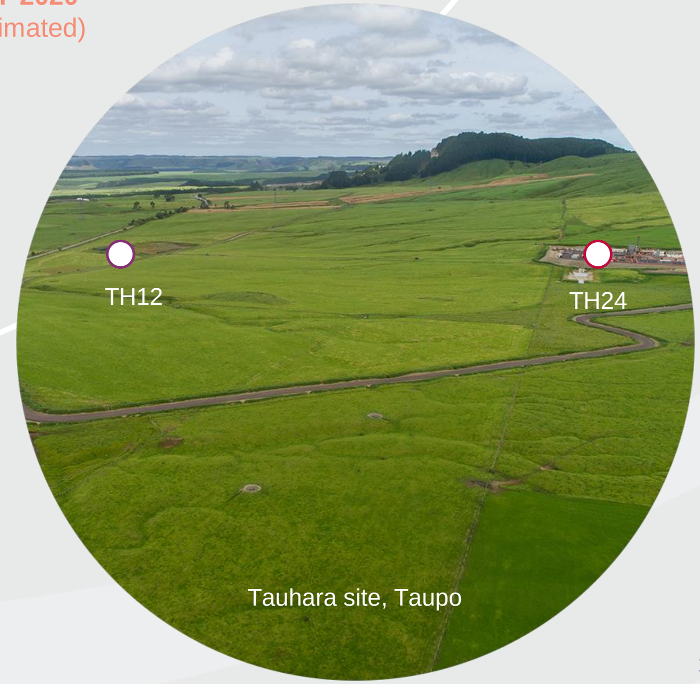
Well 4
MAY 2020
(estimated)

Project assessment continues:

Nature of the resource
Further delineation of eastern area of the reservoir has shown high temperature: ~300 degC in first well drilled indicating world-class, high-temperature reservoir extends to south and west from wells drilled in 2008.

Medium-term
Additional work packages, including Contact's work scope and high voltage connection, sufficiently advanced to enable execution as soon as market conditions allow

Cost of the project
LCOE's (levelised cost of energy) in line with expectations.



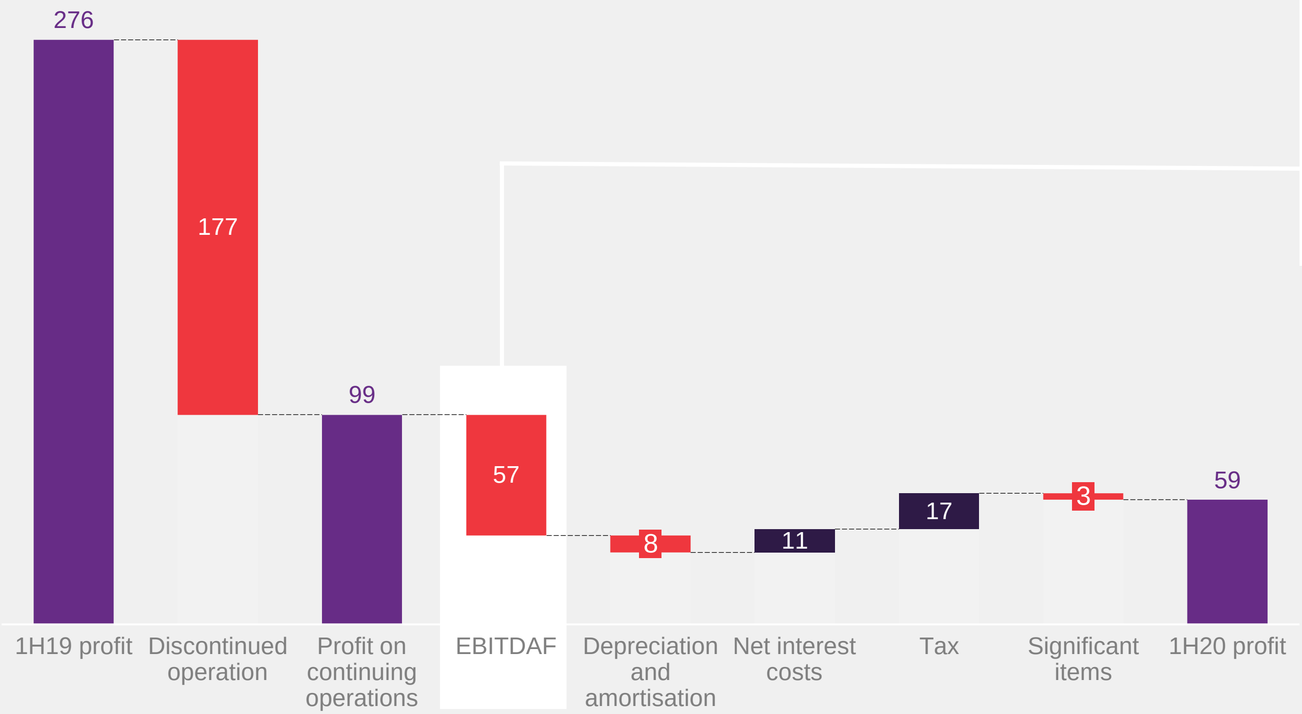
Operational performance and financial results

Dorian Devers, CFO

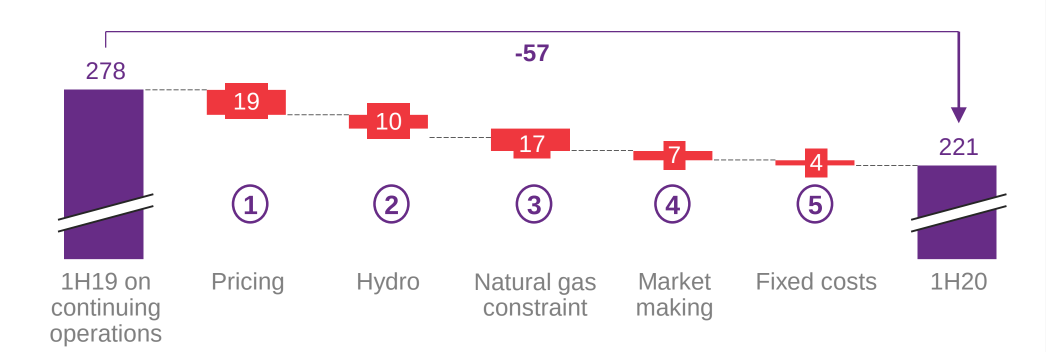
Profit of $59m.

Profit from continuing operations down by $40m, reflecting strong prior period

Profit ($m)



EBITDAF ($m)

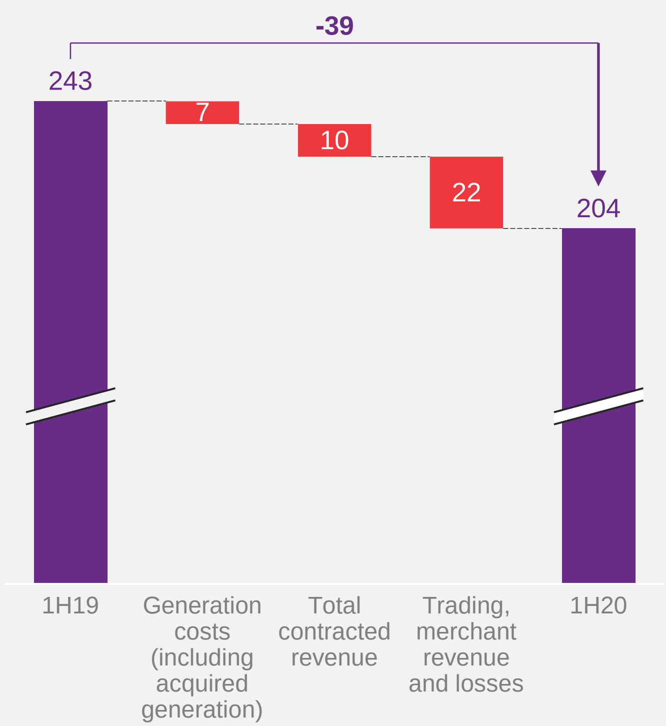


1. FY19 support to stressed market during unplanned gas field outage.
2. Lower hydro year on year.
3. Continued gas availability issues and rising costs, lower sales volumes.
4. Market makers forced into positions, driving earnings volatility
5. Full year cost of gas storage agreement.

EBITDAF from continuing operations down by $57m.

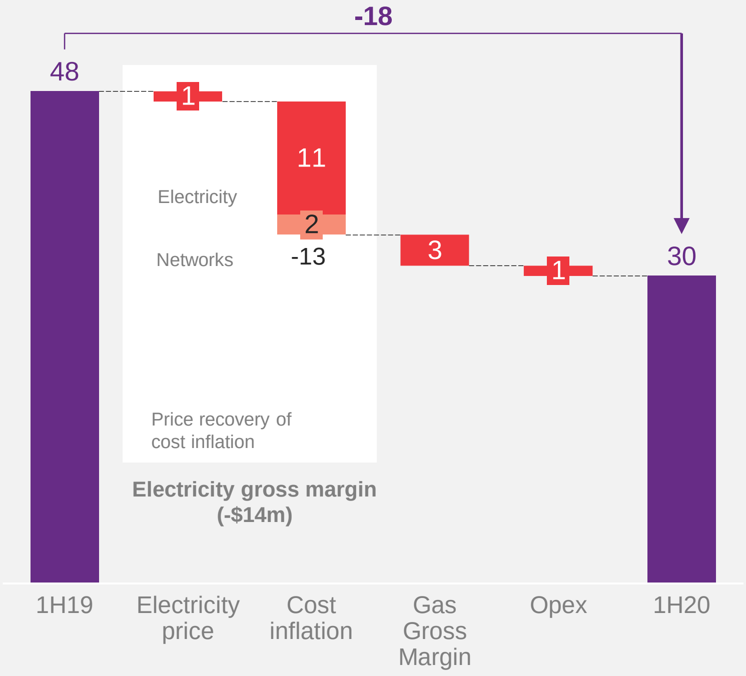
Continuing business performance by segment.

Wholesale EBITDAF ($m)



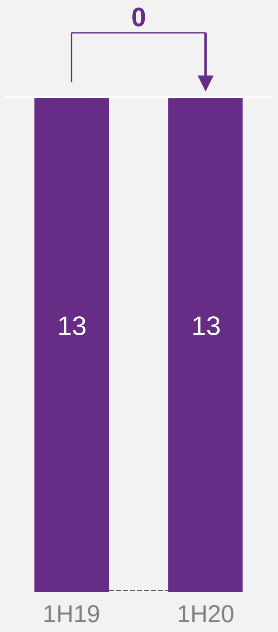
Refer to slides 22 - 24

Customer EBITDAF ($m)



Refer to slide 25

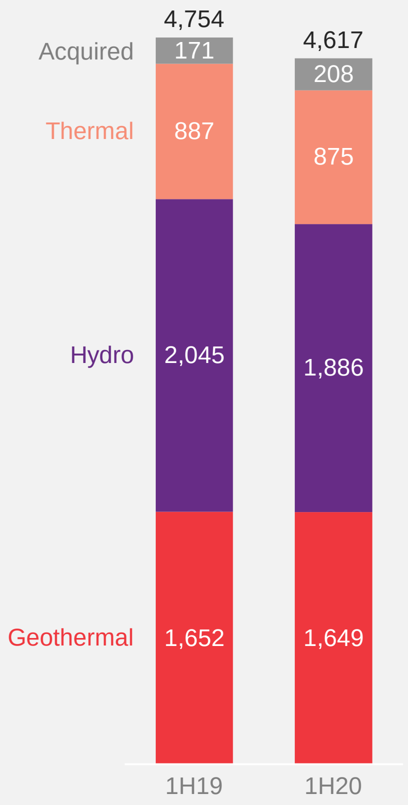
Corporate / unallocated ($m)



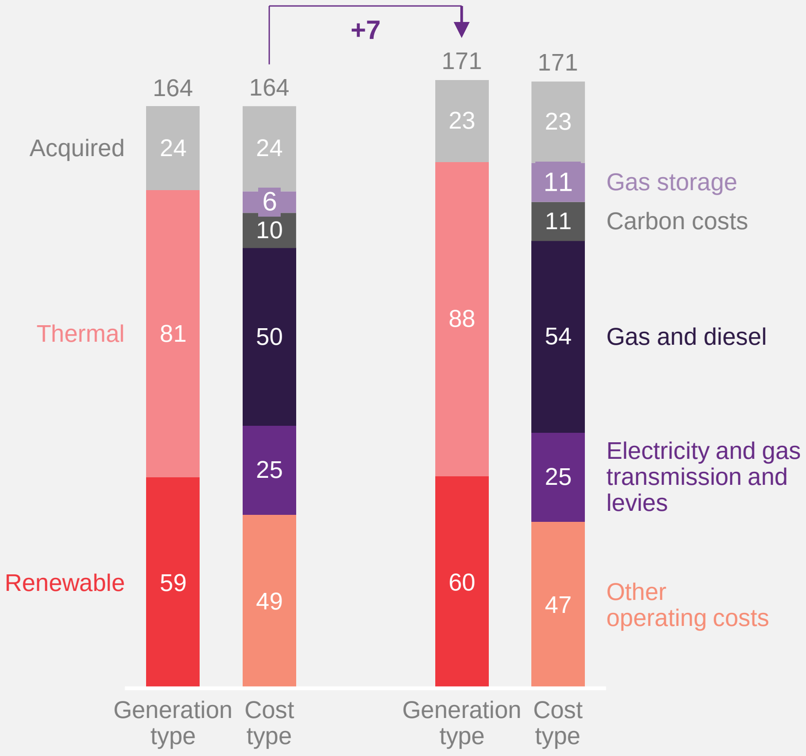
Generation costs.

Hydro generation down 8%. Costs up $7m on increased thermal fuel and gas storage costs.

Electricity generated or acquired (GWh)



Electricity generated or acquired costs ($m)



Hydro generation down 159GWh on 1H19 (-8%), 5% below that expected in a mean year. Geothermal volumes were in line with the prior year and average production.

- Renewable generation costs are predominantly fixed. Geothermal carbon costs were up $1m.

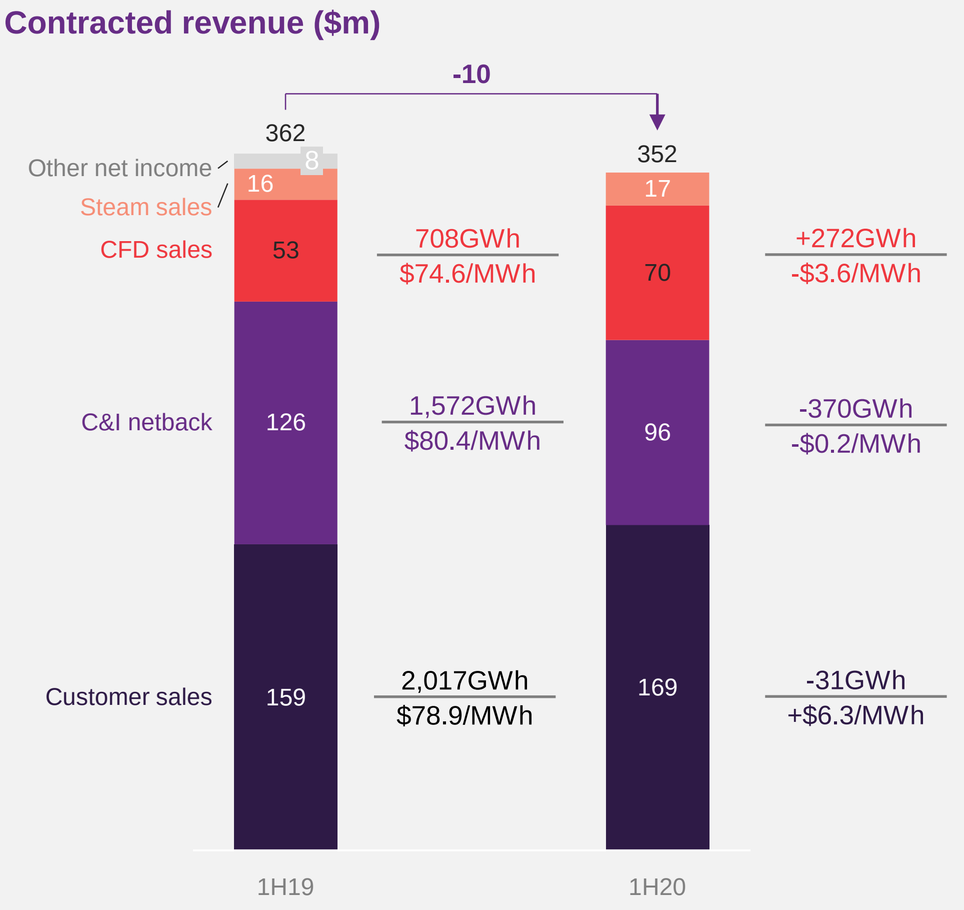
Thermal generation costs were up $8m despite marginally lower generation volumes (-1%).

- Gas and carbon costs up from $65/MWh in 1H19 to $71/MWh (+9%).
- Fixed costs, led by the new gas storage contract (since October 18), were up by $4m on the prior comparative period (net of other operating costs).

Continuing gas supply restrictions saw risk management costs remaining elevated with acquired generation volume up 22%; this was offset by acquired generation costs down from $138/MWh in 1H19 to $111/MWh (-19%).

Wholesale contracted revenue.

Sales mix adjusted to manage commodity risk; gas uncertainty limited the ability to sign long-term load.

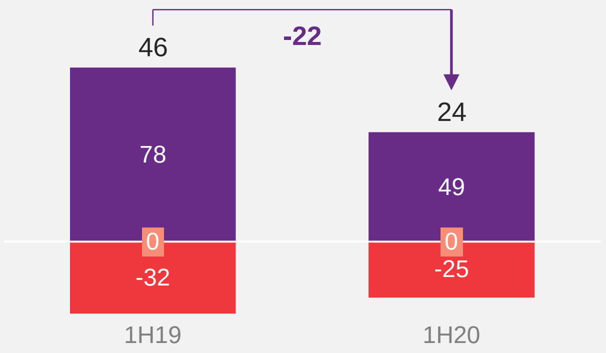


- Fixed price variable volume electricity sales to the Customer segment and C&I customers ended 401GWh lower than 1H19 (-$33m), this was partially offset by higher prices (+$13m) to the Customer business, reflecting higher wholesale prices over the three preceding years.
- CFD sales were up by 272GWh with increased sales to support NZAS, which was up by 60GWh on 1H19, electricity sales from gas tolling and CFD sales committed to part way through 1H19. Only 70GWh of CFD sales have been committed since October 2018.
- Steam revenue was up by $1m on 1H19 on a reduction in volumes but increased tariffs on rising carbon costs with customers.
- Other income was down by $8m, predominantly due to ASX market making gains in 1H19 not replicated.

Wholesale trading and merchant revenue.

In prior period supported stressed market during unplanned Pohokura outage by selling 'merchant'.

Trading EBITDAF ($m)



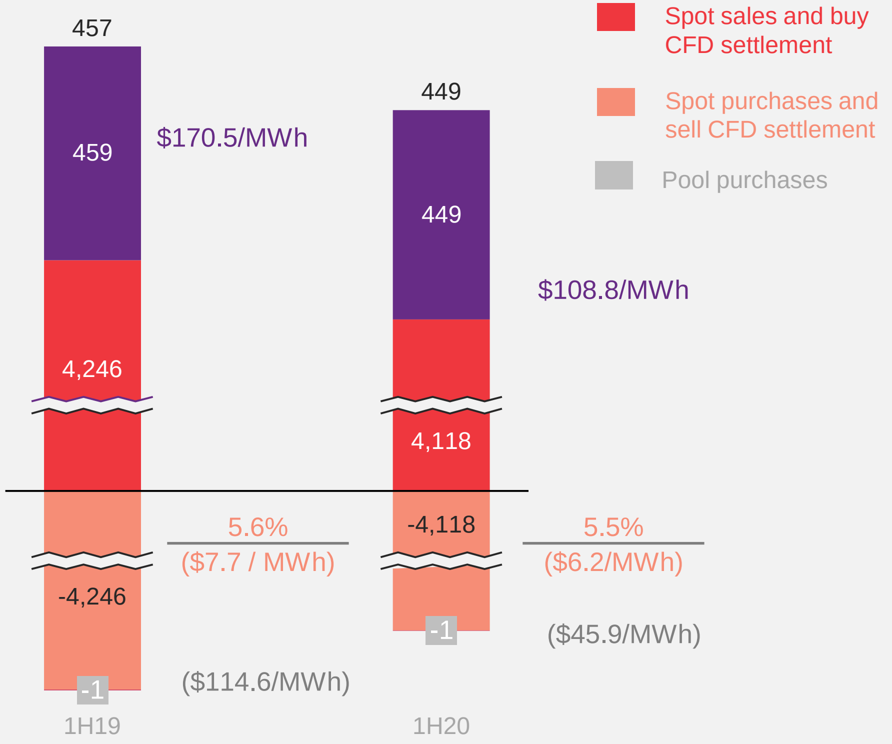
Trading revenue

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)

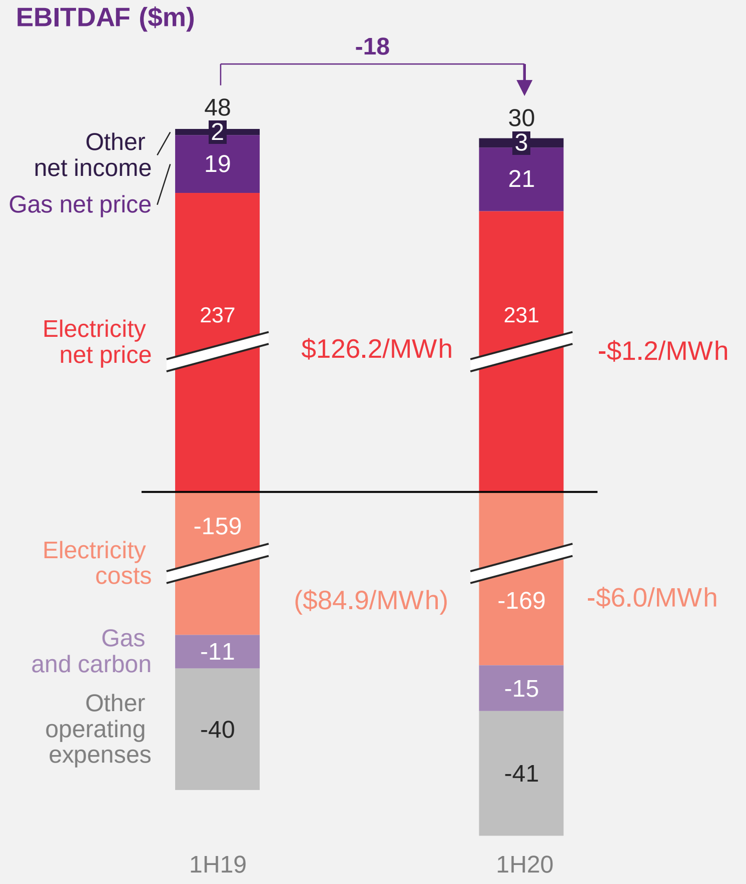


- 10GWh decrease in merchant sales volumes (-$1m). The price received for this "long" generation was down by $61.7/MWh (-$28m).
- Strong generation volumes and risk management saw limited price exposure to unhedged spot market purchases during higher wholesale price periods.
- The relative reduction in South Island hydro generation reduced locational losses by 0.1% when combined with lower wholesale prices saw absolute LWAP/GWAP reduce by $7m.

Customer business performance.

Government's regulatory review completed.

Revenue & Tariff[1] ($m)	1H19	1H20		Variance	
	$m	$m	*Tariff*	$m	*Tariff*
Electricity gross revenue	451.6	448.8	*241.2*	-2.8	0.2
PPD not taken	6.4	6.1			
Incentives paid	(5.3)	(4.1)			
Net revenue (cash)	**452.7**	**450.8**	***242.3***	**-1.9**	**0.7**
Capitalised incentives	5.3	4.1			
Amortised incentives	(3.4)	(4.6)			
Net revenue (P&L)	454.6	450.4	*242.0*	-4.2	-0.6
Gas revenue	39.2	40.5	*23.0*	1.3	0.5
Broadband revenue	1.7	7.2	*70.7*	5.5	
Other income	1.9	2.5		0.6	
Total revenue	**497.4**	**500.6**		**3.2**	
Contract Asset (closing)	14	11		(3)	



Complex retail electricity tariff structures mean transparency is essential to understand performance.

Electricity tariff changes reflect heightened regulatory environment:

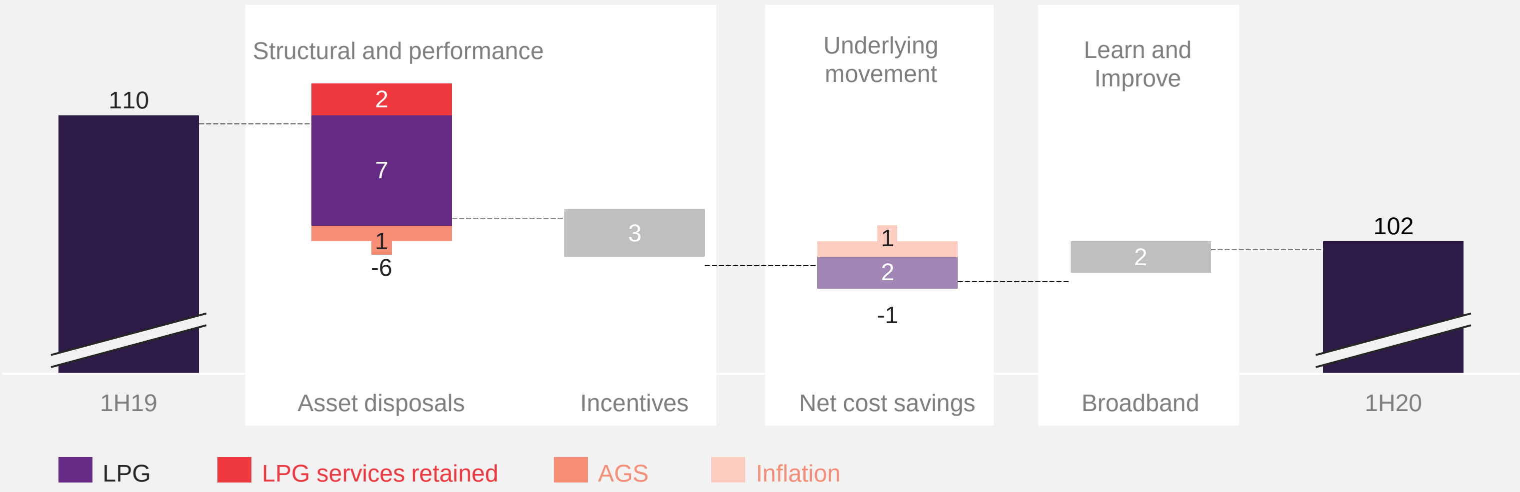
- 20k customers migrated to fit-for-purpose plans
- End to further Prompt Payment Discounts
- Only ~20% of customers received a price increase in FY19.

Smooth the impact of higher energy costs for customers, which are up by 7% on 1H19.

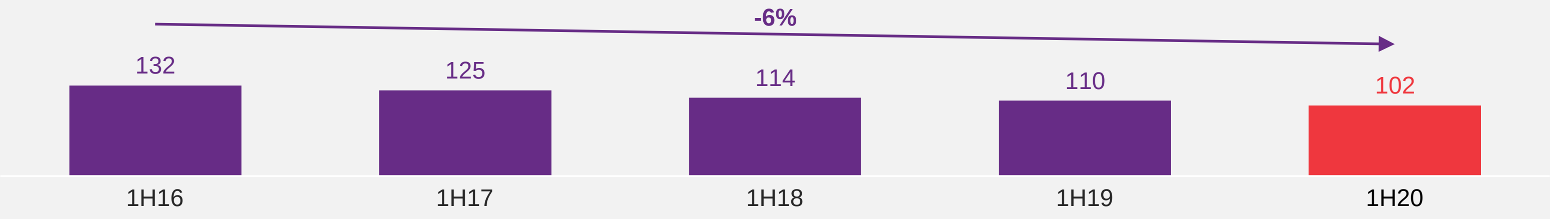
1. Tariff is $/MWh for electricity, Gas $/GJ and $ per month per customer for broadband

Controllable operational expenditure continues to fall.

Other operating cost movement ($m)



Other operating cost ($m)



Underlying movement

Delivered $2m of underlying operating cost improvement in line with our FY20 target.

$2m from ICT procurement savings:

- Configuration management database optimised applications
- Rightsizing of application support leveraging internal maturity with systems
- SAP to the cloud.

Other operating cost trajectory

Reduction of 6% CAGR since FY16.

Underlying reduction of 2% in 1H20.

Normalised and expected 1H EBITDAF assumptions.

With reconciliation to actual performance.

1H assumptions that deliver expected & normalised EBITDAF of $480m

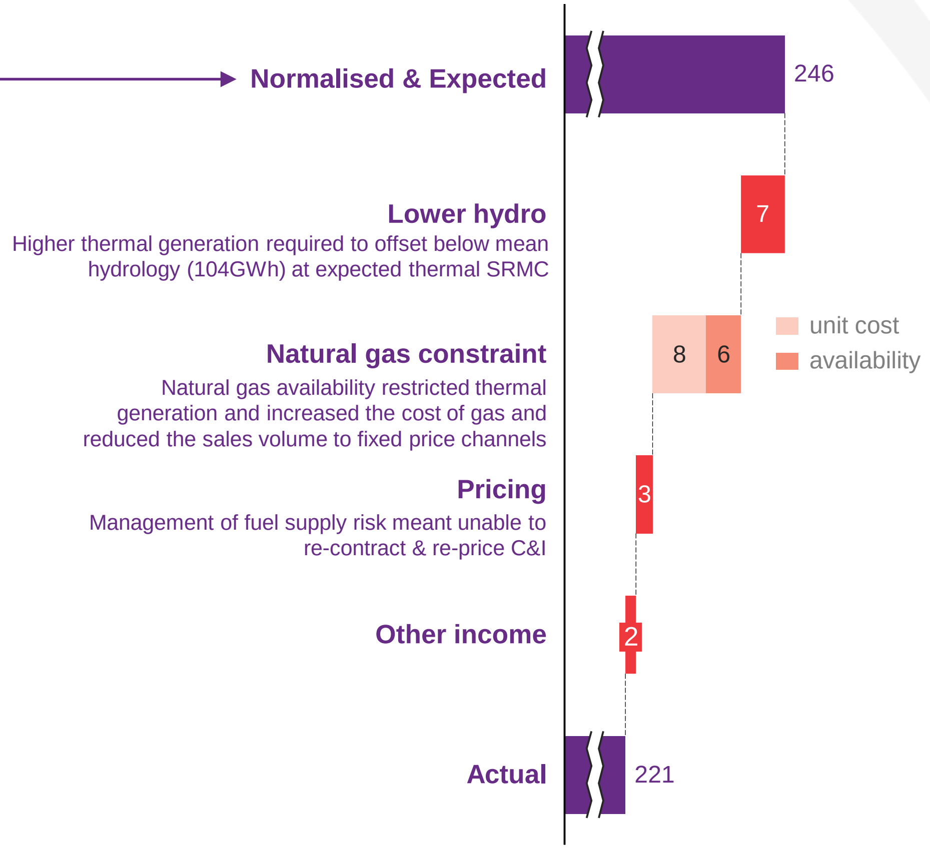
1 Channel choices maximise long term value[1]		X	2 Net price[2] driven by best commercial practices	=	Total
CFDs	725GWh	x	$64/MWh	=	$46m
C&I	1,675GWh	x	$81/MWh	=	$136m
Retail	2,014GWh	x	$117/MWh	=	$236m
Other income[3]					$29m
					$447m

3 Hydrology & Asset availability optimise generation		X	4 Access to and price of fuel* drives financials & risk position	=	Total
Hydro	1,990GWh	x	$0/MWh	=	-$0m
Geo	1,650GWh	x	$1/MWh	=	-$2m
Thermal[4]	974GWh	x	$66/MWh	=	-$64m
Acquired	50GWh	x	$100/MWh	=	-$5m
					-$71m

5 Trading delivers value to more than offset locational losses	
Length[5]	$27m
Location losses[6]	-$18m
Total	**$9m**

6 Digitalisation & continuous improvement optimise fixed costs	
Transmission/Storage	-$35m
Operating expenses	-$104m
Total	**-$139m**

EBITDAF reconciliation to 1H20



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)
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 (250GWh every 6 months)
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

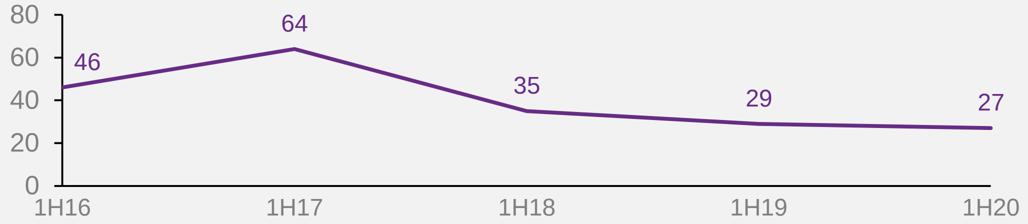
Cash flow and capital expenditure.

Underlying cash conversion remains strong.

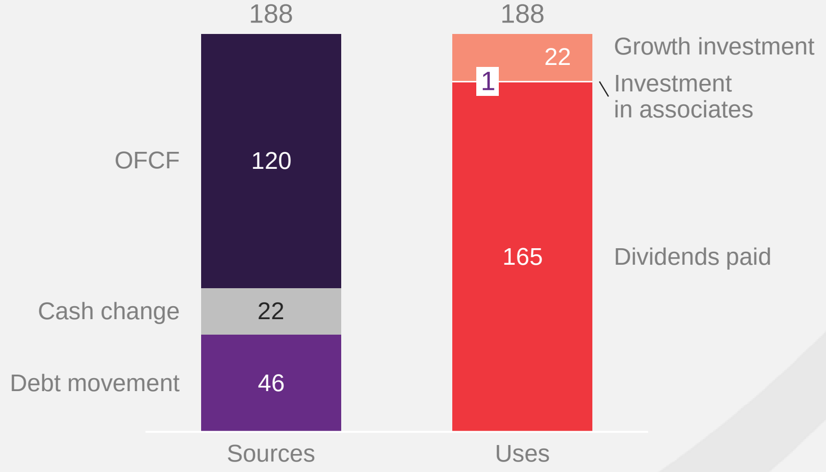
	6 months ended 31 Dec. 2019	6 months ended 31 Dec. 2018	Comparison against 1H19	
EBITDAF	**$221m**	$291m	↓	($70m)
Working capital changes	**$5m**	$18m	↓	($13m)
Tax paid	**($56m)**	($41m)	↑	($15m)
Interest paid, net of interest capitalised	**($25m)**	($36m)	↓	$11m
SIB capital expenditure	**($27m)**	($29m)	↓	$2m
Non-cash share based compensation	**$2m**	$1m	↑	$1m
Significant items	**-**	($1m)	↓	$1m
Operating free cash flow	**$120m**	$203m	↓	($83m)
Operating free cash flow per share	**16.8 cps**	28.3 cps	↓	(11.5 cps)
Proceeds from sale of assets/operations	**-**	$438m	↓	($438m)
Free cash flow	**$120m**	$641m	↓	($521m)

- EBITDAF down $70m with continuing operations down $57m with $13m from Rockgas (discontinued)
- Working capital changes $13m lower on higher injection into storage
- Capital expenditure on continuing operations of $27m in 1H20 in line with 1H19

SIB capital expenditure ($m)



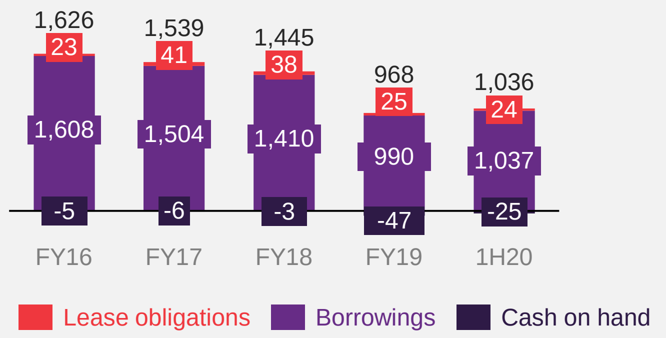
Sources and uses of cash ($m) 1H20



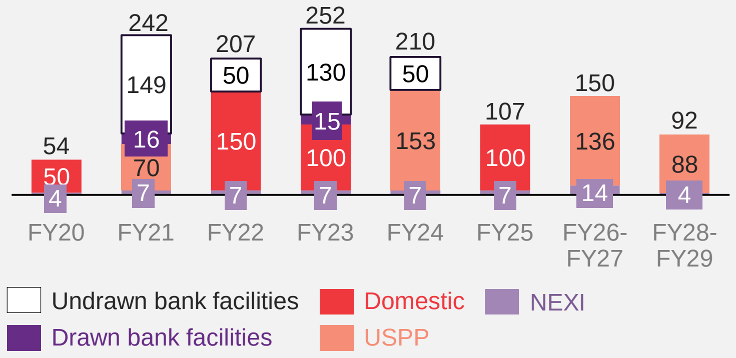
Robust balance sheet.

Well-managed, diversified portfolio with green certification. Capacity to fund further renewable generation projects.

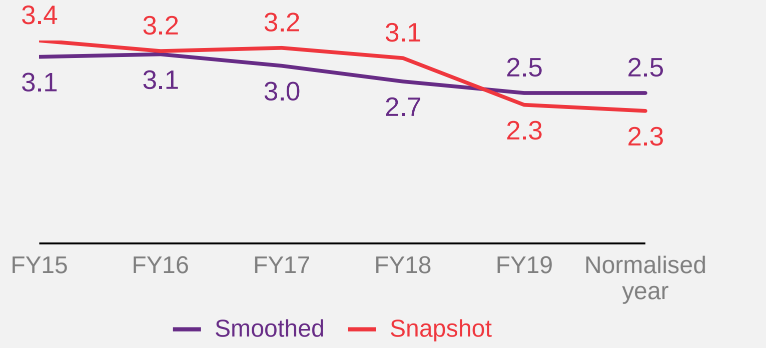
Closing net debt ($m)
Face value of borrowings less cash



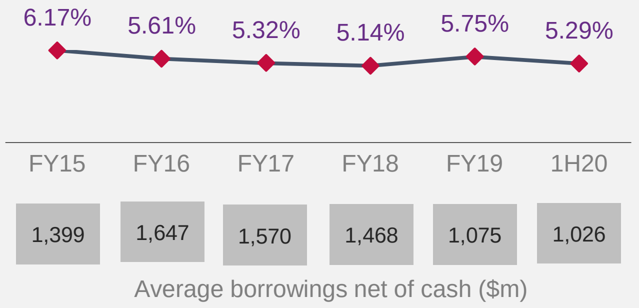
Borrowing maturities ($m)
Average tenor of 3.4 years as at 31 December 2019



Net debt to EBITDAF (x)
Includes S&P adjustments (in FY19 AGS was treated as a lease)



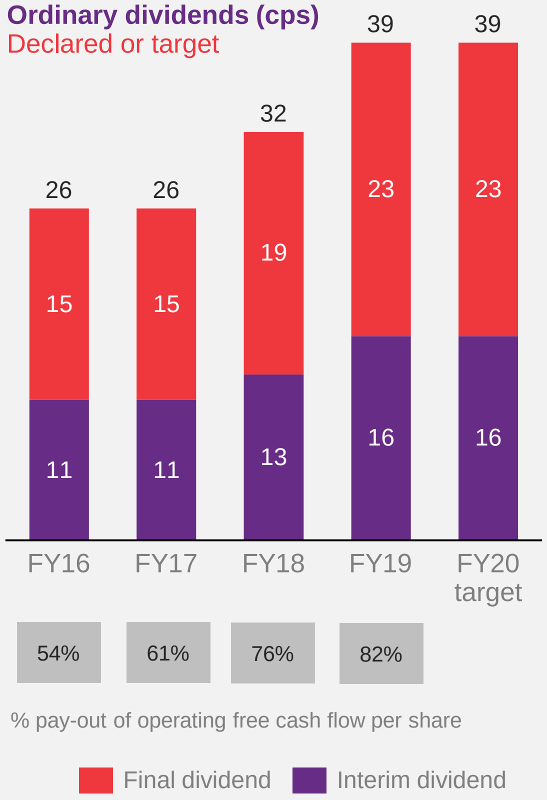
Interest rate (%)
Weighted average net interest[1] on average borrowings net of cash



- Face value of borrowings net of cash (excl. leases) increased by $68m to $1,036m since 30 June 2019 as the final dividend payment relating to FY19 and the investment in growth exceeded the operating free cash flow . Net debt has reduced by $623m since the end of FY15. Gearing increased to 29.9% at 31 December 2019, up from 28.3% at 30 June 2019.
- $50m wholesale domestic bond maturity in May 2020, to be funded through existing facilities.
- Weighted average interest rate reduced by 46bp on FY19 with a greater proportion of floating rate debt at current low interest rates in 1H20.
- Contact continues to target a credit rating of BBB (net debt / EBITDAF <2.8x).
- Contact's Green Borrowing Programme was recognised at the 2019 Deloitte Excellence in Energy Awards, winning the "Innovation in Energy" category.
- New sustainability linked loan facility executed in December 2019 to align capital structure with strategic ESG ambitions.

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

Distribution policy provides clarity to investors and drives a strong capital discipline.



Interim dividend for 1H20 of 16 cents per share

- Interim dividend of 16 cents per share (Interim FY19 16 cents per share) is imputed to 63% or 10 cents per share for qualifying shareholders. This represents a pay-out of 95% of 1H20 operating free cash flow per share.
- Target FY20 ordinary dividend of 39 cents per share (FY19 39 cents per share).
- Record date of 19 March 2020; payment date of 7 April 2020.
- The NZD/AUD exchange rate used for the payment of Australian dollar dividends will be set on 30 March 2020.
- **See Appendix (page 40 - 41) for detailed workings explaining the calculation of expected operating free cash flow.**

Market update and outlook

Dennis Barnes, CEO

A disorderly exit impacts multiple stakeholders and all gentailers.

Rio Tinto strategic review >

Target completion first quarter 2020

"Rio Tinto will work with all stakeholders including the **government, suppliers, communities and employees** in order to find a solution that will ensure a **profitable future** for this plant."

Rio Tinto Aluminium
Chief Executive, Alf Barrios
22.10.19

Production
+4kT[1]

Staff
+18% over 3 years

Cash tax paid
$21m in FY18

3 year total
EBITDA less capex[2]
+$71m

Stakeholders >

Suppliers

- Electricity would flow North, in a curtailment scenario without grid upgrades.
- Reduced return on thermal assets and lower natural gas demand.
- Transmission pricing delays – initial benefits to NZAS have been eroded.

Government

- Impact on the Southland and Taranaki economy, loss of regional jobs.
- Carbon leakage from low carbon aluminum.
- Inefficient capital investment decisions.
- Risk to New Zealand's long-term decarbonisation goals.
- Loss of tax revenue; current account impact.

Communities & employees

- Large closing costs (estimate >$300m on closure).
- Uncertainty from 12 month termination right.
- Infrastructure and supply chain to support NZAS.
- Retooling and reskilling – time and investment.

Contact's mitigations >

✓ Early LSI transmission upgrade agreed

Alternative electricity demand growth
✓ • Dairy electrification real

Thermal portfolio marginal at best
- Short gas book
- Close baseload thermal (TCC)

✓ Strong balance sheet

Manage North Island reserves, increase HVDC flow without investment

"New Zealand should support and grow our low carbon advantage and that includes supporting businesses like the smelter"

Chair Rob McDonald, 2019 Contact AGM

Independent analysis of smelter financial performance indicates positive cash flows.

[1] Commissioned a 4th potline in late 2018, increasing production backed by a new electricity contract until 12/2022, [2] Source Pacific Aluminium (New Zealand) Limited financial statements: EBITDAF is equal to Profit before Income Tax; add back Depreciation, Finance costs and fair value movements in derivatives. Capex is equal to cash payments for Plant, Property and Equipment

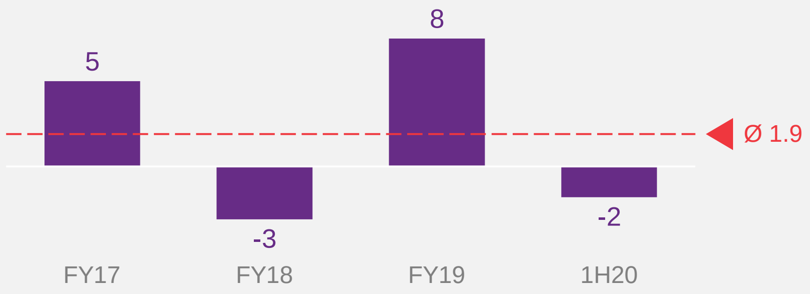
Topical regulatory matters.

Claim of undesirable trading situation (UTS) and alleged breach of high standards of trading conduct

We are continuing to support the Electricity Authority in its investigation into whether lower South Island trading conditions in November and December represented an undesirable trading situation as claimed.

- The Clutha is a run of river scheme. There is no ability to store the water that flows down the Clutha river.
- 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.
- During a flood, we need stability to meet our consent conditions and to minimise undue risk to equipment which is essential to the safe passage of flood flows. When in flood conditions there are operational reasons that mean we do not want our plant to be the marginal offer over the course of a day. Being marginal means we risk constantly adjusting the set-points of the plant and our dams' flood management systems.

Market making
Revenue / (loss) ($m)



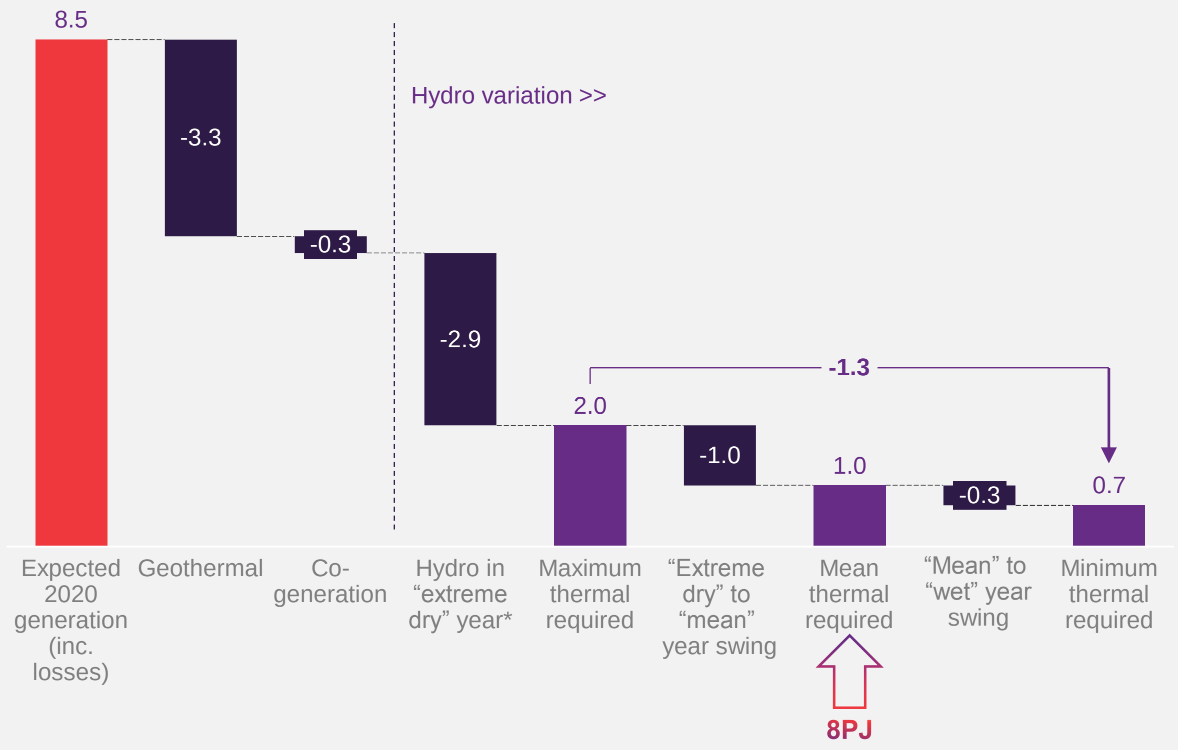
Prudential requirements ($m)

- Profit/loss in market making driven primarily by the net sales/purchase position when the forward prices move. No revenue opportunities from providing a market making service off the bid/offer spread.
- Prudential requirements have risen in line with increased volatility and higher average wholesale prices.
- The new ASX trading arrangements, in which some market participants triple market making volumes in the monthly contracts while maintaining narrower bid/offer spreads commenced on 13 January.
- We maintain that this will be for the benefit of speculative financial market participants as opposed to Tier 2 retailers or customers.

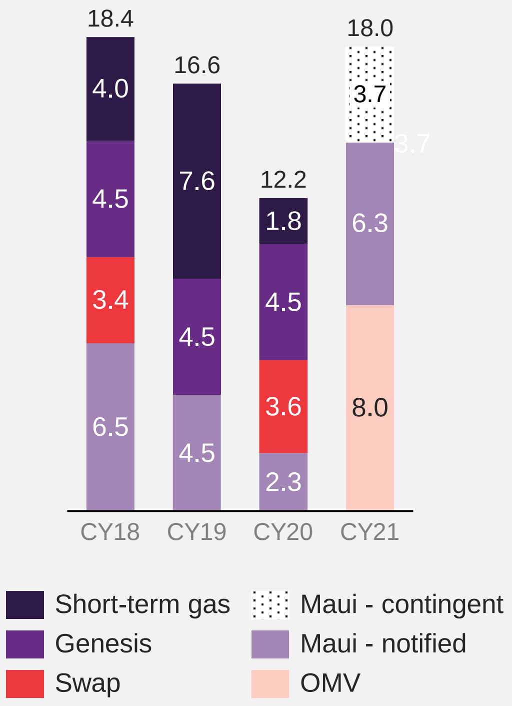
Contractual fuel position in line with firming requirements.

Gas availability improving, costs rising.

Portfolio requirements for thermal generation (TWh)

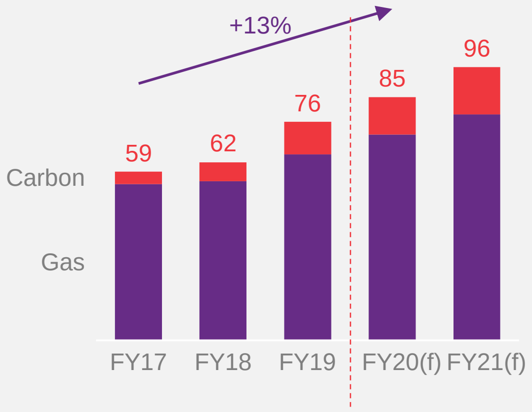


Contracted gas volumes (PJ)



Storage balance at 31 January 2020 5.7PJ

Thermal plant fuel cost ($/MWh)



The increasing price of natural gas and carbon is accelerating the case for the long-term economic substitution of baseload thermal plant.

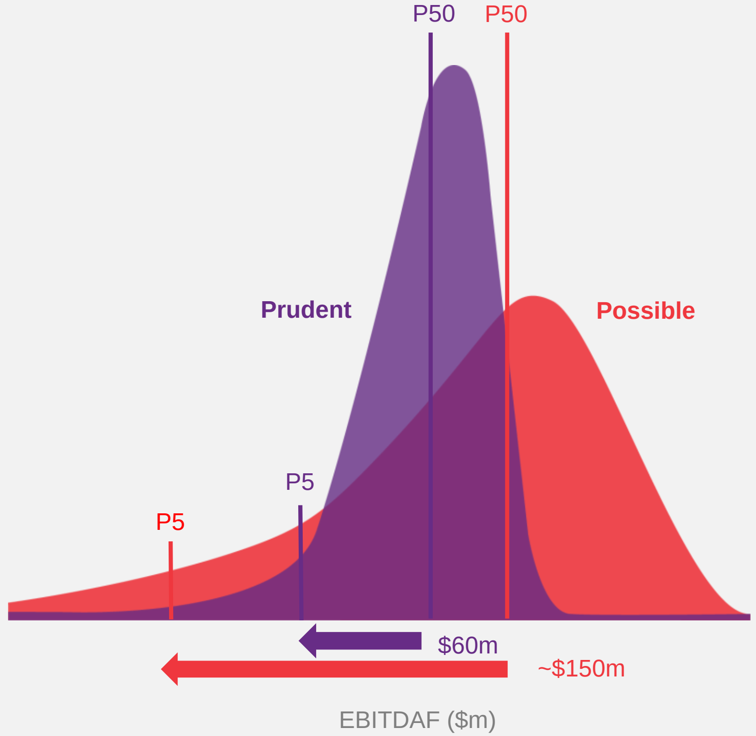
- Increased gas prices and the greater relative returns from a substitution investment in Tauhara, make it prudent to reduce the asset life of TCC to FY23 - accelerating depreciation since 1 July 2019.

* Hydro generation in FY12

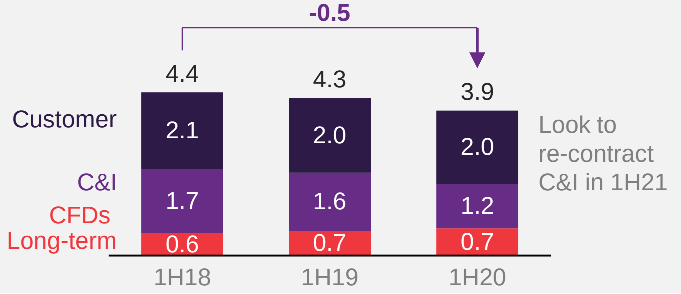
Prudent commodity risk management.

Managing earnings at risk more important than current year earnings

Limited fixed price sales, reduced mean (P50) EBITDAF but improved earning at risk (P5)



1 – Reduce sales volumes



2 – Internal risk management

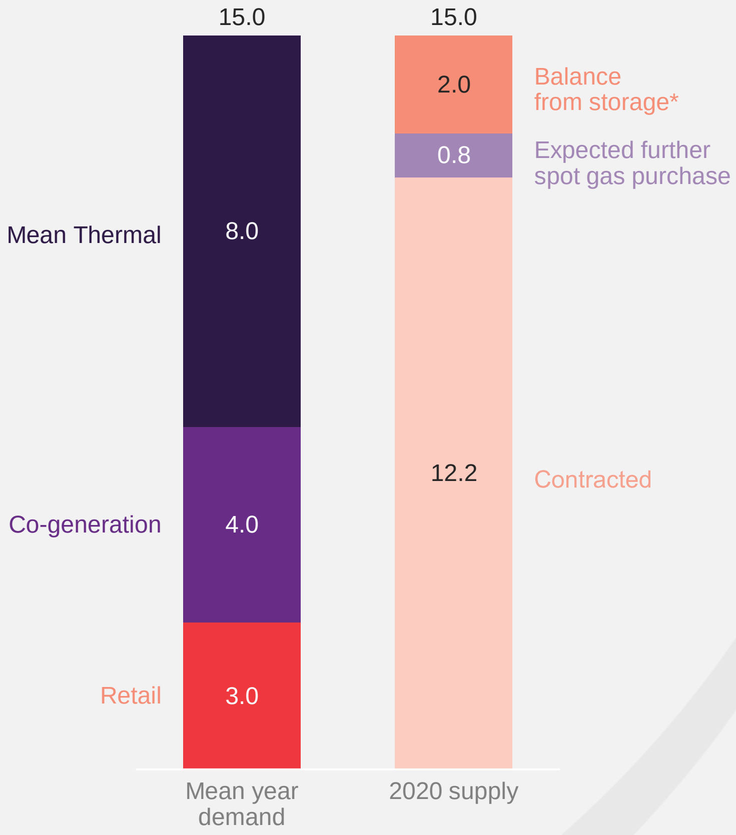
Hawea
>285GWh
of controlled storage

Whirinaki
155MW
Diesel
peaker

3 – External risk management

Huntly swaption
100MW

Gas supply and demand 2020 (PJ)



*Storage balance at 31 January 2020 5.7PJ

Priority areas.

Near term

Tiwai

Constructive engagement to promote renewable advantage. Continue to advance mitigation options.

Manage wholesale market volatility

Effective risk management.

Gas contracts will allows for greater participation in contracting fixed price sales.

Delivering value

Recover rising input costs.

Investment in digital and data to further reduce costs and develop new, innovative propositions.

Continued focus on controllable cost reduction.

CEO succession

Mike Fuge starts 24 February

Tauhara appraisal

Evaluation of the drilling results, preparation for final investment decisions

Medium term

Capture scale efficiencies

Lower the cost of geothermal.

Redesign customer journeys to capture multi-product scale efficiencies.

Decarbonisation

Develop options to enable the economic substitution of thermal generation with renewables.

Partner with customers on mutually beneficial decarbonisation opportunities.

Confidence in the ability to deliver performance improvements.

	FY20	Change to prior guidance	
Other operating costs	$200 – 205m	Cash spend forecast range unchanged	
Stay in business capital expenditure	$55 – 60m		
Cash spend (‘Totex’)	**$255 – 265m**		
Depreciation and amortisation	$213 – 223m	↑ **$18m**	TCC now to be fully depreciated by 2023. Full year impact $18m
Net interest (accounting)	$55 – 60m	↓ **$5m**	Interest on Tauhara spend capitalised to PP&E
Cash interest (in operating cash flow)	$50 – 55m		
Cash taxation	$70 – 75m	-	
Target ordinary dividend per share	39 cps	-	

Questions

Supporting material

Expected operating free cash flow.

Distribution policy

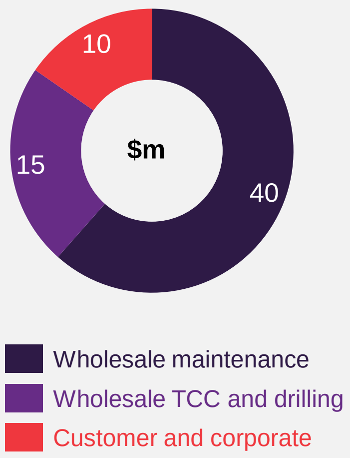
Contact's policy is to distribute ordinary dividends targeting a pay-out ratio of 100% of Operating Free Cash Flow* which is adjusted for expected medium-term stay-in-business capital expenditure, mean hydrology and the consideration of a sustainable financial structure including the targeting of a long-term credit rating of BBB.

Dividend payments are expected to be split into an interim dividend paid in April, targeting around 40% of the total expected dividend for the financial year, and a final dividend to be paid in September.

It is the intention of the Board to attach imputation credits to dividends to the extent they are available.

Long run average CAPEX ($m)

Excludes capex associated with Wairakei extension post 2026

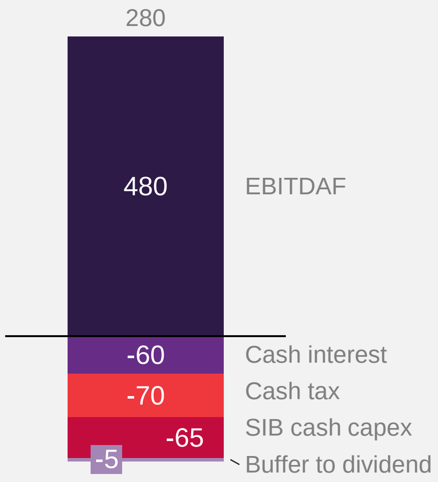


Sustainable capital expenditure is between $60 - $65m per annum and includes:

- Thermal plant refurbishment
- Geothermal well drilling to maintain geothermal generation at 3,300 GWh per annum
- Transformation and continuous improvement initiatives
- Plant and systems maintenance.

Medium term OFCF ($m)

*Operating Free Cash Flow (OFCF) is operating cash flow less stay-in-business capital expenditure



Key assumptions: Hydro generation at 3,900 GWh (mean), geothermal generation at 3,300 GWh (average).

ASX electricity futures and electricity retail margins stable.

Excludes working capital movements.

Normalised and expected FY EBITDAF assumptions.

With reconciliation to actual performance.

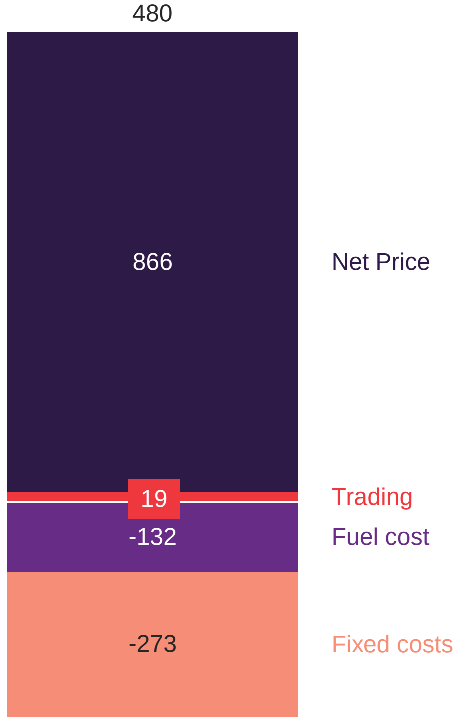
FY assumptions that deliver expected & normalised EBITDAF of $480m

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**

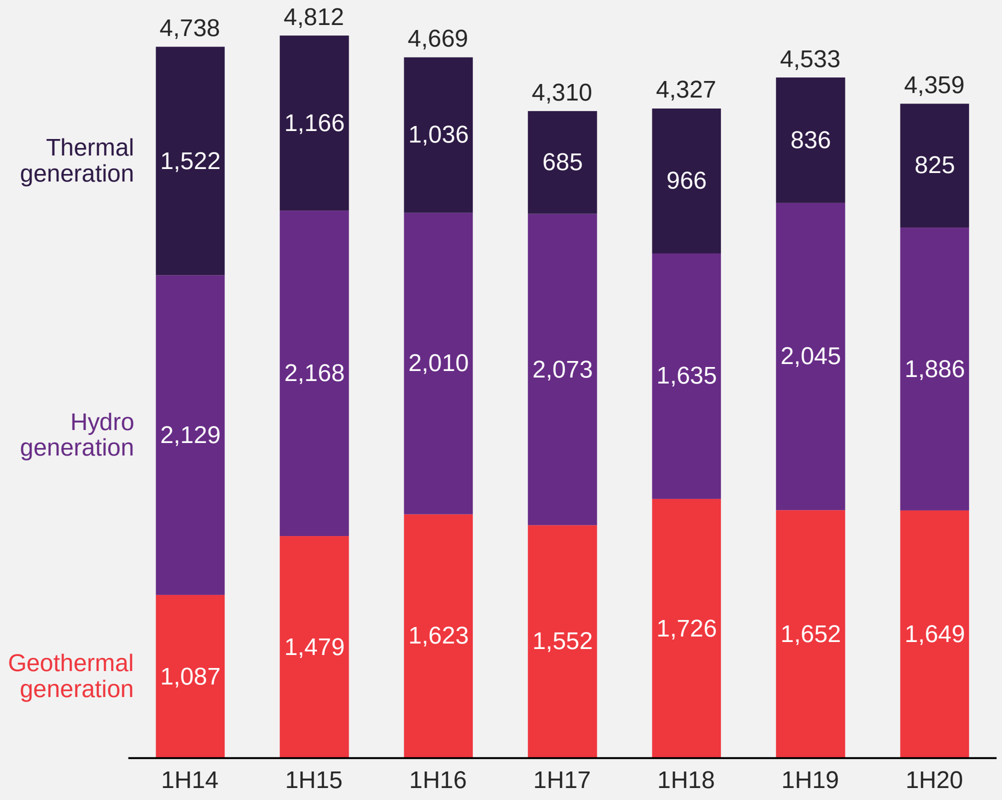
Expected & normalised FY EBITDAF

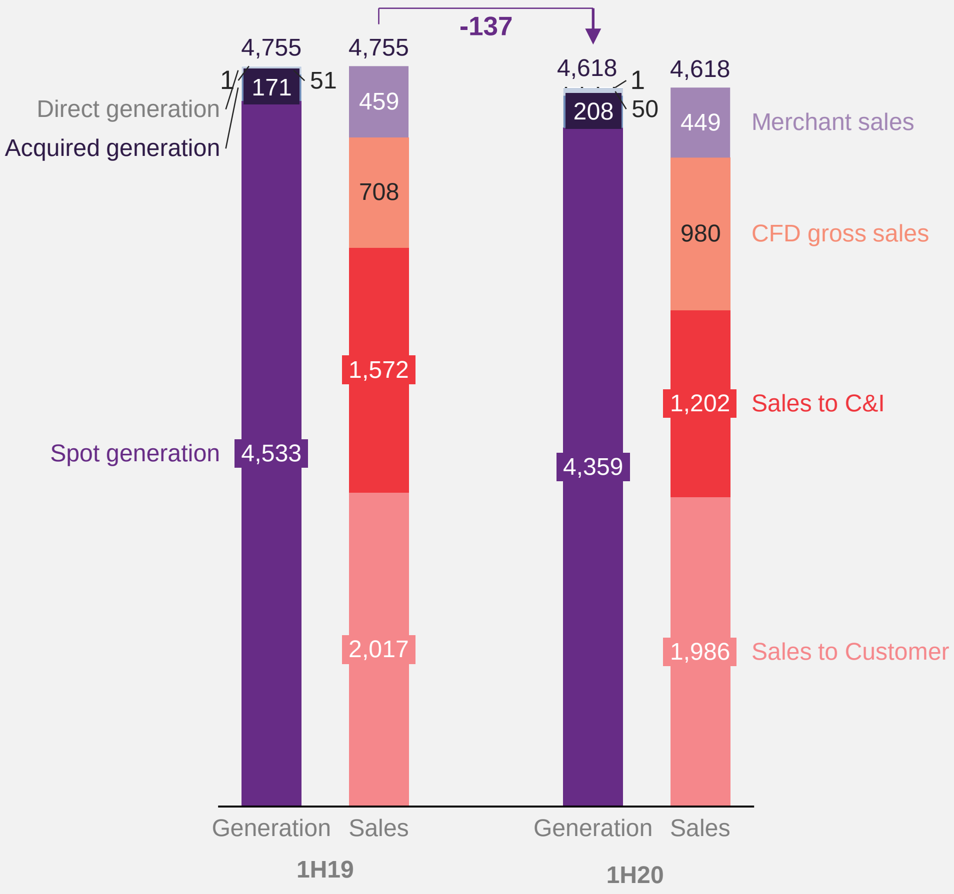


1. All volumes are at the Grid Exit Point (GXP)
2. Net price is equal to tariff less pass-through costs (network, meters and levies) /MWh
3. Steam sales, retail gas gross margin, other income
4. Gas price of $6/GJ, carbon price of $20/unit and thermal portfolio heat rate (9.25GJ/MWh)
5. Length of 500GWh 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

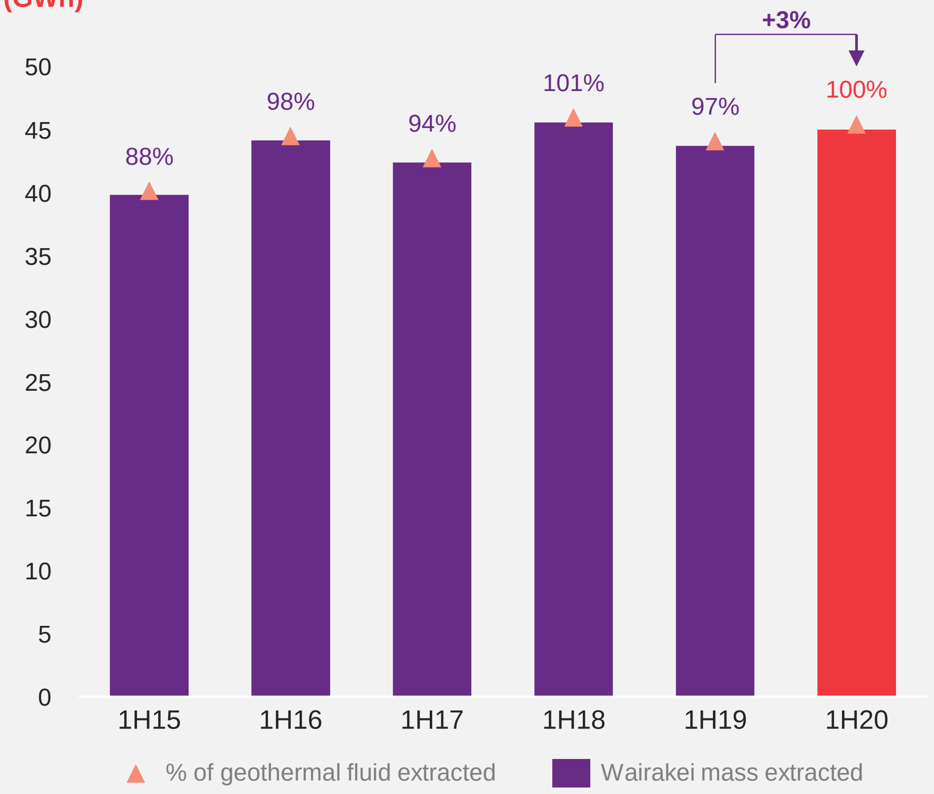
Generation and sales position.



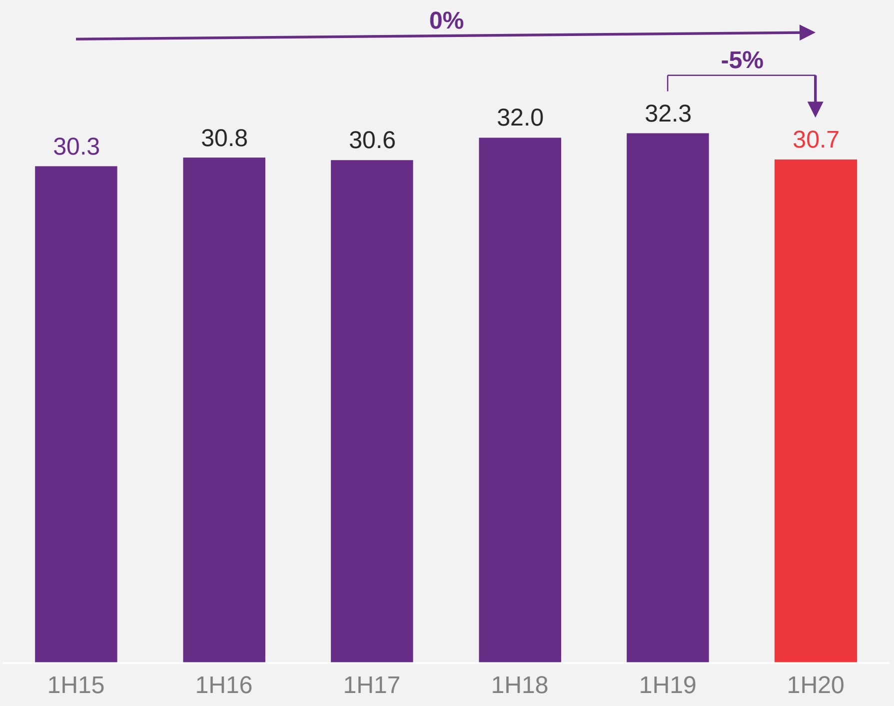


Wairakei geothermal field mass take and efficiency.

Geothermal fuel extracted at Wairakei vs consented (GWh)

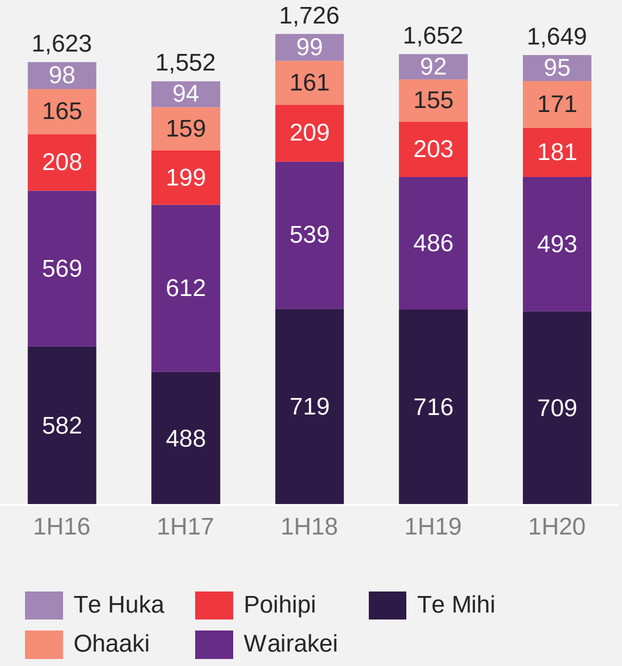


Wairakei, Poihipi and Te Mihi conversion effectiveness (MWh per kT extracted)



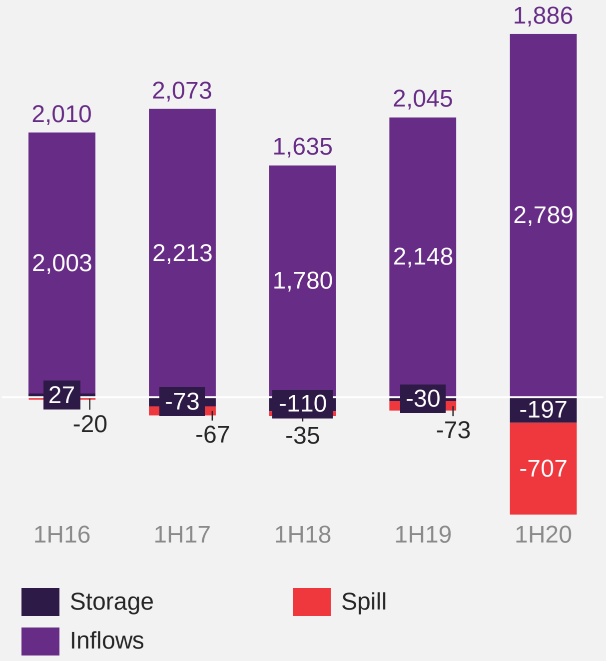
Generation volumes: renewable generation down by 4% on 1H19.

Geothermal generation (GWh)



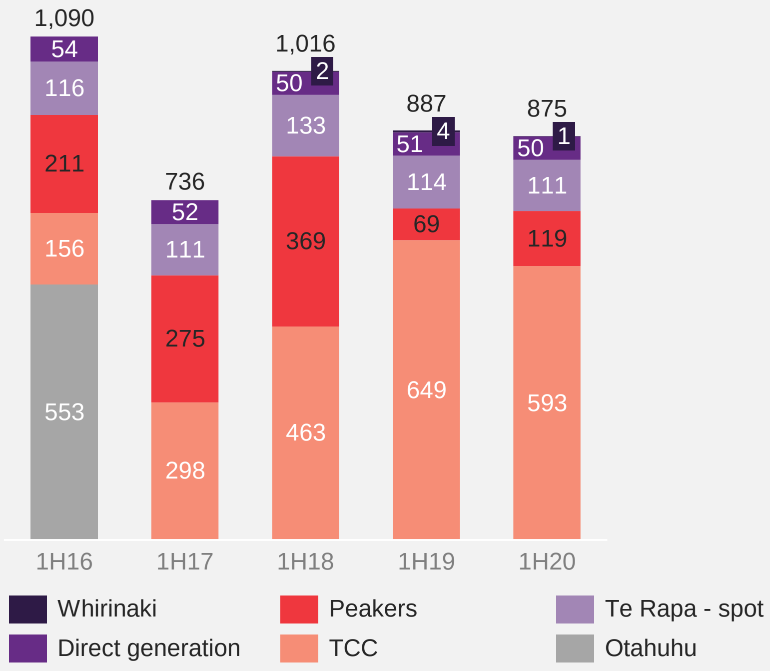
Geothermal generation was 3GWh lower than 1H19 as the reduction in generation during the scheduled 4-yearly outage at Poihipi was offset by increased generation at Ohaaki

Hydro generation (GWh)



Hydro generation was 104GWh above mean (1H 1,990GWh) in 1H20, 159GWh below 1H19 but 251GWh higher than a dry 1H18. 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 12GWh lower in 1H20 on lower sales and restricted availability of gas which reduced the ability to run baseload thermal at TCC with the Stratford peakers

Plant availability.

Hydro

	Net capacity (MW)	Availability (%)	Capacity factor (%)	Electricity output (GWh)	Pool revenue ($/MWh)	Pool revenue ($m)
1H17	784	91%	60%	2,073	42	87
1H18	784	95%	47%	1,635	88	144
1H19	784	95%	59%	2,045	129	265
1H20	784	94%	54%	1,886	98	184

Geothermal

	Net capacity (MW)	Availability (%)	Capacity factor (%)	Electricity output (GWh)	Pool revenue ($/MWh)	Pool revenue ($m)
1H17	429	89%	82%	1,552	50	78
1H18	429	97%	91%	1,726	86	148
1H19	425	91%	88%	1,652	137	226
1H20	425	94%	88%	1,649	106	175

Taranaki combined cycle (TCC)

	Net capacity (MW)	Availability (%)	Capacity factor (%)	Electricity output (GWh)	Pool revenue ($/MWh)	Pool revenue ($m)
1H17	377	95%	18%	298	52	15
1H18	377	51%	28%	463	110	51
1H19	377	63%	39%	649	119	78
1H20	377	78%	36%	593	113	67

Peakers (including Whirinaki)

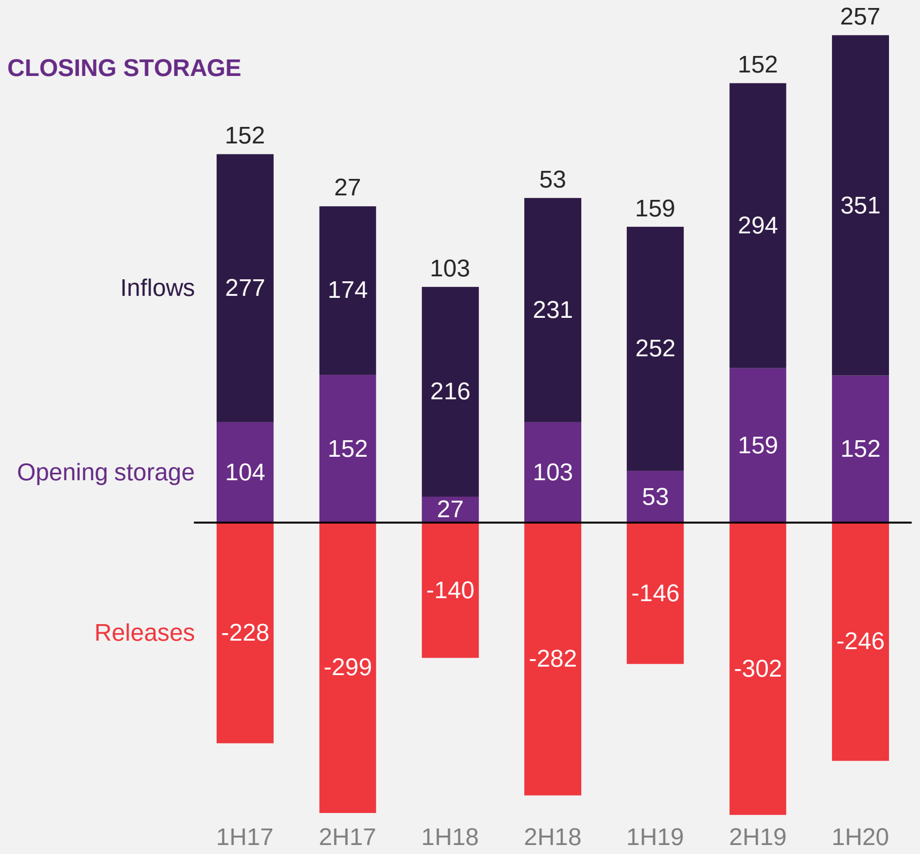
	Net capacity (MW)	Availability (%)	Capacity factor (%)	Electricity output (GWh)	Pool revenue ($/MWh)	Pool revenue ($m)
1H17	202	96%	16%	276	60	17
1H18	202	98%	21%	370	120	44
1H19	202	79%	4%	73	231	17
1H20	202	78%	7%	120	153	18

Te Rapa (spot generation only)

	Net capacity (MW)	Availability (%)	Capacity factor (%)	Electricity output (GWh)	Pool revenue ($/MWh)	Pool revenue ($m)
1H17	41	100%	31%	111	53	6
1H18	41	99%	37%	133	93	12
1H19	41	98%	32%	114	161	18
1H20	41	100%	31%	111	116	13

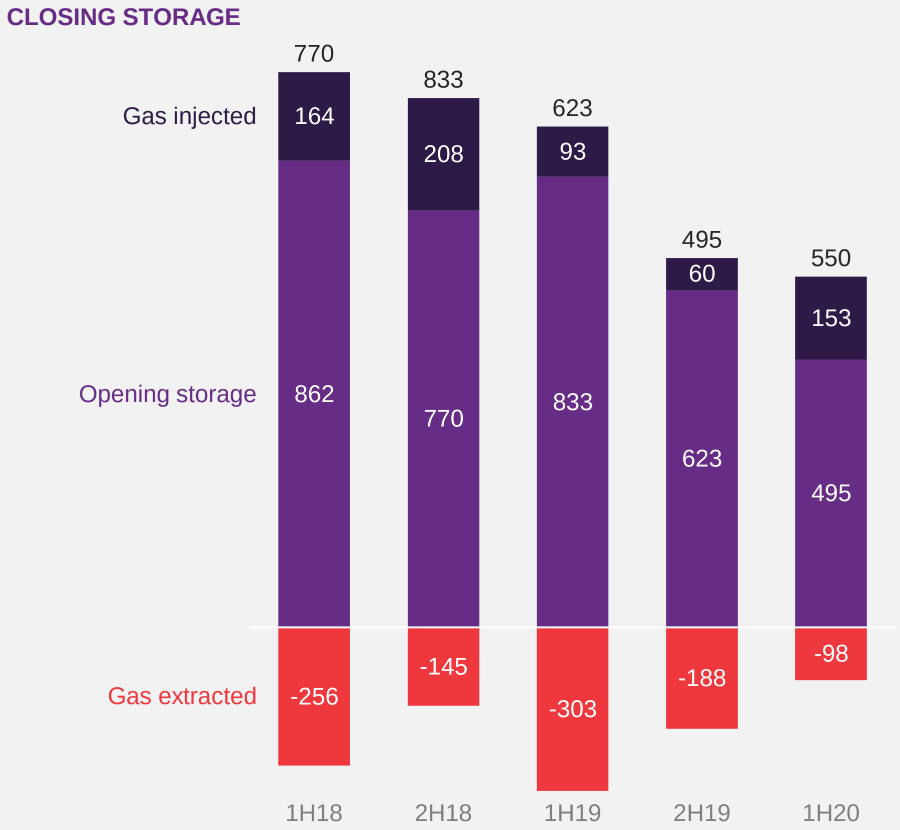
Fuel storage movements.

Hawea strorage (GWh)



Gas storage (GWh equivalent)

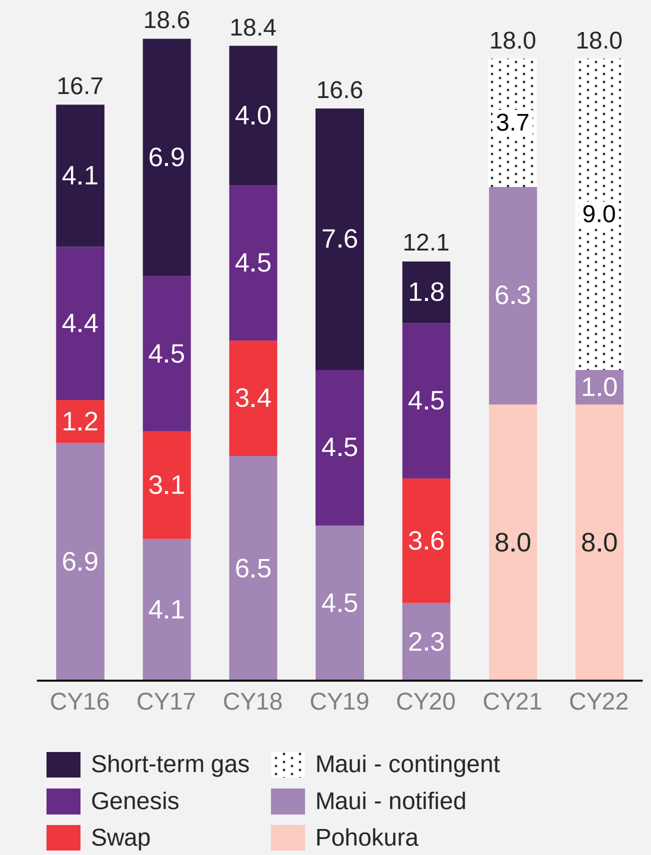
Using the 1H20 thermal efficiency (9.04 TJ/GWh)



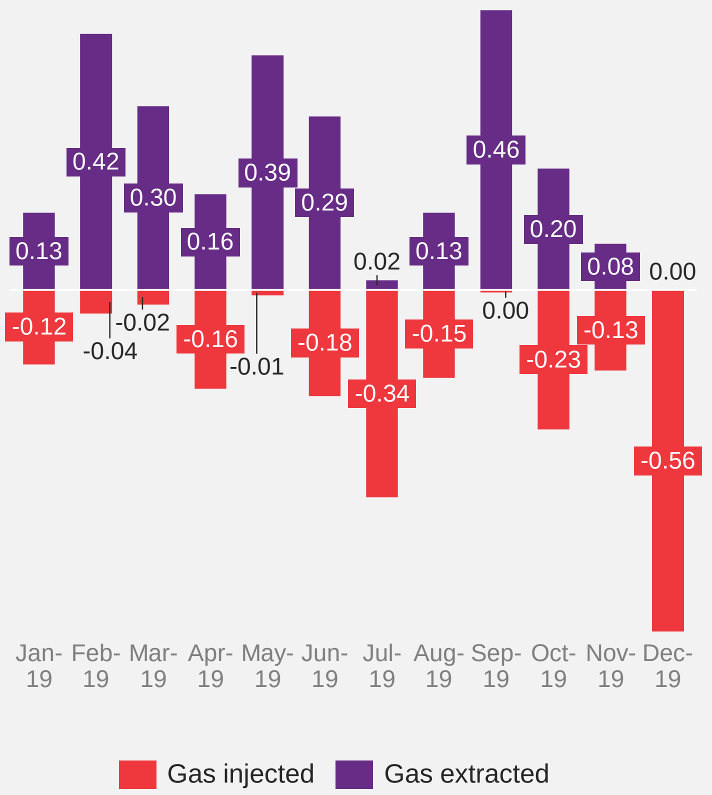
Source: NZX hydro, 8 January 2019

Contracted and stored gas.

Contracted gas volumes (PJ)

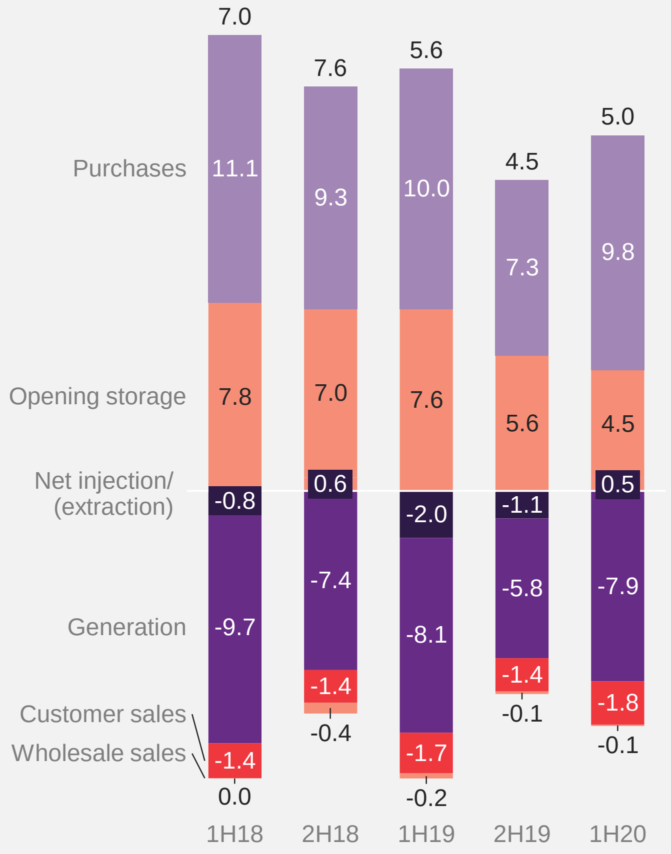


Ahuroa gas storage monthly injections and extractions (PJ)



Sources and uses of gas (PJ)

Closing storage



Storage balance at 31 January 2020 was 5.7PJ

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:

	6 months ended 31 December 2019	6 months ended 31 December 2018	Variance on prior year	
			$m	%
Profit	**59**	**276**	**(217)**	**(79%)**
Depreciation and amortisation	110	102	8	8%
Significant items (gross of tax)	(2)	(172)	170	99%
Net interest expense	28	39	(11)	(28%)
Tax expense	26	46	(20)	(43%)
EBITDAF	**221**	**291**	**(70)**	**(24%)**

- 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 1H19 are as follows:

- **Depreciation and amortisation:** Increased by $8m (8%) on 1H19 primarily resulting from the change in estimate for the expected useful life of TCC to 2023 (previously 2028) which has resulted in accelerated depreciation from 1 July 2019.
- **Change in fair value of financial instruments**: Reduced by ($2m) in 1H20 reflecting the unfavourable movement in electricity price derivatives over the period.
- **Net interest expense:** Reduced by $11m (28%) to $28m over 1H20 on reduced average borrowings and a lower interest rate as well as the capitalisation of interest relating to the Tauhara geothermal project ($3m). Net interest also includes a $3m unwind in the discount of provisions.
- **Tax expense** for the six months ended 31 December 2019 was $26m down from $43m in 1H19 on lower operating earnings and higher depreciation partially offset by lower net interest expense. Tax expense for 1H20 represents an effective tax rate of 30%. The effective tax rate for 1H19 was 14% on total earnings as the gain on the sale of Rockgas was not subject to income tax.
- **Other significant items** are detailed on the next two slides.

Reconciliation between Profit and Underlying profit.

	6 months ended 31 December 2019	6 months ended 31 December 2018	Variance on prior year	
			$m	%
Profit	**59**	**276**	**(217)**	**(79%)**
Change in fair value of financial instruments	(2)	2	(4)	
Gain on sale of Rockgas Limited (LPG)	-	(167)	167	100%
Gain on sale of Ahuroa gas storage	-	(5)	5	100%
Remediation for Holidays Act non-compliance	-	(2)	2	100%
Tax on items excluded from underlying profit	1	3	(2)	(67%)
Underlying profit	**58**	**107**	**49**	**(46%)**

- Underlying profit provides a consistent measure of Contact's ongoing performance.
- Underlying profit excludes the effect of significant items from reported 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 reported profit to underlying profit for 1H20 was:

- Change in the fair value of financial instruments (net of taxation)

The adjustments from reported profit to underlying profit for 1H19 were as follows:

- **Ahuroa Gas Storage (AGS) Facility Sale:** The sale of the AGS Facility to GSNZ SPV1 Limited (GSNZ) was completed on 1 October 2018. Cash proceeds from sale received to date are $190 million resulting in a gain on sale of $5 million before tax. Consideration of up to $10 million remains unrecognised as it is contingent on GSNZ obtaining a favourable binding ruling as to the tax treatment of the main assets it acquired.
- **Rockgas Limited Sale:** Rockgas was sold to Gas Services NZ Midco Limited on 30 November 2018, the net gain on sale recognised in 1H19 was $167m (FY19 $165m)
- **Remediation for Holidays Act non-compliance**: During 1H19, spend of $1 million was incurred in order to resolve non-compliance with aspects of the Holidays Act 2003. The provision was reduced by $2 million as a result of ongoing reassessment of the expected liability
- Change in the fair value of financial instruments
- Taxation on the items outlined above (to the extent applicable)

Historical financial information.

	Unit	1H16	1H17	1H18	1H19	1H20
Revenue	$m	1,120	1,037	1,190	1,363	1,110
Expenses	$m	866	773	954	1,072	889
EBITDAF	$m	254	264	236	291	221
Profit/(loss)	$m	(116)	96	58	276	59
Underlying profit	$m	73	82	59	107	58
Underlying profit per share	cps	10	11.5	8.2	15.0	8.0
Operating free cash flow	$m	200	134	141	203	120
Operating free cash flow per share	cps	27.3	18.7	19.7	28.3	16.8
Dividends declared[1]	cps	11.0	11.0	13.0	16.0	16.0
Total assets	$m	5,726	5,587	5,390	5,140	4,850
Total liabilities	$m	2,848	2,766	2,663	2,297	2,170
Total equity	$m	2,878	2,821	2,727	2,843	2,680
Gearing ratio	%	37.0	36.4	35.4	29.7	29.9

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.

	1H20 Six months ended 31 December 2019			1H19 Six months ended 31 December 2018			Reference number for Wholesale segment note (see following page)
Note: this table has not been rounded and might not add	Volume GWh	GWAP $/MWh	$m	Volume GWh	GWAP $/MWh	$m	
Electricity sales to Customer	**1,986**	**85.2**	**169**	**2,017**	**78.9**	**159**	1
Electricity sales to Fixed C&I (netback)	1,152	79.1	91	1,521	79.8	121	
Electricity sales – Direct	50	105.1	5	51	97.7	5	2
Electricity sales to C&I	**1,202**	**80.2**	**96**	**1,572**	**80.4**	**126**	
CfDs – Tiwai support	436			376			
CfDs - Long term sales	301			298			3
CfDs - Short term sales	243			34			
Electricity sales - CFDs	**980**	**71.0**	**70**	**708**	**74.6**	**53**	
Total contracted electricity sales	**4,168**	**80.4**	**335**	**4,296**	**78.7**	**338**	
Steam sales	**343**	**49.4**	**17**	**351**	**45.9**	**16**	4
Other income			(1)			6	5
Net income on gas sales			1			1	6
Net income on electricity related services			0			1	7
Net other income			**(0)**			**7**	
Total contracted revenue (1)	**4,512**	**77.9**	**352**	**4,647**	**77.8**	**362**	
Generation costs	4,409	(33.6)	(148)	4,583	(30.6)	(140)	8
Acquired generation cost	208	(111.3)	(23)	171	(138.1)	(24)	9
Generation costs (including acquired generation) (2)	**4,617**	**(37.1)**	**(171)**	**4,754**	**(34.5)**	**(164)**	
Spot electricity revenue	4,359	105.2	459	4,532	133.4	605	10
Settlement on acquired generation	208	124.7	26	171	166.1	28	11
Spot revenue and settlement on acquired generation (GWAP)	**4,567**	**106.1**	**485**	**4,703**	**134.6**	**633**	
Spot electricity cost	(3,138)	(114.1)	(358)	(3,538)	(138.5)	(490)	12
Settlement on CFDs sold	(980)	(105.2)	(103)	(708)	(137.8)	(98)	13
Spot purchases and settlement on CFDs sold (LWAP)	**(4,118)**	**(112.0)**	**(461)**	**(4,246)**	**(138.4)**	**(588)**	
Trading, merchant revenue and losses (3)			**23**			**45**	
Wholesale EBITDAF (1+2+3)			**204**			**243**	

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	1H17	1H18	1H19	1H20
Average connections	#	363,472	361,412	352,159	355,216
Sales volumes	GWh	1,398	1,343	1,335	1,328
Average usage	per ICP	3.8	3.7	3.8	3.7
Tariff	$/MWh	245.8	247.8	249.9	248.2
Network, meters and levies	$/MWh	-118.0	-123.3	-120.3	-119.0
Energy costs	$/MWh	-85.2	-84.2	-85.4	-91.6
Gross margin	**$/MWh**	**42.6**	**40.3**	**44.2**	**37.6**
Gross margin	$ per ICP	164	150	168	141
Gross margin	$m	60	54	59	50

Residential gas	unit	1H17	1H18	1H19	1H20
Average connections	#	59,565	60,870	61,332	61,959
Sales volumes	TJ	951	946	936	911
Average usage	per ICP	16.0	15.5	15.3	14.7
Tariff	$/GJ	29.4	29.6	29.1	30.6
Network, meters and levies	$/GJ	-17.8	-18.2	-16.7	-16.7
Energy costs	$/GJ	-5.4	-5.1	-5.6	-7.6
Carbon costs	$/GJ	-0.4	-0.5	-0.9	-1.4
Gross margin	**$/GJ**	**5.8**	**5.8**	**5.9**	**4.9**
Gross margin	$ per ICP	93	90	90	73
Gross margin	$m	6	5	6	4

SME electricity	unit	1H17	1H18	1H19	1H20
Average connections	#	56,046	57,302	55,156	55,295
Sales volumes	GWh	544	564	539	533
Average usage	per ICP	9.7	9.8	9.8	9.6
Tariff	$/MWh	224.1	222.9	224.4	226.7
Network, meters and levies	$/MWh	-106.2	-105.2	-106.5	-112.2
Energy costs	$/MWh	-82.9	-81.9	-83.6	-89.3
Gross margin	**$/MWh**	**35.0**	**35.7**	**34.2**	**25.1**
Gross margin	$ per ICP	339	352	335	242
Gross margin	$m	19	20	18	13

SME gas	unit	1H17	1H18	1H19	1H20
Average connections	#	2,820	3,582	3,865	3,991
Sales volumes	TJ	459	679	809	845
Average usage	per ICP	162.9	189.7	209.4	211.8
Tariff	$/GJ	17.0	15.5	14.8	14.9
Network, meters and levies	$/GJ	-5.1	-4.4	-5.3	-5.4
Energy costs	$/GJ	-5.4	-5.1	-5.6	-7.6
Carbon costs	$/GJ	-0.4	-0.5	-0.9	-1.4
Gross margin	**$/GJ**	**6.0**	**5.5**	**3.0**	**0.5**
Gross margin	$ per ICP	985	1,049	625	107
Gross margin	$m	3	4	2	0

Customer EBITDAF					
Electricity Gross margin	$m	79	74	77	63
Gas Gross Margin	$m	8	9	8	5
Broadband Gross Margin	$m		0	0	0
Total Gross Margin	**$m**	**87**	**83**	**86**	**68**
Other income	$m		3	2	2
Other operating costs	$m	-54	-41	-40	-41
Customer EBITDAF	**$m**	**32**	**45**	**48**	**30**
Corporate allocation (50%)[1]	$m		-7	-7	-7
Retailing EBITDAF	**$m**	**32**	**39**	**41**	**23**
EBITDAF margins (% of revenue)	%	6.5%	7.8%	8.2%	4.7%

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