2022 interim results presentation

Six months ended 31 December 2021

contact

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Agenda

1H22 performance highlights

Mike Fuge, CEO

Strong performance despite volatile market conditions, investment ramps up

	Six months ended 31 December 2021 (1H22)	Six months ended 31 December 2020 (1H21)	
EBITDAF[1]	$322m	↑	31% from $246m
Profit	$134m	↑	72% from $78m
Profit per share	17.2 cps	↑	58% from 10.9 cps
Operating free cash flow[2]	$131m	↓	17% from $157m
Operating free cash flow per share[2]	16.8 cps	↓	23% from 21.9 cps
Interim dividend declared	$109m	→	$109m
Interim dividend declared per share	14.0 cps	→	14.0 cps
Stay-in-business (SIB) capital expenditure (cash)	$35m	↑	13% from $31m
Growth capital expenditure (cash)	$116m	↑	2,220% from $5m
Strategic investments (cash)	$12m	↑	71% from $7m

1H22 market

The operating conditions in 1H22 were characterised by:

- Strong Clutha hydro flows, followed by improving national hydro storage in the second quarter of FY22.
- Improved deliverability outlook for the Maui and Kupe gas fields.
- Falling wholesale spot prices.
- Material increases to gas and carbon costs.
- Elevated wholesale electricity futures as thermal costs rise and as gas uncertainty persists.

Contact responded to the conditions by:

- Supporting the market with our diverse portfolio of assets.
- Increasing renewable generation and stored fuel for future use.
- Long-term offtake agreements signed.
- Investment programme to deliver on decarbonisation strategy ramping up.

Operating earnings (EBITDAF) were up by $76m when compared to 1H21.

[1] Refer to slides 39 for a definition and reconciliation of EBITDAF
[2] Refer to slides 25 for a reconciliation of operating free cash flow

Contact26 Key strategic highlights from 1H22

	Grow demand	Grow renewable development	Decarbonise our portfolio	Create outstanding customer experiences
Objective	Attract new industrial demand with globally competitive renewables	Build renewable generation and flexibility on the back of new demand	Lead an orderly transition to renewables	Create NZ's leading energy and services brand to meet more of our customers' needs
1H22 highlights	Positive long-term outlook for a renewables backed smelter. Consent application for a Contact-backed 10MW Clyde data centre submitted. Final consent hearing pending. Southern Green Hydrogen registration of interest completed. Preferred parties will be selected soon for formal proposal in April 2022. Dry year flexibility concept accepted. Agreed terms for PPAs with Genesis Energy, Oji Fibre, Pan Pac and Foodstuffs.	Tauhara project progressing well despite COVID impacts. Renewable capacity up by 11% to 168MW. Consent applications lodged with Waikato Regional Council for an extension of consents at Wairakei post 2026. Land use consent applications lodged in December 2021 for a potential 50MW geothermal station at Te Huka. Secured land access rights for ~600MW of wind projects across New Zealand through our Roaring40s partnership.	Intention to invest a further $37m into a new afforestation partnership. 'ThermalCo' concept released to stimulate constructive engagement from key stakeholders. Progress on the assessment of the economics of a 100MW battery energy storage system. Target FY22 investment decision.	Investing ~$30m in the upgrade of our core SAP system to S4HANA Improved brand and experience metrics demonstrated by an improvement in 'Brand Trust' ranking up 1 to #3 and NPS up 2.7 on prior year. Protected mass market customers from high wholesale prices – electricity tariff up 1.2% (vs CPI of 5.9%). Total connections up by 29k in the 6 months. Broadband up 11k. Energy up 18k. Customers lost (churn) down by 2.4% on 1H21. • Successful launch of 'Good Nights' – a pilot time-of-use plan

Contact26 Key strategic highlights from 1H22

	Our ESG commitment	Operational excellence	Transformative ways of working
Objective	Create long-term value through our strong performance across a broad set of environmental, social and governance factors	Continuously improving our operations through innovation and digitisation	Create a flexible and high-performing environment for NZ's top talent
1H22 highlights	Completed a $225m issuance of green capital bonds to retail and institutional investors. The bonds are NZs first certified green capital bonds. Reporting of key ESG metrics in our monthly operating reports. Elevating the priority of our ESG reporting alongside our financial reporting. • Scope 1 emissions from generation: 346,000 tCO_2e, a 34% reduction on the same period the previous year. • 47,259 natives planted • 2,727 pests caught Improved on DJSI ranking to 78th percentile (2020: 62 percentile 2019: 55 percentile).	Strong operational performance with high plant availability. Geothermal availability of 96%, the highest in 5 years. TCC availability at 100%. Completion of geothermal optimisation projects resulting in an increase of 6MW of output (equivalent to ~25GWh p.a.). Geothermal fluid process optimisation of consent, steamfield and capacity saw more generation at higher prices with geothermal GWAP/TWAP at 101% ($3m benefit). Invested in new digital capability to increase focus on advanced analytics, process optimisation, redesign and automation.	Launched a new learning platform 'Contact University' to grow capability with on-demand learning. Secured 'right-sized' tenancies in Wellington and Auckland to reflect the working preferences of our people. Committed to become a founding partner of the Wellbeing Tick – an accredited framework to focus on enhanced wellbeing of our people.

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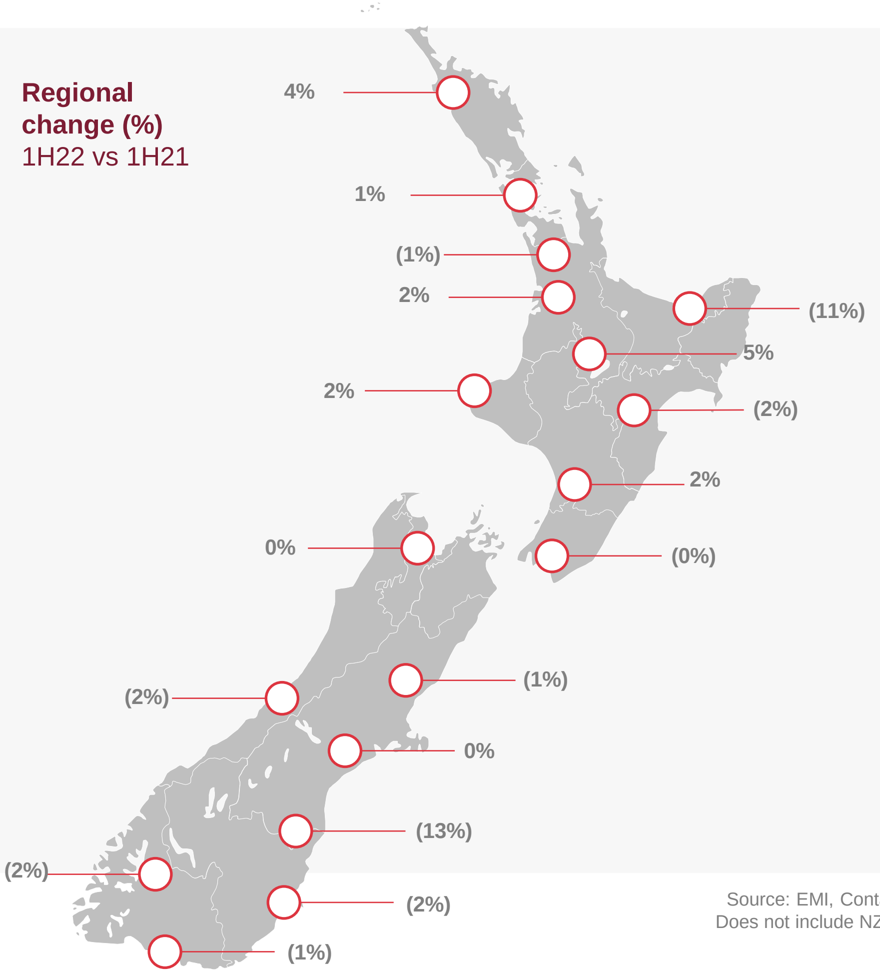
National electricity demand

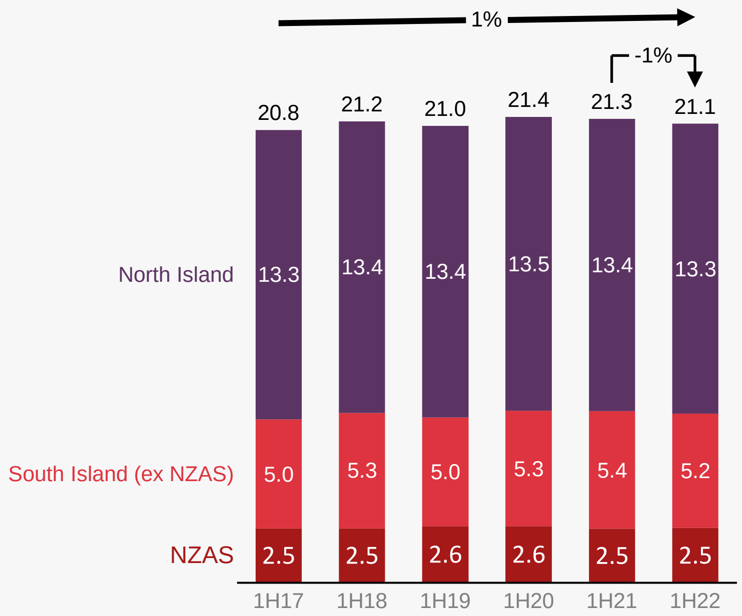
Electricity demand lower than 1H21

Regional change (%)
1H22 vs 1H21



Source: EMI, Contact.
Does not include NZAS

National electricity demand (TWh)



Source: EMI, Contact

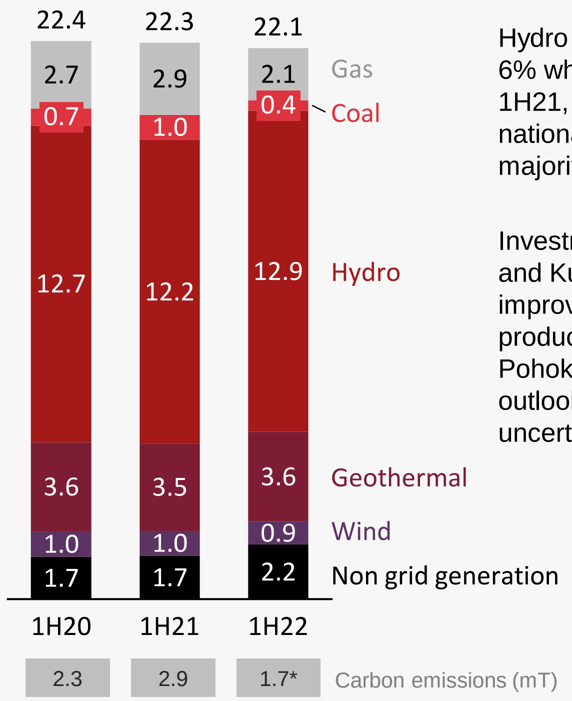
Total national electricity demand decreased by 0.2TWh (-1% from 1H21):

- Demand from large industrial users was down by 0.2TWh, largely as a result of the closure of Norske Skog in June 2021.
- Residential demand increased by 0.3TWh (5%) on increased ICPs and usage per connection as a result of COVID lockdowns and increased working from home.
- Small business demand was impacted by extensive Auckland region lockdowns (-0.2TWh).
- Wet first half of the year saw lower irrigation demand at major South Island irrigation demand nodes (-0.1TWh).

Hydrology and impact on generation mix

Improved hydro inflows and generation in 1H22 saw a reduced reliance on gas and coal

Generation by type (TWh)
Generation from generator retailers

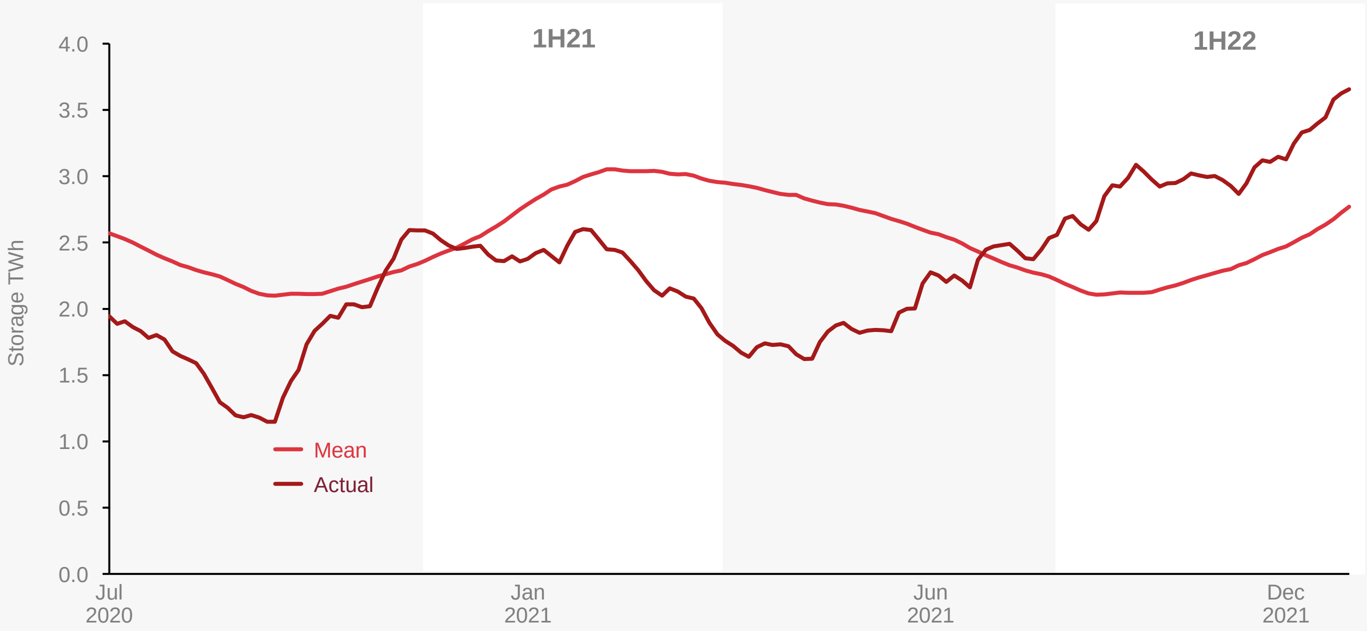


Source: EMI & MBIE

Hydro generation was up 6% when compared to 1H21, with above mean national inflows for the majority of 1H22.

Investment in the Maui and Kupe gas fields has improved the gas production outlook. Pohokura production outlook remains uncertain.

National hydro storage



Lake levels were appropriately managed through the period to manage the risk around gas availability and expected La Nina conditions in 2022.

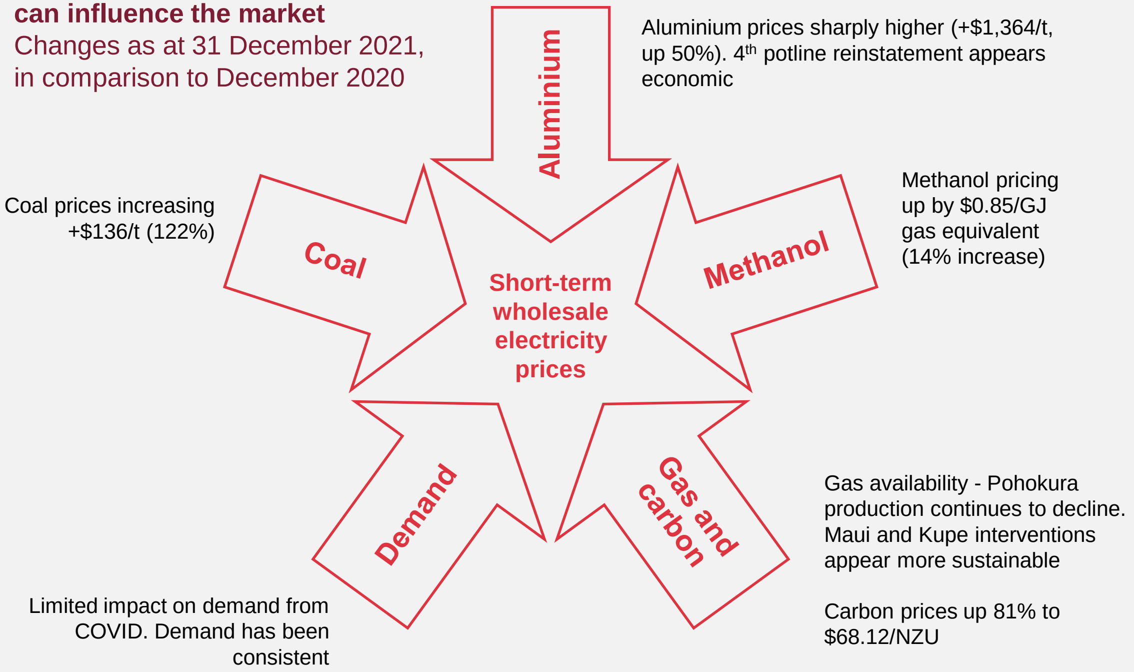
Source: NZX

*Carbon emissions for 1H22 Sep-Dec quarter has been estimated using historic conversion rates with actual generation data. The reduction in carbon emissions of 1.2mT CO2-e was due to the decrease in coal and gas generation
Some generation has been estimated based on prior period operation,

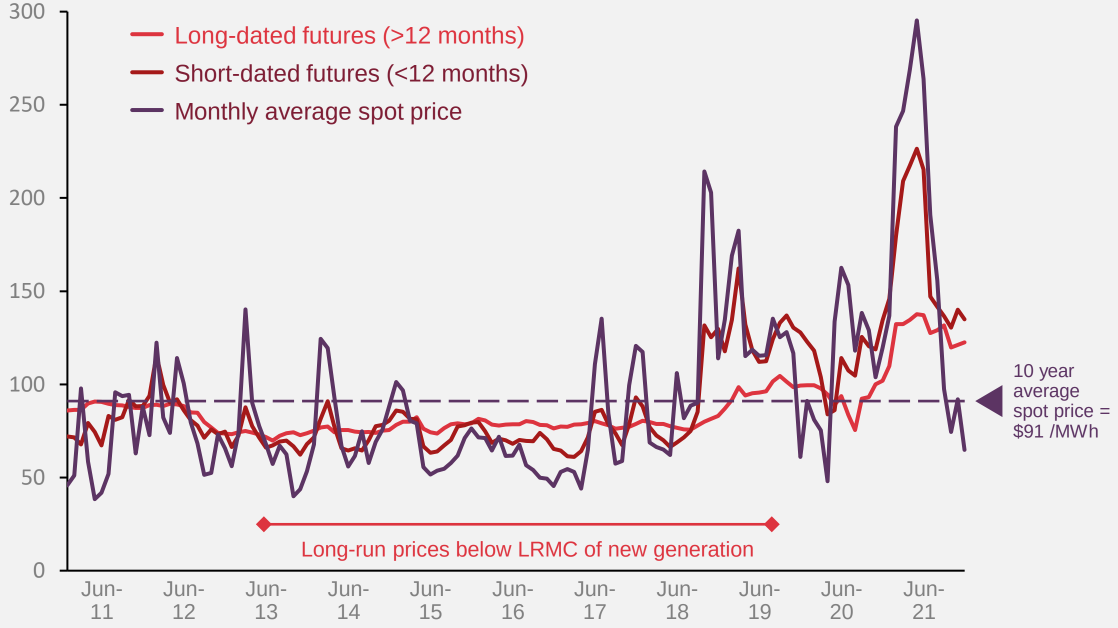
Factors that influence short-term prices, beyond hydrology, sharply higher over last 12 months

Longer-term the market is reacting to these price signals and adding new capacity

Short-term external factors that can influence the market
Changes as at 31 December 2021, in comparison to December 2020



Wholesale and futures electricity pricing ($/MWh)



Source: EMI wholesale pricing

Increasing energy input costs are impacting medium-term pricing.

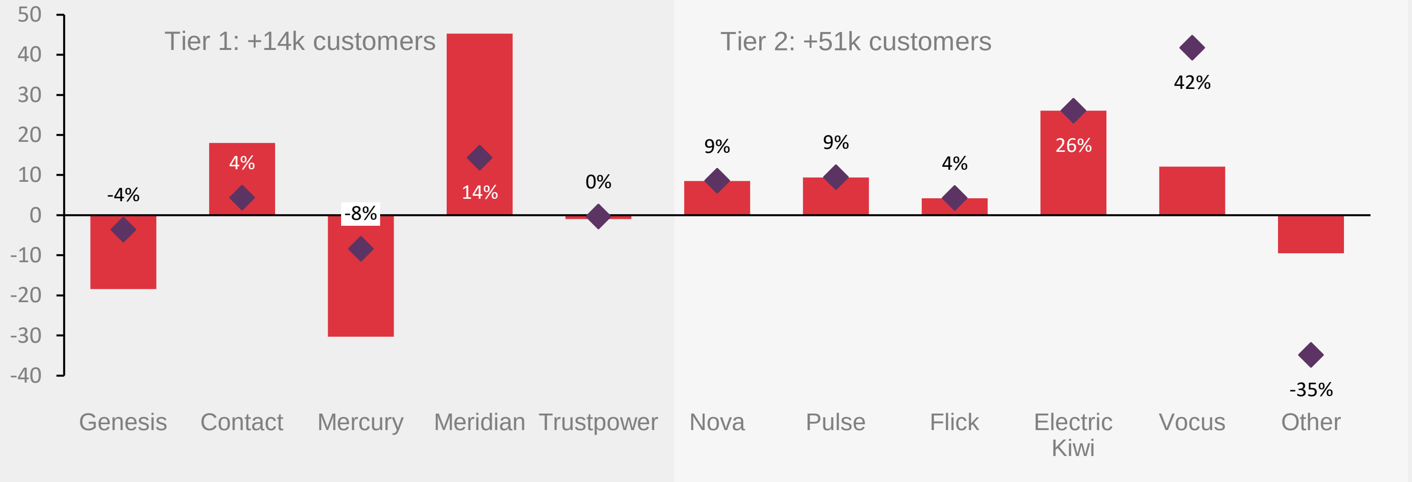
Long-term pricing is linked to the **long-run marginal costs of new renewable projects** plus costs associated with **firming renewable intermittency** to meet growing demand.

Both long-dated and short-dated prices remain well above long-term averages, reflecting higher thermal fuel costs and the risk around the availability of hydro and thermal fuel. $2bn of generation investment currently under construction expected to be onstream in 2023/2024 is reducing outer-year futures pricing.

Retail competition remains intense

Retailer's long-term view of pricing rides through short-term wholesale input cost volatility

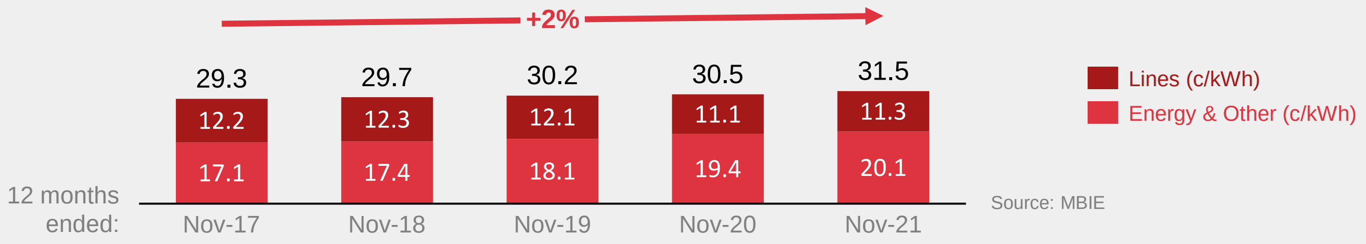
Change in customer connections (000s)



Source: EMI

- Competition remains intense, not only from new and disruptive competitors, but reinvigorated incumbents
- Increase of connections from the main players (+14k connections), Tier 2 market share now at 16% (from 14% 12 months ago)

Retail tariff changes (c/ kWh)



Source: MBIE

- Despite sharply higher wholesale prices over the last three years, tariffs up by a compound annual growth rate of only 2%.
- Households have been largely insulated from higher wholesale prices because of fixed price residential contracts and retailers' longer-term view of pricing that rides through short-term volatility.
- The real residential cost per unit of electricity has fallen in every year since 2018.

Topical regulatory matters

Key themes		What Contact is doing
Wholesale market volatility	Gas availability and lower mean water levels through 2021 have resulted in higher spot and hedge market prices, increasing pressure on unhedged energy intensive industries. The Electricity Authority continues to review wholesale electricity market competition for the period 2019-21. Its draft analysis finds that prices have generally reflected underlying supply and demand conditions, however NZAS may be paying below the opportunity cost for energy.	**Contact** is exploring further renewable generation opportunities across wind, solar and grid-scale batteries to reduce future impacts from thermal fuel volatility . **Contact** is working with customers to smooth out pricing volatility through long-term contracts. **Contact** has submitted to the Electricity Authority that the market is operating effectively and responding appropriately to recent market volatility, with the sector now entering a period of intense investment to both decarbonise existing generation and new generation to meet future demand.
Climate Change Commission	In June 2021, the Commission delivered its final report on carbon budgets and policy recommendations. The government has extended the publishing of its Emissions Reduction Plan to mid-2022.	**Contact** strongly supports the recommended direction of the Commission report, and the role that the energy sector will play in decarbonisation. **Contact** continues to closely engage in the government's work and assess the strategic opportunities and impacts for Contact. **Contact** has released its ThermalCo proposal to accelerate decarbonisation of electricity generation in support of 100% renewable generation target.

Topical regulatory matters

Key themes		What Contact is doing
New Zealand Battery project	The government is assessing options to address New Zealand's dry year risk with 100% renewable generation. This includes assessing its initially preferred solution of pumped hydro at Lake Onslow.	**Contact** supports further analysis to address dry year risk. Multiple options exist that will require careful evaluation, including interruptible green hydrogen, interruptible load for other major customers and grid-scale batteries. **Contact** has released its proposal to create a ThermalCo which would be a low capital, low cost and low risk solution to accelerate decarbonisation. **Contact** is actively engaging with government in to improve the outcomes for New Zealand.
Energy hardship	Covid-19 and the broader economic environment are placing additional pressure on New Zealand households and businesses. Contact is actively working to minimise energy hardship. The Government has established two specialist energy hardship panels to support work to alleviate energy hardship in New Zealand.	**Contact's** tikanga, pricing principles and proactive work with its customers who are struggling to pay their bills has resulted in reduced disconnections and bad debt. **Contact** offers a range of payment options including weekly and fortnightly billing, pre-pay and price smoothing products. **Contact** is working with industry through ERANZ on the EnergyMate programme and PowerCredits scheme in association with budget advisors and FinCap.

Operational performance and financial results

Dorian Devers, CFO

Key themes from the financial results

Financial performance largely as guided when higher renewable generation volumes are considered

Positive view on decarbonisation demand, including the ability to retain major electricity users

Sales channel choices delivering value

Innovative retail products launched to encourage demand shifting

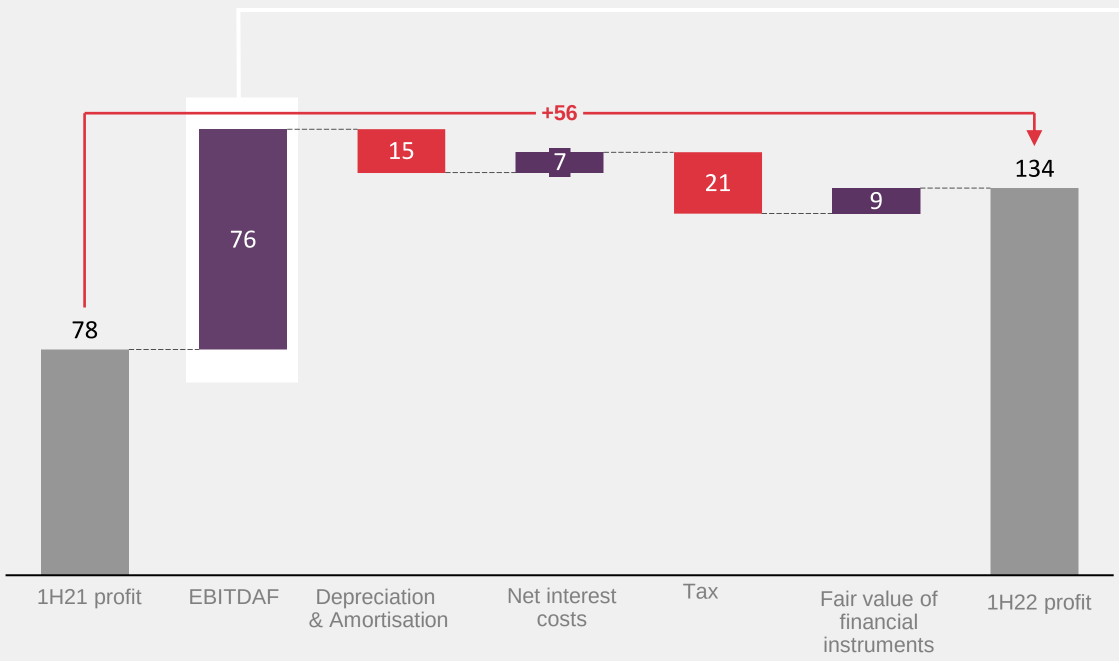
Signed a number of long-term PPAs in line with strategy

Cost to serve remains industry leading

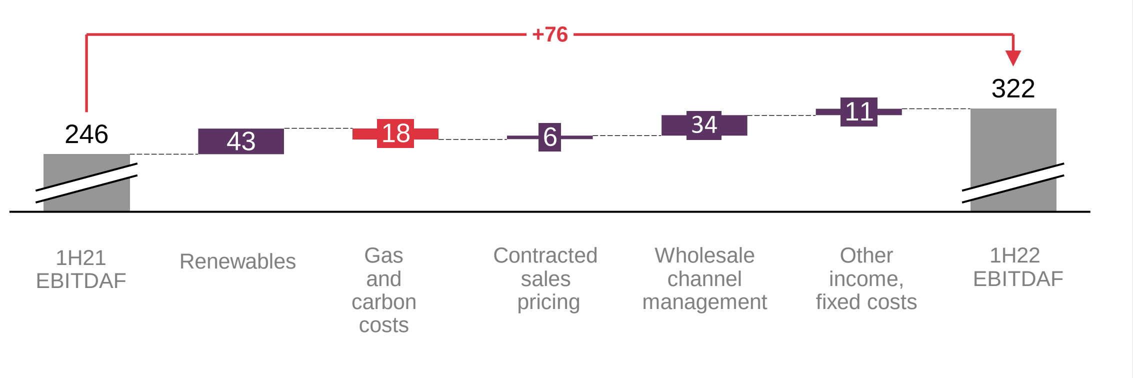
Profit of $134m, up $56m

EBITDAF up $76m, as Contact supported the wholesale market as competitors faced fuel uncertainty

Profit ($m)



EBITDAF ($m)



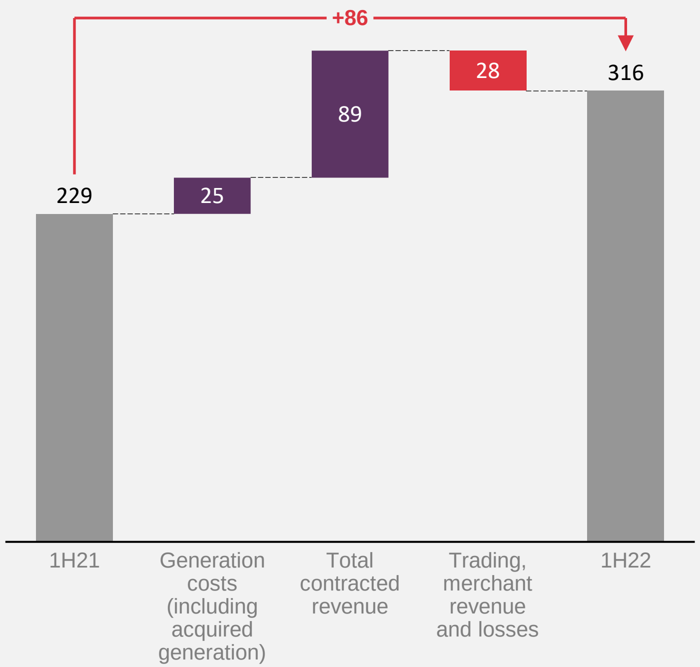
1. Higher hydro generation with above mean inflows. Geothermal generation in 1H21 impacted by outages
2. Higher gas and carbon costs to run thermal generation
3. Improved net pricing from contracted customers
4. Active channel management with increased sales to support fuel constrained market participants at a higher price
5. Higher other income (Western Energy and Broadband), and lower gas and electricity transmission costs

1H22 results

EBITDAF up by $76m

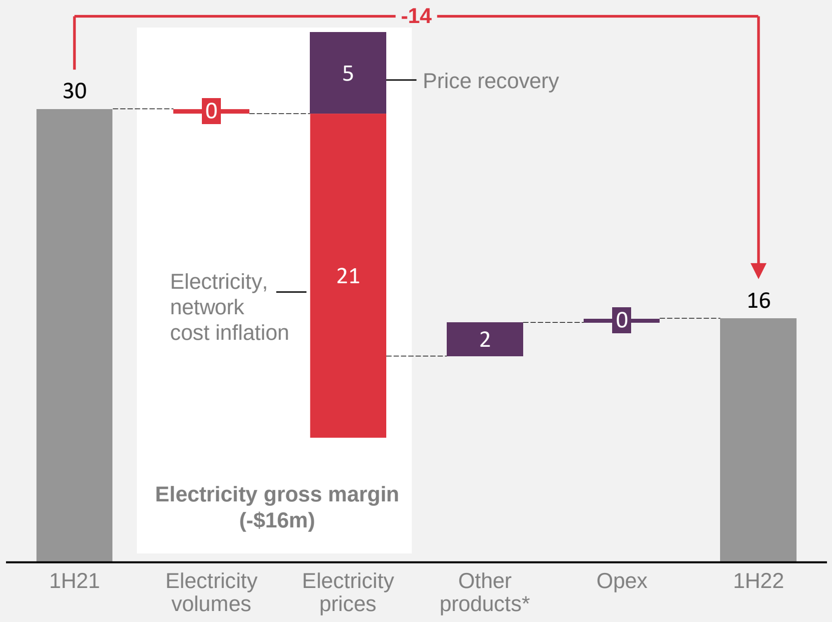
Business performance by segment

Wholesale EBITDAF ($m)



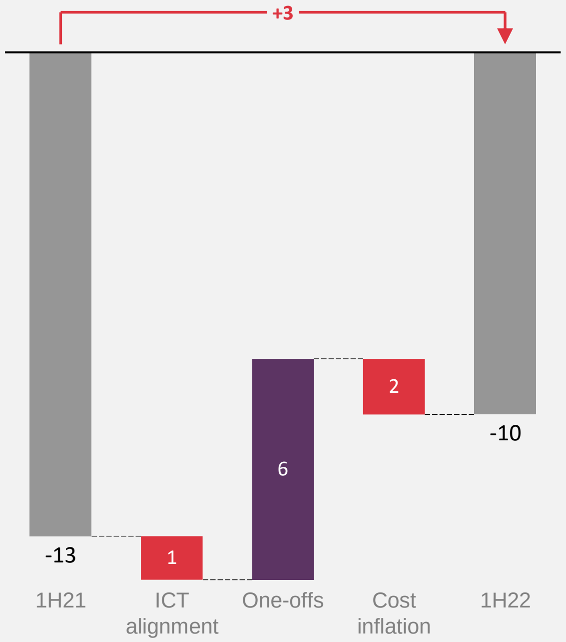
Refer to slides 18 - 20

Retail EBITDAF ($m)



Refer to slide 21

Corporate / unallocated costs ($m)



Simply and Western included within Wholesale EBITDAF

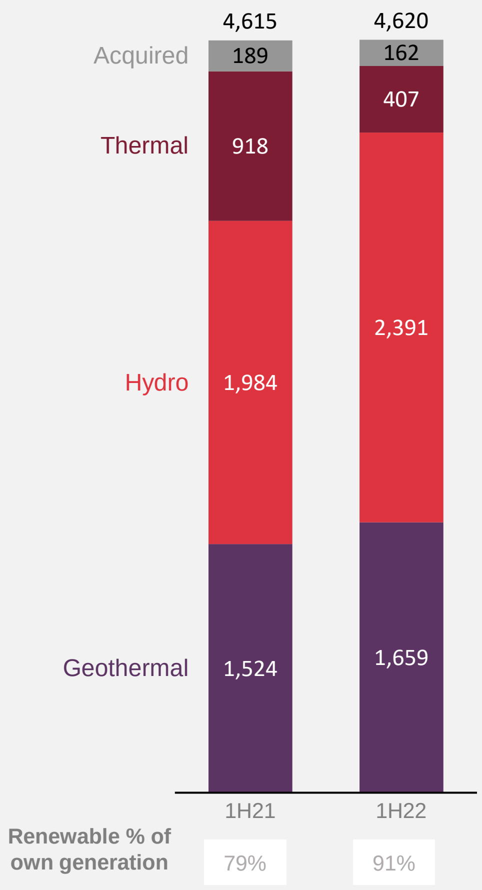
*Other products includes retail gas and broadband gross margins

ICT costs previously included within the Retail business operating costs. Prior year not restated. Full year impact $3m.
One-offs include the Holidays Act provision reversal ($6.8m) and Contact SaaS asset write off.

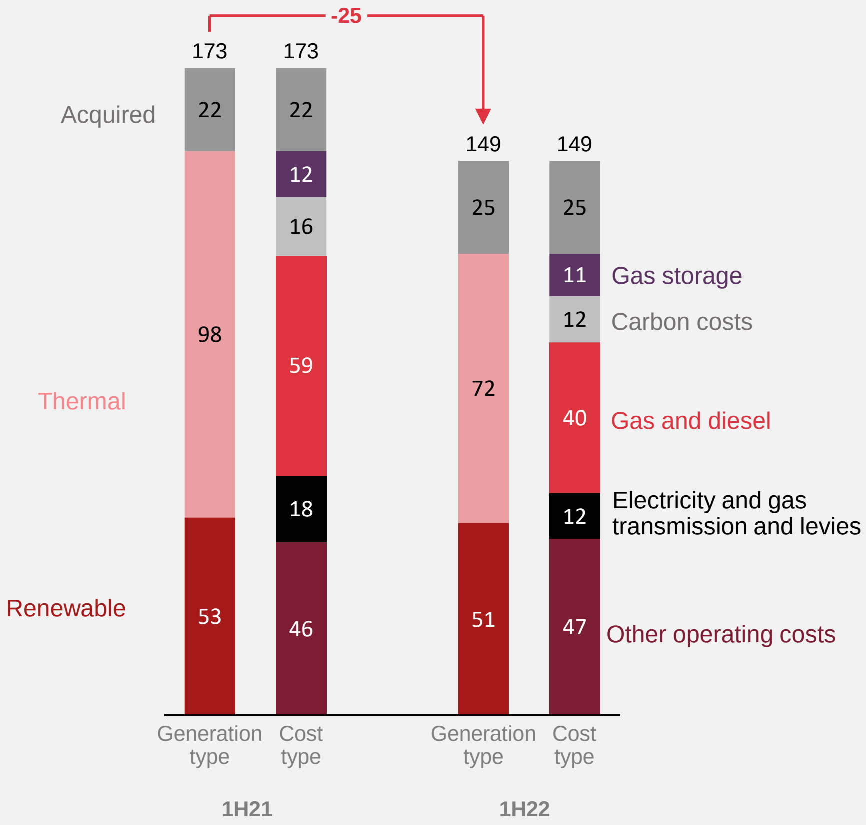
Generation costs

Costs down $25m ($5.4/MWh) on higher renewable generation, which reduced thermal volumes

Electricity generated or acquired (GWh)



Electricity generated or acquired costs ($m)



Hydro generation up 407GWh on 1H21 (+20%), 401GWh (+20%) above mean year expectations. Geothermal volumes were 135GWh up on prior year which had the 4-yearly Te Mihi outage.

- Renewable generation costs were down $2m on 1H21. Transmission costs in 1H21 included the one-off contribution to the CUWLP transmission upgrade.

Thermal generation costs were down by $26m (29%) on lower thermal volumes (down 56%).

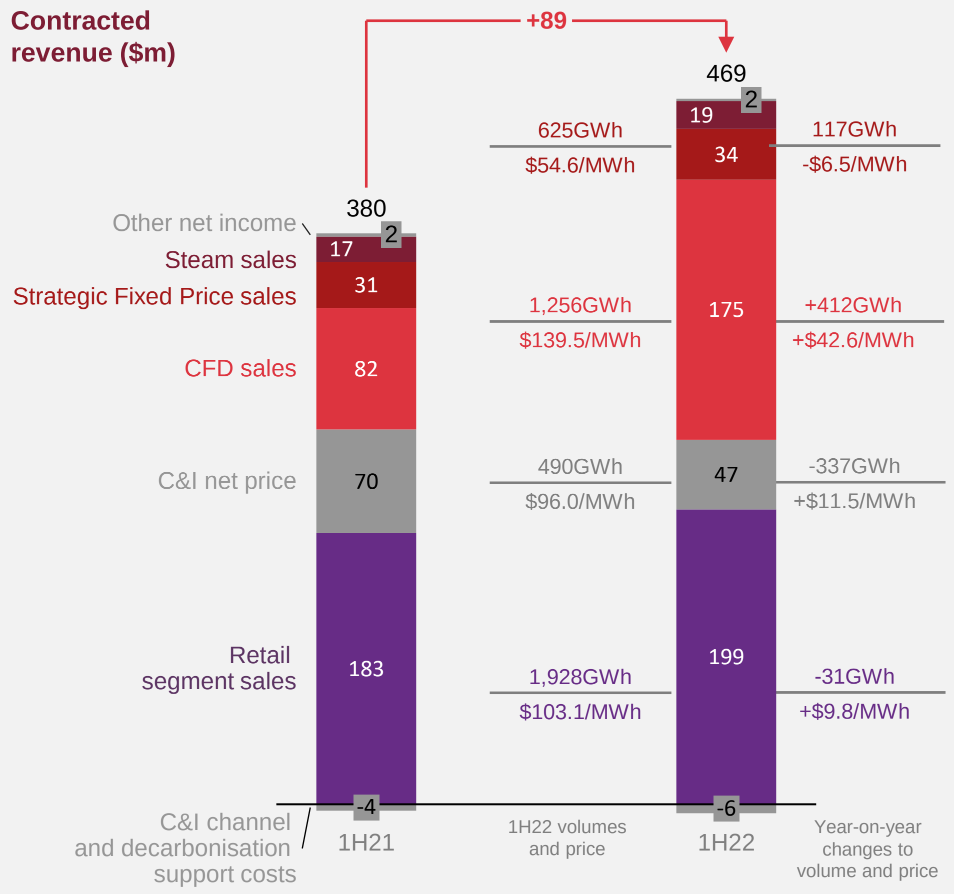
- Thermal fuel costs up from $79/MWh in 1H21 to $121/MWh (+53%). With gas (1H21 $7.2/GJ, 1H22 $9.2/GJ) and carbon prices (1H21 $29/unit, 1H22 $34/unit) higher.
- Thermal fixed costs were down by $4m on the prior comparative period on higher ACOT revenue and changes to the TCC gas transmission contract.

Acquired generation costs up by $3m as higher priced hedges were purchased to support Contact's Winter 2021 risk exposures.

*Thermal includes tolling of ~10GWh in 1H21 and 0GWh 1H22

Wholesale contracted revenue

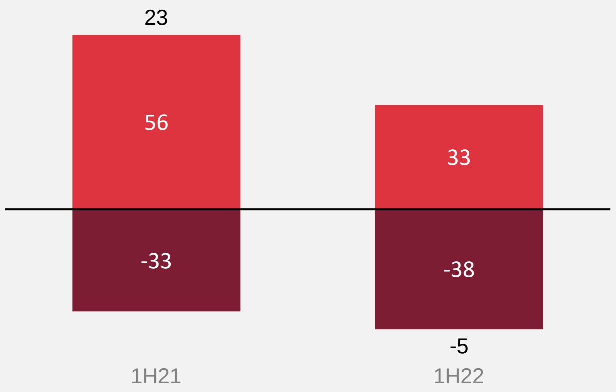
Sales mix adjusted to reflect the uncertainty of fuel availability



- Fixed price variable volume electricity sales to the Retail segment and C&I customers ended 368GWh lower than 1H21 (-$33m), this was offset by higher prices (+$27m), reflecting higher wholesale prices over the three preceding years.
- Strategic fixed price sales were 117GWh higher than 1H21 (+7m), lower NZAS pricing was partially offset by an increase in sales to customers under long-term PPAs (-$4m).
- CFD sales volumes were up by 412GWh (+$40m) as nearer term higher priced channels were prioritised at higher average prices (+$54m).
- Steam revenue was up $2m on 1H21 with steam tariffs on Te Rapa generation rising with carbon costs changes.
- Operating costs to support commercial and industrial customers higher as capability added to support decarbonisation and a closer customer relationship.
- Other income was in line with the prior year.

Wholesale trading and merchant revenue

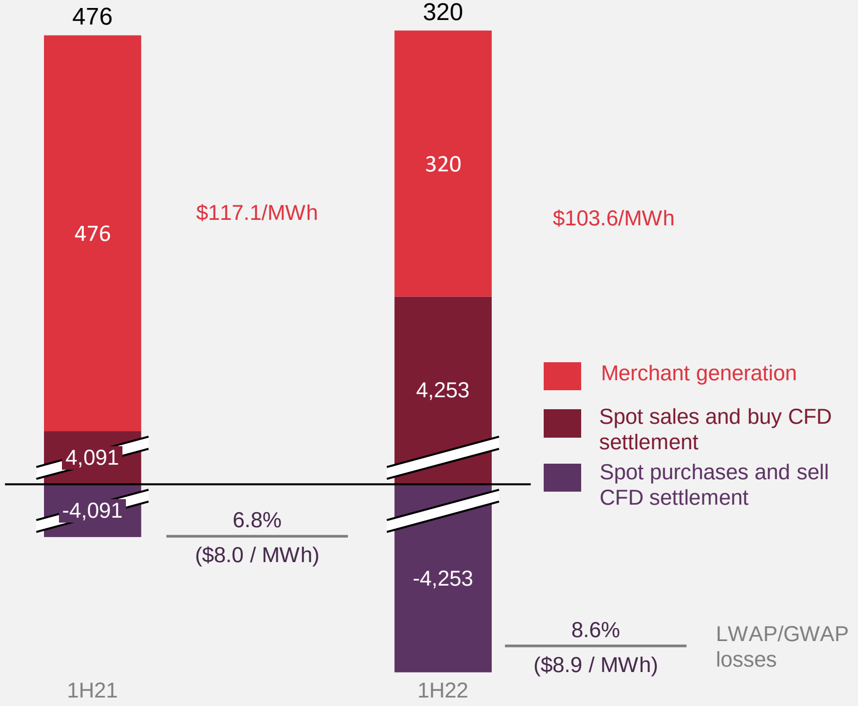
Trading EBITDAF ($m)



Trading revenue

- **Merchant sales:** short-term sales channel available when the spot prices exceed the opportunity cost of Contact generation.
- **LWAP / GWAP losses:** locational price differences between where electricity is generated and purchased.

Long / short position (GWh)

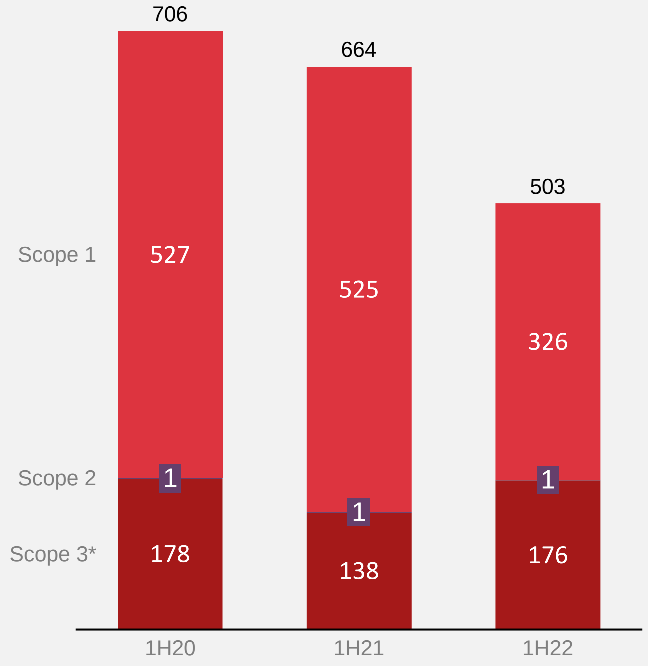


- 157GWh decrease in merchant sales volumes. The price received for this "long" generation was down by $13.5/MWh on 1H21.
- Inter-island separation increased from 7% to 9%, this was partially offset by lower absolute prices. The cost of generation losses increased by $5m.

Greenhouse gas reporting

Lower carbon emissions reflects higher renewable generation and lower thermal generation

kT of C02e emitted



Performance

- Total emissions are 161 kT lower in 1H22.
- Emissions from generation was lower in 1H22 as a result of higher hydro generation volumes.
- Scope 3 emissions have increased year-on-year due to the Tauhara construction build.

*Scope 3 emissions excluding swaption and gas have been estimated using FY21 numbers as this information is collected on an annual basis.

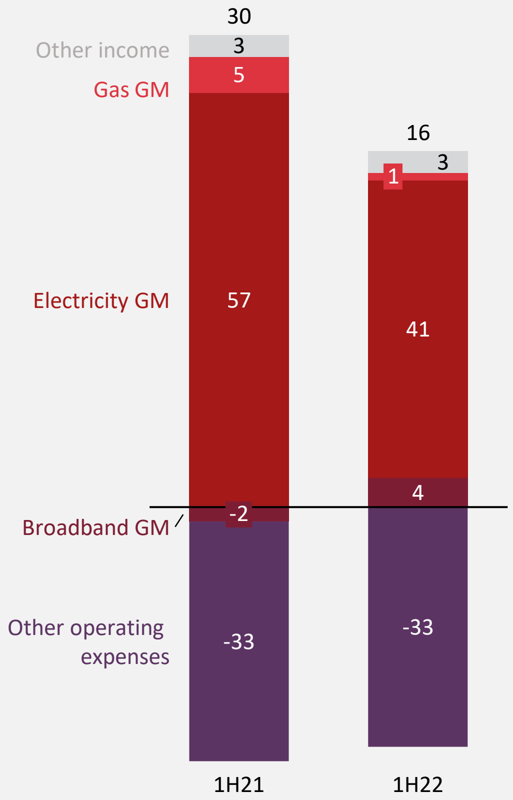
Retail business performance

Managing through elevated wholesale input costs

Revenue & Tariff[1] ($m)	1H21	1H22		Variance		
	$m	$m	*Tariff*	$m	*Tariff*	%
Electricity gross revenue	445.7	449.5	*249.8*	3.8	3.9	1.6%
PPD not taken	3.1	1.8		-1.3		
Incentives paid	-2.3	-2.7		-0.4		
Net revenue (cash)	**446.5**	**448.6**	**249.3**	**2.1**	**3.0**	**1.2%**
Capitalised incentives	3.3	3.0		-0.3		
Amortised incentives	-4.0	-3.9		0.1		
Net revenue (P&L)	**445.8**	**447.7**	**248.8**	**1.9**	**3.0**	**1.2%**
Gas revenue	41.3	43.4	27.1	2.1	2.5	9.7%
Broadband revenue	13.0	24.8	71.8	11.8	3.3[2]	4.9%
Other income	2.6	3.1		0.5		
Total revenue	**502.6**	**519.0**		**16.3**		
Contract Asset (closing)	8.5	6.2		-2.3		

Ave. number of connections ($k)	506.8	540.1		+33.3		6.5%
Cost to serve per connection ($/conn)	66.0	61.5		-4.5		-6.8%

EBITDAF ($m)



The electricity tariff changes balance the recovery of rising input costs, the competitive environment and regulatory pressures:

- 68% of our residential customers are on non-PPD products from January 2022.
- Around 55% of customers received a price increase in the last 12 months.
- Ending Prompt Payment Discounts 42% reduction in PPD not taken.

Continue to smooth the impact of higher energy costs for customers:

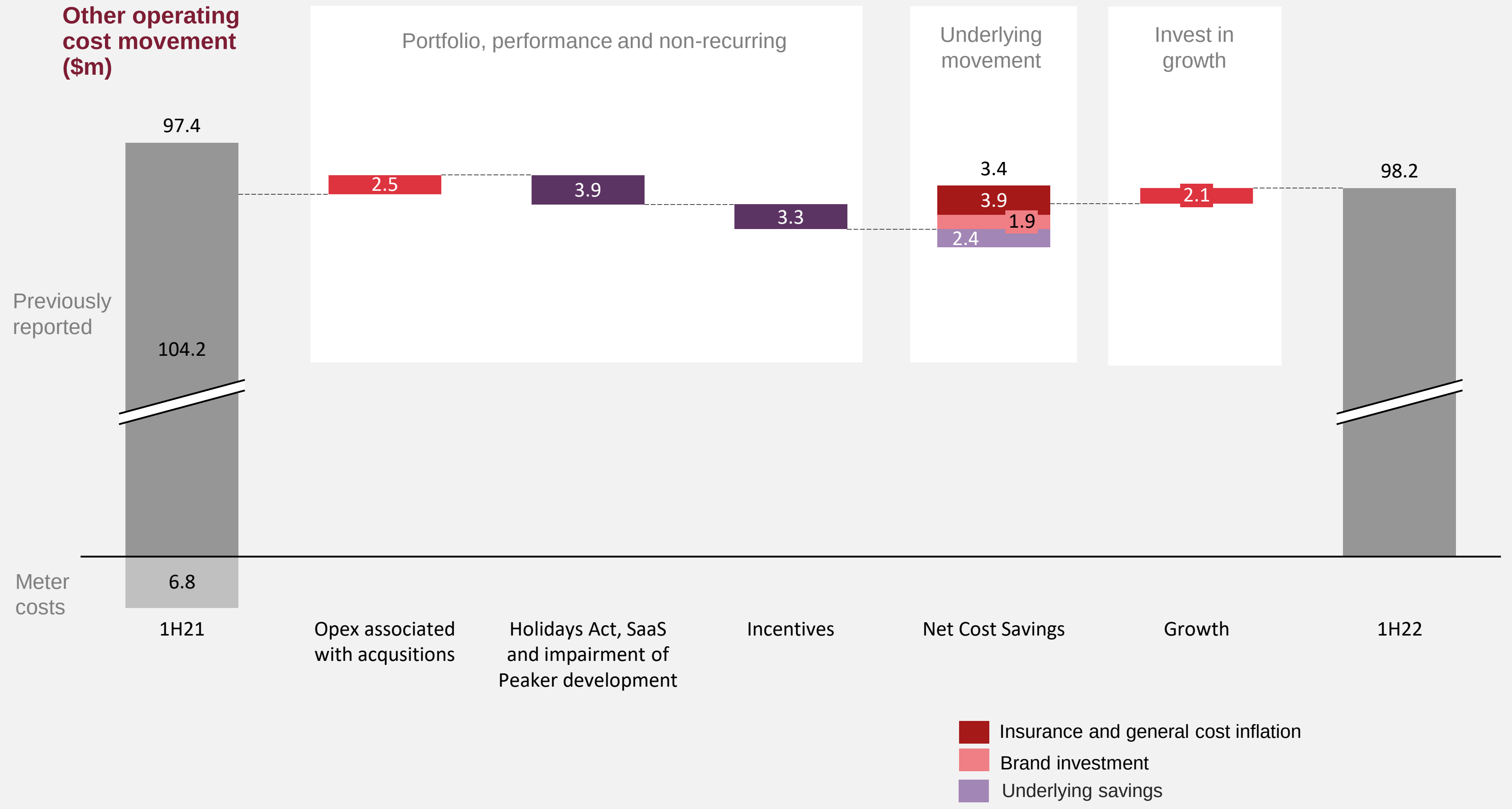
- Targeted retail price rises to recover long-run input costs
- Gas tariffs up 10% on 1H21 on sharply higher gas and carbon input costs

Strong growth in Broadband connections (+23k up on 1H21).

1. Tariff is $/MWh for electricity, Gas $/GJ and $ per month per customer connection for broadband
2. 1H21 tariff ($/customer/month) restated to include accounting adjustments that were not made in FY22 to understand broadband tariff progression

Gross Margin (GM) is Revenue less Cost of Goods [Networks, meters, levies, energy, carbon and broadband]

Operating costs flat despite acquisitions, strong performance and cost pressures



Other operating costs

- All costs associated with meters are now reflected in Cost of Goods (Network, Meters and Levies) to align with industry reporting. Previously a portion of smart meter costs were included in other operating costs to provide comparability to prior periods where there were higher manual meter reading costs.

Portfolio performance and non-recurring

- Holidays Act provision (+$6.8m) released in FY22 post successful Metro Glass appeal, partially offset by accounting adjustments related to software as a service (SaaS) and impairment of thermal development costs.
- Full six months of operating costs acquired as part of the strategic transactions of Western Energy (April 21) and Simply Energy (September 20).
- Incentive costs are lower on current assessment of a broad range of KPIs beyond financial performance.

Underlying movement

- General inflation of 6% impacts general operating costs, cost efficiency achieved through digital investment and broadband provisioning.

Growth

- Only $1m incremental investment in broadband growth opex despite connection growth up 73%.
- Resourcing a development team to deliver on strategic growth priorities.

Normalised and expected EBITDAF assumptions

With reconciliation to actual performance

1H22 assumptions that deliver expected & normalised EBITDAF of $520m over a financial year

1 Channel choices maximise long term value[1]		X	2 Net price[2] driven by best commercial practices	=	Total
Strategic fixed price	400GWh	x	$36/MWh	=	$14m
CFDs	830GWh	x	$139/MWh	=	$115m
C&I	800GWh	x	$104/MWh	=	$83m
Retail	1,920GWh	x	$125/MWh		$240m
Other income[3]					$29m
					$481m

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	1,625GWh	x	$2/MWh	=	-$3m
Thermal[4]	480GWh	x	$119/MWh	=	-$57m
Acquired	150GWh	x	$131/MWh	=	-$20m
					-$80m

5 Trading delivers value to more than offset locational losses		6 Digitalisation & continuous improvement optimise fixed costs	
Length[5]	$38m	Transmission/Storage	-$30m
Location losses[6]	-$37m	Operating expenses	-$105m
Total	**$1m**	**Total**	**-$135m**

EBITDAF reconciliation to 1H22

Normalised & Expected

Higher renewables
Renewable generation above mean (+435GWh) saw less thermal generation at expected thermal SRMC

Gas and carbon costs
Natural gas availability has led to increased cost of gas; carbon costs continue to rise

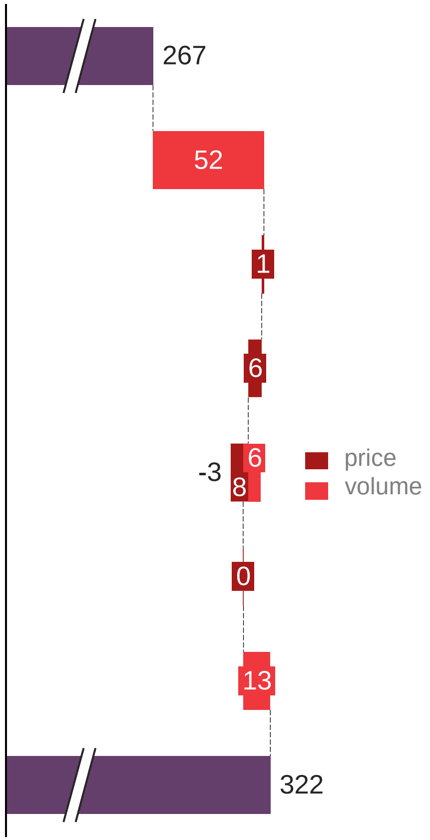
Contracted sales pricing
Pricing on fixed channels (Retail, C&I and Strategic fixed price) of $105/MWh lower than expected ($108/MWh)

Wholesale channel management
Higher sales volumes through wholesale market channel (+453GWh), pricing in merchant spot channels lower

Other income
In line with expectations

Fixed costs
Opex (-$7m) lower on one-offs and spend deferral to 2H, transmission costs lower on ACOT payments (-$6m)

Actual



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, broadband gross margin and other income
4. Gas price of $8.4/GJ, carbon price of $37/unit and thermal portfolio heat rate (11.4GJ/MWh)
5. Length of 220GWh p.a. assumed
6. Locational losses of 5.6% on spot purchases and settlement of CFDs sold at a wholesale price of $125/MWh

* Fuel is natural gas and carbon costs

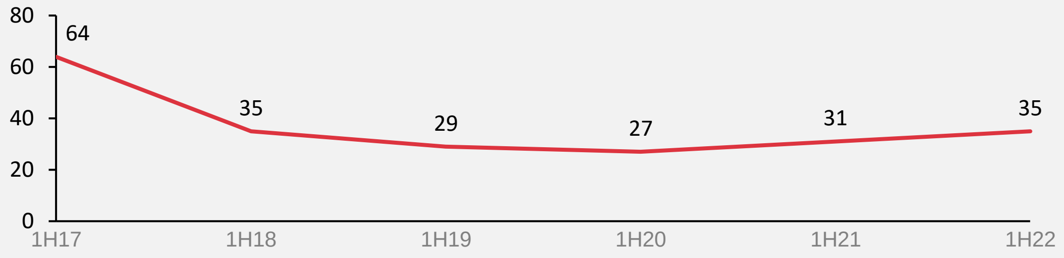
Cash flow and capital expenditure

Underlying cash conversion for 1H22 impacted by investments in gas and carbon to manage risk

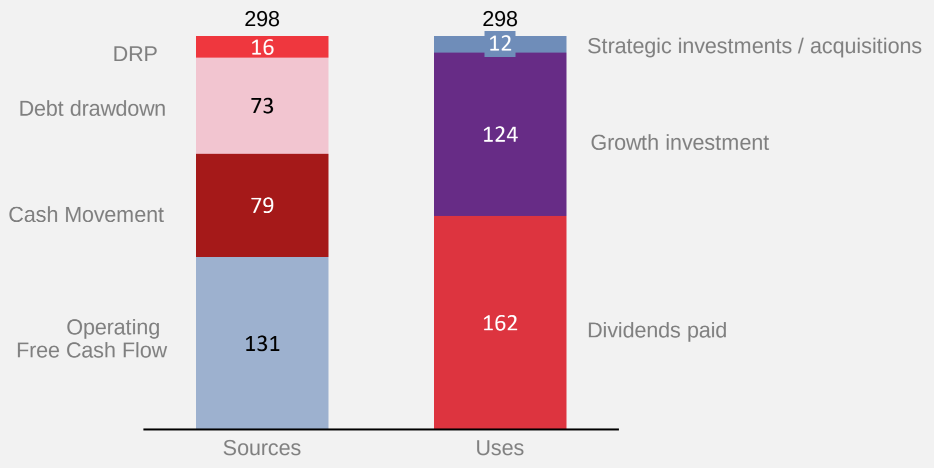
	6 months ended 31 December 2021	6 months ended 31 December 2020	Comparison against 1H21	
EBITDAF	**$322m**	$246m	↑	$76m
Working capital changes	**($69m)**	$22m	↓	($91m)
Tax paid	**($65m)**	($58m)	↓	($7m)
Interest paid, net of interest capitalised	**($15m)**	($23m)	↑	$8m
SIB capital expenditure	**($35m)**	($31m)	↓	($4m)
Non-cash items included in EBITDAF	**($7m)**	$1m	↓	$8m
Operating free cash flow	**$131m**	$157m	↓	$26m
Operating free cash flow per share	**16.8cps**	21.9cps	↓	5.1cps
Cash conversion (OpFCF / EBITDAF)	**41%**	64%	↓	23%

- EBITDAF up $76m as higher renewable generation reduced generation costs and pricing to wholesale channels rose.
- Working capital changes $91m unfavourable to FY20 due to the increased in quantity and value of gas inventory, additional purchase of carbon units from contracts entered in prior periods, reduction in gas swap payables and NZX trading movements.
- Capital expenditure (cash) $35m in FY22.

SIB capital expenditure – accounting ($m)



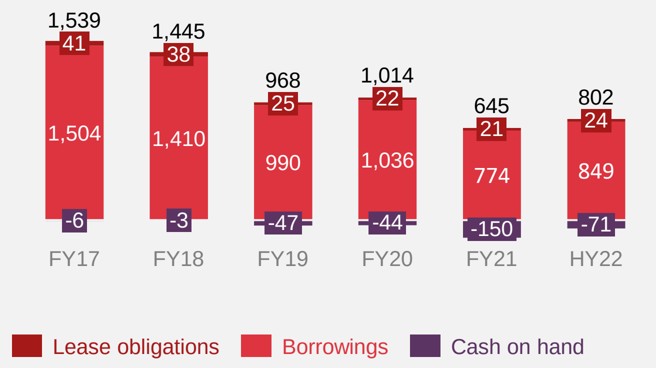
Sources and uses of cash ($m) 1H22



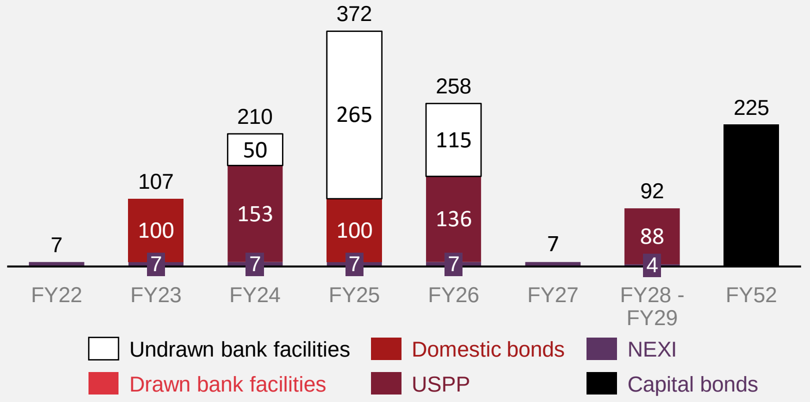
Strong balance sheet

Diverse sources of funding provide capacity to support Contact's growth strategy

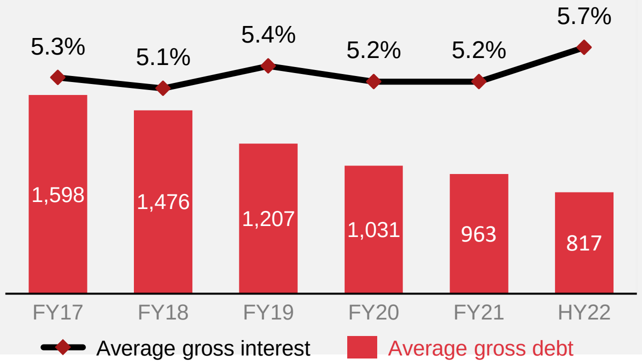
Closing net debt ($m)
Face value of borrowings less cash



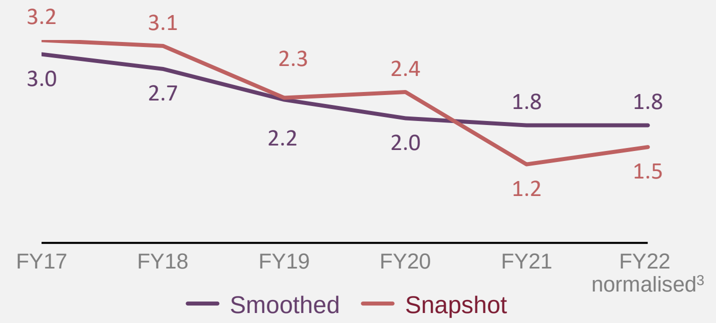
Borrowing maturities ($m)
Average tenor of 7.9 years as at 31 December 2021



Interest rate (%)
Weighted average gross interest[1] on average borrowings



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

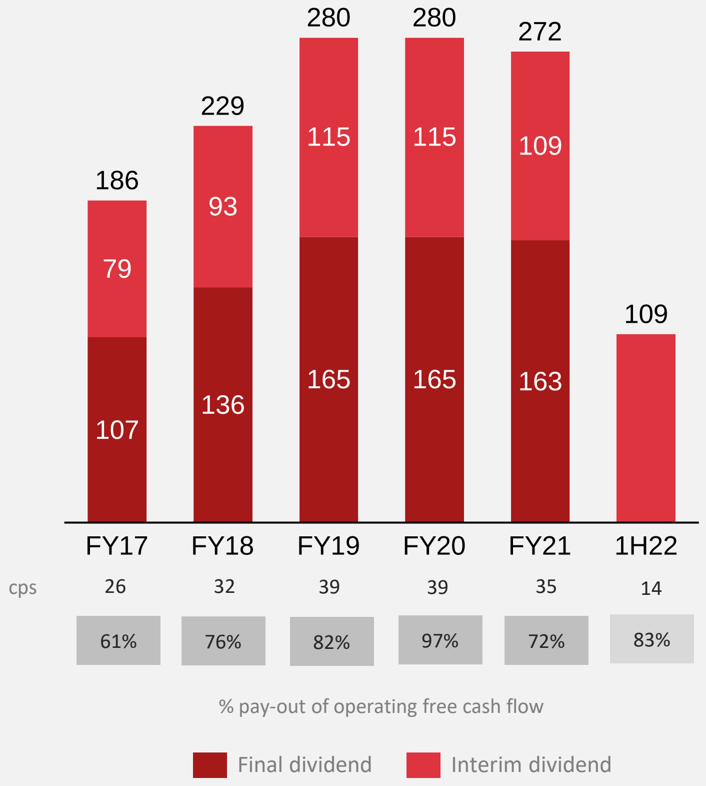


- Face value of borrowings (excl. leases) increased by $75m to $849m from 30 June 2021. The increase is due to the issuance of $225m of capital bonds replacing $150m of maturing retail bonds in November 21 to fund the Tauhara geothermal power station construction.
- Net debt has reduced by $737m since the end of FY17. Gearing[2] decreased to 19.3% at 31 December 2021, down from 22.6% at 30 June 2021.
- The average interest rate on gross debt has increased with the reduced use of lower cost flexible sources of funding following the equity raise in FY21, this is expected to reduce as debt levels increase and these lower cost options are again utilised.
- All bank facilities are sustainability linked loans, and all debt instruments are certified green.

1. Gross interest includes all interest on borrowings, bank commitment fees and deferred financing costs. Unwind of leases, provisions and capitalised interest not included.
2. Gearing calculation excludes subordinated debt as per covenants
3. From FY2c based on normalised EBITDAF of $520m. Previously $480m.

Dividend for 1H22

Ordinary dividends ($m)
Declared



Interim dividend for 1H22 of 14 cents per share

- Interim dividend of 14 cents per share (1H21 14 cents per share) is imputed to 71% or 10 cents per share for qualifying shareholders. This represents a pay-out of 83% of 1H22 operating free cash flow per share.
- Target FY22 dividend of 35 cps. This target dividend is 83% of the average operating free cash flow for the preceding four years. The dividend policy is to pay-out between 80-100% of average operating free cash flow of the preceding four years.
- Record date of 11 March 2022; payment date of 30 March 2022.
- The NZD/AUD exchange rate used for the payment of Australian dollar dividends will be set on 22 March 2022.

Dividend reinvestment plan (DRP)

- Shareholders will have the option of full, partial or no participation. If a shareholder elects to participate they will remain in the plan at the same participation level until they elect to terminate or amend their participation level.
- For this dividend, there will be no discount offered and Contact will have the right to terminate or suspend the plan at any time.
- Dividend reinvestment plan application forms must be in by 14 March 2022 to confirm participation in the plan.
- Trading period for setting price for DRP is 10 March 2022 to 16 March 2022. DRP strike price will be announced: 17 March 2022

Guidance confirmation

	Updated FY22 guidance	1H22 result	Change to prior guidance	
Other operating costs	$202-212m	$98m	↓ $13m	All meter costs now included in cost of goods ($13m annual), favourable actual one-off's offset by higher brand investment.
Stay in business capital expenditure (cash)	$88-98m	$35m	↓ $7m	Covid impacts have deferred the timing of expected spend
Cash spend ('Totex')	**$290 – 310m**	**$133m**	**↓ $20m**	
Depreciation and amortisation	$265 – 275m	$129m	-	
Net interest (accounting)	$30 – 40m	$19m	-	
Cash interest (in operating cash flow)	$20 – 30m	$15m	-	
Cash taxation	$85 – 95m	$65m (2/3rd of payments in 1H22)	-	
Corporate costs	$28m	$10m	↓ $5m	Updated to include the 1H22 one-offs (including Holidays Act)
Target ordinary dividend per share	35 cps (40%/60%)	14 cps (interim)	-	
Geothermal volumes	3,250 GWh	1,659 GWh	-	

Contact26 Our strategy to lead NZ's decarbonisation

	Grow demand	Grow renewable development	Decarbonise our portfolio	Create outstanding customer experiences
Strategic theme	Grow demand	Grow renewable development	Decarbonise our portfolio	Create outstanding customer experiences
Objective	Attract new industrial demand with globally competitive renewables	Build renewable generation and flexibility on the back of new demand	Lead an orderly transition to renewables	Create NZ's leading energy and services brand to meet more of our customers' needs

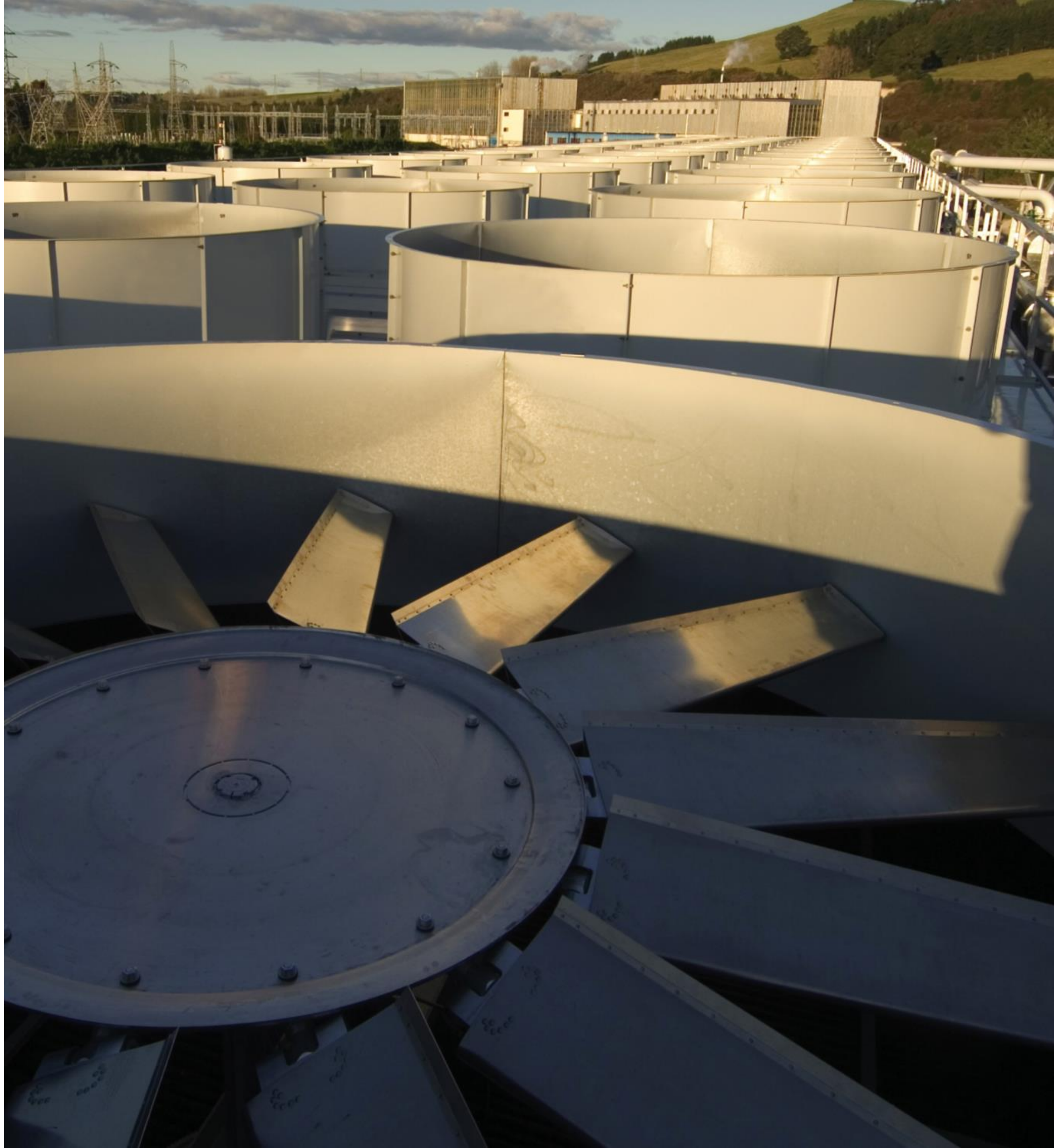
Enablers

- **ESG**: create long-term value through our strong performance across a broad set of environmental, social and governance factors
- **Operational excellence**: continuously improving our operations through innovation and digitisation
- **Transformative ways of working**: create a flexible and high-performing environment for New Zealand's top talent

Outcomes

- **Growth**
  Pivot our business to a new growth era that captures the value unlocked by decarbonisation
- **Resilience**
  Deliver sustainable shareholder returns, aligned with our ESG commitment
- **Performance**
  Realise a step-change in performance, materially growing EBITDAF through strategic investments

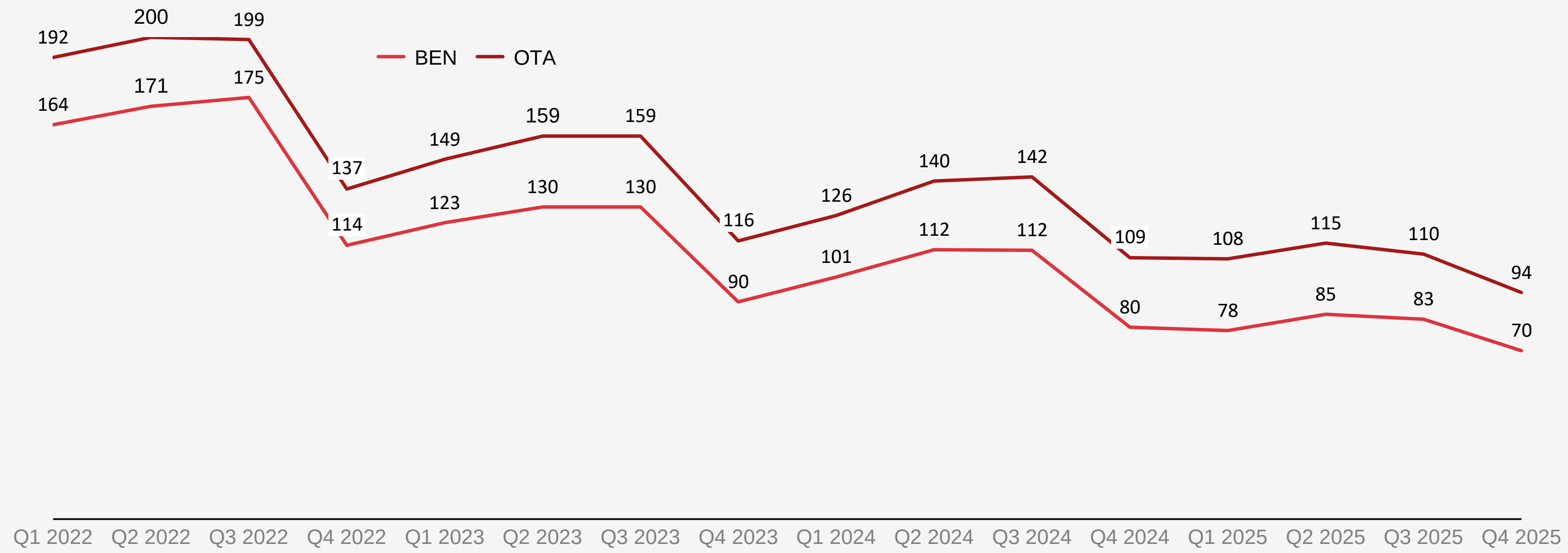
Questions



Supporting materials

ASX futures pricing in fuel risk over next 12 months

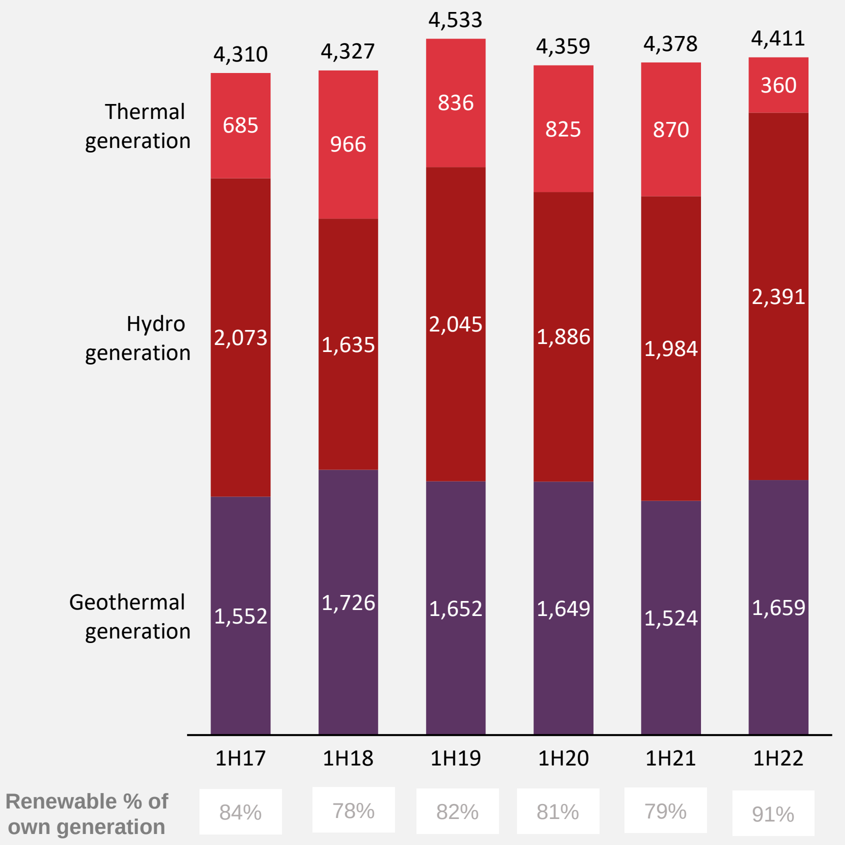
ASX electricity forward pricing ($/MWh)



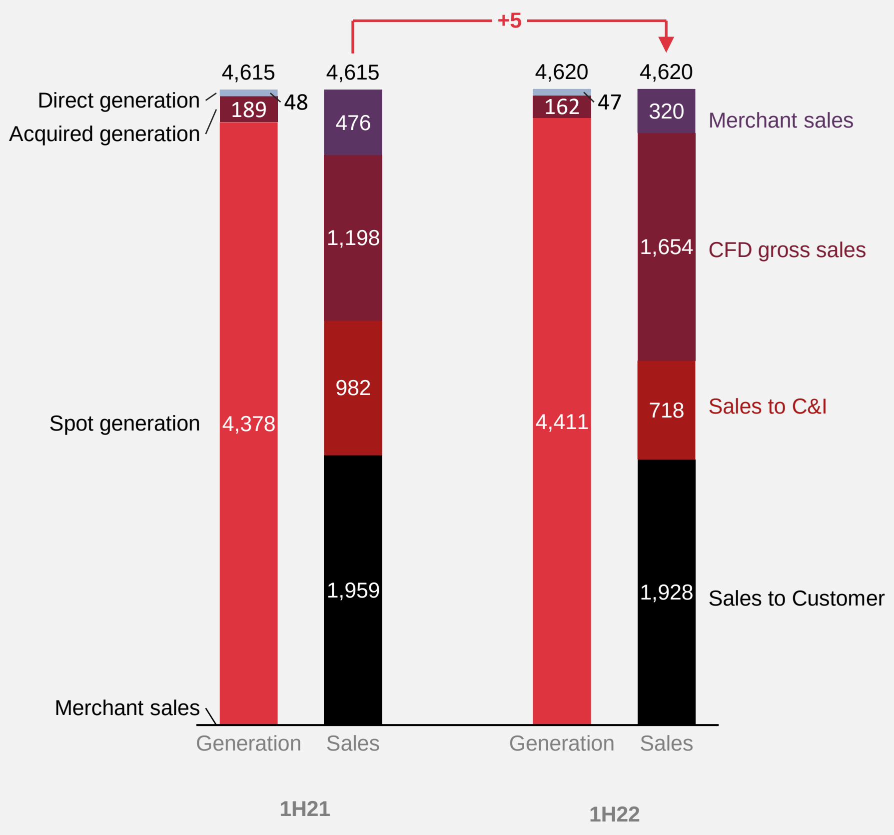
Source: ASX Energy as at 2 February 2022

Generation and sales position

Contact generation output sold to the national grid (GWh)

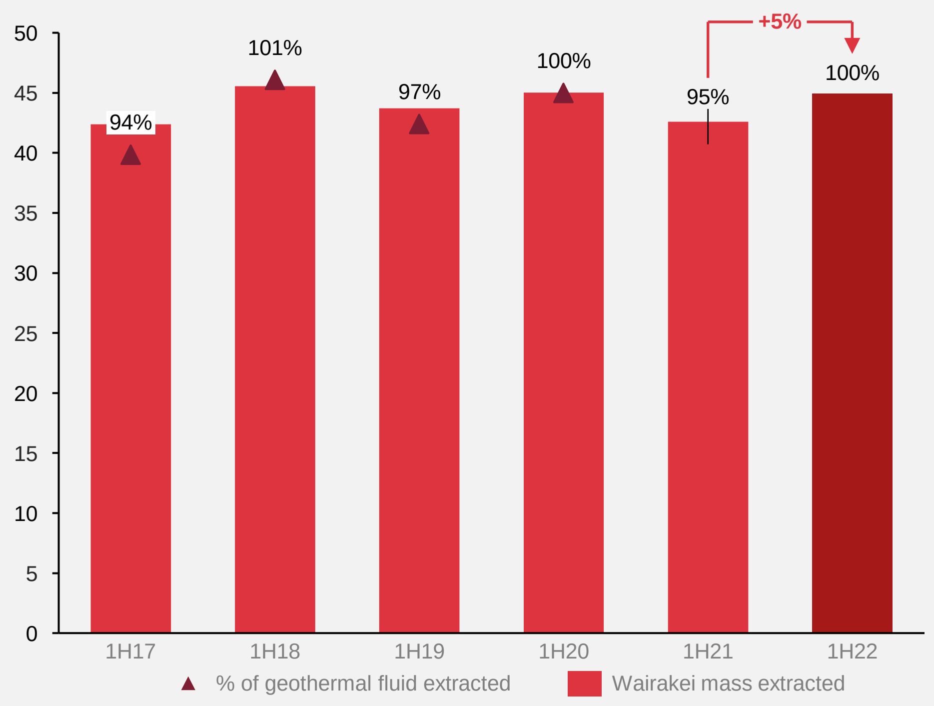


Electricity and generation sales position (GWh)

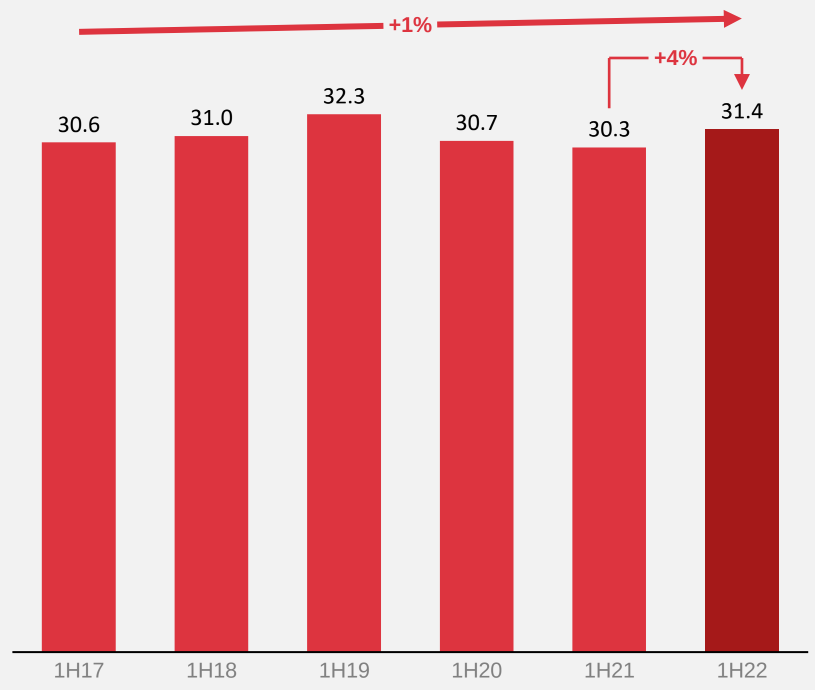


Wairākei geothermal field mass take and efficiency

Geothermal fuel extracted at Wairākei vs consented (GWh)



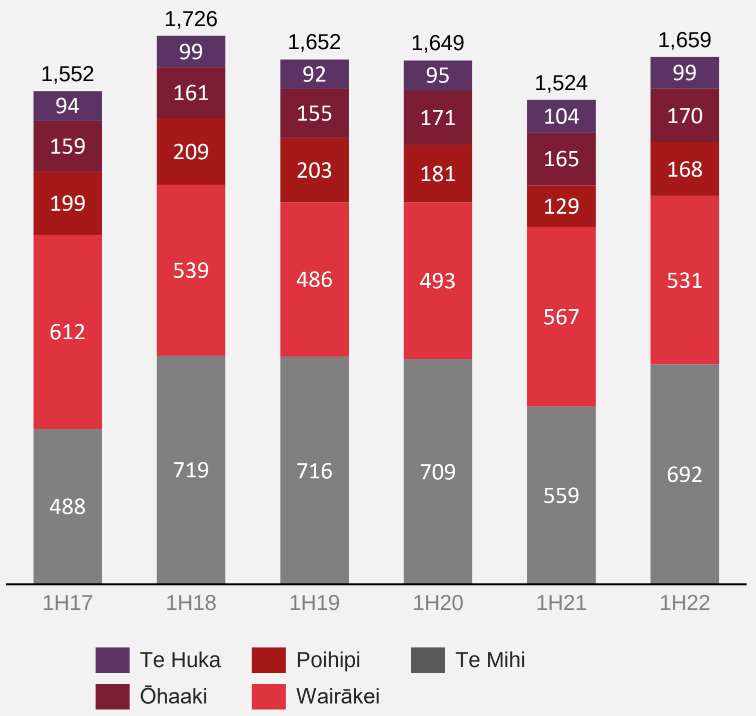
Wairākei, Poihipi and Te Mihi conversion effectiveness
(MWh per kT extracted)



Operational data

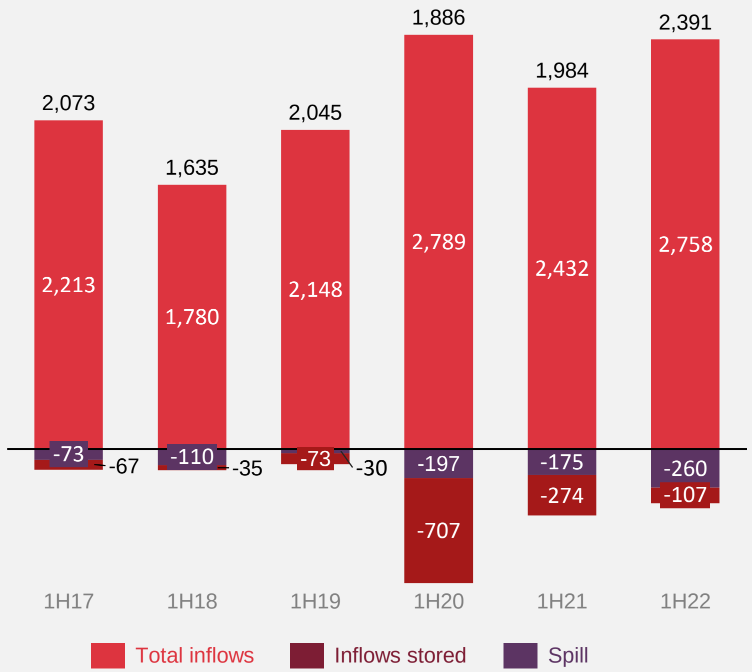
Generation volumes: renewable generation up by 15% on 1H21

Geothermal generation (GWh)



Geothermal generation was 135GWh higher than 1H21 which had the 4-yearly statutory Te Mihi outage and an extended outage required on process safety improvements required at the Te Huka binary plant.

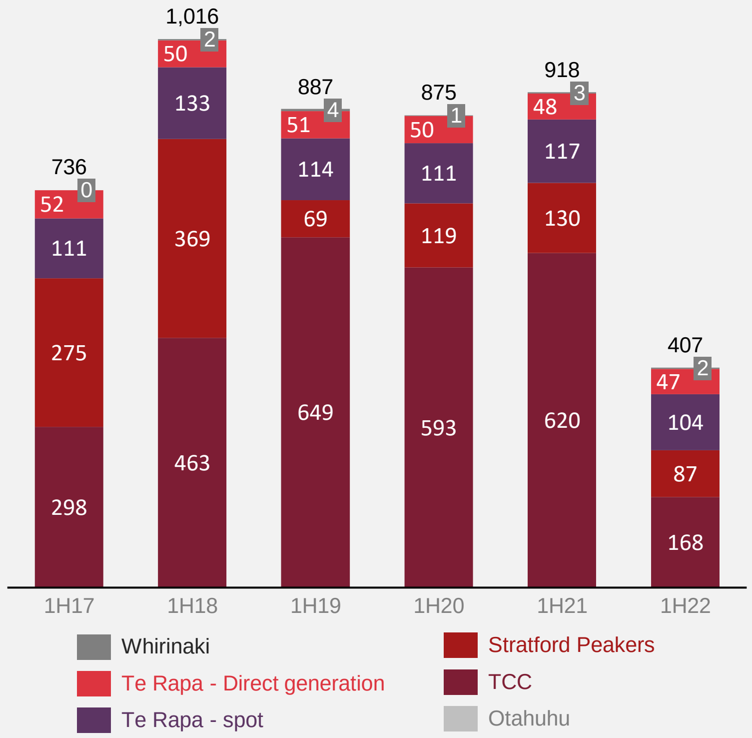
Hydro generation (GWh)



Hydro generation was 401GWh above mean (1,990GWh) in 1H22, 408GWh higher than 1H21. Inflows were consistent throughout the period which limited spill.

Inflows stored include uncontrolled storage lakes

Thermal generation (GWh)



Thermal generation volumes were 511GWh lower than 1H21 as a result of the strong renewable generation and low wholesale prices.

Plant availability

Hydro

	Net capacity (MW)	Availability (%)	Capacity factor (%)	Electricity output (GWh)	Pool revenue ($/MWh)	Pool revenue ($m)
1H18	784	95%	47%	1,635	88	144
1H19	784	95%	59%	2,045	129	265
1H20	784	94%	54%	1,886	98	184
1H21	784	85%	57%	1,984	110	218
1H22	784	83%	69%	2,391	90	215

Geothermal

	Net capacity (MW)	Availability (%)	Capacity factor (%)	Electricity output (GWh)	Pool revenue ($/MWh)	Pool revenue ($m)
1H18	429	97%	91%	1,726	86	148
1H19	425	91%	88%	1,652	137	226
1H20	425	94%	88%	1,649	106	175
1H21	425	86%	81%	1,524	118	180
1H22	410	96%	92%	1,660	105	175

Taranaki combined cycle (TCC)

	Net capacity (MW)	Availability (%)	Capacity factor (%)	Electricity output (GWh)	Pool revenue ($/MWh)	Pool revenue ($m)
1H18	377	51%	28%	463	110	51
1H19	377	63%	39%	649	119	78
1H20	377	78%	36%	593	113	67
1H21	377	96%	37%	620	127	79
1H22	377	100%	10%	167	183	31

Peakers (including Whirinaki)

	Net capacity (MW)	Availability (%)	Capacity factor (%)	Electricity output (GWh)	Pool revenue ($/MWh)	Pool revenue ($m)
1H18	360	98%	21%	370	120	44
1H19	360	79%	4%	73	231	17
1H20	360	78%	7%	120	153	18
1H21	360	88%	8%	133	150	20
1H22	360	84%	5%	87	216	19

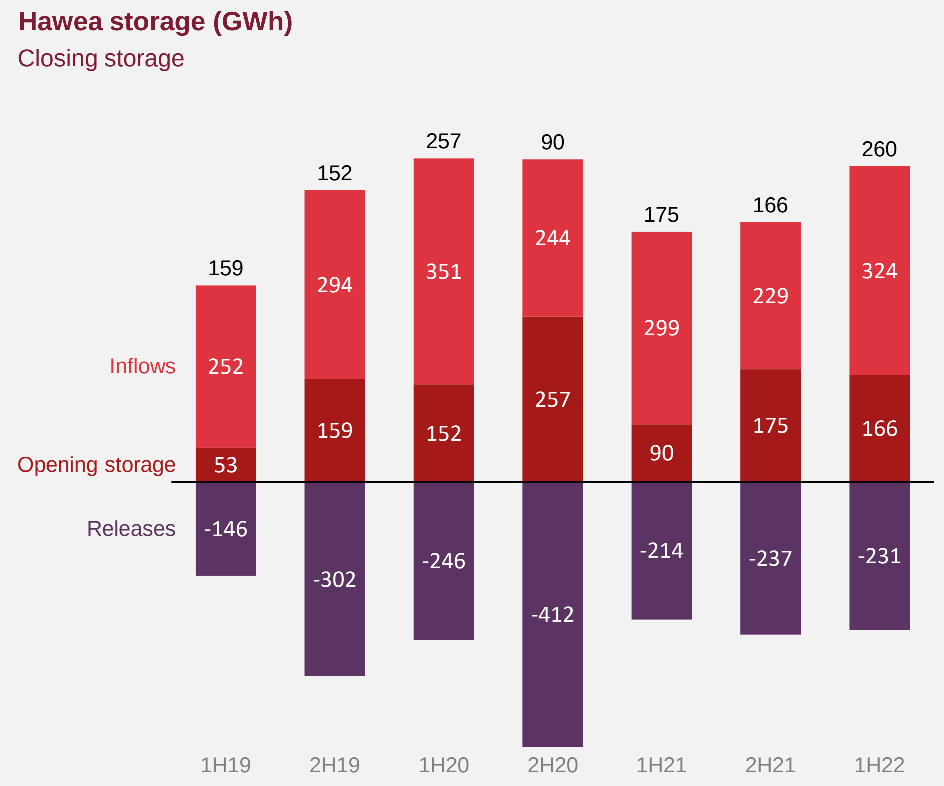
Te Rapa (spot generation only)

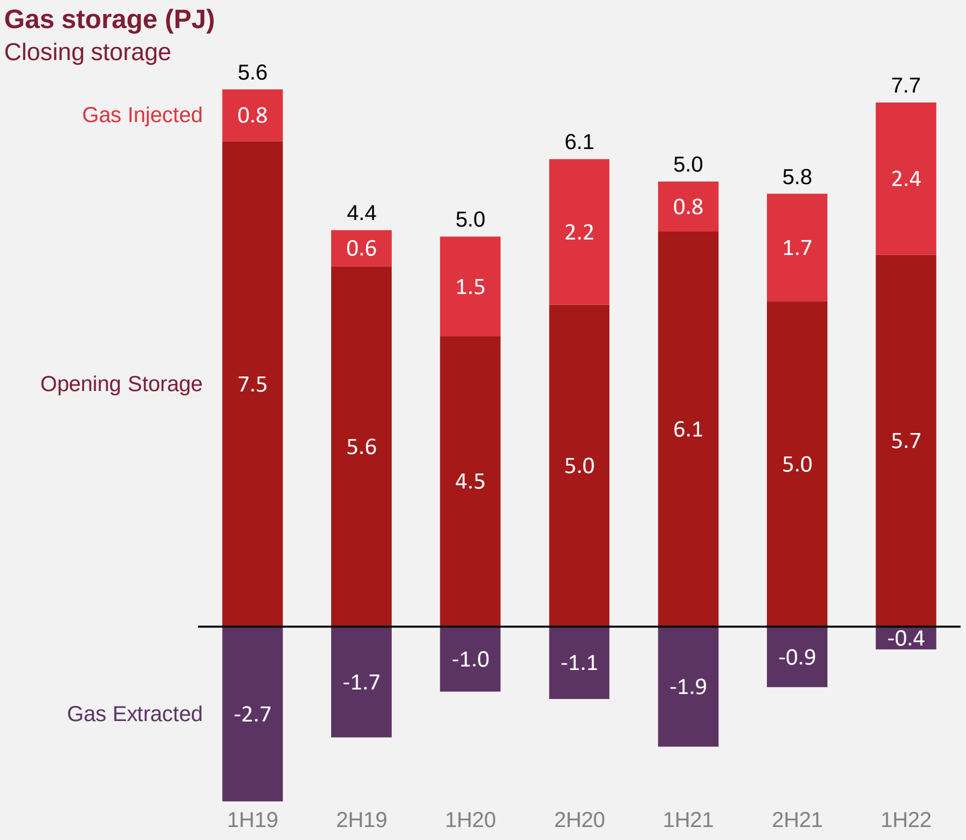
	Net capacity (MW)	Availability (%)	Capacity factor (%)	Electricity output (GWh)	Pool revenue ($/MWh)	Pool revenue ($m)
1H18	41	99%	73%	133	93	12
1H19	41	98%	63%	114	161	18
1H20	41	100%	61%	111	116	13
1H21	41	99%	65%	117	122	14
1H22	41	100%	57%	104	108	11

Availability Factor calculation includes all station outages (Planned, Maintenance, Forced) but does not consider plant deratings.

Operational data

Fuel storage movements



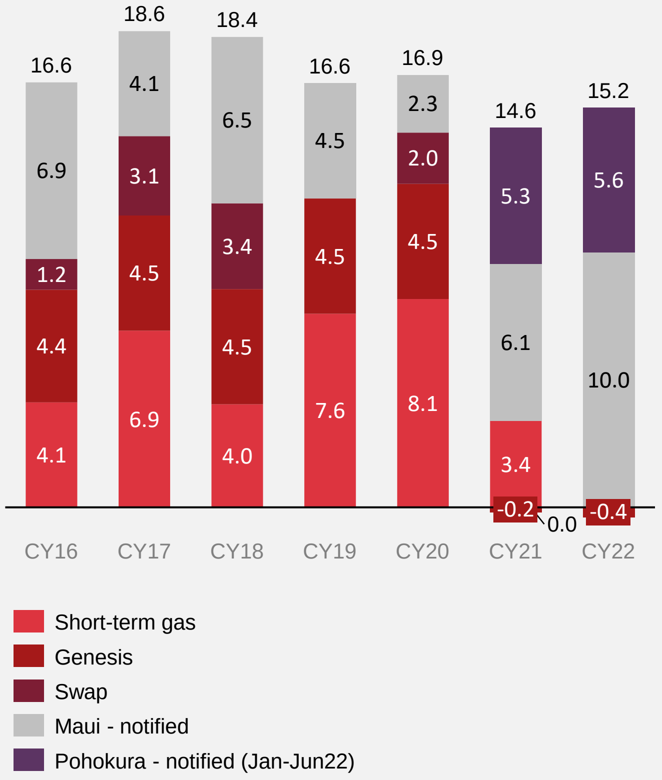


In late 2021 we were notified of an unexpected and unexplained increase in pressure recorded in the Ahuroa Gas Storage Facility (AGS) by the owner and operator of the facility, FlexGas. In conjunction with FlexGas, we will be assessing the potential implications of this on our contractual rights over the next several months. In the interim, we will support a prudent operating regime and will adapt our injection into the facility to maintain appropriate facility pressures. In a fuel short market, this is not expected to have any financial impact.

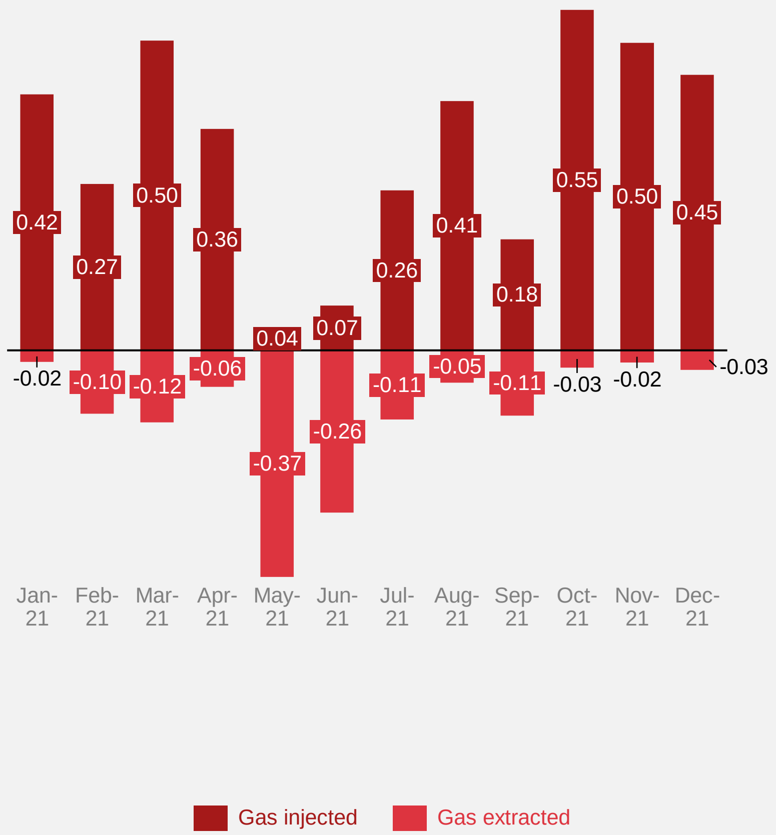
Source: NZX hydro

Contracted and stored gas

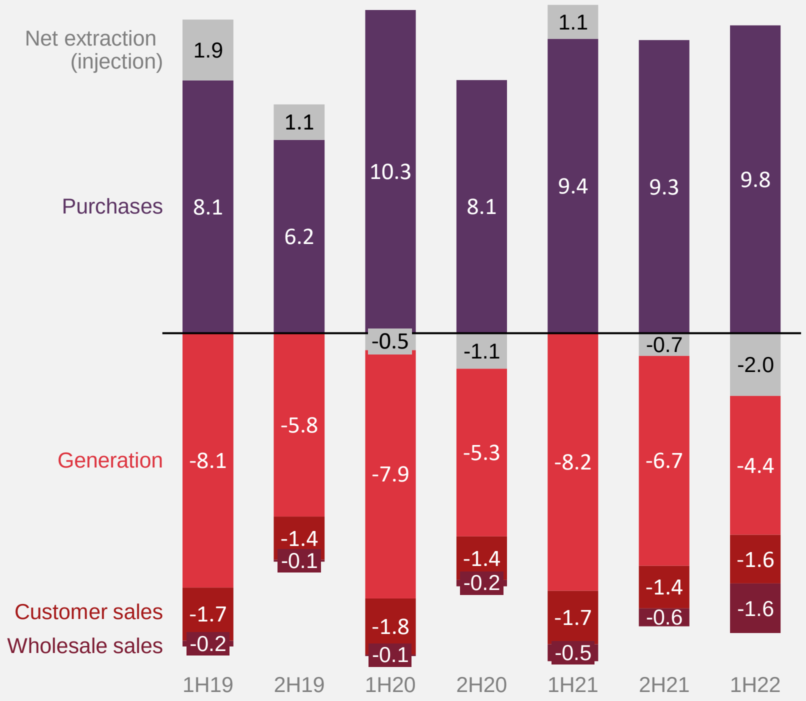
Contracted gas volumes (PJ)



Gas storage monthly injections and extractions (PJ)



Uses of gas (PJ)



Storage balance at 31 December 2021 was 7.7PJ

Reconciliation between Profit and EBITDAF

EBITDAF is Contact's earnings before interest, tax, depreciation and amortisation, and changes in fair value of financial instruments.

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 2021	6 months ended 31 December 2020	Variance on prior year	
			$m	%
Profit	**134**	**78**	**56**	**72%**
Depreciation and amortisation	129	114	15	13%
Change in fair value of financial instruments	(13)	(4)	(9)	225%
Net interest expense	19	26	(7)	(27%)
Tax expense	53	32	21	66%
EBITDAF	**322**	**246**	**76**	**31%**

Depreciation and amortisation, change in fair value of financial instruments, net interest and tax expense are explained on the right.

The adjustments from EBITDAF to reported profit and movements on 1H21 are as follows:

- **Depreciation and amortisation:** Increased by $15m (13%) on 1H21 primarily resulting from the review of Wairākei plant in 2H21.
- **Net interest expense:** Reduced by $7m (27%) with lower average borrowings post 2021 equity raise as well as the capitalisation of interest relating to the Tauhara geothermal project.
- **Tax expense** for the period increased $21m following higher operating earnings with higher depreciation partially offset by lower net interest expense. Tax expense for 1H22 represents an effective tax rate of 28%. The effective tax rate for 1H21 was 29%.

Historical financial information

	Unit	1H18	1H19	1H20	1H21	1H22
Revenue	$m	1,190	1,363	1,110	1,141	1,139
Expenses	$m	954	1,072	889	895	817
EBITDAF	$m	236	291	221	246	322
Profit	$m	58	276	59	78	134
Operating free cash flow	$m	141	203	120	157	131
Operating free cash flow per share	cps	19.7	28.3	16.8	21.9	16.8
Dividends declared (interim)	cps	13.0	16.0	16.0	14.0	14.0
Total assets	$m	5,390	5,140	4,850	4,738	4,954
Total liabilities	$m	2,663	2,297	2,170	2,212	2,003
Total equity	$m	2,727	2,843	2,680	2,526	2,951
Gearing ratio[1]	%	35.4	29.7	29.9	31.1	19.3

[1] Gearing ratio is calculated as: Senior debt - including finance lease liabilities/(Senior debt - including finance lease liabilities + Equity)

Wholesale segment

Note: this table has not been rounded and might not add	1H22 Six months ended 31 December 2021 Volume GWh	GWAP $/MWh	$m	1H21 Six months ended 31 December 2020 Volume GWh	GWAP $/MWh	$m	Reference number for Wholesale segment note (see following page)
Electricity sales to Retail segment	**1,928**	**103.1**	**199**	**1,959**	**93.2**	**183**	1
Electricity sales to C&I (netback)	671	81.6	55	934	76.7	72	
Electricity sales – Direct	47	132.7	6	48	110.4	5	2
Electricity sales to C&I	**718**	**85.0**	**61**	**982**	**79.0**	**78**	
CfDs – Tiwai support	397			353			
CfDs - Long term sales	264			301			3
CfDs - Short term sales	993			544			
Electricity sales - CFDs	**1,654**	**114.4**	**189**	**1,198**	**84.3**	**101**	
Total contracted electricity sales	**4,300**	**104.4**	**449**	**4,138**	**87.1**	**361**	
Steam sales	**361**	**51.8**	**19**	**390**	**44.1**	**17**	4
Other income			2			1	5
Net income on gas sales			1			1	6
Net income on electricity related services			(1)			1	7
Net other income			**2**			**2**	
Total contracted revenue (1)	**4,661**	**100.7**	**469**	**4,528**	**84.0**	**380**	
Generation costs	4,458	(27.7)	(124)	4,426	(34.3)	(152)	8
Acquired generation cost	162	(153.7)	(25)	189	(117.4)	(22)	9
Generation costs (including acquired generation) (2)	**4,620**	**(32.2)**	**(149)**	**4,615**	**(37.7)**	**(174)**	
Spot electricity revenue	4,411	102.7	453	4,378	117.1	513	10
Settlement on acquired generation	162	128.4	21	189	116.8	22	11
Spot revenue and settlement on acquired generation (GWAP)	**4,573**	**103.6**	**474**	**4,567**	**117.1**	**535**	
Spot electricity cost	(2,599)	(117.3)	(305)	(2,893)	(127.6)	(369)	12
Settlement on CFDs sold	(1,654)	(105.2)	(174)	(1,198)	(119.0)	(142)	13
Spot purchases and settlement on CFDs sold (LWAP)	**(4,253)**	**(112.6)**	**(479)**	**(4,091)**	**(125.1)**	**(512)**	
Trading, merchant revenue and losses (3)			**(5)**			**23**	
Wholesale EBITDAF (1+2+3)			**316**			**229**	

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 of 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	
	Electricity networks, transmission and meter costs – Fixed Price	2	
	Electricity 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

Retail segment

Residential electricity	unit	1H19	1H20	1H21	1H22
Average connections	#	352,159	355,216	357,756	367,199
Sales volumes	GWh	1,335	1,328	1,349	1,408
Average usage	per ICP	3.8	3.7	3.8	3.8
Tariff	$/MWh	249.9	248.2	251.1	251.5
Network, meters and levies	$/MWh	-123.9	-122.5	-116.2	-115.9
Energy costs	$/MWh	-85.4	-91.6	-101.1	-110.8
Gross margin	**$/MWh**	**40.6**	**34.1**	**33.8**	**24.8**
Gross margin	$ per ICP	168	141	127	95
Gross margin	$m	59	50	45	35

Residential gas	unit	1H19	1H20	1H21	1H22
Average connections	#	61,332	61,959	60,563	63,182
Sales volumes	TJ	936	911	954	970
Average usage	per ICP	15.3	14.7	15.7	15.4
Tariff	$/GJ	29.1	30.6	31.3	32.6
Network, meters and levies	$/GJ	-17.1	-17.3	-15.3	-16.2
Energy costs	$/GJ	-5.6	-7.6	-8.3	-11.3
Carbon costs	$/GJ	-0.9	-1.4	-1.4	-2.0
Gross margin	**$/GJ**	**5.5**	**4.3**	**6.3**	**3.2**
Gross margin	$ per ICP	90	70	99	50
Gross margin	$m	6	4	6	3

SME electricity	unit	1H19	1H20	1H21	1H22
Average connections	#	55,156	55,295	51,407	48,323
Sales volumes	GWh	539	533	465	392
Average usage	per ICP	9.8	9.6	9.0	8.1
Tariff	$/MWh	224.4	226.7	230.7	239.0
Network, meters and levies	$/MWh	-108.0	-113.5	-104.4	-113.0
Energy costs	$/MWh	-83.6	-89.3	-99.7	-109.0
Gross margin	**$/MWh**	**32.8**	**23.9**	**26.5**	**17.0**
Gross margin	$ per ICP	335	242	240	138
Gross margin	$m	18	13	12	7

SME gas	unit	1H19	1H20	1H21	1H22
Average connections	#	3,865	3,991	3,858	3,918
Sales volumes	TJ	809	845	720	628
Average usage	per ICP	209.4	211.8	186.7	160.4
Tariff	$/GJ	14.8	14.9	15.8	18.6
Network, meters and levies	$/GJ	-5.3	-5.4	-7.9	-8.7
Energy costs	$/GJ	-5.6	-7.6	-8.3	-11.3
Carbon costs	$/GJ	-0.9	-1.4	-1.4	-2.0
Gross margin	**$/GJ**	**3.0**	**0.5**	**-1.8**	**-3.3**
Gross margin	$ per ICP	575	97	-474	-532
Gross margin	$m	2	0	-2	-3

Broadband	unit	1H19	1H20	1H21	1H22
Average connections	#	2,677	17,038	33,197	57,498
Tariff	$/cust/mth	106.6	70.7	65.2	71.8
Network, provisioning, modems	$/cust/mth	-91.3	-68.9	-74.0	-61.6
Gross margin	$/cust/mth	**15.3**	**1.8**	**-8.8**	**10.2**
Gross margin	$m	0	0	-2	4

Retail segment EBITDAF		1H19	1H20	1H21	1H22
Electricity Gross margin	$m	72	58	58	41
Gas Gross Margin	$m	8	4	5	1
Broadband Gross Margin	$m	0	0	-2	4
Total Gross Margin	**$m**	**80**	**62**	**61**	**46**
Other income	$m	2	2	3	3
Other operating costs	$m	-34	-35	-33	-33
Retail segment EBITDAF	**$m**	**48**	**30**	**30**	**16**
Corporate allocation (50%)	$m	-7	-7	-7	-5
Retail EBITDAF	**$m**	**41**	**23**	**23**	**11**
EBITDAF margins (% of revenue)	%	8.2%	4.7%	4.6%	2.1%