2024 full year results presentation

Twelve months ended 30 June 2024

19 August 2024

contact

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Agenda

Performance supports renewable investment

Focus on delivering geothermal developments and flexing to manage fuel constraints

	Twelve months ended 30 June 2024 (FY24)		Twelve months ended 30 June 2023 (FY23)	
	Underlying[1]	*Reported*	Against underlying	
EBITDAF[2]	$663m	*$675m*	↑	16% from $573m
Profit	$230m	*$235m*	↑	9% from $211m
Profit per share	29.1 c	*29.9c*	↑	8% from 26.9c
Operating free cash flow[3]	$470m		↑	67% from $282m
Operating free cash flow per share[3]	59.8 c		↑	66% from 36.0c
Average ROIC[4]	3.7%		↑	From 3.3%
Dividend declared[5]	$292m		↑	7% from $273m
Dividend declared per share[5]	37.0 c		↑	6% from 35.0 c
Stay-in-business (SIB) capital expenditure (cash)	$110m		↓	3% from $113m
Growth capital expenditure (cash)[6]	$470m		↓	0% from $472m

Market

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FY24

- Initial high hydro storage was quickly drawn down; long dry periods were punctuated by short, concentrated inflow periods; gas supply tightened; and intermittent generation increased. The market observed:
  - Higher wholesale prices. Record prices observed in December / January and June 2024.
  - Higher thermal generation compared to FY23. Particularly evident in the second quarter (these warmer months are usually highly renewable) as water was conserved for winter 2024.

- High contracted sales volumes in anticipation of Tauhara online and strong starting fuel position.
- Balanced thermal and acquired generation to meet sales position. Contracted with market participants to best utilise constrained gas through early winter.
- Hydro outage planning flexed around prevailing conditions to capture opportune inflows.
- First calls on NZAS demand response made.
- Channel pricing aligned closer to wholesale market.

Medium term

- Significant lines cost increases from 1 April 2025.
- Disappointing results from drilling campaigns across all major gas field producers factoring into future gas availability.
- Pricing volatility increasing, particularly in peak periods, as intermittent generation continues to come online, thermal plant is closed and gas production slows.
- Decline in domestic gas production leading to a sharp rise in the price of risk management products.
- Conditions continue to support Contact's view of long-term wholesale prices at **$115-125/MWh (2024 real).**[7]

- Expect to close Taranaki Combined Cycle (TCC) gas-fired plant at end of 2024.
- New geothermal plant at Tauhara came online in Q2 2024. Te Huka 3 expected online in Q4 2024. Once at full capacity these will add 1.9TWh p.a. of renewable output to the portfolio.
- Construction underway on 100MW Glenbrook battery, adding renewable flexibility, and 168MWp Kōwhai Park solar.
- Value of gas storage changes throughout the transition.

[1] In FY23 Contact recognised a net onerous contract provision expense for AGS of ($113m) within EBITDAF and ($84m) within profit. In FY24 a net movement in the onerous contract provision equated to $12m within EBITDAF and $5m within profit. Underlying performance excludes these impacts. All variances and commentary reflect movements in underlying performance.

[2] Refer to slide 50 for a definition and reconciliation of EBITDAF. Contact now reports impairments and write-offs outside of EBITDAF to better reflect underlying performance.

[3] Refer to slide 24 for a reconciliation of operating free cash flow.

[4] Four-year average. See slide 24 for the basis of calculation of return on invested capital.

[5] Relates to interim and final FY24 dividends declared.

[6] Includes capitalised interest.

[7] As indicated in November 2022, updated for inflation and includes update to reflect higher cost of capital. This is a through-the-cycle measure in a balanced market. Prices actually achieved are a function of the market at a point in time.

Execution: What we delivered over the last 12 months

Comparison to our FY24 operational plan

Strategic theme	FY24 operational plan	FY24 achieved
Grow Demand	▪ Conclude NZAS extension negotiations with improved long-term pricing. ▪ FID for one Green Chemical deal. ▪ Facilitate at least 25MW of new demand.	Concluded new long-term NZAS deal with improved pricing and demand response. Support for HWR Richardson hydrogen/diesel initiative. CO_2 commercialisation opportunity validated. Advancing to Final Investment Decision in FY25. Around 30MW new demand facilitated.
Grow renewable development	▪ Achieve FID for Kōwhai Park solar. ▪ On track FID for North Island solar. ▪ On track FID for wind. ▪ Final Investment Decision on BESS (battery). ▪ Tauhara operational Q4 2023. ▪ Build Te Huka 3. ▪ Achieve FID for GeoFuture.	Achieved Final Investment Decision on 0.3TWh solar farm at Kōwhai Park. Consenting process underway for Glorit and Stratford solar options (each 0.3TWh). Consent lodged on 0.9-1.2TWh Southland Wind project. Achieved Final Investment Decision on 100MW BESS (battery) at Glenbrook. Tauhara came online Q2 2024 after steam separation plant re-design and rebuild. Final commissioning activity underway. Commissioning underway on Te Huka 3. Expected online in Q4 2024. GeoFuture project adjusted to a phased replacement programme (Te Mihi Stage 2&3). Te Mihi Stage 2 (around 100MW) proceeding to Final Investment Decision in Q4 2024.
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.	Progressing to meet all carbon reduction commitments under Net Zero roadmap (scope 1 & 2). $C0_2$ reinjection being installed on Te Huka 3. Approved BESS (battery) investment to reduce reliance on thermal peakers. Top rated New Zealand company in DJSI Asia-Pacific.
Create outstanding customer experiences	▪ Greater than 615k connections. ▪ Maintain leading cost to serve position. ▪ Significantly grow non-energy gross margin. ▪ Expansion of "It's good to be home" brand position. ▪ Pilot launch of Contact Mobile. ▪ Electricity net price up by around 5%.	More than 620k connections, up ~6%. Cost to serve per connection increase below CPI. Telco gross margin growth of >60%. Net Zero generation brand campaign launched. Contact Mobile launched with ~8k customers. Electricity net price up by >5% aligning closer to market while maintaining low churn.

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

Delivering 225MW new geothermal generation

Supporting the decarbonisation of NZ by bringing two world class geothermal power stations online in 2024

Tauhara

- Tauhara came online in May 2024 providing new renewable generation ahead of winter as the gas market tightened.
- Power station ran continuously during 30-day reliability run at ~152MW and was successfully tested at ~174MW.
- Current operation of Tauhara is providing an important source of renewable baseload generation, at low marginal cost, as fuel constraints (hydro and gas) have deepened.
- Final commissioning activity underway to lift initial operating capacity to ~152MW.
- Minor modifications will be made during the first outage in October 2025 to uplift operating capacity to ~174MW.

Key stats:

Capacity (planned)	174MW
Annual output (at full capacity)[1]	~1,450GWh
Status	On line
Capacity under PPA[2]	87.5MW
Total project cost[3,4]	$924m

Te Huka 3

- Recent project milestones include:
  - Completion of the NCG reinjection system to capture and reinject carbon released from geothermal fluid.
  - Steam field is ready to supply steam to the power plant.
  - Power plant is ready to receive steam by end of August 2024.
- Power station remains on track to be online in Q4 CY2024.
- This will take the total new geothermal plant completed and commissioned by Contact in 2024 to over 200MW, delivering 1.9TWh[1] p.a. of renewable output when at full capacity.

Key stats:

Capacity (planned)	51MW
Annual output (full year)	~430GWh[1]
Status	Commissioning
Expected online	Q4 CY2024
Total project cost[3]	$300m

[1] Annual output is calculated based on 174MW / 51MW for Tauhara and Te Huka 3 respectively at 95% capacity factor across 365 days (24-hour operation).
[2] PPAs totalling 25MW to Oji Fibre and Pan Pac expected to commence on completion of final commissioning activity; PPA of 62.5MW to Genesis commences 1 January 2025.
[3] Total project cost under board approvals. Tauhara includes performance payment to the EPC contractor as a result of bringing the plant online earlier than scheduled.
[4] In FY25 Contact expects to recognise Tauhara assets of around $1,080m which includes capitalisation of interest and is after adjusting for the write-off recognised in FY24 relating to remediation work.

Glenbrook battery investment to enhance Contact's renewable energy flexibility

Battery investment metrics are compelling, supported by a range of strategic benefits

Battery investment key metrics

Battery capacity	100MW
Storage duration / discharge	2 hr / ~200MWh
Modular format	56 Tesla megapacks
Target schedule	Online by Q1 CY2026
Initial EBITDAF	~$15-20m p.a. (average)[1]
Operating costs	~$5m p.a.
Total project cost	Up to $163m[2]
Target IRR	9% to 10%

Sources of value

- ✓ Participation across physical, reserve and frequency-keeping markets
- ✓ Supports retail shape and can support price cap and virtual battery products for tier 2 retailers
- ✓ Expansion option with Tesla to increase capacity to 130 MW / 260 MWh
- ✓ North Island location, close to retail load, reducing North/ South Island price separation
- ✓ Reduces reliance on gas peakers by offering intra-day peaking
- ✓ Supports new wind and solar on an intra-day and intra-week basis

Note: Battery will be located on a three hectare site leased from NZ Steel, adjacent to Transpower's GXP at Glenbrook. Consent granted by Auckand Council to operate for 35 years.

[1] Based on a range of revenue sources including ancillary services (instantaneous reserves and frequency keeping), price arbitrage and fuel cost savings.

[2] Includes sunk cost of $5.4m.

Investment in Kōwhai Park solar diversifies Contact's renewable generation base

Speed to market expected to enhance returns available to Contact from this attractive investment

Key investment metrics (Contact)

Generation under PPA to Contact	80% ~210GWh p.a.
Contact PPA term	15 years
Contact PPA price	<$90/MWh (With CPI escalation)
Contact target IRR[1]	Over 12%

(Remainder sold merchant within JV)

Key investment metrics (Project)

Capacity	~168MWp ~150MWac
Annual output	~275GWh p.a.
Project costs[2]	~$273m $1.8m/MWac
Opex and SIB capex	~$20/MWh
Target schedule	Online in Q2 CY2026

Strategic benefits

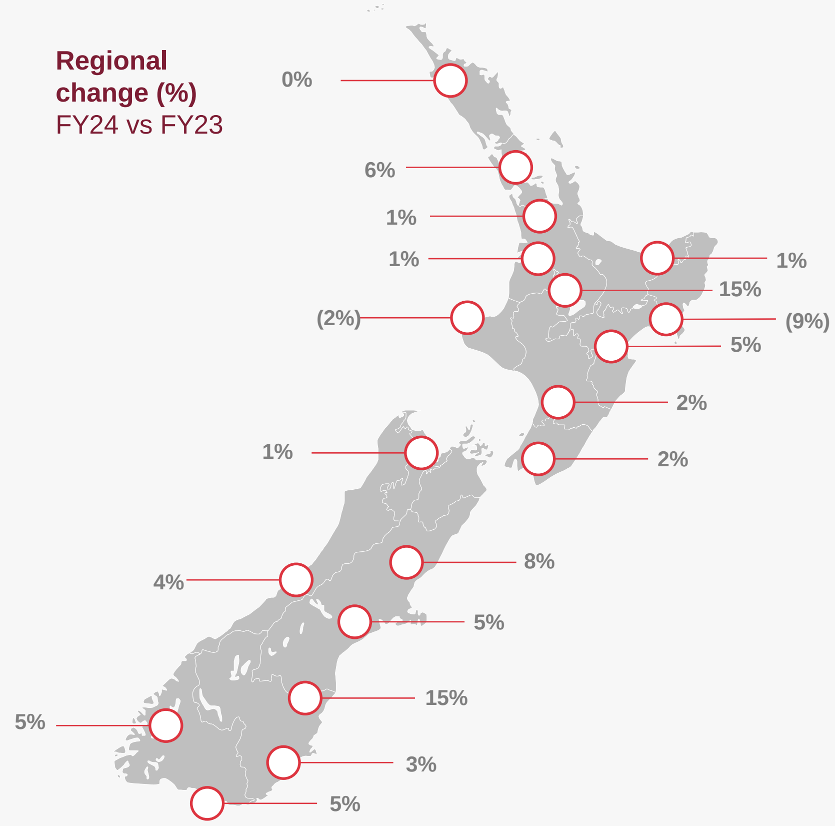
- ✓ Technological and regional diversification of Contact's generation base
- ✓ One of New Zealand's largest solar farms with 300,000 panels and a 35 year expected useful life
- ✓ Speed to market (target online by winter 2026) capturing opportunity in wholesale markets
- ✓ Delivers on the combined strengths within Contact's JV with Lightsource bp
- ✓ Comprehensive solar EPC contract with CHINTEC (with network connection by Ventia)
- ✓ JV structure (50/50) and 77% project finance[3] reduces Contact's required total capital outlay

[1] Includes JV returns and acquired generation. Return on acquired generation will ultimately depend on sales channel and market conditions.
[2] Excludes financing costs of $43m. Includes development costs.
[3] Bank facilities executed with remaining lender conditions precedent being completed in coming weeks. The final numbers could deviate slightly from those presented here once outstanding activities are completed.

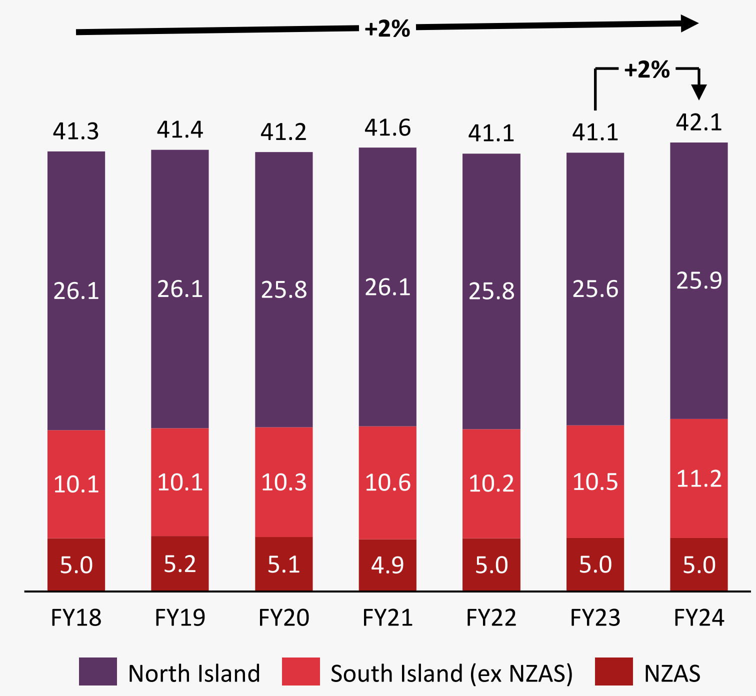
Market update

National electricity demand

New Zealand electricity demand was up ~2% on FY23



Source: EMI, Contact.
Does not include NZAS



Source: EMI, Contact

Total national electricity demand increased by 0.95 TWh (2% from FY23).

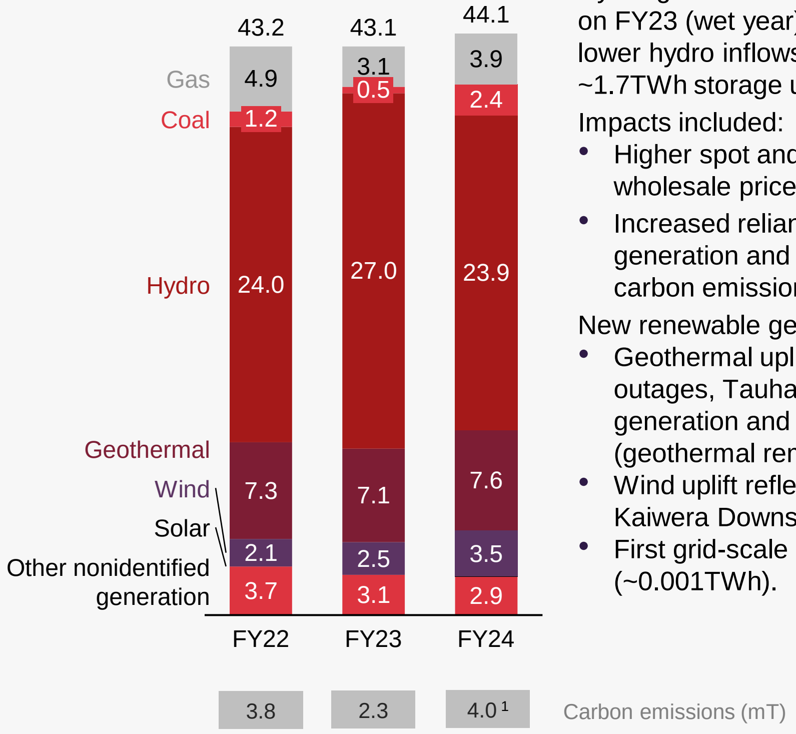
- A 15% increase in demand year on year in Huntly was largely driven by increased demand at the Te Kowhai node. This will be partly driven by the shift from embedded to grid-sourced generation at Te Rapa.
- Dry conditions in South Canterbury increased demand at major irrigation nodes, accounting for the majority of the 15% demand increase.
- East Coast regional demand was down 9%, with Pan Pac's Whirinaki site closed in 2023 after Cyclone Gabrielle flooding impacts. The plant returned online gradually through 2H24.

Drivers of underlying demand growth include data centres, South Island process heat and residential.

Low hydro inflows impacted generation mix

Below mean hydro inflows and higher demand saw increased thermal generation

Generation by type (TWh)



Hydro generation was down ~11% on FY23 (wet year), with materially lower hydro inflows offset by a ~1.7TWh storage usage.

Impacts included:

- Higher spot and futures wholesale prices.
- Increased reliance on thermal generation and higher industry carbon emissions.

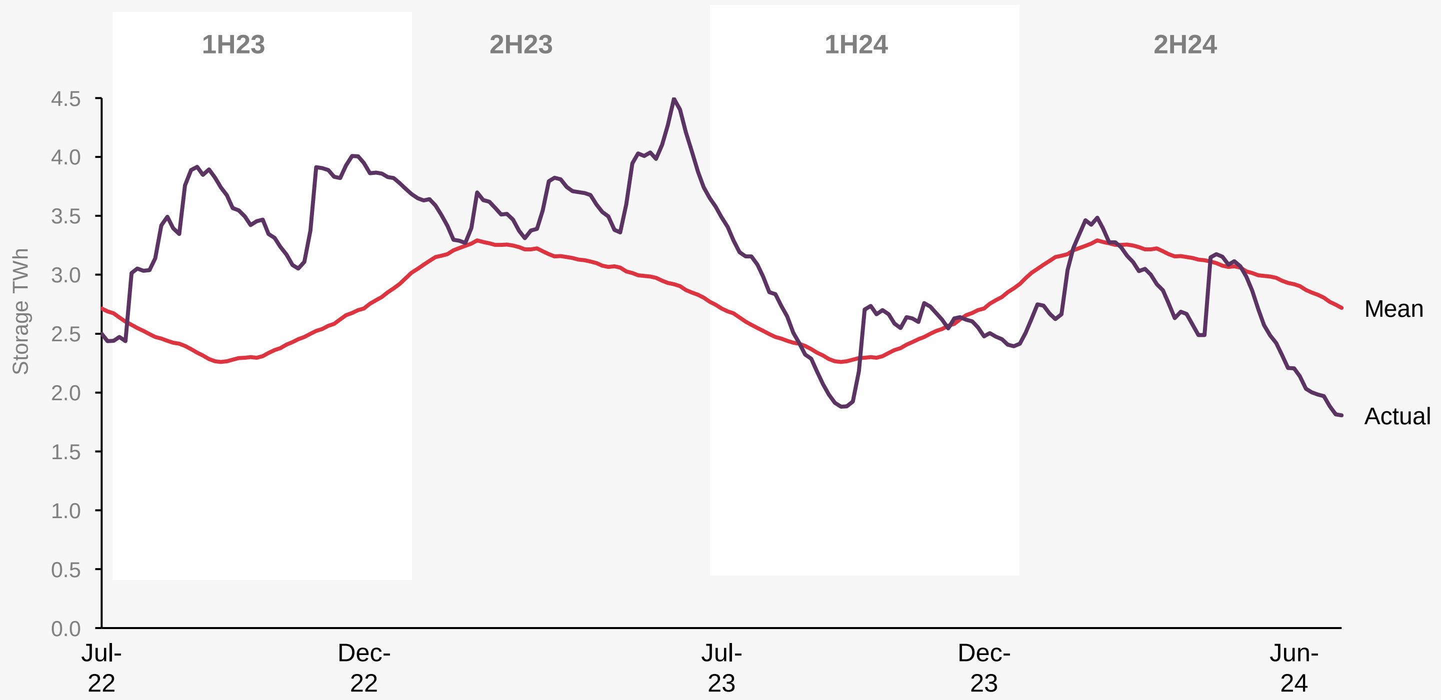
New renewable generation online:

- Geothermal uplift reflects lower outages, Tauhara initial generation and Wairakei uplift (geothermal remains >2x wind).
- Wind uplift reflects Harapaki and Kaiwera Downs coming online.
- First grid-scale solar (~0.001TWh).

FY24 saw a 1.7mT (74%) increase in carbon emissions on higher thermal generation.

Source: EMI (generation data) & MBIE (emissions data)

National hydro storage



The electricity market consumed ~1.7TWh of hydro storage in FY24, supplementing hydro generation volumes towards mean. Together with reduced coal stockpiles and stored gas (AGS), the electricity market consumed ~3.6TWh of stored energy in FY24.

Source: NZX Hydro data

[1] Carbon emissions for FY24 Apr-Jun quarter has been estimated using historic conversion rates with actual generation data.

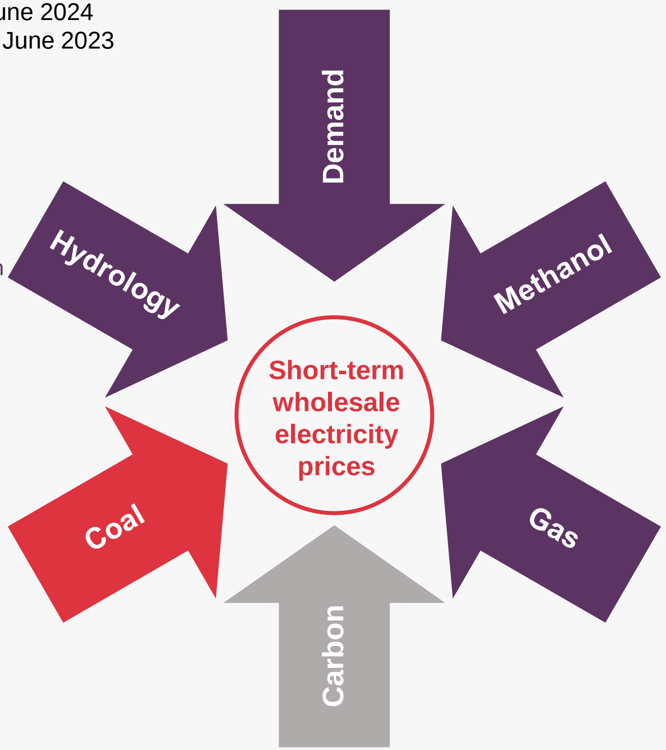
Forward wholesale pricing is reflecting low hydro storage and gas decline (fuel availability risk)

Short-term external factors that can influence the market
Changes as at 30 June 2024
in comparison to 30 June 2023

Demand was up ~2% year on year[3]

Hydro storage has been volatile over the last 12 months. Controlled storage swung between ~130% of mean (~800 GWh above mean) in July 23 to ~66% of mean (~910 GWh below mean) in June 24[1].

Methanol pricing at US$341/t (up 22% YoY) but constrained gas affecting production levels[2]

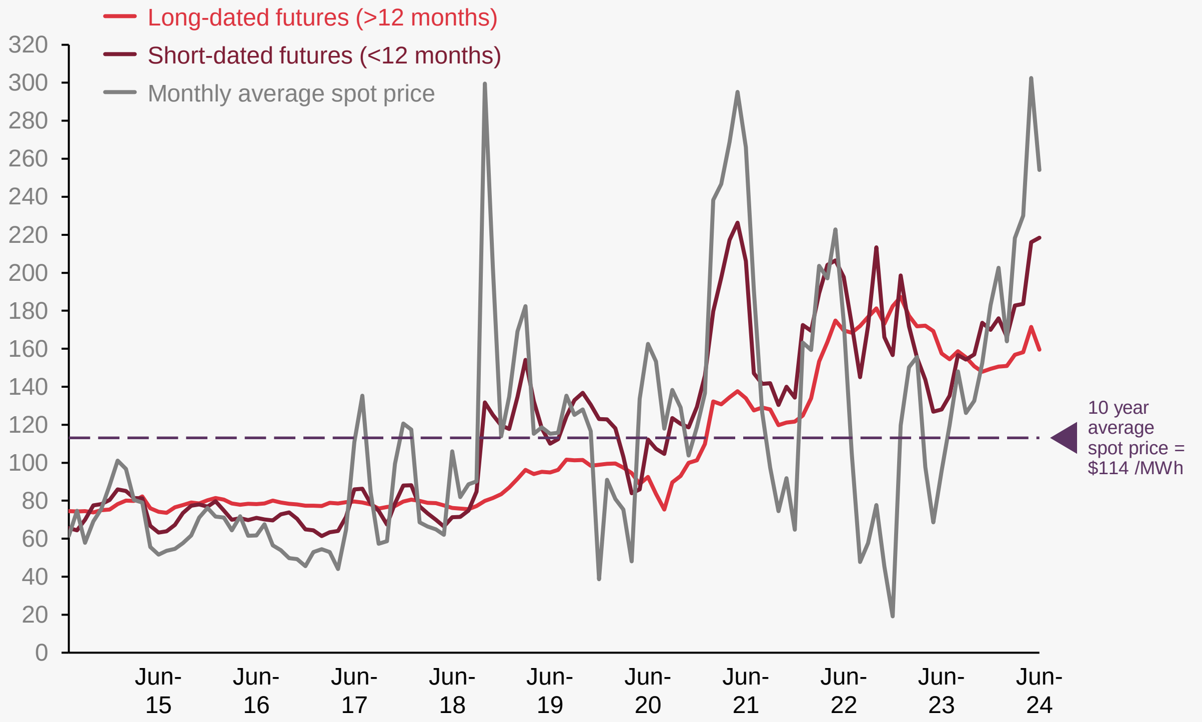


Thermal coal prices lower[2] (US$133/t, down ~11% YoY)

>$1bn drilling / maintenance on major domestic fields over the past 2-3 years have been unsuccessful at changing the overall trend of output decline[5]. Spot gas prices up ~310%[6].

Carbon prices have remained subdued (~$51 / NZ unit)[4] with the most recent June ETS auction attracting no bids

Wholesale and futures electricity pricing ($/MWh)



Source: EMI wholesale pricing

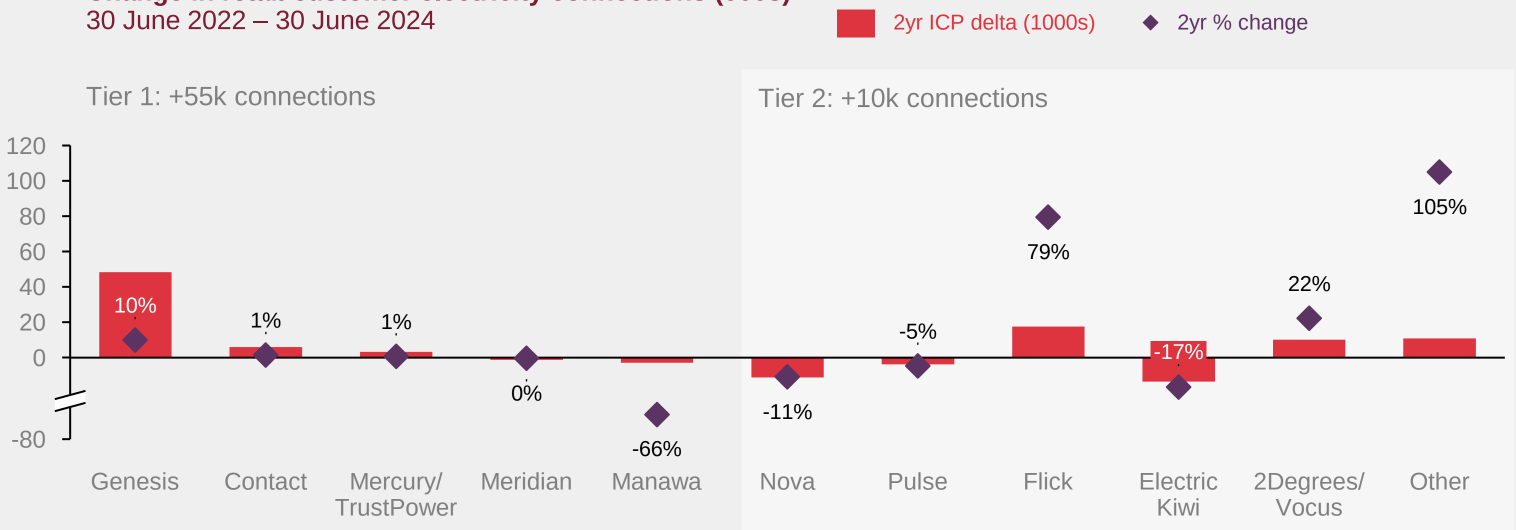
Weak hydrology conditions over the past 6 months, renewable intermittency, and increasing scarcity and cost of gas, have exacerbated spot price volatility and pushed both the spot and near-term futures prices up significantly. Long-dated futures have also priced higher over the year in response to market expectations of fuel price and availability. However, these long-dated prices are less volatile as they also reflect longer-run factors such as demand / supply and the return requirements of new-build renewables.

[1]NZX hydro information; [2] Bloomberg; [3] EMI; [4] Carbon match; [5]Recent drilling in the Kupe field (well KS-9) was unsuccessful at increasing production. In addition, both Pohokura and Maui fields have seen lower than average gas production during CY24 ~10TJ/day. *Enerlytica June 2024*.; [6] Energy Market Services

Differences in retail strategies apparent

Reflects range of views on the value of retail as a channel; Pass-through costs increasing

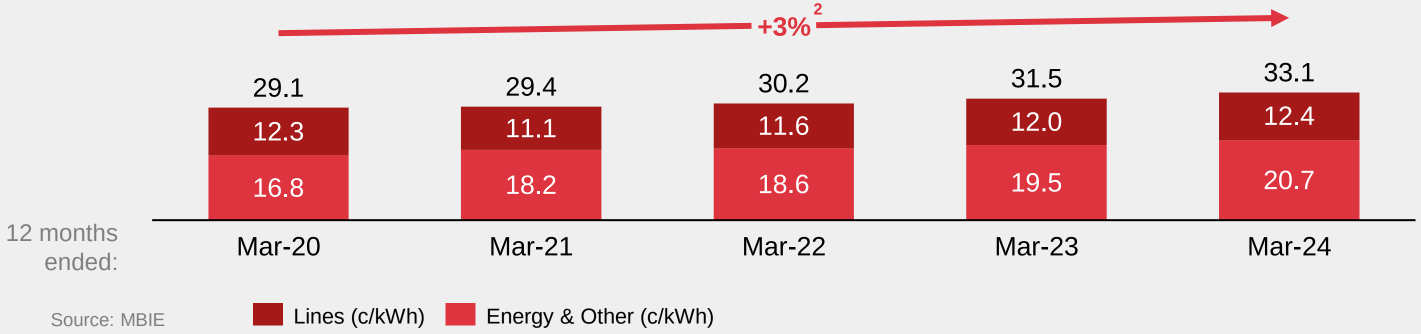
Change in retail customer electricity connections (000s)
30 June 2022 – 30 June 2024



Source: EMI

- Competition remains intense despite sustained high wholesale futures prices. Market churn continues to reflect this with switching continuing at ~19%.
- Tier 1 retailers' market share over the last two years has remained static at 84% (84% June-22 & June-24), albeit Genesis has added the most connections (+10%), with Contact, Mercury and Meridian relatively stable.
- Tier 2 retailer growth rates have been varied, with total market share flat over the last two years (at 16%). Some retailers have grown strongly (Flick, 2degrees) while others have been declining (Electric Kiwi, Pulse) possibly due to choices to reduce retail channel exposure / leverage existing hedges.
- Contact's electricity connections were up +6k from June 2022 to June 2024 equating to 20% market share.

Retail electricity tariff changes (c/ kWh)



Source: MBIE

- Increasing wholesale energy and, more recently, network costs have resulted in a lift in Residential electricity tariffs, with a compound annual growth rate of 3% across the last five years.
- Average tariff increases for the year to March 2024 of 5% were largely in line with consumer price inflation (~4%) [1]. Households have been largely insulated from increasing input costs due to retailers' longer-term view of pricing that rides through short-term volatility.
- As the energy industry decarbonises, cost pressure for retailers is expected to remain, including:
  - Significant investment in lines and distribution infrastructure.[3]
  - Continued elevated wholesale futures prices.
- This will result in an increase in the cost that consumers will pay over the coming years.

[1] Stats NZ CIP index increase in the 12 months to March 2024.
[2] Compound annual growth rate.
[3] The Commerce Commission indicated that the transmission and distribution component of a household's electricity bill will increase on average, by $15 per month from 1 April 2025, for affected networks.

Topical Regulatory matters: Net Zero 2050 imperative for NZ remains

Contact's focus on accelerating new renewable generation, flexible storage and customer-focused demand response solutions aligns with the political and societal imperative for the market to deliver a secure, low emissions, and renewable electricity market.

	Theme	*Contact Approach*	*Timing*
Fuel security	• Declining performance of NZ's natural gas fields with recent drilling campaigns underperforming expectations. • Indigenous capacity and flexibility limited. • MBIE undertaking Fuel Security Study. • Reversal of oil and gas exploration ban may increase longer-term supply, short-term supply remains tight.	• Contact transitioning from gas reliance + investing in renewable flex e.g. batteries. • Closure of Taranaki Combined Cycle gas plant (expected to close December 2024) reduces Contact's reliance on gas. • Ahuroa Gas Storage facility provides Contact with some control over fuel availability for thermal assets over the short-medium term.	• Bill to repeal oil and gas ban will be introduced in second half of 2024. • Fuel security study to start later in 2024.
Lines assets regulation / investment	• BCG report noted 30% increase in spend required on distribution infrastructure in 2026-30 relative to 2021-25. • Draft decision on 2025-30 revenue caps (effective 1 April 2025), would see the lines component of an average household's electricity bill increase by $15 per month for affected networks in the first year, with further increases expected over the following four years[1]. • Increase largely reflects CPI and changes to WACC, but it will have a material impact on some communities.	• Balance required: Crucial investment / Consumer impact. • Recommends reducing connection costs, aiding electrification projects. • Stepping up our hardship support – no disconnection or reconnection fees for non-payment.	• Final decision on lines revenue caps due in November 2024. • New charges come into effect on 1 April 2025.
Resource management reform	• Wide ranging resource management reforms underway, including Fast Track Approvals Bill, amendments to the Resource Management Act (RMA), and work to strengthen the NPS-REG. • Will play a crucial role to meet infrastructure challenges of decarbonising NZ economy.	• Contact seeks to utilise the proposed fast-track consenting Bill (if enacted) to enhance flexibility in the Clutha scheme. • Community engagement remains central to Contact's approach. • Engaging with officials and Ministers on wider reforms for alignment with our decarbonisation strategy.	• Select Committee due to report back on Fast Track Approvals Bill in September. We expect Bill to pass by the end of 2024. • Second RMA Amendment Bill to be introduced later in 2024. • Work on NPS-Reg ongoing.

[1] *Draft revenue limits and quality standards for electricity lines companies for 2025-2030,* Commerce Commission New Zealand, May 2024.

Financial results and outlook

Key themes from the financial results

Accelerated domestic gas decline leading to more expensive risk management products

Shift in national fuel mix leading to more pronounced summer / winter pricing

Higher near-term pricing is a feature of the energy transition, enabling investment in innovative technologies

Non-cash accounting topics:
Net movement in the AGS onerous contract provision of $12m within EBITDAF; Write-offs $50m outside EBITDAF (peaker, Tauhara, software upgrades)

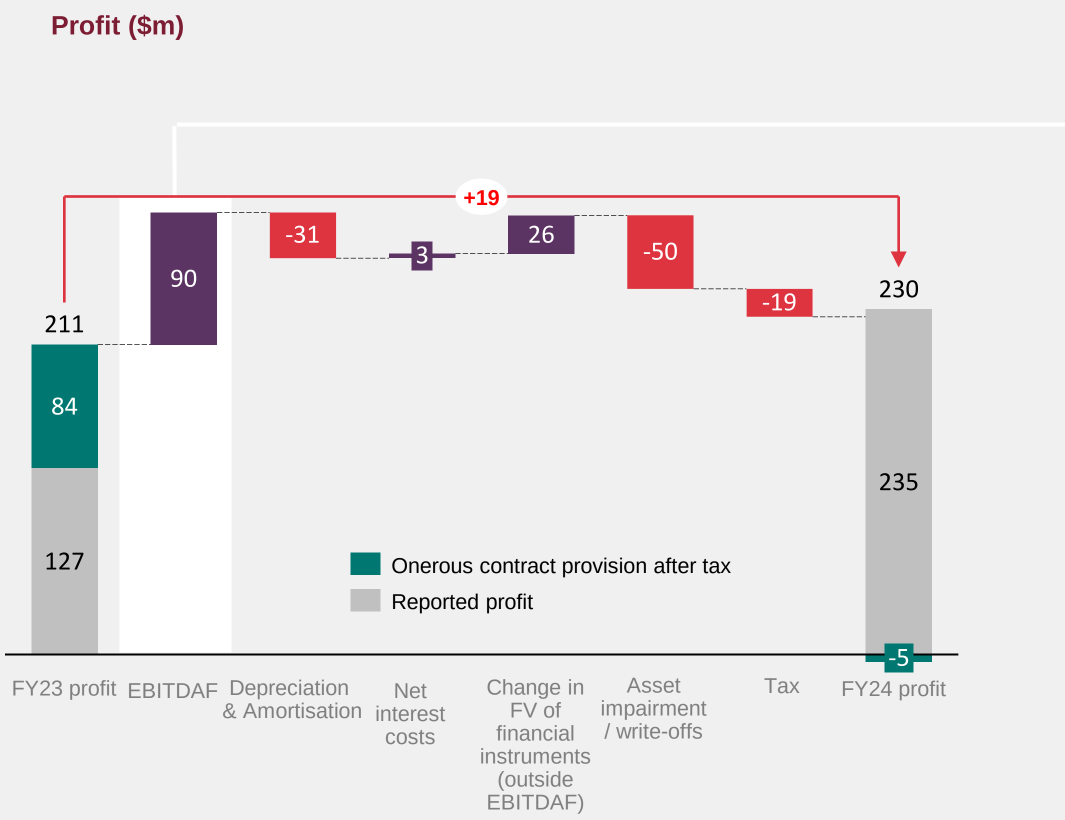
Uplift in expected and normalised EBITDAF; Outperformed FY24 guidance; Expecting $770m in FY25[1]

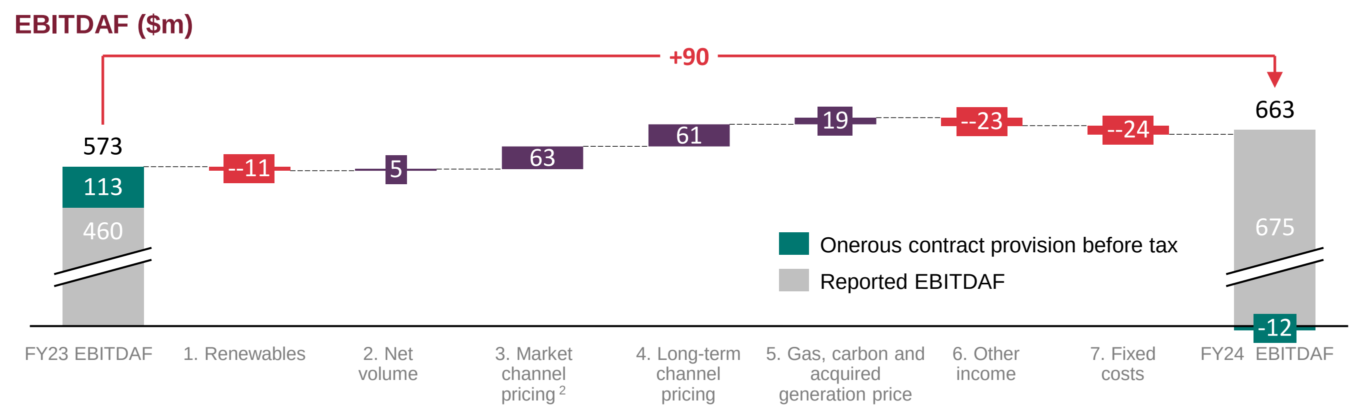
Cash conversion elevated by high thermal generation and capitalisation of Tauhara interest

[1] Normalised and expected.

Profit of $230m for FY24

Excluding the onerous contract provision, EBITDAF up $90m (underlying) largely reflecting the better alignment of long-term channel prices to wholesale market prices





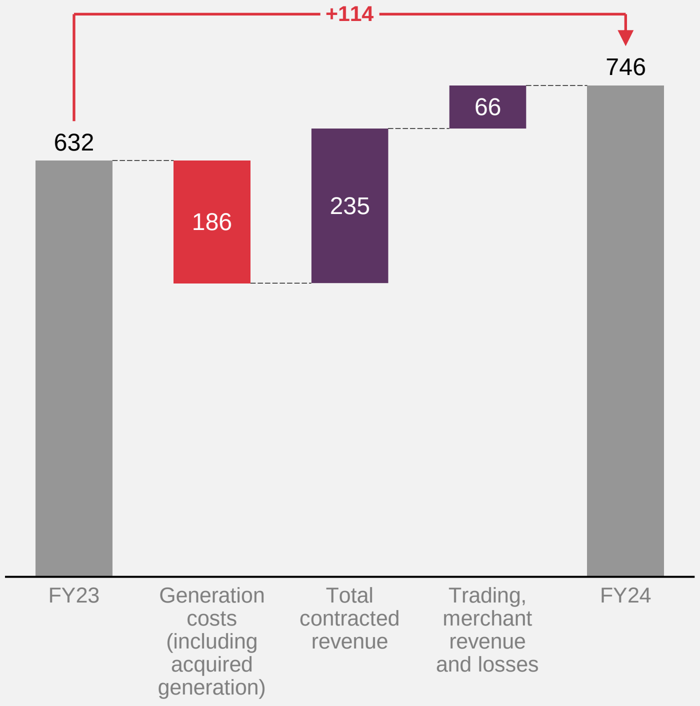
1. Renewables down 88 GWh due to a decrease in hydro generation partially offset by Tauhara[1]
2. Sales volume increase ~19% YoY, but needed to be backed with thermal fuel
3. Wholesale prices saw higher realised C&I, CFD and merchant sales
4. Retail pricing aligning to higher energy and pass-through costs
5. Increase in thermal efficiency due to closure of Te Rapa and high proportion of TCC generation
6. Down largely due to the gain on sale from Te Rapa in FY23 and Te Rapa steam revenue
7. Fixed costs higher due to inflation impacts, growth and transmission

[1] Impact calculated at thermal SRMC.
[2] Market channel pricing includes reduced $/MWh location losses.
Movements in profit and EBITDAF are shown on an underlying basis i.e. exclusive of the impacts of the onerous contract provision for AGS. Impacts of the onerous contract in FY23 are as follows, EBITDAF (-$113m), interest (-$3m), tax +$32m, NOPAT (-$84m). Impacts of the onerous contract in FY24 are as follows, EBITDAF +$12m, interest (-$5m), tax (-$2m), NOPAT +$5m.

EBITDAF (underlying) up by $90m

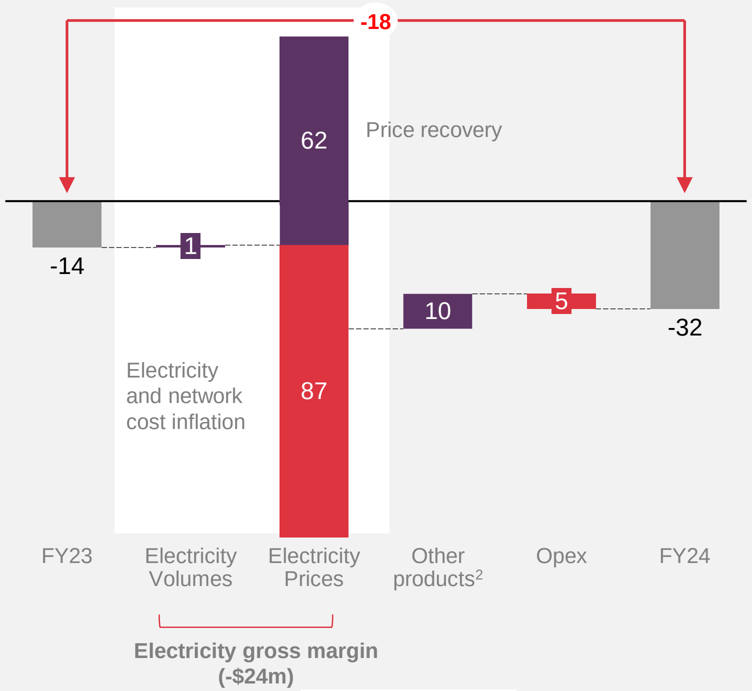
Business performance by segment

Wholesale EBITDAF[1] (underlying, $m)



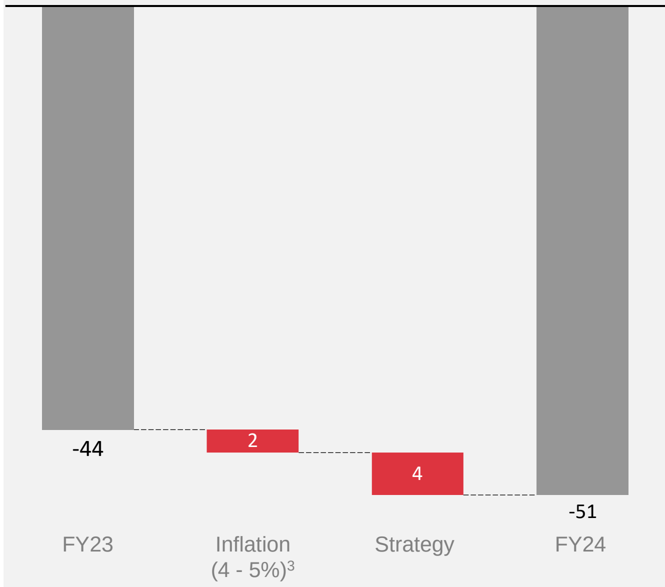
Refer to slides 19 - 21

Retail EBITDAF ($m)



Refer to slide 22

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 in FY23 and a net movement in the onerous contract provision of $12m in FY24.

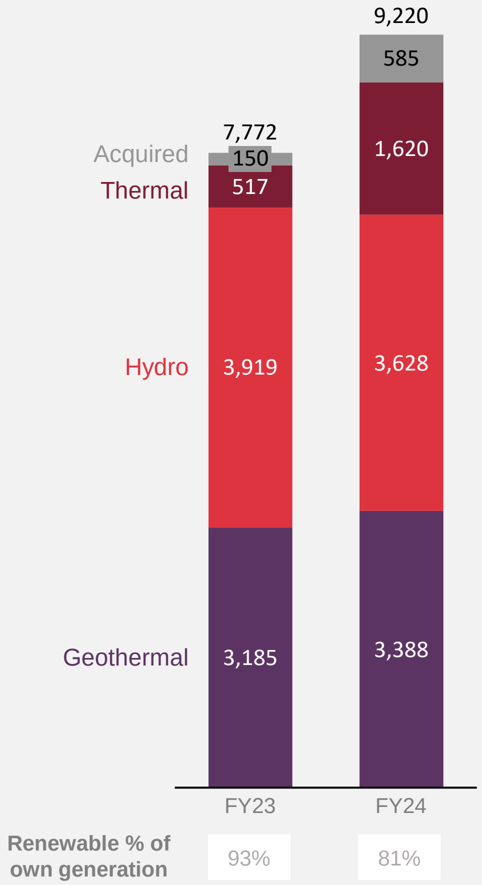
[2]Other products includes retail gas and telco gross margins.

[3] Stats NZ CPI increase over the 12 months to June 2024 plus wage inflation.

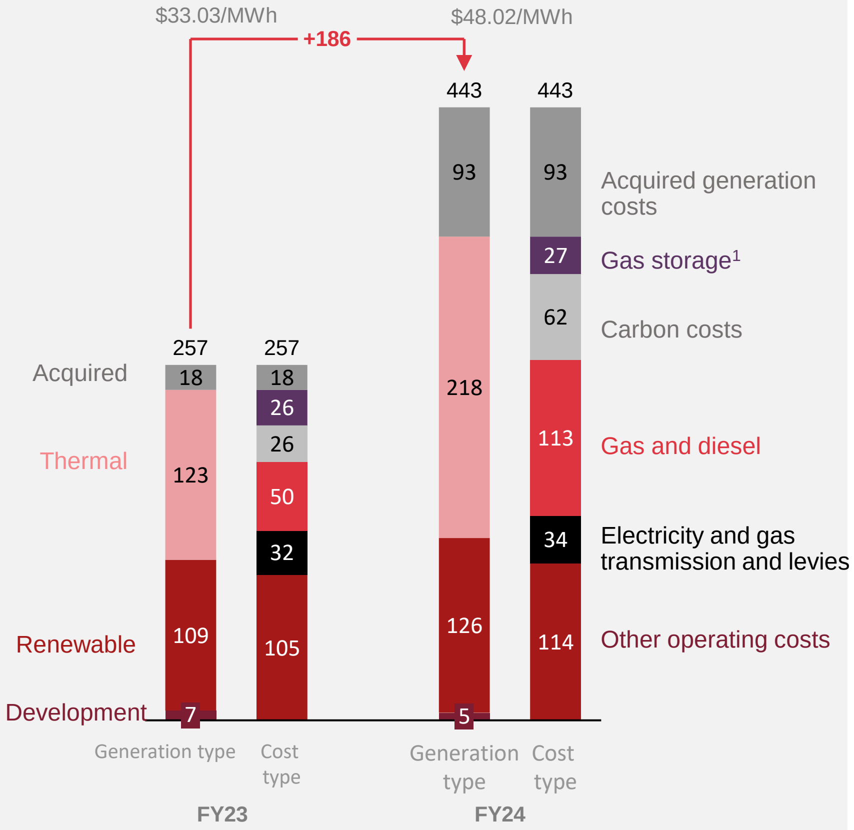
Generation costs

Costs up on increased thermal and acquired generation volumes

Electricity generated or acquired (GWh)



Electricity generated or acquired costs ($m)



Generation volumes

- Hydro generation of 3,628GWh was down 291GWh (7.4%) on FY23 and below mean (3,900GWh) following a reasonably dry end to 1H24 (a very dry hydro sequence in the final quarter).
- Geothermal volumes were up 203GWh on FY23 (6.4%). This increase on last year was a result of Tauhara coming online in the final quarter and a higher consented mass take from the Wairakei field.
- Variable rainfall sequences, largely concentrated in three distinct periods, resulted in significant swings in hydro generation over FY24. This meant long periods of dry conditions, particularly in 2H FY24, and significantly higher thermal generation than the prior year. Thermal generation of 1,620GWh was up 213% (1,103GWh) on FY23.
- Acquired generation was significantly higher than FY23 up 290% to cover a delayed Tauhara completion date.

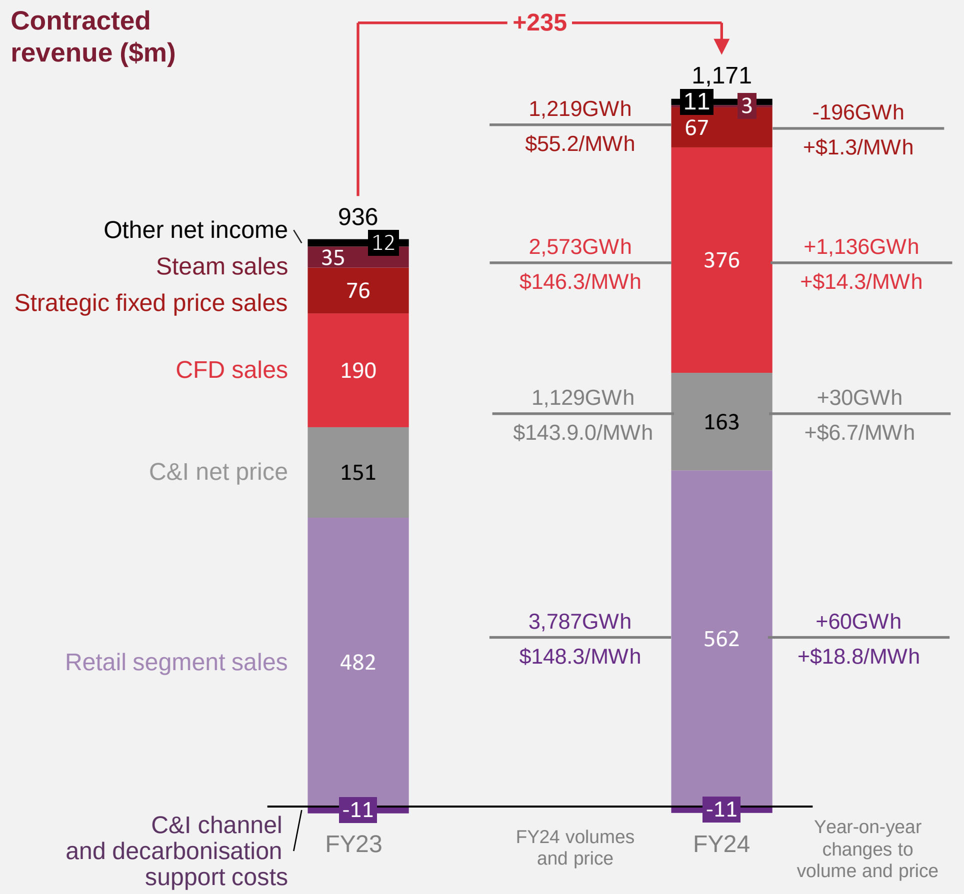
Costs

- Renewable generation costs were up $17m (16%) on FY23 due to higher geothermal generation and a marginally higher average carbon price. Also greater allocation of indirect costs as portfolio mix changes.
- Thermal generation costs, were up $95m (77%) on significantly increased thermal volumes and increased gas pricing as a result of tightening supply (FY23: $7.9/GJ FY24: $8.5/GJ). However, thermal efficiency increased on FY23 as a result of greater use of TCC due to peaker outages and the sale of Te Rapa in FY23 (FY23: 11.8TJ/MWh, FY24: 8.1TJ/MWh).

[1] Gas storage costs exclude the ($113m) onerous contract provision expense for AGS in FY23 and the net movement in the AGS provision of $12m in FY24.

Wholesale contracted revenue

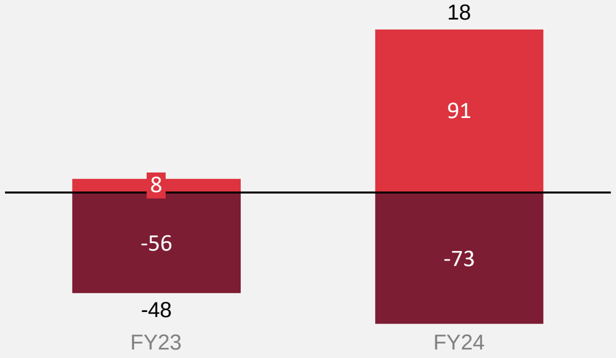
Diversified mix of long-term and ASX linked sales channels



- The closure of Te Rapa in June 2023 saw a significant decline in steam sales in FY24. the remaining steam sales ($3.4m) reflect sales from geothermal operations.
- Strategic fixed price sales were 196GWh lower than FY23, reflecting marginally lower volume under the NZAS support contract and the expiration of a long-term supply contract with Fonterra. Prices of strategic fixed priced sales were up marginally on the prior period ($1.3/MWh). In FY25 Contact expects strategic fixed price sales pricing to increase materially reflecting the recent long-term agreement with NZAS.
- With elevated starting hydro storage and in anticipation of Tauhara coming online, Contact increased its FY24 contracted load. This took the form of short-dated CFD sales and some additional C&I sales which would be backed by gas if required. CFD sales in FY24 were up 1,136GWh on FY23 and priced $14.3/MWh higher on average, reflecting elevated wholesale spot and short-dated futures prices.
- In response to the delay in the Tauhara online date, and to manage its fuel position, Contact acquired generation (see slide 19) which effectively backed out much of these additional CFD and C&I sales.
- In 2H FY24 significant calls were made under the Swaption provided to Meridian, backed by TCC. Contact was able to undertake tolling arrangements with other market participants at mutually beneficial times in the year.
- Fixed price variable volume electricity sales to the Retail segment were 60 GWh higher than FY23 (+$79m). Prices were up $18.8/MWh to $148.3/MWh, reflecting higher wholesale prices over the three preceding years.

Wholesale trading and merchant revenue

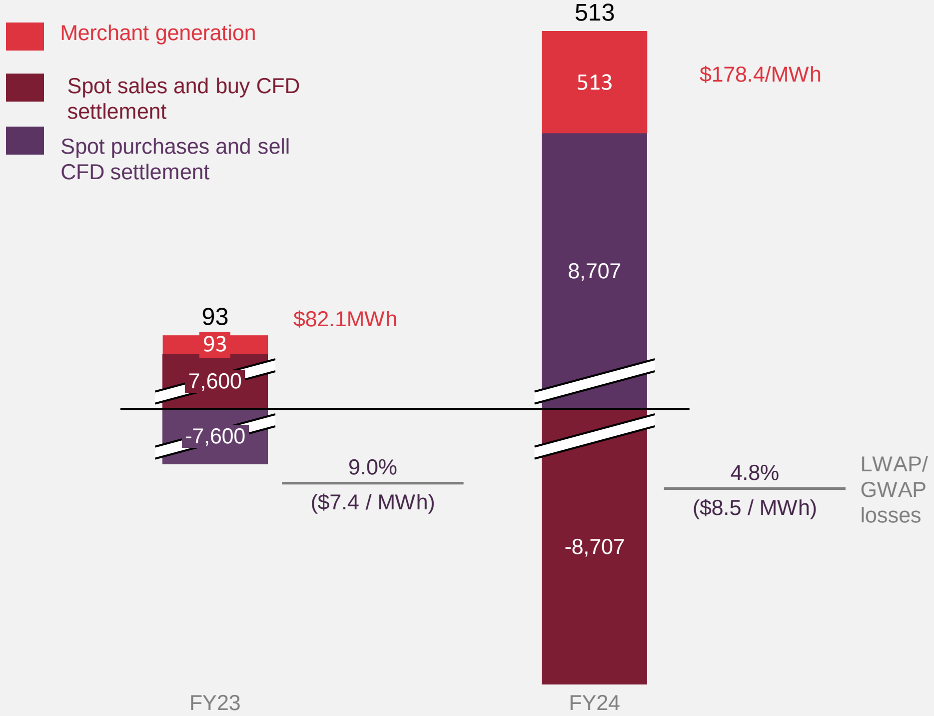
Trading EBITDAF ($m)



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)



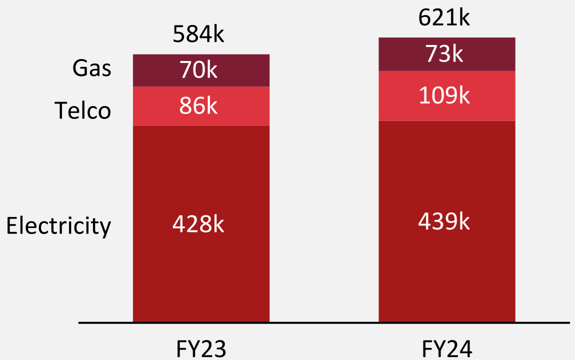
- FY23 was characterised with abundant hydrology, with low wholesale prices. Contact reduced generation from more expensive fuel sources leading to less merchant generation over the year.
- FY24 conditions included:
  - Elevated wholesale spot prices.
  - Delay to Tauhara online and lower hydro.
  - Calls made on the swaption to Meridian, increasing sales.
  - This limited merchant generation to 513GWh (6%).
- LWAP / GWAP improved to 4.8% as dry conditions over 2H FY24 reduced South Island generation, improving South Island prices relative to North Island prices.

Retail business performance

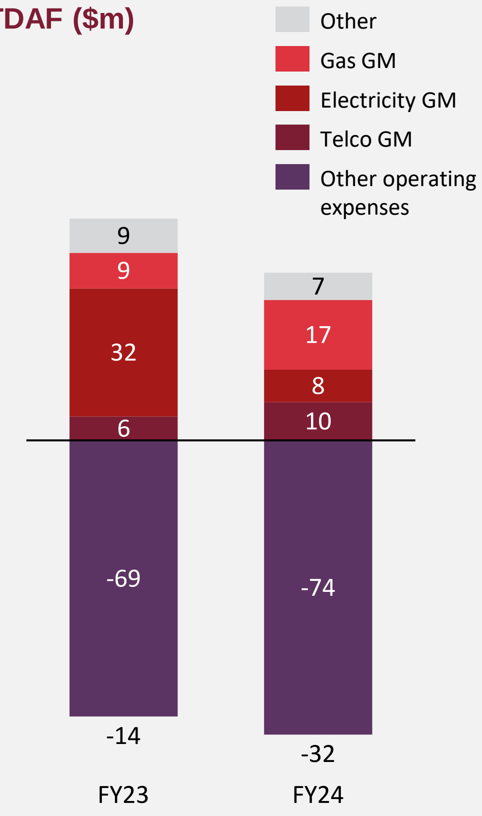
Managing through rising wholesale input costs while growing market share through a multi-product strategy

Revenue & Tariff[1] ($m)	FY23	FY24		Variance	
	$m	$m	*Tariff[1]*	$m	*Tariff*
Electricity revenue	**937**	**1,018**	**287**	**81**	**17**
Gas revenue	90	96	40	6	5
Telco revenue	66	82	72	16	2
Other income	9	10		1	
Total revenue	**1,102**	**1,206**		**104**	
Contract Asset (closing)	4	3		(1)	
# of connections (closing)[2]	***584k***	***621k***			
Cost to serve/connection[3]	*$120*	*$123*			

Closing connections (k)



EBITDAF ($m)



	FY23	FY24
Electricity transfer price[4]	$129/MWh	$148/MWh
Networks, meters and levies[4]	$113/MWh	$118/MWh

Retail margins have contracted, driven by sustained high wholesale prices and rising distribution costs.

- Retail EBITDAF decreased by $18m on FY23 largely driven by the $87m increase in electricity input costs that were not fully passed through to customers.

The average retail electricity tariff increased by 6.5% reflecting targeted retail price rises to partially offset rising wholesale and lines cost increases.

- Around 91% of customers received a price increase in the last 12 months.

As the energy industry decarbonises, cost pressure for retailers is expected to remain, including:

- Significant investment in lines and distribution infrastructure.[5]
- Continued elevated wholesale futures prices.

This will result in an increase in the cost that consumers will pay over the coming years.

Connections grew strongly in 2H24 particularly through telco and Time of Use (ToU) electricity Good plans, with a focus on multi-product customers.

- Total connections +37k on FY23 with telco up 23k and energy up 14k.
- Multi-product customers up 12% on FY23, driven by strong telco product attachment (including successful launch of new mobile product option) alongside ToU Good plans growth.

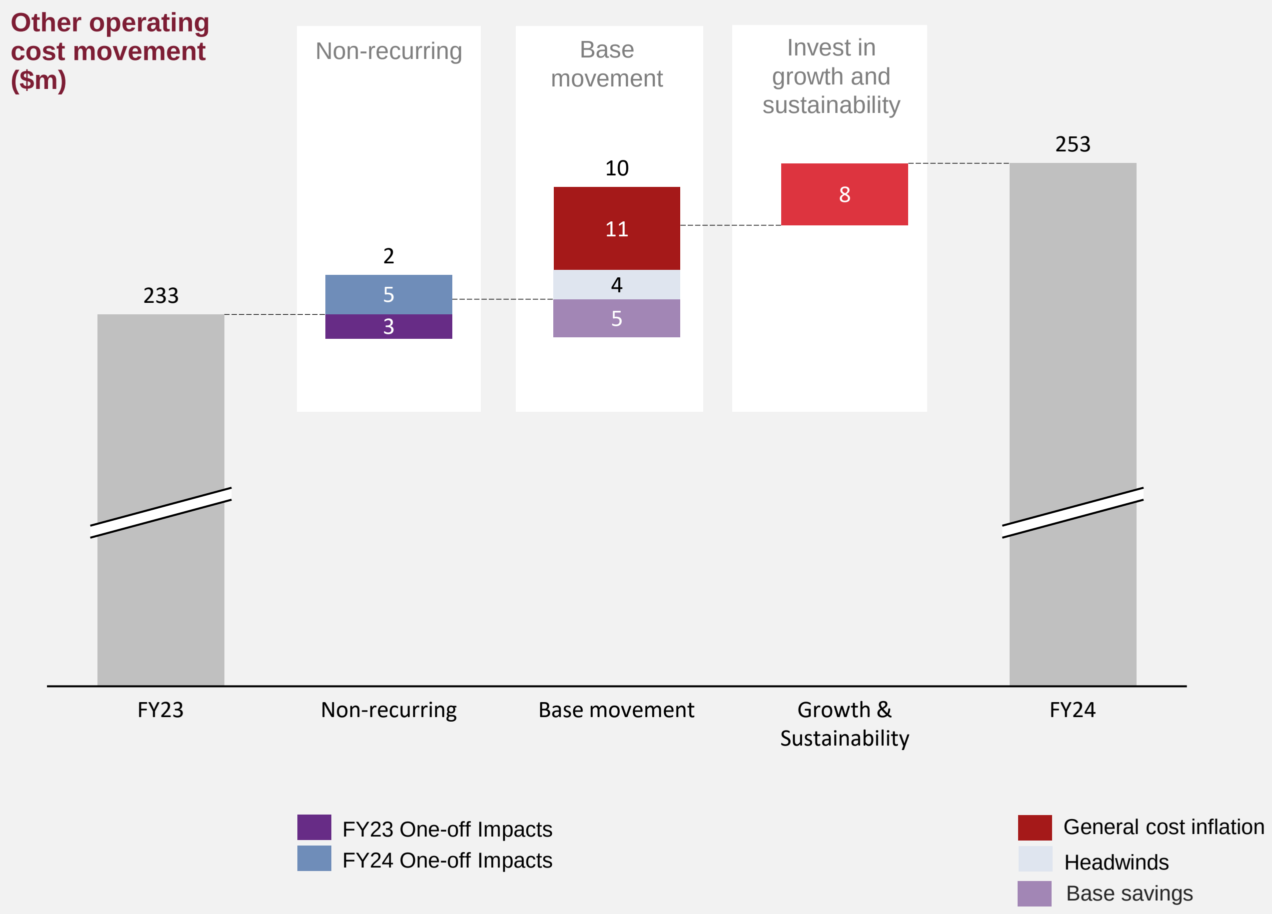
Cost to serve – increased by $3/connection, largely driven by mobile product launch marketing spend, wage inflation and higher bad debt. This was partially offset by productivity improvements through continued growth in digitised interactions.

[1] Tariff is $/MWh for electricity, $/GJ for gas and $ per month per customer connection for Telco.
[2] Retail connections only, excludes Simply Energy.
[3] Reflects total operating costs (direct and indirect) / average connections.

Gross Margin (GM) is Revenue less Cost of Goods (Networks, meters, levies, energy, carbon and telco)
[4] Input costs shown per MWh at the GXP.

[5] The Commerce Commission indicated that the transmission and distribution component of a household's electricity bill will increase on average, by $15 per month from 1 April 2025, for affected networks.

Operating costs rise due to inflationary adjustments and non-recurring expenses



Non-recurring

- 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 FY24 costs relating to tail of cyclone recovery costs and one-time spend linked to the evaluation of our Contact26 strategy.

Base movement

- General inflation of 4-5% impacting operating costs, including labour cost, rates and insurance inflation.
- Headwinds include increased level of customer bad debts and increased hosting and licence costs associated with our software platforms.
- Increased expenditure is offset by productivity improvement in our Retail Business and reduction of costs associated with Te Rapa due to its closure.

Growth and sustainability

- $1m incremental investment related to retail connection growth.
- $2m investment in advertising associated with launching Contact Mobile.
- $1m increases associated with Tauhara opex, specifically in relation to rates.
- $4m operating costs to deliver on strategic growth priorities including;
    - Sustainability and furthering ESG outcomes;
    - Procurement; and
    - Increase in corporate functions to support growth activity.
- $1m costs associated with additional uptake of Contact's updated paid parental policy "Grow your Whanau" and Women's Refuge sponsorship.

Cash flow and capital expenditure

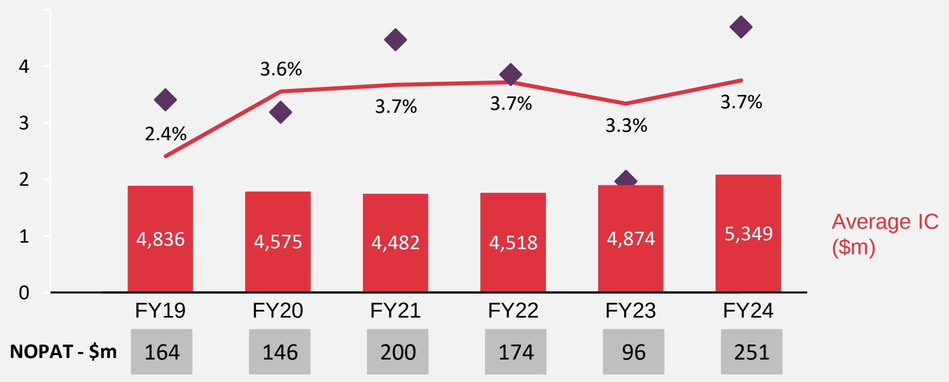
Cash conversion for FY24 up following strong EBITDAF, positive working capital changes and lower tax paid

	12 months ended 30 June 2024	12 months ended 30 June 2023	Comparison against FY23	
EBITDAF (underlying)	**$663m**	$573m	↑	$90m
Working capital changes	**$31m**	($55m)	↑	$86m
Tax paid	**($97m)**	($105m)	↑	$8m
Interest paid, net of interest capitalised	**($21m)**	($25m)	↑	$4m
SIB capital expenditure	**($110m)**	($113m)	↑	$3m
Non-cash items included in EBITDAF	**$4m**	$7m	↓	($3m)
Operating free cash flow	**$470m**	$282m	↑	$188m
Operating free cash flow per share	**59.8 c**	36.0 c	↑	23.8 c
Cash conversion (OpFCF / EBITDAF)	**71%**	49%	↑	22%

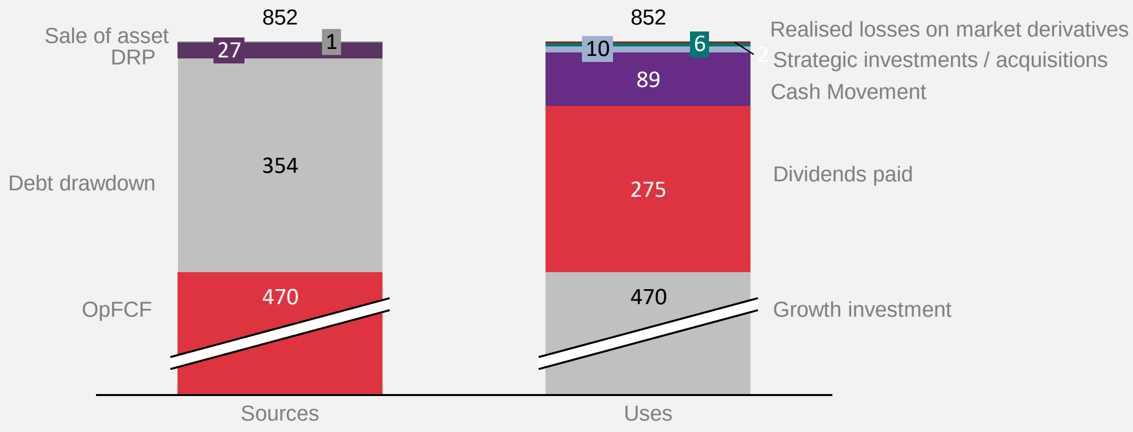
- Higher underlying EBITDAF as outlined on slide 17.
- Delta in working capital changes of $86m between FY24 vs FY23. This relates to usage of gas inventory with higher thermal generation and higher net carbon liability. This is relative to FY23 where gas inventory and carbon balances increased on lower thermal generation.
- Tax paid is down $8m on lower July wash up payments vs FY23.
- Stay-in-business capital expenditure (cash) remains relatively consistent with a decrease of $3m. In year spend includes additional spend on emergency repairs at Wairakei and spare Peaker engine damaged in FY24.

Return on invested capital (ROIC)

Net operating profit after taxes (NOPAT) / Invested capital (IC)[1]



Sources and uses of cash ($m)



[1] NOPAT is calculated as annual EBIT less tax (tax includes annual tax expense and movements in deferred tax over the year).
Invested capital is calculated as the average of the opening and closing balance of; net working capital (adjusted to remove current borrowings, current net derivatives and excess cash above $50m) + non-current assets (adjusted to remove non-current derivatives).
[2] ROIC average is calculated as NOPAT (4-year average) / Average IC (4-year average).
[3] Annual NOPAT (FY) / Average IC (FY)

Growth capital expenditure

Step-up in growth capital expenditure in FY24 reflects the advancing nature of Contact's renewable development projects

Growth capital expenditure – cash basis ($m)[1]

	Up to 30 June 2023	12 months ended 30 June 2024	Remaining under current approvals	Total[2]
Tauhara	$714m	$138m	$72m	$924m
Te Huka 3	$110m	$136m	$54m	$300m
Te Mihi Stage 2&3	$12m	$98m	$34m	$144m
Wind	$5m	$8m	$2m	$15m
Glenbrook battery	$0m	$5m	$158m	$163m
Capitalised interest	$99m	$74m	$18m[3]	$191m
Total	**$940m**	**$459m**	**$338m**	**$1,737m**

- The Tauhara geothermal station has been generating since May 2024. Final commissioning activity is underway and further modification work is planned for the first statutory outage in October 2025. Tauhara remained within Capital Work In Progress as at 30 June 2024 as final EPC testing was incomplete.
- Construction of Te Huka 3 is near complete and commissioning is underway. Plant is expected online in Q4 2024. The remaining growth capex is expected to fall in FY25.
- Remaining spend on Te Mihi Stage 2&3 (previously GeoFuture) and wind projects reflects current pre-FID approval levels and will be updated after final investment decisions, as applicable.
- Investment in a 100MW grid-scale battery (BESS) at Glenbrook was confirmed in May 2024. The project is expected to be completed in FY26 with growth capex falling across both FY25 and FY26.
- For major growth projects Contact capitalises 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.
- Investment in Kōwhai Park solar was confirmed in August 2024. Contact's investment will not be captured within growth capex, rather it will be recognised within investment in joint ventures and associates.

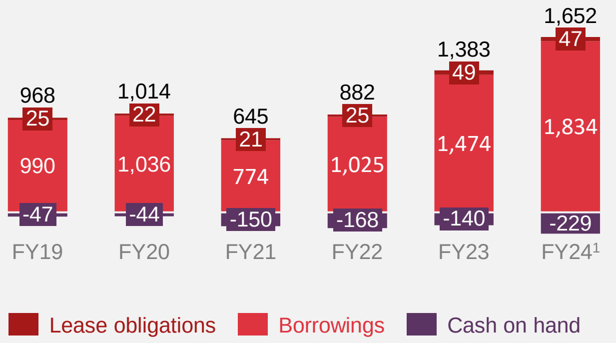
[1] Excludes $11m associated with Western Energy coil tube drilling and deployment of demand flex technology.
[2] Total under current Board approvals. Tauhara includes performance payment to the EPC contractor as a result of bringing the plant online earlier than scheduled.
[3] Relates to Te Huka 3 geothermal development (FY25 only) and Glenbrook battery development (life of project).

Strong balance sheet

Contact's sustainable finance principles are built on diversified sources of funding

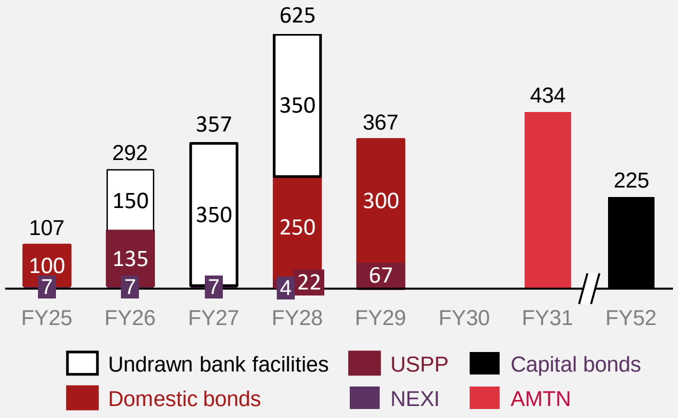
Closing net debt ($m)

Face value of borrowings less cash



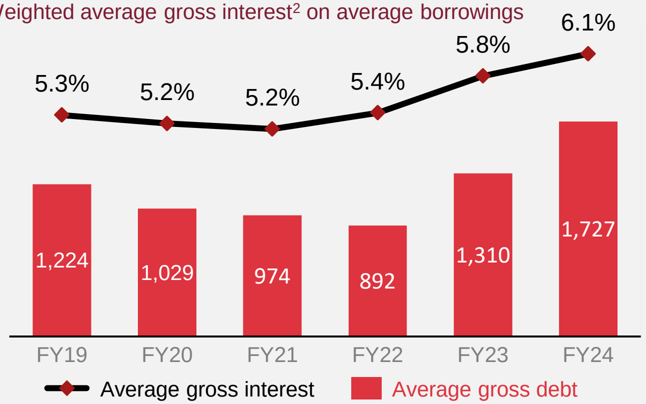
Borrowing maturities ($m)

Average tenor of 5.9 years as at 30 June 2024



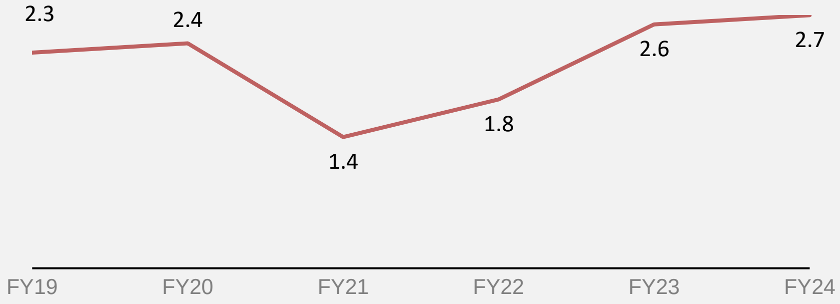
Interest rate (%)

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]



- A Green Australian Medium Term Note (AMTN) was issued during the year. This was partly to refinance a maturing tranche of USPP in December 2023, but also provided additional funding for the ongoing capital investment programme.
- During the year Contact's hydropower assets gained green certification from the Climate Bonds Initiative (CBI).
  - To gain this certification, international experts were brought on-site to undertake a Hydropower Sustainability Assessment and assess Contact's ESG performance, benchmarking the hydro schemes against best international practice.
  - This certification has increased Contacts green borrowing programme by $1.7bn.
  - Contact received silver certification from the International Hydropower Association.
- 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. Point estimate net debt to EBITDAF is currently 2.7x and Contact's EBITDAF outlook, DRP and capacity for additional hybrid bonds provide the ability to manage this metric effectively.

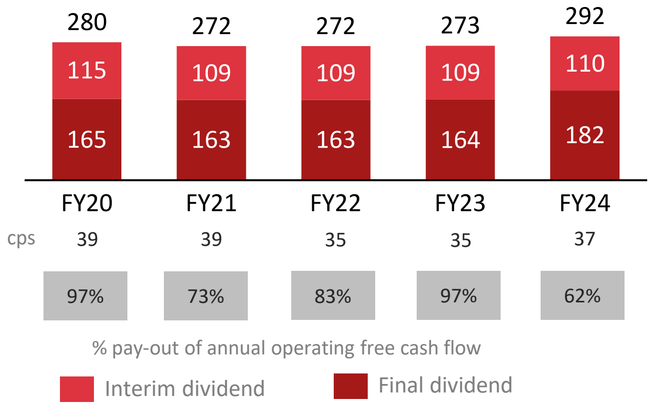
[1] Includes $87m of collateral held on deposit for margin calls associated with the trading of electricity price derivatives on the ASX.
[2] Gross interest includes all interest on borrowings, bank commitment fees and deferred financing costs. Unwind of leases, provisions and capitalised interest not included.
[3] Illustrated here on a point basis based on expected S&P adjustments. FY21 and FY22 have been restated based on latest understanding of S&P approach. See breakdown on slide 54.

Dividend per share for FY24 is up 6%

Reflects 92% of the average operating free cash flow for the preceding four years

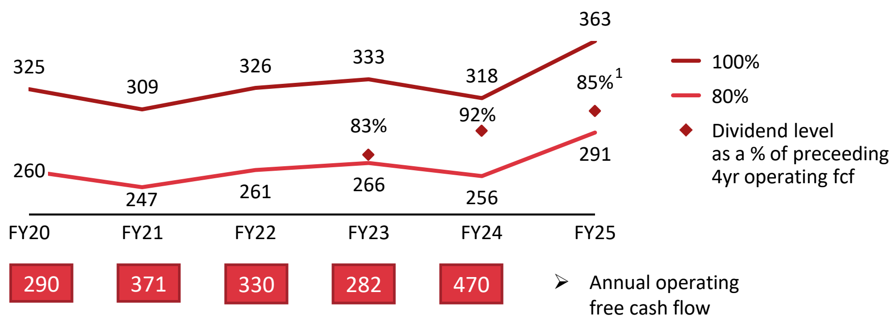
Ordinary dividends ($m)

Declared



Operating free cash flow

Average operating free 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 FY24 of 37 cents per share

- Final dividend of 23 cents per share is imputed up to 91% or 21 cents per share for qualifying shareholders. This represents a pay-out of 62% of FY24 operating free cash flow per share and 92% of the average operating free cash flow over the preceding 4 financial years (FY20-FY23).
- The dividend policy is to pay-out between 80-100% of average operating free cash flow of the preceding four years.
- Record date of 28 August 2024; payment date of 27 September 2024.
- The NZD / AUD exchange rate used for the payment of Australian dollar dividends will be set on 5 September 2024.

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.
- A 2% discount will be offered for the FY24 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 29 August 2024 to confirm participation in the plan.
- Trading period for setting price for the DRP is 27 August 2024 to 2 September 2024. DRP strike price will be announced: 3 September 2024.

Dividend expectations

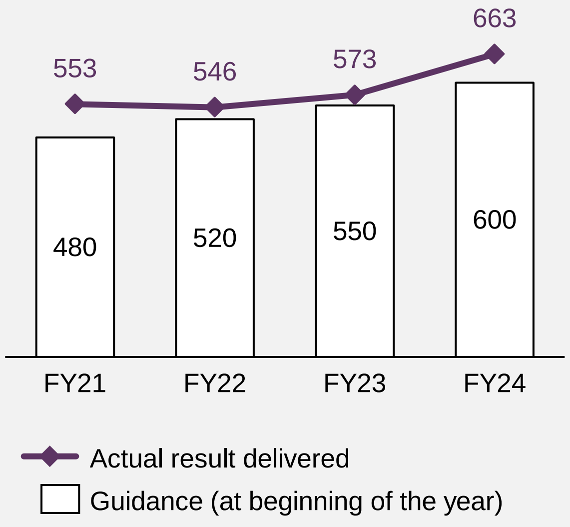
- Contact has indicated that it expects to lift the FY25 interim dividend by 2cps to 16cps, with total expected dividends in FY25 of 39cps (up 11% on FY23). While it undertakes the Te Mihi Stage 2 development (the first stage of Wairakei geothermal station replacement capex) additional increases to dividend per share are not currently anticipated.[2]
- On this basis, dividends in FY25-FY27 are expected to be imputed up to ~65%.
- Reliable ordinary dividends are expected to increase over time with growth in operating free cash flow.

[1] This calculation is based on the expected ordinary dividend of 39 cps.
[2] All dividend decisions are a matter for the Board at the conclusion of each reporting period. These align to the dividend policy and are dependent on business and market conditions when each payment decision is made.

Uplift in Contact's expected FY25 EBITDAF to be driven by the realisation of growth investment

FY25 normalised and expected EBITDAF includes generation from Tauhara and Te Huka 3 which together represent $1.2bn of investment in renewable generation

Guidance vs Actual

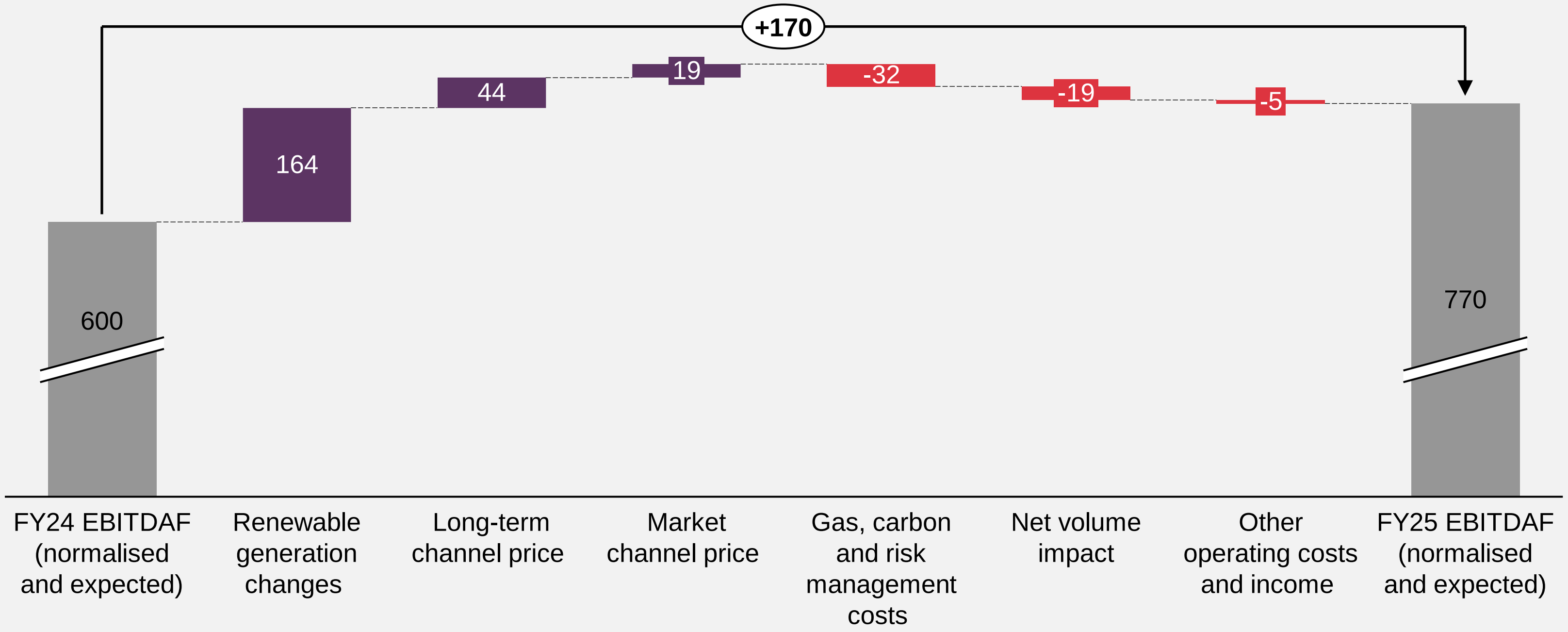


Strong track record of delivering performance above guidance

(Guidance reflects normalised and expected EBITDAF based on mean hydrology conditions)

Normalised and expected EBITDAF ($ million)[1]

Like-for-like increase of $170m (28%) on year-on-year guidance



Normalised and expected EBITDAF is based on mean hydrology conditions

Start to FY25 has been characterised by low hydro inflows and high wholesale prices. These conditions have a partially offsetting impact on earnings (resulting in above or below normalised expected performance).
Of note, July 2024 EBITDAF was $9m below normalised and mean expected.

[1] See slide 40 for assumptions underpinning FY24 normalised and expected earnings.

Recap: Capital allocation framework

Contact 26

Guiding principles

Continue to attract capital

- Deliver competitive shareholder returns including dividend commitment.
- Balance sheet strength.

Optimise existing operations and manage risk

- Reduce carbon exposure.
- Manage market volatility during the thermal transition.
- Disciplined approach to sustaining capital spend.
- Strong operating cash flow.

Invest to deliver value accretive growth

- Returns improved through prioritisation of non-equity funding.
- Projects ranked considering returns available and overall portfolio implications.

	Geothermal	Wind	Solar	Battery	Hydro
Target returns	9-11%	8-10%	10-12%	8-9%	8-9%
Returns on projects at or nearing FID	>10%	tbc	>12%	9-10%	tbc

Our commitments

Our commitments	What this means
1 **Efficient deployment of stay-in-business Capex**	Higher SIB capex over next three years reflects higher risk associated with the wholesale market environment and includes (FY25-FY27): ➢ BAU SIB capex \$75m-\$85m p.a.[1] ➢ Accelerated SIB capex programme \$48m.[2] ➢ Wairakei extension ~\$25-35m (indicative).[3]
2 **Reliable ordinary dividends that increase in line with growth in cash flow**	Pay-out ratio of 80-100% of average operating free cash-flow over the preceding 4 years. ➢ 92% in FY24 (37cps dividend declared).
3 **Allocate capital to strategic priorities, with an ability to scale down in downside scenarios**	Total growth cash capex of \$1.4-\$1.5bn over FY23-25.[4]
4 **Investment grade credit metrics through the cycle**	Target BBB <3x net debt to EBITDAF. If temporarily above, always have clear plan to restore metrics.

Considering supportive post-NZAS market conditions, current market risks around fuel availability and a broad range of attractive projects, we will prioritise investments to grow shareholder value and distributions

[1] Includes ~\$10m p.a. of provisions. Excludes geothermal well drilling which may be required within the period.
[2] Reflects planned spend in the next 3 years relating to the \$150m accelerated SIB capex programme announced to the market in 2021.
[3] Current indicative range of SIB capex to be incurred in FY26-27 for Wairakei extension activity. To be confirmed at FID for Te Mihi Stage 2.
[4] Excludes project spend that has not yet proceeded to final investment decision.

Progress on Strategy

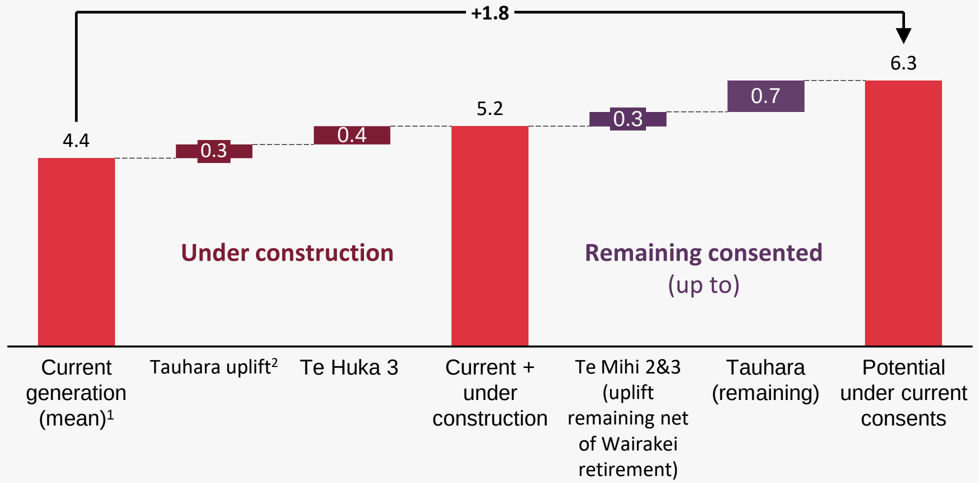
Contact26 Our strategy to lead NZ's decarbonisation

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

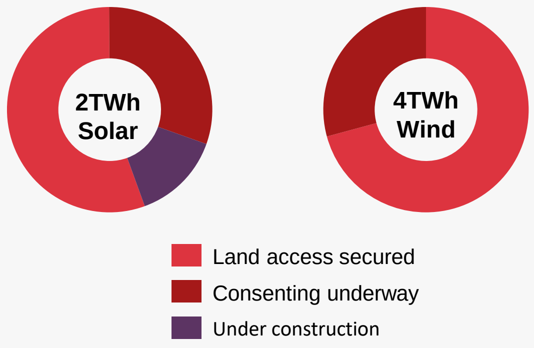
Enablers	**ESG**: create long-term value through our strong performance across a broad set of environmental, social and governance factors	**Operational excellence**: continuously improving our operations through innovation and digitisation	**Transformative ways of working**: create a flexible and high-performing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

Contact is preparing for further investment in renewable generation and storage

Geothermal generation potential (TWh p.a.)



Wind and solar options under development (TWh p.a.)[3]

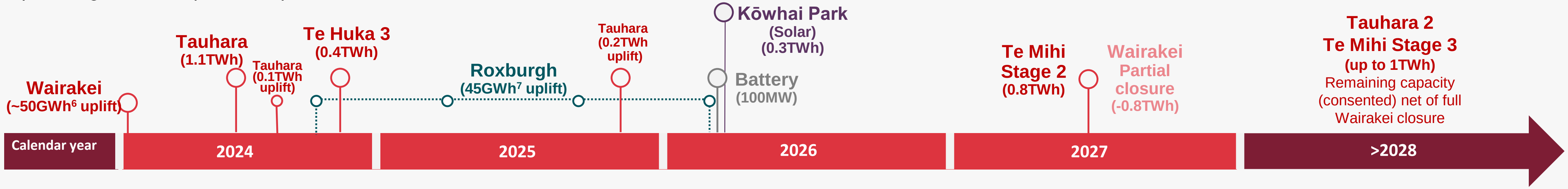


Key updates (including grid-scale batteries)

- Kōwhai Park solar (0.3TWh) and Glenbrook battery (100MW) now under construction.
- Stratford battery (100MW) consented.
- Consenting underway includes:
  - Glorit solar (0.3TWh).
  - Stratford solar (0.3TWh).
  - Southland Wind (0.9-1.2TWh).
- Earliest expected FID for these projects is FY26.
- Contact is investigating the potential to include additional battery capacity within the Glorit and Stratford solar consenting processes.[4]
- Expected FID and online dates depend on supportive market conditions and funding arrangements.

Planned Geothermal plus other renewables under construction[5]

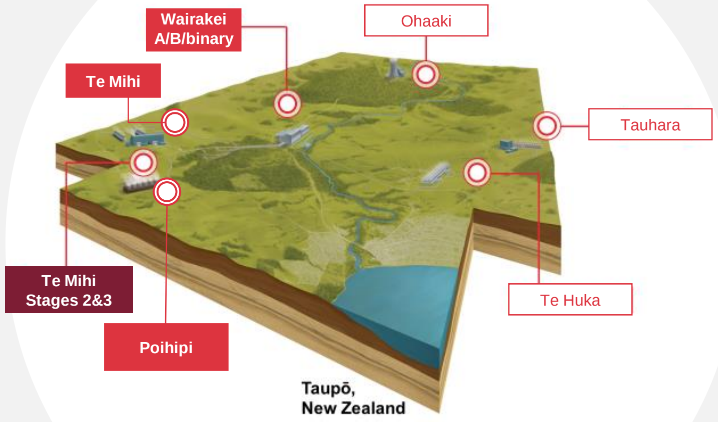
Expected generation (indicative):



[1] Includes mean geothermal generation (existing stations) plus Tauhara volume based on 135MW currently online. Also includes ~50GWh uplift already delivered on Wairakei field (see note 6).
[2] Represents uplift in Tauhara output expected from completion of final commissioning activity in 2024 (0.1TWh) and the first planned outage in October 2025 (0.2TWh)
[3] For projects included in the "land access secured" category, indicative output is shown based on early estimates of capacity per hectare and assumed capacity factors of ~40% for wind and 20-25% for solar.
[4] Consent already received for 100MW grid-scale battery at Stratford.
[5] All uncommitted investments are subject to Board investment decisions. The Tauhara, Te Huka 3, Roxburgh, Kōwhai Park and Glenbrook battery investments have been committed to.
[6] In FY24 Contact operationalised the higher consented fluid take at the Wairakei field (5kt per day) translating to a ~50GWh p.a. uplift in average geothermal generation (before new developments online) applying a ~30MWh/kt efficiency factor.
[7] 45GWh p.a. uplift is based on mean hydrology conditions.

Phased development plans for Wairakei geothermal

Contact remains committed to the long-term development of the Wairakei geothermal field



Current generating assets on the Wairakei steamfield include Wairakei A/B/binary, Poihipi and Te Mihi

Wairakei geothermal resource consented to 2058

From

Development approach	Single build
Project	GeoFuture
Scale	Up to 200MW
Technology	Binary or Steam Turbine
Target online	2H CY2026
Plans for Wairakei A/B/binary	Closure CY2026

Not proceeding

To

Development approach	Phased build	
Project	Te Mihi Stage 2	Te Mihi Stage 3
Scale	Around 100MW	Around 100MW
Technology	Binary (2 units)	Binary (2 units)
Target online	Mid CY2027	Mid CY2031
Indicative plans for Wairakei A/B/binary	Full extension of Wairakei A/B/binary to mid CY2027 + Extension of 30MW steam turbine + 7MW binary to mid CY2031	

New builds and extensions remain subject to Board final investment decisions

Te Mihi Stage 2 – Key metrics

Schedule (final investment decision)	Q4 CY2024
Estimated forward capital expenditure[1]	~$600-700m
Production / injection capacity secured	100%
Estimated MW (net export to grid)	~100MW
Estimated plant capacity factor	95%
Estimated annual output	~0.8TWh p.a.

Wairakei geothermal station extension – Indicative costs

Extension works (indicative)		Indicative SIB capex (FY26- FY27)
	Full extension of Wairakei A/B/binary to mid CY2027	$25-35m
	Extension of 30MW steam turbine + 7MW binary unit to mid CY2031	

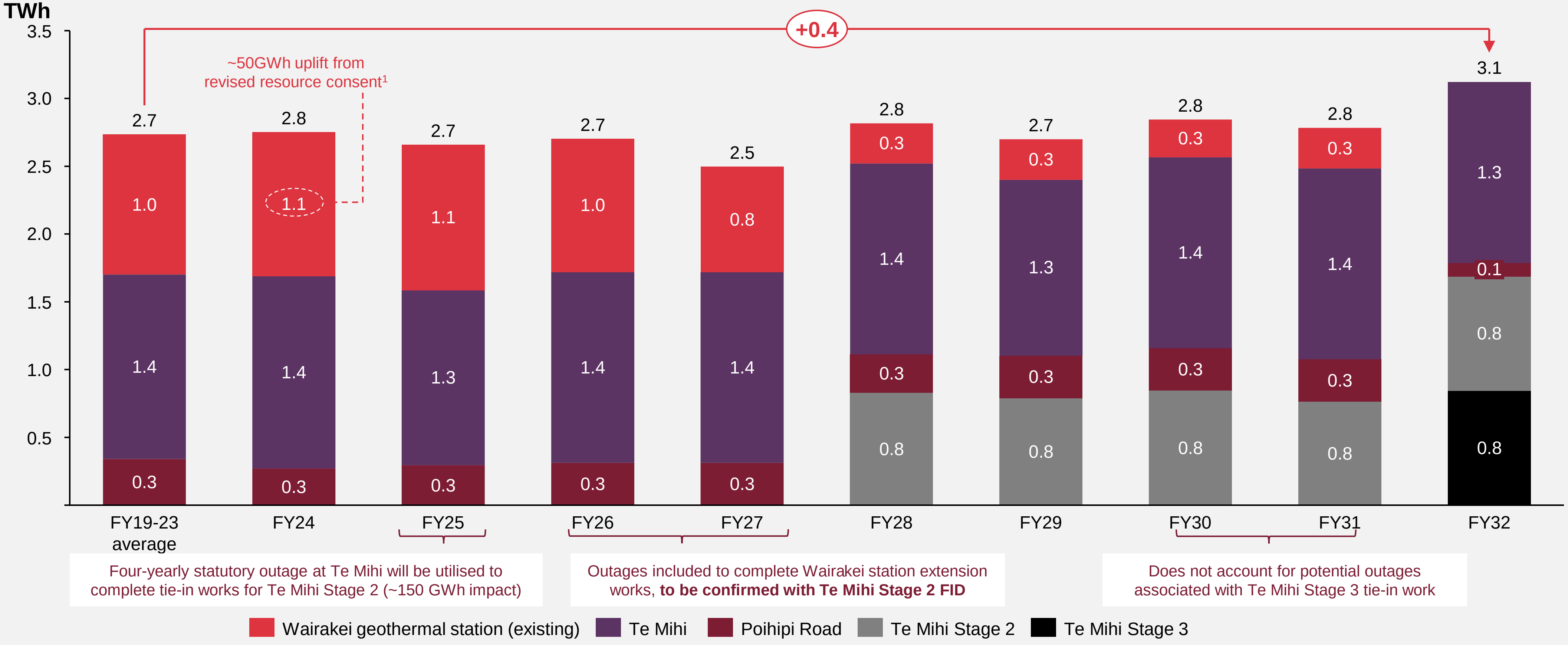
- Costs associated with the 1-year extension of the full Wairakei geothermal station reflect maintenance costs, those associated with statutory recertification, and final steps to comply with June 2026 consent conditions (consented to operate to mid CY2031).
- Working case assumes the extension of 1 steam turbine and 1 binary unit with identical standby units (steam and binary) maintained on reserve shutdown. This allows for increased reliability with 24 hour return to service capability.
- Costs to be confirmed at the same time as Te Mihi Stage 2 FID (Q4 CY2024).
- Total cash cost of extensions (SIB capex, opex) FY26-FY31 of $30-35/MWh based on the Wairakei station indicative output profile on slide 34.

[1] Excludes capitalised interest and sunk costs. Contact is assessing the allocation between Te Mihi Stage 2 and 3 of the $114m sunk costs (approved prior to May 2024) and this will be confirmed at FID for Te Mihi Stage 2.

Contact plans to deliver 0.4TWh p.a. total uplift in Wairakei field output

Total field uplift of 0.4TWh p.a. is expected to be achieved in FY32 with Te Mihi Stage 3 online (compared to historic average). Contact has already delivered ~50GWh of this benefit from its revised resource consent.

Indicative output on the Wairakei field (Wairakei geothermal station, Te Mihi, Poihipi)
(Subject to revisions and will be confirmed at final investment decision on Te Mihi Stage 2)



[1] In FY24 Contact operationalised the higher consented fluid take at the Wairakei field (5kt per day) translating to a ~50GWh p.a. uplift in average geothermal generation (before new developments online). This is based on full utlisation of the additional consented fluid at an efficiency rate of ~30MWh/kt.

Impacts of the energy transition in New Zealand are starting to become clearer

Theme	Domestic natural gas production in decline	Thermal power stations closing as more intermittent renewables come online	High level of activity to advance renewable electricity builds
Characteristics	• Ageing natural gas fields with limited forward plans for further investment. • Drilling / maintenance on major domestic fields unsuccessful. • Overall trend of output decline.	• More intermittent renewable generation entering the market, leading to increased price volatility. • High-cost baseload gas generation no longer aligns to market needs. • Thermal power stations closing.	• High volume of proposed renewable developments putting pressure on consenting bodies. • Constrained contracting market. • Generators and independent developers competing for quality resource e.g. land / sites.
Observable impacts	• Scarcity of new long-term gas contracts (and at elevated prices). • Spot gas trading at over $35/GJ. • Higher reliance on coal for electricity generation. • Stored gas and coal depleted.	• High fixed costs associated with running thermal plant need to be recovered on lower volume. • Wholesale electricity prices materially higher when thermal generation is required.	• Backlog in consenting processes. • Cost escalation on domestic construction and productive resource. • Expected returns on Contact's projects at or nearing FID remain above targets.[1]

[1] See slide 29.

Market changes indicate a value shift to flexibility, impacting future investment prioritisation

Long-run wholesale electricity prices above historic

Contact’s view of expected long-run wholesale electricity prices supports the firmed long-run cost of new renewables (annual average $115 - 125/MWh)[1]. Observed construction costs for new renewables have continued to rise.

Winter Summer Price Separation Widening

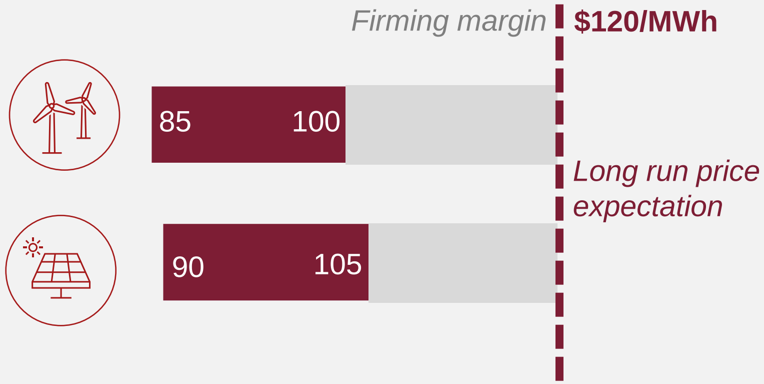
While average prices reflect long-run economics, ASX Futures illustrate winter prices rising by substantially more than summer prices. This reflects the requirement to recover thermal system fuel costs and the expected increase in must-run renewables within the market.

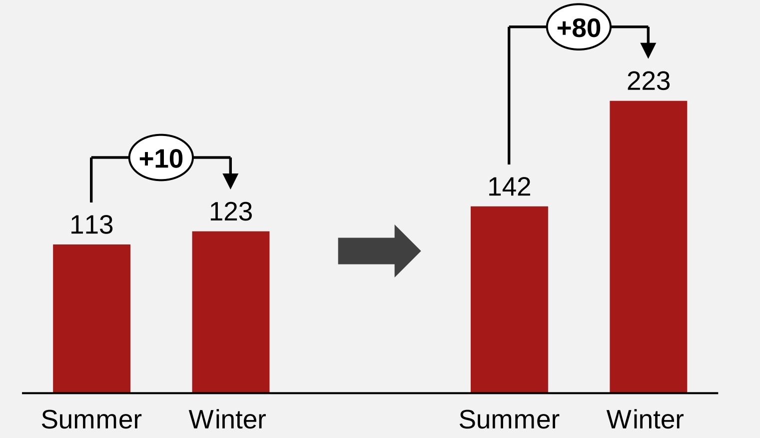
Value shift to flexibility

We expect value to shift from intermittent renewable generation to the owners of flexible, renewable storage.

LRMC of renewables

($MWh 2024 Real)[2]





Historical spot price at OTA CY2017 – CY2023 ($/MWh)[3]

ASX Future prices at OTA CY2027 ($/MWh)[4]

“Flexibility in supply and demand becomes the ‘secret sauce’ ……..as the system shifts towards renewable supply.”

Market Development Advisory Group

Sources of new renewable flexibility

- Grid scale batteries
- Demand response
- Biomass
- Hydro operating ranges
- Pumped hydro

[1] As indicated in November 2022, updated for inflation and includes update to reflect higher cost of capital. This is a through-the-cycle measure in a balanced market. Prices achieved are a function of the market at a point in time.
[2] Based on announced capex and financing structures on the most recent projects for wind (Kaiwera Downs 2) and solar (Kōwhai Park) and discount rates tied to broker WACC estimates for the industry of 7-9%.
[3] EMI daily simple average spot price data from 1/10/16 – 31/12/23. Winter is defined here as 1 Oct – 31 March, Summer is defined as 1 April – 30 Sept.
[4] ASX futures prices as at 5 August 2024

Our operational plan

What you can expect in the next 12 months

Strategic theme	FY25	
Grow Demand	New demand facilitated since FY21 to reach >120MW.[1] Add 15MW of contracted flexible demand.[2]	Achieve FID for CO_2 commercialisation.
Grow renewable development	Te Huka 3 online Q4 CY2024. Glenbrook Battery (BESS) on-track for online Q1 CY2026. Kōwhai Park Solar on track for online for Q2 CY2026.	Achieve FID for Te Mihi Stage 2. Lodge consent for Stratford Solar. Achieve consent on Glorit Solar. Achieve consent on Southland Wind.
Decarbonise our portfolio	Close TCC (Taranaki Combined Cycle) gas generation plant. Expected to close December 2024.	Sustained New Zealand leadership position in the Asia Pacific DJSI.
Create outstanding customer experiences	Multi-product customers >148k (up from 140k). Cost to serve <$123/connection.	Targeting electricity net price up 2-3%. Scale Hot Water Sorter programme[3] to >20k homes (up from ~5k).

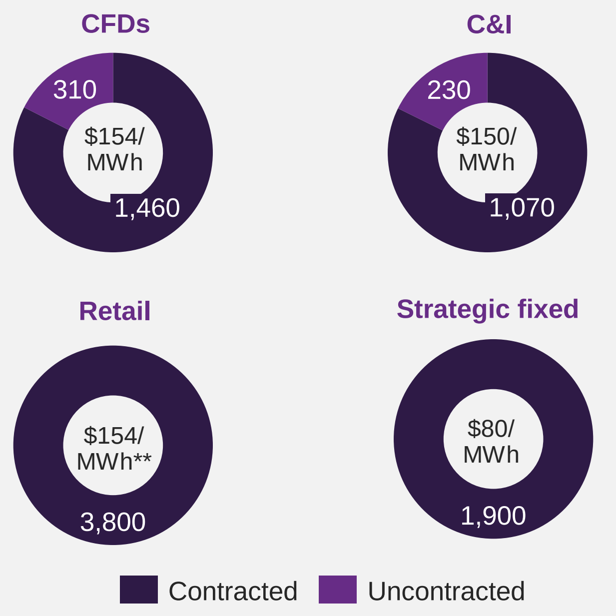
[1] Cumulative measure (~105MW at 30 June 2024).
[2] Up from 173MW contracted at 30 June 2024.
[3] Residential Demand Flex.

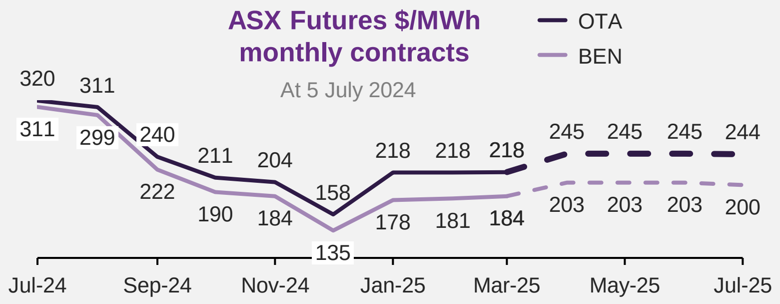
Questions

Supporting materials

Normalised and expected FY25 EBITDAF

Assumes mean hydrology conditions

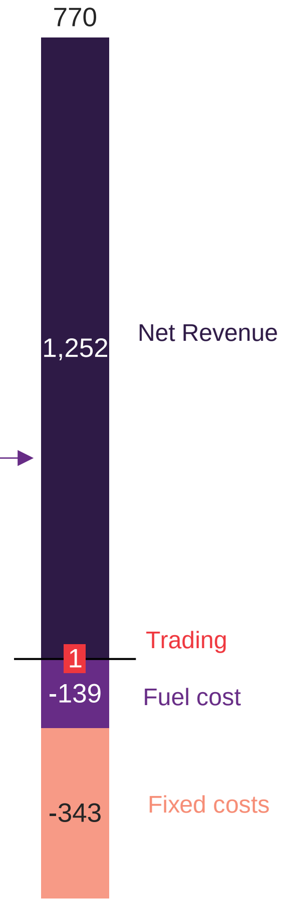




FY assumptions that deliver expected & normalised EBITDAF for FY25

1 Channel choices maximise long term value[1]		X	2 Net price[2] driven by best commercial practices	=	Total
Strategic fixed price	1,900GWh	x	$80/MWh	=	$152m
CFDs	1,770GWh	x	$154/MWh	=	$273m
C&I	1,300GWh	x	$150/MWh	=	$195m
Retail	3,800GWh	x	$154/MWh		$585m
Other income[3]					$47m
					$1,252m
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	4,620GWh	x	$4/MWh	=	-$19m
Thermal	350GWh	x	$130/MWh[4]	=	-$46m
Acquired	350GWh	x	$215/MWh		-$75m
					-$139m

5 Trading delivers value to more than offset locational losses		6 Digitalisation & continuous improvement optimise fixed costs	
Length[5]	$86m	Transmission/Storage	-$71m
Location losses[6]	-$85m	Operating expenses	-$272m
Total	**$1m**	**Total**	**-$343m**



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, telco gross margin and other income
4. Gas price of $8.20/GJ, carbon price of $80/unit and thermal portfolio heat rate (10GJ/MWh)
5. Length of 450GWh p.a. assumed
6. Locational losses of 5.1% on spot purchases and settlement of CFDs sold at a wholesale price of $190/MWh

* Fuel is natural gas and carbon costs.
** Retail volume contracted competitive risk remains on pricing achieved.

Note, all figures are subject to rounding.

Guidance below EBITDAF

	FY24 guidance	FY24 result	FY25 guidance	Commentary
Stay in Business Capex	**$120-130m[1]**	**$110m**	**$115m - $125m**	
Stay in business accelerated programme (cash)	$55m - $60m	$39m	~$40m	As at the end of FY24 we had spent $104m out of the $150m accelerated stay in business capex programme.
Stay in business capital expenditure (cash) BAU	$65m - $70m	$71m	$75m-$85m	Includes $10m of provisions related to consent obligations and decommissioning activity.
Growth capital expenditure (cash)[2]	$400m - $500m	$470m	$450m - $550m	Growth capital for Tauhara, Te Huka, GeoFuture, Wind and Battery projects.
Depreciation and amortisation	$250m - $260m	$255m	$275m - $285m	Reflects useful life changes on thermal and geothermal assets as well as introduction of Tauhara and Te Huka unit 3.
Net interest (accounting)	$45m - $55m	$40m	$115m - $125m	Reduction in capitalisation of interest with Tauhara commissioning. Higher interest rate environment and increased borrowings.
Cash interest (in operating cash flow)	$27m - $37m	$21m	$95m - $105m	
Cash taxation	$95m – $105m	$97m	$110m - $120m	FY25 provisional payments based on FY23 results and higher final tax payment relating to FY24.
Realised (gains) / losses on market derivates not in a hedge relationship	$10m - $15m	$3m	$10m - $15m	Including (gains) / losses on ASX market making.
Corporate costs	$52m	$51m	$52m	Inflation impacts in FY25 see corporate costs expected to be steady, noting that FY24 included one-off impacts for consultant spend.
Target ordinary dividend per share	Minimum 35 cps	37 cps	39 cps	Payout in line with dividend policy and reflecting Tauhara and Te Huka 3 online and new long-term NZAS deal reached in 2024.

[1] FY24 guidance range is gross i.e. before the netting of insurance proceeds of $15m.
[2] Growth capital expenditure includes capitalised interest.

Normalised and expected EBITDAF assumptions

With reconciliation to actual performance

FY24 assumptions that deliver expected & normalised EBITDAF of $600m 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	1,150GWh	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	3,900GWh	x	$0/MWh	=	-$0m
Geothermal	3,250GWh	x	$5/MWh	=	-$16m
Thermal[4]	1,800GWh	x	$120/MWh	=	-$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	-$258m
Total	**$1m**	**Total**	**-$328m**

EBITDAF guidance reconciliation to actual FY24

Normalised & Expected

Lower renewables
Renewable generation below mean (-134GWh). Impact calculated at expected thermal SRMC

Increased long–term channel price
Retail net price of $150/MWh higher than full year expectation

Increased market channel price
Higher than expected CFD price partially offset by higher $/MWh location losses

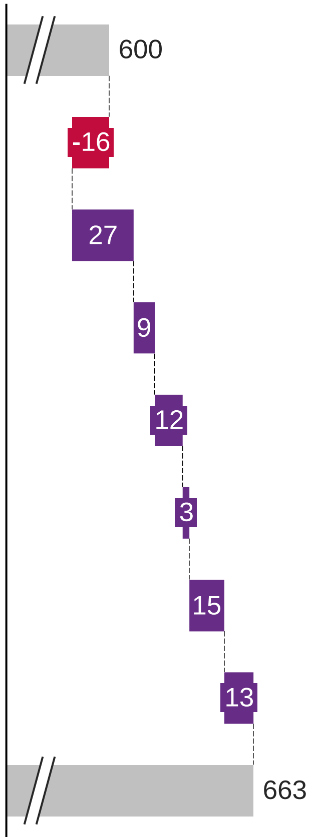
Gas, carbon, acquired generation price
Gas and carbon price as well as thermal efficiency were favourable

Net volume impact
Total sales volumes above expectations

Other income
Risk management sales premiums and expected losses from distressed gas sales not realised

Fixed costs
Received $10m 'loss and constraint excess' (LCE) rebates

Actual FY24 (underlying)



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, telco 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 assumed
6. Locational losses of 4.3% on spot purchases and settlement of CFDs sold at a wholesale price of $139/MWh

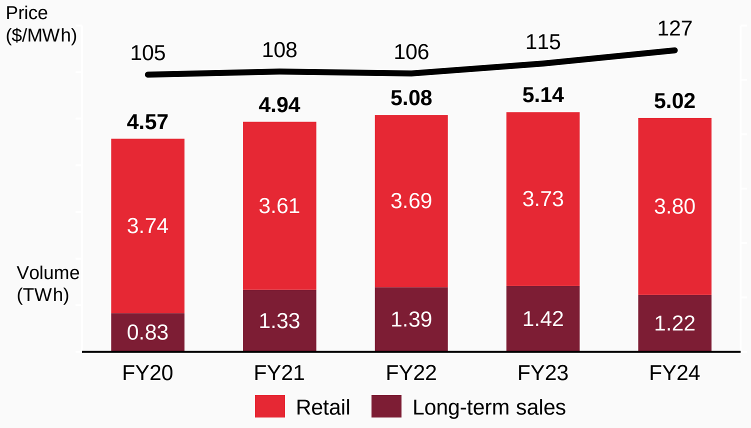
Integrated portfolio performance

Operating earnings (EBITDAF)

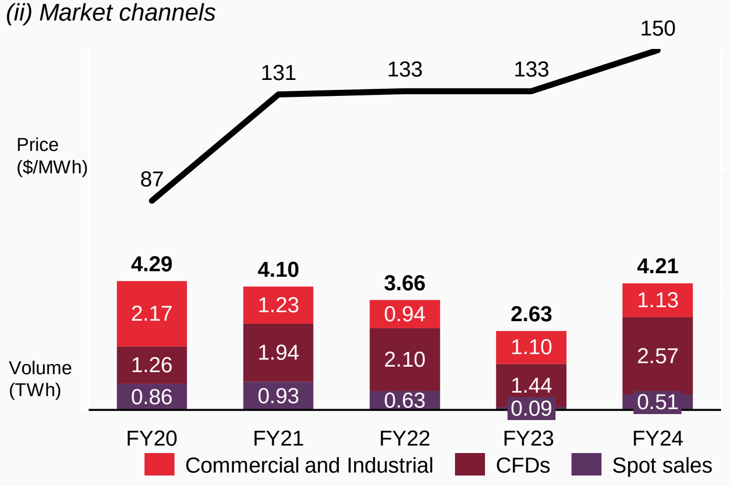
Continuing operations ($m)

1 Electricity sales

(i) Long-term channels

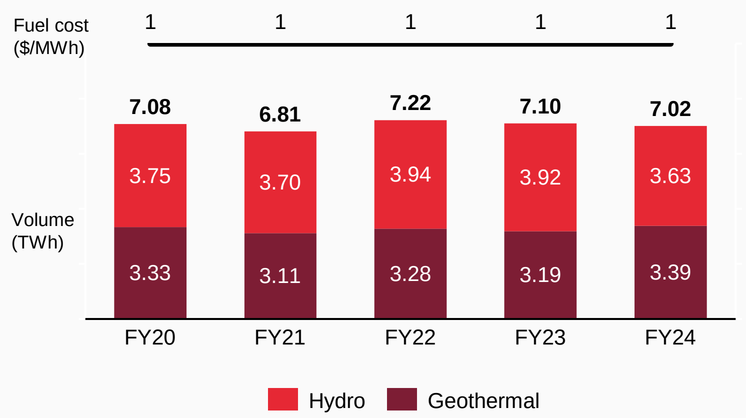


(ii) Market channels

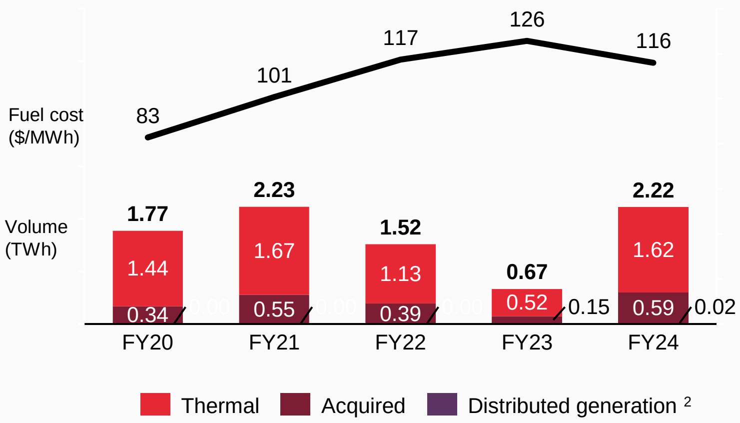


2 Variable fuel costs

(i) Renewables



(ii) Thermal and acquired



[1] Refer to slide 50 for a definition and reconciliation of EBITDAF. All EBITDAF figures are underlying i.e. excluding the impacts of the ($113m) AGS onerous contract provision expense in FY23 and $12m net movement in the AGS provision in FY24. Contact no longer reports impairments and write-downs within EBITDAF in order to better reflect underlying performance.
[2] Distributed generation reflects electricity purchased from solar customers within the retail business.

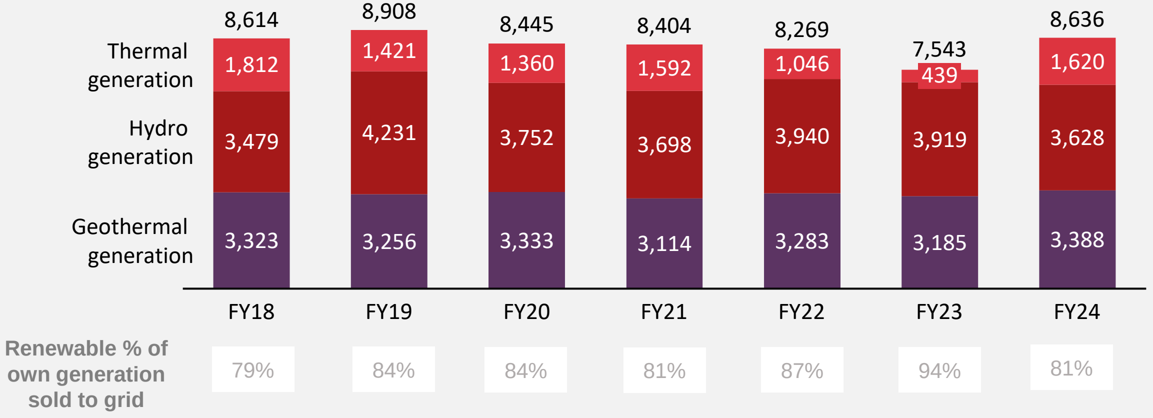
Greenhouse gas emissions

Indicator	Unit	Target	FY20	FY21	FY22	FY23	FY24
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**	**947,491**
- Stationary combustion	tC02e		920,403	1,044,537	786,544	526,282	947,131
- Mobile combustion	tC02e		270	178	297	307	332
- Fugitive emissions	tC02e		4	29	1	32	28
Indirect GHG emissions (Scope 2)	tC02e		**1,258**	**1,303**	**1,399**	**1,957**	**975**
Sub-total Scope 1 and 2	**tC02e**	**647,443**	**921,935**	**1,046,047**	**788,241**	**528,579**	**948,466**
Indirect GHG emissions (Scope 3)	**tC02e**	**259,118**	**317,384**	**555,035**	**394,784**	**273,673**	**265,034**
- 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	6,522
- Category 2 – Capital goods	tC02e		18,052	41,726	57,876	88,266	79,185
- Category 3 – Fuel and energy[1]	tC02e		91,857	330,207	149,743	1,050	5,130
- Category 4 - Upstream distribution and transportation	tC02e		14	27	444	108	254
- Category 5 – Waste	tC02e		123	149	108	47	58
- Category 6 – Business travel	tC02e		719	263	567	1,274	1,601
- Category 7 – Employee commuting	tC02e		606	306	832	965	927
- Category 11 – Use of sold products	tC02e		166,310	165,259	178,554	175,603	170,929
- Category 13 – Downstream leased assets	tC02e		306	399	289	164	429
Total Scope 1, 2 and 3 emissions	**tC02e**	**906,561**	**1,239,319**	**1,601,082**	**1,183,025**	**802,252**	**1,213,500**

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

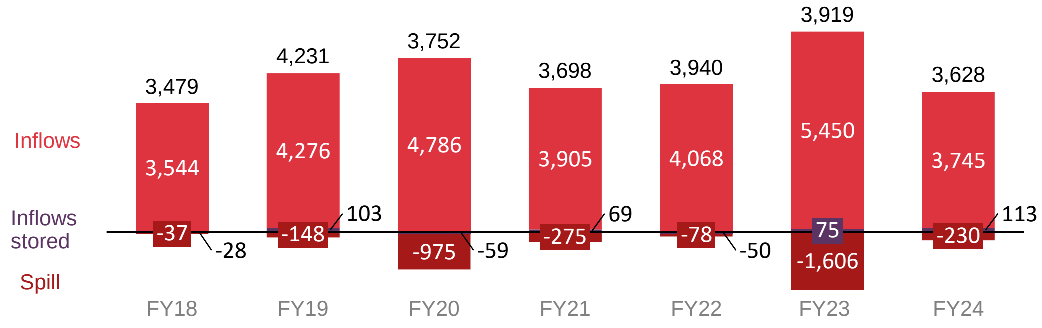
Generation and sales position

Contact generation output sold to the national grid (GWh)



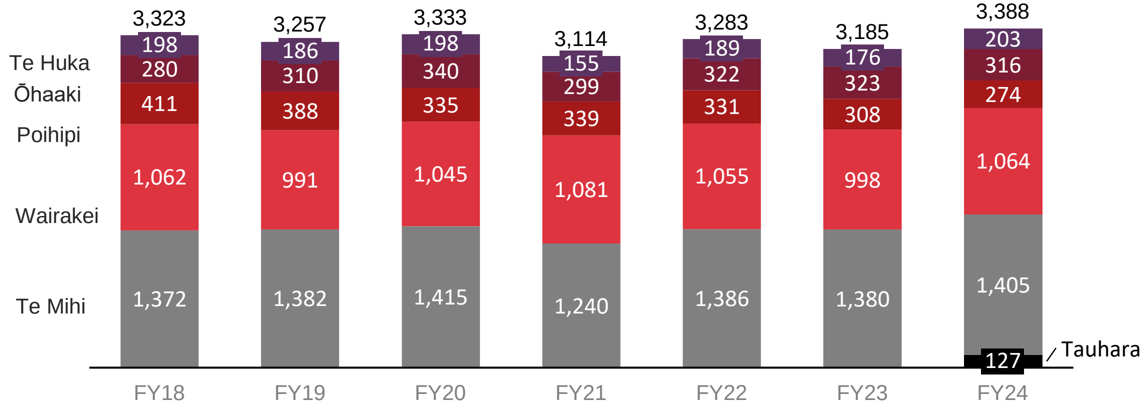
Hydro generation (GWh)

Inflows stored include uncontrolled storage lakes



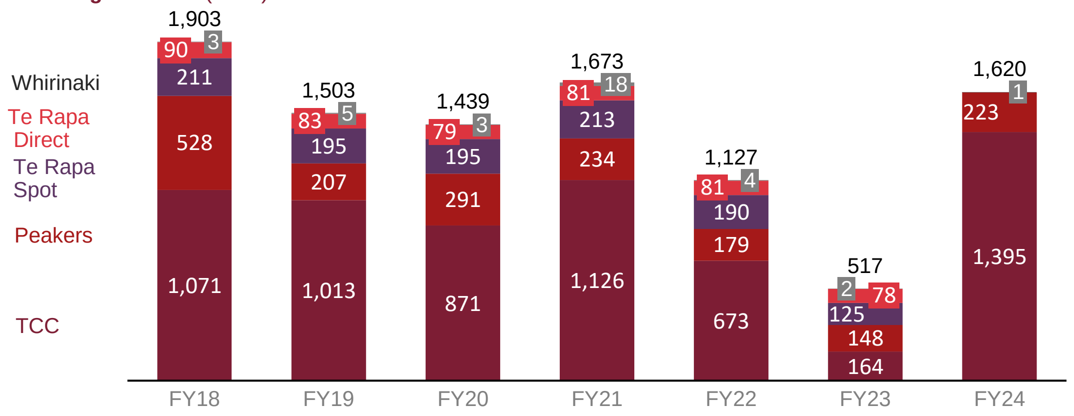
An uncharacteristic El Niño weather pattern resulted in FY24 hydro inflow volumes 31% lower than FY23 and the lowest seen since FY18. Further, inflows during the period were highly concentrated leading to spill, however this was significantly lower than spill seen in FY23.

Geothermal generation (GWh)



FY24 geothermal generation was 203 GWh higher than FY23 as a result of the increased consented mass take from the Wairakei steam field and Tauhara coming online in late FY24.

Thermal generation (GWh)

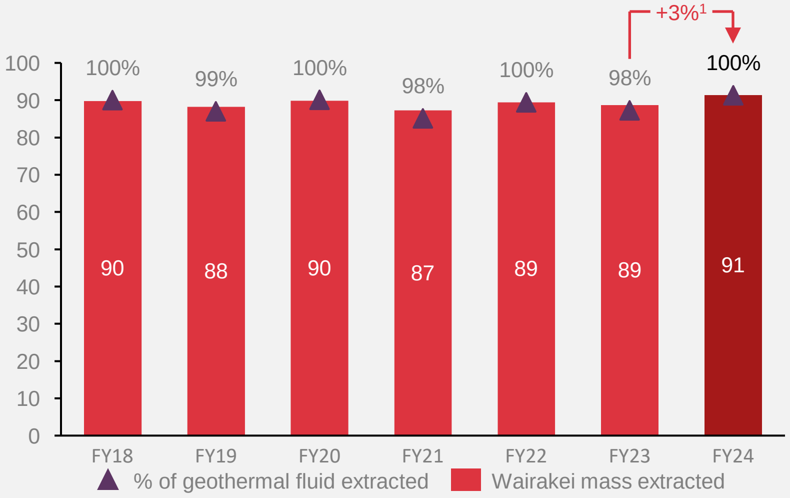


FY24 thermal generation volumes were 1,102GWh higher than FY23 due to dry conditions in summer 2023 and winter 2024, as well as the delay to Tauhara online.

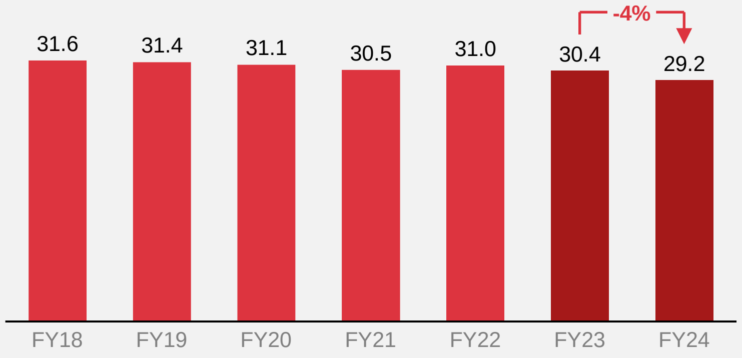
Plant and fuel performance

Geothermal fuel performance

Geothermal fuel extracted at Wairakei vs consented (mT)



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



Plant availability[3]

Hydro

	Net capacity (MW)	Availability (%)	Capacity factor (%)	Electricity output (GWh)	Pool revenue ($/MWh)	($m)
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
FY24	784	90%	53%	3,628	164	594

Taranaki combined cycle (TCC)

	Net capacity (MW)	Availability (%)	Capacity factor (%)	Electricity output (GWh)	Pool revenue ($/MWh)	($m)
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
FY24	377	82%	42%	1,395	184	257

Te Rapa (spot generation only)

	Net capacity (MW)	Availability (%)	Capacity factor (%)	Electricity output (GWh)	Pool revenue ($/MWh)	($m)
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
FY24[2]	-	-	-	-	-	-

Geothermal

	Net capacity (MW)	Availability (%)	Capacity factor (%)	Electricity output (GWh)	Pool revenue ($/MWh)	($m)
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[4]	94%	89%	3,186	80	254
FY24	586[4]	94%	89%	3,388	177	601

Stratford Peakers

	Net capacity (MW)	Availability (%)	Capacity factor (%)	Electricity output (GWh)	Pool revenue ($/MWh)	($m)
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
FY24	202	50%	12%	223	175	39

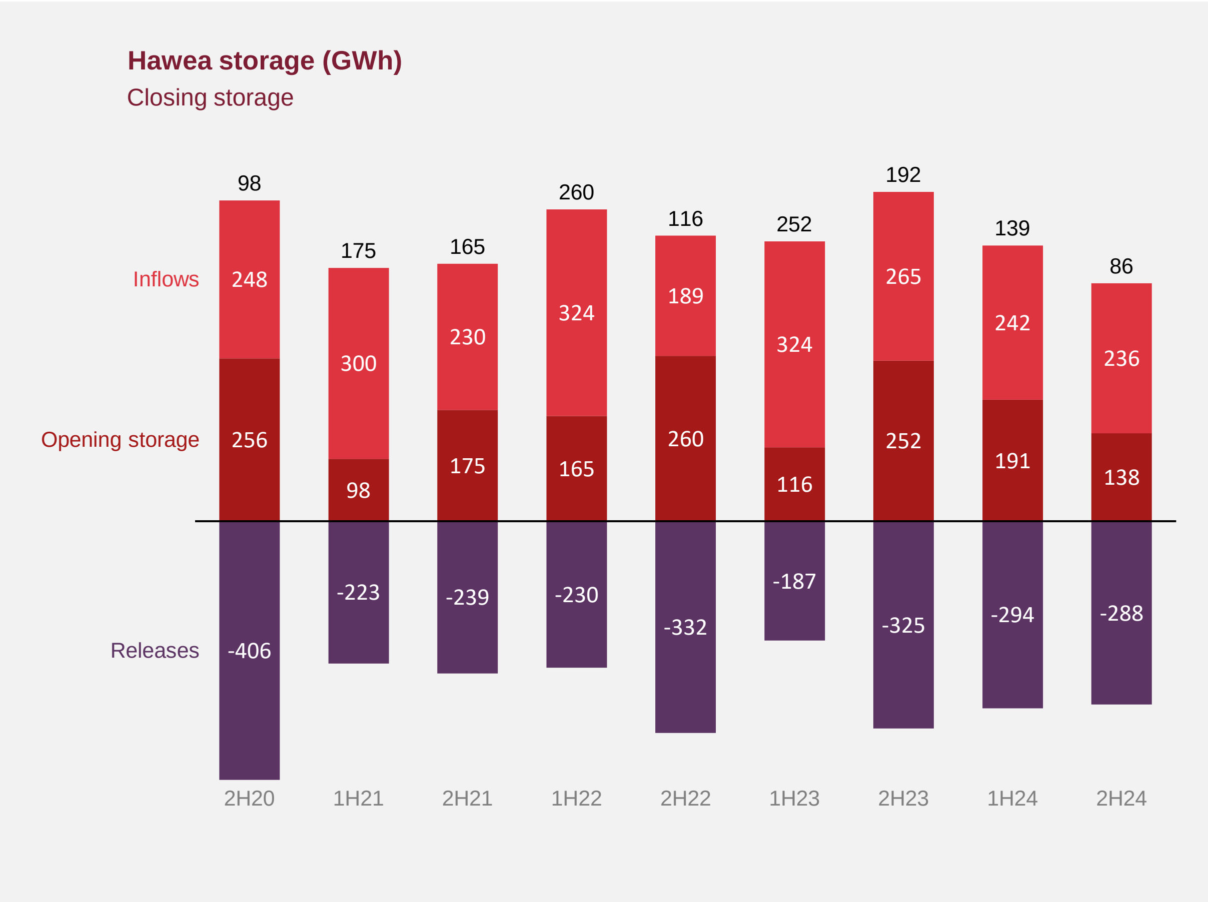
Whirinaki

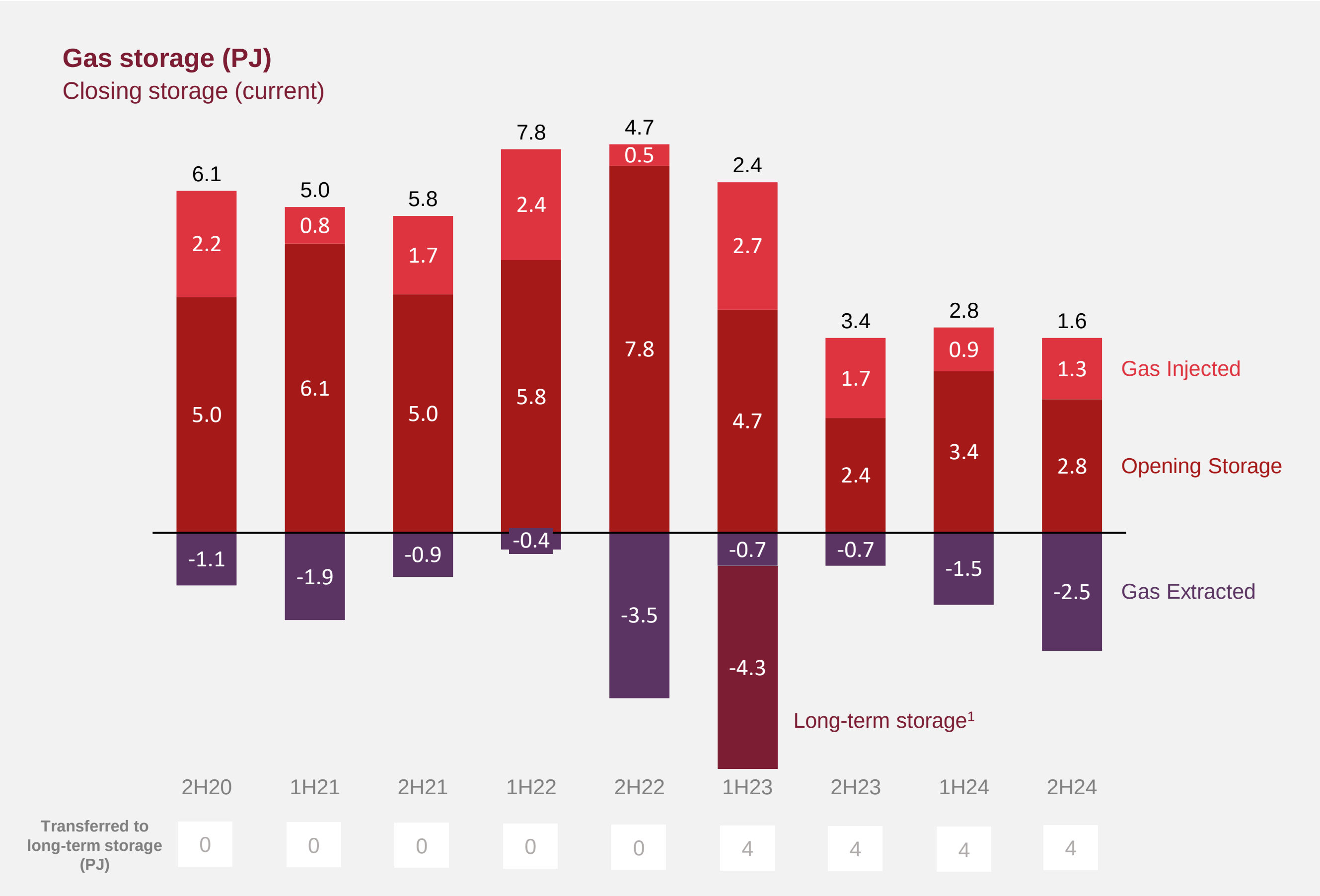
	Net capacity (MW)	Availability (%)	Capacity factor (%)	Electricity output (GWh)	Pool revenue ($/MWh)	($m)
FY20	158	98%	0%	3	293	1
FY21	158	94%	0%	18	410	7.5
FY22	158	95%	0%	4	597	2
FY23	158	82%	0%	2	491	1.2
FY24	158	97%	0%	1	687	1.1

[1] Percent change relates to the movement in geothermal mass extracted (mT) at Wairakei YoY.
[2] Te Rapa was decommissioned at the end of the FY23.

[3]Availability Factor calculation includes all station outages (Planned, Maintenance, Forced) but does not consider plant deratings.
[4]Reduction in geothermal net capacity in FY23 was a result of decommissioning of wells on the Wairakei steamfield. Increase in FY24 relates to Tauhara.

Fuel storage movements



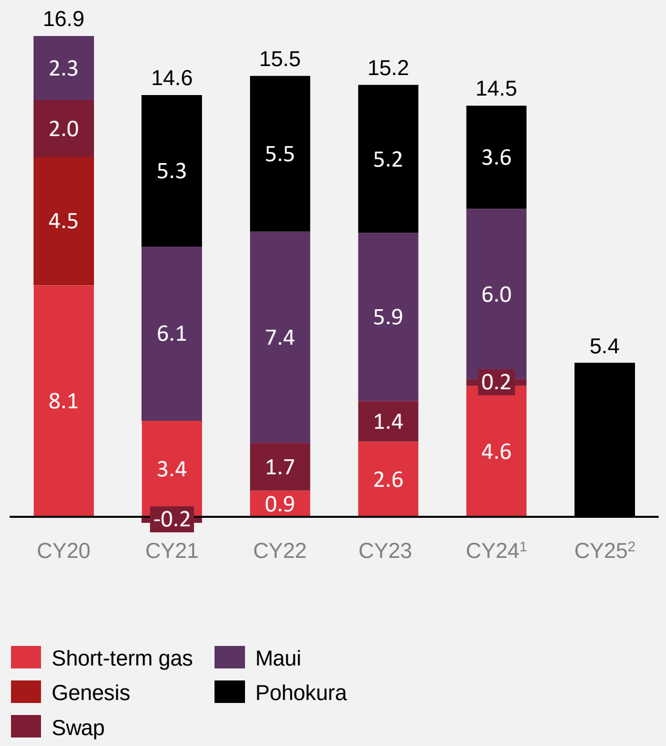


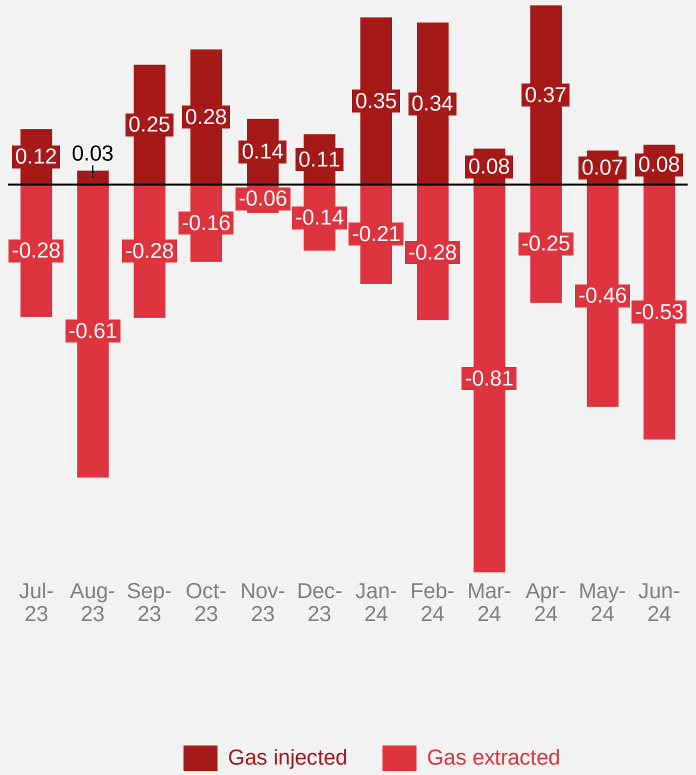
Source: NZX Hydro data

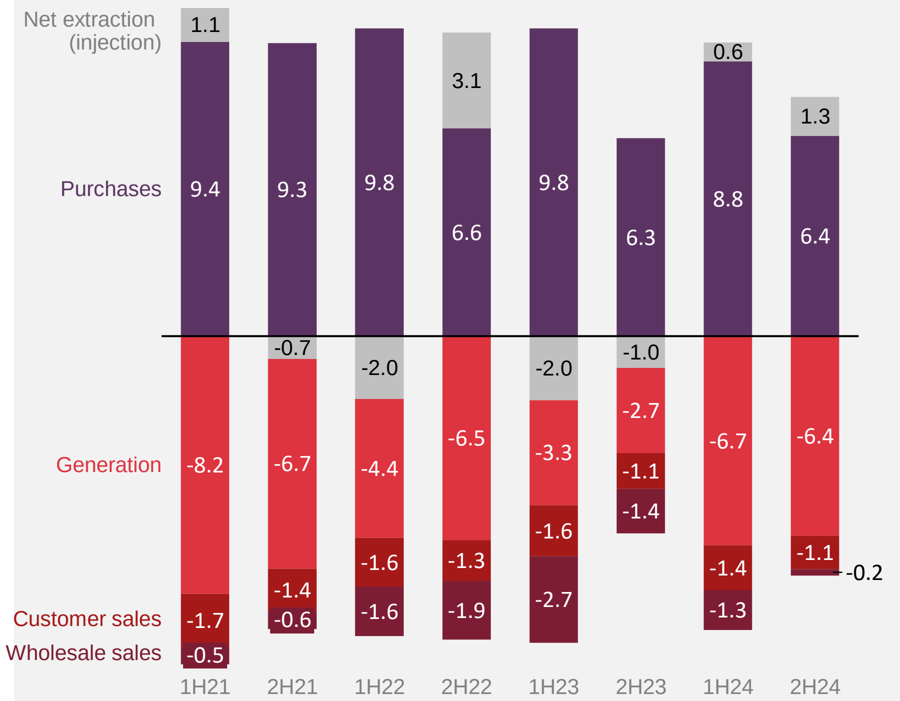
[1] Updated from previous reporting to 4.3PJ vs ~4 PJ. This change has been made to improve reporting of currently available gas storage, there has been no material change in AGS total available storage capacity.

Operational data

Contracted and stored gas



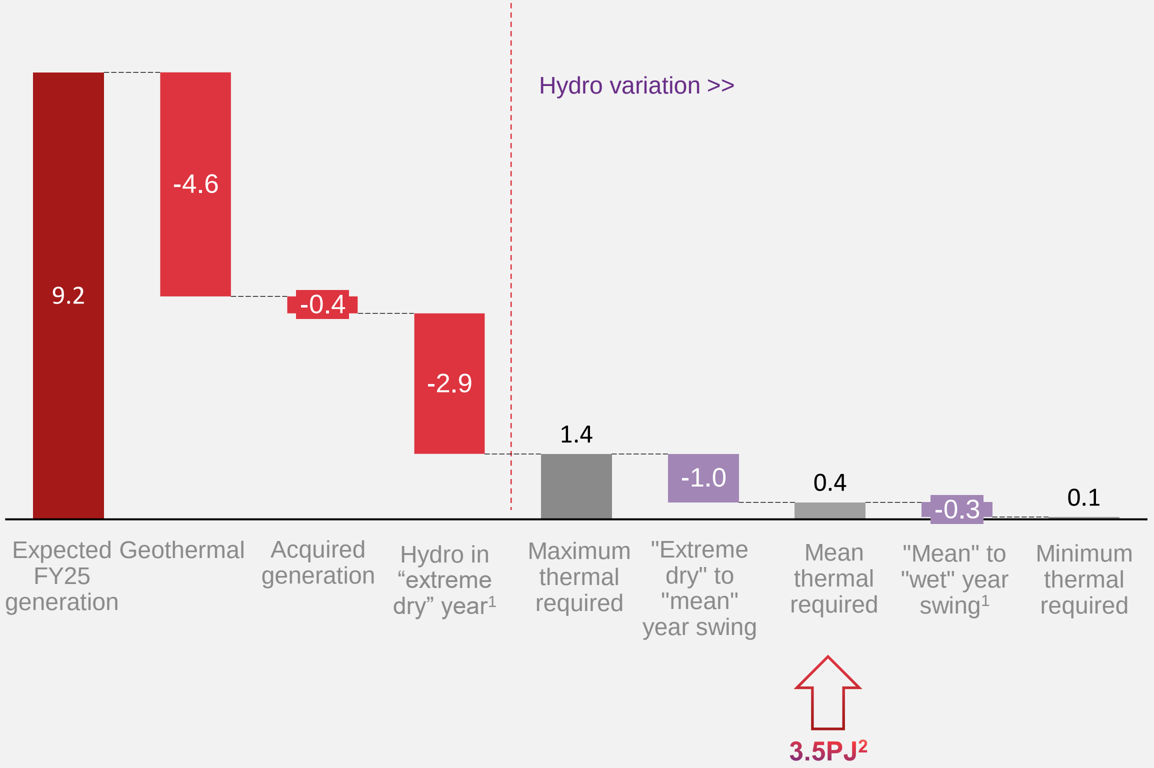




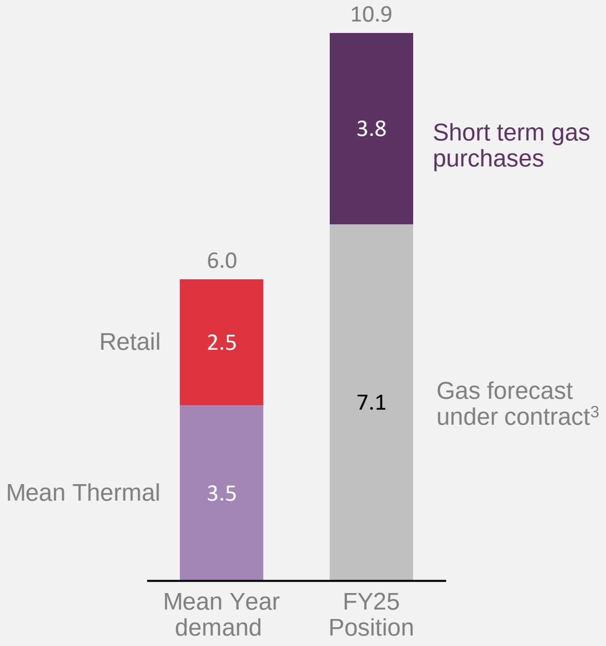
¹ CY24 reflects actual volumes and forecasts for the second half of the year.
² CY25 reflects forecast volumes.

Contractual fuel position sufficient to support expected FY25 sales position

Portfolio requirements for thermal generation (TWh)



Gas supply and demand FY25 (PJ)



Options in a dry year:

- Access to stored water in Hawea.
- Access to gas in Ahuroa Gas Storage facility (AGS).
- Purchase spot gas or short-term gas tranches / arrangements
- Stop selling uncontracted electricity
- Acquire generation from ASX

.

[1] Dry year reflects hydro generation in FY12 and wet year reflects hydro generation in FY15.
[2] Assumes mix of TCC and peaker generation (portfolio heat rate (10GJ/MWh)).
[3] This incorporates the lower bound of the range notified by our suppliers as disclosed to the market on 7 April 2024. Of note, if drilling results and well performance are lower than expected we could see a further reduction to this forecast.

Reconciliation between Profit and EBITDAF

EBITDAF is Contact's earnings before interest, tax, depreciation and amortisation, asset impairment and write-offs, 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 2024		12 months ended 30 June 2023	Variance on prior year	
				$m	%
	Underlying[1]	Reported	Underlying[1]	Against underlying	
Profit	**230**	**235**	**211**	**19**	**9%**
Depreciation and amortisation	255		224	31	14%
Change in fair value of financial instruments	(8)		18	-26	(144%)
Net interest expense	35	40	38	-3	(8%)
Tax expense	101	103	82	19	23%
Asset impairment / write-offs	50		-	50	nmf[2]
EBITDAF	**663**	**675**	**573**	**90**	**16%**

Movements in depreciation and amortisation, net interest, tax expense and asset impairment / write-offs are explained on the right.

The adjustments from EBITDAF to reported profit and movements on FY23 are as follows:

- **Depreciation and amortisation:** Increased by $31m due to increase in restoration provisions from FY23 and accelerated depreciation on Thermal and Wairakei assets in light of expected replacement. This was partially offset by extending the useful life of SAP assets upgraded as part of the recent S/4 Hana upgrade.
- **Net interest expense:** Interest is $3m lower than FY23 with increase in interest on higher debt balances being offset by increase in capitalised interest on Tauhara.
- **Tax expense** for the period increased by $19m following higher operating earnings.
- **Asset impairment** associated with:
  - Write-offs relating to peaker engine damage (GT22).
  - Write-off of Tauhara assets relating to the 2023 steam hammer event and failure of valves.
  - Write-off of software assets relating to CRM and HRIS projects not proceeding as originally planned.

[1] In FY23 Contact recognised a net onerous contract provision expense for AGS of ($113m) within EBITDAF and ($84m) within profit. In FY24 Contact has recognised a net movement in the AGS onerous contract provision of $12m within EBITDAF and $5m within profit. Underlying performance excludes these impacts. All variances and commentary reflect movements in underlying performance.

[2] Not meaningful on a percentage basis.

Historical financial information

	Unit	FY20	FY21	FY22	FY23		FY24	
					Underlying[1]	Reported	Underlying[1]	Reported
Revenue	$m	2,073	2,573	2,387	2,118		2,863	
Expenses	$m	1,627	2,020	1,820	1,500	1,613	2,200	2,188
EBITDAF	$m	446	553	546	573	460	663	675
Profit	$m	125	187	182	211	127	230	235
Operating free cash flow	$m	290	371	330	282		470	
Operating free cash flow per share	cps	40.4	50.2	42.4	36.0		59.8	
Dividends declared	cps	39	35	35	35		37	
Total assets	$m	4,896	5,028	5,166	5,808		6,208	
Total liabilities	$m	2,275	2,101	2,326	3,004		3,589	
Total equity	$m	2,621	2,927	2,840	2,804		2,619	
Gearing ratio[3]	%	31	23	28	36		42	

[1] In FY23 Contact recognised a net onerous contract provision expense for AGS of ($113m) within EBITDAF and ($84m) within profit. In FY24 Contact has recognised a net movement in the AGS onerous contract provision of $12m within EBITDAF and $5m within profit. Underlying performance excludes these impacts.

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

Note: From FY24 Contact no longer reports impairments and write-offs within EBITDAF. These are now reported separately to better reflect underlying performance. FY24 EBITDAF is stated excluding $50m of write-offs and impairments. Previous years have not been restated (FY22 includes a $1.5m peaker write-off).

Wholesale segment

Note: this table has not been rounded and might not add	FY24 Year ended 30 June 2024 Volume GWh	GWAP $/MWh	$m	FY23 Year ended 30 June 2023 Volume GWh	GWAP $/MWh	$m
Electricity sales to Retail segment	**3,787**	**148**	**562**	**3,727**	**129**	**482**
Electricity sales to C&I (netback)	1,456	129	188	1,499	114	171
Electricity sales – Direct to Customer	-	-	-	78	159	12
Electricity sales to C&I	**1,456**	**129**	**188**	**1,577**	**116**	**183**
CfDs – Tiwai support sales	892			938		
CfDs - Long term sales	752			524		
CfDs and ASX - Short term sales	1,820			913		
Electricity sales – CFDs	**3,465**	**118**	**407**	**2,375**	**94**	**223**
Total contracted electricity sales	**8,707**	**133**	**1,157**	**7,678**	**116**	**889**
Steam sales	**194**	**18**	**3.4**	**587**	**60**	**35**
Other income			8			4
Net income on gas sales			3			2
Net income on electricity related services			(0)			6
Net other income			**11**			**12**
Total contracted revenue	**8,901**	**132**	**1,171**	**8,265**	**113**	**936**
Generation costs[1]	8,635	(40)	(349)	7,622	(31)	(239)
Acquired generation cost	585	(160)	(93)	150	(120)	(18)
Generation costs (including acquired generation)	**9,220**	**(48)**	**(443)**	**7,772**	**(33)**	**(257)**
Spot electricity revenue	8,635	177	1,529	7,544	82	621
Settlement on acquired generation	585	195	114	150	66	10
Spot revenue and settlement on acquired generation (GWAP)	**9,220**	**178**	**1,643**	**7,694**	**82**	**631**
Spot electricity cost	(5,243)	(193)	(1,009)	(5,226)	(93)	(488)
Settlement on CFDs sold	(3,465)	(178)	(616)	(2,375)	(81)	(192)
Spot purchases and settlement on CFDs sold (LWAP)	**(8,707)**	**(187)**	**(1,626)**	**(7,600)**	**(89)**	**(680)**
Trading, merchant revenue and losses	**513**		**18**	**93**		**(48)**
Wholesale EBITDAF underlying[1]			**746**			**632**
Onerous contract provision			(12)			113[1]
Wholesale EBITDAF reported			**758**			**518**

[1] In FY23 Contact recognised a net onerous contract provision expense for AGS of ($113m) within EBITDAF and ($84m) within profit. In FY24 a net movement in the AGS onerous contract provision equated to $12m within EBITDAF and $5m within profit. Underlying performance excludes these impacts.

Retail segment

Residential electricity	unit	FY21	FY22	FY23	FY24
Average connections	#	357,117	373,347	380,482	388,459
Sales volumes	GWh	2,520	2,644	2,688	2,798
Average usage	MWh per ICP	7.1	7.1	7.1	7.2
Tariff	$/MWh	253.4	256.4	272.1	287.9
Network, meters and levies	$/MWh	-118.0	-119.5	-122.7	-128.0
Energy costs[1]	$/MWh	-100.2	-115.0	-138.6	-158.8
Gross margin	**$/MWh**	**35.2**	**21.9**	**10.8**	**1.1**
Gross margin	$ per ICP	249	155	77	8
Gross margin	$m	89	58	29	3

Residential gas	unit	FY21	FY22	FY23	FY24
Average connections	#	60,701	64,649	66,605	68,092
Sales volumes	TJ	1,495	1,583	1,504	1,584
Average usage	GJ per ICP	24.6	24.5	22.6	23.3
Tariff	$/GJ	35.3	36.6	42.1	45.1
Network, meters and levies	$/GJ	-18.6	-18.9	-22.9	-24.5
Energy costs	$/GJ	-8.6	-11.8	-10.1	-9.8
Carbon costs	$/GJ	-1.5	-2.1	-4.2	-3.1
Gross margin	**$/GJ**	**6.5**	**3.8**	**4.9**	**7.7**
Gross margin	$ per ICP	107	92	112	181
Gross margin	$m	10	6	7	12

SME electricity	unit	FY21	FY22	FY23	FY24
Average connections	#	49,679	48,459	46,962	44,113
Sales volumes	GWh	860	798	794	754
Average usage	MWh per ICP	17.3	16.5	16.9	17.1
Tariff	$/MWh	231.7	239.7	259.3	282.2
Network, meters and levies	$/MWh	-106.4	-112.9	-117.0	-118.3
Energy costs[1]	$/MWh	-99.3	-113.7	-138.6	-157.3
Gross margin	**$/MWh**	**26.1**	**13.0**	**3.6**	**6.6**
Gross margin	$ per ICP	451	215	62	112
Gross margin	$m	22	10	3	5

SME gas	unit	FY21	FY22	FY23	FY24
Average connections	#	3,876	3,889	3,519	2,972
Sales volumes	TJ	1,313	1,224	1,063	794
Average usage	GJ per ICP	339	315	302	267
Tariff	$/GJ	16.3	19.8	25.2	31.0
Network, meters and levies	$/GJ	-7.9	-8.3	-9.5	-11.6
Energy costs	$/GJ	-8.6	-11.8	-10.1	-9.8
Carbon costs	$/GJ	-1.5	-2.1	-4.2	-3.1
Gross margin	**$/GJ**	**-1.6**	**-2.4**	**1.4**	**6.5**
Gross margin	$ per ICP	-552	-769	412	1,750
Gross margin	$m	-2	-3	1	5

Telco	unit	FY21	FY22	FY23	FY24
Average connections	#	39,245	62,388	79,057	95,168
Tariff	$/cust/mth	68.2	70.1	69.6	71.8
Network, provisioning, modems	$/cust/mth	-69.9	-60.5	-63.5	-63.4
Gross margin	$/cust/mth	**-1.6**	**9.6**	**6.2**	**8.4**
Gross margin	$m	-1	7	6	10

Retail segment EBITDAF		FY21	FY22	FY23	FY24
Electricity Gross margin	$m	111	68	32	8
Gas Gross Margin	$m	8	3	9	17
Telco Margin	$m	-1	7	6	10
Total Gross Margin	**$m**	**118**	**79**	**47**	**35**
Other income	$m	6	7	9	7
Other operating costs	$m	-68	-68	-69	-74
Retail segment EBITDAF	**$m**	**55**	**17**	**-14**	**-32**
Corporate allocation (50%)	$m	-15	-14	-22	-25
Retail EBITDAF	**$m**	**40**	**3**	**-36**	**-57**
EBITDAF margins (% of revenue)	%	4.3%	0.3%	-3.3%	-4.8%

[1] In FY24 energy costs reflects $1.2m of electricity purchased from solar customers.

Insight to Net Debt / EBITDAF ratio (S&P approach)

	FY21	FY22	FY23	FY24
	Actuals from S&P ratings report			Estimated
Net Debt				
Carrying value of borrowings	856	1,099	1,556	1,913
Fair Value Adjustments	(64)	(55)	(43)	(41)
Restoration and environmental provisions net of tax	53	53	120	142
Hybrid bond credits[1]	-	(113)	(113)	(113)
Accessible Cash[2]	(41)	(4)	(89)	(142)
S&P Adjusted Net Debt	**804**	**980**	**1,431**	**1,759**
EBITDAF				
Reported EBITDAF (underlying)	553	546	573	663
Realised gains/losses on market derivatives	(1)	(9)	(27)	(6)
Share based compensation	3	4	4	4
Adjusted EBITDAF	**555**	**541**	**551**	**661**
Net debt/EBITDAF (x)	**1.4**	**1.8**	**2.6**	**2.7**

[1] 50% equity credit for capital bonds.
[2] Cash less restricted cash held by Macquarie for ASX prudential.

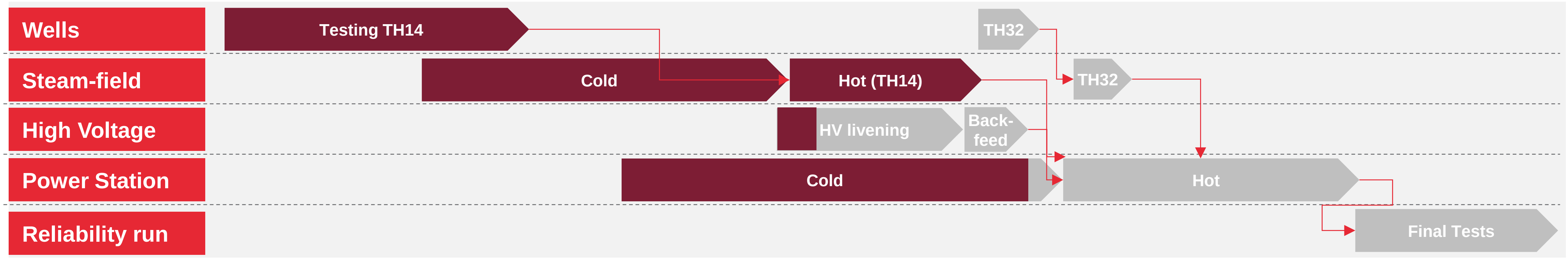
- These calculations have been provided as an illustration of the adjustments made by Contact's ratings agency, S&P Global, when assessing Contact's Net Debt/EBITDAF ratio.
- Net Debt has been adjusted from the financial statements to include certain long-term liabilities where S&P considers these to have debt-like characteristics.
- Adjusted EBITDAF reflects S&P's view of core operating items (unrelated to investing and financing).

Te Huka 3 Commissioning stages and sequencing

The commissioning process is designed to test all functions of the geothermal well operations, steam field and power station under a range of conditions, including extreme emergency simulations

Stage	Well testing	Steam-field (cold)	Power Station (cold)	Steam-field (hot)	High Voltage livening	Power Station (hot)	Reliability run
Key elements tested	Completed via flowing output test to understand flow and energy.	Check piping systems, control system functions; check valve and safety system operation (without steam).	Control system functions; valve and safety system operation, lube oil and control oil system tests (without steam).	Operating tests of plant; ensure integrity of plant and safety systems at maximum design conditions.	System configuration, protection schemes, key equipment performance. Back-feed Power Station.	Pentane admission, Steam blow, operating tests; integrity of safety system; plant performance tests.	Reliability test of all combined systems and plant output.
Duration	1 - 2 months	2 – 3 months	2 – 3 months	1 month	1 month	2-3 months	1 month

Sequencing of commissioning stages:



Note: Arrows are not to scale

Te Huka 3 key: Complete | Future activity | Sequencing dependency