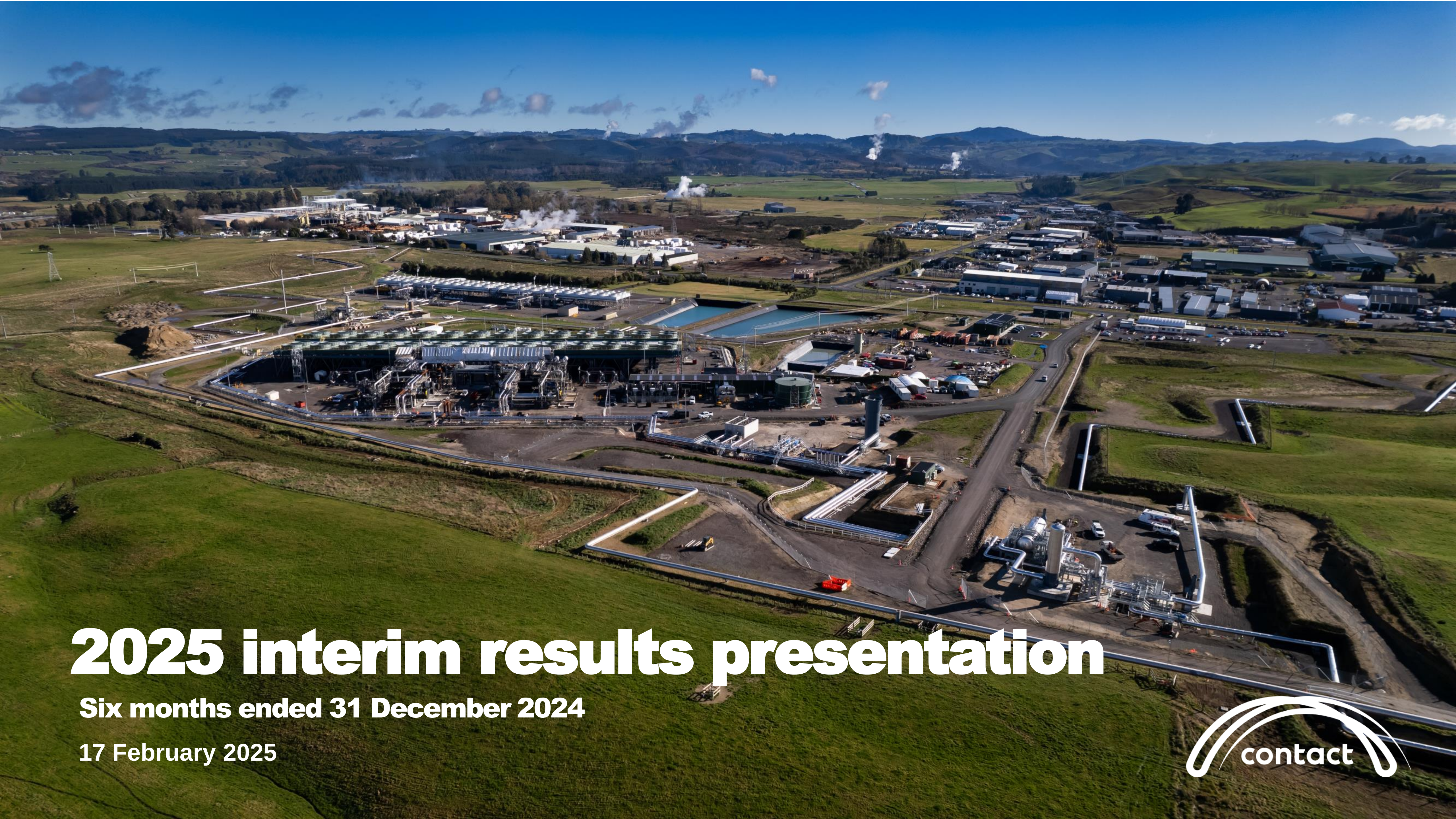

2025 interim results presentation

Six months ended 31 December 2024

17 February 2025

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This presentation contains summary information and statements about Contact and its businesses and activities as at the date of this presentation. The information is not held out as being complete or exhaustive, nor does it contain all the information which a prospective investor may require in evaluating a possible investment in Contact.

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Presenting today

Mike Fuge
Chief Executive Officer

Matt Forbes
Chief Financial Officer (Acting)

Agenda

FY25 highlights to date

Glenbrook BESS
Construction underway on 100MW grid-scale battery

Te Huka III
51MW geothermal power station online

Investment confirmed
Te Mihi Stage 2
101MW geothermal power station and Wairakei extension

Taranaki Combined Cycle
gas plant made available for 2025

Entered **Manawa** Scheme of Arrangement

Construction underway on 168MWp
Kōwhai Park Solar farm
in joint venture with lightsource bp

~415 GWh supply agreement supporting **electrification**

Continued representation within
Dow Jones Sustainability Asia Pacific Index

Annual dividend
uplift of 4cps
(+2cps August 2024 FY24 final, +2cps today – FY25 interim)

Supported the market by facilitating access to ~3.5PJ
Methanex
gas in winter 2024

Hot Water Sorter
programme expanded, shifting ~2MW load from peak demand periods

Contact included in **MSCI Global Standard Index**
in February rebalance

Executive team changes

Contact Energy has announced several key executive changes

Mike Fuge
Chief Executive Officer

Chris Abbott
Chief Corporate Affairs Officer

Jack Ariel
Major Projects Director
(Retiring February 2025)

Jan Bibby
Chief People Experience Officer

Matt Bolton
Transition Director

John Clark
Chief Generation Officer

Dorian Devers
Chief Development and Major Projects Officer

Tighe Wall
Chief Technology Officer

key Executive positions unchanged | Consolidation and/or newly established

Key Updates

- Development and Major Projects roles consolidated.
- Digital and Information Technology roles consolidated.
- Integration Office established led by Transition Director – preparing for potential acquisition of Manawa.
- Recruitment process underway for Chief Financial Officer and Chief Retail Officer.

Delivering renewable investment while supporting security of supply

	Six months ended 31 December 2024 (1H25)	Six months ended 31 December 2023 (1H24)	
	Reported	Against reported	
EBITDAF	$404m	↑	12% from $362m
Profit	$142m	↓	7% from $153m
Profit per share	17.9 c	↓	8% from 19.5c
Operating free cash flow[1]	$138m	↓	21% from $174m
Operating free cash flow per share[1]	17.4 c	↓	21% from 22.1c
Dividend declared (interim)	$128m	↑	16% from $110m
Dividend declared per share (interim)	16.0 c	↑	14% from 14.0 c
Stay-in-business (SIB) capital expenditure (cash)	$65m	↓	24% from $85m
Growth capital expenditure (cash)[2]	$179m	↓	16% from $212m

Market

contact

1H25

1H25 was characterised by hydro inflow and wholesale electricity price volatility with the market swinging between dry and wet hydro conditions. The market observed:

- Historically low hydro inflows in July and early August (following a dry 2H24) resulting in a rapid reduction in hydro storage (reaching the 3rd lowest national storage level in 80 years).
- Continued contraction in gas availability (gas production was ~30PJ lower in CY24 compared to CY23).
- Spot and forward wholesale electricity prices responded to fuel scarcity conditions, peaking at historic highs in early August.
- Rapid unwind of conditions in the second quarter with several large inflow events from mid-August and the signing of major gas supply contracts between Contact and Genesis with Methanex.
- Resultant rapid decline in spot prices and increased hydro storage volumes which finished the period well above average.

Contact took a range of proactive steps to support security of supply through the first quarter including:

- Entered new contract with NZAS starting 1 July 2024 alongside a demand response agreement with a mechanism to reduce load by up to 46MW (activated July 2024).
- Entered gas purchase agreement with Methanex in August 2024 that saw Contact buy ~3.5PJ of gas.
- Tauhara brought online in May 2024, providing consistent baseload generation improving supply / demand dynamics.
- Increased use of TCC to maximise the efficient use of Contact's gas supplies.

As market conditions changed in the second quarter, Contact:

- Utilised AGS to store gas, maximising its future utility and avoiding uneconomic thermal generation.
- Brought Te Huka 3 online in December 2024.

Medium term

- Lines cost increases to take effect from 1 April 2025.
- Gas supplies / production are expected to continue to reduce as major domestic fields reach end of life.
- Rising fixed costs at ageing thermal plants (which need to be recovered over less generation) and the rapid build out of intermittent renewable plant mean risk management costs and price volatility continue to rise.
- Increases to wind construction costs appear to be structural.
- Contact's view of long-term wholesale prices is **$115 to125/MWh.**[3]

Orderly build-out of renewable generation with multiple projects committed and commissioned in 1H25:

- Committed to Wairakei redevelopment and extension projects, securing the long-term future of geothermal on the Wairakei field.
- Committed to build Kōwhai Park solar (168MWp).
- Committed to Glenbrook BESS (100MW / 200MWh).
- Completed Tauhara commissioning and brought Te Huka 3 online, representing ~1.9TWh p.a. new geothermal output on a full year basis.
- TCC made available for 2025 if needed by the market.

[1] Refer to slide 28 for a reconciliation of operating free cash flow.
[2] Includes capitalised interest.
[3] This is a through-the-cycle measure in a balanced market and is shown on a 2025 real basis. Prices actually achieved are a function of the market at a point in time.

Contact26 Key strategic highlights from 1H25

	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 New Zealand's leading energy and services brand to meet more of our customers' needs
1H25 highlights	Tauhara-backed PPAs and new long-term NZAS contract commenced. Progress continues towards a final investment decision on food grade CO_2 project at Ohaaki. Signed a summer-weighted 10-year electricity supply agreement with Fonterra for ~415 GWh p.a.[1] Underlying demand showing signs of structural growth.	New geothermal station – Te Huka 3 – online from December 2024 (51 MW) Construction underway on Glenbrook BESS (100MW / 200MWh). Construction underway on Kōwhai Park solar farm in Christchurch (168MWp). Investment confirmed in new 101MW Te Mihi Stage 2 geothermal plant and Wairakei extension, securing the long-term future of geothermal production on the Wairakei field.	Invited interest in market-wide, intra-day storage service for a potential 100MW BESS[2] at Stratford (a consented site). TCC to be kept available in 2025, if required by the market, to support New Zealand's security of supply. Purchased additional ~8% interest (taking total to 22%) in Forest Partners (January 2025), increasing investment in long-term sustainable forestry.	Total Retail closing connections +39k on 1H24, with a focus on multiproduct customer growth (+16k) while maintaining targeted retail channel sales volume. Scaled time of use 'Good' plans (+54k) and Telco connections up (+23k) on 1H24. Expansion of Hot Water Sorter programme to ~7k customers, shifting ~2MW per day out of peak demand periods. Removed disconnection and reconnection fees under Contact's Energy Wellbeing programme. Energy Retailer of the Year finalist (for the third consecutive year).

[1] Approximately two thirds of this volume represents new demand for electricity in the dairy sector. This new demand will step up between August 2026 and 2028 as transmission upgrades are completed.
[2] Battery Energy Storage System (BESS).

Contact26 1H25 delivery supported by enablers

	Our ESG commitment	Operational excellence	Transformative ways of working
Objective	Create long-term value through our strong performance across a broad set of environmental, social and governance factors	Continuously improving our operations through innovation and digitisation	Create a flexible and high-performing environment for NZ's top talent
1H25 highlights	Included in Dow Jones Sustainability (DJSI) Asia Pacific Index for the third consecutive year. Rated “A – Leader” and ranked second out of 61 New Zealand companies in Forsyth Barr’s Carbon & ESG Ratings for 2024. Extended partnership with Women's Refuge for a further three years. Issued $250m of Green Capital bonds.	Commissioning completed in December 2024 on the first of four replacement turbines at Roxburgh hydro dam. Process safety upgrade completed at Te Mihi during its four yearly statutory outage in October 2024. Launched Contact’s new Trading and Risk Management platform (Trade Deal Capture). Launched new versions of Contact’s customer mobile app and online self-service experiences for Retail (85% of all service interactions are now through these channels).	Wellbeing Award winner, NZ Energy Excellence Awards, for Contact’s Skin Checks Wellbeing initiative. Launched Leadership Programme (Mau Taniwha Mauri Ora) for both existing and emerging leaders. Received continued Wellbeing Tick Accreditation. Enhanced KiwiSaver and broad-based Contact share scheme (Contact Share) benefits for employees.

Demand: Industrial process heat electrifies

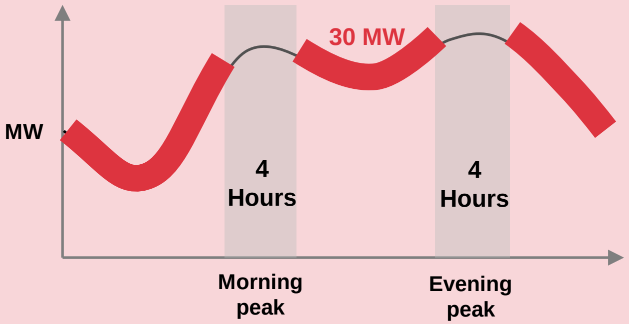
Uncertainty about fuel availability is accelerating the transition for customers currently using natural gas. Existing industrial customers are also adopting demand response as a means of lowering energy costs.

Contact is helping to lead the charge with several major, innovative, supply agreements

New Zealand Steel

Industrial decarbonisation:
NZ Steel – Electric Arc Furnace

- Expected online early CY2026. Contact supplying 30MW.



- **In light of rising peak price volatility, the off-peak winter structure helped unlock electrification.**

Fonterra

Dairy / primary sector decarbonisation:
Fonterra – Electrode boiler replacement

- Fonterra is undertaking a staged energy transformation that includes the installation of electrode boilers at selected sites.
- Contact has entered a new 10-year agreement to supply ~415GWh p.a. to Fonterra's Whareroa dairy site.
- Agreement begins August 2026 at ~140GWh p.a. to cover existing demand. Steps up over time to reach ~415GWh p.a. in 2028 to support the electrification of the site.
- **The shape of the supply agreement is weighted to summer, well aligned to Contact's renewable generation portfolio.**

Industrial / primary sector (existing load):
Innovative, economic contract structures

- Existing industrial customers across a range of sectors are now actively exploring demand response and other contract shaping mechanisms.
- Contact is engaged in developing a number of bespoke solutions to meet the changing needs of customers.
- **The shared benefits of demand response, between supplier and customer, have the potential to support the retention of significant existing industrial demand.**

Renewable builds: Online and underway

Projects Online

Tauhara

~200,000 *Equivalent homes powered*

May 2024 *Online date*	**$924m[1]** *Total Investment*
174MW *Installed Capacity*	**1,450GWh** *Estimated Annual Output*

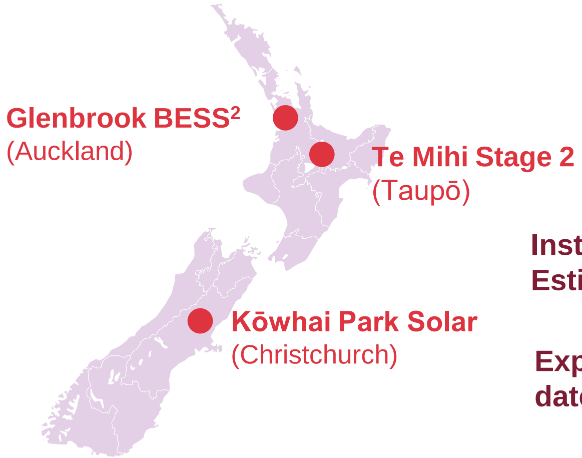
Te Huka 3

~60,000 *Equivalent homes powered*

Dec 2024 *Online date*	**$300m[1]** *Total Investment*
51MW *Installed Capacity*	**430GWh** *Estimated Annual Output*

[1]Total under current approvals.

Projects Under Construction

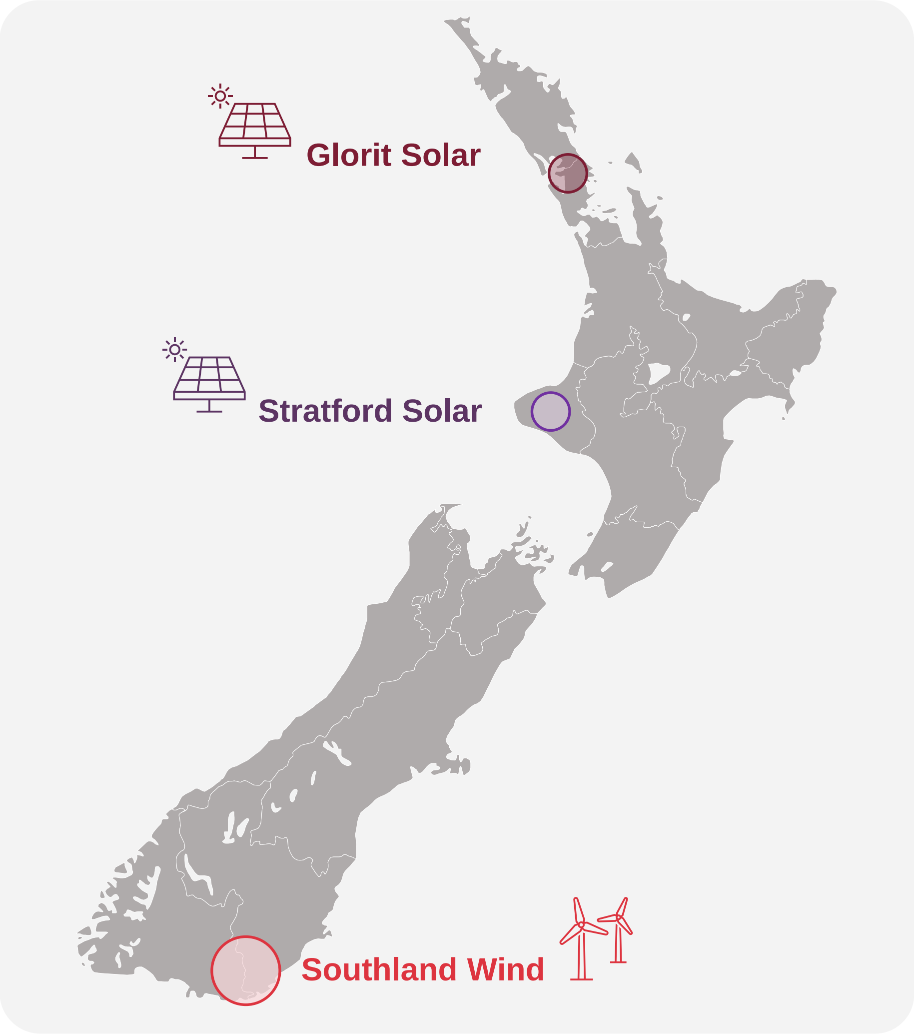


Announcement Date	1 July 2024	16 Aug 2024	13 Nov 2024
	Glenbrook BESS[2]	Kōwhai Park Solar	Te Mihi Stage 2 Geothermal
Installed capacity / Estimated annual output	100MW	168MWp | 275GWh	101MW | 830GWh
Expected online date	On track Q1 CY2026	On track Q2 CY2026	On track Q3 CY2027

[2] Battery Energy Storage System.

Renewable builds: Next in line priority sites

Focusing on advancing next development options



Glorit

- **Upper North Island** generation benefits GWAP
- **Strong** fit with portfolio

Status: Consent lodged ✓ → Panel Convened ✓ → Assessment underway

FY26	180MWp	300GWh
Expected FID date	*Estimated Capacity*	*Estimated Annual Output*

Stratford

- **Existing** substation
- **Potential** for BESS[1] co-location (100MW consented)

Status: Consenting activities underway ✓ → Lodge consent, targeting CY2025

FY26	180MWp	300GWh
Earliest expected FID date	*Estimated Capacity*	*Estimated Annual Output*

Southland

- **Ease of** Grid access
- **Most** advanced wind project

Status: Consent lodged ✓ → Panel Convened ✓ → Consent under assessment

FY26	330MW	1,200GWh
Earliest expected FID date	*Estimated Capacity*	*Estimated Annual Output*

Note: Additional North Island BESS[1] options under consideration are not shown in the diagram above.

[1] Battery Energy Storage System.

Regulatory focus: Transition to Net Zero 2050

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 gas capacity and production flexibility limited. • While the oil and gas exploration ban has been reversed, short-term supply remains tight. • Industry and government together investigating Liquified Natural Gas (LNG) import options.	• Contact transitioning from gas reliance and investing in renewable flex e.g., batteries. • Making Taranaki Combined Cycle gas plant available for 2025 (if supported by the market). • Entered into heads of agreement to investigate the potential for using Huntly to manage dry year risk.	• Bill to repeal oil and gas ban is underway. • Decisions regarding LNG import or other fuel security options expected in early 2025. • Huntly dry year cover arrangement could be in place for 2026.

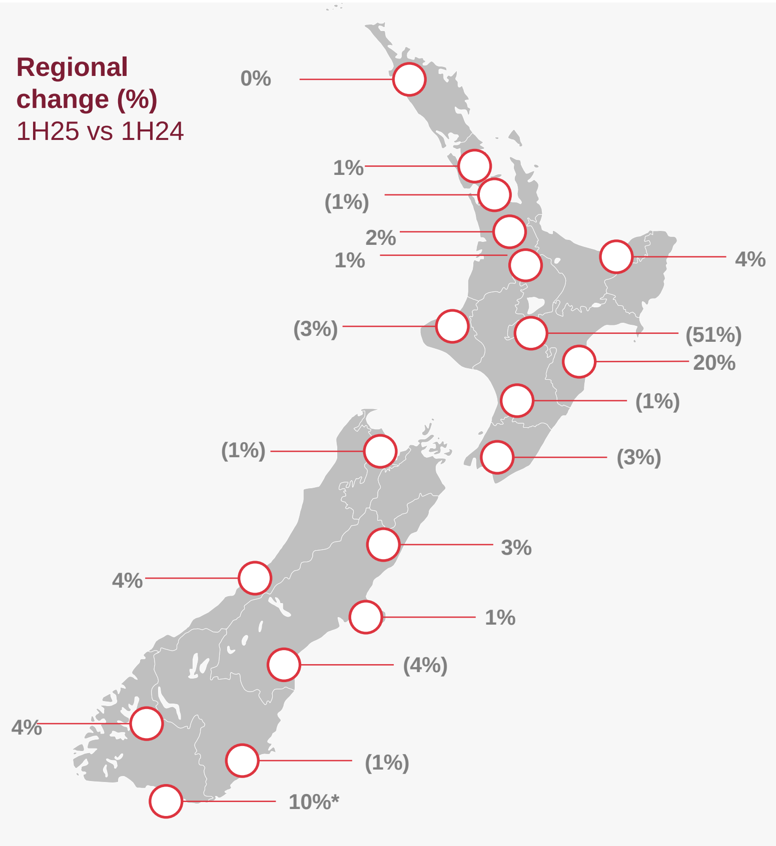
Supporting the evolution of the market	• The continued expansion of renewable technology may require some market adjustments to ensure they are integrated efficiently, and resulting volatility is manageable.
	• Government has initiated reviews of both the market settings and the regulatory framework to consider what (if any) changes are necessary. Two reviews are underway:
	    • EA and ComCom Energy Competition Task Force
	    • Review of Electricity Market Performance, led by Frontier Economics.
		• Contact's focus is on ensuring the regulatory settings support our continued advancement of the investment pipeline.
		• Contact is engaging closely with government reviews currently underway, including providing expert input to support good decision making.
			• Task Force consulting on proposals over 1H CY2025.
			• Review of Electricity Market Performance expected to be completed by the end of June 2025.

Resource management reform	• Wide ranging resource management reforms underway, including Fast Track Approvals Act, amendments to the Resource Management Act (RMA), and work to strengthen the National Policy Statement on Renewable Energy Generation (NPS-REG). • Will play a crucial role to meet infrastructure challenges of decarbonising NZ economy.	• Contact will seek to utilise fast-track consenting to enhance flexibility in the Clutha scheme. • Community engagement remains central to Contact's approach. • Engaging with officials and Ministers on wider RMA reforms for alignment with our decarbonisation strategy.	• Fast Track Approvals Act was passed into law at the end of 2024. • Second RMA Amendment has been introduced and is expected to be passed into law by mid-2025. • Work on NPS-REG ongoing.

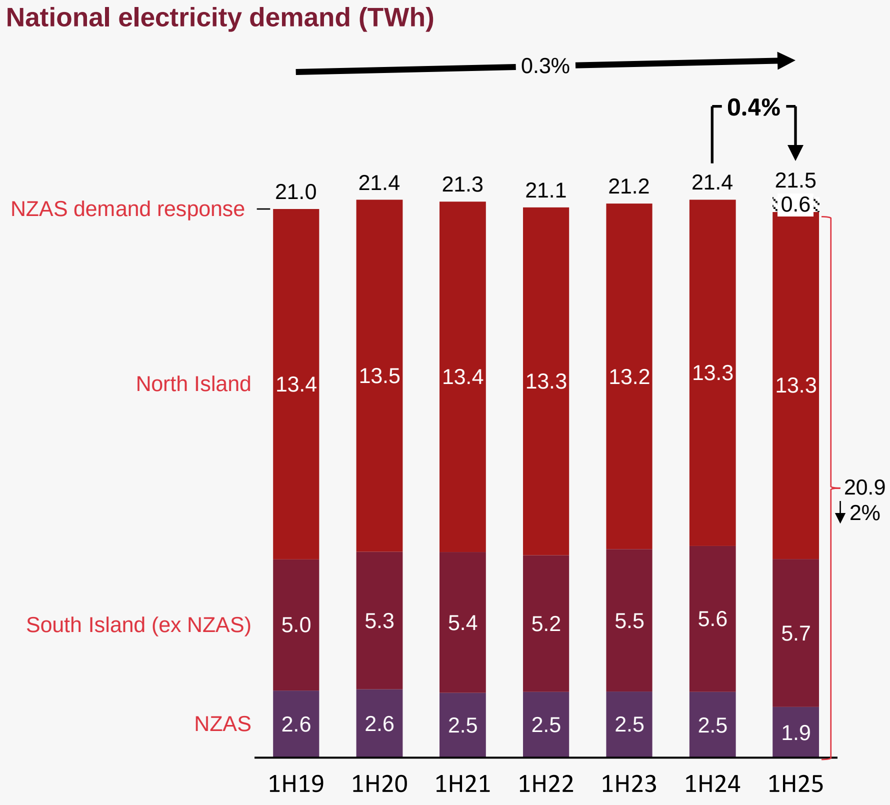
Market context

National electricity demand

NZAS demand response was called on to support dry market conditions, contributing to a reduction in national New Zealand electricity demand of ~2% on 1H24 (up ~0.4% normalised for NZAS)



Source: EMI, Contact.
*Does not include NZAS



Source: EMI, Contact. EMI demand data is grossed up to account for losses in distribution networks.

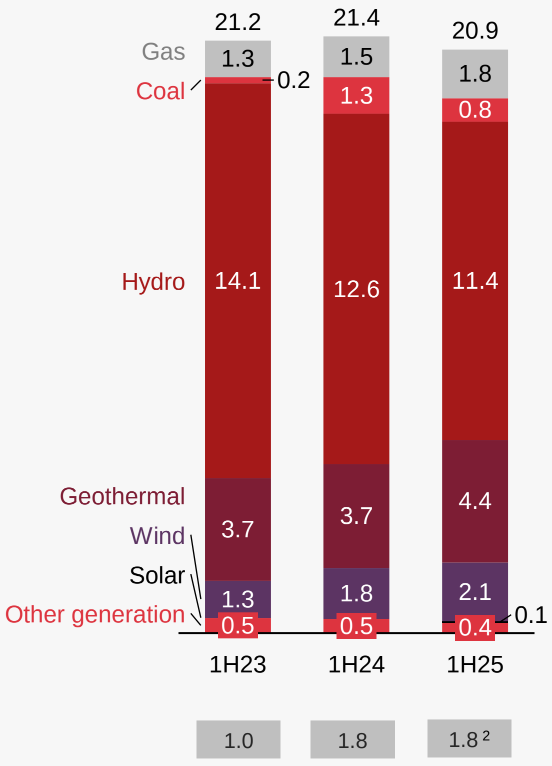
Total national electricity demand decreased by 0.5 TWh (2% from 1H24).

- Central North Island demand was down 51% on the prior comparable period on the back of operational pauses and closures at the Tangiwai / Karioi pulp and paper mills in August.
- East Coast regional demand was up 20% with Pan Pac’s Whirinaki site reopening after temporary closures last year as a result of impacts from Cyclone Gabrielle.
- Normalising for NZAS demand response (activated at the beginning of the half year) demand was up ~0.4%.

Hydrology significantly impacted generation mix

Hydro volatility highlights the role of thermal generation for security of supply; geothermal powers up

Generation by type (TWh)[1]



Hydro generation was down 9.2% on 1H24, as a result of historically low inflow volumes at the beginning of 1H25 and below average storage volumes at the end of FY24.

Impacts included:

- Volatile spot wholesale prices.
- Need for thermal generation.
- Higher industry carbon emissions.

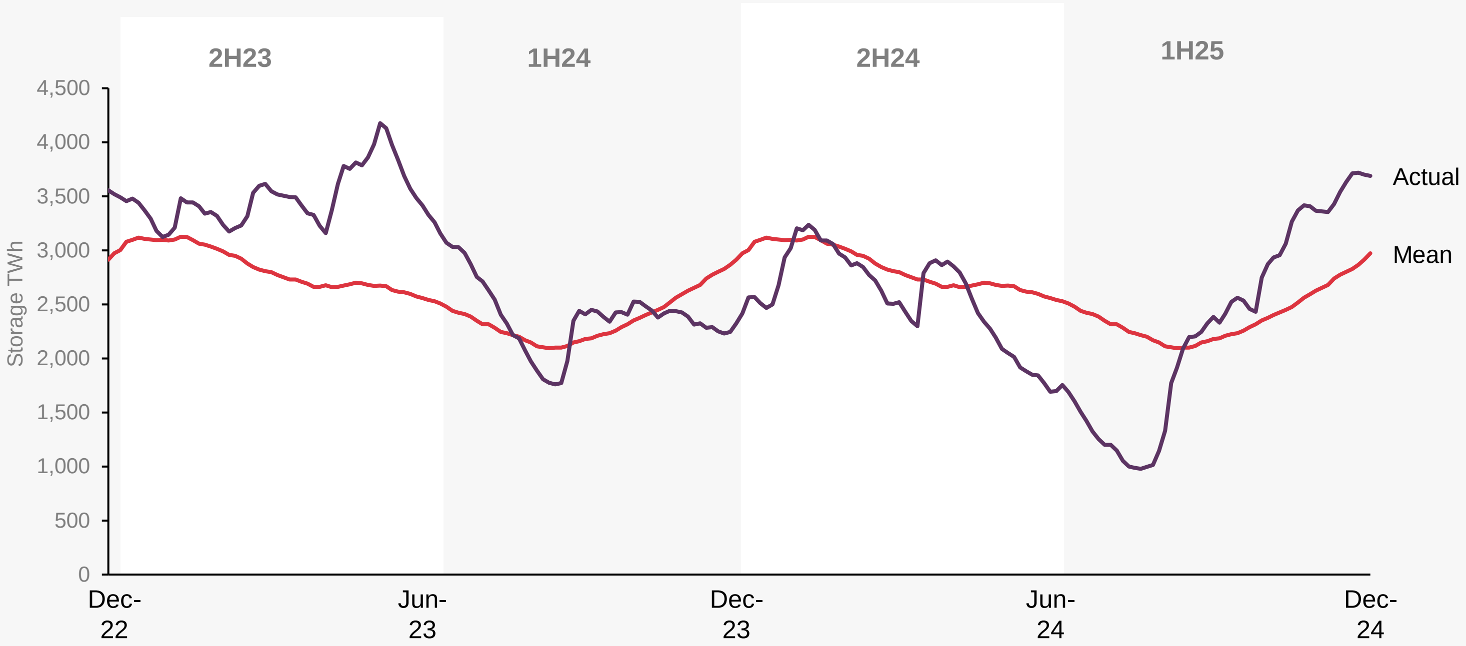
Diesel generation was significantly higher than 1H24 as Whirinaki was brought on in July / August[3].

Geothermal generation volumes increased materially in 1H25 with Tauhara operational and Te Huka 3 entering commissioning during the period.

Carbon emissions remained elevated in 1H25 due to diesel and gas generation in 1Q25.

Source: EMI & MBIE

National hydro storage



Hydro storage levels started 1H25 significantly lower than the historical mean following a very dry end to FY24. Storage continued to be drawn down quickly as dry conditions persisted through July and into the beginning of August. Conditions eased from August following several heavy rainfall events starting in late August and storage recovered quickly before ending the period well above mean. This hydro storage and inflow variability lead to spot price volatility in the first quarter and highlighted the market's continued reliance on thermal generation to maintain supply.

Source: NZX – mean represents post-market mean storage volumes.

[1] Generation by type has been restated for prior periods due an adjustment in methodology.
[2] Carbon emissions for 1H25 Oct-Dec quarter has been estimated using historic conversion rates with actual generation data.
[3] Diesel generation volume (17.6GWh) is included in other generation figures.

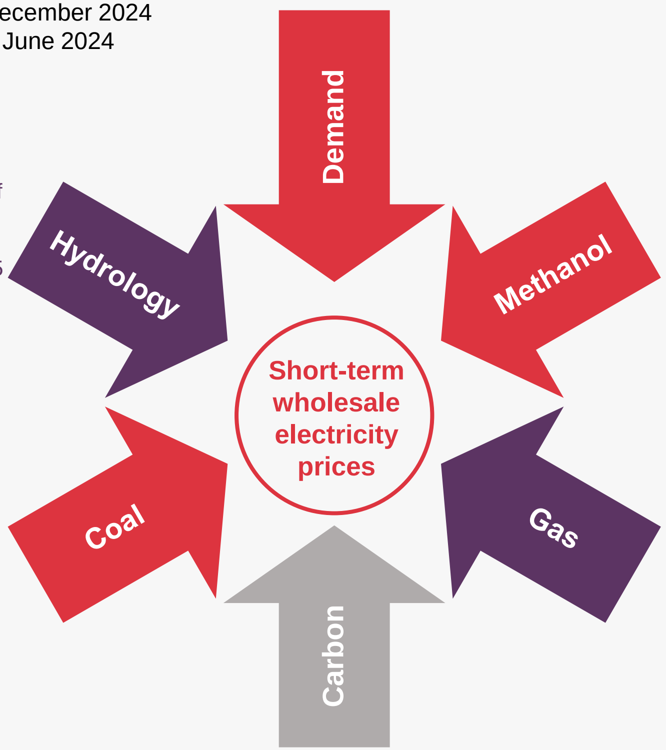
Forward wholesale pricing reflects gas cost and increasing cost of new-build renewables

Short-term external factors that can influence the market
Changes as at 31 December 2024 in comparison to 30 June 2024

Demand down ~2% year on year.[3]

Hydro storage has been volatile over the period. Controlled storage swung between ~43% of mean (~1,278 GWh below mean) in Aug 24 to ~115% of mean (~995 GWh above mean) in November 2024.

Methanol pricing at US$344/t (up 1%) but constrained gas affecting domestic production levels.[2]

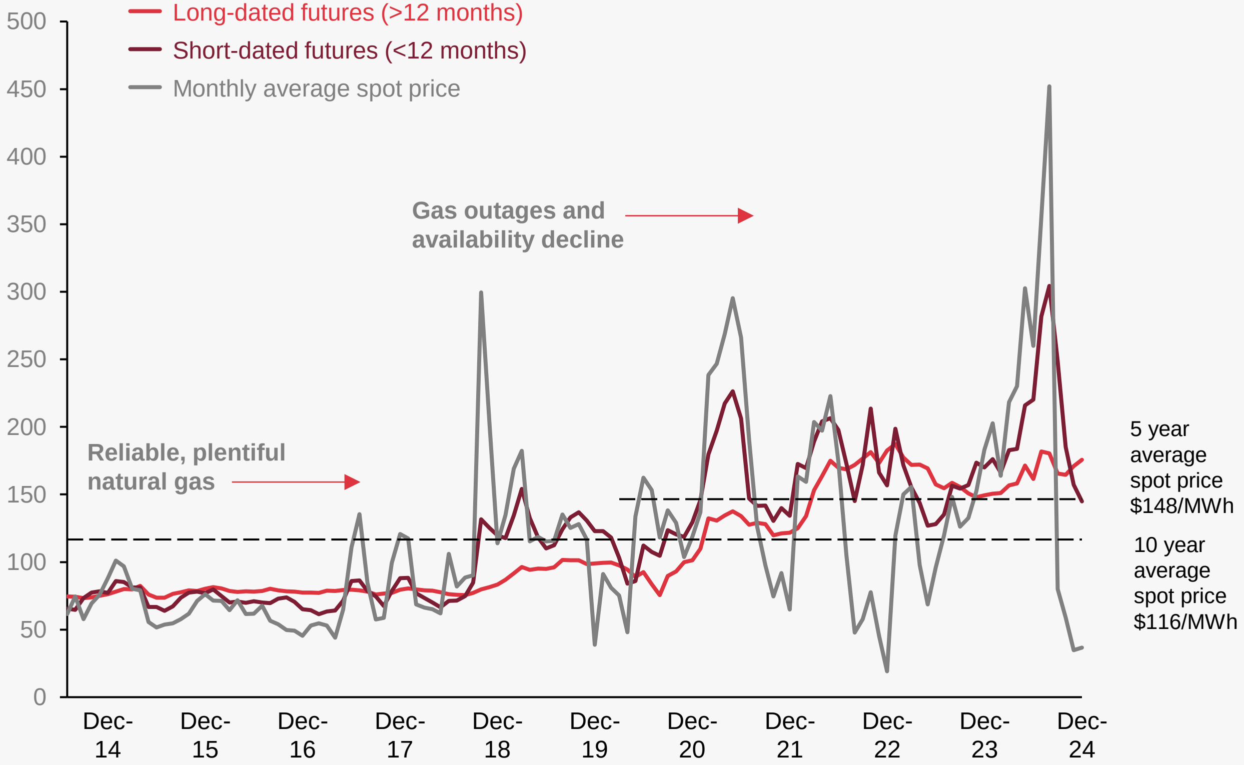


Thermal coal prices lower[2] (US$129/t, down ~3%).

Spot gas prices were volatile, from record highs in August ending the period down ~27% after hydro storage concerns abated.[5.]

Carbon prices remained subdued (~$62 / NZ unit).[4]

Wholesale and futures electricity pricing ($/MWh)



Source: EMI wholesale pricing

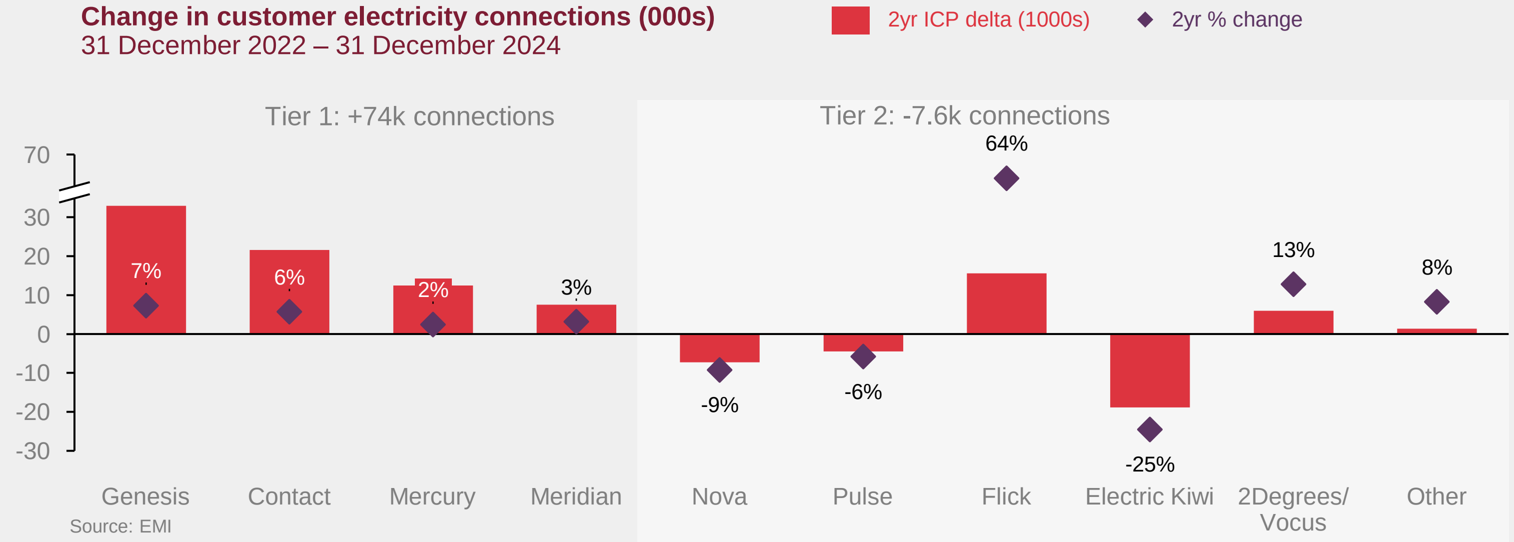
Dry hydrology conditions at the end of FY24 and beginning of 1H25, and increasing scarcity and cost of gas, dramatically increased spot price volatility and pushed both the spot and near-term futures prices to all time highs. These prices quickly reversed when dry conditions eased and the Methanex deals with Genesis and Contact were announced (average monthly spot prices dropped 92% from their peak). However, long-dated futures have remained elevated reflecting market expectations of structurally higher gas prices and lower availability and the increasing long-run costs of new-build renewables.

[1]NZX hydro information; [2] Bloomberg; [3] EMI; [4] As at 20 December 2025; [5] Energy Market Services

Differences in retail strategies apparent

Electricity and lines costs continue to rise; pass-through cost increases to continue

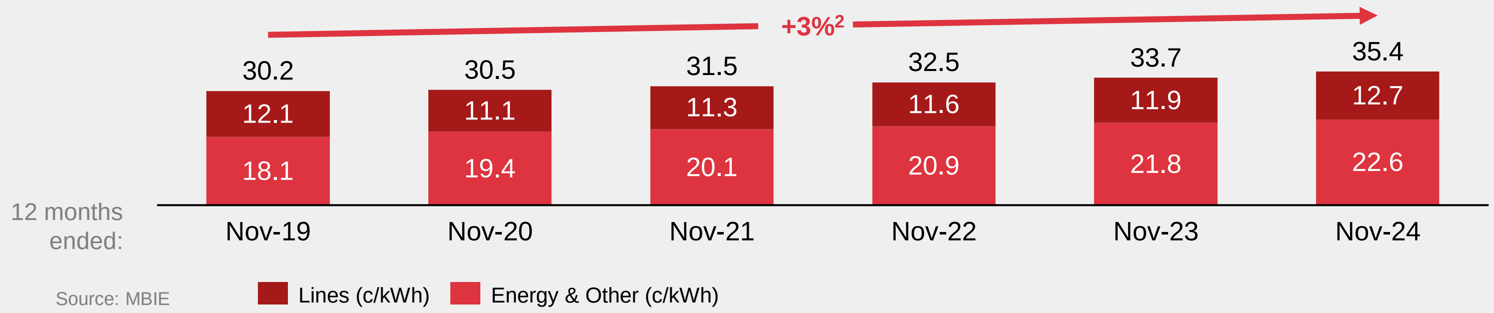
Change in customer electricity connections (000s)
31 December 2022 – 31 December 2024



Source: EMI

- Competition remains intense despite sustained high wholesale futures prices. Market churn continues to reflect this with residential switching at ~20%.
- New buildings contributed to a continued ~1.4% p.a. growth in total residential ICPs on the prior year.
- Tier 1 retailers have a seen a 1% increase in market share to ~84% in December 2024 (~83% December 2022).
- Tier 2 retailer growth rates have been mixed as they have repriced to rising input costs (energy and networks), resulting in a collective decline in market share to ~16% (~17% December 2022). Flick and 2Degrees continue to grow strongly.
- Since 31 December 2022, 2Degrees has grown connections by 6k (+12.7%) while Flick Electric has seen a 16k increase in connections (+64%)
- Contact electricity connections are up +22k from December 2022 to December 2024, resulting in a ~20% market share.

Retail electricity tariff changes[1] (c/ kWh)



Source: MBIE

- Increasing wholesale energy and, more recently, network costs have resulted in a lift in residential electricity tariffs with the compound annual growth rate of 3% across the last five years to November 2024.
- Average tariff increases for the year to November 2024 of 5% were above consumer price inflation (~2.2%)[3], with residential price increases rising to cover both increasing lines costs and continue the partial recovery of energy costs.
- Input cost pressure for retailers is expected to continue with ongoing elevated wholesale prices and significant network cost increases starting from 1 April 2025. Residential price increases are expected to remain above the level of inflation to recover these rising input costs.

[1] Inclusive of GST
[2] Compound annual growth rate
[3] Stats NZ CPI index increase in the 12 months to December 2024.

Financial results and outlook

Key themes from the financial results

Two new geothermal plants online, Tauhara and Te Huka 3, delivering 0.6TWh

Facilitated Methanex gas supply arrangement (~3.5PJ) to support the market through winter 2024

New long-term NZAS contract commenced 1 July 2024 on improved pricing – demand response immediately activated

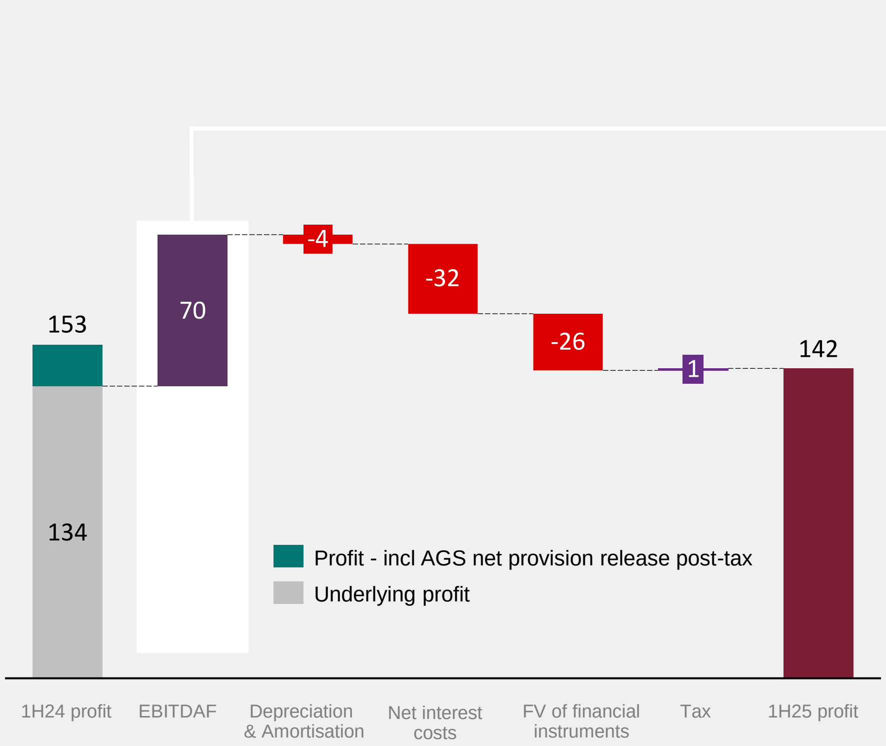
Announced Manawa Scheme of Arrangement – now preparing for combination with Manawa[1]

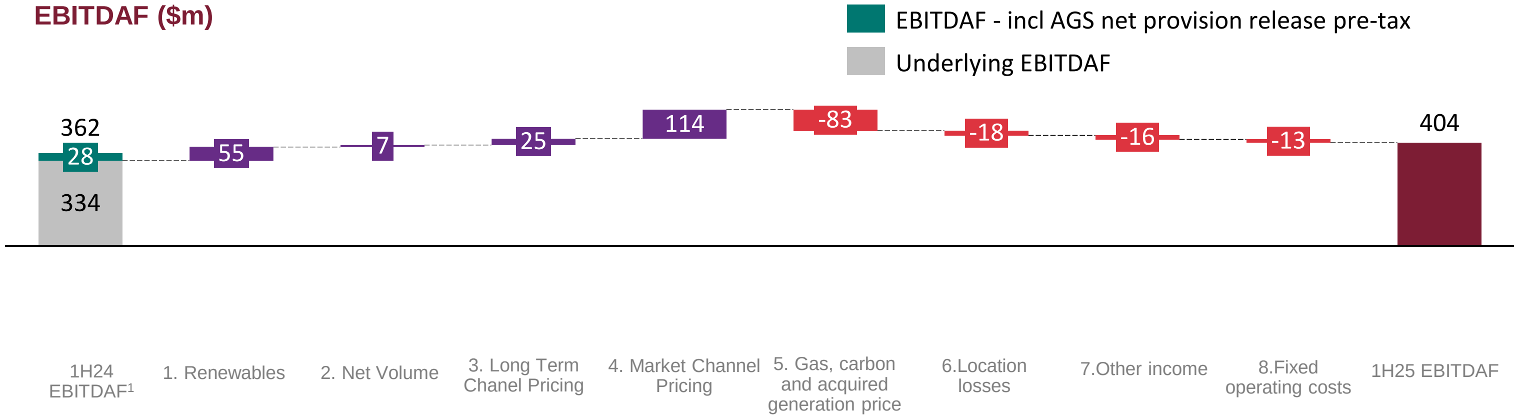
Improved plant availability for winter 2025 and secured long-term gas to support security of supply

[1] The transaction (and proposed combination with Manawa) remains subject to conditions, including NZ Commerce Commission clearance, approval of the Scheme by the High Court and by Manawa shareholders by the requisite majorities. See slide 35.

Profit of $142m for 1H25

EBITDAF up $70m (21%) on 1H24 underlying, reflecting an increase in renewable generation from Tauhara and Te Huka 3 during the period, the net impact of gas-backed CFDs and long-term contracts commencing





1. Renewables up 527GWh including 491GWh uplift in geothermal volumes.

2. Higher contracted sales volumes partially offset by NZAS demand response.

3. Reflects net impact of new repriced NZAS contract and Tauhara-linked PPAs coming online.

4. Higher realised CFD prices from sales linked to Methanex gas.

5. Gas and acquired generation costs were impacted by the cost of Methanex gas and NZAS demand response.

6. Location losses were elevated as a result of low wholesale prices in 2Q25 following significant hydro inflows.

7. Other income reflects loss on sale of excess gas (-$18m).

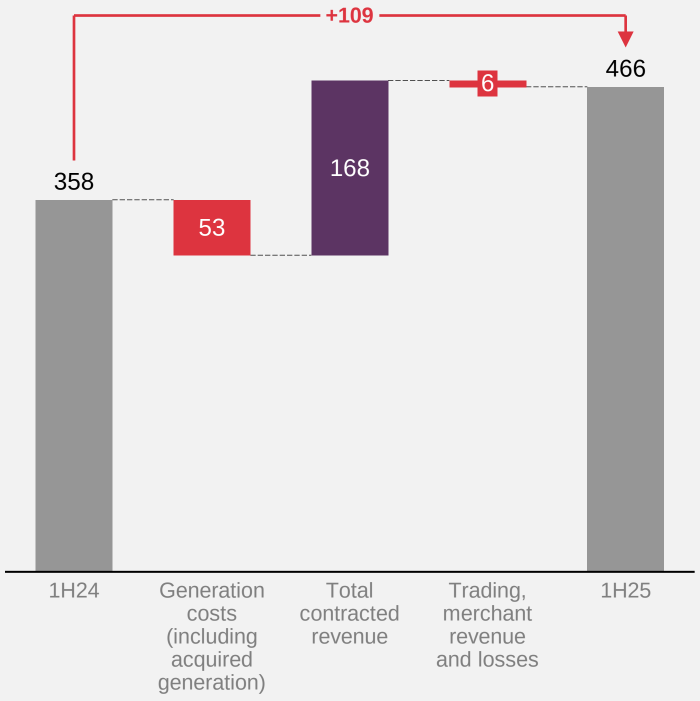
8. Fixed costs higher due to inflation impacts, growth and one-off costs associated with the proposed Manawa acquisition ($10m).

Note: All 1H24 figures are exclusive of the impacts of the onerous contract provision for AGS. Impacts of the onerous contract in 1H24 are as follows, EBITDAF (+$29m), interest (-$3m), tax (-$7m), NOPAT (+$19m). The provision has not been recalculated in 1H25, however, the monthly unwind and interest impacts of the provision are included in the reported 1H25 figures as follows, EBITDAF (+$7m), interest (-$2m), tax (-$1m), NOPAT (+$4m).

EBITDAF up by $70m on underlying 1H24

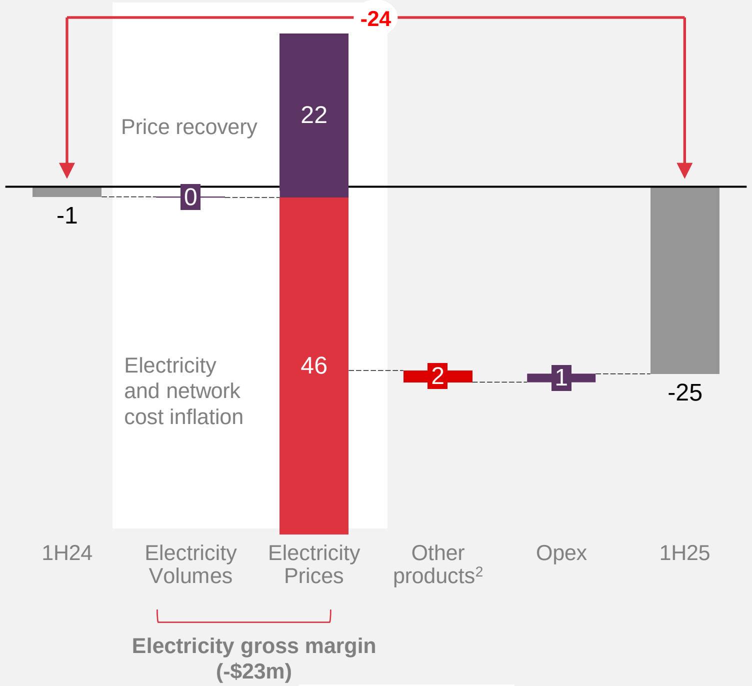
Business performance by segment

Wholesale EBITDAF[1] ($m)



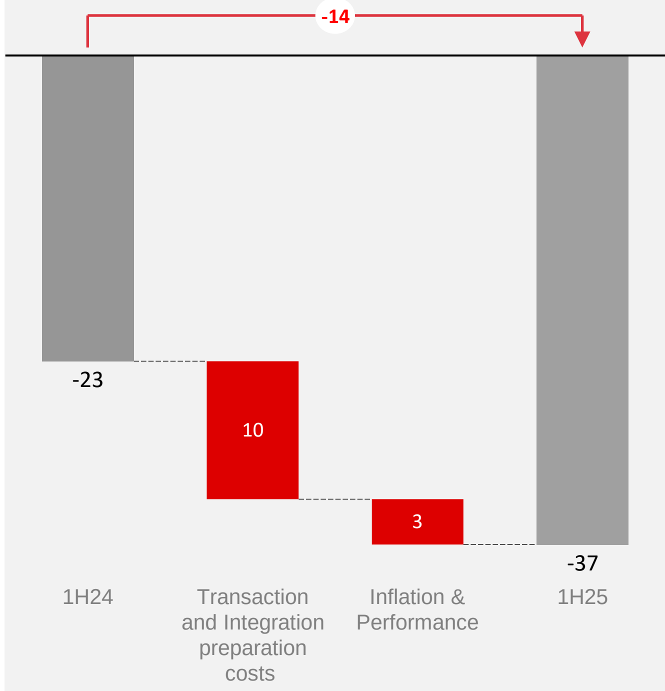
Refer to slides 23 - 25

Retail EBITDAF ($m)



Refer to slide 26

Corporate / unallocated costs ($m)

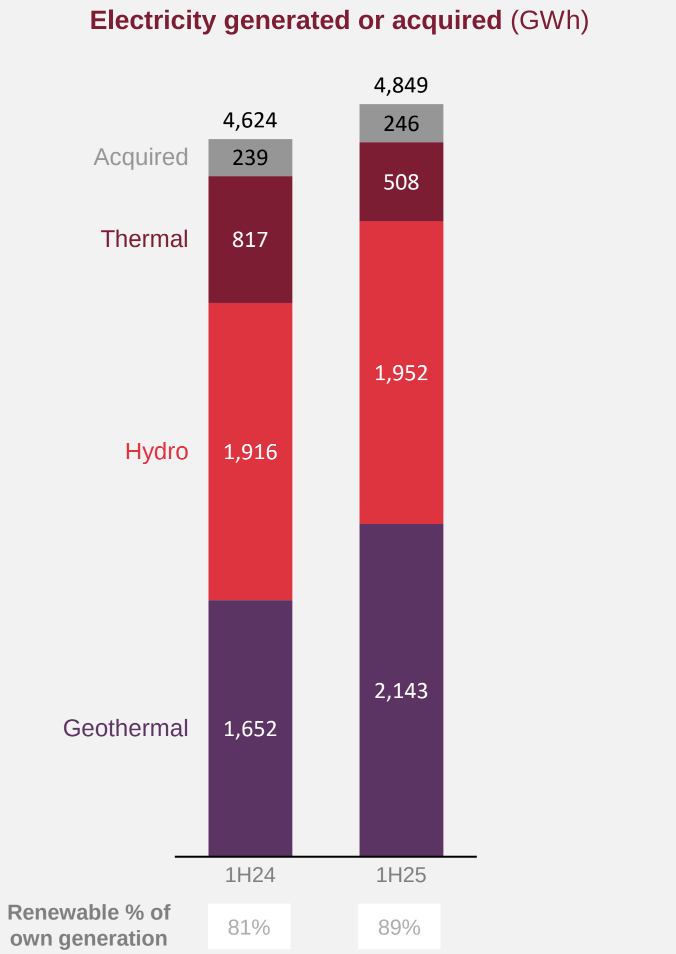


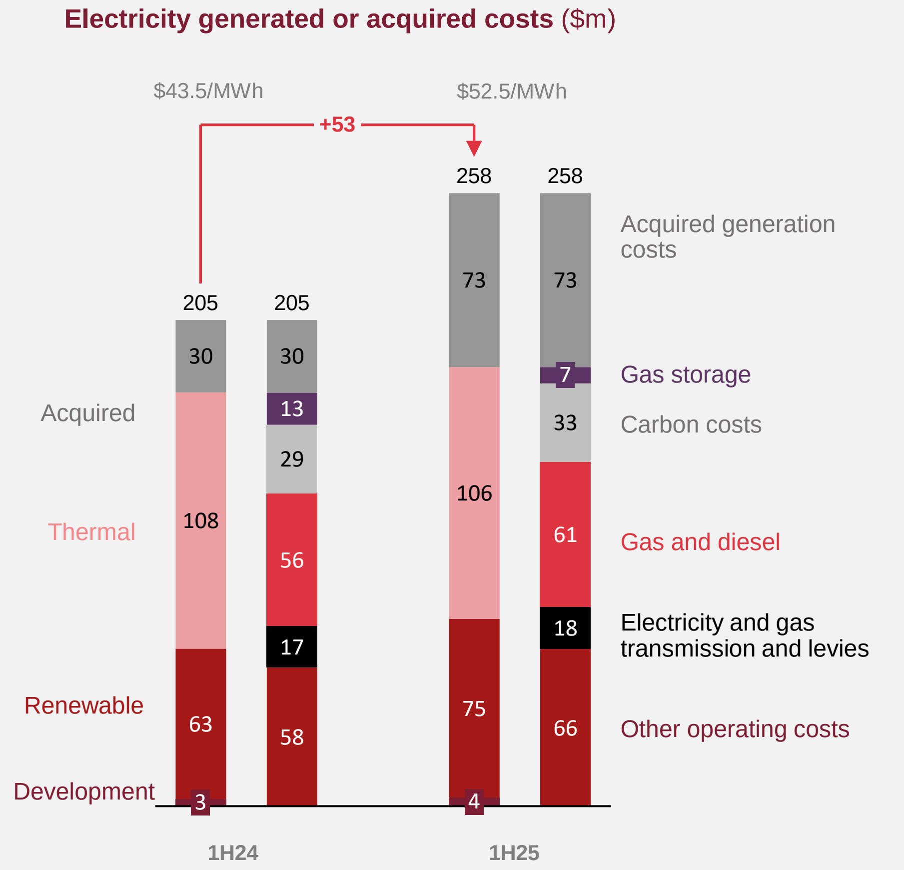
[1] Simply and Western included within Wholesale EBITDAF.
1H24 EBITDAF is shown as underlying, excluding $29m net release of the onerous contract provision for AGS. 1HY25 EBITDAF includes monthly unwind of +$7m.

[2] Other products includes retail gas and telco gross margins and other revenue/costs.

Generation costs

Costs up $53m driven by higher cost of thermal fuel and acquired generation plus Tauhara online





All 1H24 analysis in this section is presented on an underlying basis. As such, 1H24 gas storage costs exclude the $29m net release within EBITDAF of the onerous contract provision for AGS. 1H25 gas storage costs include an AGS provision unwind benefit (+$7m positive impact).

Generation volumes

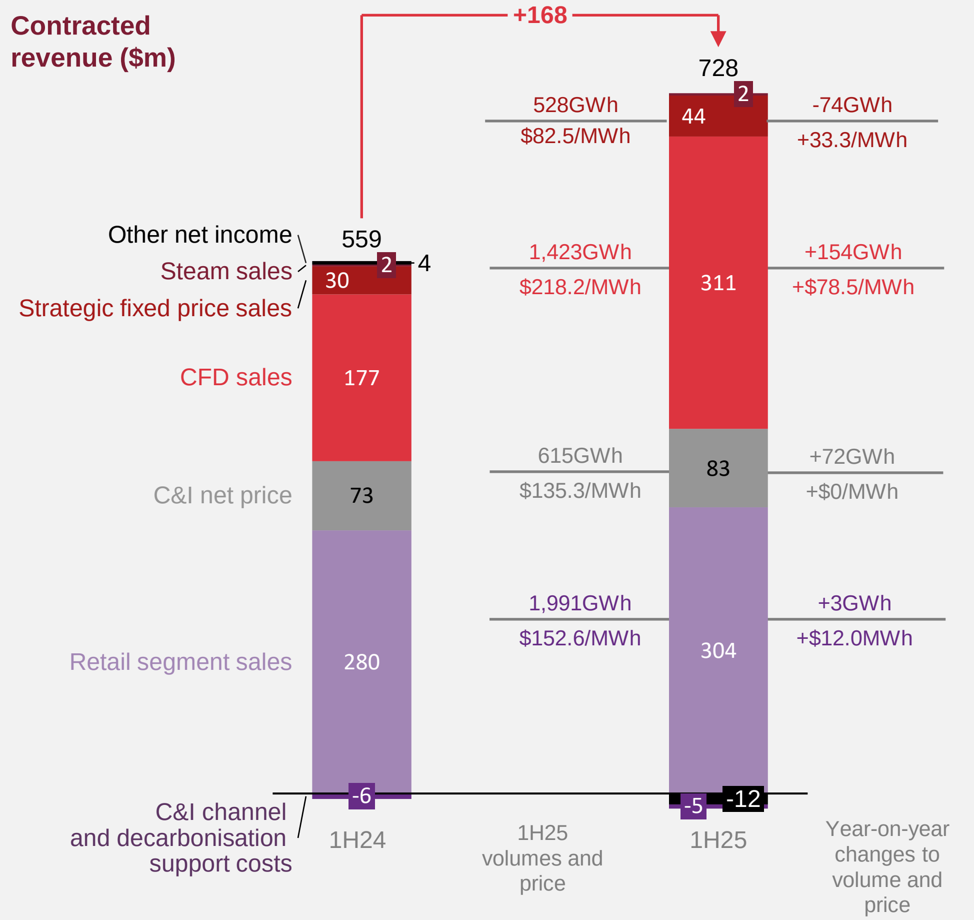
- Hydro generation of 1,952GWh was up on 1H24 (2%) owing to high inflows in the second quarter of 1H25.
- Geothermal generation was up 491GWh (30%) on 1H24, from Tauhara generation (584GWh) and Te Huka U3 generation during commissioning in December (40GWh). Additional volumes were partially offset by a planned outage at Te Mihi.
- Despite a dry start to the period, 1H25 thermal generation volumes were down 309GWh down (-38%) on 1H24. This is in part because;
  - 1H24 saw significant use of thermal to cover a delay to Tauhara’s online date alongside some must-run winter 2024 gas contracts, and
  - The second quarter of 1H25 saw significant inflows which, when combined with new geothermal generation, offset thermal generation.

Costs

- Renewable generation costs were up $12m (19%) as a result of higher geothermal carbon and operational costs associated with Tauhara.
- Thermal generation costs in 1H25 benefited from an unwind of the AGS provision (+$7m). This was partially offset by higher thermal fuel and carbon costs (-$5m).
- Thermal fuel costs increased to $166.80/MWh (1H24: $96.40/MWh) due to a higher cost of gas (1H24: $8.3/GJ, 1H25: $15.2/GJ), higher utilisation of Whirinaki (1H24: 0GWh, 1H25:18GWh) and a higher unit price of carbon (1H24 $59/unit, 1H25 $74/unit).
- Acquired generation costs were significantly higher in 1H25 ($43m up on 1H24) as purchases were made ahead of winter 2025 and due to NZAS demand response payments. In comparison, in 1H24 gas was more readily available and Contact was able to use this to deliver similar cover.

Wholesale contracted revenue

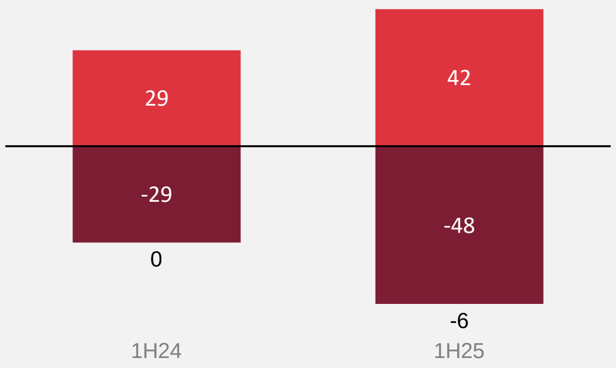
The Methanex gas deal at the beginning of 1H25 was backed by an electricity supply agreement with Meridian leading to a significant increase in CFD sales volumes



- Fixed price variable volume electricity sales to the Retail segment and C&I customers ended 75GWh higher than 1H24 (+$34.2m). The volume shift is attributed to C&I as Retail volumes held largely steady.
  - Pricing to C&I was broadly in line with last year given short term channels (including CFDs) were prioritised over C&I re-contracting in response to uncertainty of gas supply contracts, geothermal plant commissioning and prior swaption supply contracts.
  - Transfer price to the Retail channel was up $12/MWh to $152.6/MWh reflecting higher wholesale prices over the three preceding years.
- Strategic fixed price sales were 74GWh lower than 1H24 but average pricing across the channel was up significantly resulting in a $14m uplift in revenue. This movement in pricing and volume reflects:
  - Pricing: The signing of the long term deal with NZAS (in 2H24 – beginning 1H25) was at a higher price than the prior contract.
  - Volumes: Lower volumes reflect the implementation of demand response by NZAS at the beginning of the period in response to dry conditions.
- CFD sales volumes were up by 154GWh as a result of Tauhara being online for the whole period and a significant risk management contract sold to Meridian at the beginning of 1H25. Prices were up by $78.5/MWh reflecting the market conditions at the end of FY24 and the beginning of 1H25.
- Steam sales were steady in both volume and revenue compared to 1H24.
- Other income was significantly lower (-$14.6m) primarily as a result of losses on sale of gas that could not be stored or economically used for generation in the period.

Wholesale trading and merchant revenue

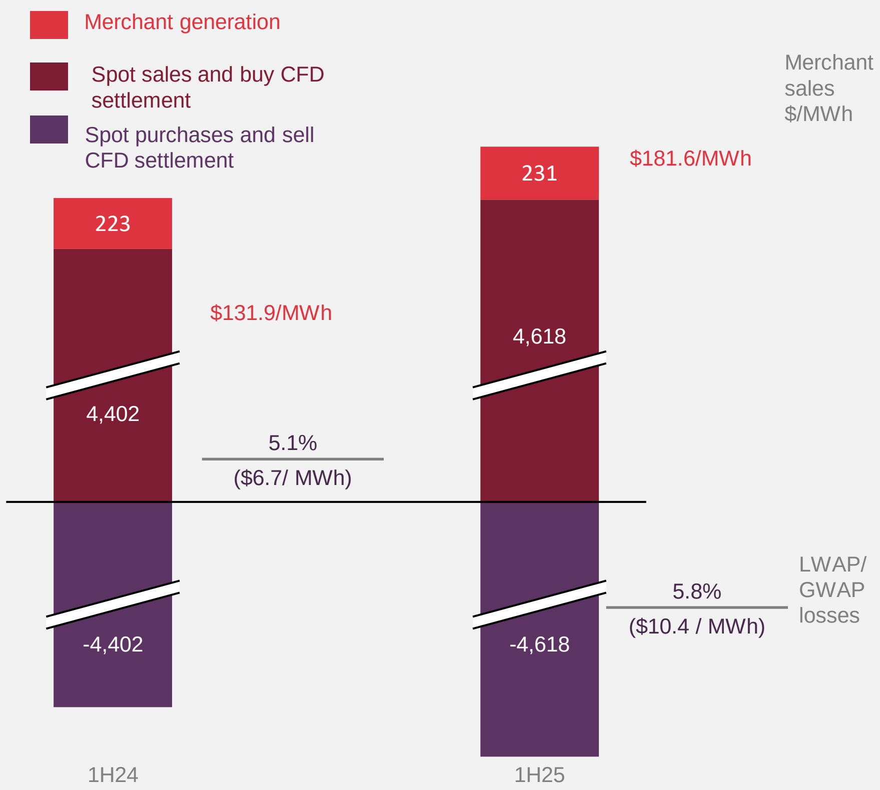
Trading EBITDAF ($m)



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)



Merchant generation revenue in 1H25 was characterised by two distinct periods –

- In Q1 Contact was broadly neutral on merchant sales volumes in a much higher priced spot market (much of our potential merchant revenue in this period was converted to short dated CFD's). Higher prices in Q1 meant Contact's LWAP / GWAP costs were largely covered.
- In Q2 the significant rainfall saw periods of spill in Contact's hydro dams, reducing hydro length and causing some LWAP/GWAP losses (at very low spot prices). The net result was that LWAP / GWAP losses outstripped merchant revenue over the quarter. This volatility also saw location risk management products (FTRs) out of the money.

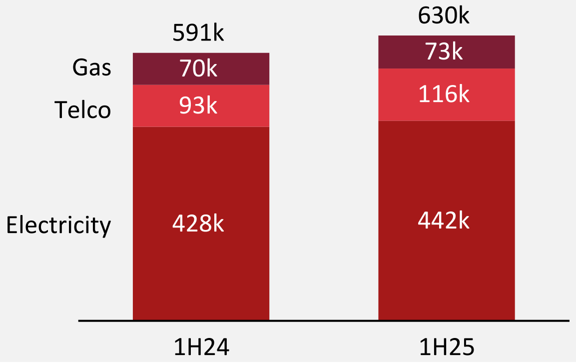
During 1H25 an accrual adjustment was made in relation to final settled electricity prices during the August 2021 UTS resulting in a $1.6m expense relating to accruals from FY22.

Retail business performance

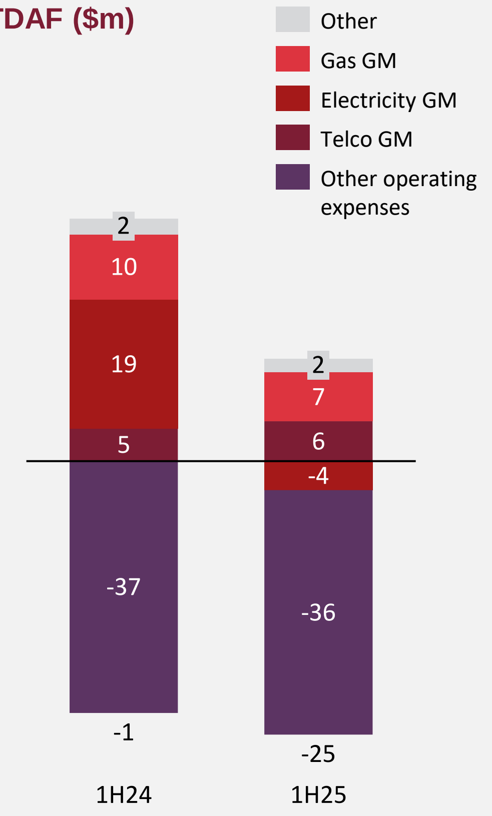
Margins contract as wholesale electricity and lines costs rise faster than tariff; Contact gaining connections via time of use and multi-product offerings

Revenue & Tariff[1] ($m)	1H24	1H25		Variance	
	$m	$m	*Tariff[1]*	$m	*Tariff*
Electricity revenue	**524**	**544**	**292**	**20**	**12**
Gas revenue	51	52	43	1	6
Telco revenue	39	48	71	9	(1)
Other income	4	4		-	
Total revenue	**618**	**648**		**30**	
Contract Asset (closing)	4	5		1	
# of connections (closing)[2]	***591k***	***630k***			
Cost to serve/connection[3]	*$63*	*$57*			

Closing connections (k)[2]



EBITDAF ($m)



	1H24	1H25
Electricity transfer price[4]	$141/MWh	$153/MWh
Networks, meters and levies[4]	$113/MWh	$122/MWh

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

- Retail EBITDAF decreased by $24m on 1H24 largely driven by the $46m increase in electricity input costs that were not fully passed through to customers.

Contact's average retail electricity tariff increased by 4.3% reflecting retail price rises to partially offset rising wholesale and lines cost increases.

- Around 90% 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 infrastructure.[5]
- Elevated wholesale futures prices over the medium term.

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

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

- Total connections +39k on 1H24 with telco up 23k and energy up 16k.
- Multi-product customers up 12% on 1H24, driven by telco products (including successful launch of new mobile product option) alongside ToU 'Good' plans growth.

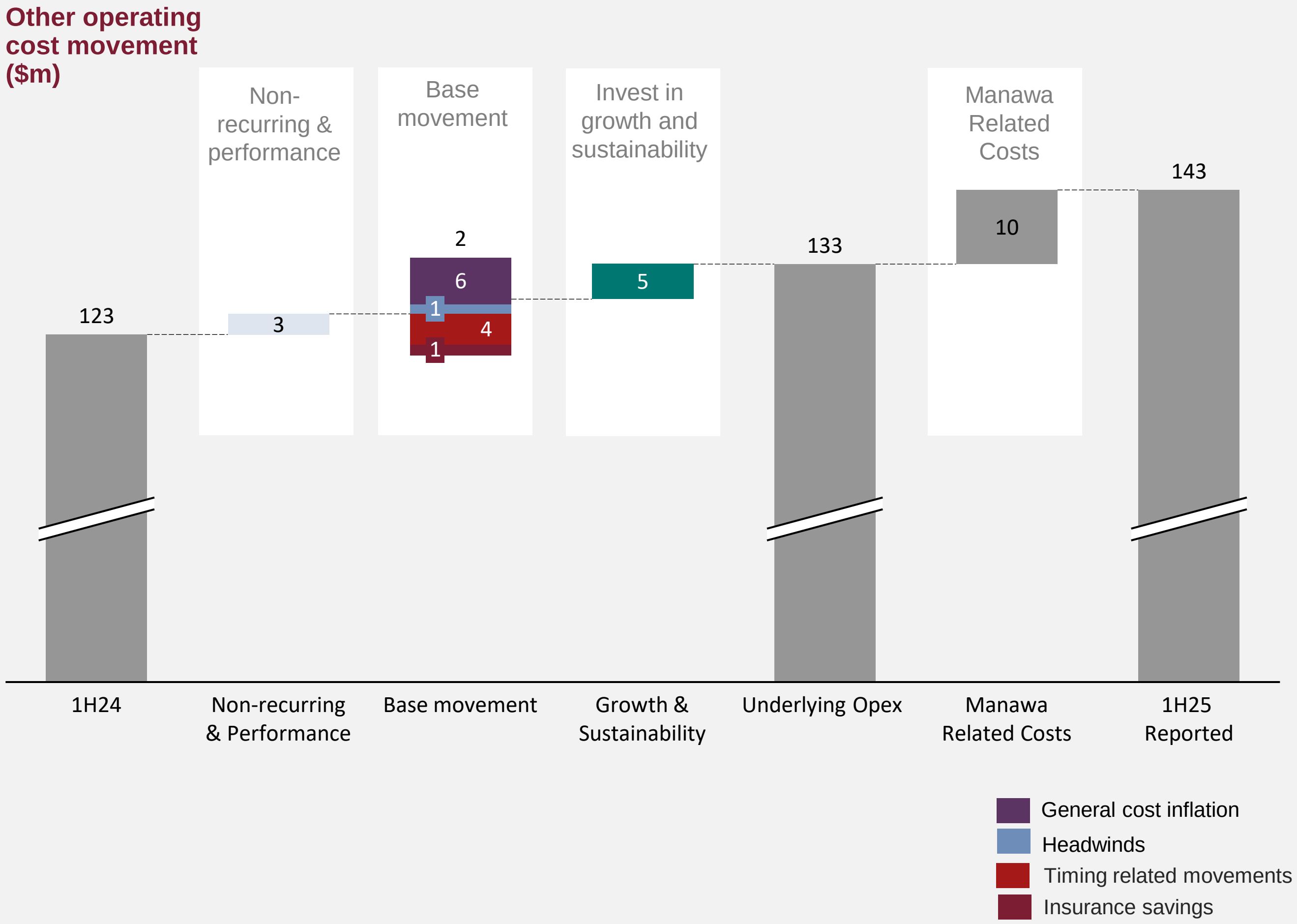
Cost to serve – reduced by $6/connection, largely driven by timing of the marketing spend and productivity improvements through continued growth in digitised interactions, partially offset by wage inflation.

[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 $10 to $20 per month from 1 April 2025, for affected networks (varies across regions and customer profiles).

Operating costs increase on inflation and growth



Non-recurring & performance

- $2m costs related to movement in performance-based accrued costs in line with year-to-date performance.
- $1m nonrecurring costs relate to Wairakei extension feasibility.

Base movement

- $6m general inflation of 2-4% impacting operating costs. These have been seen across the business, including labour cost and local body rates.
- $1m headwinds related to premium increases for staff health insurance programmes and extra staffing required to support Retail call centres during a period of higher than normal price change activity.
- -$4m timing movements largely driven by timing of Retail marketing and other activity.
- -$1m insurance savings from change in insurance programme provider.

Growth and sustainability

- $3m incremental costs with Tauhara online.
- $1m incremental investment related to retail connection growth.
- $1m increase in development projects which are in feasibility phase.

Manawa related costs

- $10m of transaction and integration related costs incurred. Made up of $8.6m of transaction related costs and $1.6m of integration planning activity.

Note:1H24 Opex is adjusted from that presented in the 1H24 results presentation due to an accounting treatment change relating to asset write-offs and impairments.

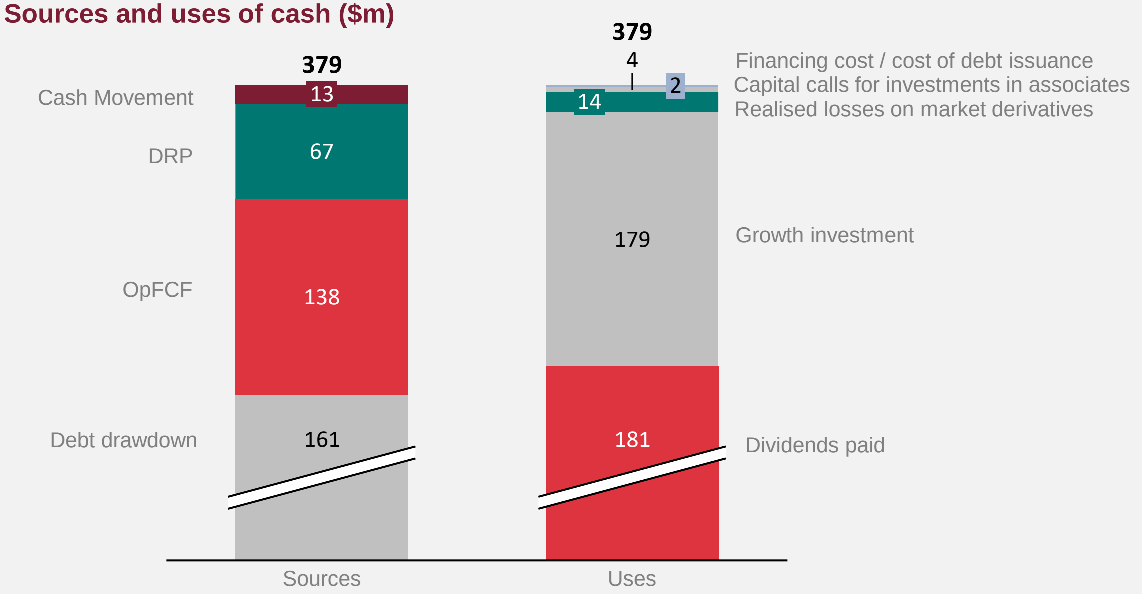
Cash flow and capital expenditure

Cash conversion for 1H25 impacted by higher EBITDAF, higher fuel inventory and higher interest payments

	6 months ended 31 December 2024 (1H25)	6 months ended 31 December 2023 (1H24)	Comparison against 1H24	
EBITDAF[1]	**$404m**	$334m	↑	$70m
Working capital changes	**($80m)**	($10m)	↑	$70m
Tax paid	**($74m)**	($66m)	↑	$8m
Interest paid, net of interest capitalised	**($43m)**	($9m)	↑	$34m
SIB capital expenditure	**($65m)**	($85m)	↓	$20m
Non-cash items included in EBITDAF	**($4m)**	$10m	↓	$14m
Operating free cash flow	**$138m**	$174m	↓	$36m
Operating free cash flow per share	**17.4 c**	22.1c	↓	4.7 c
Cash conversion (OpFCF / EBITDAF)	**34%**	52%	↓	18%

- Higher underlying EBITDAF on greater alignment of channel prices to the wholesale market.
- Working capital changes were $70m greater than in the prior year due to higher value and levels of stored gas following the purchase of gas from Methanex.
- Interest paid, net of capitalised interest, was $34m higher than 1H24, with the completion of Tauhara reducing the interest capitalised to the project.
- 1H25 stay-in-business (SIB) capital expenditure includes completion of the Peaker refurbishment and Te Mihi spare rotor acceleration projects. Te Mihi Stage 2 pre-FID costs have been reclassified as SIB capex in 1H25 ($2m) and 1H24 ($22m). These were previously allocated to growth capex.
- Non-cash items included within EBITDAF in 1H25 include the AGS onerous provision unwind (+7m).

Sources and uses of cash ($m)



[1]1H24 EBITDAF is shown as underlying, excluding $29m net release of the onerous contract provision for AGS. 1HY25 EBITDAF includes monthly unwind of +$7m.

Growth capital expenditure

Growth capital expenditure in 1H25 reflects Contact's continued commitment to renewable development

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

	Up to 30 June 2024	6 months ended 31 Dec 2024	Remaining under current approvals	Total[2]
Tauhara	$852m	$46m	$26m	$924m
Te Huka 3	$246m	$24m	$30m	$300m
Te Mihi Stage 2[3]	$57m	$47m	$608m	$712m
Wind	$13m	$4m	$3m	$20m
Glenbrook battery	$5m	$37m	$121m	$163m
Capitalised interest	$173m	$10m	$63m[4]	$246m
Total	**$1,346m**	**$168m**	**$851m**	**$2,365m**

- The Tauhara geothermal station has been generating since May 2024. Final commissioning activity was completed in 1H25. Construction of Te Huka 3 is substantially complete and final commissioning activity is underway.
- Investment in Te Mihi Stage 2 was confirmed in November 2024. The Wairakei extension project is classified as stay-in-business capex and is illustrated on slide 36 (excluded from this slide).
- Construction is underway on a 100MW grid-scale battery (BESS) at Glenbrook, with $42m spent as at 31 December 2024. The BESS is expected to be completed in FY26 with remaining growth capex falling across both 2H25 and FY26.
- Remaining spend on wind projects reflects current pre-FID approval levels and will be updated after final investment decisions, as applicable.
- 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.

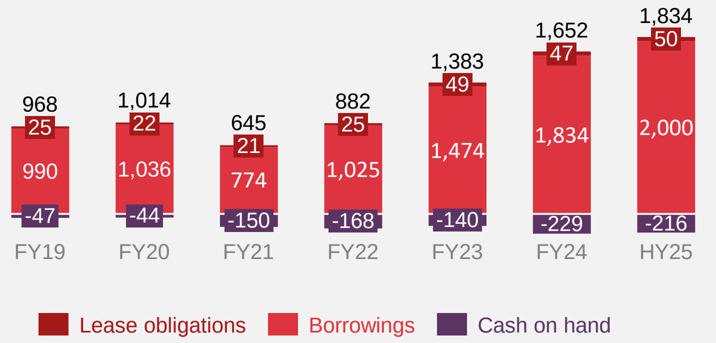
[1] Excludes $11m associated with Western Energy coil tube drilling and deployment of demand flex technology.
[2] Total under current Board approvals.
[3] Growth capital expenditure for Te Mihi Stage 2 (previously GeoFuture) has been restated following the project reaching FID in November 2024. A portion of capital spent up to June 2024 ($41m) was reclassified to stay in business capex as it related to spend on both existing plant within the Wairakei field and the extension of Wairakei power station. Stay in Business capital spent for the Wairakei extension in 1H25, and expected capital spend to the end of FY25, is broken down further on slide 36.
[4] Relates to Te Huka 3 geothermal development (FY25 only) , Te Mihi Stage 2, and Glenbrook battery development (life of project).

Strong balance sheet

Supporting Contact's growth with diverse sources of funding with strong green credentials

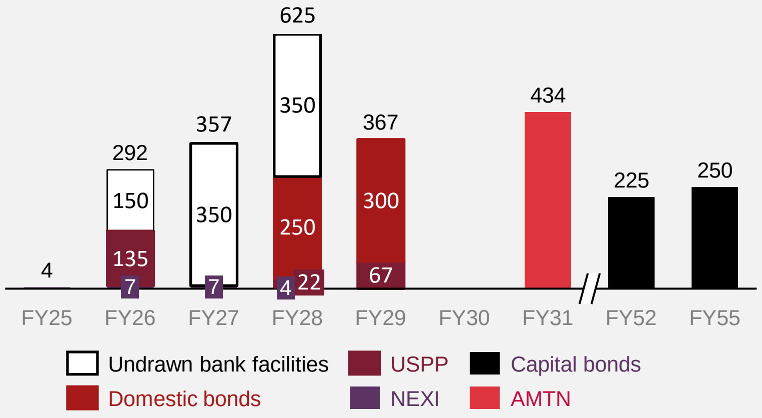
Closing net debt ($m)

Face value of borrowings less cash



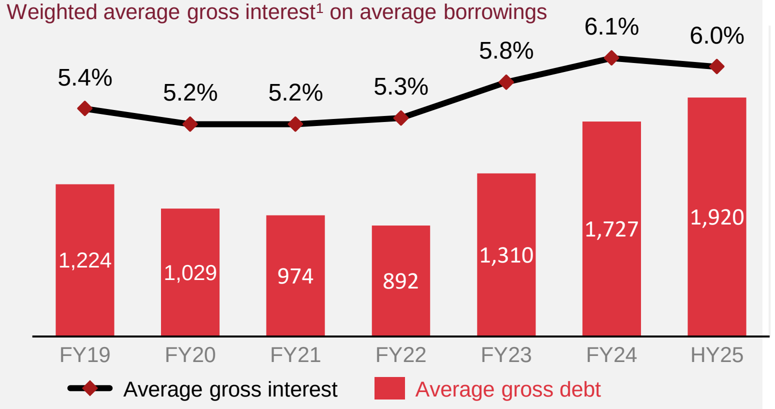
Borrowing maturities ($m)

Average tenor of 8.3 years as at 31 December 2024



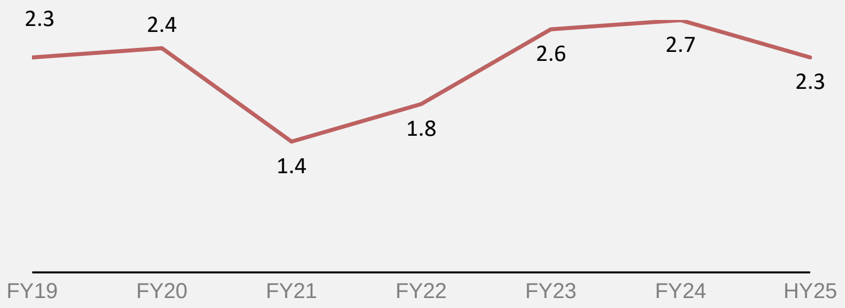
Interest rate (%)

Weighted average gross interest[1] on average borrowings



Net debt to EBITDAF (x)

Includes S&P adjustments (prior to FY20, AGS was treated as a lease)[2]

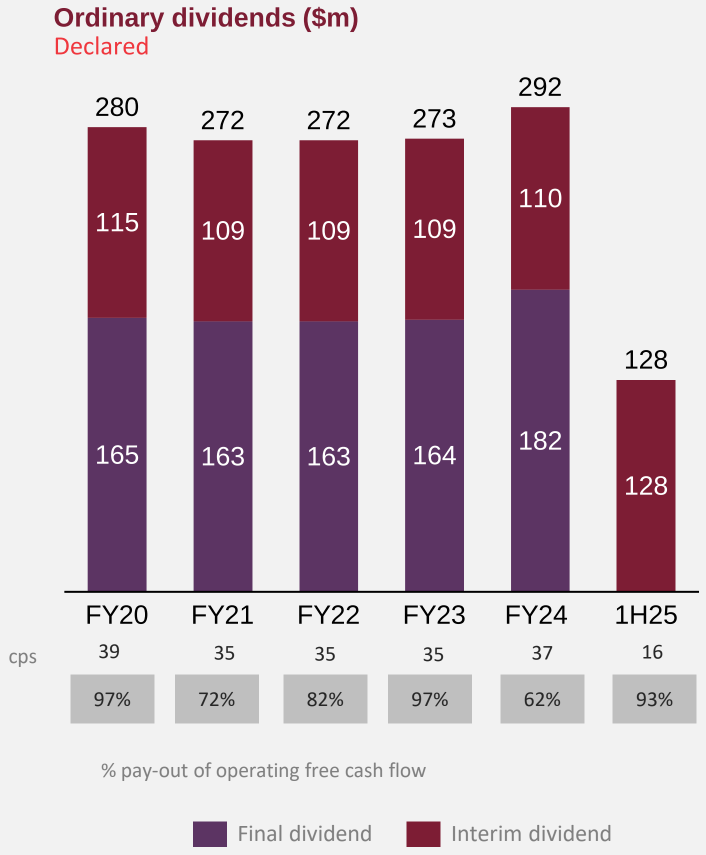


- Gross debt has increased in line with the continued build out of the capital investment programme. This is expected to continue to grow as projects are constructed.
- A $100m Retail Bond matured in August 2024 and was replaced with a $250m Capital Bond in October 2024. The hybrid structure of the new bond provides an equity credit for Contact's S&P rating (50%), reducing S&P net debt for the Net Debt / EBITDAF calculation.
- Contact targets a BBB investment grade credit rating with S&P. This requires net debt to EBITDAF to remain below 3.0x over a sustained period. Point estimate net debt to EBITDAF is currently 2.3x at the half year. Contact's EBITDAF outlook, DRP and capacity for further hybrid bonds allow this metric to be managed effectively.
- Contact continues to be at the forefront of sustainable finance and has extended its $850m sustainably-linked loan[3]. This loan has KPIs with financing incentives or penalties relating to emissions reductions, renewable energy development and performance in the Dow Jones Sustainability Index (DJSI).

[1] Gross interest includes all interest on borrowings, bank commitment fees and deferred financing costs. Unwind of leases, provisions and capitalised interest not included.
[2] Illustrated here on a point basis based on expected S&P adjustments. FY25 is based on a normalised EBITDAF of $770m.
[3] Term extended by 12 months.

Dividend for 1H25

Uplift of 2 cents per share on 1H24, in line with 39 cents per share guidance for FY25



Interim dividend for 1H25 of 16 cents per share

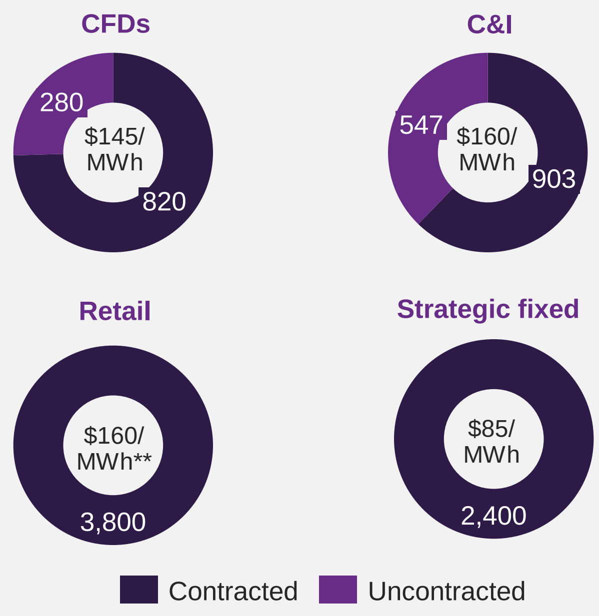
- Interim dividend of 16 cents per share is imputed to 88% or 14 cents per share for qualifying shareholders.
- Record date of 25 February 2025; payment date of 18 March 2025.
- The NZD/AUD exchange rate used for the payment of Australian dollar dividends will be set on 6 March 2025.

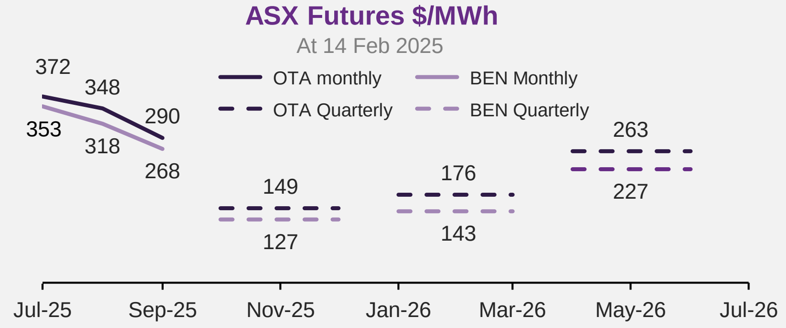
Dividend reinvestment plan (DRP)

- 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 FY25 interim 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 26 February 2025 to confirm participation in the plan.
- Trading period for setting the price for the DRP is 24 February 2025 to 28 February 2025. DRP strike price will be announced: 6 March 2025.

Normalised and expected FY26 EBITDAF

Assumes mean hydrology conditions



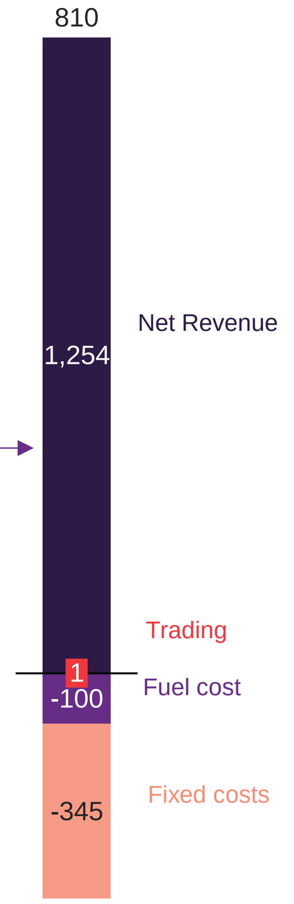


FY assumptions that deliver expected & normalised EBITDAF for FY26

1 Channel choices maximise long term value[1]		X	2 Net price[2] driven by best commercial practices	=	Total
Strategic fixed price	2,400GWh	x	$85/MWh	=	$204m
CFDs	1,100GWh	x	$145/MWh	=	$160m
C&I	1,450GWh	x	$160/MWh	=	$232m
Retail	3,800GWh	x	$160/MWh	=	$608m
Other income[3]					$50m
					$1,254m

3 Hydrology & Asset availability optimise generation		X	4 Access to and price of fuel* drives financials & risk position	=	Total
				=	
Hydro mean	3,940GWh	x	$0/MWh	=	-$0m
Geothermal average	4,970GWh	x	$4/MWh	=	-$20m
Thermal	250GWh	x	$200/MWh[4]	=	-$50m
Acquired	100GWh	x	$300/MWh		-$30m
					-$100m

5 Trading delivers value to more than offset locational losses		6 Digitalisation & continuous improvement optimise fixed costs	
Length[5]	$102m	Transmission/Storage	-$65m
Location losses[6]	-$101m	Operating expenses	-$280m
Total	**$1m**	**Total**	**-$345m**

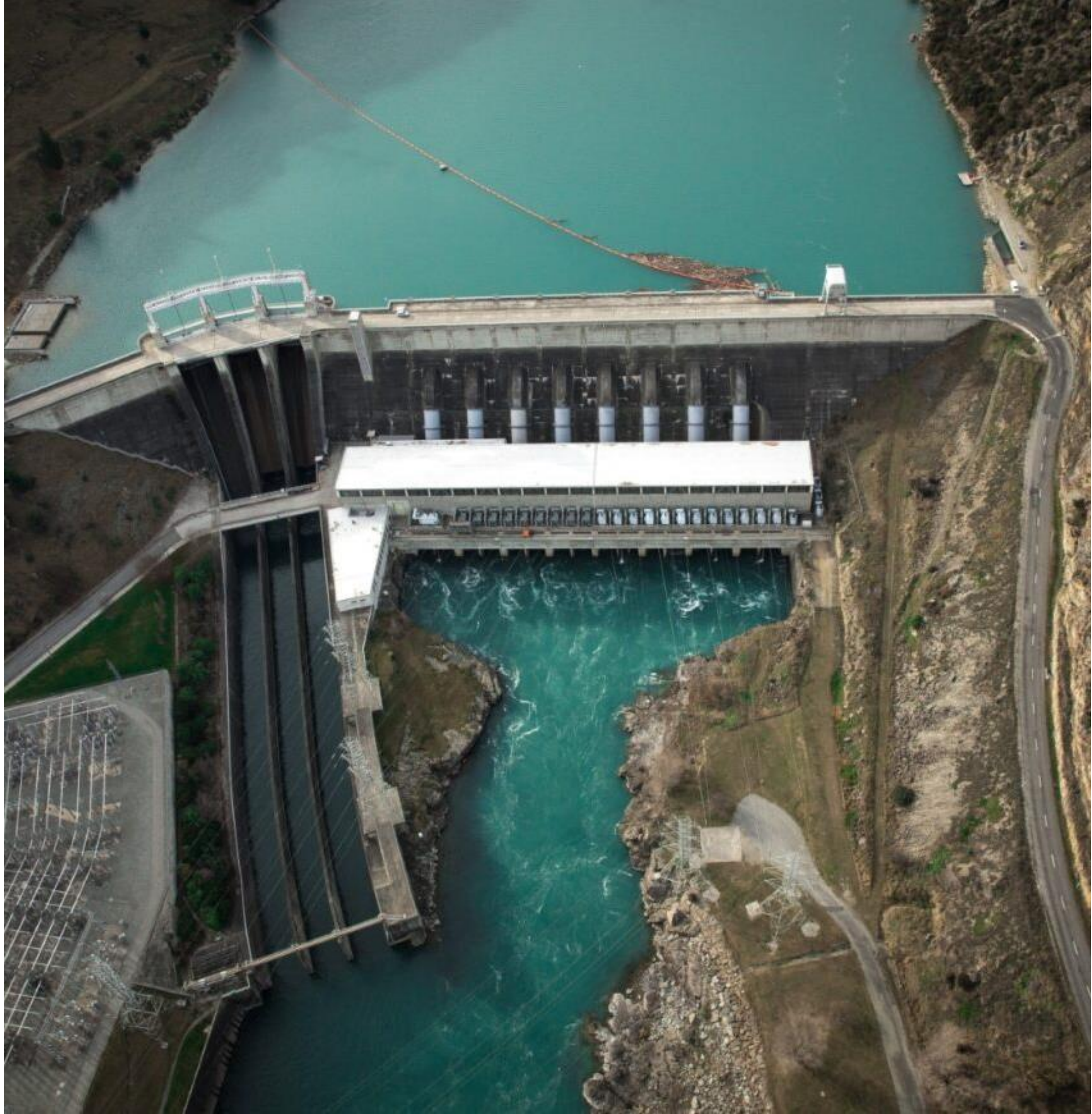


1. All volumes are at the Grid Exit Point (GXP)
2. Net price is equal to tariff less pass-through costs (network, meters and levies) /MWh
3. Steam sales, retail gas gross margin, telco gross margin and other income
4. Gas price of $15.0/GJ, carbon price of $76/unit and thermal portfolio heat rate (10.5GJ/MWh)
5. Length of 510GWh p.a. assumed
6. Locational losses of 5.8% on spot purchases and settlement of CFDs sold at a wholesale price of $145/MWh

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

Note, all figures are subject to rounding.

Questions



Supporting materials

Preparing for Contact's combination with Manawa

Targeting completion around the end of the first half of 2025

- On 11th September 2024, Contact entered into a Scheme Implementation Agreement (SIA) to acquire 100% of Manawa via a mixture of Contact shares and cash.
- The proposed combination is expected to create a more diversified, resilient and efficient Contact business, which will be positioned to better manage dry year risk, execute on renewable development opportunities and support New Zealand's energy transition.[1]
- The transaction is subject to various conditions, each as set out in detail in the SIA, including NZ Commerce Commission (NZCC) clearance, approval of the Scheme by the High Court and by Manawa shareholders by the requisite majorities.
- Contact is preparing for the combination with Manawa to ensure that the strategic, financial and energy transition benefits are fully delivered.
  - Integration Director appointed and Integration Management Office established October 2024.

Indicative transaction timeline[2]

Key event	Indicative date
Entry in Scheme Implementation Agreement	11 September 2024
NZ Commerce Commission (NZCC) application registered	30 September 2024
Receipt of initial Court orders	13 February 2025
NZCC decision	31 March 2025 *(current schedule)*
Issuance of Scheme Booklet to Manawa shareholders	As soon as practicable following NZCC approval
Manawa Scheme Meeting	Four weeks post issuance of Scheme Booklet
Second Court hearing	Approximately two weeks post Scheme Meeting
Target for implementation of the Scheme	**End of first half CY2025**

NZ Commerce Commission update

- Statement of Issues (SoI) released on 5th February 2025 with submissions due by 21st February 2025.
- Contact and Manawa have each provided substantive supporting evidence to the NZCC as part of its ongoing assessment process and will continue to assist the NZCC in its understanding of the matters noted in the SoI.

[1] For a full description of transaction rationale and benefits, see Contact's announcement and presentation released on the NZX on 11th September 2024, linked here

[2] All dates are indicative only and subject to change. The dates assume there are no delays or complications, including with respect to court and regulatory approvals, and will depend on the timing of each other step and satisfaction of the conditions precedent.

Guidance confirmation

	Updated FY25 guidance	1H25 result	Change to prior guidance	
Stay in Business Capex	**$120m - $130m**	**$65m**	+$4 - 5m	
Stay in business accelerated programme (cash)	~$40m	$25m	-	
Stay in business capital expenditure (cash) BAU	$77m - $87m	$40m	+$2m	Ohaaki statutory outage brought forward into FY25.
Stay in business capital expenditure (cash) Wairakei	$2m - $3m	$1m	+$2 - 3m	Wairakei extension costs reclassified from growth capex ($1m) and project costs brought forward.
Growth capital expenditure (cash)[1]	$450m - $550m	$179m	-	
Depreciation and amortisation	$275m - $285m	$130m	-	
Net interest (accounting)	$105m - $115m	$52m	-$10m	Reduction in interest rates from initial guidance setting.
Cash interest (in operating cash flow)	$85m - $95m	$43m		
Cash taxation	$105m - $115m	$74m	-$5m	Reduction in final FY24 tax cash payment due to utilisation of prior period tax credits
Realised (gains) / losses on market derivatives not in a hedge relationship	$15m - $20m	$14m	+$5m	Higher 1H25 result due to volatility in the market August/September 2024 (realised).
Corporate costs (ex Manawa)	$54m	$27m	+$2m	Movement in performance-based costs in line with YTD performance.
Corporate costs (Manawa transaction and integration)	$20m	$10m	n/a	Excludes costs linked to a successful transaction completion outcome.
Target ordinary dividend per share	39 cps	16cps	-	In line with target payout of 39 cps – Interim dividend 41% of the expected total.

[1] Growth capital expenditure includes capitalised interest and is based on current Board-approved capital spend.

Normalised and expected EBITDAF assumptions

With reconciliation to actual performance

1H25 assumptions that deliver expected & normalised EBITDAF of $770m 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	700GWh	x	$80/MWh	=	$56m
CFDs	885GWh	x	$154/MWh	=	$136m
C&I	650GWh	x	$150/MWh	=	$98m
Retail	2,050GWh	x	$154/MWh	=	$315m
Other income[3]					$24m
					$629m

3 Hydrology & Asset availability optimise generation		X	4 Access to and price of fuel* drives financials & risk position	=	Total
Hydro	2,030GWh	x	$0/MWh	=	-$0m
Geothermal	2,100GWh	x	$4/MWh	=	-$8m
Thermal[4]	130GWh	x	$200/MWh	=	-$26m
Acquired	175GWh	x	$215/MWh	=	-$38m
					-$72m

5 Trading delivers value to more than offset locational losses		6 Digitalisation & continuous improvement optimise fixed costs	
Length[5]	$42m	Transmission/Storage	-$36m
Location losses[6]	-$42m	Operating expenses	-$136m
Total	**$0m**	**Total**	**-$172m**

EBITDAF reconciliation to 1H25 ($m)

Normalised & Expected

Lower renewables
Renewable generation below mean (-35GWh) at expected thermal SRMC

Increased long-term channel price
Strategic fixed price sales price of $83/MWh in 1H25 higher than full year expectation

Higher market channel price
CFD net price of $218/MWh in 1H25 higher than full year expectation due to CFD sales backed by Methanex gas

Gas, carbon, acquired generation price
Uplift driven by Methanex gas and NZAS demand response

Net volume impact
Higher sales volumes were offset by increased cost of acquired generation and SRMC of thermal generation

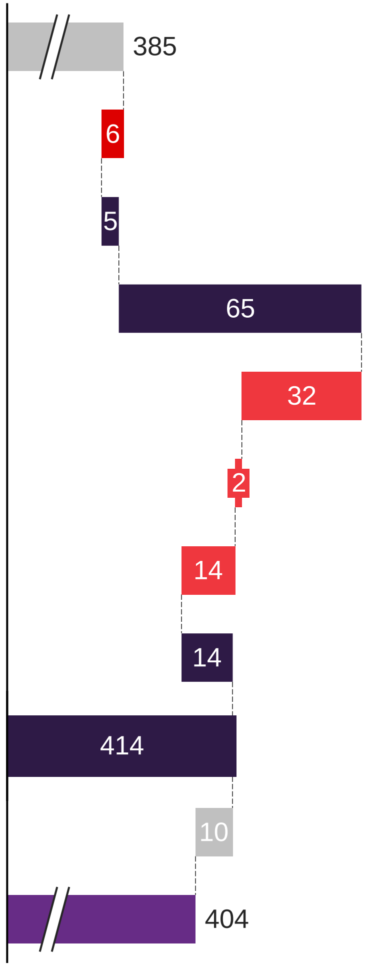
Other income
Losses from sale of excess gas (-$18m) partly offset by income associated with hedge products

Fixed costs
Driven by AGS provision unwind (+$7m non-cash) and LCE rebates

EBITDAF pre-Manawa related costs

Manawa related costs
Transaction and integration preparation costs associated with the proposed Manawa acquisition (-$10m)

Reported



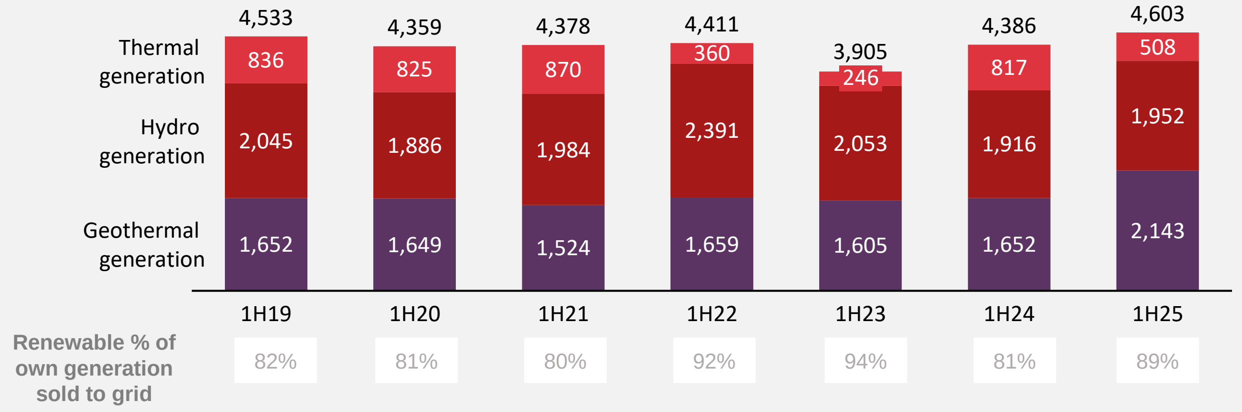
1. All volumes are at the Grid Exit Point (GXP)
2. Net price is equal to tariff less pass-through costs (network, meters and levies) /MWh
3. Steam sales, retail gas gross margin, broadband gross margin and other income
4. Gas price of $8.2GJ, carbon price of $80/unit and thermal portfolio heat rate (10GJ/MWh)
5. Length of 223GWh for 1H25 assumed
6. Locational losses of 5.4% on spot purchases and settlement of CFDs sold at a wholesale price of $155/MWh

* Fuel is natural gas and carbon costs

Operational data

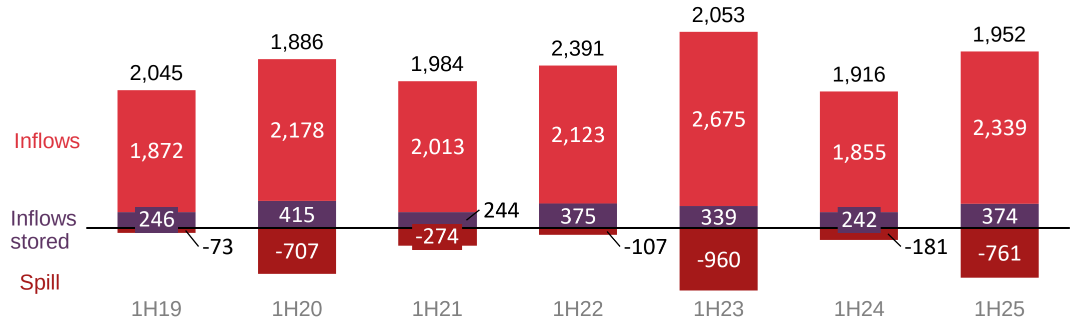
Generation and sales position

Contact generation output sold to the national grid (GWh)



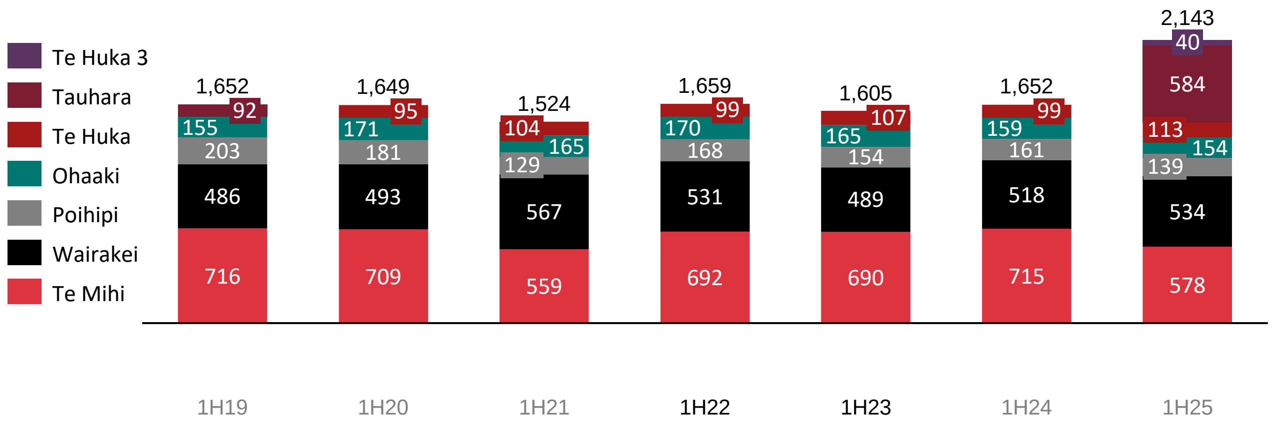
Hydro generation (GWh)

Inflows stored include uncontrolled storage lakes



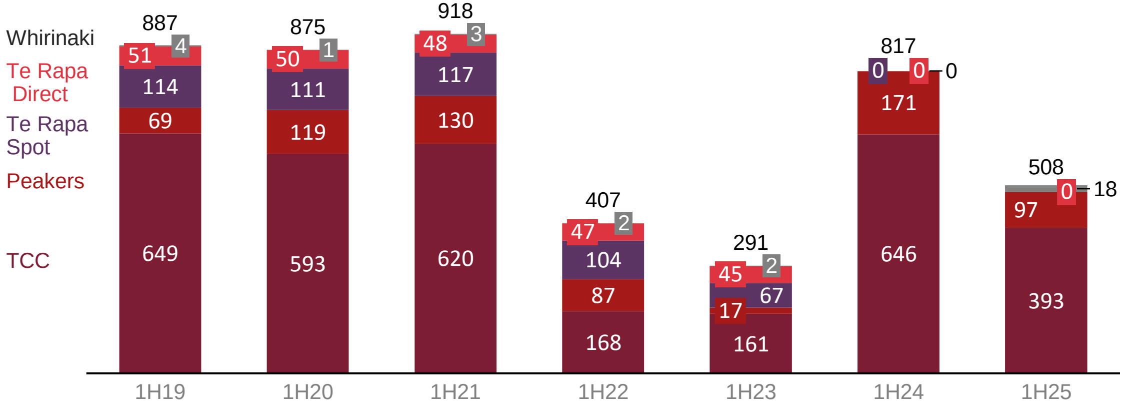
Highly concentrated inflows in the second quarter of 1H25, after a very dry end to 2H24, saw Hawea storage volumes increase significantly over the period. However, the highly correlated nature of the inflows also led to high levels of spill.

Geothermal generation (GWh)



Geothermal generation was up 491GWh (30%) on 1H24, the uplift is attributable to Tauhara being online for the period and Te Huka 3 entering commissioning and providing power to the grid in December. Partially offset by the planned Te Mihi outage.

Thermal generation (GWh)



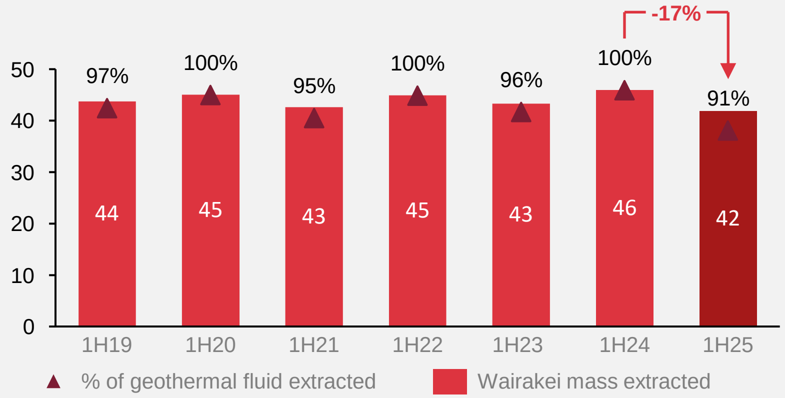
1H25 thermal generation volumes were 309GWh (38%) lower than 1H24 due to the following:

- Additional thermal generation was required to meet an increased sales position in light of the delay to Tauhara online in 1H24; and
- Significant hydro inflows in the second quarter of 1H25, in conjunction with new geothermal output, reduced reliance on thermal generation.

Plant and fuel performance

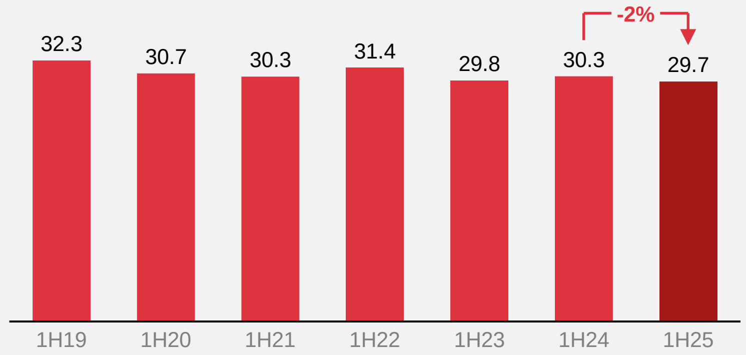
Geothermal fuel performance

Geothermal fuel extracted at Wairakei vs consented (mT)



Wairakei total mass extracted, and extracted volumes as a % of consented mass take, was significantly down on 1H24 as a result of a planned outage (25 days) at Te Mihi between September and October.

Wairakei, 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)
1H21	784	85%	57%	1,984	110	218
1H22	784	83%	69%	2,391	90	215
1H23	784	87%	59%	2,053	52	107
1H24	784	93%	55%	1,916	123	235
1H25	784	92%	57%	1,952	129	252

Taranaki combined cycle (TCC)

	Net capacity (MW)	Availability (%)	Capacity factor (%)	Electricity output (GWh)	Pool revenue ($/MWh)	Pool revenue ($m)
1H21	377	96%	37%	620	127	79
1H22	377	100%	10%	168	183	31
1H23	377	89%	10%	161	107	17
1H24	377	69%	39%	646	127	82
1H25	377	100%	23%	393	418	164

Whirinaki

	Net capacity (MW)	Availability (%)	Capacity factor (%)	Electricity output (GWh)	Pool revenue ($/MWh)	Pool revenue ($m)
1H21	158	91%	0%	3	305	0.8
1H22	158	98%	0%	2	783	1.8
1H23	158	97%	0%	2	274	0.4
1H24	158	100%	0%	0	0	0.0
1H25	158	95%	3%	18	667	12

Geothermal

	Net capacity (MW)	Availability (%)	Capacity factor (%)	Electricity output (GWh)	Pool revenue ($/MWh)	Pool revenue ($m)
1H21	425	86%	81%	1,524	118	180
1H22	410[1]	96%	92%	1,659	105	175
1H23	410	94%	89%	1,605	56	89
1H24	410	95%	91%	1,652	134	221
1H25	584	90%	80%	2,143	167	357

Stratford Peakers

	Net capacity (MW)	Availability (%)	Capacity factor (%)	Electricity output (GWh)	Pool revenue ($/MWh)	Pool revenue ($m)
1H21	202	86%	14%	130	151	20
1H22	202	74%	10%	87	216	19
1H23	202	57%	2%	17	190	3
1H24	202	56%	19%	171	152	26
1H25	202	60%	11%	97	123	12

Upcoming geothermal statutory turnarounds (outages)[2]

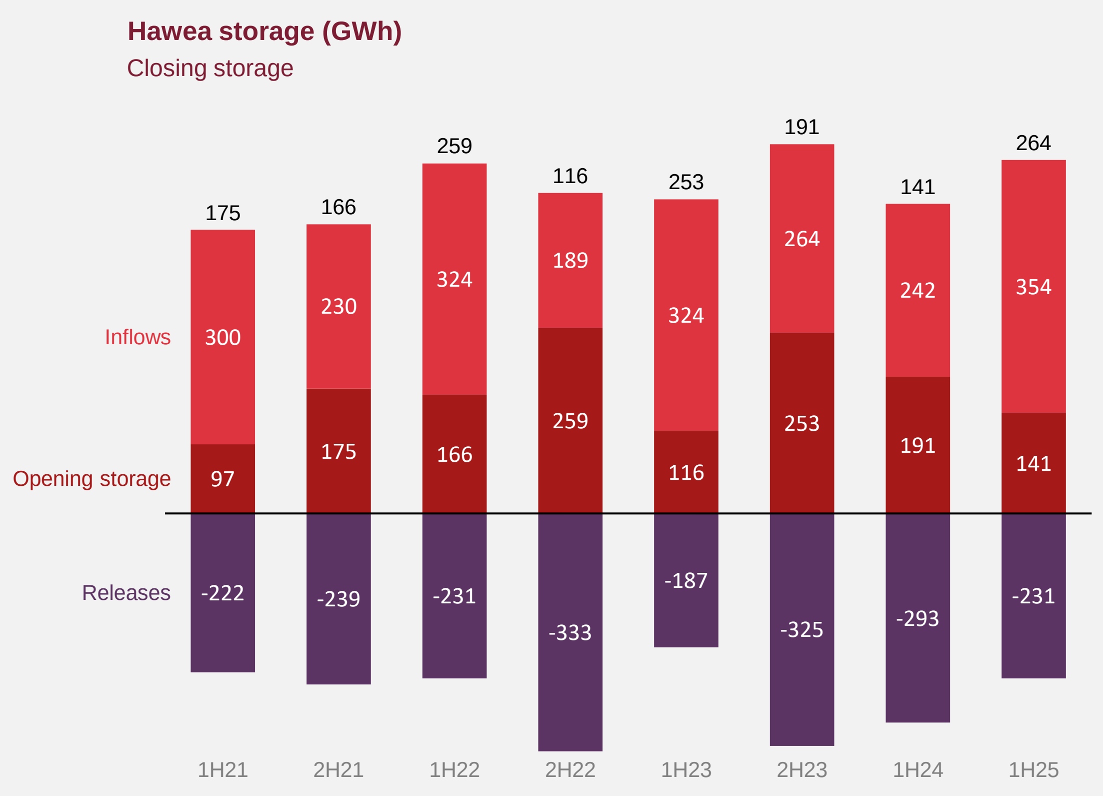
Plant	Impact (GWh)	FY	Frequency & type
Te Mihi	90	25	4y Stat turnaround
Te Huka 1&2	8	25	4y Stat turnaround
Te Huka 3	28	25	One-off commissioning outage
Ohaaki	28	25	4y Stat turnaround
Tauhara	118	26	Y1 Stat turnaround
Te Huka 3	32	26	Y1 Stat turnaround
Wairakei	25	26	4y Stat turnaround
Wairakei	330	27	4y Stat turnaround + ext works
Poihipi	31	28	4y Stat turnaround
Tauhara	147	28	Y3 Stat turnaround

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.

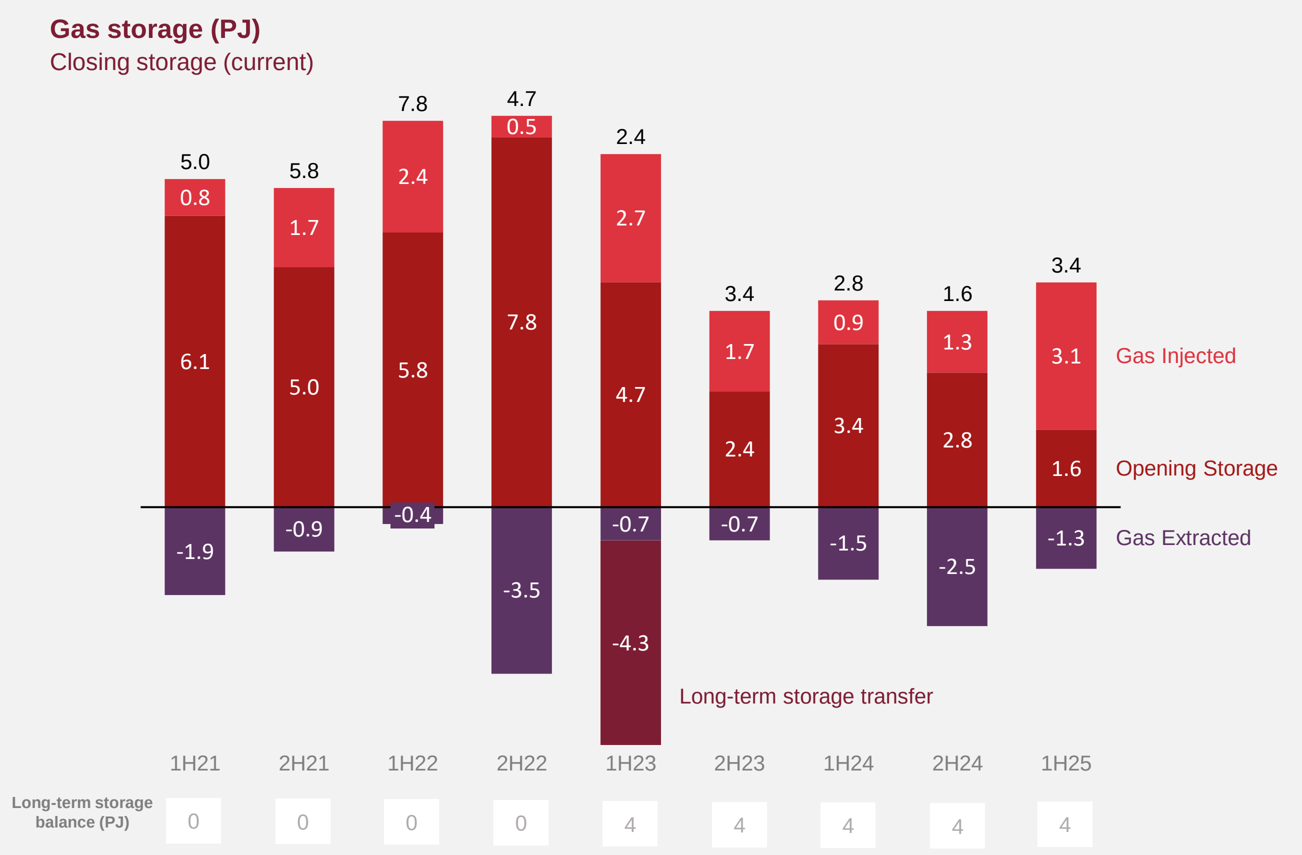
[2] Statutory turnarounds occur after the first operating year of a new plant, again in operating year 3, and every four years thereafter. The table shows which plant have a major statutory turnaround in the next 3 calendar years. The GWh impact is an estimate based on understood scope at the time of publishing. Turnarounds in FY27 and 28 are indicative.

Operational data

Fuel storage movements



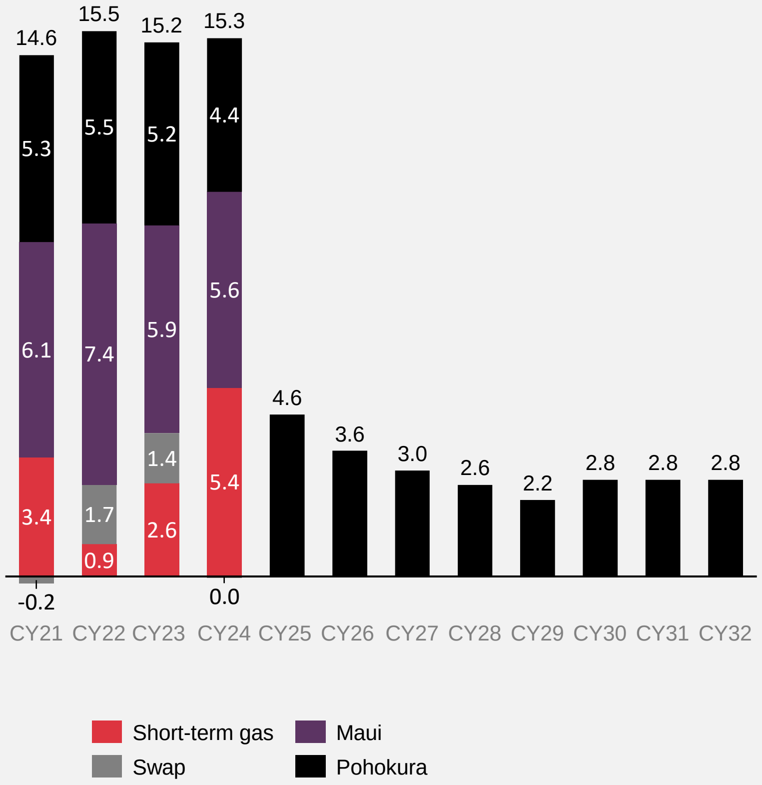
Source: NZX hydro



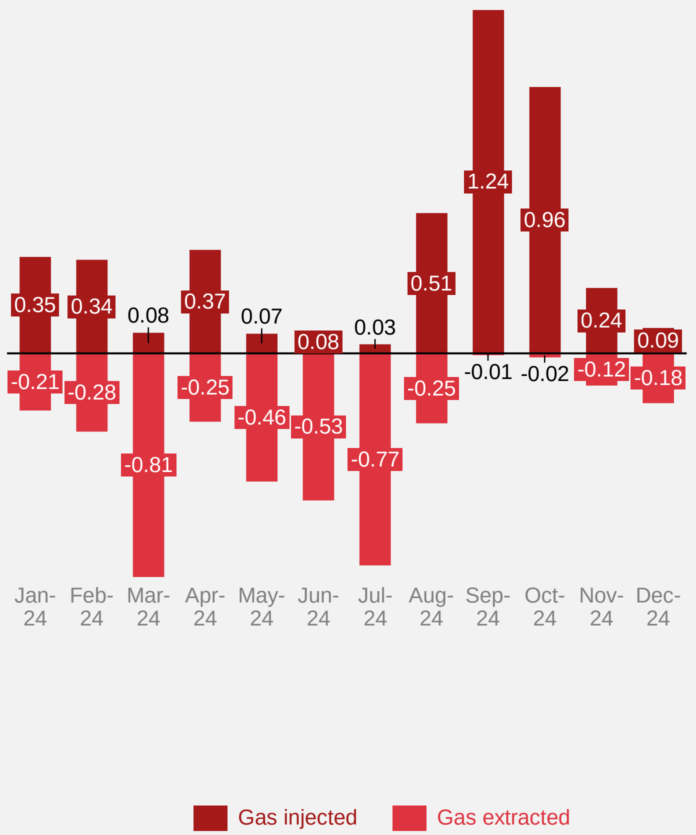
Following the completion of a joint technical working group, set up by Contact and the Ahuroa Gas Storage Facility (AGS) owner FlexGas, approximately 4.3PJs of gas owned by Contact and currently stored in AGS may only be available for extraction at the end of the contract in 2033.

Contracted and stored gas

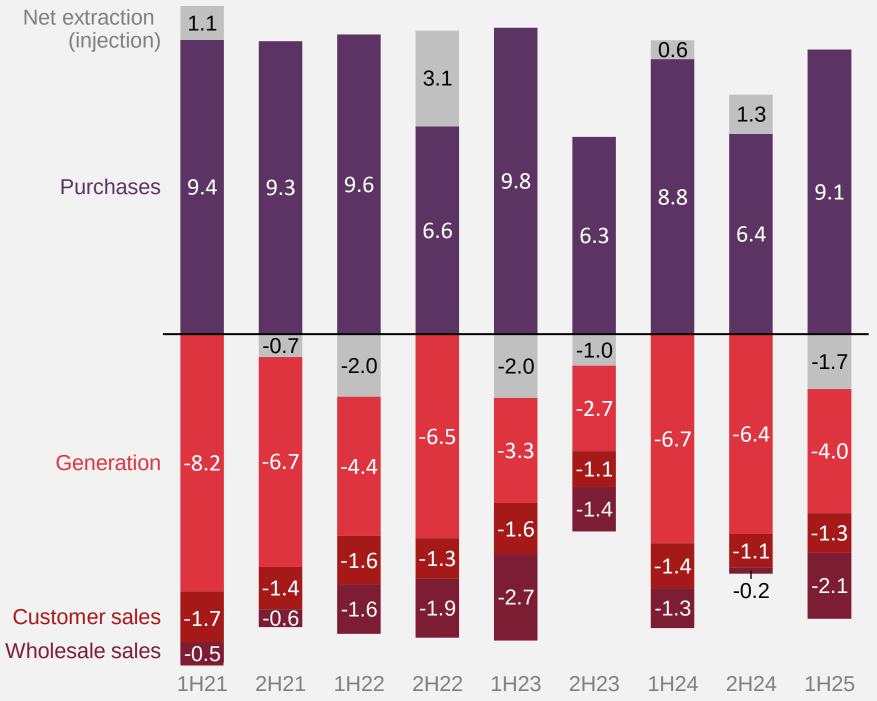
Contracted gas volumes (PJ)



Gas storage monthly injections and extractions (PJ)



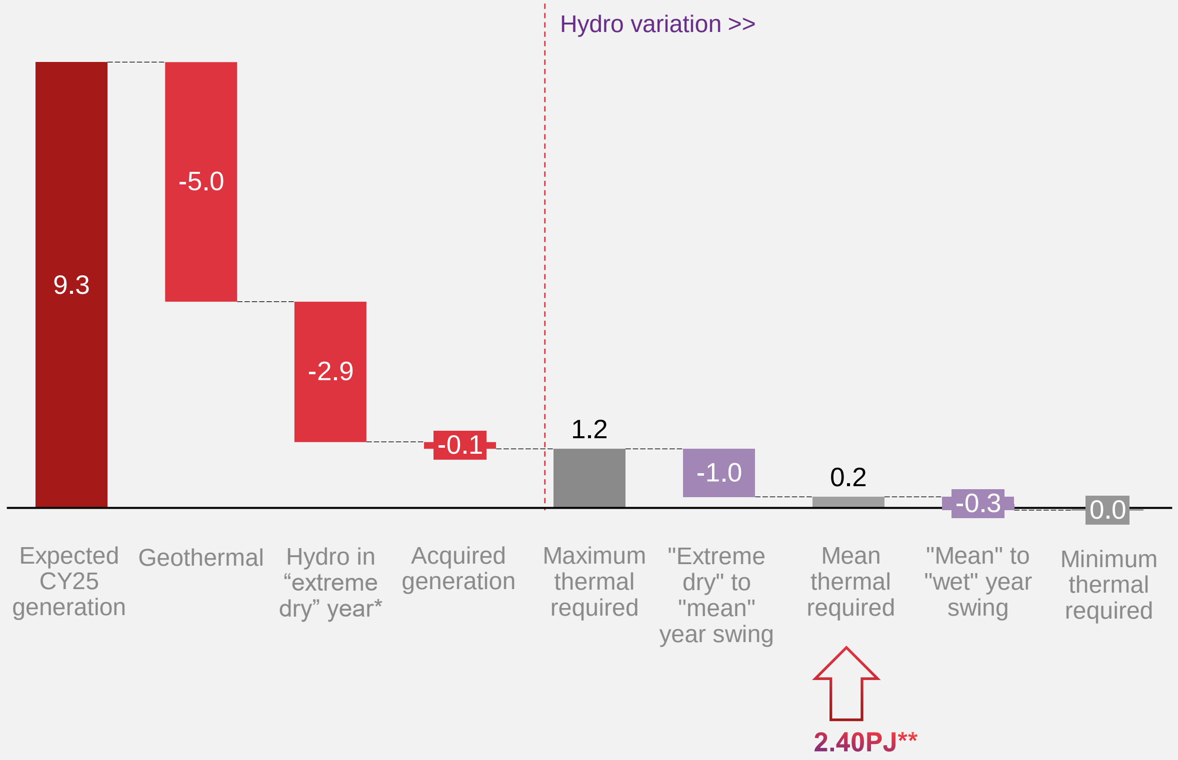
Uses of gas (PJ)



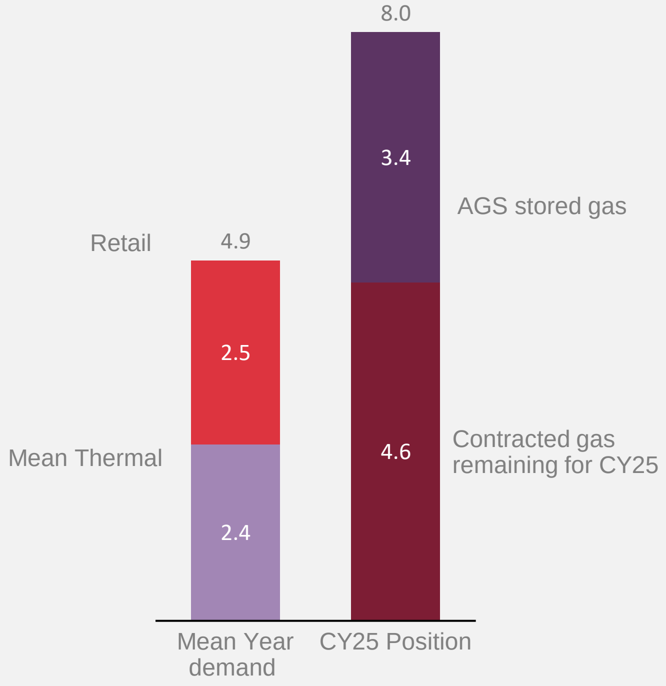
CY2025 volumes reflect current forecasts. This is ~1PJ below contacted volumes as a result of lower actual production volumes. CY2026-32 reflects the maximum volume of gas available under contract. Forecasted volumes for these periods are not yet available.

Contractual fuel position sufficient to support expected sales position under mean hydro conditions

Portfolio requirements for thermal generation CY25 (TWh)



Gas supply and demand CY25 (PJ)
Includes stored gas



Options in a dry year:
- Access to stored water in Hawea
- Purchase spot gas
- Acquire generation from ASX
- Contracted gas above expected mean position

Options in a wet year:
- Gas swaps
- Gas sales
- Hawea storage
- Sell short term ASX
- AGS storage

*Hydro generation in FY12.
** Assumes peaker generation only (heat rate 10.5GJ/MWh) i.e., assumes TCC is not used during the period.

Reconciliation between Profit and EBITDAF

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

EBITDAF is commonly used in the electricity industry so provides a comparable measure of Contact's performance.

Reconciliation of statutory profit back to EBITDAF:

	6 months ended 31 December 2024 (1H25)	6 months ended 31 December 2023 (1H24)		Variance on prior year	
				$m	%
	Reported	Underlying[1]	Reported	Against reported	
Profit	**142**	**134**	**153**	**(11)**	**(7%)**
Depreciation and amortisation	130	126		(4)	(3%)
Change in fair value of financial instruments	21	-5		(26)	(520%)
Asset write-offs and impairments	-	8		(8)	N/A
Net interest expense	52	17	20	32	160%
Tax expense	59	53	60	(1)	(2%)
EBITDAF	**404**	**334**	**362**	**42**	**12%**

Depreciation and amortisation, net interest and tax expense are explained on the right.

The adjustments from EBITDAF to reported profit and movements on 1H24 are as follows:

- **Depreciation and amortisation:** increased by $4m and is linked to depreciation on Tauhara being recognised post completion. This has been partially offset by lower usage of thermal assets compared to 1H24.
- **Change in fair value of financial instruments:** includes unrealised gains/losses associated with the new NZAS contract which is not eligible for hedge accounting. Expected to drive increased volatility in profit going forward. See slide 44 for more detail.
- **Net interest expense:** significantly higher than 1H24 as Tauhara was completed in 2H24 and interest in relation to borrowings to build the project are no longer being capitalised.
- **Tax expense:** for the period decreased by $1m following lower profit before tax in 1H25 vs 1H24, partially offset by higher non-deductible expenditure related to the proposed Manawa transaction.

[1] Underlying 1H24 figures are exclusive of the impacts of the onerous contract provision for AGS. Impacts of the onerous contract in 1H24 are as follows, EBITDAF (+$29m), interest (-$3m), tax (-$7m), NOPAT (+$19m). The provision has not been recalculated in 1H25, however, the monthly unwind and interest impacts of the provision are included in the reported 1H25 figures as follows, EBITDAF (+$7m), interest (-$2m), tax (-$1m), NOPAT (+$4m).

Reconciliation of change in fair value of financial instruments

Change in fair value of financial instruments	Realised / unrealised	1H25	1H24	Variance	Description
(A) Net market making	**Realised**	**(14)**	**(2)**	**12**	Realised gains or losses on the settlement of electricity derivatives entered into to meet Contact's market making obligations
- Market making	Unrealised	4	4	-	Mark-to-market of open electricity derivatives in future periods
- NZAS long-term sale CFD		(17)	-	(17)	NPV of the changes to the forecast forward wholesale price path vs the wholesale path when the contracts were agreed
- Kōwhai Park acquired PPA		3	-	3	
- Other non-hedged movements		3	3	-	Mark-to-market of open electricity derivatives in future periods
(B) Unrealised movements in non-hedge effective electricity derivatives	Unrealised	(7)	7	(14)	
Total change in fair value of financial instruments as per segment note (A+B)	**Realised and unrealised**	**(21)**	**5**	**(26)**	
Commercial hedges recognised in EBITDAF that do not qualify for hedge accounting					
– Financial Transmission Rights (FTR) settlements and Exchange for Physical (ASX)	Realised	(4)	(2)	(2)	Financial contracts that hedge portfolio sales that are settled in the period
– Net settlement of NZAS contract in the period		(36)	-	(36)	Realised settlement (difference between the fixed contract and spot settlement)
Change in fair value of financial instruments as per Income statement		(61)	3	(64)	

In the period, Contact entered into two long-term contracts for difference (CFD) that were not eligible for hedge accounting. These contracts relate to the sales of electricity to NZAS and the purchase of electricity from the under-development Kōwhai Park solar farm (online in FY26).

As a result, movements in expected wholesale prices when compared to forward wholesale prices when the contracts were entered into are recognised in change in fair value of financial instruments, increasing volatility of Net Profit After Tax. These non-cash movements, which relate to future periods, are recognised in the current period.

The primary change to wholesale price expectations in the period was the listing of the 2028 ASX contract from October 2024, which was higher than Contact's internally generated price path for the same period.

Historical financial information

	Unit	1H21	1H22	1H23[1]		1H24		1H25
				Underlying	Reported	Underlying[2]	Reported	Reported[2]
Revenue	$m	1,141	1,141	994		1,306		1,707
Expenses[3]	$m	895	819	737	857	981	952	1,263
EBITDAF	$m	246	322	257	137	334	362	404
Profit	$m	78	134	79	(7)	134	153	142
Operating free cash flow	$m	157	131	71		174		138
Operating free cash flow per share	cps	21.9	16.8	9.1		22.1		17.4
Dividends declared	cps	14.0	14.0	14.0		14.0		16.0
Total assets	$m	4,738	4,978	5,408		6,059		6,383
Total liabilities	$m	2,212	2,027	2,748		3,375		3,738
Total equity	$m	2,526	2,951	2,660		2,684		2,645
Gearing ratio[4]	%	31.1	19.3	30.6		38.4		38.6

[1] In 1H24 Contact 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). 1H23 Expenses, EBITDAF and operating free cash flow were restated accordingly.

[2] 1H24 figures are exclusive of the impacts of the onerous contract provision for AGS. Impacts of the onerous contract in 1H24 are as follows, EBITDAF (+$29m), interest (-$3m), tax (-$7m), NOPAT (+$19m). The provision has not been recalculated in 1H25, however, the monthly unwind and interest impacts of the provision are included in the reported 1H25 figures as follows, EBITDAF (+$7m), interest (-$2m), tax (-$1m), NOPAT (+$4m).

[3] Includes realised gains/(losses) on risk management derivatives not in a hedge relationship.

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

Wholesale segment

Note: this table has not been rounded and might not add	1H25 Six months ended 31 December 2024 Volume GWh	GWAP $/MWh	$m	1H24 Six months ended 31 December 2023 Volume GWh	GWAP $/MWh	$m
Electricity sales to Retail segment	**1,991**	**153**	**304**	**1,989**	**141**	**280**
Electricity sales to C&I	**777**	**124**	**97**	**686**	**118**	**81**
CfDs – Tiwai support sales	303			458		
PPAs	62			-		
CfDs - Long term sales	219			390		
CfDs and ASX - Short term sales	1,265			879		
Electricity sales – CFDs	**1,849**	**182**	**336**	**1,727**	**112**	**193**
Total contracted electricity sales	**4,618**	**160**	**737**	**4,402**	**126**	**554**
Steam sales	**127**	**20**	**2**	**118**	**16**	**2**
Other income			6			2
Net income on gas sales			(18)			2
Net income on electricity related services			1			0
Net other income			**(11)**			**4**
Total contracted revenue	**4,745**	**153**	**728**	**4,520**	**124**	**559**
Generation costs[1,2]	4,603	(39)	(181)	4,386	(32)	(171)
Acquired generation cost	246	(297)	(73)	239	(127)	(30)
Generation costs (including acquired generation)	**4,849**	**(52)**	**(254)**	**4,624**	**(37)**	**(201)**
Spot electricity revenue	4,603	176	812	4,386	132	579
Settlement on acquired generation	246	280	69	239	130	31
Spot revenue and settlement on acquired generation (GWAP)	**4,849**	**182**	**881**	**4,624**	**132**	**610**
Spot electricity cost	(2,769)	(208)	(576)	(2,675)	(142)	(380)
Settlement on CFDs sold	(1,849)	(168)	(312)	(1,727)	(133)	(230)
Spot purchases and settlement on CFDs sold (LWAP)	**(4,618)**	**(192)**	**(888)**	**(4,402)**	**(139)**	**(610)**
Trading, merchant revenue and losses	***231***		***(6)***	*223*		*(0)*
Wholesale EBITDAF underlying[1]			**466**			**358**
Onerous contract provision			**-**			**29[1]**
Wholesale EBITDAF reported			**466**			**387**

[1] Underlying 1H24 figures are exclusive of the impacts of the onerous contract provision for AGS (EBITDAF +$29m). The provision has not been recalculated in 1H25, however, the monthly unwind and interest impacts of the provision are included in the reported 1H25 figures (EBITDAF impact of +$7m)

[2] From FY24 Contact no longer reports impairments and write-offs within EBITDAF. These are now reported separately to better reflect underlying performance. Generation costs for 1H24 have been restated to exclude a one-off write-off of $4.0m relating to peaker damage.

Retail segment

Residential electricity	unit	1H22	1H23	1H24	1H25
Average connections	#	367,199	381,222	386,540	400,518
Sales volumes	GWh	1,408	1,445	1,478	1,506
Average usage	MWh per ICP	3.8	3.8	3.8	3.8
Tariff	$/MWh	251.5	261.4	281.2	291.7
Network, meters and levies	$/MWh	-115.9	-118.2	-122.1	-132.8
Energy costs	$/MWh	-110.8	-128.7	-149.9	-164.5
Gross margin	**$/MWh**	**24.8**	**14.5**	**9.2**	**-5.6**
Gross margin	$ per ICP	95	55	35	-21
Gross margin	$m	35	21	14	-8

Residential gas	unit	1H22	1H23	1H24	1H25
Average connections	#	63,182	66,796	67,658	70,322
Sales volumes	TJ	970	881	916	884
Average usage	GJ per ICP	15.4	13.2	13.5	12.6
Tariff	$/GJ	32.6	38.1	41.3	45.8
Network, meters and levies	$/GJ	-16.2	-20.7	-20.8	-25.3
Energy costs	$/GJ	-11.3	-10.2	-9.7	-10.7
Carbon costs	$/GJ	-1.9	-4.2	-3.0	-4.3
Gross margin	**$/GJ**	**3.2**	**3.0**	**7.8**	**5.6**
Gross margin	$ per ICP	50	39	106	70
Gross margin	$m	3	3	7	5

SME electricity	unit	1H22	1H23	1H24	1H25
Average connections	#	48,323	47,702	44,746	42,563
Sales volumes	GWh	392	421	392	355
Average usage	MWh per ICP	8.1	8.8	8.8	8.3
Tariff	$/MWh	239.0	249.2	276.6	294.4
Network, meters and levies	$/MWh	-113.0	-113	-114	-121
Energy costs	$/MWh	-109.0	-129.8	-148.0	-161.7
Gross margin	**$/MWh**	**17.0**	**6.4**	**14.6**	**11.7**
Gross margin	$ per ICP	138	56	128	98
Gross margin	$m	7	3	5	4

SME gas	unit	1H22	1H23	1H24	1H25
Average connections	#	3,918	3,656	3,100	2,721
Sales volumes	TJ	628	635	465	336
Average usage	GJ per ICP	160.4	173.6	149.9	123.5
Tariff	$/GJ	18.6	23.1	29.5	34.7
Network, meters and levies	$/GJ	-8.7	-8.4	-11.4	-12.8
Energy costs	$/GJ	-11.3	-10.2	-9.7	-10.7
Carbon costs	$/GJ	-2	-4.2	-3.0	-4.3
Gross margin	**$/GJ**	**-3.3**	0.3	5.5	7.0
Gross margin	$ per ICP	-532	54	828	864
Gross margin	$m	-3	0.2	3	2

Telco[1]	unit	1H22	1H23	1H24	1H25
Average connections	#	57,498	74,974	89,831	113,324
Tariff	$/cust/mth	71.8	70.4	72.2	71.2
Network, provisioning, modems	$/cust/mth	-61.6	-62.8	-63.3	-62.5
Gross margin	$/cust/mth	**10.2**	**7.6**	**8.9**	**8.7**
Gross margin	$m	4	4	5	6

Retail segment EBITDAF		1H22	1H23	1H24	1H25
Electricity Gross margin	$m	41	24	19	-4
Gas Gross Margin	$m	1	3	10	7
Broadband Gross Margin	$m	4	4	5	6
Total Gross Margin	**$m**	**46**	**31**	**34**	**9**
Other income	$m	3	5	4	4
Other direct costs	$m			-1	-2
Other operating costs	$m	-33	-35	-37	-36
Retail segment EBITDAF	**$m**	**16**	**1**	**-1**	**-25**
Corporate allocation (50%)	$m	-5	-11	-14	-19
Retail EBITDAF	**$m**	**11**	**-10**	**-15**	**-44**
EBITDAF margins (% of revenue)	%	2.10%	-1.80%	-2.43%	-6.78%

[1] Telco includes both broadband and mobile from 1H24 (previously broadband only).