2026 full year results presentation

Twelve months ended 30 June 2026

10 August 2026

contact

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Agenda

FY26 Highlights		**Mike Fuge** Chief Executive Officer	**Slides 4 to 9**
Financial results & outlook		**Matt Forbes** Chief Financial Officer	**Slides 10 to 22**
Strategy update		**Mike Fuge** Chief Executive Officer	**Slides 23 to 29**
Supporting materials			**Slides 31 to 51**

FY26 highlights

Delivering financial performance

+31% **EBITDAF**[1] $1,011M
up **$237M** YoY

+62% **NPAT** $423M
up **$162M** YoY

+100bps **Average ROIC**[2]
5.9% up **100bps** YoY

Delivering portfolio change

Manawa acquisition completed
100% of the **$28M** identified cost synergies **secured** (run-rate basis)

Manawa hydro and PPAs increased renewable output by **2.4TWh** in FY26

Generation at new Te Huka 3 geothermal plant **0.4TWh** in FY26

Delivering renewable energy growth

+37% Renewable output YoY

98% **renewable** in FY26[3]

Financial close reached on **Glorit solar** 150MWac / 287GWh p.a.

Kōwhai Park solar in commissioning 150MWac / 275GWh p.a.

Delivering for customers

Commenced electricity supply to **NZ Steel's new EAF**[4]

AoG[5] **contract providing 2PJ** of gas to core community assets

165k households choosing discounted or free off-peak energy[6]

Contact Good Initiative $5M supporting customers and communities

Delivering for shareholders

+9% Total shareholder return FY26

40cps
Total dividend

S&P Global MSCI

Continued representation within **DJ BIC Asia Pacific and MSCI indices**

Delivering for the market

Contracted 50MW Huntly Firming Option for 10 years to manage dry year risk, supporting security of supply

Glenbrook-Ohurua
100MW battery online and 200MW battery under construction

1. Refer to slide 46 for a definition and reconciliation between statutory profit and the non-GAAP profit measure earnings before net interest expense, tax, depreciation, amortisation, change in fair value of financial instruments (EBITDAF). FY25 EBITDAF is an underlying figure that excludes release of the AGS onerous contract provision that increased reported EBITDAF by $98M and profit by $71M. | 2 ROIC average is calculated as NOPAT (4-year average) / Average IC (4-year average). Refer to slide 19 for the operating free cash flow reconciliation and for the basis of calculation of return on invested capital. | 3. Renewable generation includes wind and geothermal PPA purchases but excludes short-term acquired generation purchases e.g. fuel replacement via ASX which will reflect the renewable mix of the market | 4. Electric Arc Furnace (EAF). | 5. All of Government (AOG). | 6. As at 30 June 2026.

New Zealand electricity market was 93% renewable in FY26

High inflows, energy storage and record renewable generation have led to subdued pricing

Inflows & hydro:
Hydro inflows 118% of post market mean.[1]

Total market renewable percentage was **93%** [2]**,** the highest rate achieved since the market was introduced.

Energy storage:
FY26 ended with hydro lakes at 135% of mean[3], gas storage (AGS[4]) close to full, and the Genesis coal stockpile at 1,189kt (up 70% on prior year), all contributing to low fuelling risk for winter 2026.

ASX futures soften:
Winter 2026 pricing fell by more than 60% over 2H FY26, reflecting high energy storage.[5]

Longer-term futures pricing fell 27% over 2H FY26,[2] with the market moving into supply / demand balance on the back of renewable generation investment.

Demand returns:
Demand was robust, up ~3% on FY25, ~1% normalised for NZAS[6] demand response.[7]

Network and transmission pressures continue:
Lines cost increases from 1 April 2025.[8]

Gas production continues to decline:
2P Gas production forecast for 2027 is down 24% compared to the same forecast last year.[9]

1. Source: NZX Hydro. | 2. Source: EMI. | 3. Source: Electricity Authority. Generation output by plant. | 4. Ahuroa Gas Storage Facility (AGS). | 5. Source: ASX. Change in ASX Settlement prices at Otahuhu for Q3 2026 from 31 December 2025 to 30 June 2026. | 6. New Zealand Aluminium Smelters Ltd. On 1 July 2024, responding to dry market conditions, Meridian called on its demand response contract with NZAS resulting in operations being turned down and demand for electricity being reduced temporarily in 1H25. | 7. Source: EMI and Contact. | 8. Source: Commerce Commission. From 1 April 2025, Commerce Commission-approved changes to network charges began to take effect, increasing household bills by $10-$25 per month on average (depending on region and usage profile). | 9. Source: MBIE electricity & gas data.

The market has adapted for the energy transition

Sector investment, customer innovation and market settings have all advanced as New Zealand has progressed through the energy transition

Investing at pace in renewable energy

Delivered

- Fast Track consenting regime now operating.
- New renewable generation added 4TWh over the last five years (BCG).[1]
- Electricity market reached 93% renewable in FY26.

Looking ahead

- RMA Reform: Planning and Environment Bills expected to pass by end of year.
- ~3TWh of generation either committed or under construction and expected to come online by 2027.[2]

Managing fuel security and dry year risk

Delivered

- NZAS demand response mechanisms in place for dry year support.
- Huntly Firming Options signed to support dry year capacity.
- Strategic coal reserve and stored gas and hydro.

Looking ahead

- Consultation to conclude in 2026 on MBIE's proposed Winter Reliability Obligation framework.
- Potential to extend HFO for further dry year support.
- Potential for right-sized LNG import terminal to enhance fuel diversity.
- Potential for diesel storage as an additional strategic reserve.

Enhancing market settings

Delivered

- Market and regulatory settings have evolved alongside the energy transition.
  - Non-discrimination obligations and super-peak market making have been implemented.
  - Enhanced EA enforcement and regulatory powers have been introduced.

Innovating for industrial and commercial customers

Delivered

- NZAS now operating on long-term supply contracts coupled with demand response.
- 1TWh of committed dairy electrification projects to be supported by summer-weighted generation.
- NZ Steel's Electric Arc Furnace backed by shaped supply contract.

Looking ahead

- Potential reopening of NZAS Line 4 potline at Tiwai Point.
- Continued dairy electrification, aligned to summer load.
- Estimated New Zealand data centre capacity of up to ~725MW by 2035 (Invest NZ).[3]

Supporting energy wellbeing

Delivered

- Industry-wide focus on energy wellbeing consumer care and reducing barriers to access.
- Disconnections viewed as last resort.
- No disconnection or reconnection fees (Contact).
- In FY26 Contact Good Initiative provided ~$5M of customer and community support.

Looking ahead

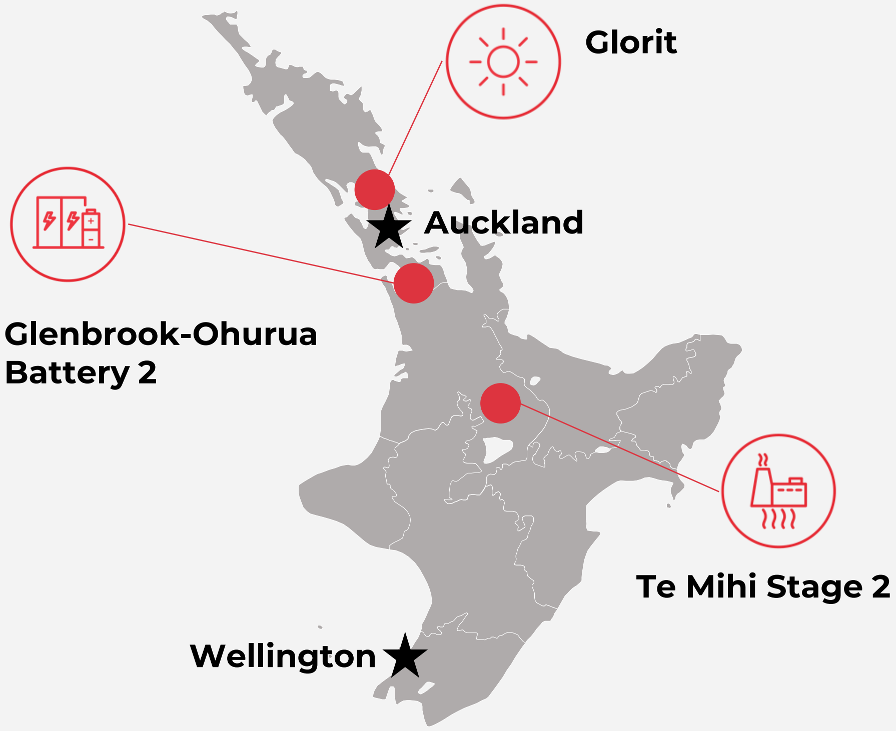
- Contact advocating for a market-wide obligation to connect to further lift energy wellbeing outcomes.
- $7.5M committed through Contact Good Initiative in FY27 to support customers and communities.

1. Boston Consulting Group. Energy to Grow: Securing New Zealand's Future (2025). | 2. Company announcements and Contact's analysis. | 3. Invest New Zealand, Data and AI infrastructure Report (2026). Data based on base case scenario.

Renewable investment programme continues

Current projects under construction represent ~$1.3b of investment[1], ~0.5TWh of net new generation

Under construction:



Glorit
Solar

150MWac / 287GWh p.a.

Target online Q4 CY28

Target IRR >12% at FID[2]

- Financial close reached in June 2026.
- Early works underway.
- Notice to proceed issued to EPC contractor.

Glenbrook-Ohurua
Battery 2

200MW / 400MWh

Target online Q1 CY28

Target IRR >10% at FID[3]

- Construction underway. Earthworks began March 2026.
- Battery packs under construction with lithium price locked in second half 2025.

Te Mihi Stage 2
Geothermal

101MW / ~840GWh p.a.

(~200GWh net uplift)[4]

Target online Q3 CY27

Target IRR ~10% at FID[3]

- Steamfield separator, heat exchangers and turbines for the first unit installed. Cooling tower near complete.
- Delays being incurred in equipment delivery, in part due to global shipping constraints.
- Target online remains Q3 CY27.

Recent projects – Continuous build programme since 2021:

Tauhara
Online May 2024
+1,450GWh p.a.

Te Huka 3
Online Dec 2024
+430GWh p.a.

Glenbrook-Ohurua Battery 1
Online Mar 2026
+100MW / 200MWh

Kōwhai Park
In commissioning
+275GWh p.a.

1. Total construction cost over the life of the projects including joint venture and project financing (solar). | 2. Target Contact IRR includes joint venture returns and margin on acquired generation. Return on acquired generation will ultimately depend on sales channel and market conditions. | 3. Representing target ungeared project IRRs. | 4. Indicative average uplift from new generation accounting for the planned partial closure of Wairakei geothermal station.

Benefits from Manawa integration realised

An $84M uplift has been secured in FY27, excluding benefits from generation normalisation, 35% higher than the long-run benefit indicated at deal announcement

Integration benefits secured, FY27[1]

	GWh	Change $/MWh	EBITDAF uplift $M
Mercury volume resold to C&I and CFD channels[2]	500	52	26
Mercury volume shifted to ASX-linked pricing[3]	869	50	44
Mercury wind PPA repricing	640	(22)	(14)
Net repricing benefit			**56**
Cost synergies achieved (FY26 exit run-rate)			28
Total uplift			**84**

Integration benefits of
$84M
secured for FY27
(excluding generation normalisation)[1]

+35%
on long-run expected benefits indicated at deal announcement

Opex synergies delivered, $M (in-year)

100%
of identified cost synergies have been secured at $28M
(FY26 exit run-rate basis)

$23M to $28M
targeted at deal announcement

Development pipeline advanced

Legacy Manawa development options Huriwaka (wind), Kaihiku (wind)[4] and Argyle (solar) are being actively advanced.

Together they represent potential to contribute **2.1TWh p.a.** of output.[5]

1. Benefits have been illustrated excluding generation normalisation as this can be expected to fluctuate year on year with hydrology and wind conditions. | 2. Indicative price change reflects a mix of FY27 channel pricing of $168/MWh for C&I (net price) and $155/MWh for CFD, which are 95% and 98% sold respectively. Compared to fixed price in FY26. Includes portfolio benefit of $16M given Contact's ability to sell 300GWh of Manawa generation that would previously be held as a risk buffer. | 3. Repriced with reference to ASX. As at publication, ~97% of FY27 repricing is confirmed. Compared to fixed price in FY26. | 4. Kaihiku is a 50:50 JV with Pioneer Energy. | 5. All development options remain subject to FID. Pending appropriate market conditions and projects meeting returns thresholds.

Contact has delivered on the FY26 plan

Impressive delivery of the strategic targets outlined at the start of the year

Strategic theme	FY26 operational plan	FY26 achieved
Decarbonise our portfolio	▪ Close TCC gas generation plant late CY25. ▪ Scope 1 & 2 emissions <650ktCO_2e. ▪ Sustained New Zealand leadership position in the Asia Pacific DJSI.	TCC closed, at end-of-life, after 30 years in service. FY26 Scope 1 & 2 CO2e of 319kt (gross). Contact maintained in the Dow Jones Best-in-Class Asia Pacific Index (formerly Asia Pacific DJSI).
Grow Demand	▪ New demand facilitated since FY21 to reach >250MW.[1] ▪ At least 50% of new demand contracted in-year structured with favourable shape (considering load and generation). ▪ Achieve FID for CO_2.	New demand facilitated since FY21 is 258MW of which 157MW is currently operational. Additional 101MW expected online in FY27. New in-year demand contracted in FY26 of ~28MW of which 26MW is summer-weighted. The CO_2 project is under development with active technology trials underway.
Grow renewable development	▪ Glenbrook-Ohurua Battery 1 online Q1 CY26. ▪ Te Mihi Stage 2 geothermal on track for online Q3 CY27. ▪ Kōwhai Park solar online Q2 CY26. ▪ Consents lodged on at least 2 renewable development projects. Subject to market conditions and obtaining consents, achieve FID on: ▪ Solar (e.g. Glorit, Argyle); and/or ▪ Glenbrook-Ohurua Battery 2 (200MW).	Glenbrook-Ohurua Battery 1 online in March 2026. Te Mihi Stage 2 on track to be online for Q3 CY27. Kōwhai Park in commissioning, expected online Q3 CY26. Lodged for Glenbrook-Ohurua Battery 2 and Stratford hybrid-solar. FID achieved (Glorit). Reached financial close in June 2026. FID achieved. Construction underway.
Create outstanding customer experiences	▪ Multi-product customers >156k (up from 149k). ▪ Targeting net price up by ~2%. ▪ Cost to serve <$116/connection.[2]	Multi-product customers 165k. Net price target exceeded. Cost to serve $117 per connection.[2]
Manawa integration	In-year benefits target: ▪ Opex reduction $10M to $20M. ▪ Portfolio benefits $5M.[3] Exit run-rate benefits target: ▪ Portfolio benefits $10M to $20M.[3] ▪ Opex reduction $22M to $25M.	Opex reduction of $22M achieved in-year. Portfolio benefits >$5M achieved in-year. Portfolio benefits of $16M secured for FY27.[4] Exit run-rate achieved. Opex reduction exit run-rate of $28M achieved.

1. Cumulative measure, shown on a total contracted basis. | 2. Total retail operating costs (direct and indirect) / average connections. Includes customer acquisition costs. This is $113 per connection based on closing connections. | 3. This is a through-the-cycle measure. Actual result will be impacted by hydrology, fuel and other market conditions. | 4. Based on the sale of 300GWh risk management buffer at a blend of FY27 CFD and C&I pricing. Refer to slide 8 for detail.

Financial results and outlook

Strong result with $1,011M EBITDAF reflecting investments in renewable generation

	Twelve months ended 30 June 2026 (FY26)[1]	Twelve months ended 30 June 2025 (FY25)[1]
	Reported	Against underlying[2]
Revenue[3]	$3,206M	↓ 3% from $3,306M
EBITDAF[4]	$1,011M	↑ 31% from $774M
EBITDAF margin	32%	↑ 900bps from 23%
Profit	$423M	↑ 62% from $261M
Profit per share	41.5c	↑ 27% from 32.7c
Operating free cash flow[5]	$648M	↑ 49% from $434M
Operating free cash flow per share[5]	64.0c	↑ 18% from 54.4c
Average ROIC	5.9%	↑ 100bps from 4.9%
Dividend declared	$419M	↑ 18% from $355M
Dividend declared per share	40.0c	↑ 3% from 39.0c
Stay-in-business (SIB) capital expenditure (cash)	$145M	↑ 32% from $110M
Growth capital expenditure (cash)[6]	$375M	↑ 3% from $363M

Key themes from the results

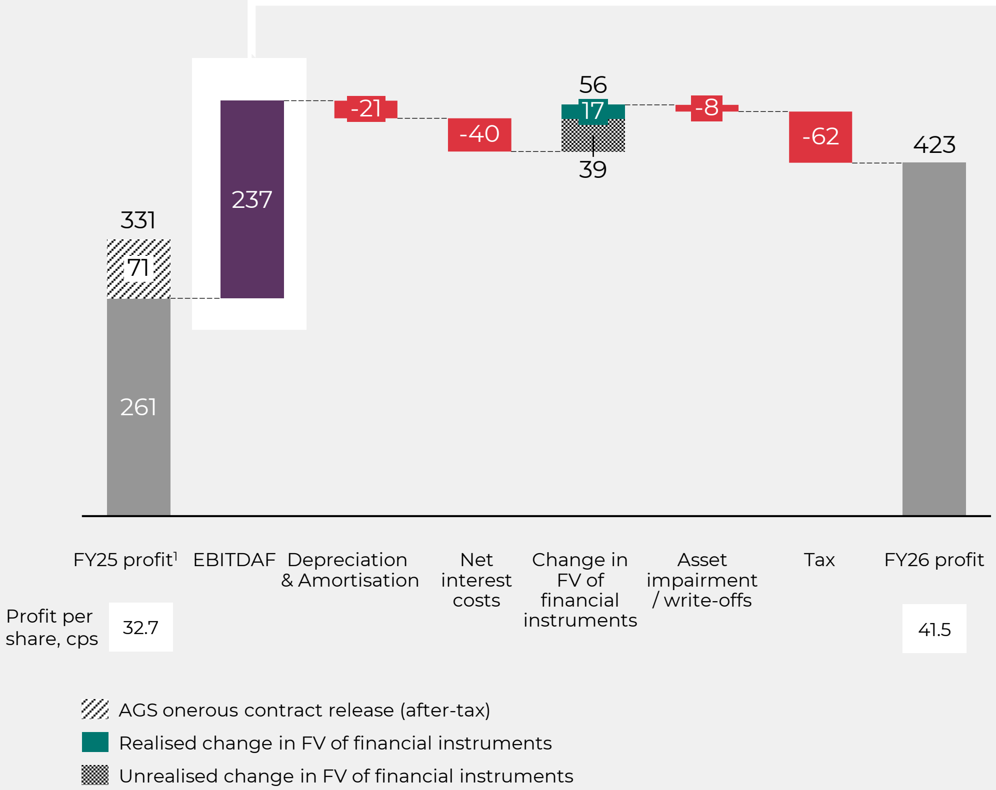
- Manawa acquisition added 2.4TWh of additional volume in-year from hydro generation and PPA contracts
- Increasing sales to major users in the long-term inflation-protected, strategic fixed price sales channel
- TCC closure and reduction in gas generation (down 79% on FY25)
- Delivering on the benefits of the Manawa acquisition with 100% of cost synergies delivered: $22M in-year ($28M run-rate basis)
- Glenbrook-Ohurua Battery 1 online, shifting 11GWh of volume in the first 3 months of operating
- Record performance reflecting greater scale from renewable development and the Manawa acquisition

1. Includes Manawa from 11 July 2025. Prior period does not include Manawa. | 2. In FY25, the release of the AGS onerous contract provision increased reported EBITDAF by $98M and profit by $71M. These impacts have been removed from underlying performance. All variances and commentary reflect year-on-year changes in underlying performance. | 3. Revenue figures align with the treatment of realised movements in financial instruments within the segment note of the financial statements. | 4. FY26 EBITDAF was $1,037M excluding Manawa transaction and integration costs of $26M. Refer to slide 46 for a definition and reconciliation of profit to EBITDAF. | 5. Refer to slide 19 for a reconciliation of operating free cash flow. | 6. Includes capitalised interest.

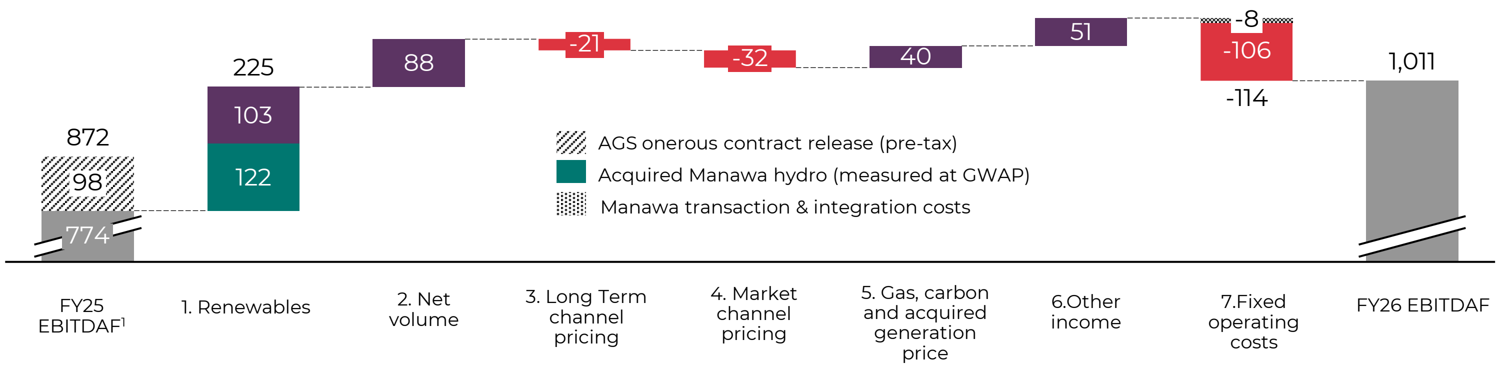
Profit of $423M for FY26

EBITDAF up $237M (31%) on FY25 (underlying), reflecting the Manawa acquisition and increase in renewable generation

Profit, $M



EBITDAF, $M



1 Renewables up with the addition of Manawa generation, normalisation of hydro output, and a full year of Te Huka 3.

2 Higher contracted sales volumes underpinned by higher generation and Manawa contracted sales acquired as part of the transaction.

3 Combination of higher channel pricing and a mix shift between strategic and retail channels.

4 Hydro conditions led to a normalisation of CFD prices. These were elevated in FY25 as risk management contracts reflected challenging market conditions.

5 Prior period gas and acquired generation prices were elevated by short-term Methanex gas, NZAS demand response and fuel scarcity conditions.

6 This now includes Manawa irrigation income.

Prior period included losses on sale of excess Methanex gas.

7 Manawa fixed costs, inflation impacts, non-recurrence of AGS provision unwind benefit and transaction and integration costs ($8M higher than prior period).

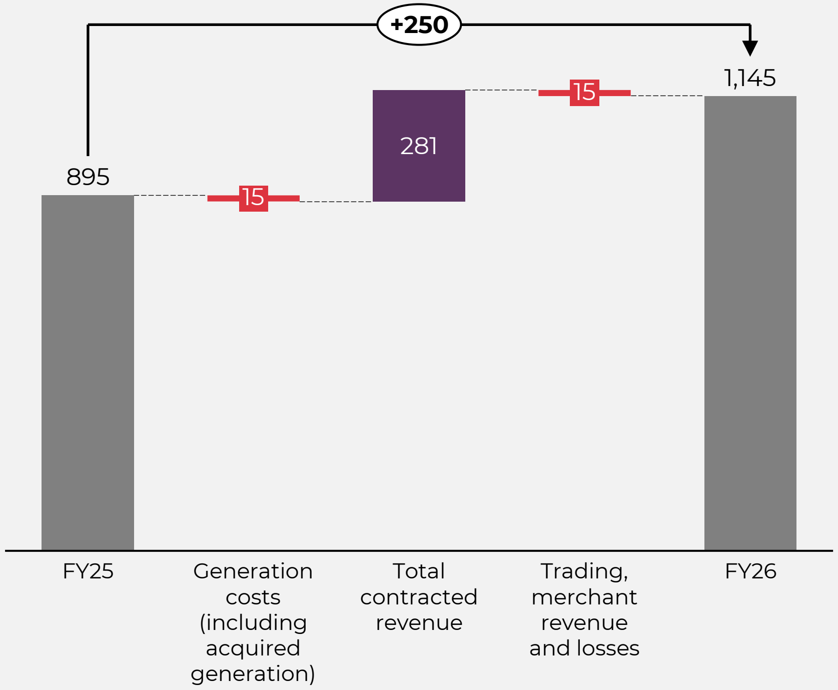
Partly offset by in-year cost synergies and productivity benefits.

1. In FY25, the release of the AGS onerous contract provision increased reported EBITDAF by $98M and profit by $71M. These impacts have been removed from underlying performance. All variances and commentary reflect year-on-year changes in underlying performance.

EBITDAF up by $237M

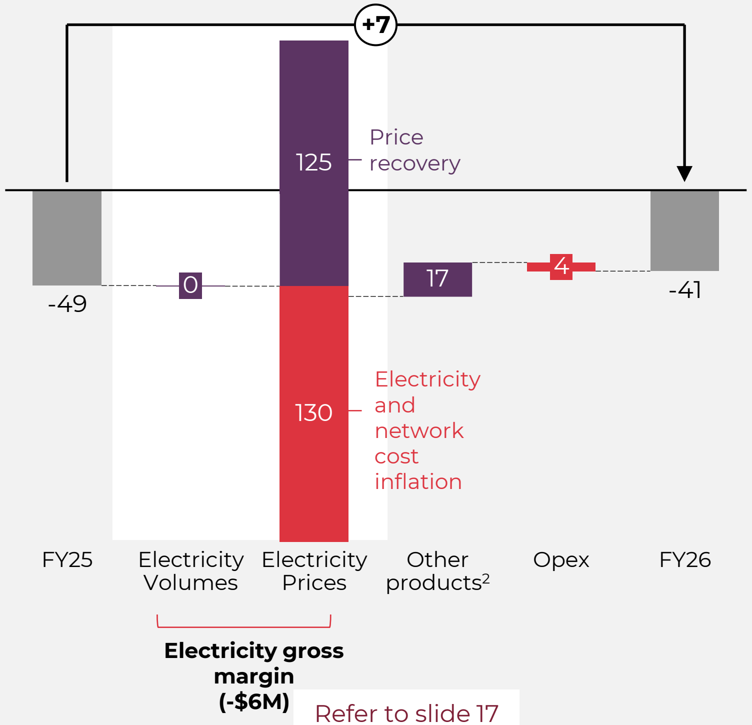
Operating performance by segment

Wholesale EBITDAF, $M[1]



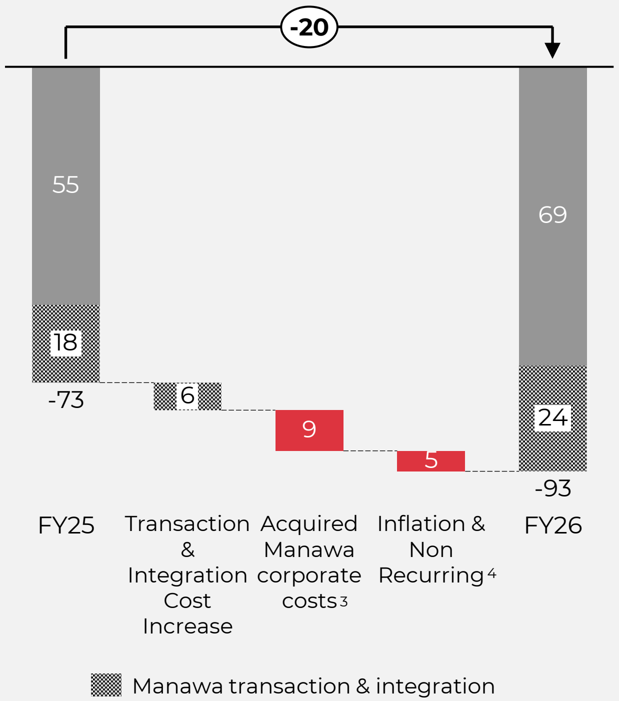
Refer to slides 14 - 16

Retail EBITDAF, $M



Refer to slide 17

Corporate / unallocated costs, $M



1. Simply and Western included within Wholesale EBITDAF. EBITDAF is shown excluding a $98M provision release in FY25 (underlying EBITDAF).

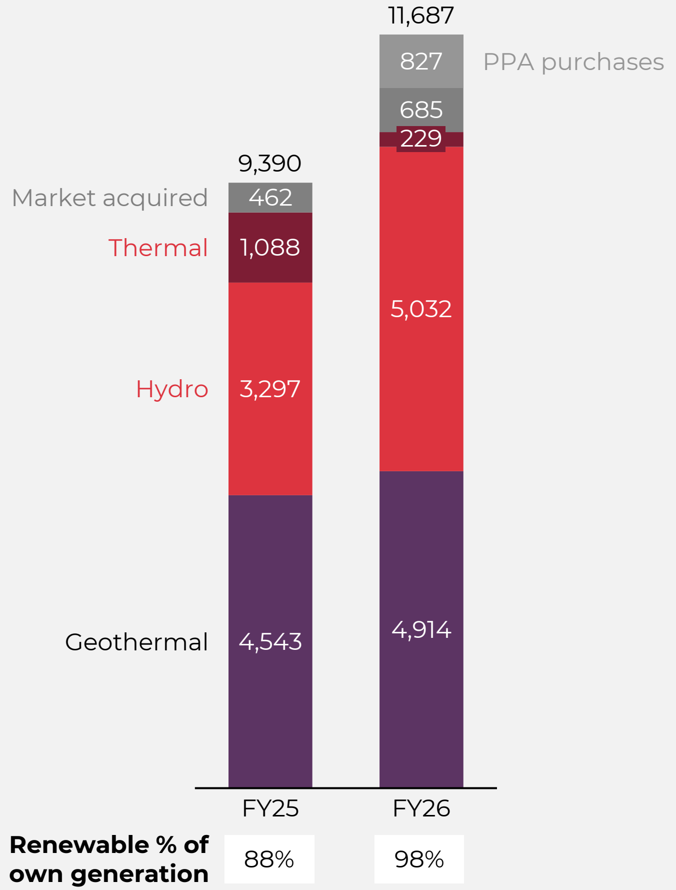
2. Other products includes retail gas and telco gross margins.

3. Increase net of in-year synergies. | 4. Stats NZ CPI increase over the 12 months to June 2026 plus wage inflation.

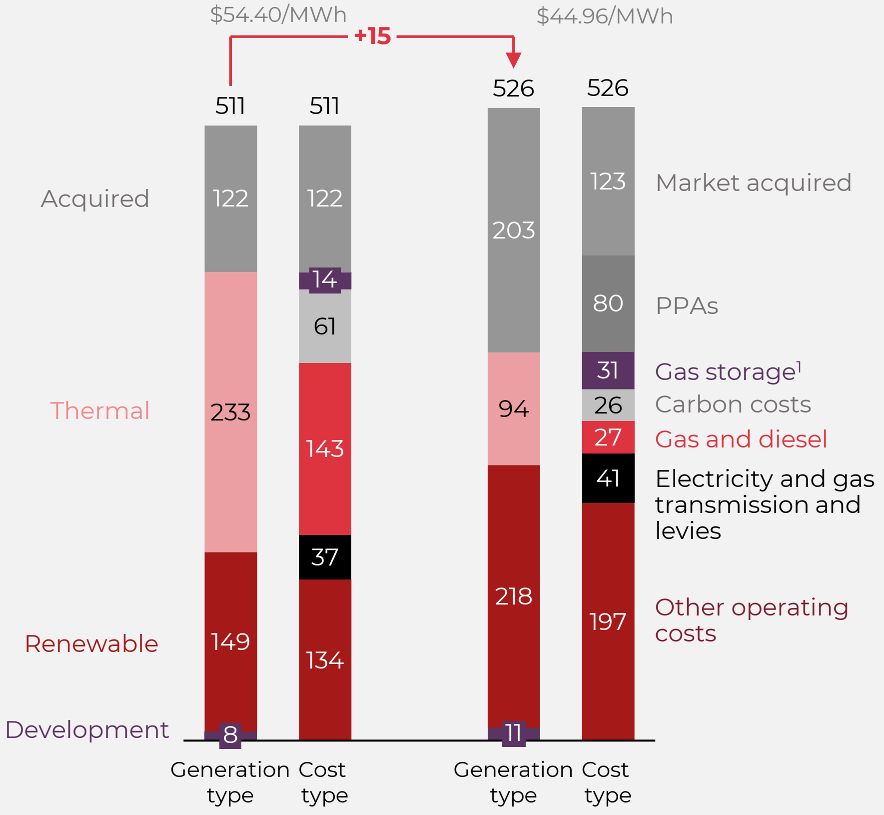
Generation costs

Generation volume rises significantly, reflecting greater scale and portfolio diversity

Electricity generated or acquired, GWh



Electricity generated or acquired costs, $M



Generation volumes

- Contribution from Manawa hydro assets and a normalisation of hydro output led to a 53% increase (1,735 GWh) in hydro generation. Despite high inflows, generation was ~718GWh below Contact's mean expectation for FY26 (5,750GWh) owing to a period of spill in summer 2025.
- Geothermal volumes were up 371GWh on FY25 (8%) supported by a full period of Te Huka 3. This was partially offset by statutory outages at Tauhara, Te Huka 3 and Wairakei.
- Thermal generation supported Winter 2025, however, strong hydro inflows and new renewables brought online in the last 18 months reduced the need for thermal with generation falling 859GWh, 79% year on year.
- PPA purchases of 827GWh in FY26 reflected wind and geothermal PPAs acquired with Manawa.
- Market acquired generation was purchased to cover geothermal statutory outages and when spot prices were advantageous. Total volume was up 223GWh on FY25. Costs were $84.4/MWh lower than FY25 despite HFO premiums now being included.

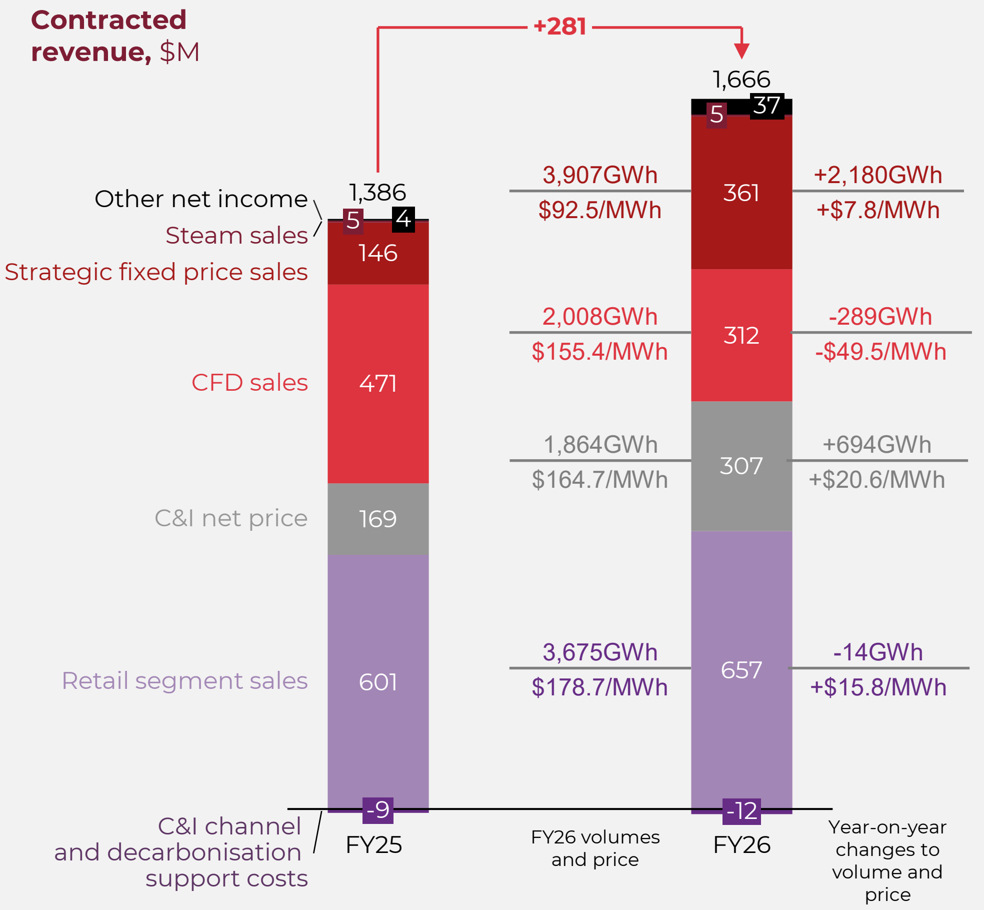
Costs

- Renewable generation costs were up $69M (46%) on FY25, including $66M from hydro ($53M driven by operating new stations).
- Thermal generation costs were down $139M (-60%) on a lower cost of gas per unit (FY25: $15.4/GJ, FY26: $13.9/GJ).

1. In FY25, gas storage costs included a $14.6 million provision unwind released throughout the year.

Wholesale contracted revenue

Diversified mix of long-term and ASX-linked sales channels



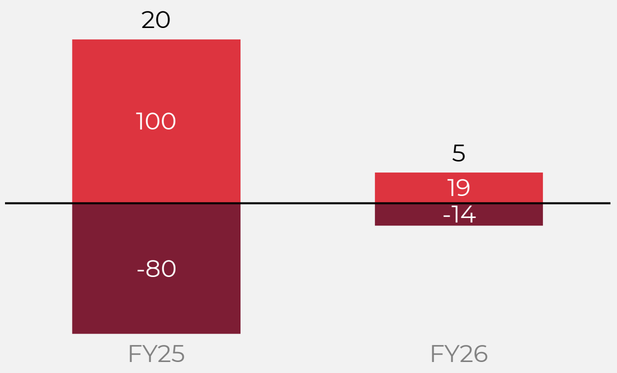
Contracted wholesale revenue increased in aggregate as Contact made additional sales backed by the addition of the Manawa assets and PPAs.

- Sales to the retail segment were down 14GWh as lower average customer usage offset growth in customer connections during FY26. Pricing on sales to retail increased by $15.8/MWh to $178.7/MWh, reflecting higher wholesale electricity prices over recent years.
- C&I channel sales were up 694GWh driven by growth in customer contract volumes, including the addition of contracts acquired through the Manawa transaction. Net Price increased $20.6/MWh reflecting contract repricing and the inclusion of higher-priced contracted volumes acquired through Manawa.
- CFD sales volumes were down 289GWh as a greater proportion of contracted sales were directed into strategic long-term channels and C&I contracts. Hydro conditions led to a normalisation of CFD pricing, down $49.5/MWh to $155.4/MWh. Prices were elevated in FY25 as risk management contracts reflected challenging market conditions.
- Strategic fixed price volumes were up 2,180GWh driven by the acquisition of the long-term Mercury CFD from Manawa, a full year of Tauhara-linked CFDs, increased sales to NZAS and the commencement of the NZ Steel contract. Prices were up by $7.8/MWh as new long-term agreements better reflect Contact's long-run view of electricity pricing.
- Other income was $33M higher due to the inclusion of irrigation net income from Manawa (+$11M), non recurrence of gas sold at a loss in FY25 (+$14M) and Peaker GT22 insurance proceeds ($12M).

Wholesale trading and merchant revenue

Trading EBITDAF reflected reduced merchant exposure and subdued wholesale spot prices

Trading EBITDAF, $M

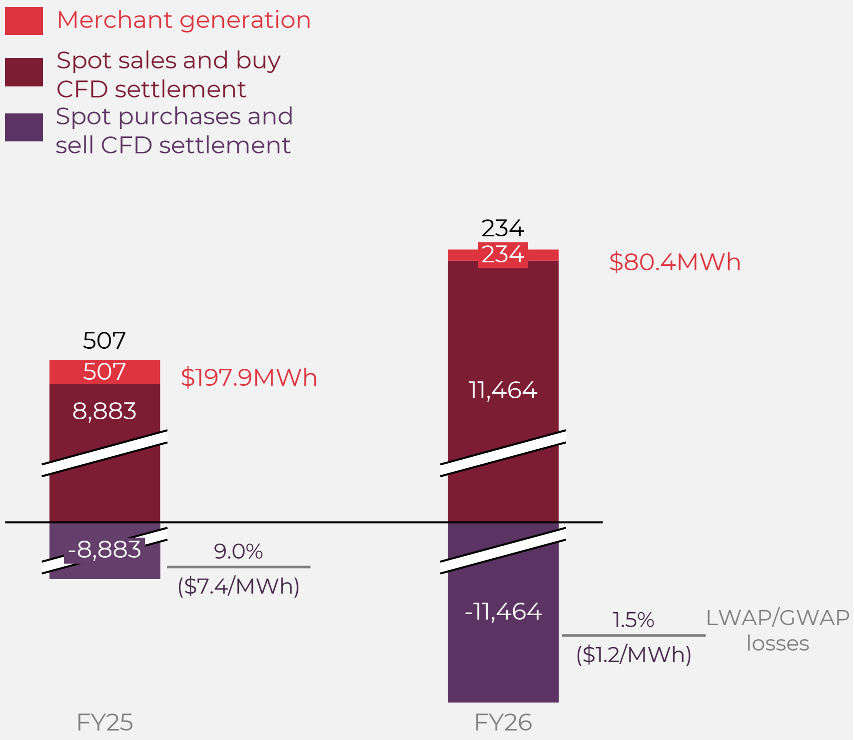


Trading revenue

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



In FY26 high hydro inflows coupled with strong wind conditions in 1H26 and the addition of new renewable generation brought online in the last 12 months led to subdued spot prices. FY26 conditions were shaped by:

- Elevated but highly concentrated hydro inflows led to spill, reducing hydro output.
- High wind conditions in 1H26 compounding the increase in supply and adding to spill conditions.
- Subdued wholesale spot prices throughout the year.
- A shift away from merchant exposure, to long-term contracts.

Contact's LWAP/GWAP spread fell to ~1% on the back of revised portfolio dynamics following the Manawa integration and geothermal build, very low spot prices, and improved FTR[1] outcomes. This resulted in a very low absolute LWAP / GWAP spread, significantly reducing Contact's LWAP / GWAP losses.

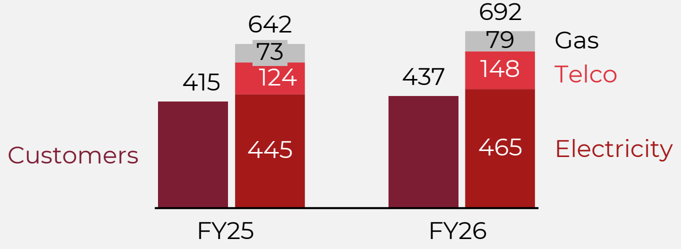
1. Financial Transmission Rights (FTRs).

Retail business performance

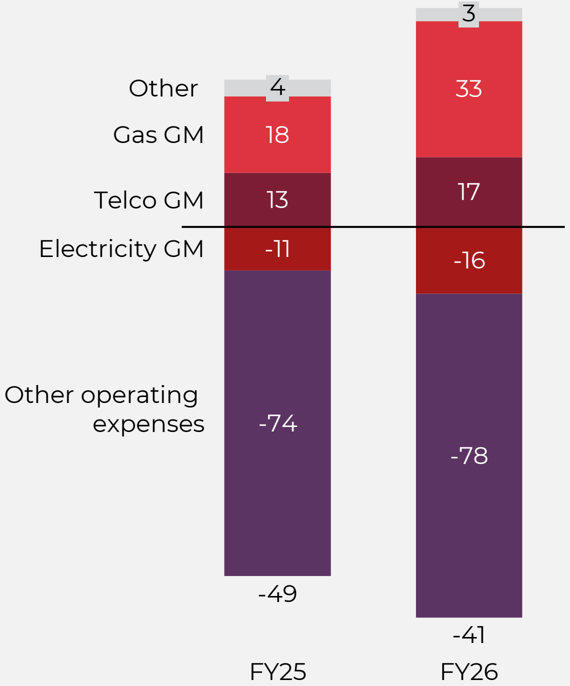
Retail EBITDAF up $7M despite higher energy and lines costs, supported by Gas and Telco margin growth and 50k connection growth

Revenue & Tariff $M	**FY25**	**FY26**		**Variance**	
	$M	$M	*Tariff*	$M	*Tariff*
Electricity revenue	**1,079**	**1,207**	***$350/MWh***	**128**	***+$38/MWh***
Gas revenue	103	198	*$47/GJ*	95	*-$2/GJ*
Telco revenue	101	117	*$71/cn*	16	*-$1/connection*
Other income	7	4		-3	
Total revenue	**1,290**	**1,527**		**237**	
Cost to serve/customer[1]	*$129*	*$134*			
Average connections	633k	666k			
Opex per connection	*$116*	*$117*			

Closing customers & connections[2], '000s



EBITDAF, $M



	FY25	FY26
Energy cost[3]	$164/MWh	$181/MWh
Networks, meters and levies[3]	$132/MWh	$153/MWh

Retail EBITDAF increased by $7M on FY25 largely due to strong growth in Gas and Telco margins, partially offset by high wholesale prices and rising distribution costs:

- +$130M increase in electricity input costs, which were not fully passed through to customers.
- The average Retail electricity tariff increased by +12% reflecting widespread retail price rises to partially offset higher wholesale costs and full recovery of lines cost increases.
- Around 90% of customers received a price increase in the last 12 months.

Cost pressures on the lines component of the tariff are expected to remain as the increased costs of transmission and distribution infrastructure continue to be incurred.[4]

Moderating wholesale prices are expected to lower the electricity component over time.

Connections grew strongly throughout FY26, particularly through Telco and Time of Use (ToU) electricity Good plans, with a focus on multi-product customers.

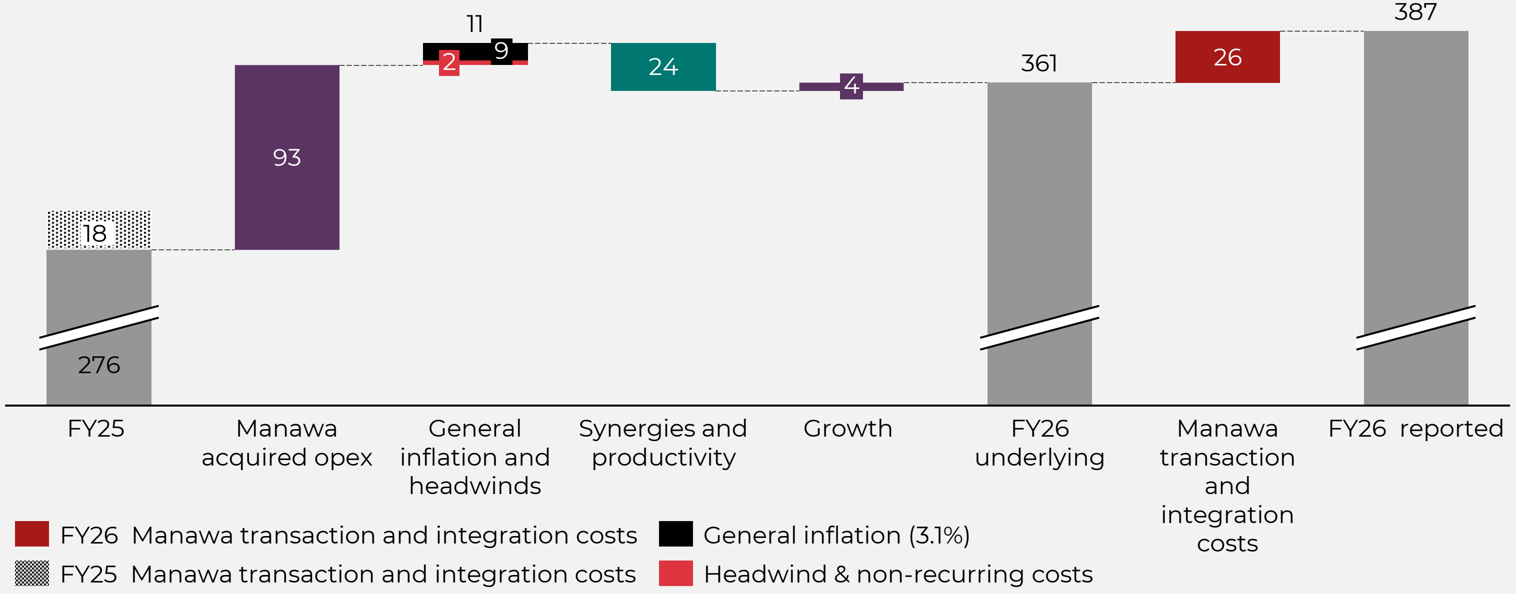
- Total connections +50k on FY25 with Telco up 24k and Energy up 26k.
- Multi-product customers up 10% on FY25, driven by strong Telco product attachment alongside ToU Good plans growth.

Opex – increased by $1/connection, largely driven by wage inflation, partially offset by increased connections, and productivity improvements through continued growth in digitised interactions.

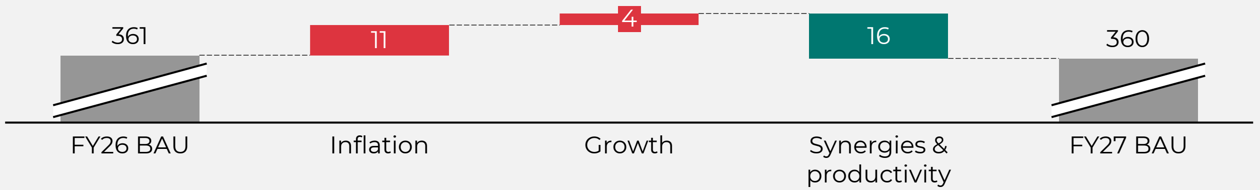
1. Reflects total operating costs (direct and indirect) less customer acquisition costs / closing customers. | 2. Retail connections and customers only, excludes Simply Energy. Gross Margin (GM) is Revenue less Cost of Goods (Networks, meters, levies, energy, carbon and telco). | 3. Input costs shown per MWh at the GXP. | 4. From 1 April 2025, Commerce Commission-approved changes to network charges began to take effect, increasing household bills by $10–$25 per month on average (depending on region and usage profile). Costs are increasing annually.

Operating costs increase on inflation and growth

Other operating cost movement FY26, $M



Expected other operating cost movement FY27[1], BAU $M



FY26 movement commentary

Manawa acquired opex

- $93M Manawa related opex from FY25 Manawa financial statements ($117M) excluding one-off bad debt for Prime Energy (-$7M), transaction costs (-$7M) and transmission costs which Contact includes in gross margin (-$10M).

Base movement and headwinds

- $9M general inflation of 3.1% impacting operating costs. These have been seen across all cost categories including labour cost.
- $2M increase in bad debts over Retail mass market and C&I segment with Kiwi Crunch liquidation.

Synergies & productivity delivered

- $22M from Manawa related synergy delivered within FY26.
- $2M related to continued efficiency from Retail cost to serve.

Growth

- $2M incremental costs with Te Huka 3 online vs prior year.
- $2M incremental investment related to retail connection growth.

Manawa transaction and integration related costs

- $8M additional transaction and integration related costs incurred with transaction related costs up $3M and integration costs up $5M.

1. BAU opex will exclude SaaS implementation and Manawa integration costs.

Cash flow and capital expenditure

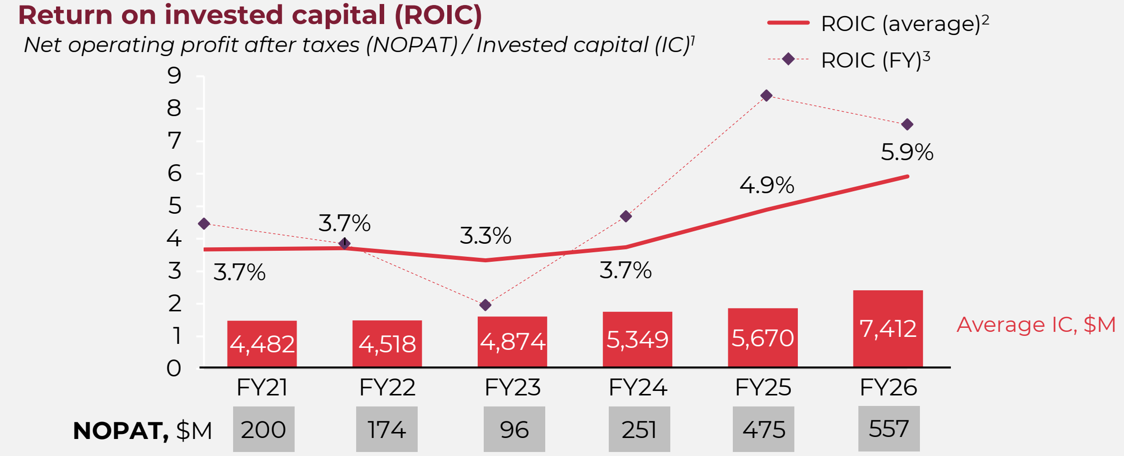
Cash conversion higher driven by strong EBITDAF growth and reduced value of fuel inventory

	12 months ended 30 June 2025	12 months ended 30 June 2026	Comparison against FY25	
EBITDAF	$774M	$1,011M	↑	$237M
Working capital changes	($35M)	$20M	↓	$55M
Tax paid	($106M)	($119M)	↑	($13M)
Interest paid, net of interest capitalised	($77M)	($122M)	↑	($45M)
SIB capital expenditure	($110M)	($145M)	↑	($35M)
Non-cash items included in EBITDAF	($12M)	$3M	↓	$15M
Operating free cash flow	$434M	$648M	↑	$213M
Operating free cash flow per share	54.4 c	64.0 c	↑	9.6 c
Cash conversion (OpFCF / EBITDAF)	55%	64%	↑	up 900bps

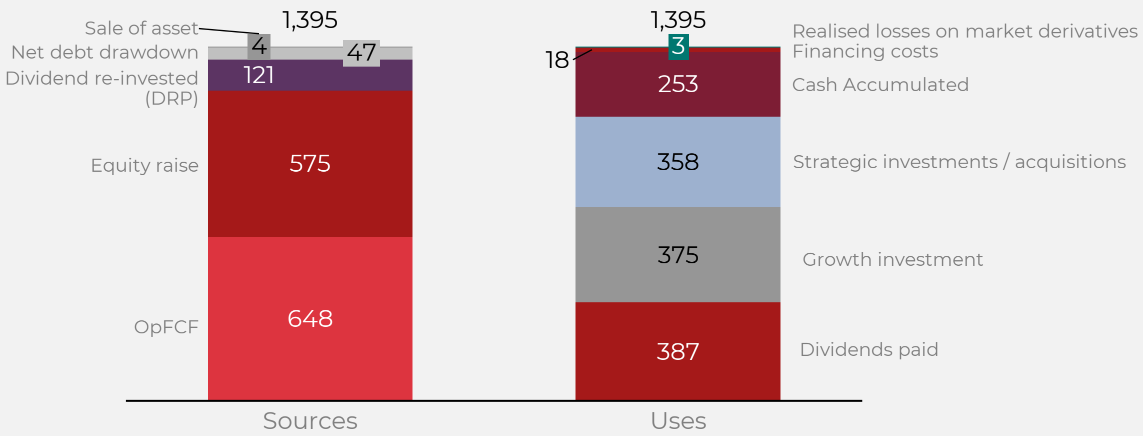
- Higher EBITDAF on FY25 (underlying), as detailed on slide 12.
- Working capital change was a positive $20M impact to OpFCF (vs. negative $35M in FY25), mainly due to a reduction in carbon unit inventory reflecting changes in thermal generation.
- Tax paid was $13M higher, reflecting the addition of provisional tax payments for Manawa and KCE groups, offset by a lower FY25 final tax payment that is paid during FY26.
- Interest paid, net of capitalised interest, rose by $45M. Linked to increased borrowing in support of the Manawa acquisition.
- FY26 stay-in-business (SIB) capital expenditure includes previous accelerated programme ($14M), geothermal and hydro enhancement projects and integration ($12M), Wairakei extension ($21M) and risk-rated and improvement projects ($98M).

Return on invested capital (ROIC)

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



Sources and uses of cash, $M

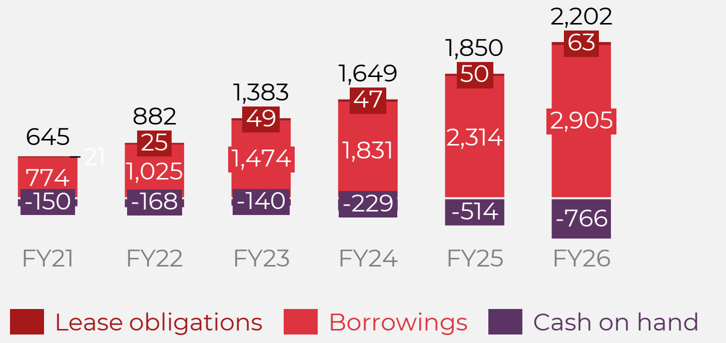


1. NOPAT is calculated as annual EBIT less tax (tax includes annual tax expense and movements in deferred tax over the year as a proxy for cash tax paid). Invested capital is calculated as the average of the opening and closing balance of: net working capital (adjusted to remove current borrowings, current net derivatives and excess cash above $50M) + non-current assets (adjusted to remove non-current derivatives). The ROIC calculation includes movement in the AGS provision for FY23, FY24 and FY25. | 2. ROIC average is calculated as NOPAT (4-year average) / Average IC (4-year average). | 3. ROIC (FY) is calculated as Annual NOPAT (FY) / Average IC (FY).

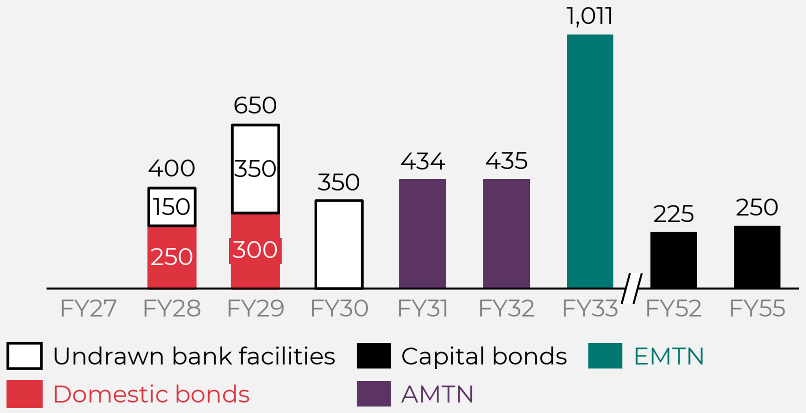
Streamlined balance sheet

Post the $575M February equity raise and debt consolidation, Contact is well positioned to advance investments aligned with Contact31+

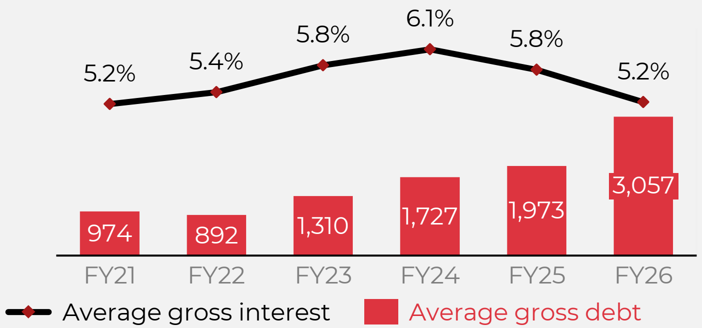
Closing net debt, $M
Face value of borrowings less cash



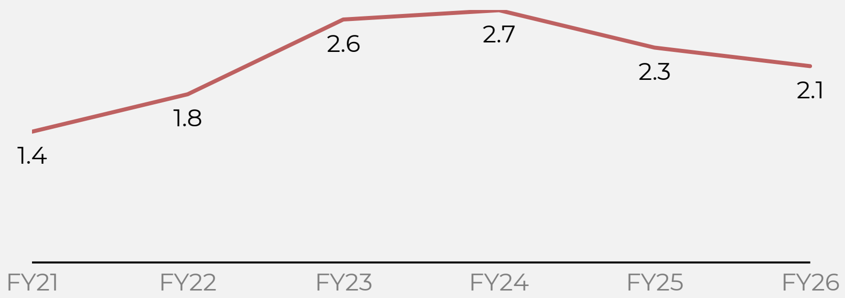
Borrowing maturities, $M
Average tenor of 7.2 years as at 30 June 2026



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



Net debt to EBITDAF, X
Includes S&P adjustments[2]



Approach and FY26 highlights

- Contact's capital management strategy is anchored to maintaining an investment grade credit rating, which is supported by a net debt to EBITDAF sustainably below 3.0x. At FY26 year-end, the point estimate of net debt to EBITDAF was 2.1x.
- During FY26, Contact issued an inaugural €500m European Medium Term Note (EMTN). This debt was certified against the Green Bond Principles under Contact's Sustainable Finance framework and supported the funding of the Manawa acquisition.
- Contact repaid the $14M of remaining NEXI export credit facility and $88M US Private Placement debt (USPP) early in April and May 2026 respectively and closed out the related cross currency swaps.

Looking ahead

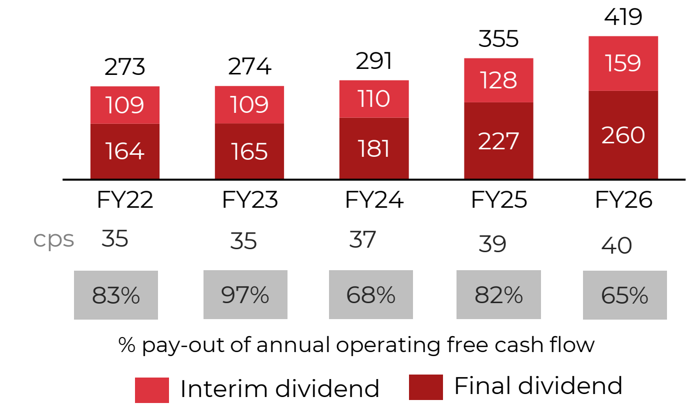
- The first reset date of the Capital Bond issued in 2021 is approaching in November 2026. Contact intends to redeem the bonds at this reset date and issue a replacement in line with market expectations.

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. See breakdown of S&P approach on slide 47.

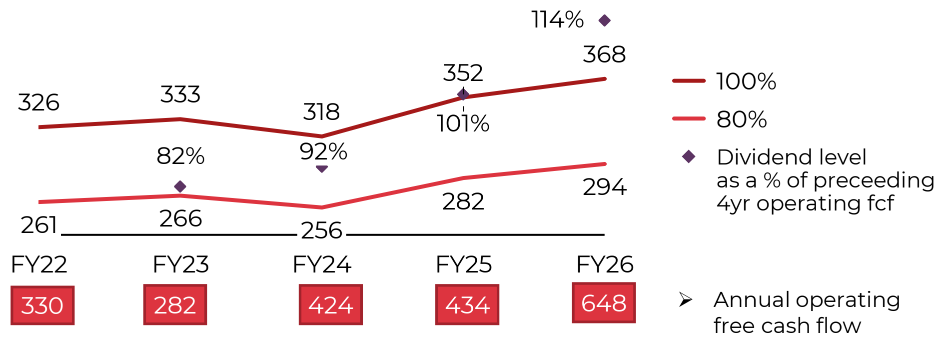
Dividend per share for FY26 up 3% to 40cps

Reflects 65% of FY26 operating free cash flow and 114% 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



Contact's dividend policy is to pay dividends of 80-100% of average operating free cash flow of the preceding four years. As the historic measure will not capture the operating free cash flow contribution from Manawa within the history, the Board will apply discretion in the first few years post-acquisition, if the measure is temporarily above 100%, so that it is not constrained in delivering the expected DPS uplift. This has been the approach taken in FY26. If the shares issued in FY26 as consideration for Manawa, the February 2026 equity raise, and the acquisition of KCE are excluded, the dividend declared would represent a pay-out of 50% of FY26 operating free cash flow and 89% of the preceding 4-year average.

Dividend for FY26 of 40 cents per share

- The final dividend of 24 cents per share is imputed up to 79% or 19 cents per share for qualifying shareholders.
- This takes the total FY26 dividend declared to 40 cents per share, representing a pay-out of 65% of FY26 operating free cash flow and 114% of the average operating free cash flow over the preceding 4 financial years (FY22-FY25).
- The record date is 18 August 2026; payment date is 23 September 2026.
- The NZD / AUD exchange rate used for the payment of Australian dollar dividends will be set on 25 August 2026.

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 FY26 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 19 August 2026 to confirm participation in the plan.
- The trading period for setting the price for the DRP is 17 August 2026 to 21 August 2026. The DRP strike price will be announced: 25 August 2026.

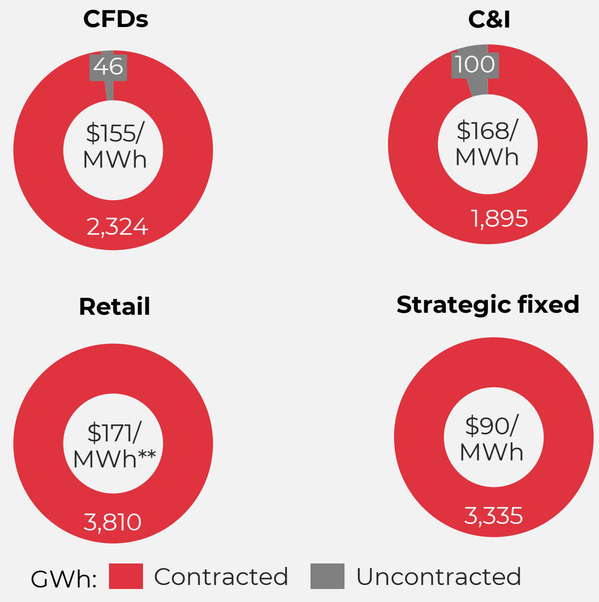
Dividend expectations

- Contact expects to lift the total dividend in FY27 to 42 cents per share.[1]
  - On this basis, dividends in FY27-FY28 are expected to be imputed up to ~70%.
- Reliable ordinary dividends are expected to increase over time with growth in operating free cash flow.

1. 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.

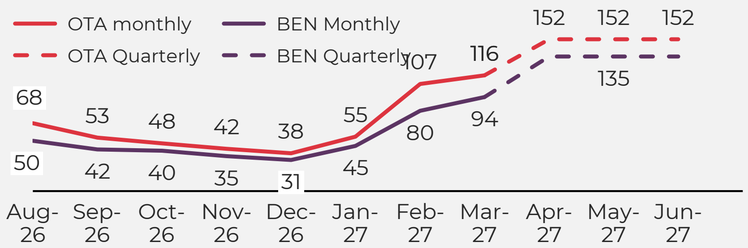
Normalised and expected FY27 EBITDAF $1,045M[1]

Assumptions based on mean hydrology and wind conditions



ASX Futures, $/MWh

At 23 Jul 2026



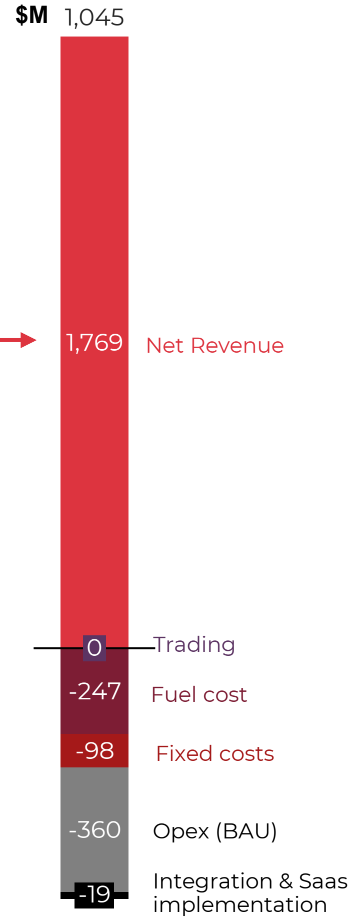
FY assumptions that deliver expected & normalised EBITDAF for FY27

1 Channel choices maximise long term value[2]		X	2 Net price[3] driven by best commercial practices	=	Total
Strategic fixed price	3,335GWh	x	$90/MWh	=	$299M
CFDs	2,370GWh	x	$155/MWh	=	$367M
C&I	1,995GWh	x	$168/MWh	=	$335M
Retail	3,810GWh	x	$171/MWh	=	$652M
Other income[4]					$116M
					$1,769M

3 Hydrology & Asset availability optimise generation		X	4 Access to and price of fuel* drives financials & risk position	=	Total
Hydro mean	5,850GWh		$0/MWh		-$0M
Geothermal average	4,635GWh	x	$2.5/MWh	=	-$11M
Thermal	291GWh	x	$178/MWh[5]	=	-$52M
Renewable PPAs	950GWh	x	$107/MWh	=	-$102M
Market acquired	425GWh	x	$193/MWh[6]	=	-$82M
					-$247M

5 Trading delivers value to largely offset locational losses	
Length[7]	$56M
Location losses[8]	-$56M
Total	**$0M**

6 Digitalisation & continuous improvement optimise fixed costs	
Transmission/Storage	**-$98M**
Opex BAU	-$360M
Opex – Integration costs	-$7M
Opex – SaaS implementation cost	-$12M
Total Opex	**-$379M**
Total	**-$477M**



1. Normalised and expected EBITDAF assumes mean hydrology and wind for the year and assumes planned asset availability / capacity i.e. adjusts for planned in-year outages (e.g. geothermal statutory outages, hydro refurbishments). | 2. All volumes are at the Grid Exit Point (GXP). | 3. Net price is equal to tariff less pass-through costs (network, meters and levies) /MWh. | 4. Steam sales, retail gas gross margin, telco gross margin, irrigation and other income. | 5. Gas price of $15/GJ, carbon price of $59/unit and thermal portfolio heat rate (9.8GJ/MWh). | 6. Acquired generation price includes premiums paid for HFO and NZAS demand response. | 7. Length of 557GWh assumed. | 8. Locational losses of 5.6% on spot purchases and settlement of CFDs sold at a wholesale price of $87/MWh.

* Fuel is natural gas, carbon and PPA costs.

** Retail volume contracted. Competitive risk remains on pricing achieved.

Note: All figures are subject to rounding.

Strategy update

Leading New Zealand's renewable energy future

Strategic pillars

Extend our advantage as NZ's geothermal leader
Scale on high-quality existing fields, explore new options, and continue to improve our cost-leadership position

Lead on new flexibility in NZ
Accelerate batteries, build advantage in hydro flex and maintain gas flex, optimising our portfolio in real time

Build into new demand with wind and solar
Deliver lowest-cost diversified wind and rapidly deploy solar, anchored on long-term industrial partnerships

Lead the energy transition at home
Empower our customers to shift energy use, while making every interaction easy and personal

Enablers

Empowered people and leaders
Unite our people behind Contact31+ and develop NZ's best energy leaders

Relationships with our stakeholders
Maintain enduring trust with stakeholders, investing for secure, affordable renewable energy while upholding our environmental commitment

Tech advantage
Establish a distinctive edge in data and AI on a simplified and secure technology platform

Productivity
Drive disciplined growth by simplifying processes and deploying automation

Underpinned by continued operational excellence across our diverse and resilient portfolio

Values

- Own the future
- Brave humility
- Performance edge

Contact31+ is anchored on building renewables in connection with long-term industrial partnerships

Opportunities for new electricity demand exist at scale across key sectors

Data Centres

Opportunities totalling **4 – 6TWh**[1] from existing and proposed sites

Electrification of dairy

Dairy decarbonisation could see **1.8 – 4.6TWh**[2] of new demand

Metals

Announced metals projects could add **>600GWh**[3] of new demand

Contact can draw on its deep set of enabling capabilities to support customer energy transition and growth

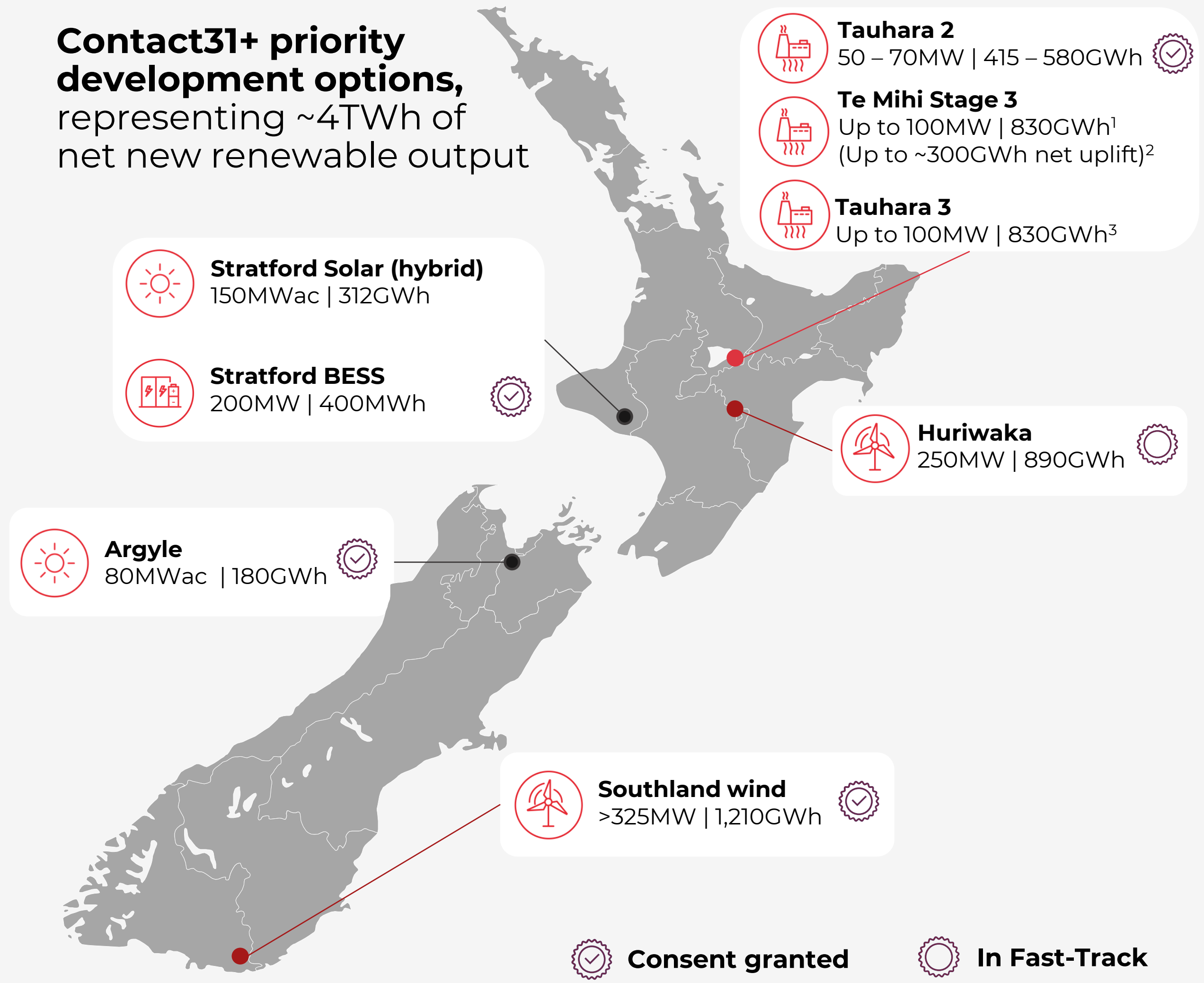
Tangata whenua relationships	Environmental stewardship	Grid / network connectivity	Fuel flexibility management
Local government engagement	Sustainable business practices	Planning and project governance	Energy firming and resilience
Community involvement	Consenting processes	Local contracting relationships	Flexible load contracting

1. Based on ~185MW total capacity at existing sites, with ~15% average 2025 utilisation estimated, and the disclosed, uncommitted pipeline capacity across major existing and potential large operators. | 2. Includes known and committed biomass and electricity conversions. Upper bound is based on manufacturing and fuel use disclosure in Fonterra's FY25 Climate Statement. Suitability for electrification to be confirmed. It is expected a portion of load from shifting dairy manufacturing away from coal will go to biomass. | 3. Includes NZ Steel's Electric Arc Furnace and the potential reopening of NZAS Line 4 potline. The consented National Green Steel EAF presents further upside.

We are advancing 4TWh+ of development options, to be anchored on long-term industrial partnerships

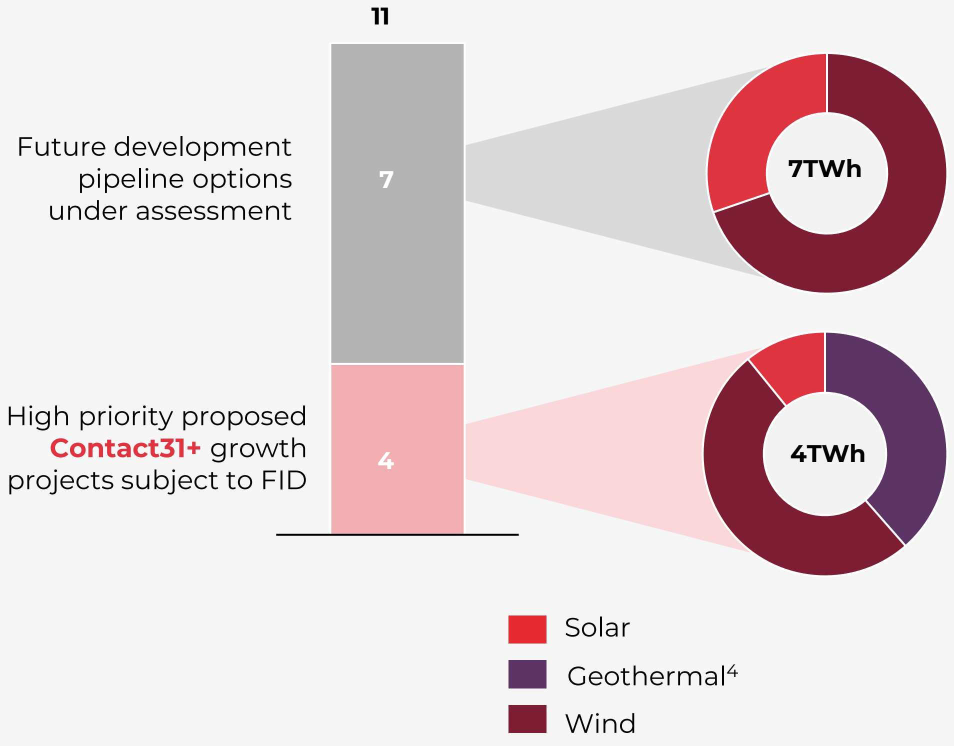
And can draw additional projects from our 11TWh+ total pipeline as customer needs evolve

Contact31+ priority development options, representing ~4TWh of net new renewable output



Total uncommitted generation pipeline of 11TWh+, provides optionality to meet demand as it materialises

Renewable generation development pipeline options, TWh



1. Ultimate size is subject to additional consented mass-take. | 2. Represents potential net uplift in output after accounting for the planned closure of the Wairakei geothermal station. | 3. Fluid take is partially consented. Ultimate size is dependent on additional land access and consented mass-take. | 4. Te Mihi Stage 3 is included on a net uplift basis.

A pathway is in place for NZAS to act as long-term customer underpinning Contact's 1TWh+ Southland Wind Farm

Contact is advancing strategic partner identification and targeting mid-2027 for Final Investment Decision

Electricity stats

Up to
55 Turbines

>325MW
total capacity

Average annual output expected to be
>1,210GWh

Project updates

- **Consent approved** April 2026.
- **Specialised infrastructure advisor, Mafic, appointed** to run identification and selection process for a strategic partner for Contact's extensive wind pipeline.
- We have engaged a shortlist of **credible wind partners.**
- Non-binding letter of intent (LOI) signed with Rio Tinto for a PPA to support the **potential restart of 50MW Line 4 potline at NZAS.**

Contact has partnered with CDC to explore data centre development at its highly strategic Stratford site

Following the March 2026 closure of Contact's Taranaki Combined Cycle baseload gas plant (TCC), Contact is taking steps to leverage the unique combination of site resources and support growth in the Taranaki region

Contact and CDC will seek resource consent for a 250MW data centre[1]. It would be supported by co-located battery storage development. Current activities focus on consenting, site and infrastructure design, customer engagement and development planning.

Solar and battery development options

150MWac / 312GWh p.a. solar farm in consenting, with DC coupled batteries potentially providing up to 750MWh storage.[2]

500MW grid-scale battery capacity consented.

High-capacity fibre connection

Diverse high-capacity fibre, both terrestrial and subsea, provides connection to Auckland where New Zealand's international cables land.

Existing generation

The operation of Contact's existing 200MW fast-start gas peaking assets at Stratford is not impacted by the data centre concept.

.

Available transmission capacity

350MW transmission capacity available within 1-2 years with minimal substation work.

600MW expected to be available within 2-3 years following planned upgrades.[3]

Land owned and under option

Existing site complemented by significant adjacent land options.

Able to support scalable renewable and load growth opportunities.

Long-term member of the community

50 years operating in the Stratford community.

Long-standing relationships with local stakeholders including councils and tangata whenua.

1. IT / compute load of 250MW. Approximately 350MW total load including ancillary load at peak times (subject to final design). | 2. Based on batteries with 5-hour duration. | 3. BCG analysis based on Transpower data and disclosures.

What you can expect from us in the next 12 months

We have already accelerated the delivery on a number of our FY27 Contact31+ strategy pillar targets

★ Accelerated / early (FY26) delivery

Strategic pillars	FY27 pillar targets
Extend our advantage as New Zealand's geothermal leader	• Te Mihi Stage 2 on track (for delivery FY28) • Tauhara 2 FID taken[1] • Tauhara 3 option progressed
Lead on new flexibility in New Zealand	• Glenbrook-Ohurua 100MW battery delivered ★ • Additional 200MW battery under construction ★ • Manawa portfolio benefits of $10-20M p.a. delivered ★
Build into new demand with wind and solar	• 0.5TWh industrial energy demand electrified • Kōwhai Park solar delivered • FID on 1-2 additional solar farms[1] ★ • 1+ wind farms consented ★
Lead the energy transition at home	• Future technology stack selected and execution commenced • Cost-to-serve $135 per customer[2] • 15 – 20MW retail demand flex under management

FY27 financial targets

Benefits of productivity programme clear

Manawa benefits delivered

42cps dividend in FY27[3]

1. Each FID to be considered in isolation with all information available at the time. Pending appropriate market conditions and projects meeting returns thresholds. | 2. Cost-to-serve per customer (real 2026). Target rebaselined to include all direct and indirect retail opex other than cost to acquire (previous method did not include all indirect costs allocated from corporate). Will be measured excluding any SaaS implementation costs associated with investment in future retail platform. This differs from $/connection previously measured under Contact26. | 3. All future dividend decisions are at the discretion of the Board at the time.

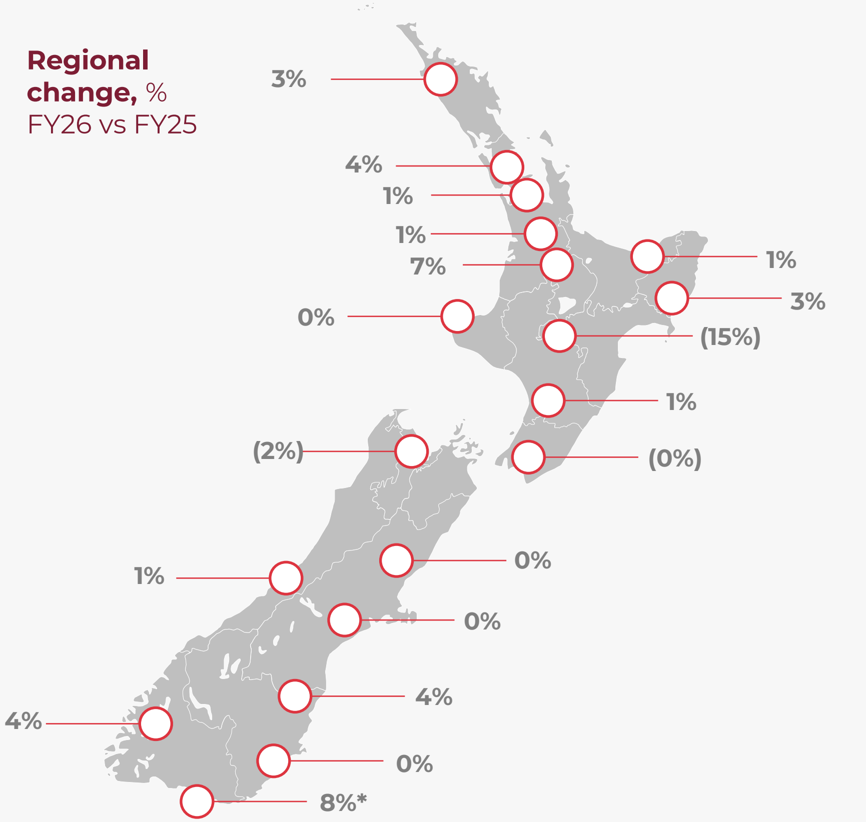
Questions

Supporting materials

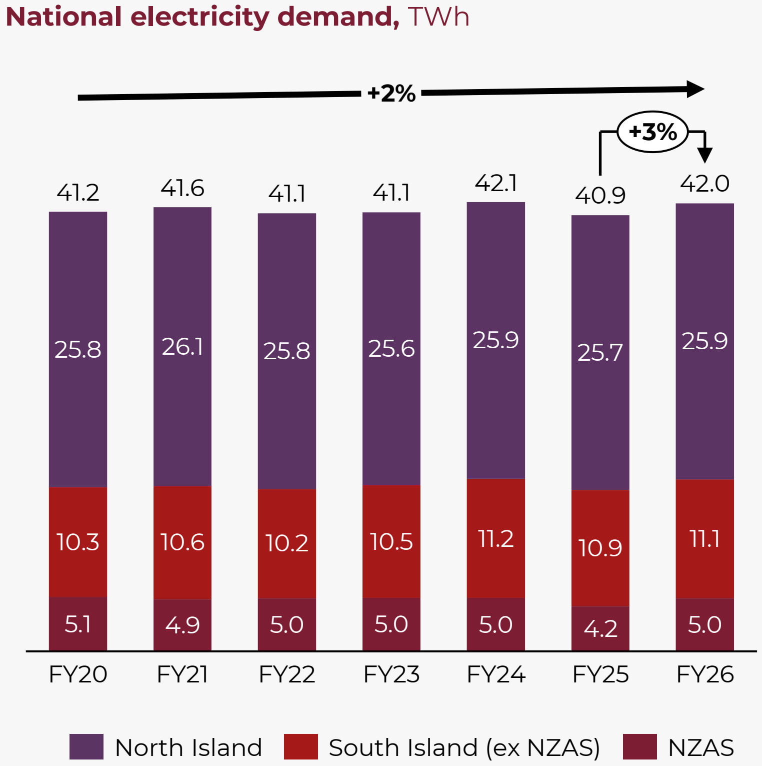
Market update

National electricity demand

NZ electricity demand up ~3% (up ~1% normalised for NZAS demand response)



Source: EMI, Contact.
Does not include NZAS.



Source: EMI, Contact.
NZAS demand response is estimated by comparing total demand in FY25 against average demand at the Tiwai node over the preceding 4 years.

National electricity demand in FY26 was up ~3% year-on-year to 42TWh. Adjusting for NZAS demand response – called by Meridian in 1H25 to support challenging hydro conditions – *demand was up ~1%.*

Demand at the Central North Island node was down 15% due to the impact of the Winstone Karioi pulp mill and Tangiwai sawmill closures in August 2024, reflecting broader challenges in wood and paper processing without the protection of fixed price electricity hedging.

Huntly node demand increased 7% in FY26, due to population growth in the Waikato/Hamilton region and increasing electricity use from electrification and industrial customers.

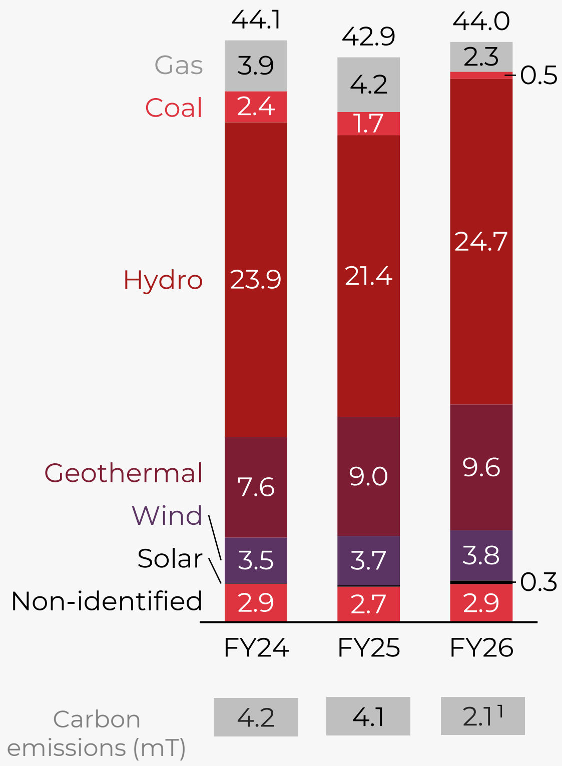
Seasonal conditions at irrigation nodes, along with population growth, have resulted in a 4% increase in demand in South Canterbury.

Southland demand growth appears to be driven by ongoing industrial electrification, particularly in the dairy and meat processing sectors, alongside broader regional growth.

Record renewable period

High hydro inflows and new renewable generation online pushed thermal generation market share to its lowest since the market was introduced

Generation by type, TWh



Hydro generation was up ~15% on FY25, driven by high inflows from Q2 FY26.

Impacts included:

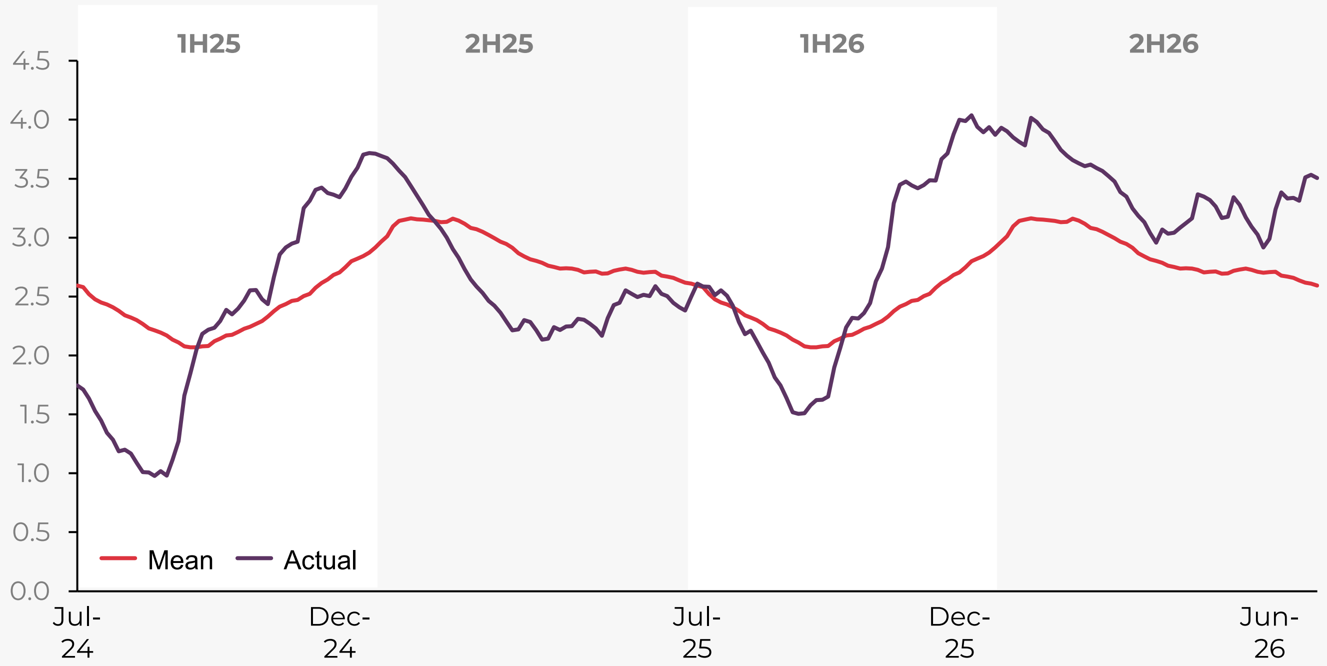
- The lowest thermal generation share since the introduction of the market (~6%).
- Lower spot wholesale prices than in FY25.
- Lower total industry carbon emissions.

Geothermal generation volume was up ~6% with the addition of TOPP 2 and Ngā Tamariki OEC5 in 2H26 and a full operational period of Te Huka 3.

Solar increased from 17GWh to ~270GWh, ~0.7% of total market generation.

Battery storage discharged ~40GWh during the period.[2]

National hydro storage, TWh



- FY26 began with storage levels close to the post-market average before a short dry spell saw levels draw down over winter. Hydro storage reached its lowest level in August 2025, some 0.5TWh higher than the lowest point in August 2024.
- Strong inflows from September drove a rapid recovery, with storage peaking in December 2025.
- Drier conditions followed through the second half of the year, although storage remained above historical averages for the remainder of the period, closing with national hydro storage 135% of post-market mean.

Source: EMI (generation data), MBIE (emissions data, Electricity data tables) and NZX Hydro data.
1. Carbon emissions for FY26 Apr-Jun quarter have been estimated using historic conversion rates with actual generation data. | 2. Battery storage discharge is not included in total generation numbers.

The market is responding to record investment in renewable generation and actions to reduce dry year risk

FY26 spot wholesale pricing

- Spot wholesale electricity prices fell sharply following Winter 2025 as intense rainfall and high wind conditions lifted renewable generation volumes.
- This displaced the need for thermal generation (leading to the lowest thermal generation market share since the introduction of the market).
- These conditions led to the lowest recorded monthly average spot price in January 2026 ($4/MWh).

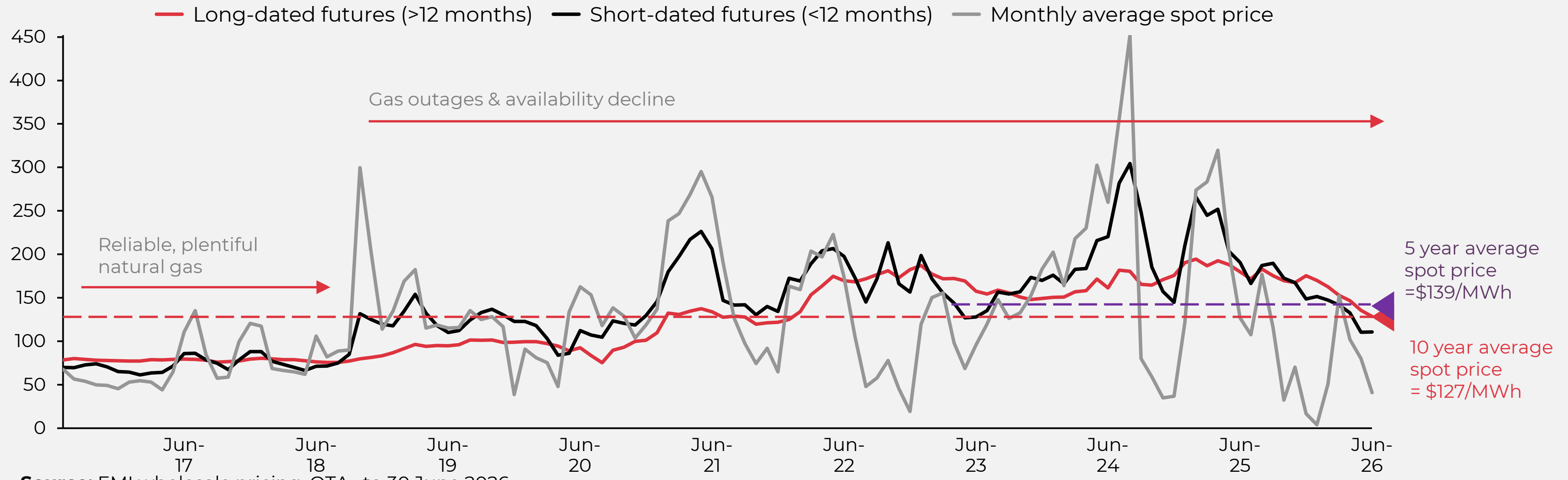
Short-term pricing (reflected in short-dated futures)

- Reduced thermal generation allowed more gas to be stored in AGS, while Genesis replenished its coal stockpile (backed by the HFO). As a result, short-dated futures moved lower alongside spot prices, responding to low risk of fuel scarcity in Winter 2026.
- The low fuelling risk led to ASX settlement prices for Q3 2026 falling >60% over 2H FY26[1].

Long-term pricing (reflected in long-dated futures)

- Long-dated futures declined 27% over 2H FY26, reflecting an expectation that the market is largely moving back into supply / demand balance.
- ~3TWh of generation either committed or under construction and expected to come online by 2027[2].
- Contact expects the long-term wholesale price to settle around $115-125/MWh[3] reflecting the marginal costs of new renewable projects and the costs associated with firming renewable intermittency.

Wholesale and futures electricity pricing, $/MWh

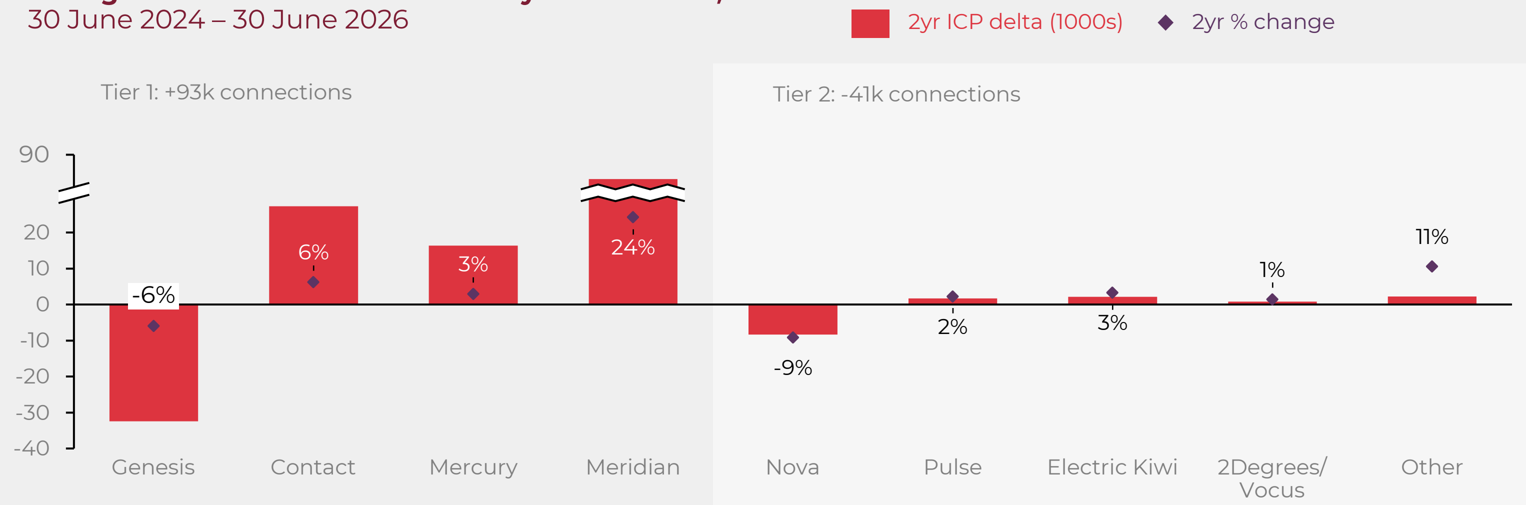


Source: EMI wholesale pricing, OTA, to 30 June 2026.

1. Change in ASX Settlement prices at Otahuhu for Q3 2026 from 31 Dec 2025 to 30 June 2026. Source: ASX. | 2. Company announcements and Contact's analysis. | 3. 2025 real – Otahuhu Node OTA, Auckland. This is a through-the-cycle measure in a balanced market. Prices achieved are a function of the market at a point in time.

Competition remains strong as Tier 1 retailers extend market share leadership

Change in retail customer electricity connections, '000s
30 June 2024 – 30 June 2026

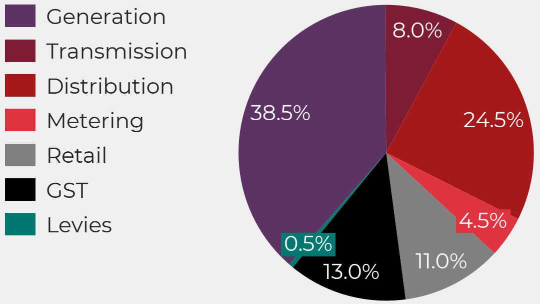


Source: EMI – residential ICPs only

Retail electricity market connection trends

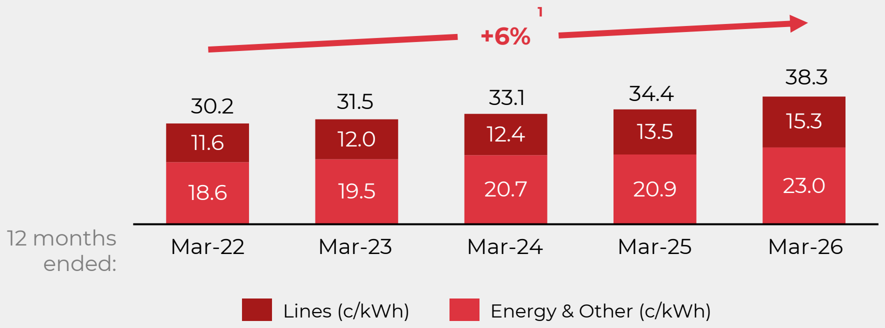
- Retail competition remained active, with customer churn broadly unchanged at ~19.5%.
- Tier 1 retailers now hold ~86% market share. Growth over the last 2 years was led by Meridian (+12% over two years, excluding Flick), followed by Contact (+6%) and Mercury (+3%).
- Genesis' decline has been driven by the closure of Frank Energy (announced June 2025) and a shift to focus on margin quality over raw customer numbers.
- Tier 2 retailers held steady, while Nova fell by 9%. The ~41k connection loss across Tier 2 retailers was largely driven by Meridian's acquisition of Flick Energy in May 2025.
- Contact added 27k electricity connections over the past two years, resulting in a 20% market share.

Breakdown of an average household electricity bill



Source: Electricity Authority

Retail electricity tariff changes, c/ kWh



Source: MBIE

Retail pricing trends

- Residential electricity prices have risen steadily, at a compound annual growth rate of ~6% over the five years to March 2026.
- Average prices increased ~11% in the year to March 2026, reaching 38.3 c/kWh.
  - The lines component rose 13%, while the energy and other component increased 10%.
- Cost pressures on the lines component of the tariff are expected to remain as the increased cost of transmission and distribution infrastructure continues to be incurred.[2]
- Moderating wholesale prices are expected to lower the electricity component over time.

1. Compound annual growth rate. | 2. From 1 April 2025, Commerce Commission-approved changes to network charges began to take effect, increasing household bills by $10–$25 per month on average (depending on region and usage profile). Costs are increasing annually.

Supporting materials

Financial results

Guidance topics

	FY26 guidance[1]	FY26 result	FY27 guidance	FY27 Guidance Commentary
Other operating costs	**$385M - $395M**	**$387M**	**$375M - $385M**	
Other operating costs – BAU[2]	$360M	$361M	$360M	
Other operating costs – SaaS	-	-	$10M - $15M	Reflects costs of implementing new systems designated as SaaS, reduces SIB capex, includes costs to FID for the Future Retail Platform.
Other operating costs – Manawa integration and transaction	$25M - $35M	$26M	$5M - $10M	Non-recurring costs relating to the Manawa acquisition.
Stay in business (SIB) capex (cash)	**$170M - $185M**	**$145M**	**$178M - $188M**	
SIB capital expenditure BAU	$115M - $125M	$82M	$134M - $139M	
SIB accelerated programme	$12M - $13M	$14M	-	Completion of programme in FY26.
SIB capital expenditure Tauhara spare rotor	-	$15M	-	Spend brought forward into FY26 with remainder expected in FY28.
SIB capital expenditure Wairakei	$20M - $25M	$21M	~$17M	Completion of extension work activities to occur within FY27.
SIB capital expenditure Manawa refurbishment	$18M - $22M	$5M	$7M - $12M	Continued upgrade work on Highbank and Coleridge hydro sites.
SIB capital expenditure decommissioning provisions		$1M	~$5M	Decommissioning relating to TCC and Wairakei.
SIB capital expenditure Geothermal Wells		$5M	-	
SIB capital expenditure integration		$2M	~$15M	Completion of system integration from Manawa transaction.
Growth capital expenditure (cash)[3]	$500M - $510M	$375M	$460M - $470M	Te Mihi Stage 2, Glenbrook-Ohurua Battery 2 and pre-FID activity.
Depreciation and amortisation	$280M - $290M	$294M	$310M - $320M	Increase with Battery and Wairakei depreciation and increase in digital assets.
Net interest (accounting)	$115M - $125M	$140M	$120M - $130M	
Cash interest (in operating cash flow)	$105M - $115M	$122M	$100M - $110M	
Cash taxation	$120M - $130M	$119M	$80M - $90M	FY27 lower tax due to benefits of investment boost policy and tax credit on decommissioning of TCC.
Realised (gains) / losses on market derivatives not in a hedge relationship	$5M - $10M	($4M)	$5M - $10M	Including (gains) / losses on ASX market making.
Target ordinary dividend per share	40 cps	40 cps	42 cps	Increase in the ordinary dividend to reflect benefits of the Manawa acquisition.
Operating cash flow conversion	~50%	64%	65 - 70%	Increase due to impact of lower cash tax and higher capitalised interest due to Te Mihi Stage 2 and Glenbrook-Ohurua Battery 2.

1. Updated at 1H26 results. | 2. Includes corporate costs (ex integration and transaction) of $69M in FY26 (vs. $60-70M guidance) and ~$65M in FY27 guidance. | 3. Growth capital expenditure includes capitalised interest.

Normalised and expected EBITDAF assumptions[1]

With reconciliation to actual performance

FY26 assumptions that deliver normalised & expected EBITDAF of $945M over a financial year

1 Channel choices maximise long term value[2]		X	2 Net price[3] driven by best commercial practices	=	Total
Strategic fixed price	3,960GWh	x	$95/MWh	=	$376M
CFDs	1,700GWh	x	$155/MWh	=	$264M
C&I	1,750GWh	x	$165/MWh	=	$289M
Retail	3,825GWh	x	$164/MWh	=	$627M
Other income[4]					$100M
					$1,656M

3 Hydrology & asset availability optimise generation		X	4 Access to and price of fuel* drives financials & risk position	=	Total
Hydro	5,750GWh	x	$0/MWh	=	-$0M
Geothermal	4,950GWh	x	$4/MWh	=	-$20M
Thermal[4]	275GWh	x	$215/MWh[5]	=	-$59M
Renewable PPAs	830GWh	x	$100/MWh	=	-$83M
Market acquired[6]	200GWh	x	$260/MWh	=	-$52M
					-$214M

5 Trading delivers value offsetting locational losses	
Length[7]	$139M
Location losses[8]	-$140M
Total	**-$1M**

6 Digitalisation & continuous improvement optimise fixed costs	
Transmission/Storage	**-$90M**
Operating expenses – BAU	-$370M
Opex - integration and transaction costs	-$35M
Total Opex	**-$405M**
Total	**-$495M**

$M

Normalised & Expected FY26 at start of year

Lower renewables
Renewable generation below mean (-754GWh)
Calculated at thermal SRMC

Net volume impact
Lower sales volumes were offset by meeting sales with lower thermal and more acquired generation at lower prices

Increased long-term channel price
Retail net price outperformed guidance assumption by $10/MWh

Market channel price
Lower GWAP on merchant sales was more than offset by very low location losses. Contact's LWAP/GWAP spread reduced to ~1%

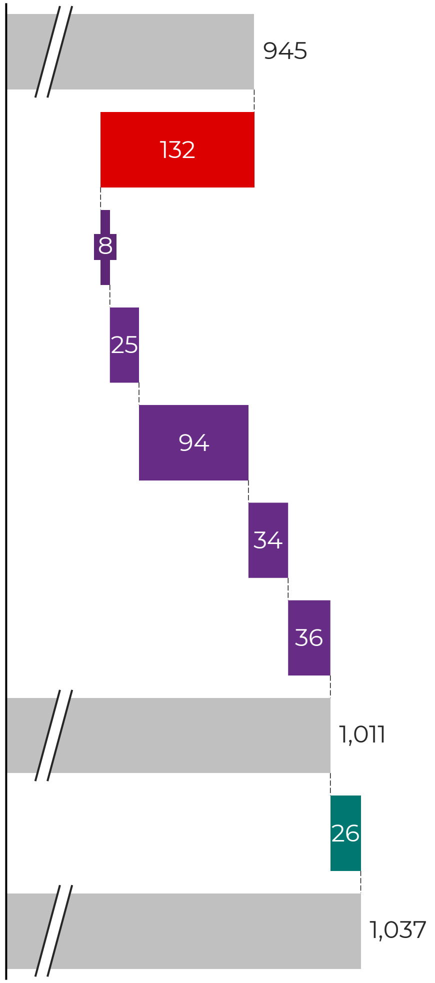
Gas, carbon, acquired generation price
Lower thermal heat rate due to final run of TCC and acquired generation price lower than assumed (-$80/MWh)

Fixed costs
Transmission & storage costs were $18M lower than forecast, supported by LCE rebates. Reclassification of $10M to fixed costs. Integration & transaction costs were $9M lower than forecast.

Reported FY26 EBITDAF

Non-recurring Manawa related costs

FY26 EBITDAF normalised for non-recurring Manawa transaction and integration costs

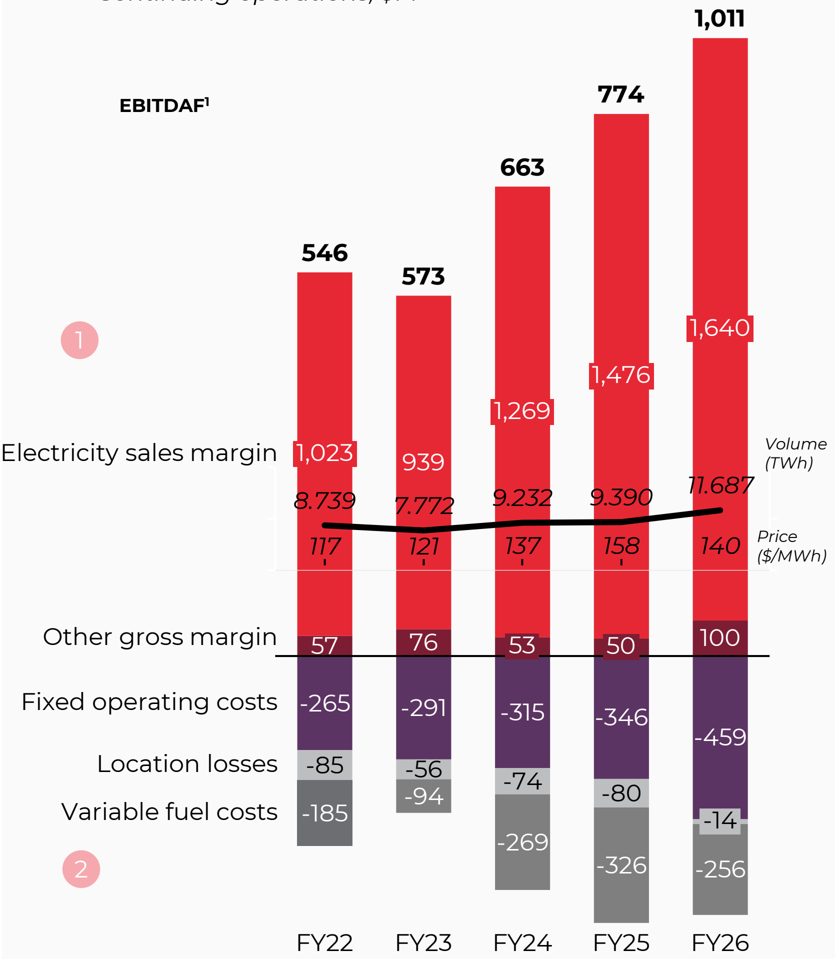


1. Normalised and expected EBITDAF assumes mean hydrology and wind for the year and assumes planned asset availability/capacity i.e. adjusts for planned in-year outages (e.g. geothermal statutory outages, hydro refurbishments). | 2. All volumes are at the Grid Exit Point (GXP). | 3. Net price is equal to tariff less pass-through costs (network, meters and levies) /MWh. | 4. Steam sales, retail gas gross margin, broadband gross margin, irrigation and other income. | 5. Gas price of $16/GJ, carbon price of $80/unit and thermal portfolio heat rate (10.5GJ/MWh). | 6. Acquired generation price includes premiums paid for HFO (operational from 1 Jan 2026) and NZAS demand response. | 7. Length of 770GWh for FY26 assumed. | 8. Locational losses of 6.5% on spot purchases and settlement of CFDs sold at a wholesale price of $180/MWh.

Integrated portfolio performance

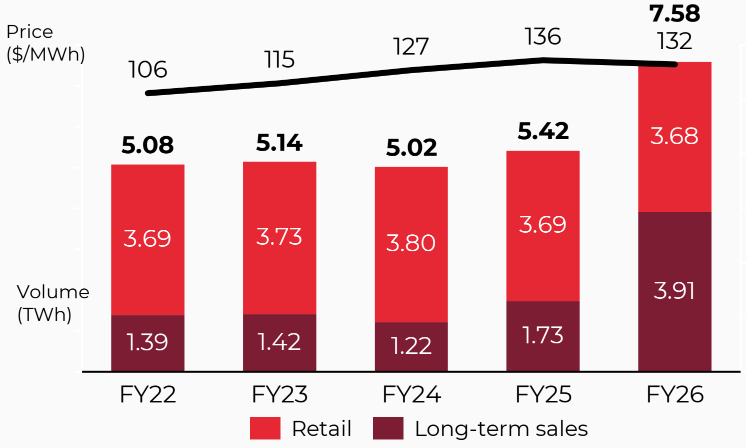
Operating earnings (EBITDAF)

Continuing operations, $M

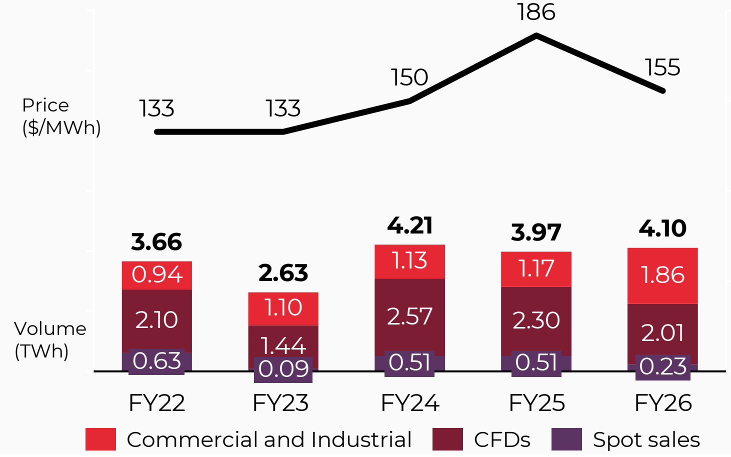


1 Electricity sales

(i) Long-term channels

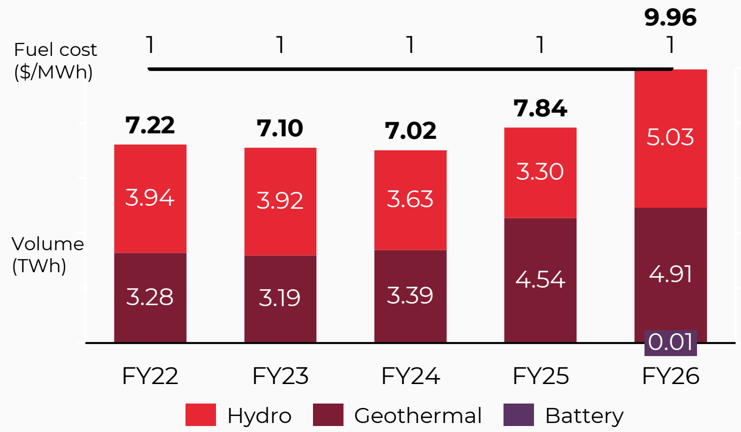


(ii) Market channels

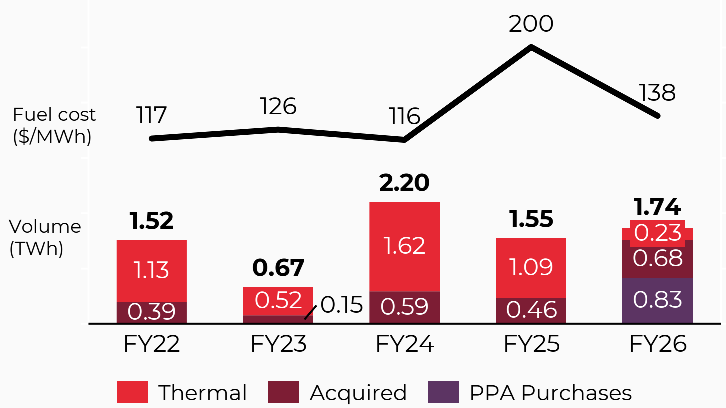


2 Variable fuel costs

(i) Renewables



(ii) Thermal, acquired and PPAs



1. Refer to slide 46 for a definition and reconciliation of EBITDAF. EBITDAF figures are underlying i.e. excluding the impacts of the ($113M) AGS onerous contract provision expense in FY23, a $12M net movement in the AGS provision in FY24, and a release of the AGS provision of $98M in FY25.

Greenhouse gas emissions

Indicator	Unit	Target	FY22	FY23	FY24	FY25	FY26
Direct GHG emissions (Scope 1)	**tCO2e**	45% reduction of 2018 Scope 1 and 2 emissions by 2026, equivalent to 647,443 tCO2e. [2]	**786,842**	**526,621**	**947,491**	**740,468**	**317,255**
- Stationary combustion (generation)	tCO2e		786,544	526,282	947,131	739,790	316,112
- Mobile combustion	tCO2e		297	307	332	409	824
- Fugitive emissions	tCO2e		1	32	28	114	50
- Stationary combustion (ancillary equipment)	tCO2e					155	269
Indirect GHG emissions (Scope 2)	tCO2e		**1,399**	**1,957**	**975**	**1,183**	**2,460**
Sub-total Scope 1 and 2	**tCO2e**		**788,241**	**528,579**	**948,466**	**741,651**	**319,715**
Indirect GHG emissions (Scope 3)	**tCO2e**		**394,784**	**273,673**	**265,034**	**369,583**	**390,731**
- Category 1 – Purchased goods and services	tCO2e	34% reduction of 2018 Scope 3 GHG emissions from use of sold products by 2026, equivalent to 244,311 tCO2e. [2]	6,371	6,197	6,522	8,799	15,517
- Category 2 – Capital goods	tCO2e		57,876	88,266	79,185	87,203	79,634
- Category 3 – Fuel and energy[1]	tCO2e		149,743	1,050	5,130	8,006	4,251
- Category 4 – Upstream distribution and transportation	tCO2e		444	108	254	205	478
- Category 5 – Waste	tCO2e	45% reduction of 2018 Scope 1 and Scope 3 emissions from all sold electricity by 2026, equivalent to 688,253 tCO2e. [2]	108	47	58	69	93
- Category 6 – Business travel	tCO2e		567	1,274	1,601	1,081	1,720
- Category 7 – Employee commuting	tCO2e		832	965	927	956	2,044
- Category 11 – Use of sold products[3]	tCO2e		178,554	175,603	170,929	250,612	267,348
- Category 13 – Downstream leased assets	tCO2e		289	164	429	339	8,678
- Category 14 – Investments	tCO2e		-	-	-	12,313	11,979
Total Scope 1, 2 and 3 emissions	**tCO2e**		**1,183,025**	**802,252**	**1,213,500**	**1,111,235**	**711,456**

1. Contact's swaption with Genesis Energy ended 31 December 2022 and was not called during FY23. | 2. All science-based targets are expressed as absolute emissions reductions and measured on a calendar-year basis. | 3. The target for Scope 3 emissions from use of sold products increased due to Contact's role in supplying gas to essential All-of-Government public services.

Growth capital expenditure

Contact's FY26 growth investment demonstrates progress in the strategic execution of its renewable development pipeline

Growth capital expenditure – cash basis, $M[1]

	Up to 30 June 2025	12 months ended 30 June 2026	Remaining under current approvals	Total[2]
Tauhara[3]	905	27	8	940
Te Huka 3	292	10	3	305
Te Mihi Stage 2[4]	201	205	305	712
Wind	21	11	6	38
Glenbrook-Ohurua Battery 1	91	56	15	163
Glenbrook-Ohurua Battery 2	1	27	207	235
Tauhara Unit 2	-	16	23	39
Other[5]	19	2	1	21
Capitalised interest	196	21	117	335
Total	**1,727**	**375**	**686**	**2,789**

Investment in joint ventures and associates, $M

	Up to 30 June 2025	12 months ended 30 June 2026	Remaining under current approvals	Total[2]
Solar[6]	-	22	63	86
CO_2	6	1	2	9
Forestry	83	1	0	84
Total	**89**	**24**	**65**	**179**

Project status

- Construction commenced in FY25 on three major renewable projects: Glenbrook-Ohurua Battery 1, Kōwhai Park solar and Te Mihi Stage 2 geothermal. Contact's first battery is now operational, with final costs and close out activities to come.
- Construction of Glenbrook-Ohurua Battery 2 commenced during FY26 and Notice to Proceed was issued to the EPC contractor for Glorit solar.
- Construction of the Tauhara and Te Huka 3 geothermal plants is now complete, with remaining spend relating to final close out activities.
- Tauhara 2 is now in the Select stage as well as pre-FID drilling works.
- Contact does not currently have any wind projects under construction. The reported wind development spend reflects pre-FID activity only.

Financial treatment

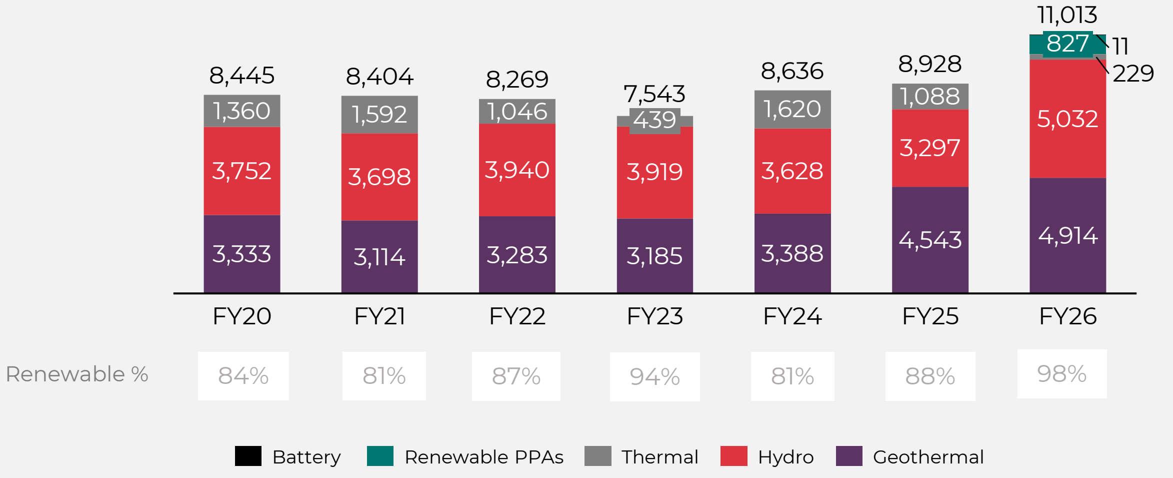
- For major growth projects, Contact capitalises interest from the point of FID—or from the commencement of significant pre-FID works—through to commissioning. The capitalisation rate reflects the average interest rate across the portfolio.
- Contact's investments in the Kōwhai Park solar farm and Glorit solar farm are accounted for as investments in joint ventures and associates, and are therefore excluded from growth capital expenditure.

1. Excludes ~$0.6M of development capex that was incurred by Manawa prior to acquisition. | 2. Total under current board approvals. | 3. Additional funding was approved in FY26 to close out the Tauhara project including replacement of pipework and acid dosing systems. | 4. For Te Mihi Stage 2 at FID, the board approved an additional $49M contingency (over and above the contingency amount already included in the expected and approved total construction cost of $712M) to account for a scenario where a broader range of risks materialise and to ensure prudent balance sheet management. If called on, this would take the total cost to $761M. | 5. Relates primarily to deployment of demand flex technology and Clutha consenting. | 6. Solar covers both Kōwhai Park and Glorit investment and excludes pre-FID development expenses for solar which are captured within receivables. Glorit obtained Financial Close during FY26.

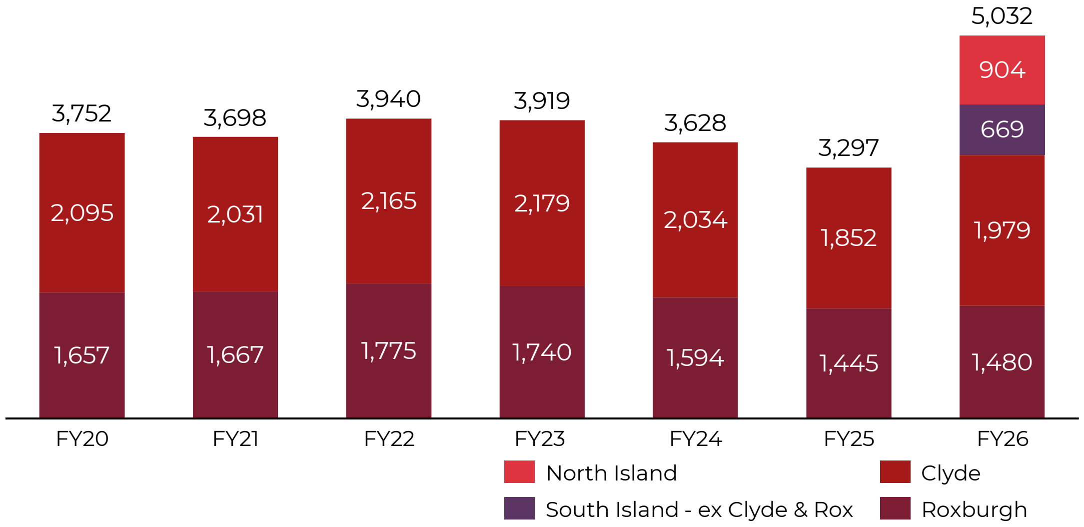
Operational data

Generation and sales position

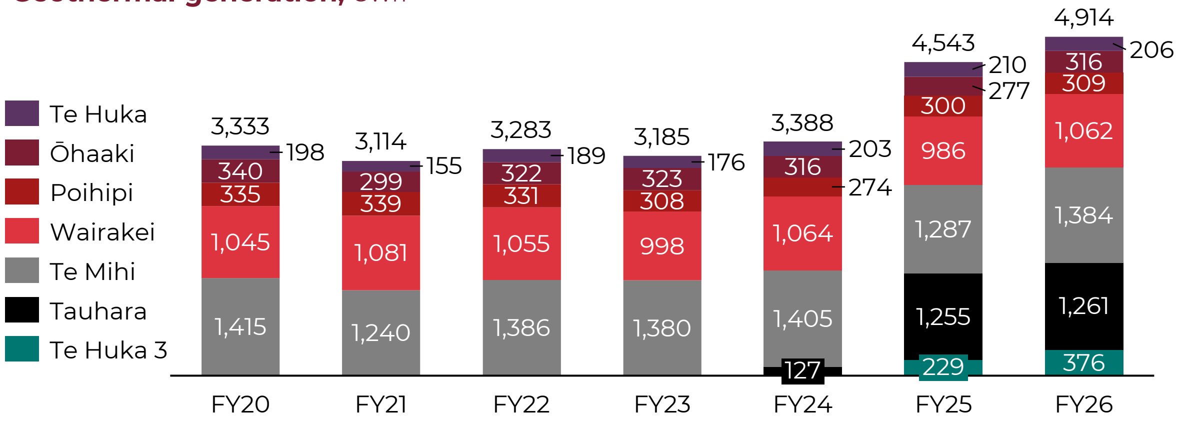
Output from Contact generation and renewable PPAs sold to the national grid, GWh



Hydro generation, GWh

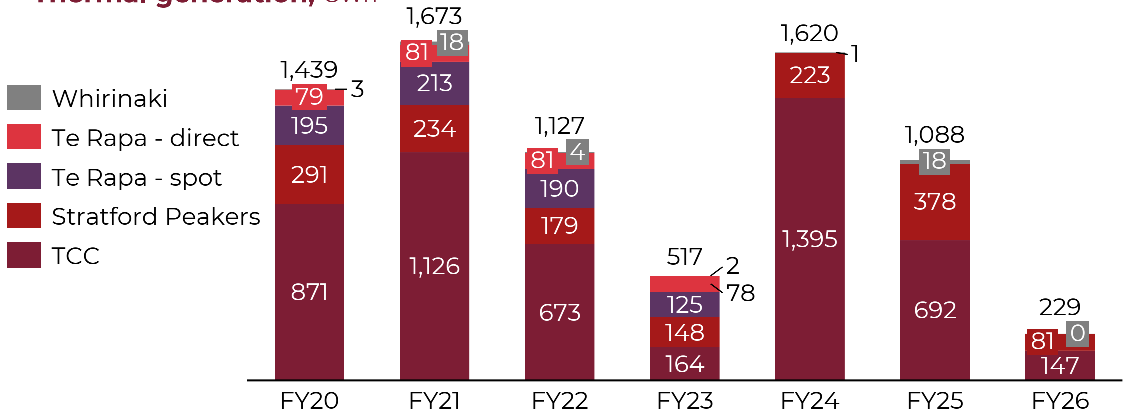


Geothermal generation, GWh



FY26 geothermal generation was 371GWh higher than FY25. A full period of generation Te Huka 3 was partially offset by statutory outages at Te Huka 3, Tauhara and Wairakei.

Thermal generation, GWh



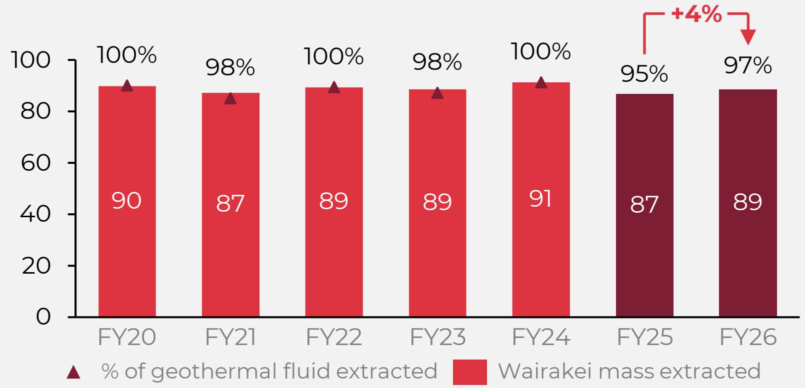
Thermal generation was 859GWh lower than FY25 due to high hydro inflows and additional renewable generation brought online in the last 18 months displacing both Contact, and the market's, need for thermal generation outside of winter 2025. Following the closure of TCC, Contact's mean expected thermal volume is now 250 – 300GWh p.a.

Operational data

Plant and fuel performance

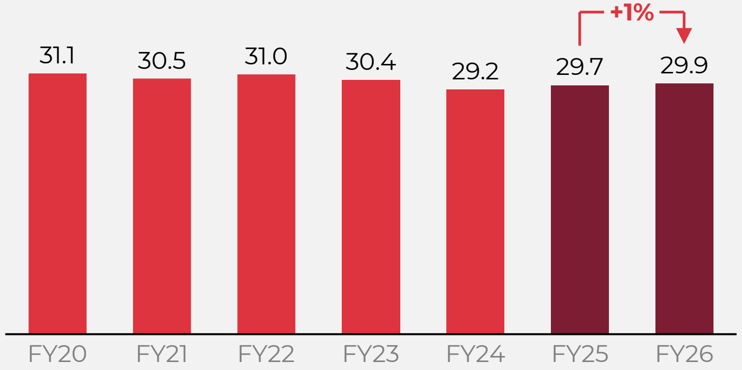
Geothermal fuel performance

Geothermal fuel extracted at Wairakei vs consented, mT



Despite a planned outage at Wairakei in FY26, total mass extracted, and extracted volumes as a % of consented mass take, were up on FY25 (which included a planned outage (25 days) at Te Mihi and an electrical outage at Wairakei A&B station).

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



Plant availability[1]

Hydro

	Net capacity MW	Availability	Capacity factor	Electricity Output, GWh	Pool revenue $/MWh	Pool revenue $M
FY22	784	83%	57%	3,940	121	478
FY23	784	84%	57%	3,919	74	290
FY24	784	90%	53%	3,628	164	594
FY25	784	87%	48%	3,297	163	538
FY26	1,295	78%	40%	5,032	81	410

Taranaki combined cycle (TCC)

	Net capacity MW	Availability	Capacity factor	Electricity Output, GWh	Pool revenue $/MWh	Pool revenue $M
FY22	377	84%	20%	673	180	121
FY23	377	85%	5%	164	107	18
FY24	377	82%	42%	1,395	184	257
FY25	377	89%	21%	692	330	229
FY26	377	93%	9%	147	183	27

Diesel Peakers

	Net capacity MW	Availability	Capacity factor	Electricity Output, GWh	Pool revenue $/MWh	Pool revenue $M
FY22	158	95%	0%	4	597	2
FY23	158	82%	0%	2	491	1.2
FY24	158	97%	0%	1	687	1.1
FY25	158	92%	1%	18	661	12
FY26	167	95%	0%	0	122	0.1

Geothermal[2]

	Net capacity MW	Availability	Capacity factor	Electricity output GWh	Pool revenue $/MWh	Pool revenue $M
FY22	425	97%	91%	3,283	140	458
FY23	410	94%	89%	3,185	80	254
FY24	586	94%	89%	3,388	177	601
FY25	649	90%	84%	4,543	186	845
FY26	649	92%	88%	4,914	73	360

Stratford Peakers

	Net capacity MW	Availability	Capacity factor	Electricity Output, GWh	Pool revenue $/MWh	Pool revenue $M
FY22	202	53%	10%	179	212	38
FY23	202	77%	8%	148	207	31
FY24	202	50%	12%	223	175	39
FY25	202	70%	22%	378	217	82
FY26	202	85%	4%	81	122	10

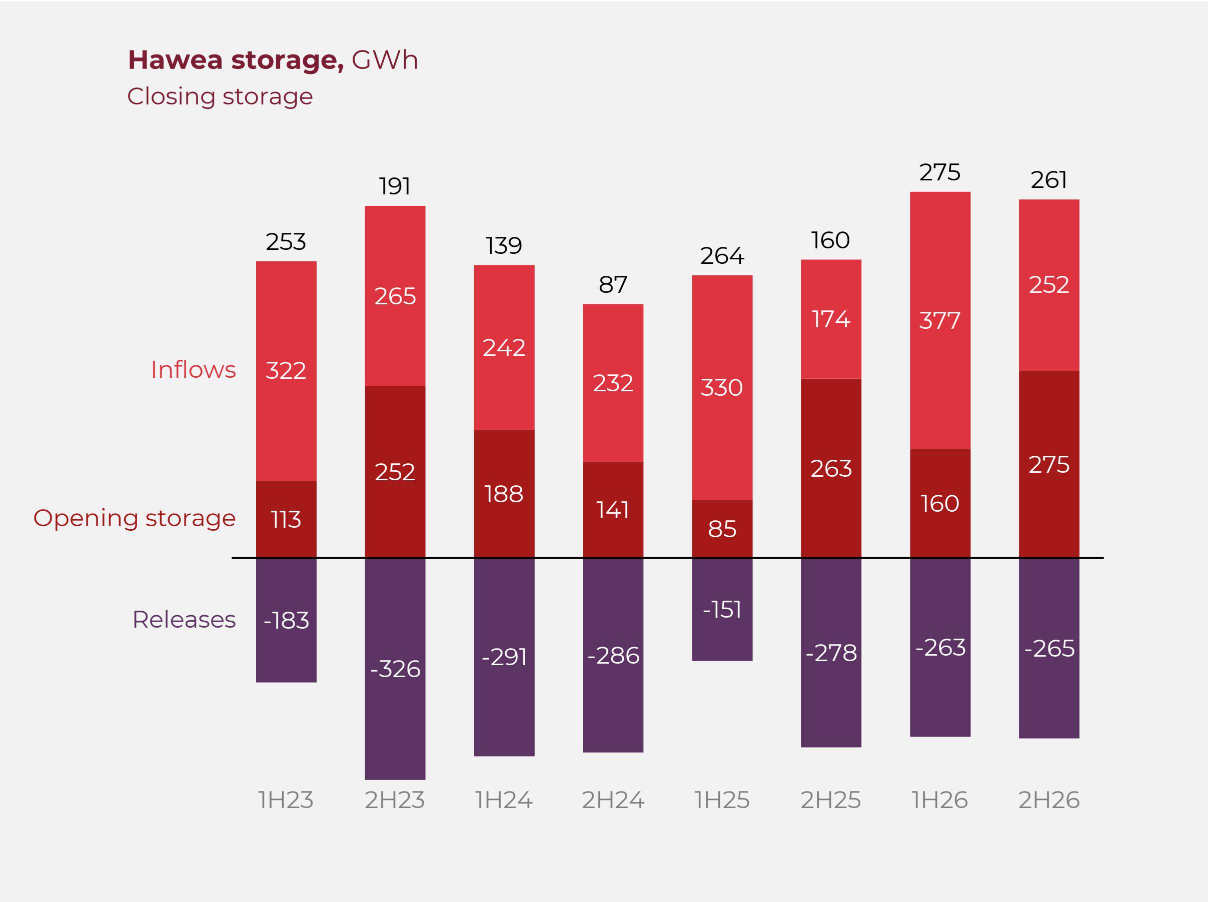
Upcoming geothermal statutory turnarounds (outages)[3]

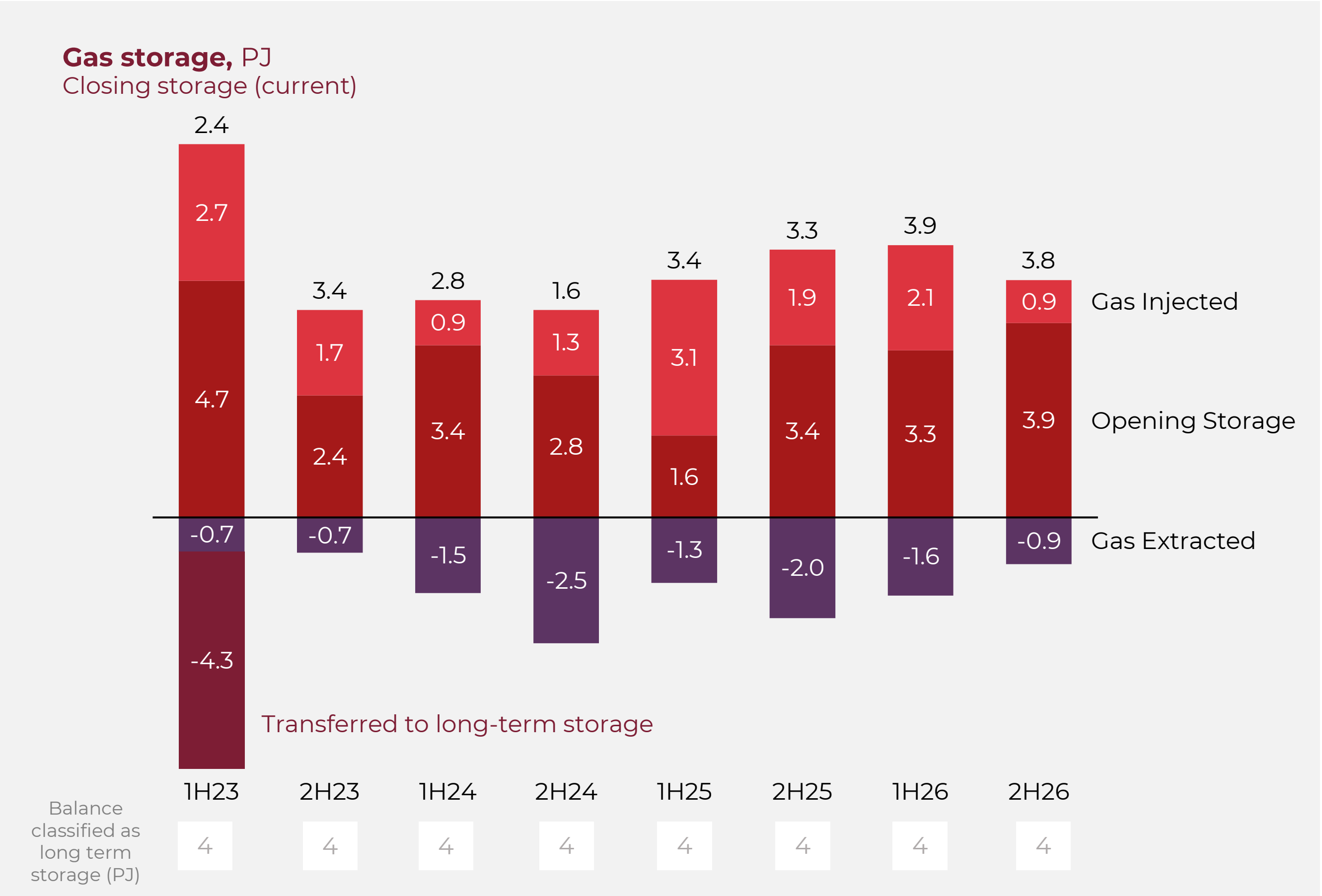
Plant	Impact (GWh)	FY	Frequency & type
Te Huka 1&2	16	27	4y Stat Turnaround
Wairakei	320	27	4y Stat turnaround + ext works
Poihipi	31	28	4y Stat turnaround
Te Mihi Stage 2	73	28	Y1 Stat Turnaround
Tauhara	169	28	Y3 Stat Turnaround
Te Huka 3	57	28	Y3 Stat Turnaround
Te Mihi	158	29	4y Stat turnaround

1. Availability Factor calculation includes all station outages (Planned, Maintenance, Forced) but not plant deratings. | 2. Reduction in geothermal net capacity in FY23 was a result of decommissioning wells on the Wairakei steam field. Increases in FY24 and FY25 related to Tauhara and Te Huka 3 respectively. | 3. 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 FY28 are indicative. Excludes impact of reduced Wairakei field output in FY27 associated with Wairakei station decommissioning and switchover to Te Mihi Stage 2.

Operational data

Fuel storage movements



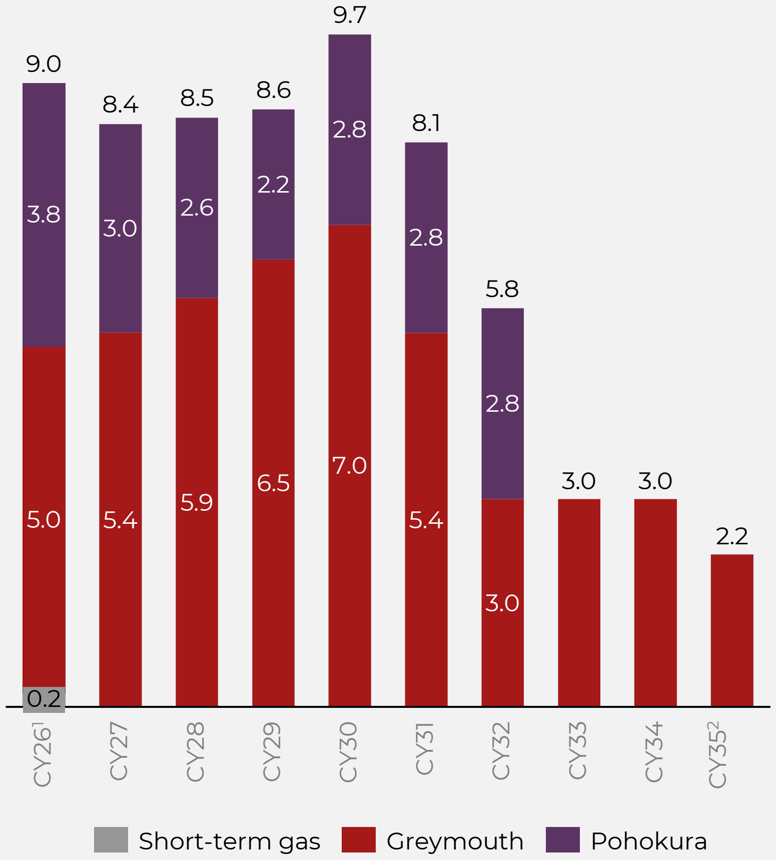


Source: NZX Hydro data

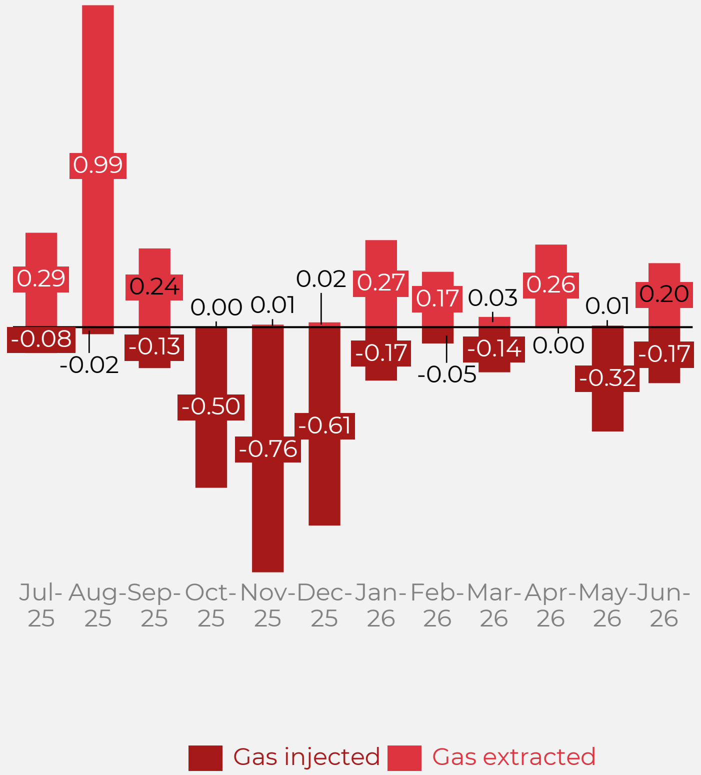
Operational data

Contracted and stored gas

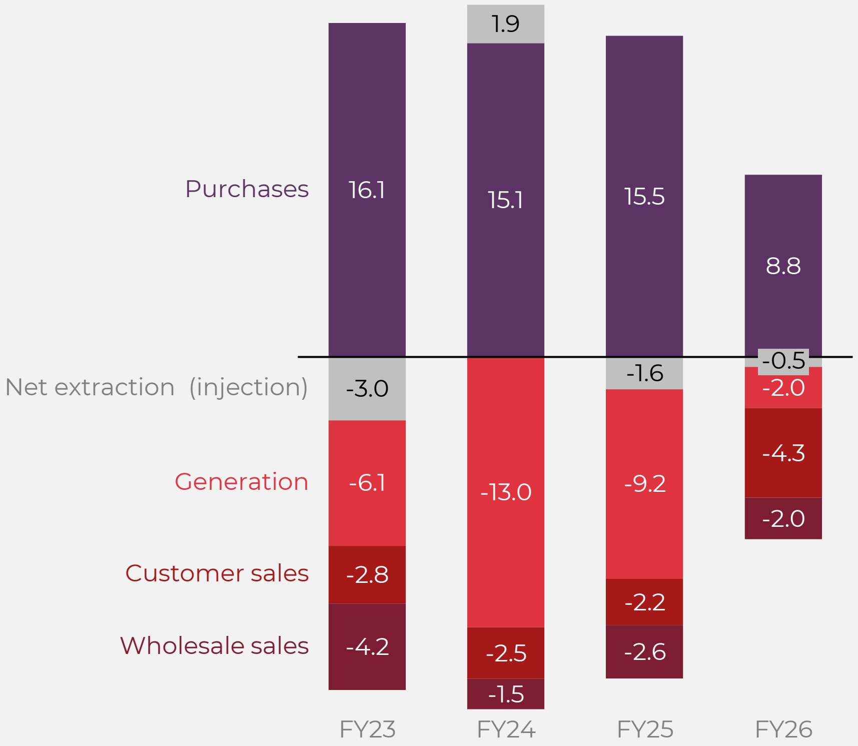
Contracted gas volumes, PJ



Gas storage monthly injections and extractions, PJ



Uses of gas, PJ



1. CY26 reflects actual volumes and forecasts for the second half of the year. | 2. CY26-CY35 reflects the maximum volume of gas available under contracts.

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 2025		12 months ended 30 June 2026	Variance on prior year	
				$M	%
	Underlying[1]	Reported	Reported	Against underlying[1]	
Profit	**261**	**331**	**423**	**162**	**62%**
Depreciation and amortisation	273		294	21	7%
Change in fair value of financial instruments	35		(21)	(56)	na
Net interest expense	100		140	40	40%
Tax expense	104	132	166	62	60%
Asset impairment / write-offs	1		9	8	800%
EBITDAF	**774**	**872**	**1,011**	**237**	**31%**

The movements between FY26 and FY25 underlying profit are as follows:

- **Depreciation and amortisation:** increased by $21M as a result of an increase in fixed assets from the purchase of Manawa and a full year of Te Huka 3 depreciation. This has been partially offset by significantly lower usage of thermal assets compared to FY25.
- **Net interest expense:** higher than FY25 as a result of additional borrowing to complete the Manawa acquisition and interest no longer being capitalised on Te Huka 3.
- **Tax expense:** increased by $62M due to the tax impact of higher operating earnings.
- **Asset impairment / write offs:** Asset write offs related to equipment replaced during first Tauhara outage (inclusive of pipework upgrade) and inventory related to TCC post decommissioning.

1. All variances and commentary reflect movements in underlying performance. In FY25, reported results include a release of the AGS onerous contract provision of $98M pre-tax ($71M after tax). Underlying performance excludes the impact of the provision release.

S&P Net Debt / EBITDAF ratio

$M	FY22	FY23	FY24	FY25	FY26
	Actuals from S&P ratings report				Estimated
Net Debt					
Carrying value of borrowings	1,099	1,556	1,913	2,449	3,051
Fair value adjustments	(55)	(43)	(41)	(94)	(90)
Restoration and environmental provisions net of tax	53	120	142	165	181
Hybrid bond credits[1]	(113)	(113)	(113)	(238)	(238)
Accessible cash[2]	(4)	(89)	(146)	(514)	(766)
S&P Adjusted Net Debt	**980**	**1,431**	**1,763**	**1,768**	**2,138**
EBITDAF					
Reported EBITDAF (underlying)	546	573	663	774	1,011
Utilised AGS provision released	-	-	-	(15)	-
Realised gains/losses on market derivatives	(9)	(27)	(6)	(13)	(3)
Share based compensation	4	4	4	5	7
Transaction costs related to the Manawa acquisition	-	-	-	11	14
S&P Adjusted EBITDAF	**541**	**551**	**661**	**762**	**1,029**
Net debt/EBITDAF (x)	**1.8**	**2.6**	**2.7**	**2.3**	**2.1**

- 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).

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

Reconciliation of change in fair value of financial instruments

Change in fair value of financial instruments $M	Realised / unrealised	FY26	FY25	Change	Description
(A) Net market making	**Realised**	**4**	**(13)**	**17**	Realised gains or losses on the settlement of electricity derivatives entered into to meet Contact's market making obligations
Market making	Unrealised	4	2	2	Mark-to-market of open electricity derivatives in future periods
NZAS long-term sale CFD		(77)	(7)	(70)	NPV of the changes to the forecast forward wholesale price path vs the wholesale path when the contracts were agreed
Kōwhai Park acquired PPA		24	(13)	37	
Mercury CFD (Manawa)		66	-	66	
Other non-hedged movements		5	(4)	9	Mark-to-market of open electricity / interest rate derivatives in future periods
Share of unrealised gains/(losses) from joint ventures		(5)	-	(5)	Contact recognises a share of the profit that joint ventures make in the Income Statement. This is the amount within their profit that relates to the joint venture's unrealised derivative movements.
(B) Unrealised movements in non-hedge effective electricity derivatives	Unrealised	17	(22)	39	
Total change in fair value of financial instruments as per segment note (A+B)	**Realised and unrealised**	**21**	**(35)**	**56**	
Commercial hedges recognised in EBITDAF that do not qualify for hedge accounting					
Financial Transmission Rights (FTR) settlements and Exchange for Physical (ASX)	Realised	(15)	(5)	(10)	Financial contracts that hedge portfolio sales that are settled in the period
Net settlement of NZAS and Mercury contracts in the period		(42)	(134)	92	Realised settlement (difference between the fixed contract and spot settlement)
Reclass share of unrealised gains/(losses) from joint ventures to Statement of Comprehensive Income		5	-	5	
Change in fair value of financial instruments as per Income Statement		**(31)**	**(174)**	**143**	

In the period, Contact acquired Manawa Energy and all of its associated long-term sales contracts. This included several major contracts for difference (CFD) that are not eligible for hedge accounting. The most significant of these is the sale of electricity to Mercury Energy.

As with Contact's existing CFDs ineligible for hedge accounting, movements in expected wholesale prices, when compared to forward wholesale prices when the contracts were entered into, drive changes in their recorded fair value.

These non-cash movements, which relate to future periods, are recognised in the current period in the change in fair value of financial instruments line item. These movements increase the volatility of Contact's reported Net Profit After Tax.

Historical financial information

	Unit	FY22	FY23		FY24		FY25		FY26
			Underlying[2]	Reported	Underlying[2]	Reported	Underlying[2]	Reported	
Revenue[1]	$M	2,387	2,118		2,867		3,306		3,206
Expenses[1]	$M	1,820	1,500	1,613	2,204	2,192	2,532	2,434	2,195
EBITDAF	$M	546	573	460	663	675	774	872	1,011
Profit	$M	182	211	127	230	235	261	331	423
Operating free cash flow	$M	330	282		424		434		648
Operating free cash flow per share	cps	42.4	36.0		53.9		54.4		64.0
Dividends declared	cps	35	35		37		39		40
Total assets	$M	5,166	5,808		6,208		6,813		10,661
Total liabilities	$M	2,326	3,004		3,589		4,053		5,432
Total equity	$M	2,840	2,804		2,619		2,760		5,229
Gearing ratio[3]	%	28	36		42		47		37

1. Revenue and expense figures align with the treatment of realised movements in financial instruments within the segment note of the financial statements. | 2. In FY23 Contact recognised a net onerous contract provision expense for AGS of ($113M) within EBITDAF and ($84M) within profit. In FY24 Contact recognised a net movement in the AGS onerous contract provision of $12M within EBITDAF and $5M within profit. In FY25, the release of the AGS onerous contract provision increased reported EBITDAF by $98M and profit by $71M. Underlying performance excludes these impacts. | 3. 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	FY25 Year ended 30 June 2025 Volume GWh	GWAP $/MWh	$M	FY26 Year ended 30 June 2026 Volume GWh	GWAP $/MWh	$M
Electricity sales to Retail segment	**3,689**	**163**	**601**	**3,675**	**179**	**657**
Electricity sales to C&I (netback)	**1,566**	**133**	**208**	**2,189**	**151**	**331**
CfDs – Tiwai support sales	920			1,270		
Tauhara PPAs	411			677		
CfDs – Mercury[1]	-			1,517		
CfDs – Other Long term sales	394			507		
CfDs and ASX - Short term sales	1,903			1,618		
Electricity sales – CfDs	**3,629**	**157**	**569**	**5,589**	**114**	**637**
Total contracted electricity sales	**8,883**	**155**	**1,377**	**11,454**	**142**	**1,624**
Steam sales	**229**	**21**	**5**	**247**	**20**	**5**
Other income			14			23
Net income on gas sales			(12)			2
Irrigation net income			-			11
Net income on electricity related services			1			1
Net other income			**4**			**37**
Total contracted revenue	**9,112**	**152**	**1,386**	**11,701**	**142**	**1,666**
Generation costs[2]	8,928	(44)	(389)	10,175	(32)	(323)
Acquired generation cost	462	(264)	(122)	1,512	(134)	(203)
Generation costs (including acquired generation)	**9,390**	**(54)**	**(511)**	**11,687**	**(45)**	**(526)**
Spot electricity revenue	8,928	195	1,742	10,186	81	824
Settlement on acquired generation	462	252	116	1,512	77	117
Spot revenue and settlement on acquired generation (GWAP)	**9,390**	**198**	**1,858**	**11,698**	**80**	**941**
Spot electricity cost	(5,255)	(218)	(1,143)	(5,875)	(87)	(509)
Settlement on CFDs sold	(3,629)	(191)	(695)	(5,589)	(76)	(427)
Spot purchases and settlement on CfDs sold (LWAP)	**(8,883)**	**(207)**	**(1,838)**	**(11,464)**	**(82)**	**(936)**
Trading, merchant revenue and losses	**507**		**20**	**234**		**5**
Wholesale EBITDAF[2]			**895**			**1,145**
Onerous contract provision unwind			98			-
Wholesale EBITDAF reported			**994**			**1,145**

1. Mercury volume included from 11 July 2025 (completion of Manawa acquisition). | 2. FY25 EBITDAF (underlying) excludes the release of the AGS onerous contract provision equated to $98M.

Retail segment

Residential electricity	unit	FY23	FY24	FY25	FY26
Average connections	#	380,482	388,459	401,332	414,387
Sales volumes	GWh	2,688	2,798	2,809	2,871
Average usage	MWh per ICP	7.1	7.2	7.0	6.9
Tariff	$/MWh	272.1	287.9	311.5	348.4
Network, meters and levies	$/MWh	-122.7	-128.0	-142.2	-163.4
Energy costs[1]	$/MWh	-138.6	-158.8	-174.5	-191.2
Gross margin	**$/MWh**	**10.8**	**1.1**	**-5.1**	**-6.2**
Gross margin	$ per ICP	77	8	-36	-43
Gross margin	$M	29	3	-14	-18

Residential gas	Unit	FY23	FY24	FY25	FY26
Average connections	#	66,605	68,092	70,369	71,538
Sales volumes	TJ	1,504	1,584	1,509	1,521
Average usage	GJ per ICP	22.6	23.3	21.4	21.3
Tariff	$/GJ	42.1	45.1	52.9	63.0
Network, meters and levies	$/GJ	-22.9	-24.5	-29.1	-32.0
Energy costs	$/GJ	-10.1	-9.8	-11.0	-17.0
Carbon costs	$/GJ	-4.2	-3.1	-4.4	-3.9
Gross margin	**$/GJ**	**4.9**	**7.7**	**8.5**	**10.1**
Gross margin	$ per ICP	112	181	182	215
Gross margin	$M	7	12	13	15

SME electricity	Unit	FY23	FY24	FY25	FY26
Average connections	#	46,962	44,113	41,654	39,893
Sales volumes	GWh	794	754	651	582
Average usage	MWh per ICP	16.9	17.1	15.6	14.6
Tariff	$/MWh	259.3	282.2	313.4	355.4
Network, meters and levies	$/MWh	-117.0	-118.3	-132.9	-161.9
Energy costs[1]	$/MWh	-138.6	-157.3	-174.5	-190.8
Gross margin	**$/MWh**	**3.6**	**6.6**	**5.9**	**2.7**
Gross margin	$ per ICP	62	112	93	40
Gross margin	$M	3	5	4	2

SME gas	Unit	FY23	FY24	FY25	FY26
Average connections	#	3,519	2,972	2,662	3,872
Sales volumes	TJ	1,063	794	607	2,721
Average usage	GJ per ICP	302	267	228	703
Tariff	$/GJ	25.2	31.0	38.5	37.6
Network, meters and levies	$/GJ	-9.5	-11.6	-13.9	-10.4
Energy costs	$/GJ	-10.1	-9.8	-11.0	-17.0
Carbon costs	$/GJ	-4.2	-3.1	-4.4	-3.9
Gross margin	**$/GJ**	**1.4**	**6.5**	**9.2**	**6.3**
Gross margin	$ per ICP	412	1,750	2,130	4,473
Gross margin	$M	1	5	6	18

Telco	Unit	FY23	FY24	FY25	FY26
Average connections	#	79,057	95,168	116,709	136,730
Tariff	$/cust/mth	69.6	71.8	72.1	71.4
Network, provisioning, modems	$/cust/mth	-63.5	-63.4	-62.8	-61.2
Gross margin	**$/cust/mth**	**6.2**	**8.4**	**9.3**	**10.3**
Gross margin	$M	6	10	13	17

Retail segment EBITDAF		FY23	FY24	FY25	FY26
Electricity Gross margin	$M	32	8	-11	-16
Gas Gross Margin	$M	9	17	18	33
Telco Margin	$M	6	10	13	17
Total Gross Margin	**$M**	**47**	**35**	**21**	**34**
Other net income	$M	9	7	4	3
Other operating costs	$M	-69	-74	-74	-78
Retail segment EBITDAF	**$M**	**-14**	**-32**	**-49**	**-41**
EBITDAF margins (% of revenue)	%	-1.2%	-2.6%	-3.8%	-2.7%

1. Energy costs reflect electricity purchased from solar customers: $1.2M in FY24, $2.7M in FY25 and $3.2M in FY26.