2023 full year results presentation

Twelve months ended 30 June 2023

14 August 2023

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Agenda

Delivering a solid FY23 performance while investing for decarbonisation

	Twelve months ended 30 June 2023 (FY23)		Twelve months ended 30 June 2022 (FY22)	
	Underlying[1]	*Reported*	Against underlying	
EBITDAF[2]	$573m	*$460m*	↑	5% from $546m
Profit	$211m	*$127m*	↑	16% from $182m
Profit per share	26.9 c	*16.3 c*	↑	15% from 23.4c
Operating free cash flow[3]	$282m		↓	15% from $330m
Operating free cash flow per share[3]	36.0 c		↓	15% from 42.4c
Dividend declared	$273m		↑	$272m
Dividend declared per share	35.0 c		→	35.0 c
Stay-in-business (SIB) capital expenditure (cash)	$113m		↑	43% from $79m
Growth capital expenditure (cash)[4]	$472m		↑	62% from $291m

FY23 market

Operating conditions in FY23 were characterised by the highest nationwide hydro inflows in post-market history, with North Island rainfall the highest on record. This led to:

- Lower wholesale spot prices.
- Lower thermal generation.
- Higher price separation between North and South Islands.

Over the medium term:

- Pricing volatility increasing, particularly in peak periods, as intermittent generation comes online.
- Electricity futures prices have softened with recent reductions in spot coal and carbon prices.
- Pricing is still influenced by lower expected gas availability, notified reduction in gas storage capacity, the end of ‘swaption’ contracts and high expected marginal cost of thermal fuel and carbon.
- Rising thermal fixed costs will need to be recovered over less generation as renewable penetration increases.
- Conditions continue to support a view of long-term wholesale prices at $100-110/MWh (2022 real).

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Contact has responded to the short-term conditions by:

- Securing additional gas in Q2 FY23 enabling additional CFD sales for 2023.
- Running short to take advantage of soft wholesale market conditions.
- Reducing thermal generation, to the lowest on Contact record, saving on fuel costs.

Contact over the medium term:

- Channel pricing aligned closer to the wholesale market.
- Te Rapa closed in June 2023 and TCC will run until the end of its operating hours (expected end of 2024).
- Preparing sales book for the Q2 FY24 commissioning of Tauhara geothermal plant, which will add 1.4TWh of new renewable output to the portfolio annually.
- Recognising a net $113 million onerous contract provision expense within EBITDAF for Ahuroa Gas Storage facility (AGS).[1]

[1] Contact has recognised a net onerous contract provision expense for AGS of $113m within EBITDAF and $84m within profit. Underlying performance excludes these impacts. All variances and commentary reflect movements in underlying performance.
[2] Refer to slide 43 for a definition and reconciliation of EBITDAF. Contact has made reclassifications to better align with IFRIC guidance on IFRS 9 resulting in realised gains/losses from market derivatives not in a hedge relationship (includes market making activity) no longer being reported in operating income (EBITDAF). FY22 figures restated accordingly.
[3] Refer to slide 22 for a reconciliation of operating free cash flow.
[4] Includes capitalised interest.

Contact26 Our strategy to lead NZ's decarbonisation

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

Contact26

Execution: What we delivered over the past 12 months

Strategic theme	FY23 achievements / progress		Updated ambitions (FY27)[1]
Grow demand	Completed assessment of hydrogen economics NZAS negotiations underway 10-year renewable energy attribute agreement with Microsoft. Growing data centre pipeline	Lock in major industrial electrification. Entered 30MW off-peak supply arrangement with NZ Steel Commence boiler electrification Flexible demand more than 80MW	• Facilitate 100MW of new demand • Reach 100MW total Demand Flex and start pivoting to Demand Response • New green chemical channel established contributing incremental EBITDAF
Grow renewable development	Build Tauhara. Online Q4 2024. Te Huka 3 investment decision and entered build phase Wairākei geothermal replacement consented. GeoFuture proceeding to investment decision in FY24 Selected to deliver 150MW solar farm at Kōwhai Park. Proceeding to investment decision in FY24	Secure and consent wind sites. Entering consenting for 0.9-1.2TWh Southland wind project in FY24 Complete battery feasibility. 100MW battery investment proceeding to investment decision in FY24 Roxburgh turbine replacement	• Grow to 10.3TWh p.a of total renewable assets from geothermal new build, solar and wind • 100MW battery operational
Decarbonise our portfolio	Te Rapa closed in June 2023 Confirmed TCC will run its remaining operating hours or as market needs dictate. Decommissioning expected at end of 2024	On track to meet all carbon reduction commitments Thermal review complete. Contact to manage its thermal peaking assets through the energy transition, playing a key role in system security	• Scope 1 and 2 GHG emissions run-rate of ~300ktCO2e, working towards our 2035 net zero commitment • Renewable flexibility strategy to reduce reliance on thermal peaking
Create outstanding customer experiences	Targeted growth in broadband and energy connections. Now more than 588,000, an increase of over 65,000 since FY21 Unlock further cost to serve improvements and increases in Net Promoter Score through digitisation programme	SAP ERP finance and generation upgrade complete. CRM options to be reviewed Wireless broadband launched along with new targeted EV plan. Pilot offering of mobile in August 2023	• Greater than 685k connections • Cost to serve (CTS) at global benchmark of <$80/ connection • Triple EBITDAF contribution from non-energy lines of business • Top quartile NZ Business for Sustainability survey[2] and most Trusted Energy brand[3]

Key: Complete / on-track — Minor delay and / or cost increase — Major delay and / or cost increase

[1] Set in May 2023.
[2] As measured by Kantar Better Futures survey.
[3] As measured by Contact's independently surveyed brand tracker.

Geothermal investment programme update

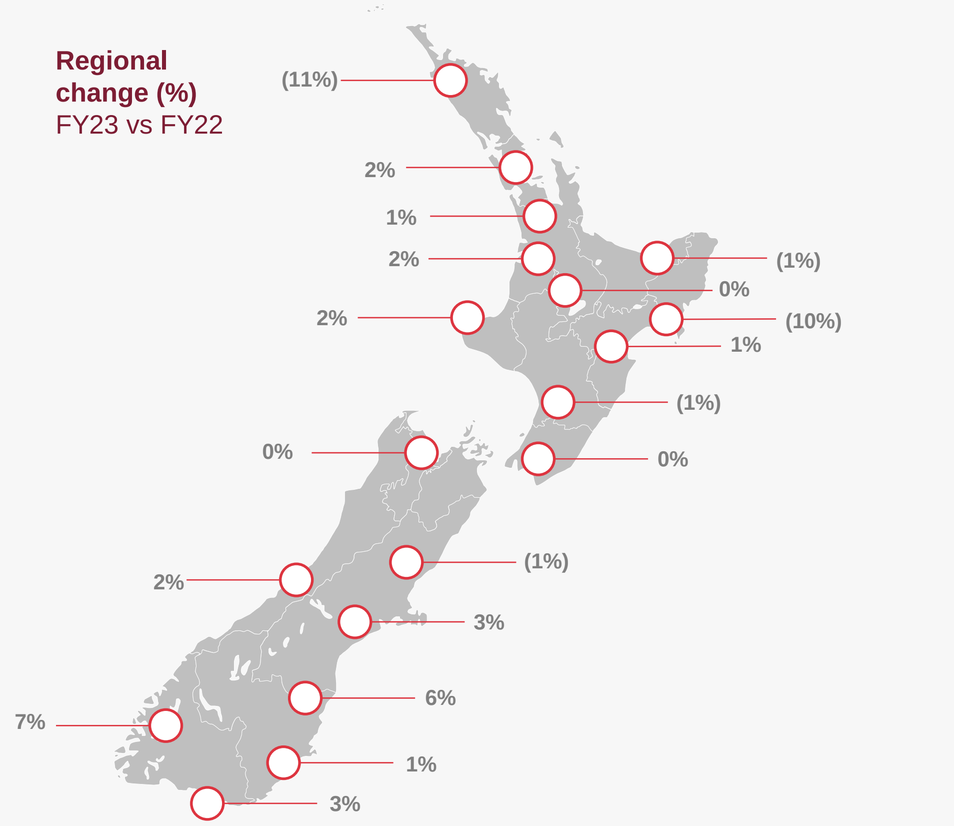
Supporting the decarbonisation of New Zealand by building world class geothermal power stations

	Tauhara	Te Huka 3	GeoFuture[2]
Size (TWh p.a)	1.4	0.4	1.4[3]
FID date	Feb 2021	Aug 2022	Early 2024
Online date	Q4 2023	Q4 2024	2H 2026
Project progress (at 30 Jun)	96%	38%	Pre-FID development
Spend to date (to 30 Jun)[1]	$748m	$116m	$12m
Committed spend[1]	$880m	$300m	$114m[4]
Total expected project cost	$880m	$300m	$5.3 – 5.7m/MW

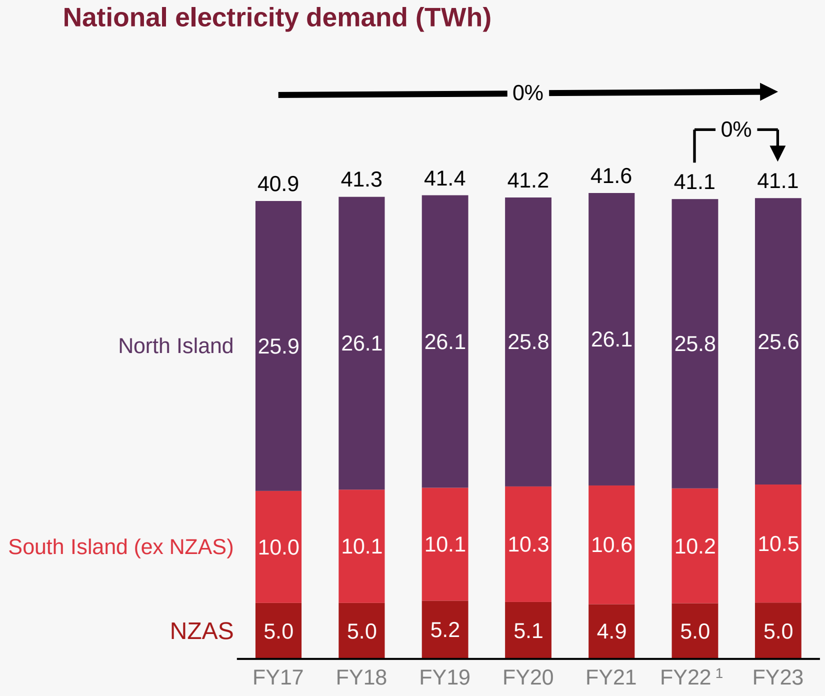
[1] Includes sunk costs. Excludes capitalised interest.
[2] Subject to final investment decision (FID).
[3] Based on mid-point of 160-180MW indicative capacity range. Represents a net uplift of 0.4TWh per annum following the closure of Wairākei plants.
[4] Approved pre-FID development costs. We are undertaking drilling from September 2023 and advancing steamfield design.

National electricity demand

New Zealand electricity demand is flat on FY22 in spite of industrial closures and warmer weather impacts



Source: EMI, Contact.
Does not include NZAS



Source: EMI, Contact

Total national electricity demand increased by 0.1 TWh (0.23% from FY22):

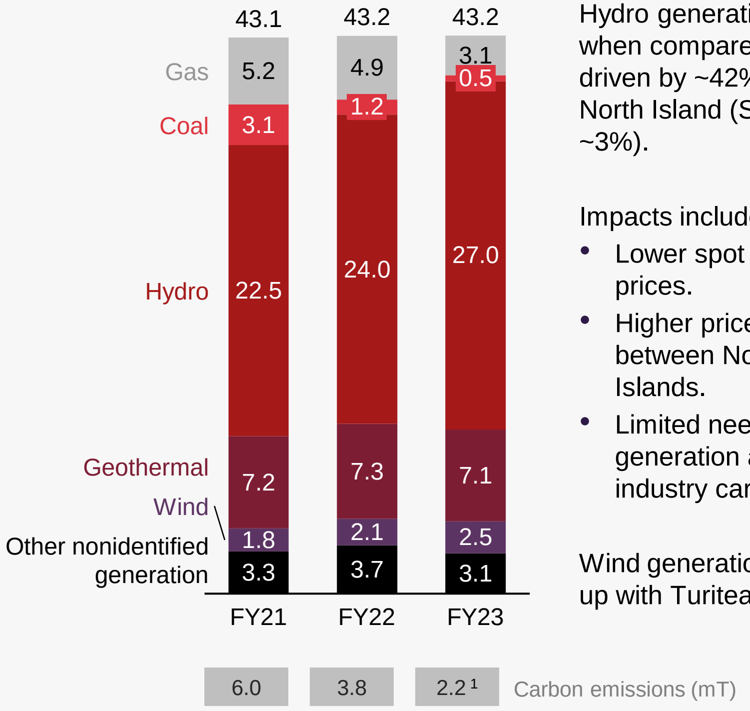
- The decrease in Northland regional demand (11%) was a result of Marsden Point refinery converting to an import-only terminal from April 2022 – a reduction of 177GWh on the prior year.
- East Coast regional demand is down 10% as Pan Pac's Whirinaki site is closed until further notice, due to impacts from flooding from Cyclone Gabrielle.
- A dry summer for the South Island in 2022/23 saw higher irrigation demand at major South Island irrigation demand nodes.
- Removing the impact from known major industrial variations, unusual weather and other known impacts, indicates that underlying demand is up ~1-2% on FY22.

[1] FY22 demand data has been restated to be consistent with the most recent demand data released by EMI.

Hydrology significantly impacted generation mix

High hydro inflows limited the need for thermal generation

Generation by type (TWh)



Hydro generation was up 13% when compared to FY22, driven by ~42% uplift in the North Island (South Island up ~3%).

Impacts included:

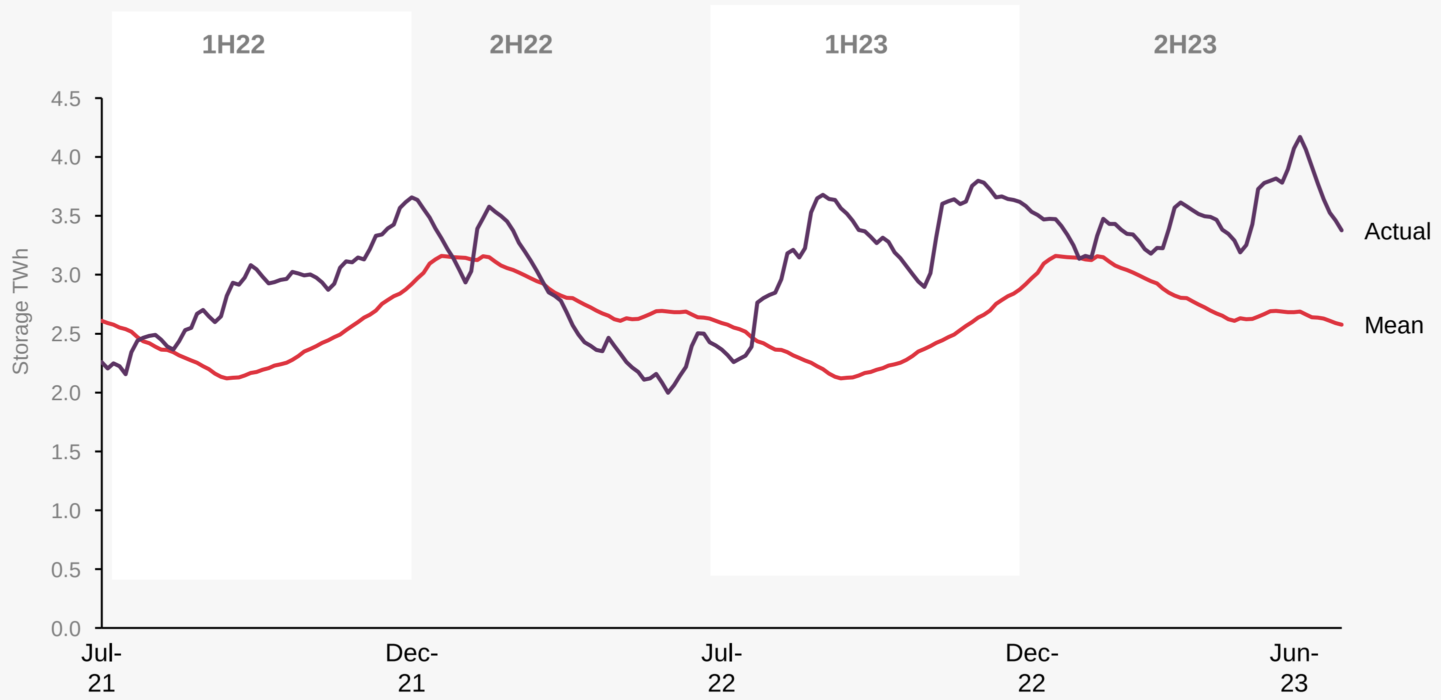
- Lower spot wholesale prices.
- Higher price separation between North and South Islands.
- Limited need for thermal generation and lower industry carbon emissions.

Wind generation has stepped up with Turitea coming online.

The reduction in carbon emissions of 1.6mT (42%) CO_2-e was due to the decrease in coal and gas generation year on year.

Source: EMI & MBIE

National hydro storage



Strong hydro inflows in FY23 saw actual storage levels higher than mean throughout the year, reducing reliance on gas and coal.

Source: NZX

[1] Carbon emissions for FY23 Apr-Jun quarter has been estimated using historic conversion rates with actual generation data.

Forward wholesale pricing continues to reflect high fuel cost and availability risk

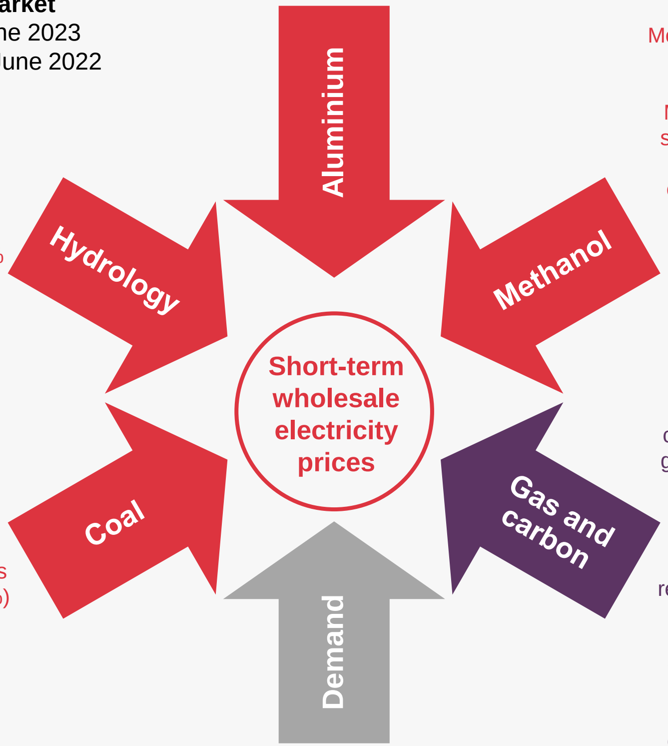
Short-term external factors that can influence the market
Changes as at 30 June 2023 in comparison to 30 June 2022

Aluminium prices lower (-$440/t, down 13%)

Methanol pricing at US$281/t (down 30%)

Methanex outage allowed summer to winter shape in gas supply as hydro conditions transpired and AGS limitations were felt

Record rainfall led to above mean hydro storage over the last 12 months. Controlled storage at ~130% of mean (~800 GWh above mean) in June



Technical Working Group concluded that 4PJ of stored gas at AGS is unavailable for immediate use

Drilling campaigns on major fields undertaken, ultimate results less than envisaged at 2022 reserves assessment

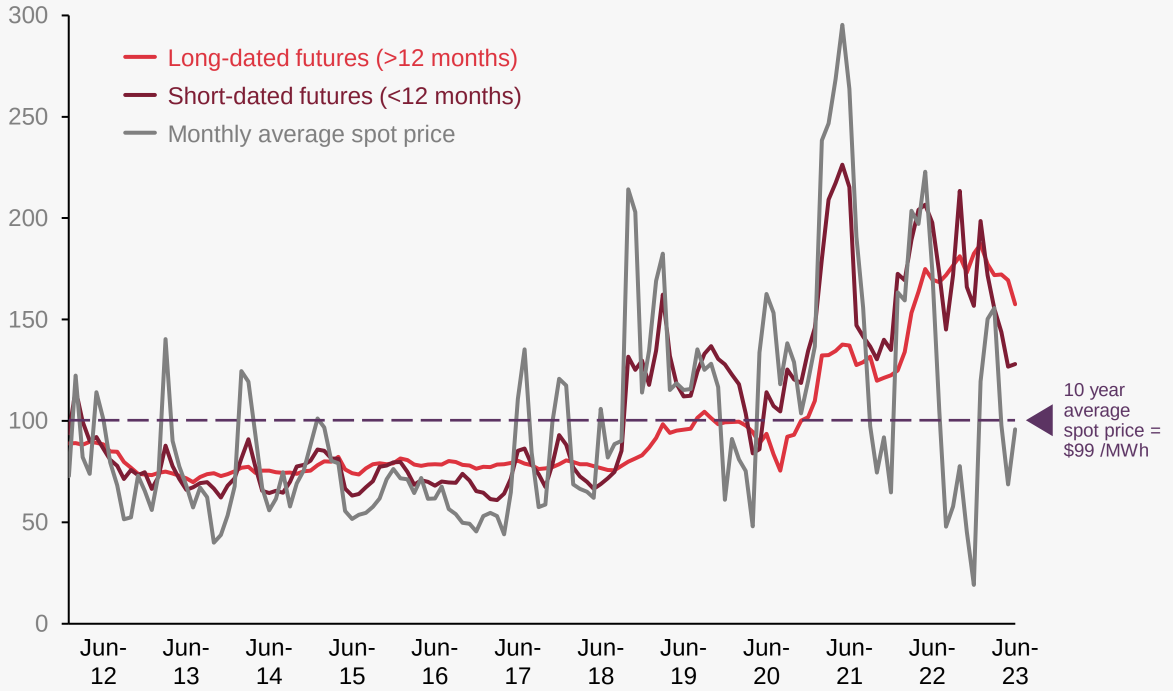
Carbon prices down 85% to $41/New Zealand Unit

Government has announced it will apply Climate Change Commission advice on ETS settings from December 2023

Decrease in coal prices (-US$236/t, down158%)

Demand was flat year on year

Wholesale and futures electricity pricing ($/MWh)



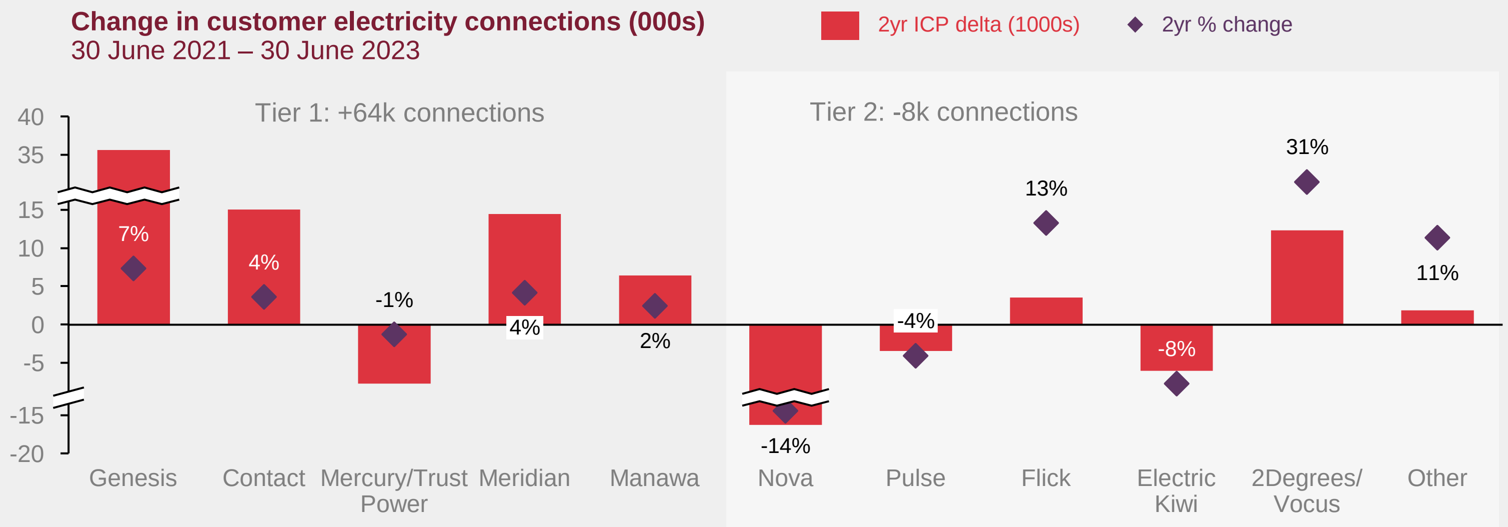
Source: EMI wholesale pricing

While some short-term inputs to wholesale pricing have softened, notably spot Newcastle coal and New Zealand carbon unit prices, fuel price volatility and availability risk remain as drivers of forward wholesale prices, with expected future marginal thermal costs still supporting the forward electricity price path. Domestically, strong hydrology conditions over the past 12 months have masked this and have suppressed wholesale electricity prices. Fundamental requirement for thermal generation to support a hydro dominated electricity system supports forward electricity prices..

Retail competition remains intense

A wide range of market players continue with very competitive pricing despite rising costs

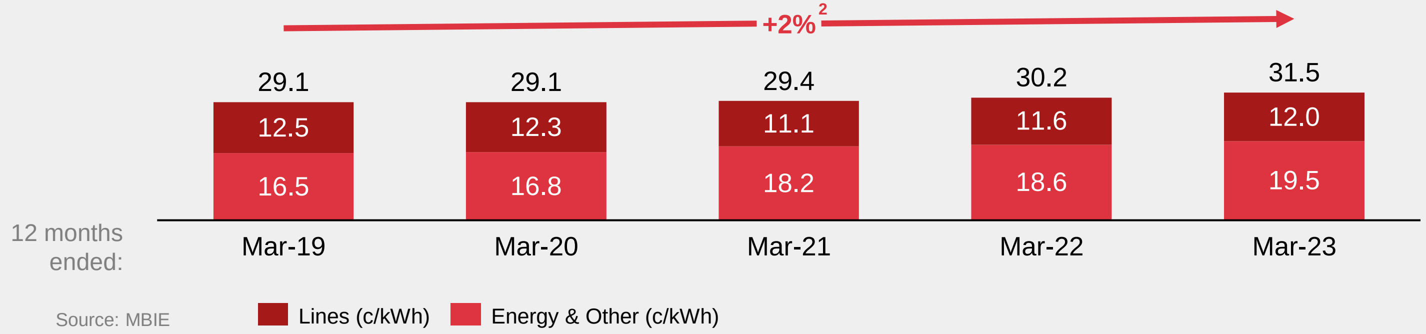
Change in customer electricity connections (000s)
30 June 2021 – 30 June 2023



Source: EMI

- Competition remains intense despite sustained high wholesale futures prices. Market churn continues to reflect this with switching at 19%.
- Tier 1 retailers have a seen a 1% increase in market share to ~85% (84% June-21 & 85% June-23). This is largely due to added connections as household formation contributed to a continued ~1% p .a. growth in ICPs.
- Tier 2 retailer growth rates have been impacted due to the sharp lift in wholesale energy prices resulting in a 1% decline in market share to ~15% (16% June-21).
- Mercury purchased the Trustpower retail business in FY22 and is now the largest retailer by ICP (26% market share).
- 2degrees and Vocus merged on 1 June 2022 becoming the third largest telco, while also providing energy products. Since acquisition, 2Degrees has grown connections by 12k and are now the leading Tier 2 in electricity connections.
- Contact electricity connections +15k from June 2021 to June 2023 equating to 19% market share.

Retail electricity tariff changes (c/ kWh)



Source: MBIE

- Increasing wholesale energy and network costs have resulted in a lift in Residential electricity tariffs with the compound annual growth rate of 2% across the last five years to March 2023.
- Average tariff increases for the year to March 2023 of 4.3% were materially below consumer price inflation (~7%) [1], with households largely insulated from increasing input costs due to retailers' longer-term view of pricing that rides through short-term volatility.
- Input cost pressure for retailers is expected to remain with continued firming future wholesale prices and significant network cost increases due to the 1 April 2025 price regulation reset. Retailers' pricing will need to increase in order to recover these rising costs.

[1] Stats NZ CIP index increase in the 12 months to March 2023.

Topical regulatory matters

Contact's focus on building new renewable generation, flexible storage and customer-focused demand response solutions is well aligned with the political and societal imperative to deliver net zero for NZ by 2050. Orderly decarbonisation of Contact's portfolio is underway, with a focus on system security and affordability at each junction.

	Wholesale market security	Energy Strategy	Battery project (Project Onslow)	Lines assets regulation / investment	Decarbonisation incentives	Resource management reform
Theme	Elevated futures pricing and peak volatility is placing pressure on unhedged energy intensive industries. Industry, Transpower and the EA paying close attention to capacity this year and beyond.	Government developing NZ Energy Strategy to address strategic challenges in the energy sector and signal pathways away from fossil fuels. Expected to account for Energy Hardship considerations.	Government is investigating solutions to NZ's dry year electricity problem. Potential solutions include pumped hydro, or a portfolio approach using a range of technologies.	Government price regulation of EDBs and Transpower for 2025-30. BCG report found a need for $22bn[1] of additional capital spend on distribution infrastructure by 2030 to meet NZ's decarbonisation goals.	Government will implement CCC recommendations on ETS auction settings in December 2024. GIDI[2] funding has targeted large emitters. May be discontinued if there is a change in government.	Government is replacing the RMA [3] with the Natural and Built Environment Bill and the Spatial Planning Bill, as well as, refreshing the national policy statement for renewable electricity generation (NPS-REG).
Contact Approach	Investment in new renewables, storage and demand response. Long term contracts to smooth price volatility. Engagement with EA on long term impacts of price volatility.	Working with electricity industry to establish near-term actions to implement the complementary plan set out in BCG's report "the Future is Electric". Orderly decarbonisation of own portfolio. Focus on energy security and affordability.	Supportive of further analysis of NZ's dry year risk. Recommends a market-led solution.	Sufficient line capacity is critical to decarbonisation, however, must be balanced against the impact on consumers. Recommends regulatory changes to reduce connection costs aiding electrification projects.	ETS requires stability to remain a credible tool to encourage decarbonisation. Direct government support for decarbonisation projects is an important complement to the ETS costs. We will continue to work with government to find opportunities.	Contact has advocated for a balance between environmental effects and the need to decarbonise our economy. Current draft Bills go some way towards addressing our concerns, and draft NPS-REG looks promising.
Timing	Engagement ongoing. Contact targeting 10.3TWh of renewables and 100MW battery by FY27.	Five discussion papers released 9th August 2023. NZ Energy Strategy due for completion by end of 2024.	Detailed business case presented to cabinet soon to inform on which options to undertake. FID expected in 2027/28.	Draft decision on 2025-30 revenue caps due in May 2024, and a final decision in November 2024.	Decisions on ETS forestry credits are expected post election. Applicants can apply for GIDI funding at any time.	Bills are expected to be passed before the general election (October), but there will be a transition period of ~7-10 years.

[1] Note $22bn refers to additional capital spend required out to 2030. Additional capital spend required on distribution infrastructure out to 2050 is $71bn.

[2] Government Investment in Decarbonisation

[3] Resource Management Act

Financial results and outlook

Key themes from the financial results

Key accounting topics: Recognised onerous contract provision and applied updated guidance on IFRS 9

A strong second half meant that we outperformed our updated guidance at 1H23 of $530m and our original guidance

Sales channels repricing to better align with wholesale market, further opportunity exists

Provisions increased to reflect portfolio changes and associated decommissioning

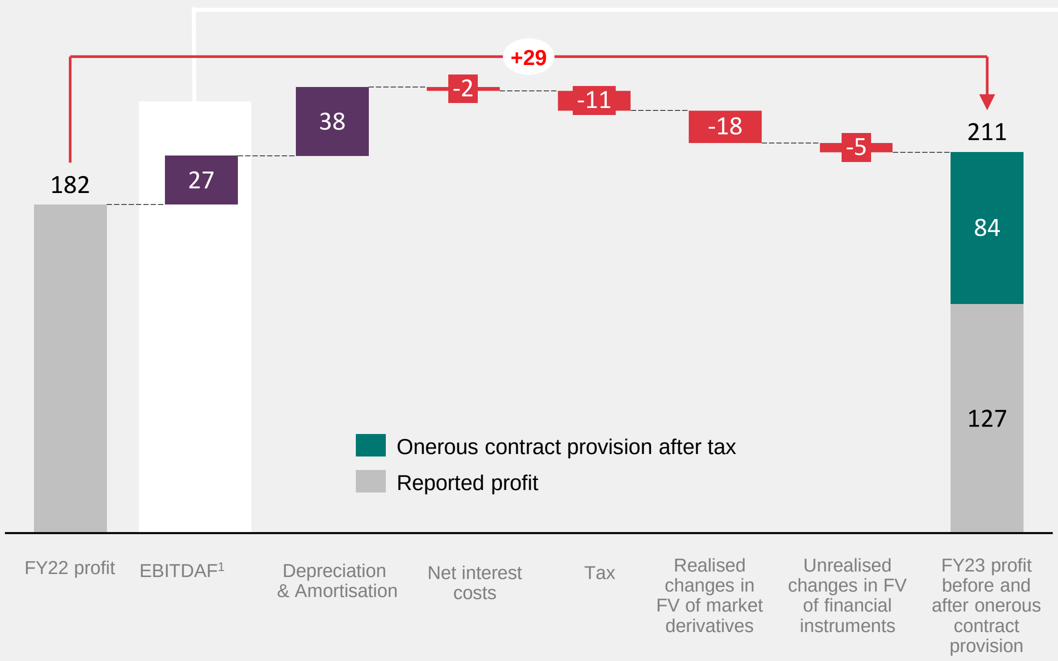
Cash conversion has decreased with record low thermal generation and higher SIB capex as guided

Regulated asset base cost increases will be a key consideration for the industry as this could slow decarbonisation

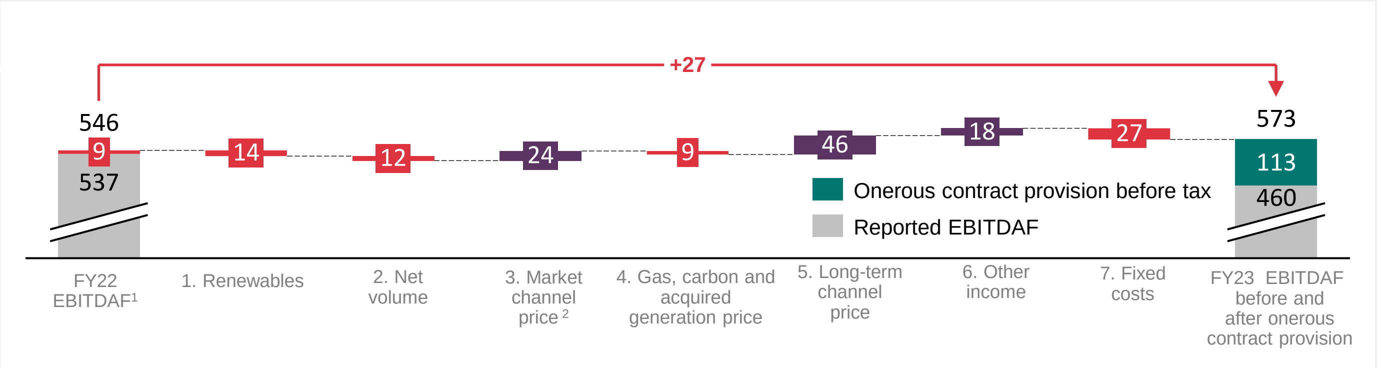
Profit of $127m for FY23

Excluding the onerous contract provision, EBITDAF up $27m (underlying) largely reflecting the better alignment of long-term channel prices to the wholesale market

Profit ($m)



EBITDAF ($m)



1. Renewables down 119 GWh mainly due to a decrease in geothermal generation due to outages (impact calculated at thermal SRMC)
2. An 11% reduction in sales volumes outweighed the cost benefit of reduced generation volumes yoy
3. Higher C&I re-pricing and lower location losses partially offset by lower spot and CFD prices
4. Driven by higher unit price of carbon and decrease in thermal efficiency due to a higher proportion of Te Rapa and Peaker generation
5. 5% increase in long-term channel (retail, strategic fixed price) prices, aligning to rising wholesale market costs
6. Other income is up due to the gain on sale from Te Rapa, an increase in gas gross margin and other
7. Fixed costs higher with increase in other operating costs (-$23m) and higher electricity transmission costs (-$4m) from the removal of ACOT

[1] Contact has made reclassifications to better align with IFRIC guidance on IFRS 9 resulting in realised gains/losses from market derivatives not in a hedge relationship (includes market making activity) no longer being reported in operating income (EBITDAF). FY22 figures restated accordingly.

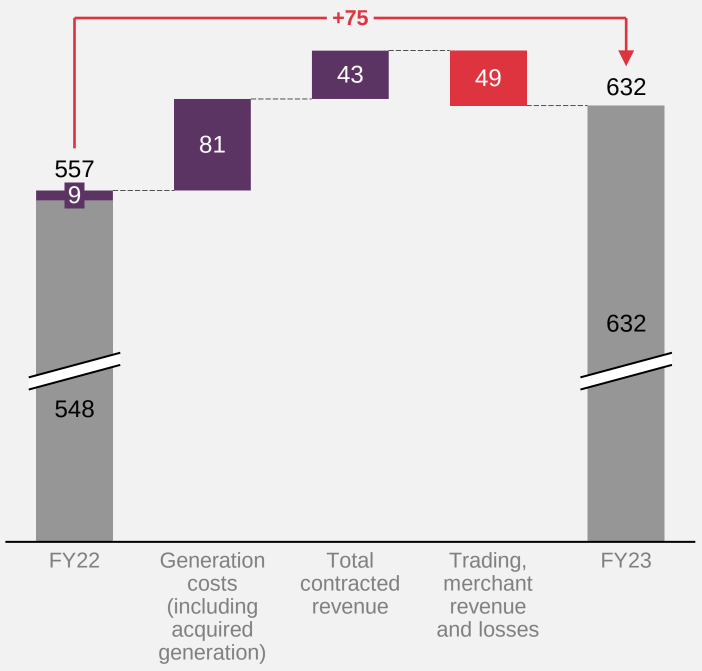
[2] Market channel pricing includes Includes reduced $/MWh location losses resulting from soft spot wholesale pricing

All figures are exclusive of the impacts of the onerous contract provision for AGS. Impacts of the onerous contract are as follows, EBITDAF (-$113m), interest (-$3m), tax (+$32m), NOPAT (-$84m).

EBITDAF (underlying) up by $27m

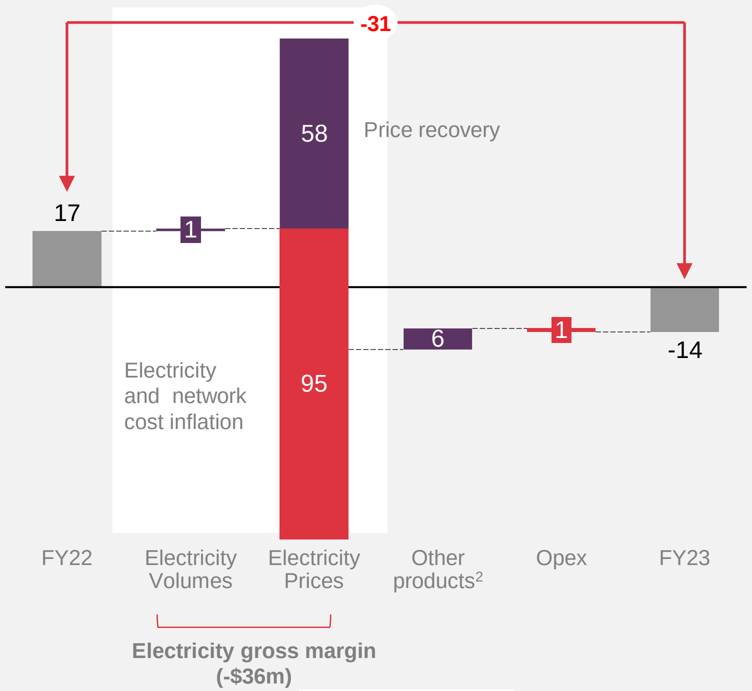
Business performance by segment

Wholesale EBITDAF[1] (underlying, $m)



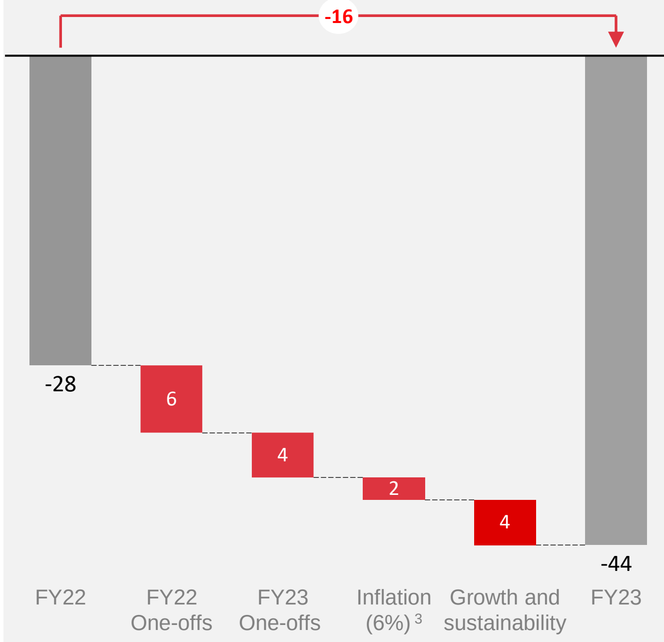
Refer to slides 17 - 19

Retail EBITDAF ($m)



Refer to slide 20

Corporate / unallocated costs ($m)



[1]Simply and Western included within Wholesale EBITDAF.
Underlying EBITDAF is shown excluding a net $113 million onerous contract provision expense for AGS. Contact has made reclassifications to better align with IFRIC guidance on IFRS 9 resulting in realised gains/losses from market derivatives not in a hedge relationship (includes market making activity) no longer being reported in operating income (EBITDAF). FY22 figures restated accordingly.

[2]Other products includes retail gas and broadband gross margins and gains on sale of legacy meter assets

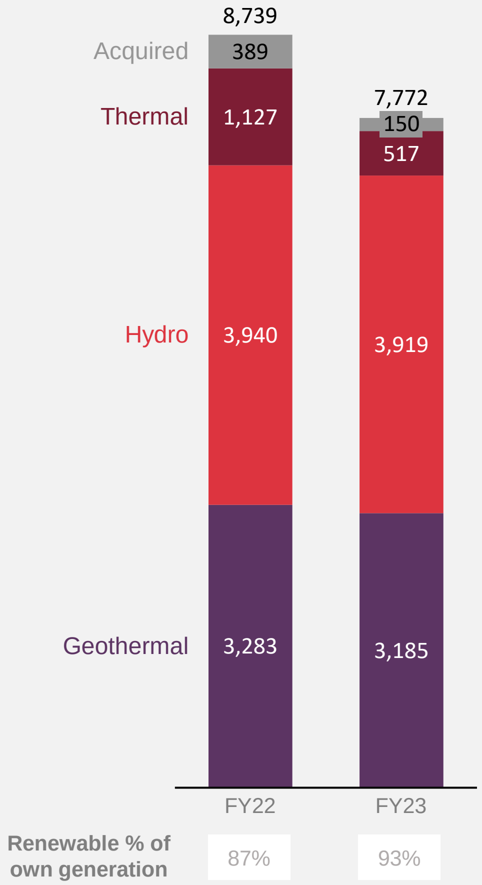
One-off movements from FY22 include the Holidays Act provision reversal and SaaS asset write off (together totaling $6m). FY23 included execution programme setup costs and industry report ($4m).

[3]Stats NZ CPI increase in the 12 months to June 2023.

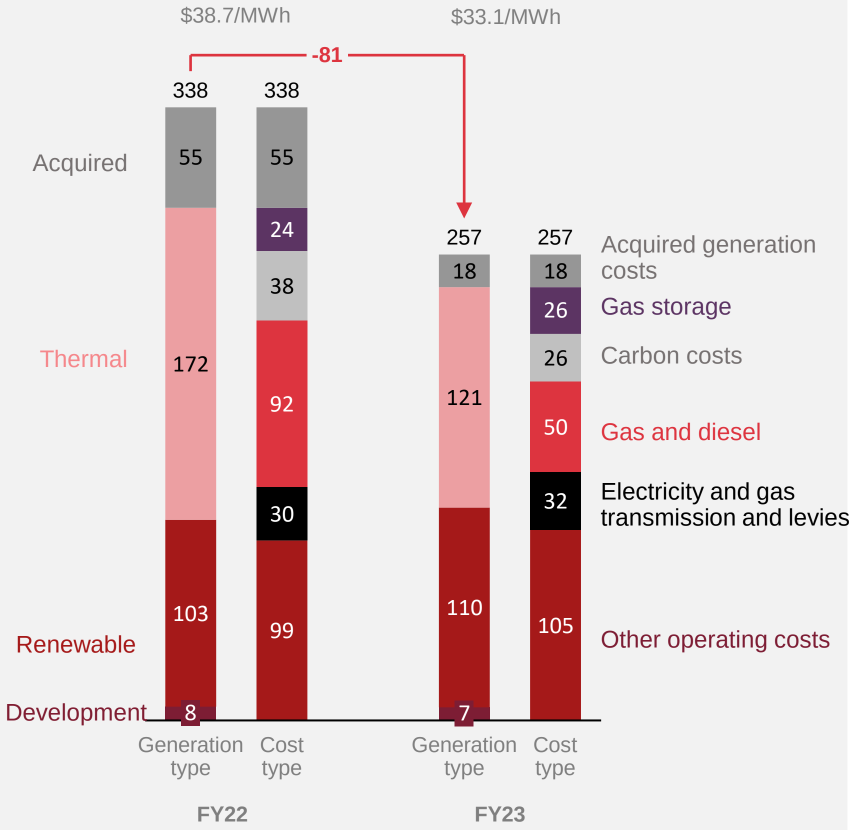
Generation costs

Costs down $81m on reduced thermal and acquired generation volumes

Electricity generated or acquired (GWh)



Electricity generated or acquired costs ($m)



Generation volumes

- Hydro generation of 3,919GWh was down 21GWh (1%) on FY22 and came in slightly above mean (3,900GWh) following a strong hydro sequence in the final quarter.
- Geothermal volumes were down 98GWh on FY22 (3%), 65GWh below mean (3,250GWh), as a result of the 5 yearly Wairākei plant outage and an unplanned outage at Te Huka.
- Significant country-wide rainfall sequence resulted in the wettest year on record in the North Island and the wettest year in New Zealand post-market. Thermal generation of 517GWh was down 54% (610GWh) on FY22 and was Contact's lowest thermal generation on record.

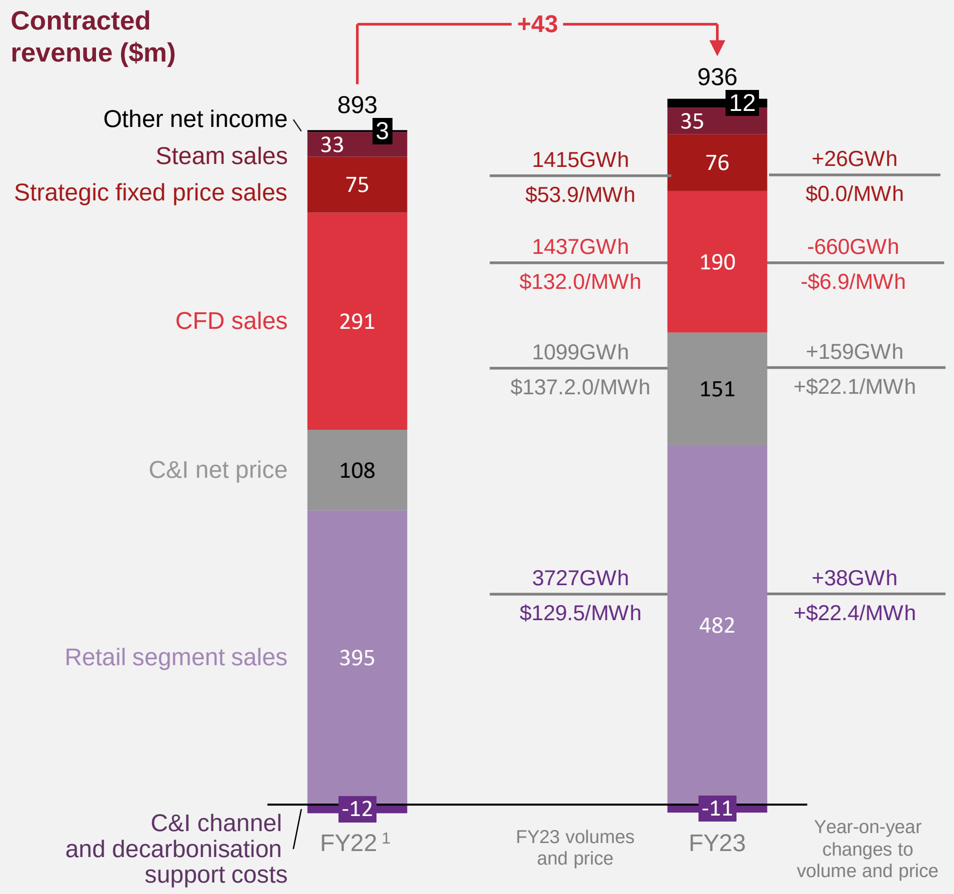
Costs

- Renewable generation costs were up $7m (6%) on FY22 due to the removal of ACOT payment for Te Huka, higher unit carbon costs on geothermal and inflationary pressures pushing up operating costs.
- Thermal generation costs, excluding the onerous contract provision expense for AGS ($113m) were down $51m (29%) on significantly reduced thermal volumes.
- Thermal fuel costs rose to $127/MWh (FY22: $109/MWh). With thermal efficiency decreased due to a higher proportion of Te Rapa and Peaker generation (FY22: 9.7 TJ/MWh, FY23: 11.8 TJ/MWh) and higher unit price of carbon (FY22 $40/unit, FY23 $48/unit), slightly offset by lower gas costs (FY22: $8.3/GJ, FY23: $7.9/GJ).

*Gas storage costs exclude the FY23 $113m onerous contract provision expense for AGS.

Wholesale contracted revenue

Diversified mix of long-term and ASX linked sales channels

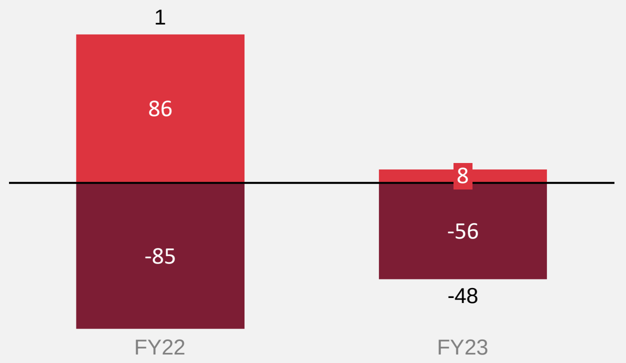


- Fixed price variable volume electricity sales to the Retail segment and C&I customers ended 198 GWh higher than FY22 (+$22m). Prices were up $22.50/MWh to $132.50/MWh (+$109m), reflecting higher wholesale prices over the three preceding years.
- Strategic fixed price sales were 26GWh higher than FY22 (+$1m), reflecting more volume under the NZAS support contract. Prices to strategic fixed priced sales remained in line with prior period ($0m) as inflationary adjustments to long-term sales were not enough to offset the mix change from proportionally higher NZAS volume.
- CFD sales volumes were down by 660GWh (-$92m) on lower renewable generation, lower wholesale prices and reduced thermal sales from thermal generation. Prices were down by $7/MWh reflecting hydro inflows (-$10m).
- Operating costs to support commercial and industrial customers were lower (+$1m) as Simply acquisition synergies were captured.
- Steam sales up on higher carbon price (+$2m).
- Other income was higher (+$9m) mainly due to a gain on sale of Te Rapa of $7m.

[1] Contact has made reclassifications to better align with IFRIC guidance on IFRS 9 resulting in realised gains/losses from market derivatives not in a hedge relationship (includes market making activity) no longer being reported in operating income (EBITDAF). FY22 figures restated accordingly.

Wholesale trading and merchant revenue

Trading EBITDAF ($m)

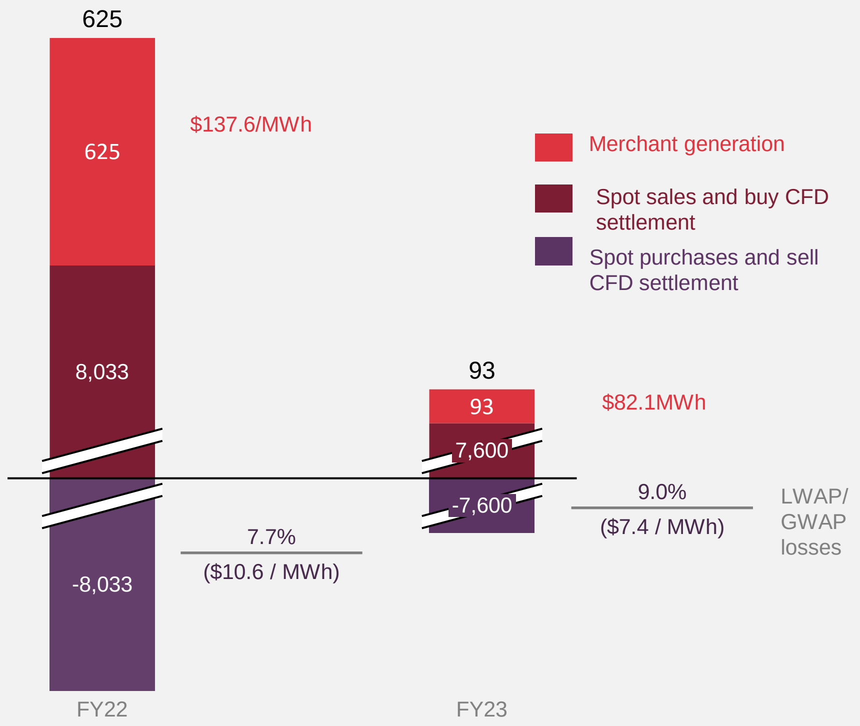


Trading revenue

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)



- Wholesale market conditions (average OTA price of $86.71/ MWh[1]) did not support additional CFD sales nor length that was thermal generation backed.
- Contact ran significantly short through Q4 FY23 to take advantage of soft spot wholesale market conditions, saving fuel costs.

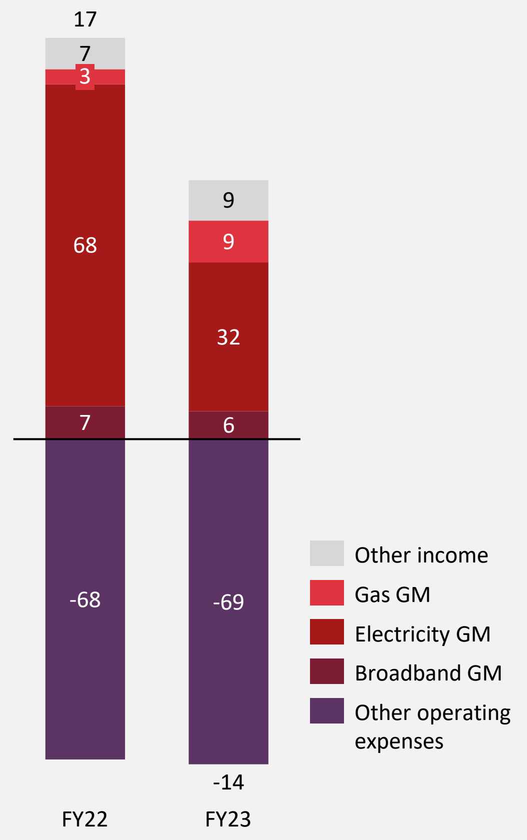
[1] Source: EMI

Retail business performance

Managing through elevated wholesale input costs while growing market share through a multi-product strategy

Revenue & Tariff[1] ($m)	FY22	FY23		Variance	
	$m	$m	*Tariff[1]*	$m	*Tariff*
Electricity gross revenue	872	942	*270*	69	17
PPD[2] not taken	3	3		(0)	
Incentives paid	(5)	(4)		0	
Net revenue (cash)	**871**	**940**	***270***	**70**	**17**
Capitalised incentives	5	1			
Amortised incentives	(6)	(5)			
Net revenue (P&L)	**869**	**937**	***269***	**68**	**17**
Gas revenue	82	90	*35*	8	6
Broadband revenue	53	66	*70*	14	(1)
Other income	7	9		2	
Total revenue	**1,011**	**1,102**		**91**	
Contract Asset (closing)	7	4		(3)	
# of connections (closing)[3]	574k	584k		10k	
Cost to serve/connection	$123	$120		($3)	

EBITDAF ($m)



Retail margins have contracted, driven by sustained high wholesale futures prices.

- Retail EBITDAF decreased by $31m on FY22 largely driven by the $83m increase in electricity costs that were not fully passed through to customers.

The Retail business has continued to insulate customers from rising input costs by keeping the average tariff increase largely in line with consumer price inflation.

- The average Retail tariff increased by 6.7% reflecting targeted retail price rises to partially offset rising wholesale and network cost increases.
- Around 83% of customers received a price increase in the last 12 months.
- Retail energy tariffs will need to rise to recover the continued firming future wholesale prices and significant network cost increases due to the 1 April 2025 price regulation reset.

Connection growth slowed in FY23 given increased focus on multiproduct connections and value in electricity.

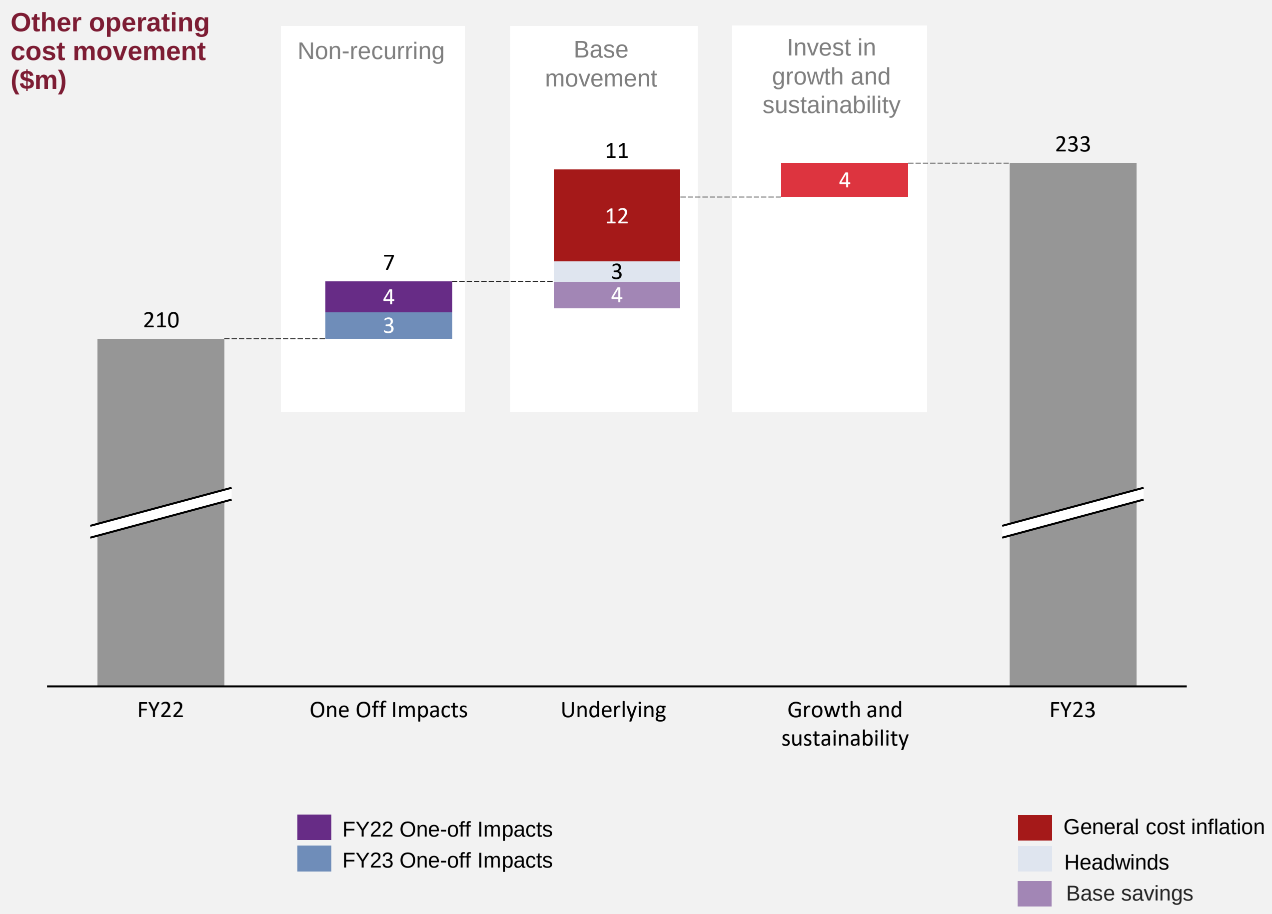
- Total connections still +10k on FY22 primarily through continued growth in broadband.
- Multiproduct customers up 10% on FY22, assisted by new fixed wireless broadband and Dream Charge EV products launched.

Cost to serve – digitised interactions continue to grow driving improvements in cost to serve per connection (down $3/connection on FY22) and customer experience (NPS +4 points on FY22).

[1] Tariff is $/MWh for electricity, $/GJ for gas and $ per month per customer connection for broadband
[2] Prompt Payment Discount
[3] Retail connections only, excludes Simply Energy

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

Operating costs up on investments in growth strategy and cost pressures



Non-recurring

- FY22 one-off impacts relate to the release of Holidays Act credit and early-stage development costs which have shifted into the capitalisation phase of the projects in FY23.
- FY23 one-off impacts represent strategic execution set up costs, Contact's share of BCG industry report, cost of retaining Te Rapa employees until plant closure and cyclone recovery costs incurred at Whirinaki and Geothermal sites. This has been offset by cost deferrals linked to reprioritisation of activity.

Base movement

- General inflation of 5-9% impacting operating costs. These have been seen across the business, including labour cost and insurance inflation.
- Headwinds include increase in travel expenditure in a post-Covid environment.

Growth and sustainability

- $1m incremental investment related to retail connection growth.
- Operating costs to deliver on strategic growth priorities including;
  - Ongoing costs of transformation.
  - ESG and compliance opex investments to increase capability, furthering ESG outcomes.
- Targeted leadership development training, and costs associated with "Grow your Whanau" policy implementation.

Cash flow and capital expenditure

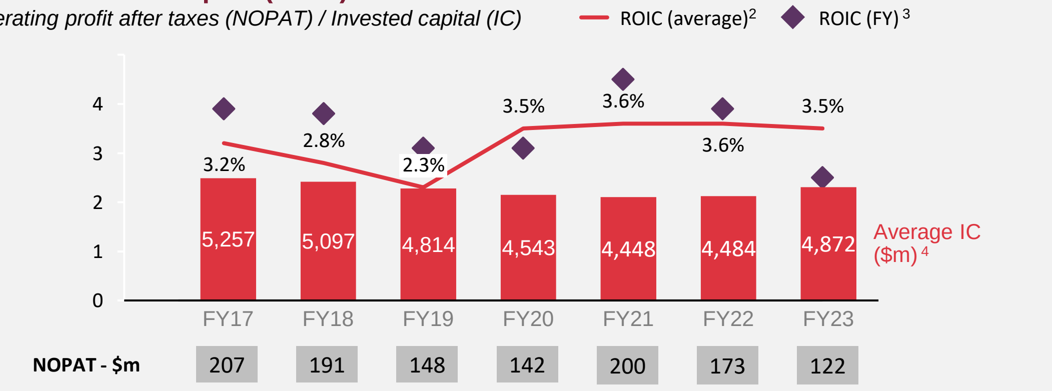
Cash conversion for FY23 impacted by higher tax paid, SIB capex and an increase in gas and carbon unit inventory

	12 months ended 30 June 2023	12 months ended 30 June 2022	Comparison against FY22	
EBITDAF (underlying[1])	**$573m**	$546m[1]	↑	$27m
Working capital changes	**($55m)**	($17m)	↓	($38m)
Tax paid	**($105m)**	($89m)	↓	($16m)
Interest paid, net of interest capitalised	**($25m)**	($28m)	↑	$3m
SIB capital expenditure	**($113m)**	($79m)	↓	($34m)
Non-cash items included in EBITDAF	**$7m**	($3m)	↑	$10m
Operating free cash flow	**$282m**	$330m[1]	↓	($48m)
Operating free cash flow per share	**36.0 c**	42.4 c[1]	↓	(6.4 c)
Cash conversion (OpFCF / EBITDAF)	**49%**	61%	↓	(12%)

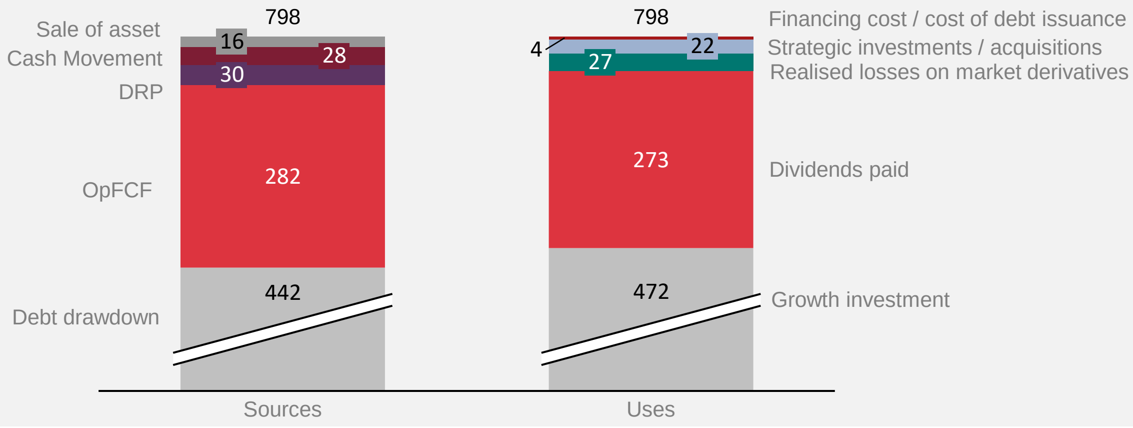
- Higher underlying EBITDAF on execution of long-term channel prices increases.
- Working capital increase of $38m in FY23. This relates to higher levels of gas and carbon unit inventory following lower thermal generation in FY23 as a result of strong national hydrology.
- Tax paid is up $16m on higher provisional tax payments based on strong FY21 earnings.
- Stay-in-business capital expenditure (cash) increase of $34m is linked to accelerated spending identified to support higher asset availability and output as well as an SAP systems upgrade project. Accelerated SIB capex programme spend in the period totalled $38m.

Return on invested capital (ROIC)

Net operating profit after taxes (NOPAT) / Invested capital (IC)



Sources and uses of cash ($m)



[1] Contact has made reclassifications to better align with IFRIC guidance on IFRS 9 resulting in realised gains/losses from market derivatives not in a hedge relationship (includes market making activity) no longer being reported in operating income (EBITDAF). FY22 figures restated accordingly.

[2] NOPAT (4-year average) /Average IC (4-year average)
[3] NOPAT (FY)/Average IC (FY)
[4] Net working capital adjusted to remove current borrowings, current net derivatives and excess cash above $50m. Long-term assets adjusted to remove non-current derivatives. Average = Invested capital (opening + closing balance) / 2

Growth capital expenditure

Step-up in growth capital expenditure in FY23 reflects the advancing nature of Contact's renewable development projects

Growth capital expenditure ($m)

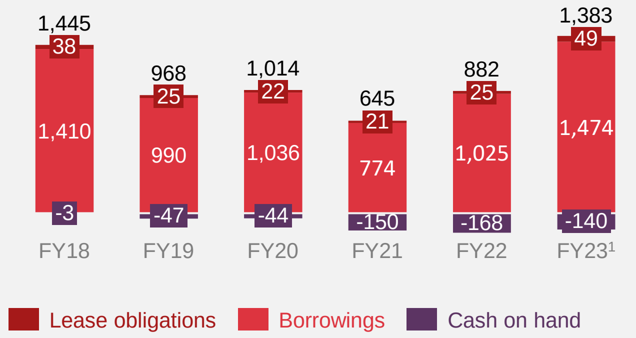
	Up to 30 June 2022	12 months ended 30 June 2023	Remaining under current approvals	Total
Tauhara	$408m	$340m	$132m	$880m
Te Huka 3	$28m	$88m	$184m	$300m
GeoFuture	-	$12m	$102m	$114m
Wind	-	$5m	$5m	$10m
Capitalised interest	$55m	$44m	$60m	$159m
Total	**$491m**	**$490m**	**$483**	**$1,463m**

- The Tauhara geothermal project is due for completion in Q4 2023, with the remaining growth capex all scheduled to be incurred in FY24.
- The construction of Te Huka 3 is well underway and is due to be completed in Q4 2024. The remaining growth capex will fall across FY24 and FY25.
- Remaining spend on GeoFuture and Wind projects reflects current pre-FID approval levels and will be updated after final board investment decisions, as applicable.
- For major growth projects we capitalise interest from the time of Final Investment Decision (FID) or significant pre-FID works through to commissioning on a rate that reflects the average portfolio interest rate.

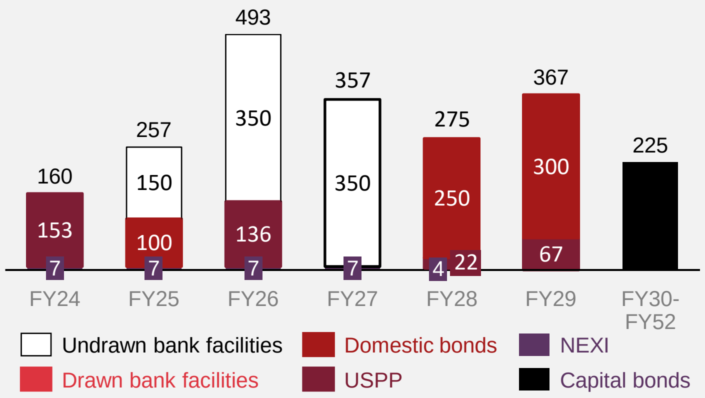
Strong balance sheet

A green and sustainably-linked debt portfolio aligned to our Contact26 strategy

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

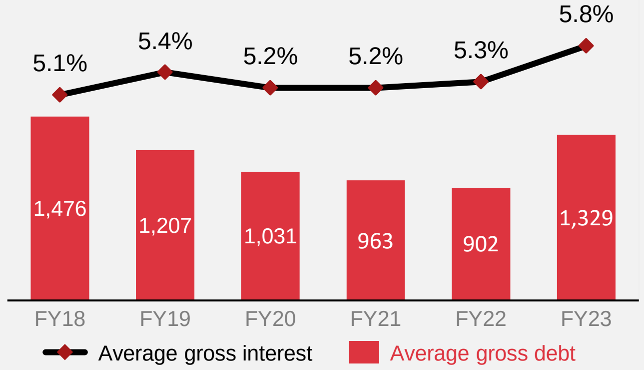


Borrowing maturities ($m)
Average tenor of 5.9 years as at 30 June 2023

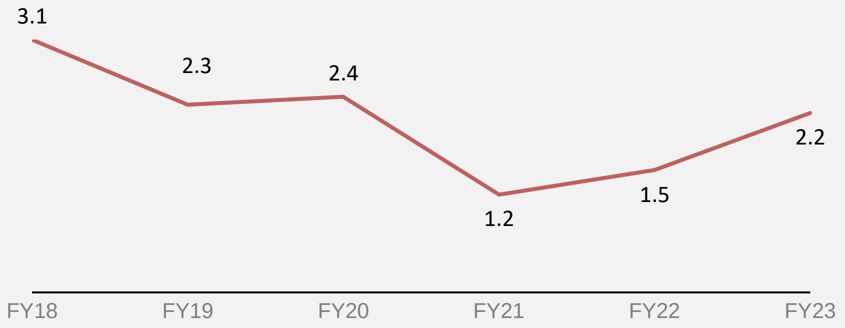


- Face value of borrowings (excl. leases) increased by $449m to $1,474m from 30 June 2022.
- Two green bonds were issued during the year, partly to refinance a maturing $100m retail bond in November with the remainder to fund the ongoing construction of the Te Huka and Tauhara geothermal stations.
- All facilities are classified green under Contact's sustainable finance framework, and the bank facilities are sustainably linked with alignment to the Contact26 strategy to lead decarbonisation in New Zealand.
- Contact's planning aligns with maintaining its investment grade credit rating. This requires net debt to EBITDAF to remain below 3.0x over a sustained period. Of note, S&P calculates EBITDAF on a smoothed basis, with a recent re-weighting toward future periods reflecting Contact's current growth profile.
- Point estimate net debt to EBITDAF is currently 2.2x and Contact's EBITDAF outlook, DRP and capacity for additional hybrid bonds provide the ability to mange this metric effectively.

Interest rate (%)
Weighted average gross interest[2] on average borrowings



Net debt to EBITDAF (x)
Includes S&P adjustments (prior to FY20, AGS was treated as a lease)[3]

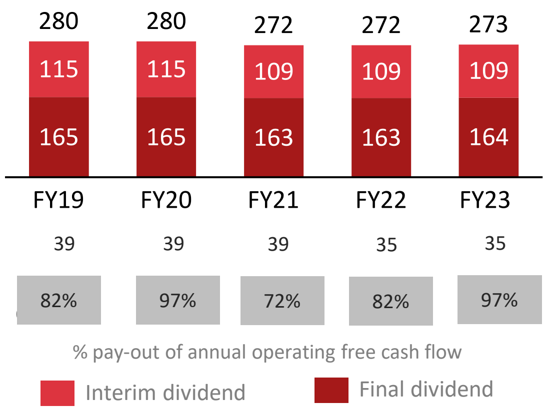


[1] Includes $51m of collateral held on deposit for margin calls associated with the trading of electricity price derivatives on the ASX.
[2] Gross interest includes all interest on borrowings, bank commitment fees and deferred financing costs. Unwind of leases, provisions and capitalised interest not included.
[3] Illustrated here on a point basis based on the last 12 months.

Dividend for FY23 in line with performance

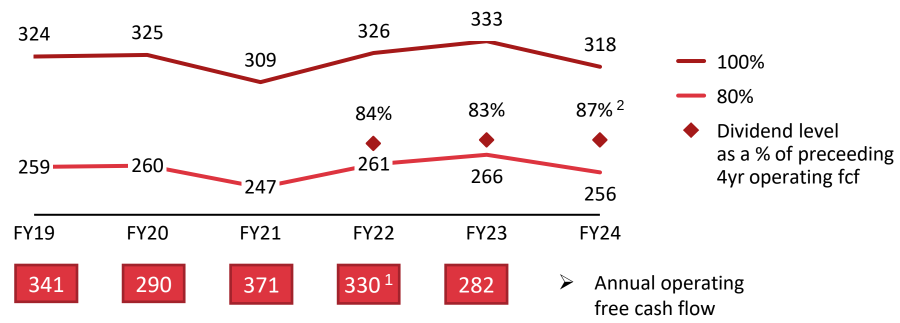
Ordinary dividends ($m)

Declared



Operating free cash flow

Average operating cash flow for the preceding four financial years



Dividend policy range: 80-100% of average operating free cash flow for the preceding four years

Dividend for FY23 of 35 cents per share

- Final dividend of 21 cents per share is imputed up to 86% or 18 cents per share for qualifying shareholders. This represents a pay-out of 97% of FY23 operating free cash flow per share and 83% of the average operating free cash flow over the preceding 4 financial years (FY19-FY22)
- The dividend policy is to pay-out between 80-100% of average operating free cash flow of the preceding four years.
- Record date of 8 September 2023; payment date of 26 September 2023.
- The NZD/AUD exchange rate used for the payment of Australian dollar dividends will be set on 15 September 2023.

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.
- There will be no discount offered for the FY23 final dividend and Contact will have the right to terminate or suspend the plan at any time.
- Dividend reinvestment plan application forms must be in by 11 September 2023 to confirm participation in the plan.
- Trading period for setting price for DRP is 7 September 2023 to 13 September 2023. DRP strike price will be announced: 15 September 2023.

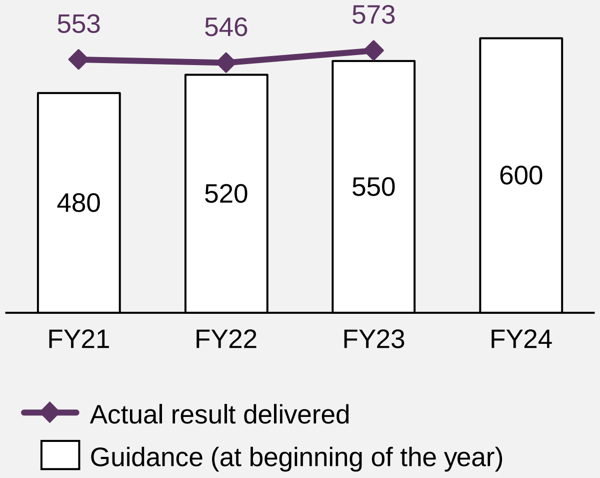
[1] Contact has made reclassifications to better align with IFRIC guidance on IFRS 9 resulting in realised gains/losses from market derivatives not in a hedge relationship (includes market making activity) no longer being reported in operating income (EBITDAF). FY22 figures restated accordingly.
[2] This calculation is based on the minimum target ordinary dividend of 35 cps. Guidance will be confirmed no later than the 1H24 results, given potential for long term Tiwai supply agreement to be reached.

Uplifts in Contact’s normalised and expected EBITDAF have been driven by pricing and channel management

FY24 guidance does not include EBITDAF from Tauhara online

Guidance vs Actual

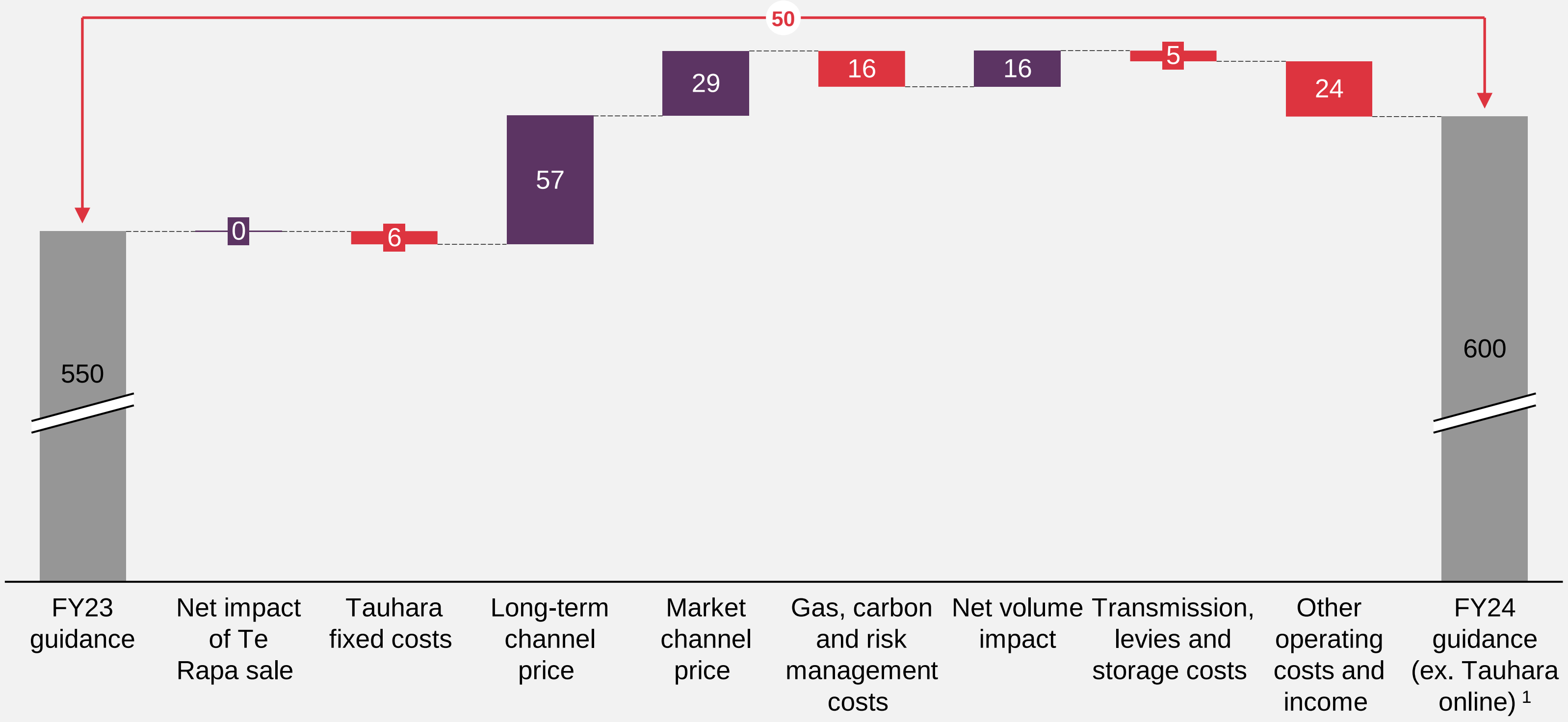
Guidance CAGR FY21 to FY24 (8% p.a.)



Strong track record of delivering performance above guidance

Normalised and expected EBITDAF ($ million) – excluding Tauhara online

Like-for-like increase of $50m (9%) in year-on-year guidance



[1] See slide 34 of for assumptions underpinning FY24 normalised and expected earnings

[2] Contact has made reclassifications to better align with IFRIC guidance on IFRS 9 resulting in realised gains/losses from market derivatives not in a hedge relationship (includes market making activity) no longer being reported in operating income (EBITDAF). FY22 figures restated accordingly.

Guidance below EBITDAF

	FY23 guidance	FY23 result	FY24 guidance	Commentary
Stay in Business Capex	**$110m-120m**	**$113m**	**$115m - $125m[1]**	
Stay in business accelerated programme (cash)		$38m	$55m - $60m	As at end of FY23 we had spent $65m out of the $150m accelerated stay in business capex programme[2].
Stay in business capital expenditure (cash) BAU		$79m	$60m - $65m	Sustainable SIB capex remains $65m p.a.
Growth capital expenditure (cash)[3]	$465m-$565m	$472m	$400m - $500m	Growth capital for Tauhara, Te Huka, GeoFuture and Wind.
Depreciation and amortisation	$220m-230m	$224m	$230m - $240m	Reflects higher mix of short life-cycle assets.
Net interest (accounting)	$35m-45m	$41m	$65m - $75m	Reduction in capitalisation of interest with Tauhara commissioning. Higher interest rate environment and increased borrowings.
Cash interest (in operating cash flow)	$20m-30m	$25m	$47m - $57m	
Cash taxation	$110m-120m	$105m	$95m – $105m	FY24 provisional payments based on FY22 results and lower final tax payment relating to FY23.
Realised (gains) / losses on financial instruments (cash)	$0m	$27m	$10m - $15m	Including (gains) / losses on ASX market making.
Corporate costs	$42m	$44m	$48m	Inflation and growth.
Target ordinary dividend per share	35 cps	35 cps	Minimum 35 cps	Guidance will be confirmed no later than the 1H24 results, given potential for long term Tiwai supply agreement to be reached.

[1] FY24 guidance range is gross i.e. before the netting of insurance proceeds of $15m.
[2] Accelerated stay in business programme total is stated net of insurance proceeds of $15m. The capex and insurance income will be separately disclosed in the financial statements.
[3] Growth capital expenditure includes capitalised interest.

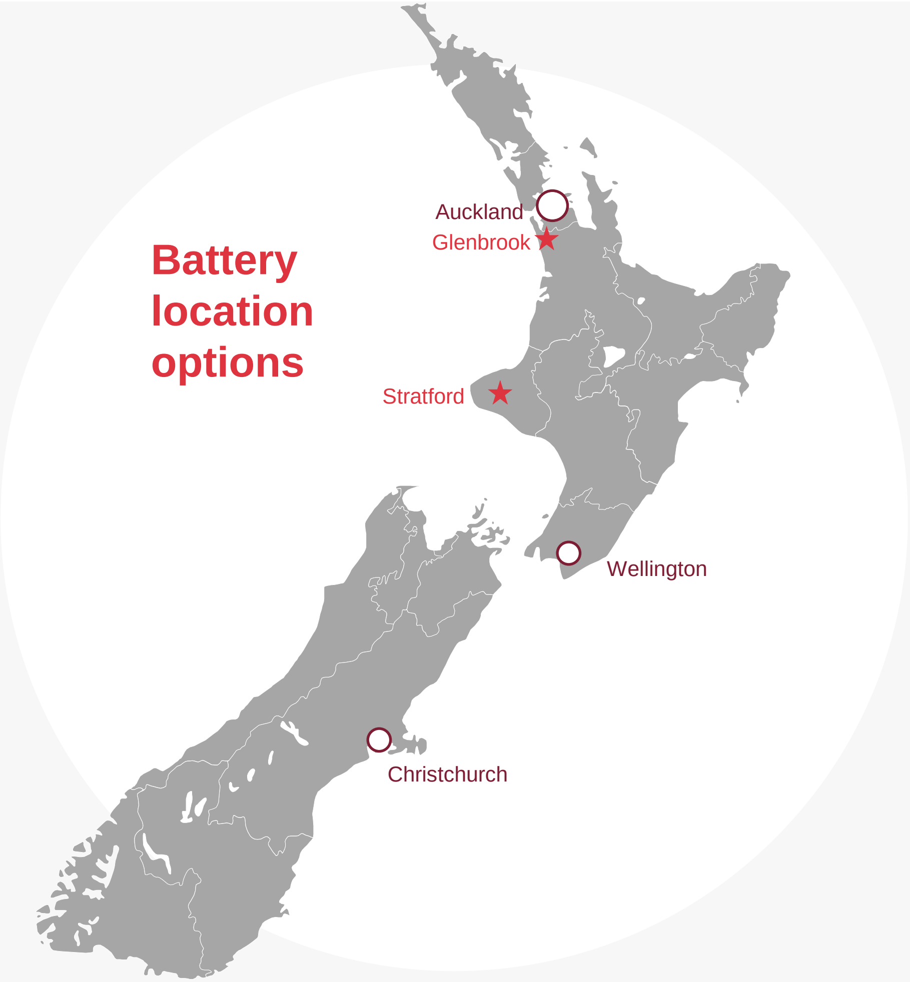
Progress on Strategy

Grid-scale battery investment lined up

Contact is planning to invest in renewable energy flexibility in the North Island

Battery investment key metrics[1]

Battery capacity	100MW
Storage duration / discharge	2 hr / ~200MWh
Total estimated construction costs	~$170m to $190m
Final Investment Decision	1H FY24

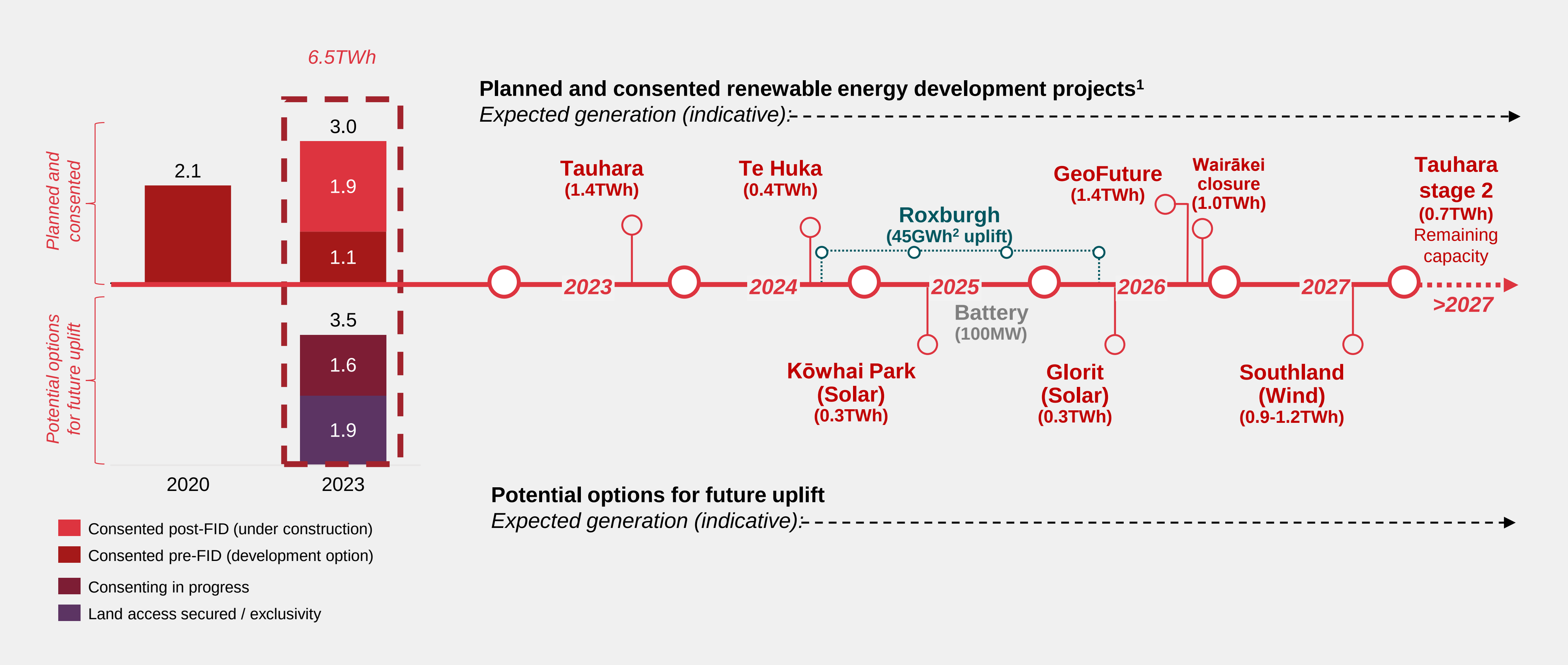


- Participation across physical, reserve and frequency-keeping markets.
- Supports both retail growth and offering capacity contracts to third parties.
- North Island location, close to retail load, reducing North/South Island price separation.
- Reduced reliance on gas peakers.
- Glenbrook site preferred (subject to consent). Stratford option already consented.
- Supports new wind and solar.

[1] All subject to Final Investment Decisions

Market leading renewable development pipeline

Contact has built a renewable electricity development pipeline of >6TWh, and is targeting 10.3TWh of renewable generation output online by end of FY27



Note: Timeline is shown based on calendar years.
[1] All uncommitted investment / closures are subject to Board investment decisions. The Tauhara, Te Huka and Roxburgh investments have been committed to.
[2] 45GWh p.a. uplift is based on mean hydrology conditions.

Our operational plan

What you can expect in the next 12 months

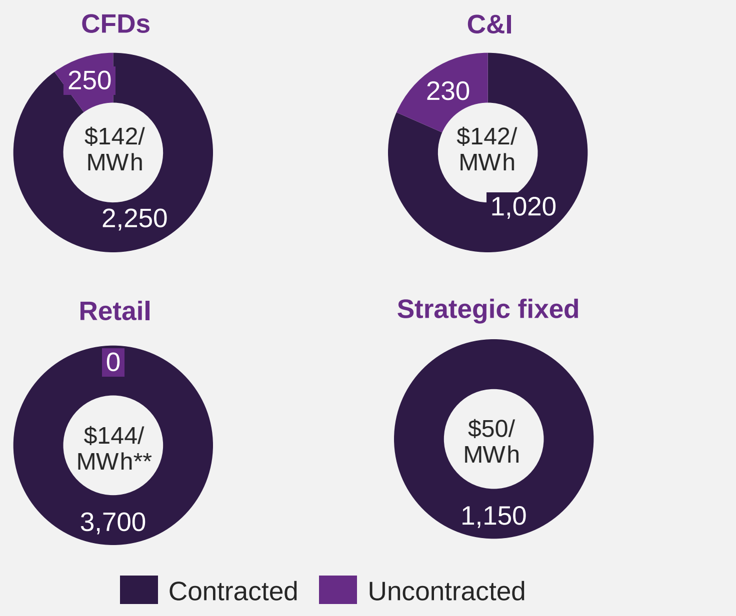
Strategic theme	FY24	
Grow Demand	Conclude NZAS extension negotiations with improved long-term pricing. FID for one Green Chemical deal.	Facilitate at least 25MW of new demand.
Grow renewable development	Achieve FID for GeoFuture and Kōwhai Park solar. On track FID for North Island solar. On track FID for wind.	Tauhara operational Q4 2023. Final Investment Decision on BESS (battery).
Decarbonise our portfolio	Net zero roadmaps agreed (Scope 1 and 2). Investment plans for further carbon offsets.	Final Investment Decision on BESS (battery). Sustained entry into the DJSI.
Create outstanding customer experiences	Electricity net price up by around 5%. Greater than 615k connections. Maintain leading cost to serve position.	Significantly grow non-energy gross margin. Further expansion of "It's good to be home" brand position. Pilot launch of Contact Mobile.

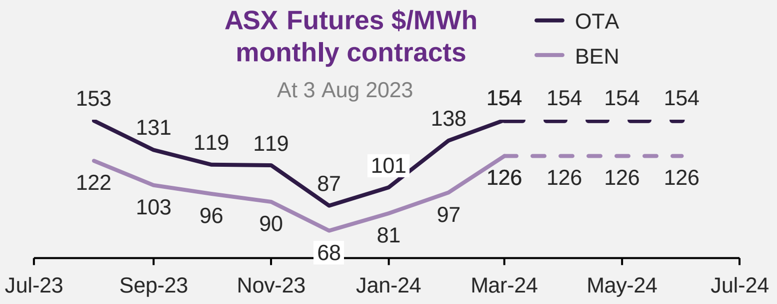
Questions

Supporting materials

Normalised and expected FY24 EBITDAF

Guidance to be updated for Tauhara once online



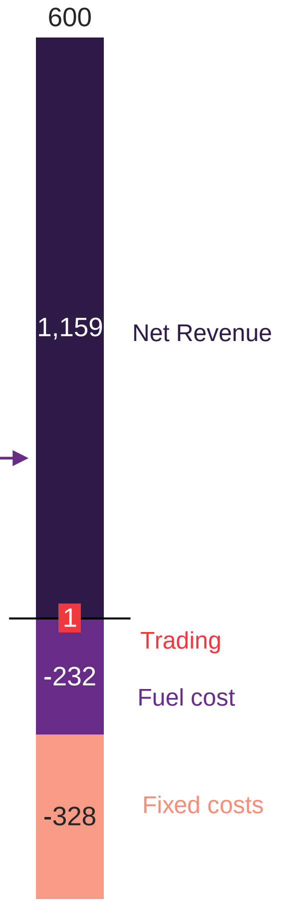


FY assumptions that deliver expected & normalised EBITDAF for FY24 (excluding Tauhara online)

1 Channel choices maximise long term value[1]		X	2 Net price[2] driven by best commercial practices	=	Total
Strategic fixed price	1,150GWh	x	$50/MWh	=	$58m
CFDs	2,500GWh	x	$140/MWh	=	$350m
C&I	1,250GWh	x	$145/MWh	=	$181m
Retail	3,700GWh	x	$144/MWh		$533m
Other income[3]					$38m
					$1,159m

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	3,250GWh	x	$5/MWh	=	-$16m
Maximum thermal	1,800GWh	x	$120/MWh[4]	=	-$216m
Acquired	0GWh	x	$0/MWh		-$0m
					-$232m

5 Trading delivers value to more than offset locational losses		6 Digitalisation & continuous improvement optimise fixed costs	
Length[5]	$53m	Transmission/Storage	-$70m
Location losses[6]	-$52m	Operating expenses	-$257m
Total	**$1m**	**Total**	**-$328m**



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 $9.50/GJ, carbon price of $70/unit and thermal portfolio heat rate (9.5GJ/MWh)
5. Length of 350GWh p.a. assumed
6. Locational losses of 4.3% on spot purchases and settlement of CFDs sold at a wholesale price of $139/MWh

- Fuel is natural gas and carbon costs
- Retail volume contracted competitive risk remains on pricing achieved (FY23 $138.1/MWh)
- Note, these figures are subject to rounding.
- Dependent on volumes from Tauhara, guidance to be updated when Tauhara comes online.

Normalised and expected EBITDAF assumptions

With reconciliation to actual performance

FY23 assumptions that deliver expected & normalised EBITDAF of $550m 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	1,450GWh	x	$54/MWh	=	$78m
CFDs	1,600GWh	x	$135/MWh	=	$216m
C&I	1,200GWh	x	$140/MWh	=	$168m
Retail	3,700GWh	x	$132/MWh		$488m
Other income[3]					$70m
					$1,021m

3 Hydrology & Asset availability optimise generation		X	4 Access to and price of fuel* drives financials & risk position	=	Total
Hydro	3,900GWh	x	$0/MWh	=	-$0m
Geothermal	3,250GWh	x	$3/MWh	=	-$10m
Thermal[4]	1,050GWh	x	$115/MWh	=	-$121m
Acquired	250GWh	x	$150/MWh	=	-$38m
					-$168m

5 Trading delivers value to more than offset locational losses		6 Digitalisation & continuous improvement optimise fixed costs	
Length[5]	$81m	Transmission/Storage	-$68m
Location losses[6]	-$80m	Operating expenses	-$235m
Total	**$1m**	**Total**	**-$304m**

EBITDAF guidance reconciliation to FY23

Normalised & Expected

Lower renewables
Renewable generation slightly below mean (-46GWh). Impact calculated at expected thermal SRMC

Increased long–term channel price
Price increases put through long-term channels have outperformed expectation

Lower market channel price
Strong hydrology softened market prices however this was largely offset by reduced $/MWh location losses

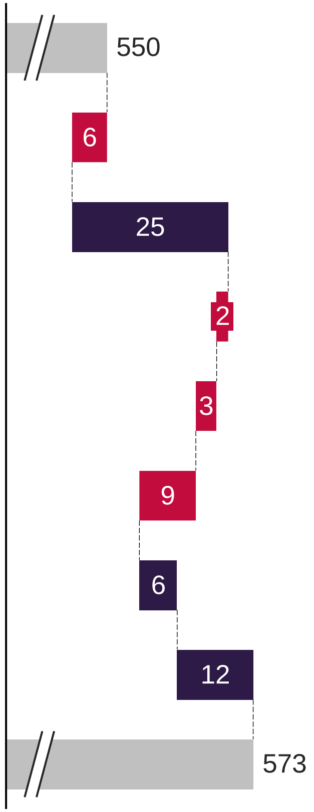
Gas, carbon, acquired generation price
Thermal efficiency 5% unfavourable with higher proportional Te Rapa generation, partially offset by lower acquired generation costs

Net volume impact
Generation volumes for the year were 8% below expectations

Other income
This includes a gain on the sale of Te Rapa

Fixed costs
Received 'loss and constraint excess' (LCE) rebates due to substantial price separation. Lower gas transmission charges

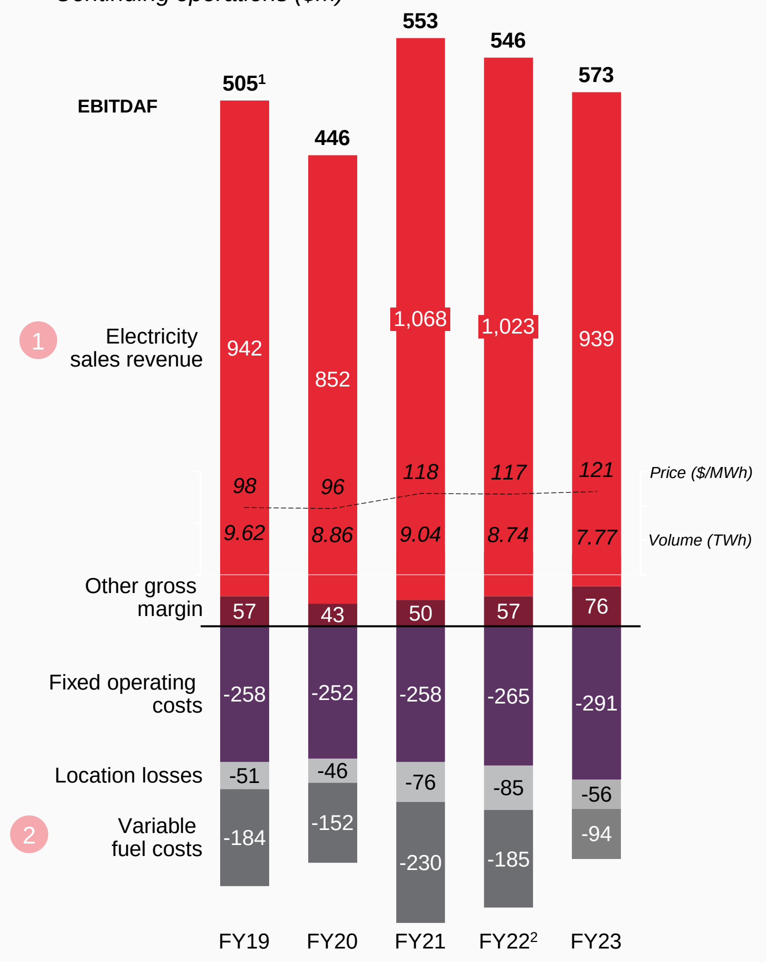
Actual



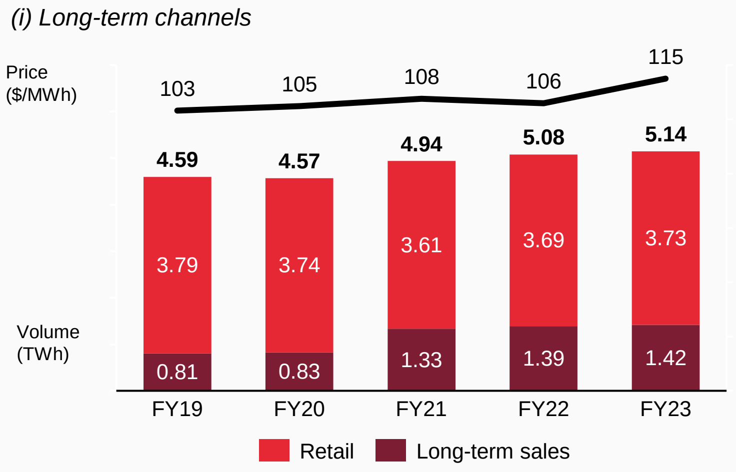
1. All volumes are at the Grid Exit Point (GXP)
2. Net price is equal to tariff less pass-through costs (network, meters and levies) /MWh
3. Steam sales, retail gas gross margin, broadband gross margin and other income
4. Gas price of $7.9/GJ, carbon price of $50/unit and thermal portfolio heat rate (11.2GJ/MWh)
5. Length of 500GWh for FY23 assumed
6. Locational losses of 6.7% on spot purchases and settlement of CFDs sold at a wholesale price of $150/MWh

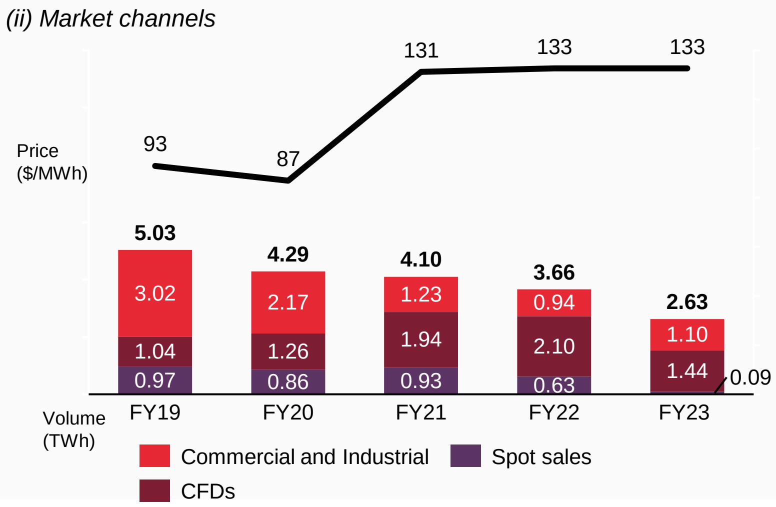
Integrated portfolio performance

Operating earnings (EBITDAF)

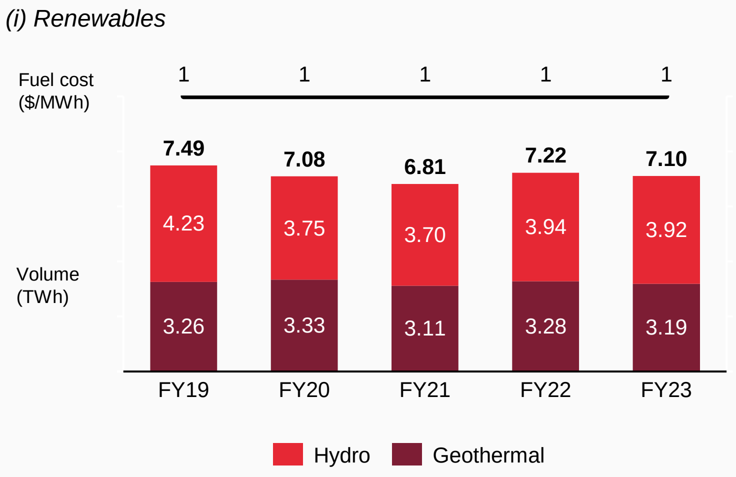


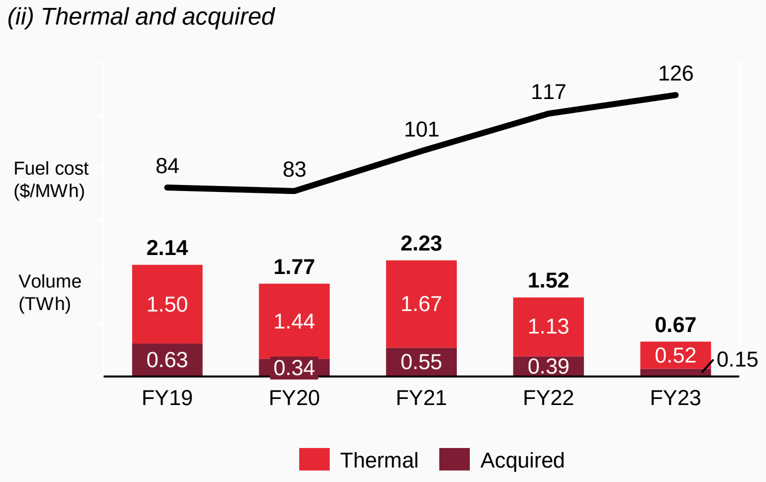
1 Electricity sales





2 Variable fuel costs





[1] Underlying EBITDAF excluding the impact of the sale of Rockgas (LPG business)

[2] Refer to slide 43 for a definition and reconciliation of EBITDAF. Contact has made reclassifications to better align with IFRIC guidance on IFRS 9 resulting in realised gains/losses from market derivatives not in a hedge relationship (includes market making activity) no longer being reported in operating income (EBITDAF). FY22 figures restated accordingly.

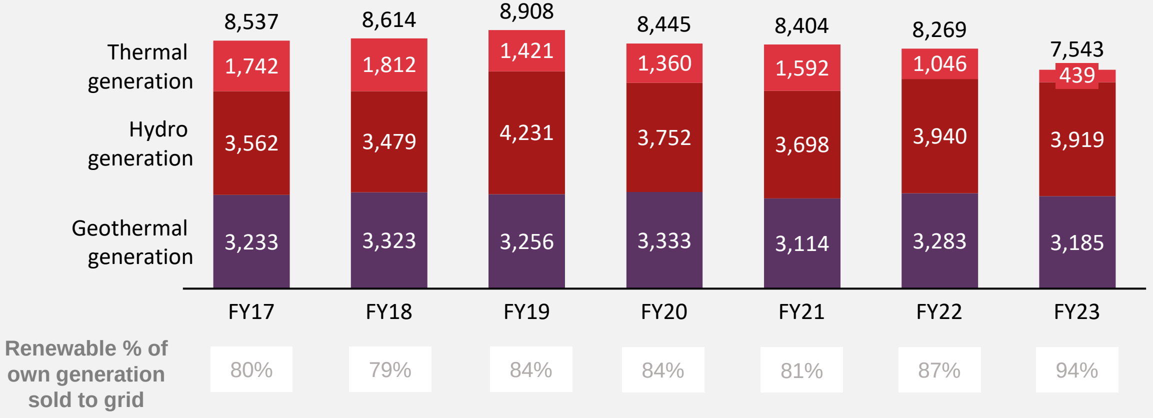
Greenhouse gas emissions

Indicator	Unit	Target	FY20	FY21	FY22	FY23
Direct GHG emissions (Scope 1)	**tC02e**	45% reduction of 2018 Scope 1 and 2 emissions by 2026 (Absolute emissions reduction target)	**920,403**	**1,044,744**	**786,842**	**526,621**
- Stationary combustion	tC02e		920,403	1,044,537	786,544	526,282
- Mobile combustion	tC02e		270	178	297	307
- Fugitive emissions	tC02e		4	29	1	32
Indirect GHG emissions (Scope 2)	tC02e		**1,258**	**1,303**	**1,399**	**1,957**
Sub-total Scope 1 and 2	**tC02e**	**647,443**	**921,935**	**1,046,047**	**788,241**	**528,579**
Indirect GHG emissions (Scope 3)	**tC02e**	**259,118**	**317,384**	**555,035**	**394,784**	**273,673**
- Category 1 – Purchased goods and services	tC02e	30% reduction of 2018 Scope 3 GHG emissions from use of sold products by 2026.	39,397	16,699	6,371	6,197
- Category 2 – Capital goods	tC02e		18,052	41,726	57,876	88,266
- Category 3 – Fuel and energy[1]	tC02e		91,857	330,207	149,743	1,050
- Category 4 - Upstream distribution and transportation	tC02e		14	27	444	108
- Category 5 – Waste	tC02e		123	149	108	47
- Category 6 – Business travel	tC02e		719	263	567	1,274
- Category 7 – Employee commuting	tC02e		606	306	832	965
- Category 11 – Use of sold products	tC02e		166,310	165,259	178,554	175,603
- Category 13 – Downstream leased assets	tC02e		306	399	289	164
- Category 14 – Franchise	tC02e					
Total Scope 1,2 and 3 emissions	**tC02e**	**906,561**	**1,239,319**	**1,601,082**	**1,183,025**	**802,252**

[1] Contacts swaption with Genesis Energy ended 31 December 2022 and was not called during FY23.

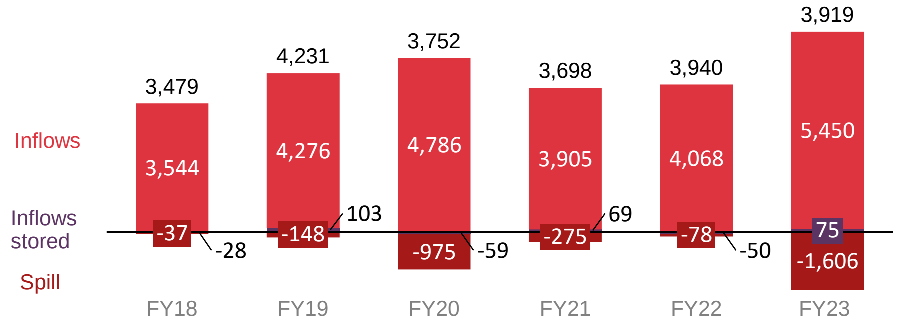
Generation and sales position

Contact generation output sold to the national grid (GWh)



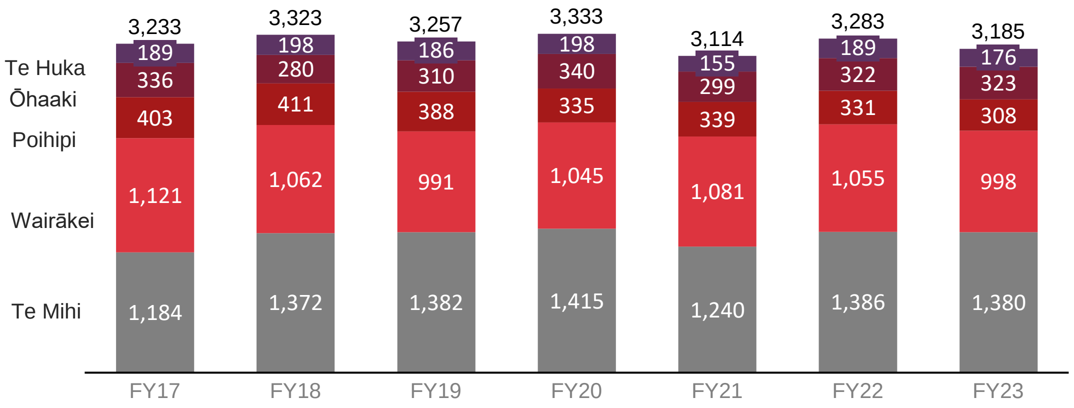
Hydro generation (GWh)

Inflows stored include uncontrolled storage lakes



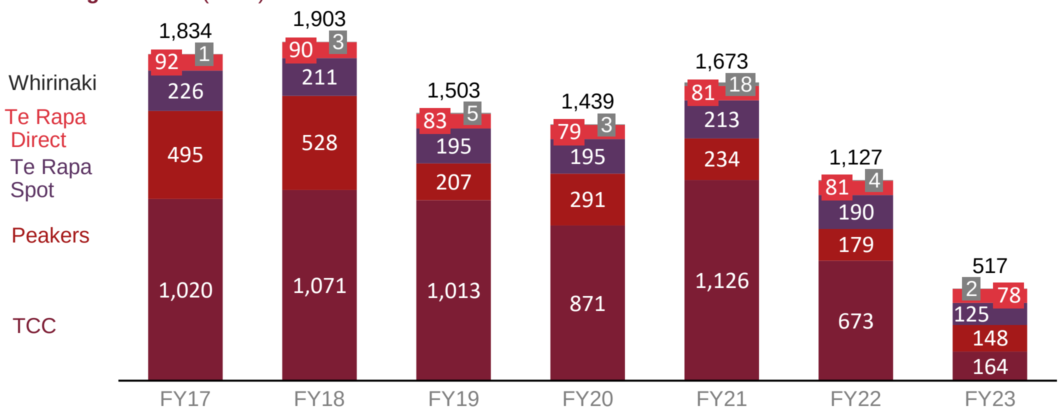
Spill in FY23 was a result of strong hydrology inflows in the first half coming in three main rain events coupled with some longer outages which effected our ability to generate

Geothermal generation (GWh)



FY23 geothermal generation was 98 GWh lower than FY22 as result of a Wairākei station statutory inspection (once every 5 years), a Te Huka outage and reduced Poihipi generation to manage fuelling restrictions.

Thermal generation (GWh)

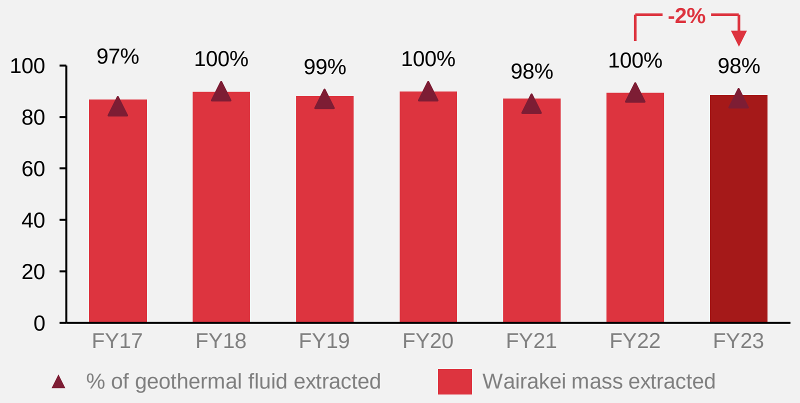


FY23 thermal generation volumes were 610GWh lower than FY22 as a result of the strong renewable generation and low wholesale prices. Thermal generation accounted for 4% of total revenue in FY23 (8% in FY22) calculated as thermal pool revenue + Te Rapa direct sales as % of total revenue.

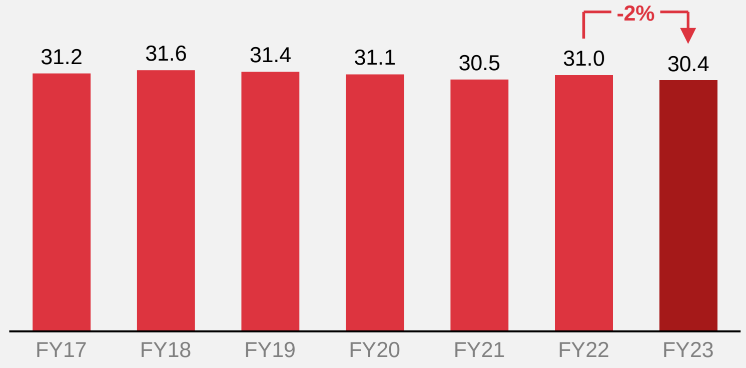
Plant and fuel performance

Geothermal fuel performance

Geothermal fuel extracted at Wairākei vs consented (GWh)



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



Plant availability

Hydro

	Net capacity (MW)	Availability (%)	Capacity factor (%)	Electricity output (GWh)	Pool revenue ($/MWh)	Pool revenue ($m)
FY19	784	97%	62%	4,231	123	521
FY20	784	92%	54%	3,752	90	338
FY21	784	84%	54%	3,698	167	617
FY22	784	83%	57%	3,940	121	478
FY23	784	84%	57%	3,919	74	290

Taranaki combined cycle (TCC)

	Net capacity (MW)	Availability (%)	Capacity factor (%)	Electricity output (GWh)	Pool revenue ($/MWh)	Pool revenue ($m)
FY19	377	63%	31%	1,031	115	117
FY20	377	88%	26%	871	120	104
FY21	377	89%	34%	1,126	193	217
FY22	377	84%	20%	673	180	121
FY23	377	85%	5%	164	107	18

Te Rapa (spot generation only)

	Net capacity (MW)	Availability (%)	Capacity factor (%)	Electricity output (GWh)	Pool revenue ($/MWh)	Pool revenue ($m)
FY19	41	96%	54%	195	160	31
FY20	41	98%	51%	195	106	21
FY21	41	93%	58%	213	174	37
FY22	41	95%	54%	190	145	28
FY23	41	92%	30%	125	94	12

Geothermal

	Net capacity (MW)	Availability (%)	Capacity factor (%)	Electricity output (GWh)	Pool revenue ($/MWh)	Pool revenue ($m)
FY19	425	92%	87%	3,256	133	434
FY20	425	95%	89%	3,333	99	330
FY21	425	89%	84%	3,114	175	546
FY22	425	97%	91%	3,284	140	458
FY23	410[1]	94%	89%	3,186	80	254

Stratford Peakers

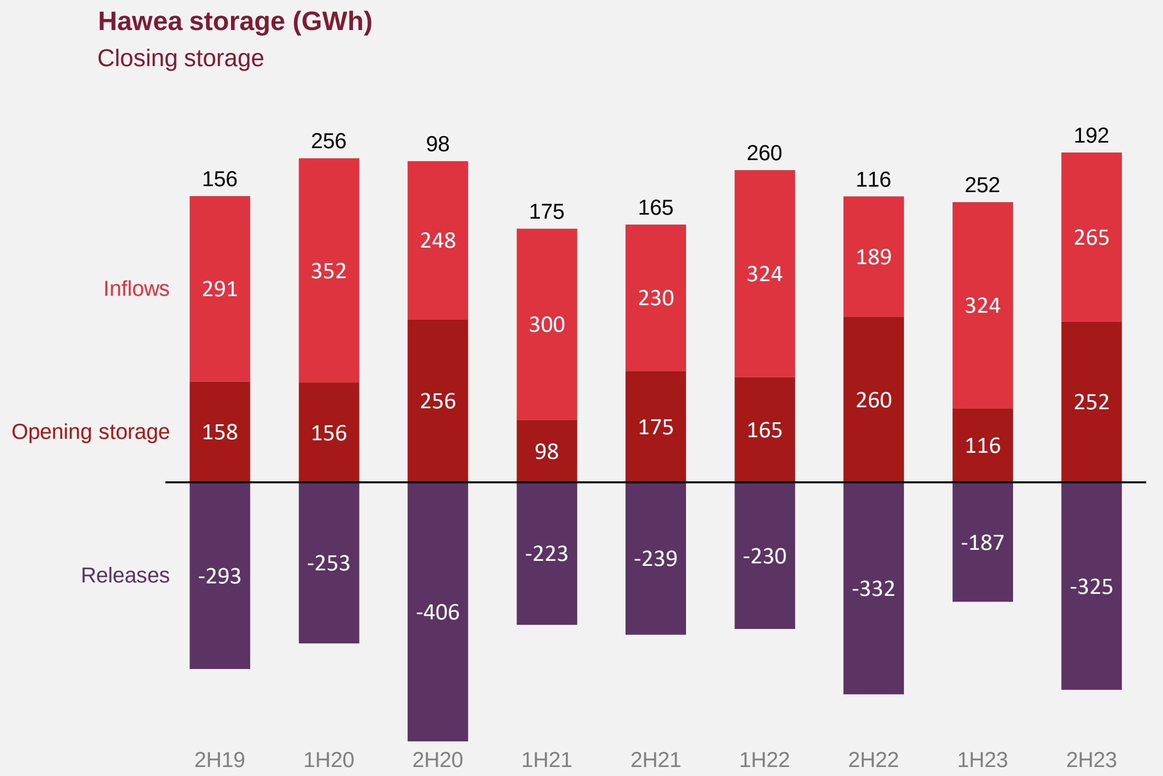
	Net capacity (MW)	Availability (%)	Capacity factor (%)	Electricity output (GWh)	Pool revenue ($/MWh)	Pool revenue ($m)
FY19	202	64%	12%	207	185	38
FY20	202	80%	16%	291	161	47
FY21	202	90%	13%	234	230	54
FY22	202	53%	10%	179	212	38
FY23	202	77%	8%	148	207	31

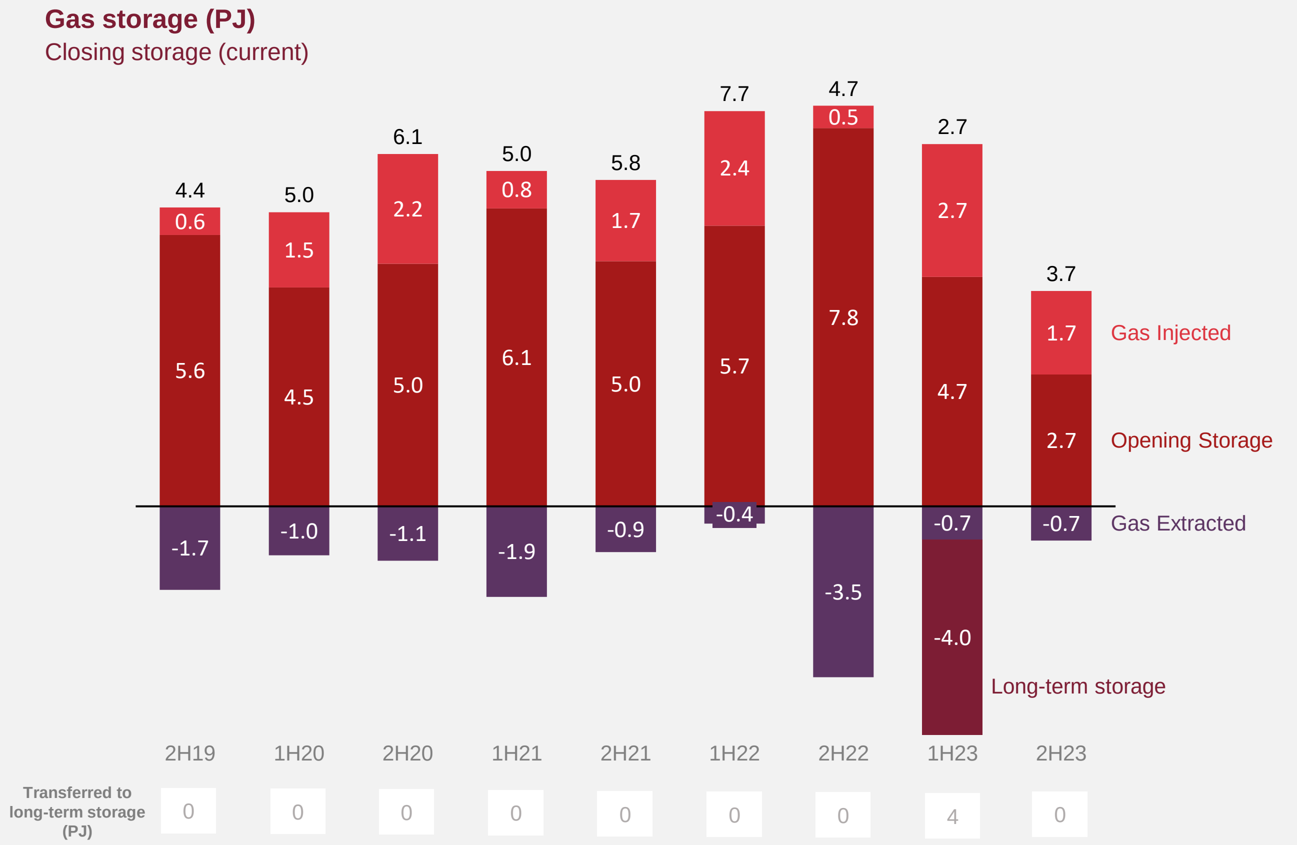
Whirinaki

	Net capacity (MW)	Availability (%)	Capacity factor (%)	Electricity output (GWh)	Pool revenue ($/MWh)	Pool revenue ($m)
FY19	158	98%	0%	5	472	2.5
FY20	158	98%	0%	3	293	1.0
FY21	158	94%	0%	18	410	7.5
FY22	158	95%	0%	4	597	2.4
FY23	158	82%	0%	2	491	1.2

Availability Factor calculation includes all station outages (Planned, Maintenance, Forced) but does not consider plant deratings.
[1] Reduction in geothermal net capacity is a result of decommissioning of wells on the Wairakei steam field.

Fuel storage movements





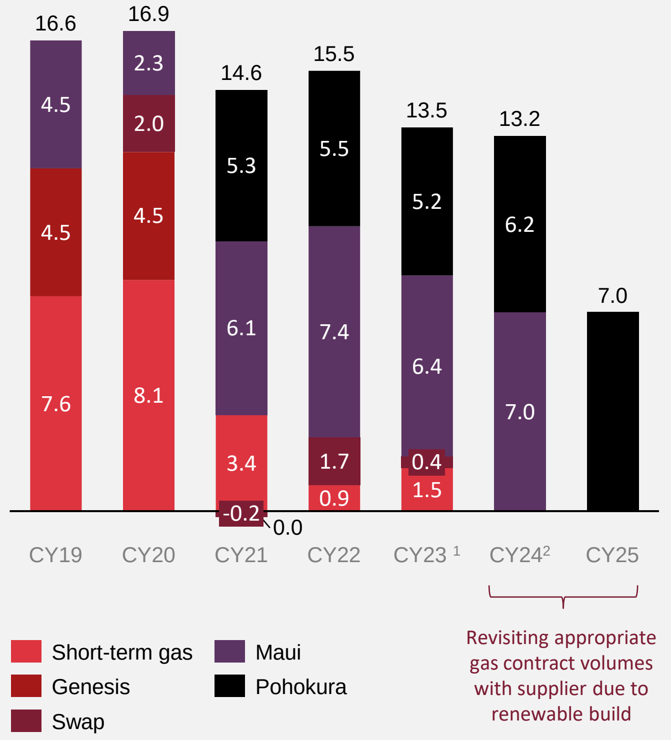
Following the completion of a joint technical working group, set up by Contact and the Ahuroa Gas Storage Facility (AGS) owner FlexGas in 2022, Contact advised the market in December 2022 that approximately 4PJs of gas owned by Contact and currently stored in AGS may only be available for extraction at the end of the contract in 2033. Excluding this volume, the estimated storage capacity of the facility is ~6-8PJ (P-50). Information about the total volume of gas in the facility can be found at https://www.gasindustry.co.nz/data/gas-storage/

Source: NZX hydro

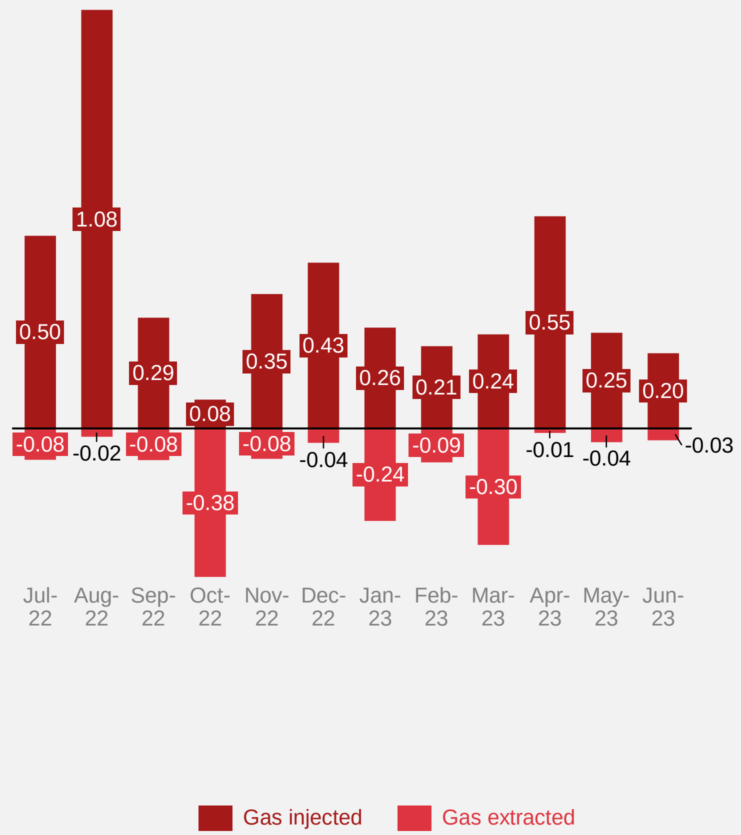
Operational data

Contracted and stored gas

Contracted gas volumes (PJ)



Gas storage monthly injections and extractions (PJ)

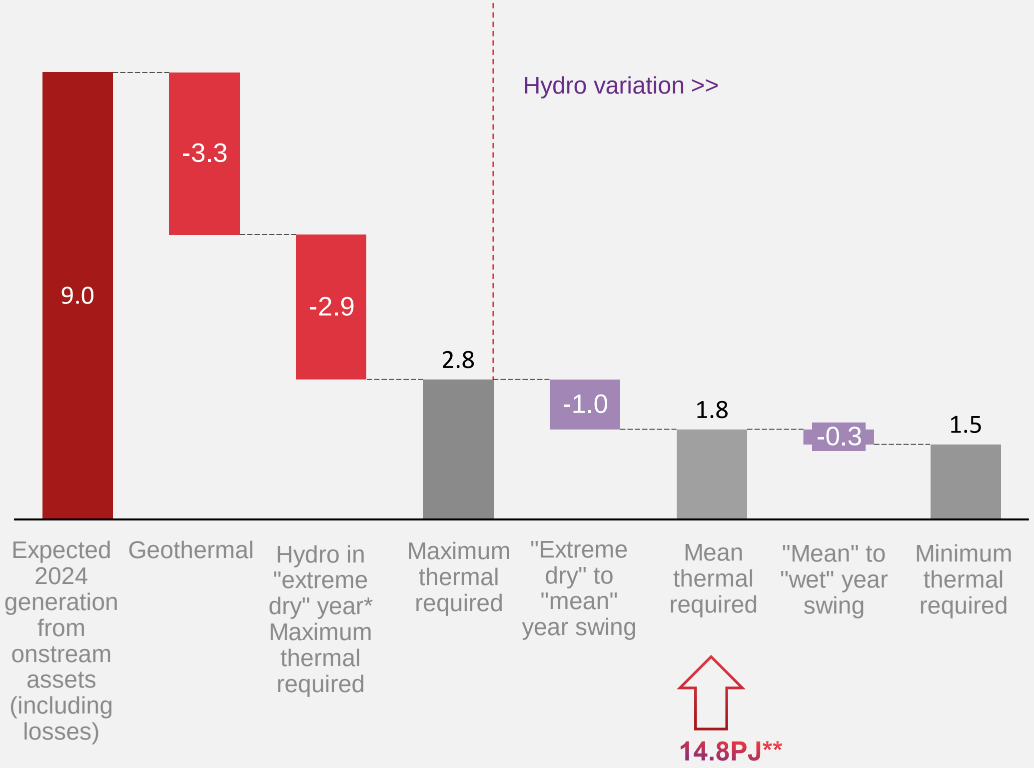


Uses of gas (PJ)

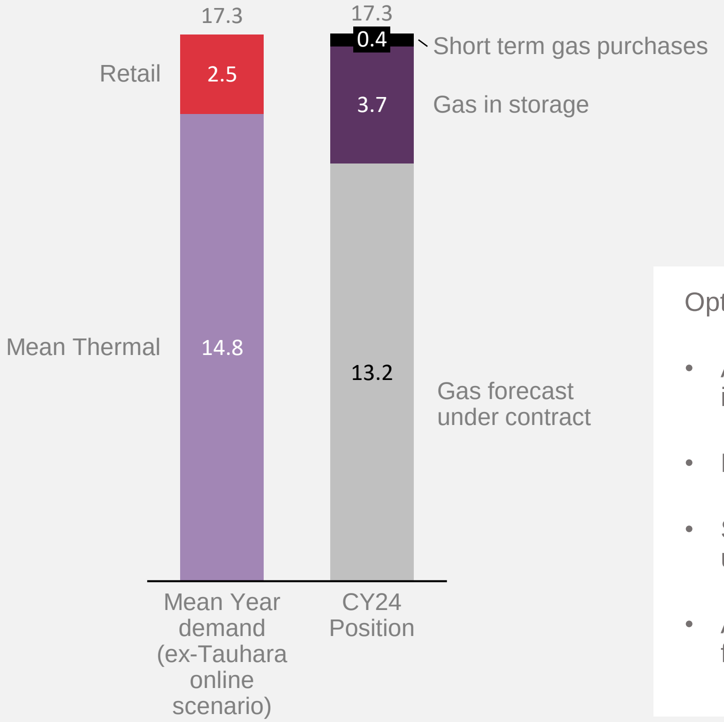
[1] Maui and Pohokura volumes for CY24 reflect forecast volumes.
[2] No forecast currently available for CY25. Contracted amounts shown.

Contractual fuel position sufficient to support expected sales position

Portfolio requirements for thermal generation (TWh)
Scenario shown is pre-Tauhara online, backed by TCC



Gas supply and demand 2024 (PJ)



Options in a dry year:

- Access to stored water in Hawea
- Purchase spot gas
- Stop selling uncontracted electricity
- Acquire generation from ASX

- Hydro generation in FY12

** Assumes mix of TCC and peaker generation (portfolio heat rate (8.2GJ/MWh))

*** Revisiting appropriate gas volumes with supplier due to renewable build.

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:

	12 months ended 30 June 2023		12 months ended 30 June 2022	Variance on prior year	
				$m	%
	Underlying[1]	Reported	Reported[2]	Against underlying	
Profit	**211**	**127**	**182**	**29**	**2%**
Depreciation and amortisation	224		262	-38	-15%
Change in fair value of financial instruments	18		-5	23	nmf
Net interest expense	38	41	36	2	6%
Tax expense	82	50	71	11	15%
EBITDAF	**573**	**460**	**546**	**27**	**5%**

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 FY22 are as follows:

- **Depreciation and amortisation:** decreased by $38m (15%) on FY22 primarily resulting from acceleration of depreciation for aspects of SAP due to SAP upgrade project in FY22 and lower depreciation on TCC with lower usage and change in useful life through to end of winter 2024.
- **Net interest expense:** Slightly higher than FY22 on higher average borrowings and higher interest rates. This is partially offset by higher capitalised interest on Tauhara and Te Huka projects.
- **Tax expense** for the period increasing by $11m following higher operating earnings.

[1] Contact has recognised a net onerous contract provision expense for AGS of $113m within EBITDAF and $84m within profit. Underlying performance excludes these impacts. All variances and commentary reflect movements in underlying performance.
[2] Contact has made reclassifications to better align with IFRIC guidance on IFRS 9 resulting in realised gains/losses from market derivatives not in a hedge relationship (includes market making activity) no longer being reported in operating income (EBITDAF). FY22 figures restated accordingly.

Historical financial information

	Unit	FY19	FY20	FY21	FY22[1]	FY23	
						Underlying[2]	Reported
Revenue	$m	2,519	2,073	2,573	2,387	2,118	
Expenses	$m	2,001	1,627	2,020	1,820	1,500	1,613
EBITDAF	$m	518	446	553	546	573	460
Profit	$m	345	125	187	182	211	127
Operating free cash flow	$m	341	290	371	330	282	
Operating free cash flow per share	cps	47.5	40.4	50.2	42.4	36.0	
Dividends declared	cps	39	39	35	35	35	
Total assets	$m	4,954	4,896	5,028	5,166	5,808	
Total liabilities	$m	2,172	2,275	2,101	2,326	3,004	
Total equity	$m	2,782	2,621	2,927	2,840	2,804	
Gearing ratio[3]	%	28	31	23	28	36	

[1] Contact has made reclassifications to better align with IFRIC guidance on IFRS 9 resulting in realised gains/losses from market derivatives not in a hedge relationship (includes market making activity) no longer being reported in operating income (EBITDAF). FY22 Expenses, EBITDAF and operating free cash flow are restated accordingly; FY22 operating free cash flow has also been restated following the reclassification of $4 million of growth capex to SIB capex.

[2] Contact has recognised a net onerous contract provision expense for AGS of $113m within EBITDAF and $84m within profit. Underlying performance excludes these impacts.

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

Segmental performance

Wholesale segment

Note: this table has not been rounded and might not add	FY23 Year ended 30 June 2023 Volume GWh	FY23 GWAP $/MWh	FY23 $m	FY22 Year ended 30 June 2022 Volume GWh	FY22 GWAP $/MWh	FY22 $m[2]
Electricity sales to Retail segment	**3,727**	**129**	**482**	**3,689**	**107**	**395**
Electricity sales to C&I (netback)	1,499	114	171	1,373	95	130
Electricity sales – Direct to Customer	78	159	12	81	134	11
Electricity sales to C&I	**1,577**	**116**	**183**	**1,454**	**97**	**141**
CfDs – Tiwai support sales	938			875		
CfDs - Long term sales	524			470		
CfDs and ASX - Short term sales	913			1,627		
Electricity sales – CFDs	**2,375**	**94**	**223**	**2,972**	**109**	**323**
Total contracted electricity sales	**7,678**	**116**	**889**	**8,114**	**106**	**859**
Steam sales	**587**	**60**	**35**	**595**	**56**	**33**
Other income			4			(1)
Net income on gas sales			2			3
Net income on electricity related services			6			(1)
Net other income			**12**			**1**
Total contracted revenue	**8,265**	**113**	**936**	**8,709**	**103**	**893**
Generation costs[1]	7,622	(31)	(239)	8,350	(34)	(283)
Acquired generation cost	150	(120)	(18)	389	(142)	(55)
Generation costs (including acquired generation)	**7,772**	**(33)**	**(257)**	**8,739**	**(39)**	**(338)**
Spot electricity revenue	7,544	82	621	8,269	137	1,129
Settlement on acquired generation	150	66	10	389	160	62
Spot revenue and settlement on acquired generation (GWAP)	**7,694**	**82**	**631**	**8,658**	**138**	**1,192**
Spot electricity cost	(5,226)	(93)	(488)	(5,062)	(153)	(775)
Settlement on CFDs sold	(2,375)	(81)	(192)	(2,972)	(140)	(415)
Spot purchases and settlement on CFDs sold (LWAP)	**(7,600)**	**(89)**	**(680)**	**(8,033)**	**(148)**	**(1,190)**
Trading, merchant revenue and losses	**93**		**(48)**	**625**		**1**
Wholesale EBITDAF underlying[1]			**632**			**557**
Onerous contract provision			113[1]			
Wholesale EBITDAF reported			**519**			**557**

[1] Contact has recognised a net onerous contract provision expense for AGS of $113m within EBITDAF and $84m within profit. Underlying performance excludes these impacts.

[2] Contact has made reclassifications to better align with IFRIC guidance on IFRS 9 resulting in realised gains/losses from market derivatives not in a hedge relationship (includes market making activity) no longer being reported in operating income (EBITDAF). FY22 figures restated accordingly.

Retail segment

Residential electricity	unit	FY20	FY21	FY22	FY23
Average connections	#	355,073	357,117	373,347	380,482
Sales volumes	GWh	2,532	2,520	2,644	2,688
Average usage	MWh per ICP	7.1	7.1	7.1	7.1
Tariff	$/MWh	250.4	253.4	256.4	272.1
Network, meters and levies	$/MWh	-122.1	-118.0	-119.5	-122.7
Energy costs	$/MWh	-94.8	-100.2	-115.0	-139
Gross margin	**$/MWh**	**33.5**	**35.2**	**21.9**	**10.8**
Gross margin	$ per ICP	239	249	155	77
Gross margin	$m	85	89	58	29

Residential gas	unit	FY20	FY21	FY22	FY23
Average connections	#	61,591	60,701	64,649	66,605
Sales volumes	TJ	1,577	1,495	1,583	1,504
Average usage	GJ per ICP	25.6	24.6	24.5	22.6
Tariff	$/GJ	33.1	35.3	36.6	42.1
Network, meters and levies[1]	$/GJ	-18.5	-18.6	-18.9	-22.9
Energy costs	$/GJ	-7.9	-8.6	-11.8	-10.1
Carbon costs	$/GJ	-1.4	-1.5	-2.1	-4.2
Gross margin	**$/GJ**	**5.3**	**6.5**	**3.8**	**4.9**
Gross margin	$ per ICP	136	107	92	112
Gross margin	$m	8	10	6	7

SME electricity	unit	FY20	FY21	FY22	FY23
Average connections	#	55,033	49,679	48,459	46,962
Sales volumes	GWh	991	860	798	794
Average usage	MWh per ICP	18.0	17.3	16.5	16.9
Tariff	$/MWh	229.3	231.7	239.7	259.3
Network, meters and levies	$/MWh	-115.8	-106.4	-112.9	-117.0
Energy costs	$/MWh	-93	-99.3	-113.7	-138.6
Gross margin	**$/MWh**	**20.5**	**26.1**	**13.0**	**3.6**
Gross margin	$ per ICP	369	451	215	62
Gross margin	$m	20	22	10	3

SME gas	unit	FY20	FY21	FY22	FY23
Average connections	#	3,949	3,876	3,889	3,519
Sales volumes	TJ	1,441	1,313	1,224	1,063
Average usage	GJ per ICP	365	339	315	302
Tariff	$/GJ	15.4	16.3	19.8	25.2
Network, meters and levies	$/GJ	-6.0	-7.9	-8.3	-9.5
Energy costs	$/GJ	-7.9	-8.6	-11.8	-10.1
Carbon costs	$/GJ	-1.4	-1.5	-2.1	-4.2
Gross margin	**$/GJ**	**0.2**	**-1.6**	**-2.4**	**1.4**
Gross margin	$ per ICP	63	-552	-769	412
Gross margin	$m	0	-2	-3	1

Broadband	unit	FY20	FY21	FY22	FY23
Average connections	#	19,979	39,245	62,388	79,057
Tariff	$/cust/mth	70.1	68.2	70.1	69.6
Network, provisioning, modems	$/cust/mth	-69.6	-69.9	-60.5	-63.5
Gross margin	$/cust/mth	**0.5**	**-1.6**	**9.6**	**6.17**
Gross margin	$m	0.1	-1	7	6

Retail segment EBITDAF		FY20	FY21	FY22	FY23
Electricity Gross margin	$m	105	111	68	32
Gas Gross Margin	$m	9	8	3	9
Broadband Gross Margin	$m	0	-1	7	6
Total Gross Margin	**$m**	**114**	**118**	**79**	**47**
Other income	$m	5	6	7	9
Other operating costs	$m	-69	-68	-68	-69
Retail segment EBITDAF	**$m**	**50**	**55**	**17**	**-14**
Corporate allocation (50%)	$m	-15	-15	-14	-22
Retail EBITDAF	**$m**	**35**	**40**	**3**	**-36**
EBITDAF margins (% of revenue)	%	3.6%	4.3%	0.3%	-3.3%

[1] FY22 Retail residential and SME gas network costs split was re-stated to align to the latest data