2017 Full Year Results Presentation

Dennis Barnes, Chief Executive Officer
Graham Cockroft, Chief Financial Officer

Year ended 30 June 2017

14 August 2017

Disclaimer

This presentation may contain projections or forward-looking statements regarding a variety of items. Such forward-looking statements are based upon current expectations and involve risks and uncertainties.

Actual results may differ materially from those stated in any forward-looking statement based on a number of important factors and risks.

Although management may indicate and believe that the assumptions underlying the forward-looking statements are reasonable, any of the assumptions could prove inaccurate or incorrect and, therefore, there can be no assurance that the results contemplated in the forward-looking statements will be realised.

EBITDAF, underlying profit, free cash flow and operating free cash flow are non-GAAP (generally accepted accounting practice) measures. Information regarding the usefulness, calculation and reconciliation of these measures is provided in the supporting material.

Furthermore, while all reasonable care has been taken in compiling this presentation, Contact accepts no responsibility for any errors or omissions.

This presentation does not constitute investment advice.

Agenda

Resilient cash flow despite rare hydrology sequences

Summary of key financial performance measures

	Year ended 30 June 2017	Comparison against FY16
EBITDAF[1]	$494m	down 6% from $523m
Profit/(loss)	$150m	up $216m from ($66m)
Earnings per share (cents)	21.0 cps	up 30.1c from (9.1 cps)
Underlying profit[1]	$141m	down 10% from $157m
Underlying profit per share (cents)	19.7 cps	down 9% from 21.7 cps
Declared dividend (cents)	26.0 cps	no change from 26.0 cps
Operating free cash flow[2]	$300m	down 15% from $352m
Operating free cash flow per share (cents)[2]	41.9 cps	down 14% from 48.5 cps
Capital expenditure	$102m	down 20% from $128m

[1] Refer to slides 40-43 for a definition and reconciliation of EBITDAF and underlying profit

[2] Refer to slide 27 for a reconciliation of operating free cash flow

[3] Refer to slide 44 for a reconciliation of the Ahuroa Gas Storage accounting treatment change

- » Contact changed the classification of Ahuroa gas storage facility costs[3] and refined some non-GAAP cash flow definitions to assist with the focus on cash flow
  - » Introduced an operating free cash flow measure to report on sustainable cash flow generation
  - » Tightened the definition around growth capital expenditure and included the cash spend on restoration / environmental rehabilitation in stay-in business capital
- » Operating free cash flow for the period remained strong at $300m despite lower EBITDAF, with FY16 boosted by a tax credit due to the closure of the Otahuhu power station (+$38m)

Highlights for the year

Sound improvements to leading performance indicators on the back of operational focus

Comparison against FY16

MAINTAINING FINANCIAL DISCIPLINE

Strong cost control with other operating costs flat, $11m reduction in ongoing operating costs. Capital expenditure down 20%. $106m in debt reduction.

+20%
Reduction in capital expenditure

ENHANCED CUSTOMER EXPERIENCE

Net promoter score for the year of +14, significantly up from the -3 recorded in FY16 on the implementation of operational improvements. Below market churn.

+17
Improvement in NPS

ENGAGED EMPLOYEES

68% of Contact employees are engaged, 12% up on FY16 with a stronger connection to Contact's purpose.

+12%
Improvement in employee engagement

SAFETY ADVANCE

Our process safety programme and HSE cultural improvements have seen our TRIFR improve slightly to 3.2 from 3.3 in FY16 and below the 5 year average of 3.8.

-0.1
Improvement in safety performance

Strategy and market dynamics

Dennis Barnes

FY17 Results Presentation

14 August 2017
Contact Energy Limited

Contact's strategy is to optimise the Customer and Generation businesses to deliver strong cash flows

Customer

Will deliver value by providing customers with choice, certainty and control while reducing cost to serve and improving the customer experience through systems-enabled operational improvements

Generation

A low cost, long life and flexible generation portfolio with a continuous improvement programme focusing on safety, spend, reliability and resource utilisation to improve the efficiency of our generation assets

Underpinned by a disciplined and transparent approach to operating and capital expenditure while continuing to investigate ways to optimise our portfolio of assets

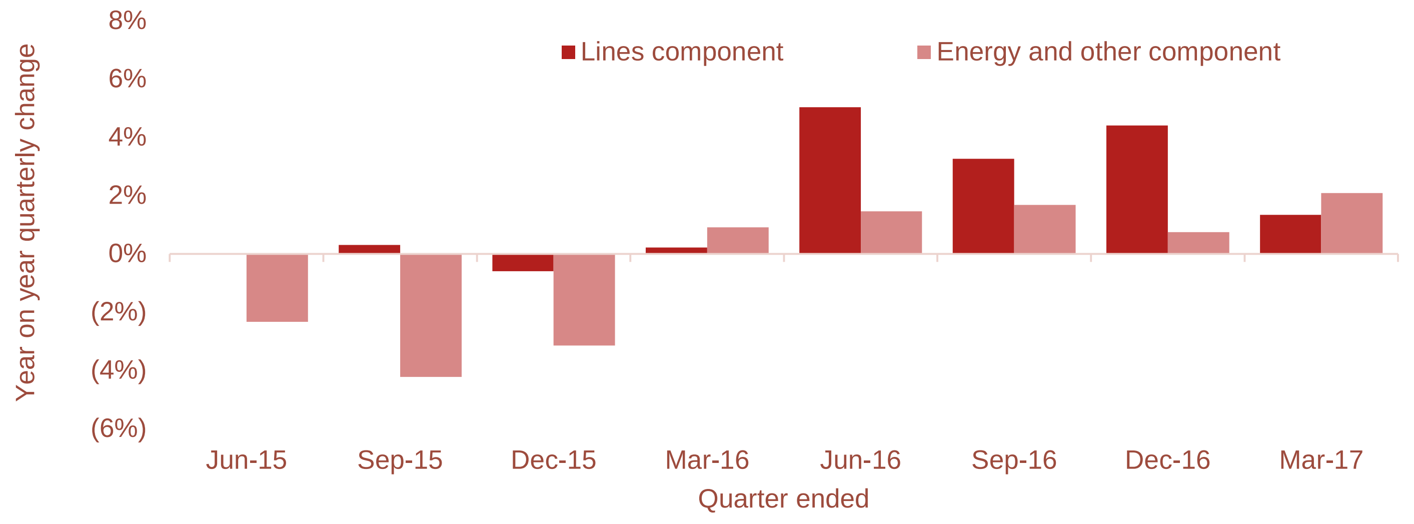
Retail electricity market remains competitive with tier 2 retailers capturing market share

Electricity pricing up in a competitive retail market

- Price increases from the tier 1 retailers
  - Residential prices rose in the March quarter by 1.8% (1.3% line costs and 2.1% energy related)
- FY17 customer switching activity remained near historic highs with the 12 month rolling switch rate at 21.4% with trader switches down
  - Tier 2 retailers continued to gain customers (market share by ICP up 1.5% to 10.3%), primarily through discounted pricing and promoting wholesale electricity spot exposed products as they attempt to build economic, mass market customer bases
    - Elevated hydro storage levels and benign wholesale market conditions have supported new entrants to date, new retailers are currently experiencing more stressed market conditions

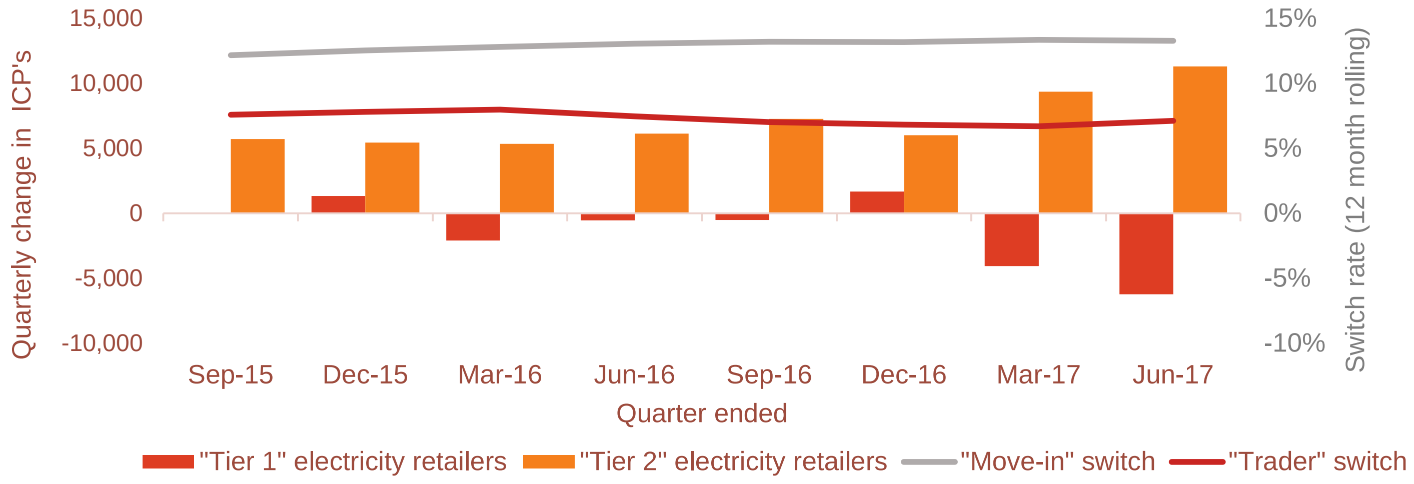
Year on year quarterly change in residential electricity prices

Source: MBIE Quarterly Survey of Domestic Electricity Prices



Tier 2 retailers continue to gain market share

Source: EA, ICP market share



National electricity supply was influenced by the disparate hydrology sequences in the year

Strong hydro generation was a feature of the first 9 months of the year

» National hydro generation for the first 9 months of the financial year of 19.8 TWh was 10% above the 10 year average which increased the renewable share of national generation to 86%

  » Thermal generation of 4.3 TWh for the first 9 months of the financial year was the lowest thermal generation for more than 30 years

Divergent hydro conditions for North and South Island generation in the final quarter

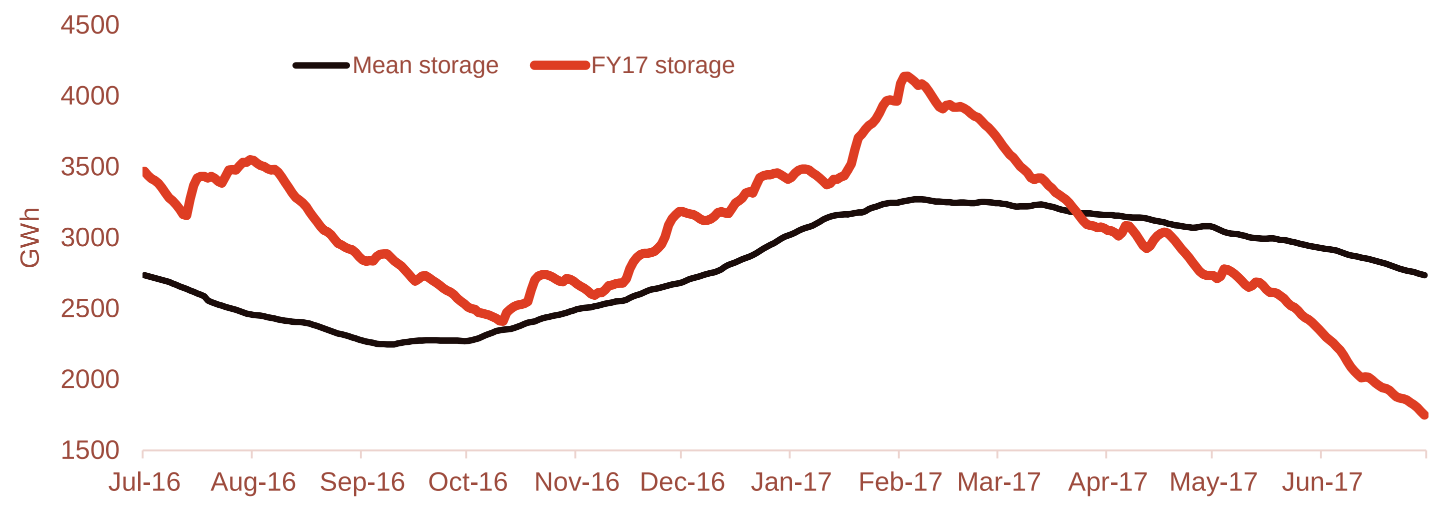
» National inflows were 12% below mean for the final quarter of the financial year

  » North Island hydro inflows of 2.5 TWh were 49% above mean

  » South Island hydro inflows of 2.6 TWh were 37% below mean

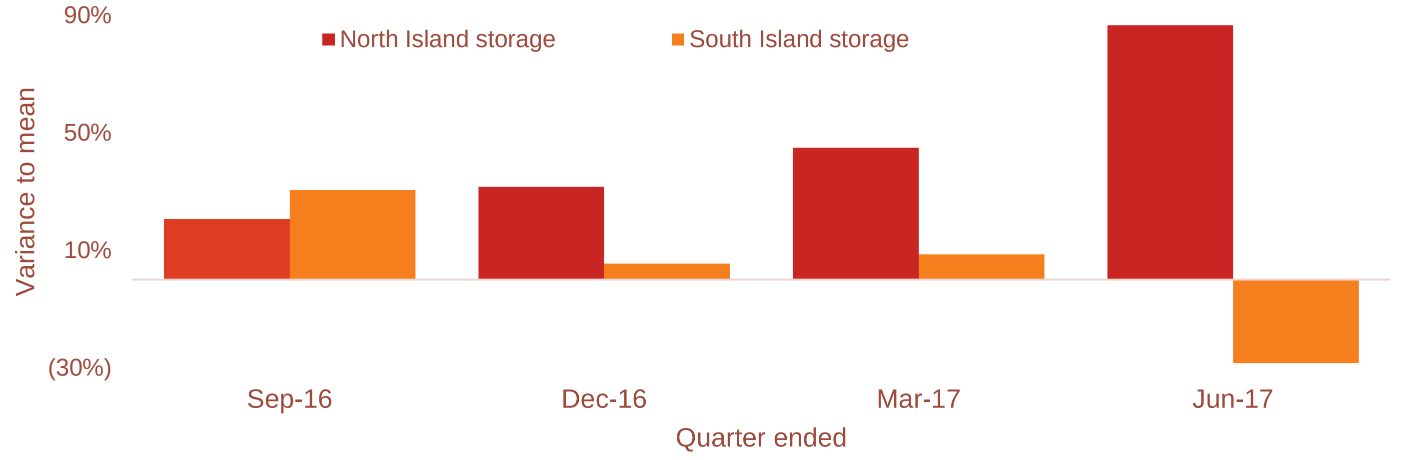
National hydro storage against mean storage

Source: *NZX hydro*



Quarterly hydro storage variance to mean storage

Source: *NZX hydro*



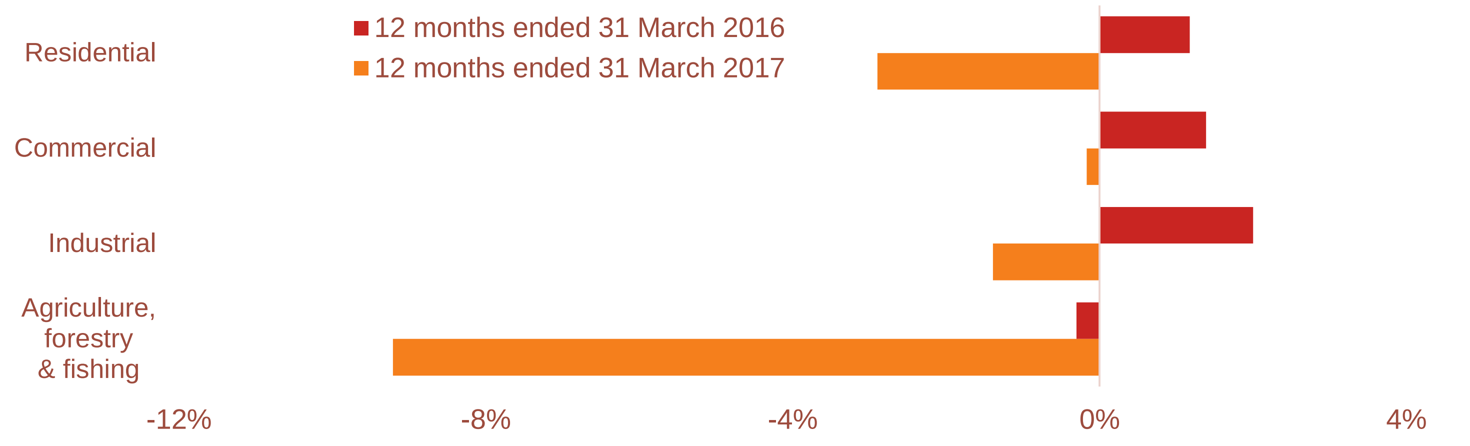
National electricity demand only marginally down on FY16 after reversion to average temperatures

National electricity demand was down 2% over the first 9 months compared to FY16, on warmer, wetter weather

- The wetter autumn saw key irrigation loads significantly reduce electricity demand when compared to FY16
- Demand from the 1% growth in new customer connections was offset by the warmer winter at the start of FY17, which reduced residential demand
- May and June demand rebounded on cooler weather, confirming the reduction in FY17 demand was not structural

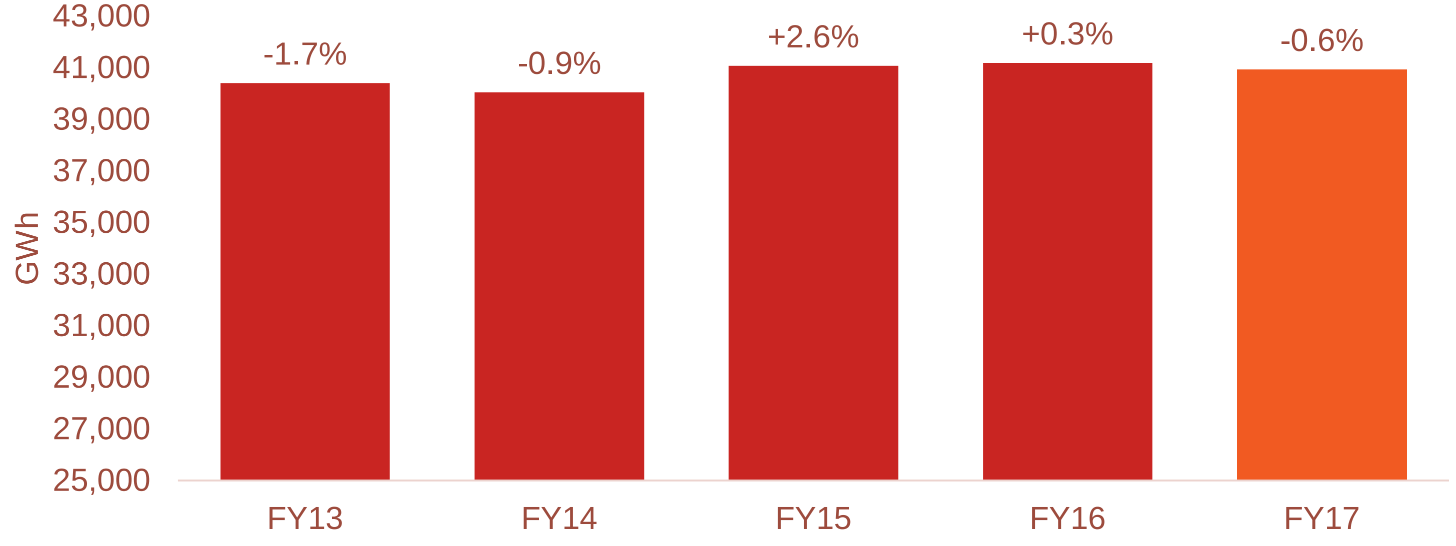
12 month change in electricity consumption

Source: *MBIE*



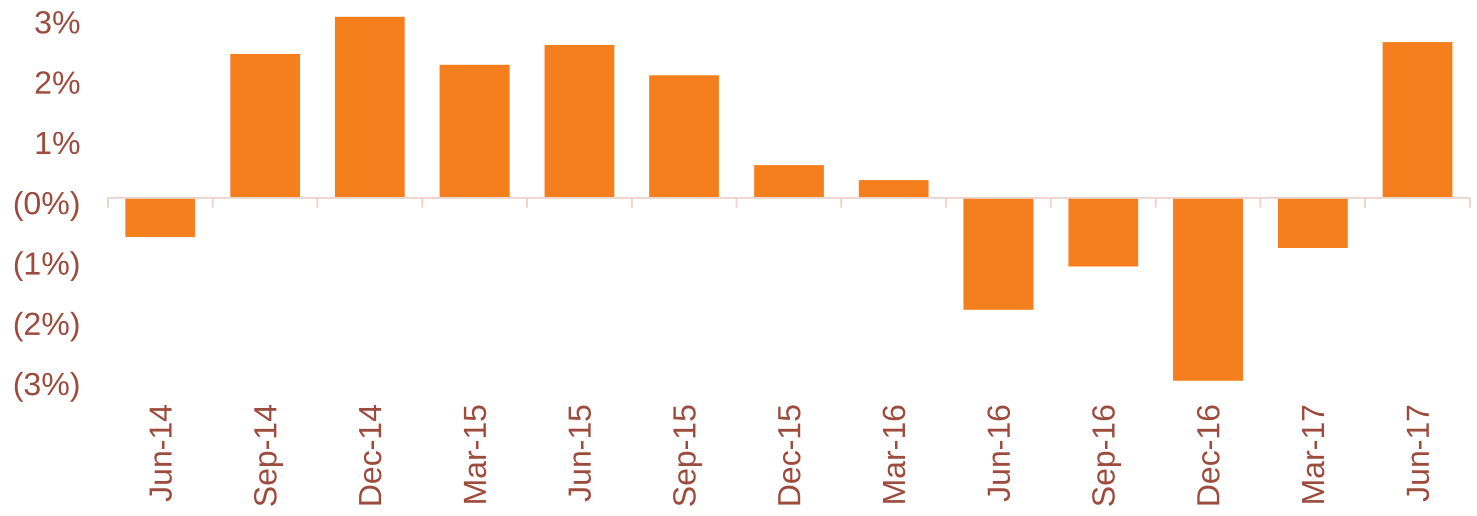
National electricity demand

Source: EA reconciled demand data



Year on year quarterly change in electricity consumption

Source: EA reconciled demand data



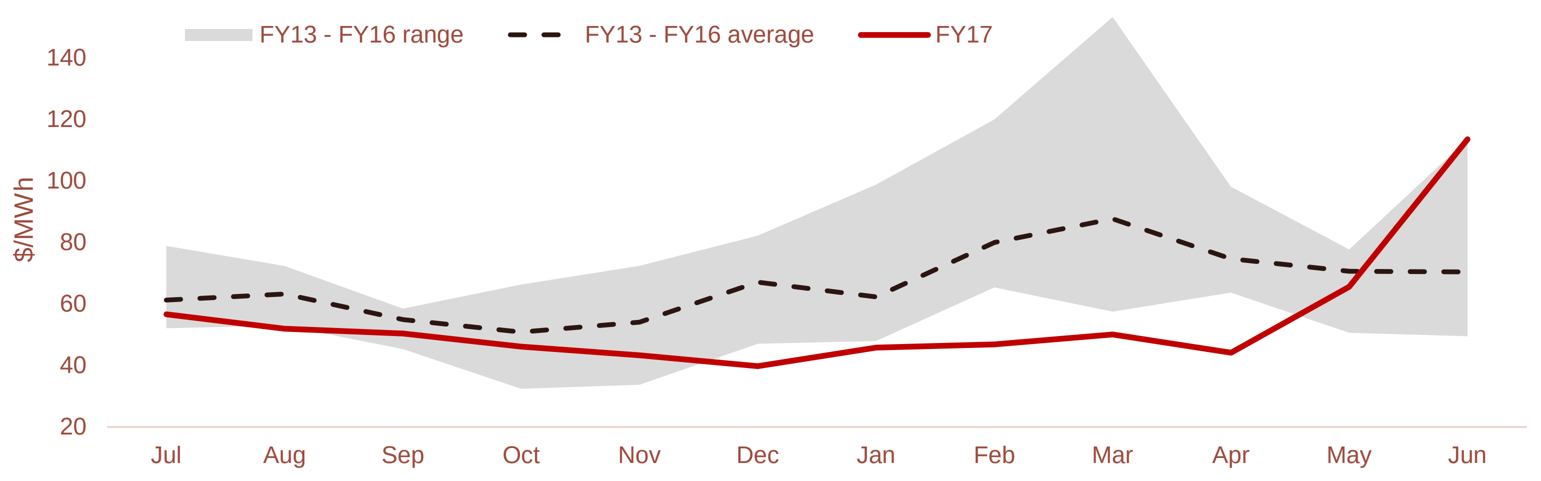
Wholesale electricity prices in the year impacted by excess hydro generation and muted demand

Tighter market supply and demand balance saw wholesale prices rise in June 2017

- For most of the year wholesale prices were weak even comparing to the prior four years, a period with excess thermal capacity, with average wholesale prices 18% below the average for this period despite the wholesale price increasing in June
- Prices were impacted by the excess hydro generation with short-dated futures prices averaging $64/MWh between November 2016 to March 2017
- Long-dated futures prices ended the year higher at $80/MWh from $77/MWh over summer FY17
- Above average hydro storage since thermal capacity retirement has masked the tighter supply demand balance. With national hydro storage down 2.3 TWh between February and June, this has now transferred into futures prices

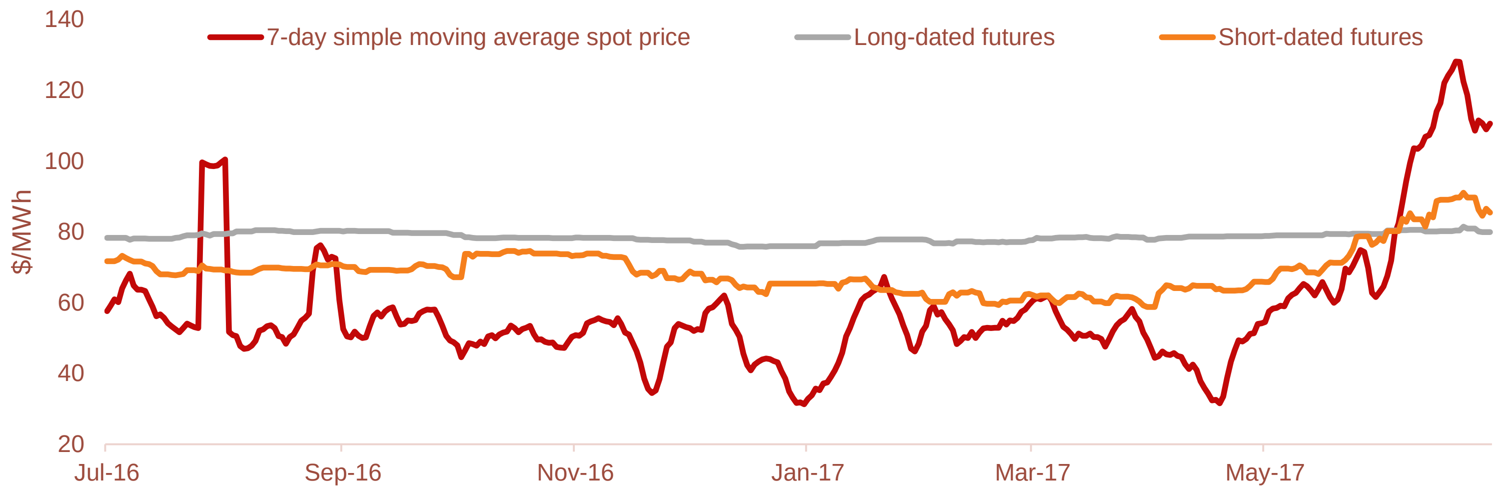
Generation weighted monthly wholesale electricity prices

Source: EA – Wholesale energy prices



Forward price curves

Source: EA – Forward price curves



Contact managed the variability in hydrological conditions using portfolio flexibility

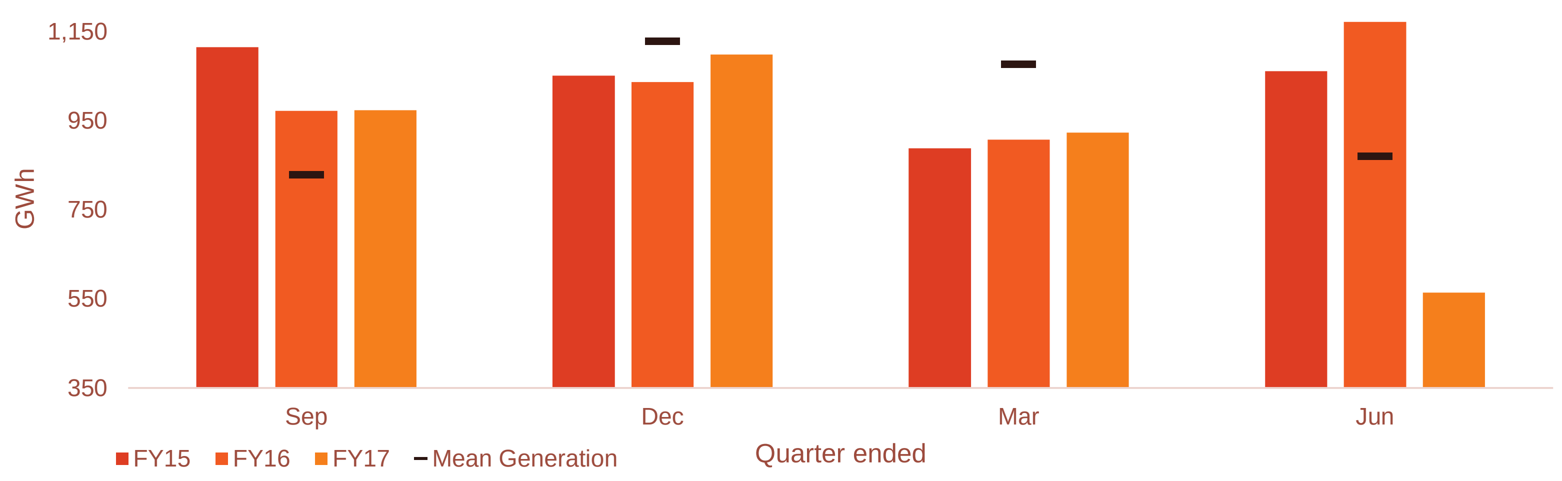
Value of Ahuroa gas storage evident in FY17

» While the market was oversupplied with hydro generation, Contact's flexible gas contracting strategy and gas storage allowed Contact to limit thermal generation while un-economic and inject excess contract and spot gas at favourable prices

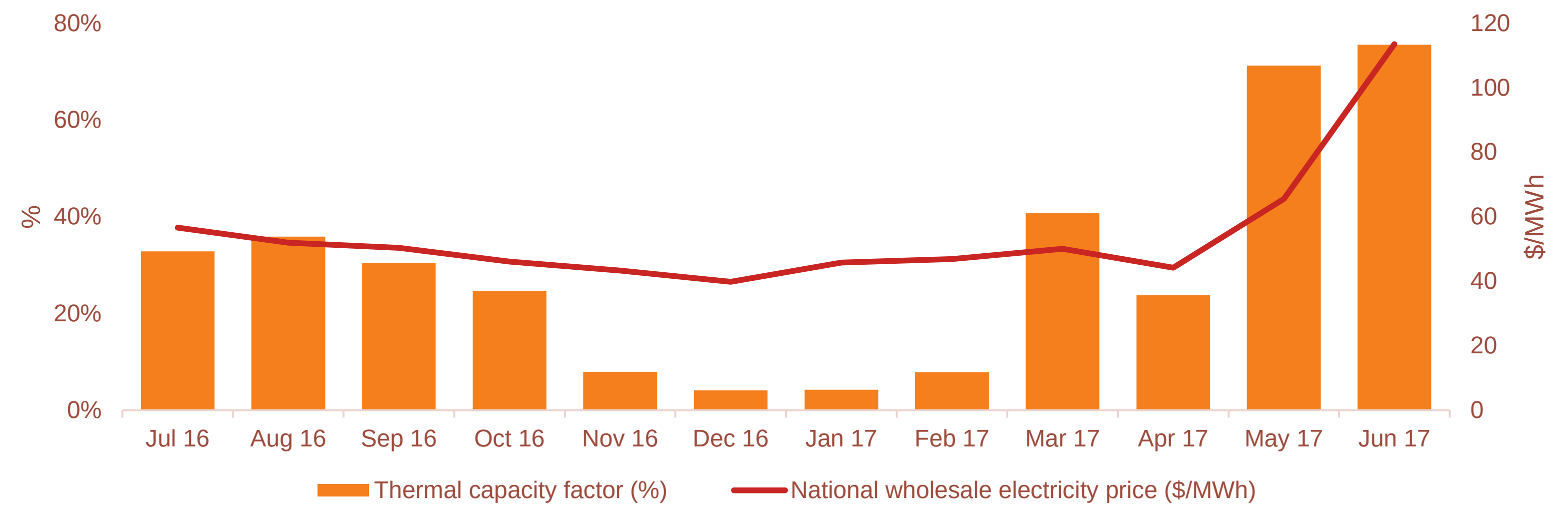
» Once South Island hydro inflows receded, Contact was able to use thermal capacity and gas storage to substitute the significant reduction in hydro generation which was an average of 280MW lower than FY16 in the final quarter

» This portfolio flexibility allows Contact to extract value by selling more load at a higher hedge level than our renewable generation only

Contact hydro generation by quarter for FY15 – FY17



Thermal utilisation by month and wholesale electricity price



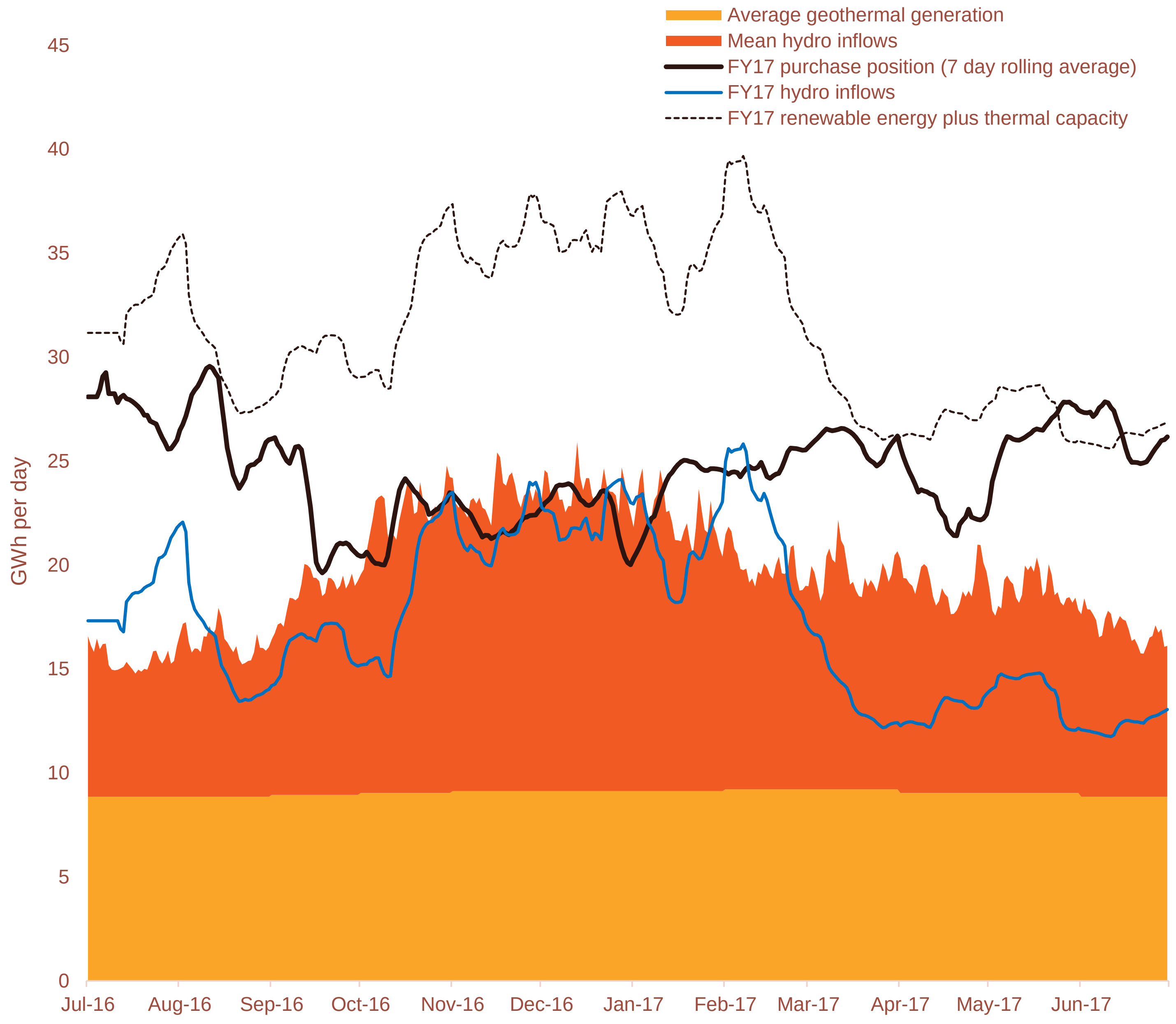
Contact seeks to maximise the value of its renewable assets

By selling all renewable generation at a fixed price

- Contact's hydro inflows typically peak during summer
- Traditionally, wholesale and futures prices are lowest between October and February
- Flexible thermal generation, limited hydro storage, gas storage and hedges allows us to "firm" the renewable variability
- Over the past 3 years this has enabled fixed priced sales at 125% of mean renewable generation, in contrast to integrated renewable generation only peers who sell between 70-85%
- Keeping our hedge level in line with peers at 70-85%, would have resulted in an annual average of 1-2 TWh per annum of renewable generation being sold into the spot / futures market at $60-70/MWh
- Over a 3 year period, the average frequency of dry sequences, we are better to be fully hedged from a cash flow perspective
- Even with current stressed market conditions, returns are inadequate to justify holding additional high fixed cost thermal plant

Contact's mean renewable energy and purchase position

Source: Contact, NZX hydro



Strong internalised risk management delivers stable cash flows despite hydrological variation

While lower hydro generation increases the cost of generation in the short-term, Contact has appropriate risk mitigations to limit exposure to prolonged adverse hydrological events

» Commodity risk management system sets limits based on total energy supply and risk on thermal plant availability

» With New Zealand gas pricing weakly correlated to the electricity market, gas storage allows for injection of cheaper gas in periods with excess hydro generation and extraction of gas in peak periods

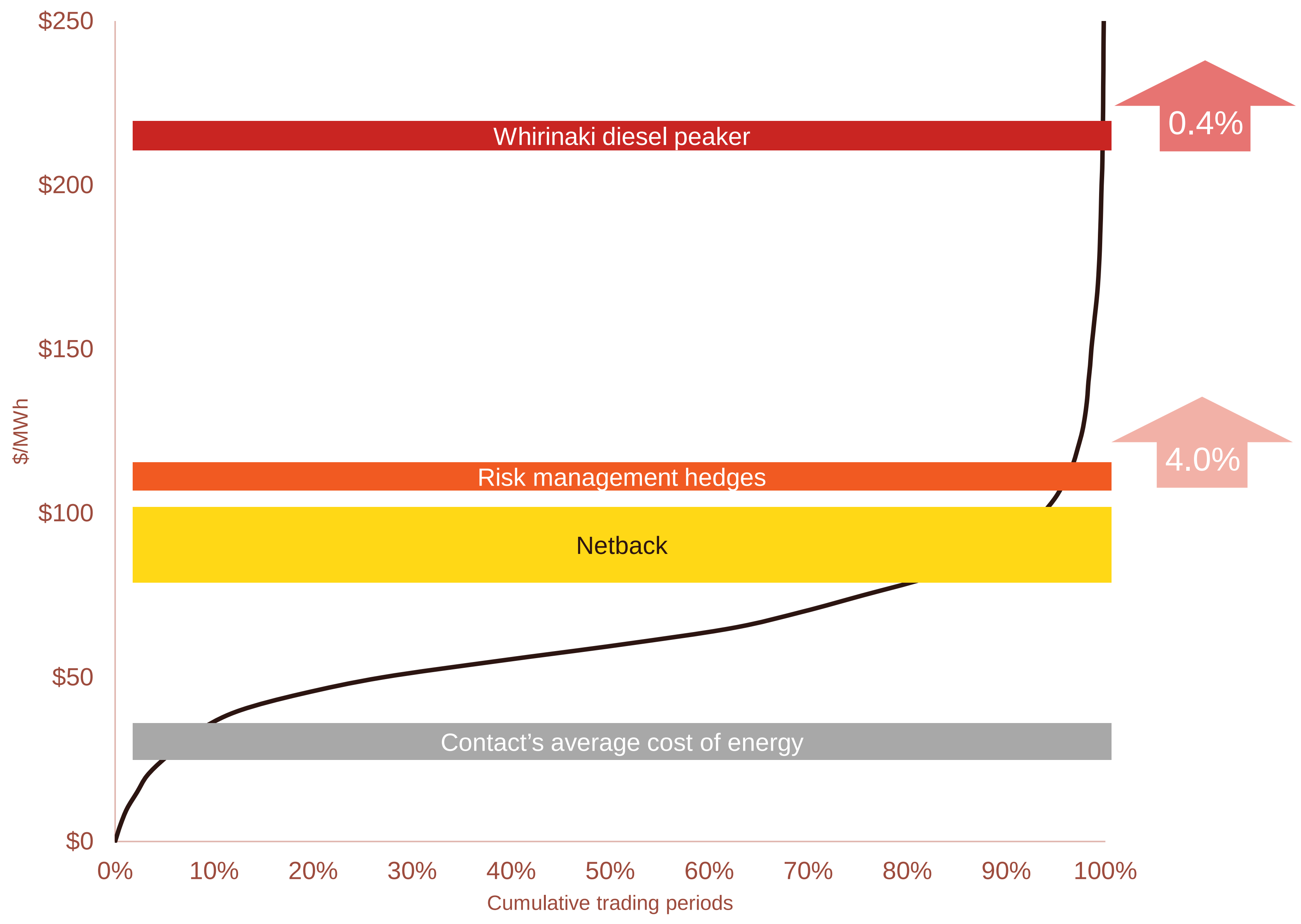
» We utilise risk management products including hedges and energy swaps

» Whirinaki diesel peaker provides internalised portfolio insurance

» Our hedge level is under constant review with a view to optimising cash flow without bearing too much risk to extreme events. With the tightened supply/demand position we may favour a less hedged position going forward

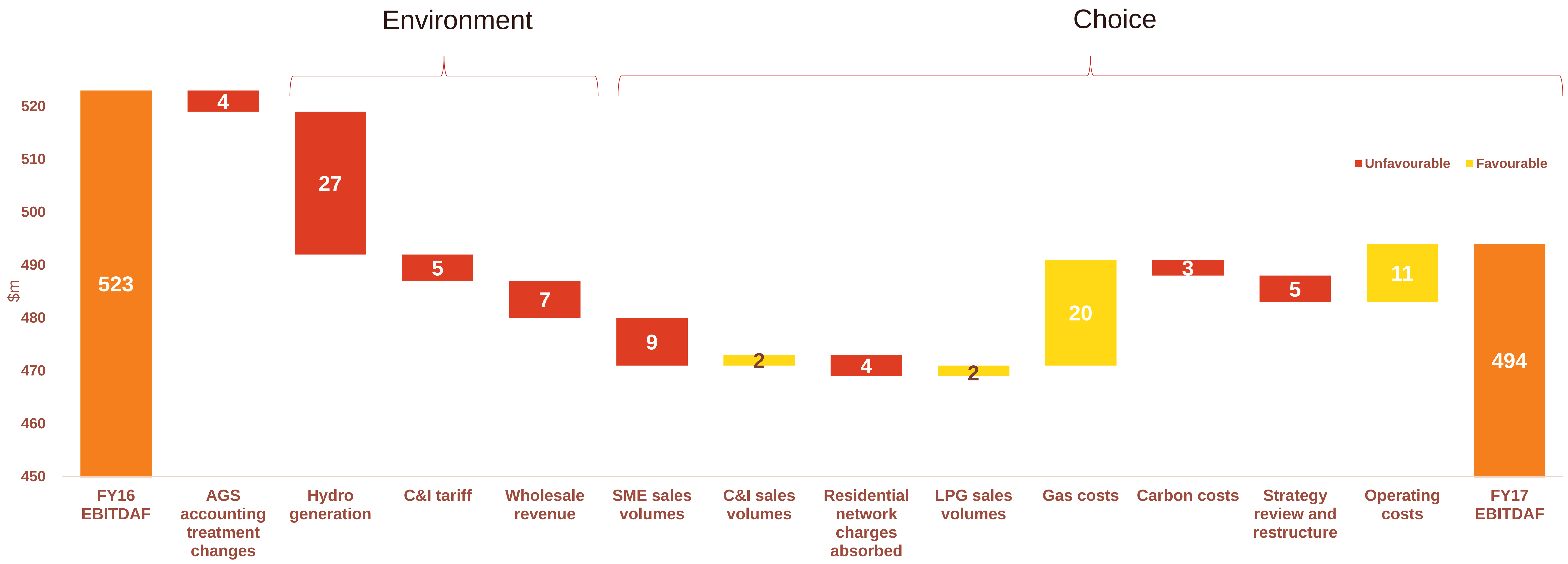
Demand-weighted average wholesale energy prices by trading period (FY15 – FY17)

Source: EA



Portfolio flexibility positions Contact to manage short-term adverse market outcomes

With strong internalised risk management and by delivering operational performance improvements



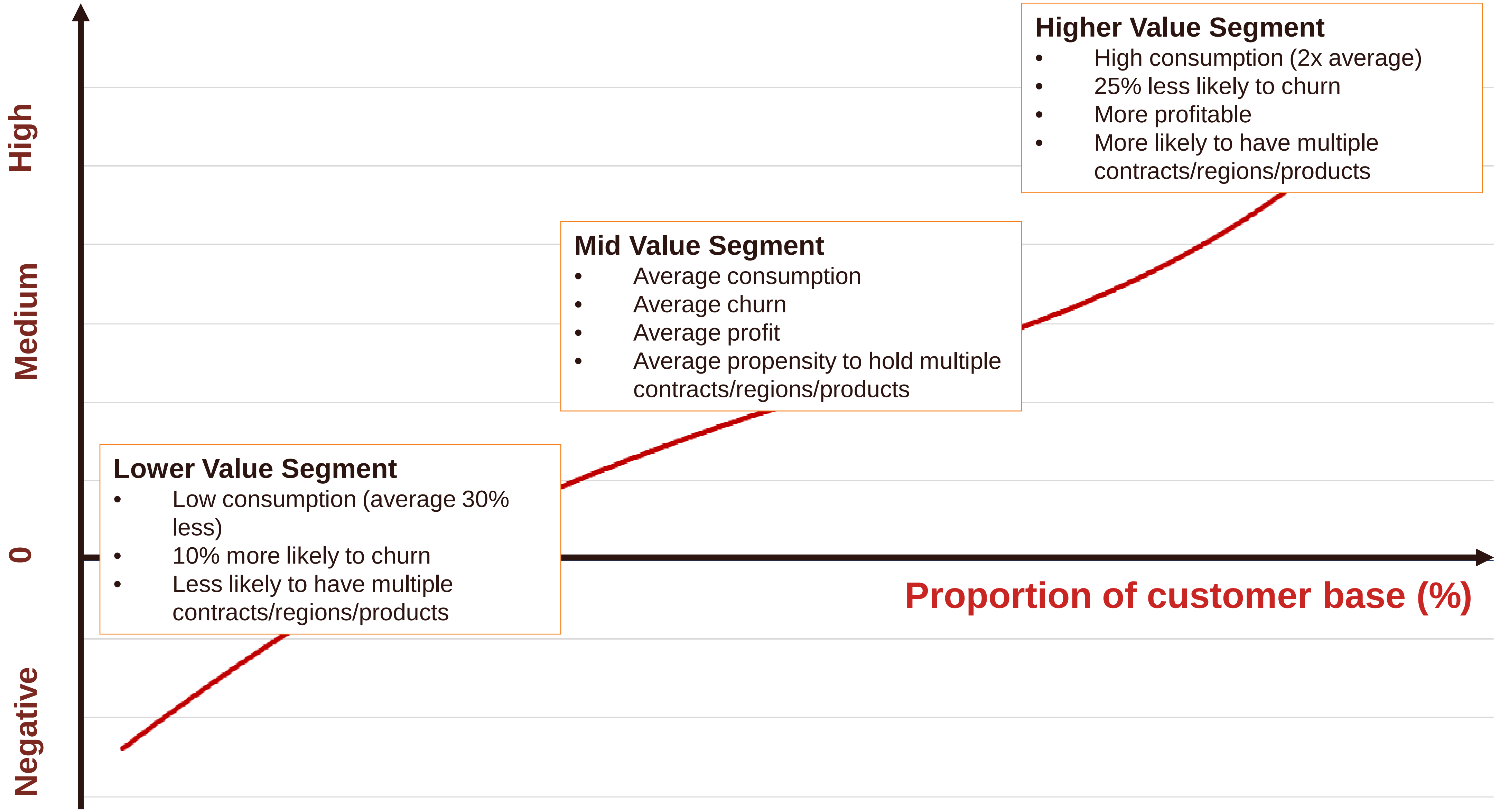
Channel optimisation driven by CLV	Maintaining focus on the drivers of value	Transparency, efficiency and focus on controllable costs

Operationalisation of CLV allows focus on the value of an individual customer

Reduction in SME sales volumes driven by consideration of CLV rather than purely competing on price or volume

Distribution of customer base by CLV segment

Source: Contact, electricity and gas customers



» Across this distribution, customers demonstrate different behaviours, moving up the value curve is linked with higher consumption, a lower likelihood to churn and a higher propensity to hold multiple products

» We are starting to manage customers differently across this distribution

» This view lets us take appropriate actions for each customer segment in an attempt to move them up the value curve

» As a result of this insight, Contact did not re-contract 115 GWh of SME sales volumes and sold additional C&I volumes for a net FY17 EBITDAF impact of $7m

Contact seamlessly executed on significant changes to energy product and reward offers

Contact delivered products and services that customers want and value

- » Fresh customer-centric products, enabled by SAP, launched in August 2016
  - » Innovative data driven retention strategies successfully managed the 1 August 2016 roll-off of 35,000 customers
- » Energising fuel reward plans launched in April 2017 provides customers with compelling fuel discounts
  - » Actionable customer insight into highly engaged customers, through partnership with AA Smartfuel
- » Delivered phase 1 of our digital programme which included website redesign to drive self serve and improve the customer experience

While maintaining focus on the key drivers of value in the Customer business

- » Mass market electricity netback stable despite absorbing network cost increases in April
  - » Contact price changes for some mass market electricity customers from 1 August 2017
- » Residential electricity sales volumes marginally up on FY16, offset by volume reduction in SME as a result of the consideration of CLV
- » C&I sales volumes flat on FY16, with margins negatively impacted by lower tariff's and an increase in CfD sales
- » LPG and gas sales volume growth offset product cost increases

Customer EBITDAF **+$3m**

Cost to serve (CTS) **Flat**

compared to FY16

Operational efficiency and transparency leading to a reduction in ongoing operating costs

Transparency of performance is driving focus

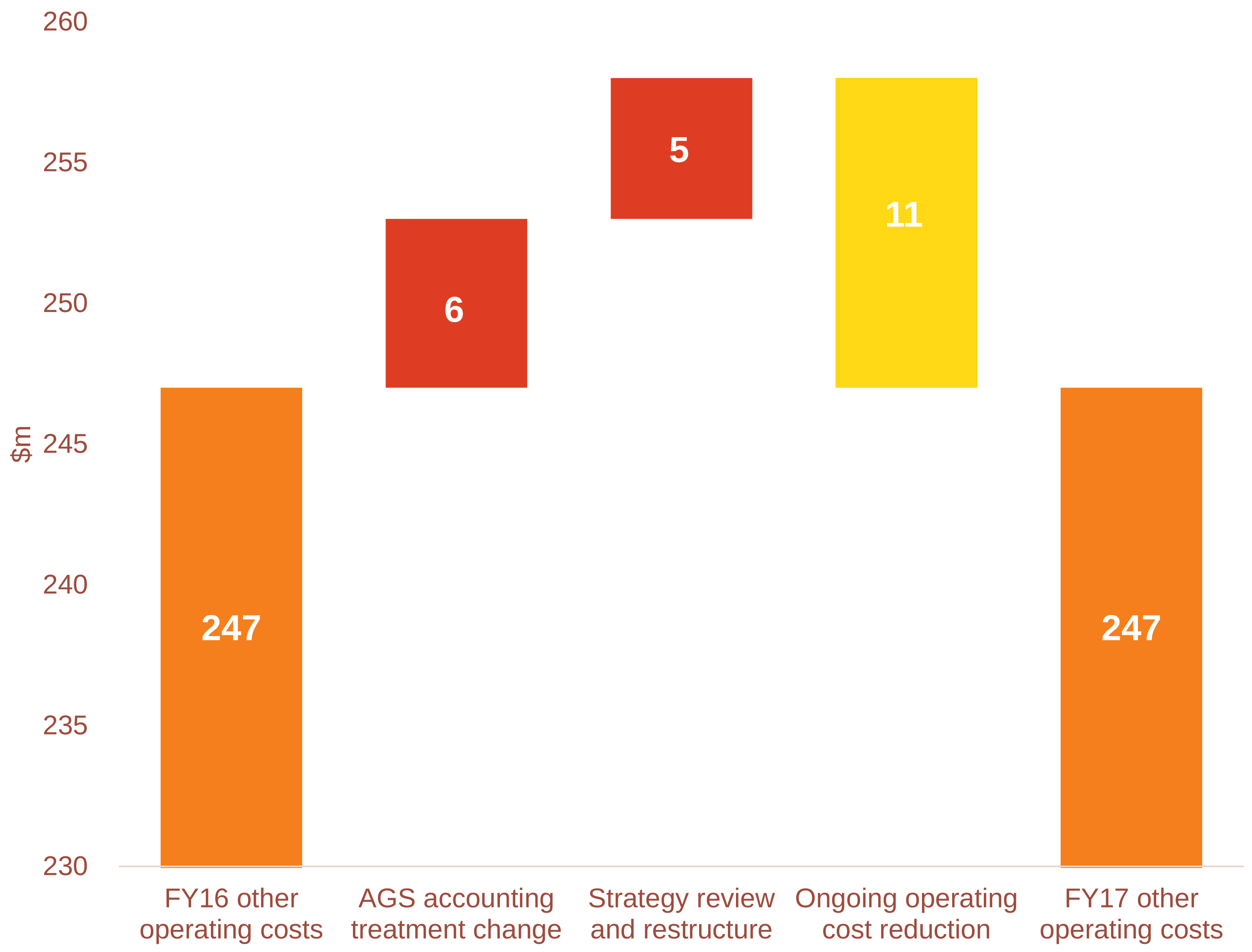
» Fixed costs to operate Ahuroa gas storage have also now been included under other operating costs from FY17, this improves the transparency and focus on these costs

» During the year we have moved to report the performance of our Customer and Generation businesses separately. The focus this brings is used to monitor and drive improved performance

» In the year we completed a strategic review which confirmed our strategy prior to committing to a distribution policy change. This review also led to a reduction and realignment of our corporate services functions resulting in $5m in restructuring costs

» Performance initiatives implemented have seen ongoing operating costs reduce by $11m on FY16

FY17 operating efficiency cost gains



Operational and financial review

Graham Cockroft

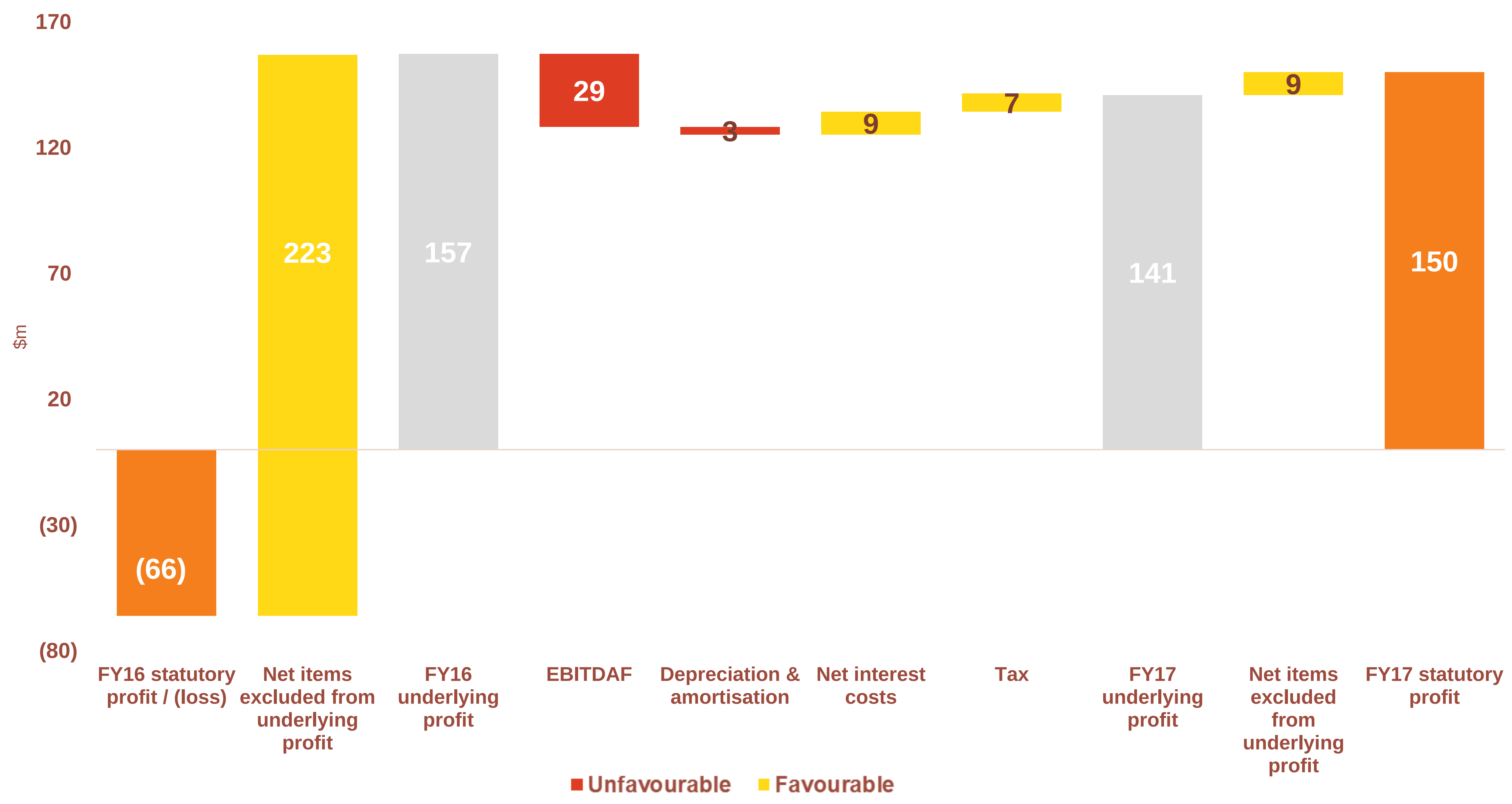
FY17 Results Presentation

14 August 2017
Contact Energy Limited

Statutory profit of $150m, up $216m with prior period impairments not repeated

Underlying profit down 10% from $157m in FY16 to $141m

Contact's statutory profit



Financial performance compared to FY16

» Underlying profit of $141m, was down $16m (10%), reflecting the $29m reduction in EBITDAF, which resulted in lower tax (-$7m)

» Net interest costs reduced by $9 million on lower average interest rates and a reduction in average debt

» The net significant items excluded from underlying profit in the current period were the increase in the fair value of financial instruments (+$23m), transition costs relating to the ICT change and transition programme (-$7m) and an estimate to address historic non-compliance with the Holidays Act (-$5m). The tax expense associated with these significant items was (-$2m)

Transfers of value between the two segments appropriately reflect market conditions

Inter-segment electricity and gas transfer price

» The fixed price, variable volume transfer price between the Customer and Generation segments is set in a manner similar to transactions with independent retailers to enable an accurate picture of the financial performance of each segment.

Mass market electricity

» A prudent retailer, offering fixed price variable volume products would contract their forecast load incrementally. For Customer, 90 days before the start of a quarter the electricity transfer price is fixed and takes into account:

- The simple average of ASX settlement prices for the preceding 3 years for the quarter to be contracted
- Adjustments for location, seasonality and line loss based on the Customer business load profile for preceding 12 months

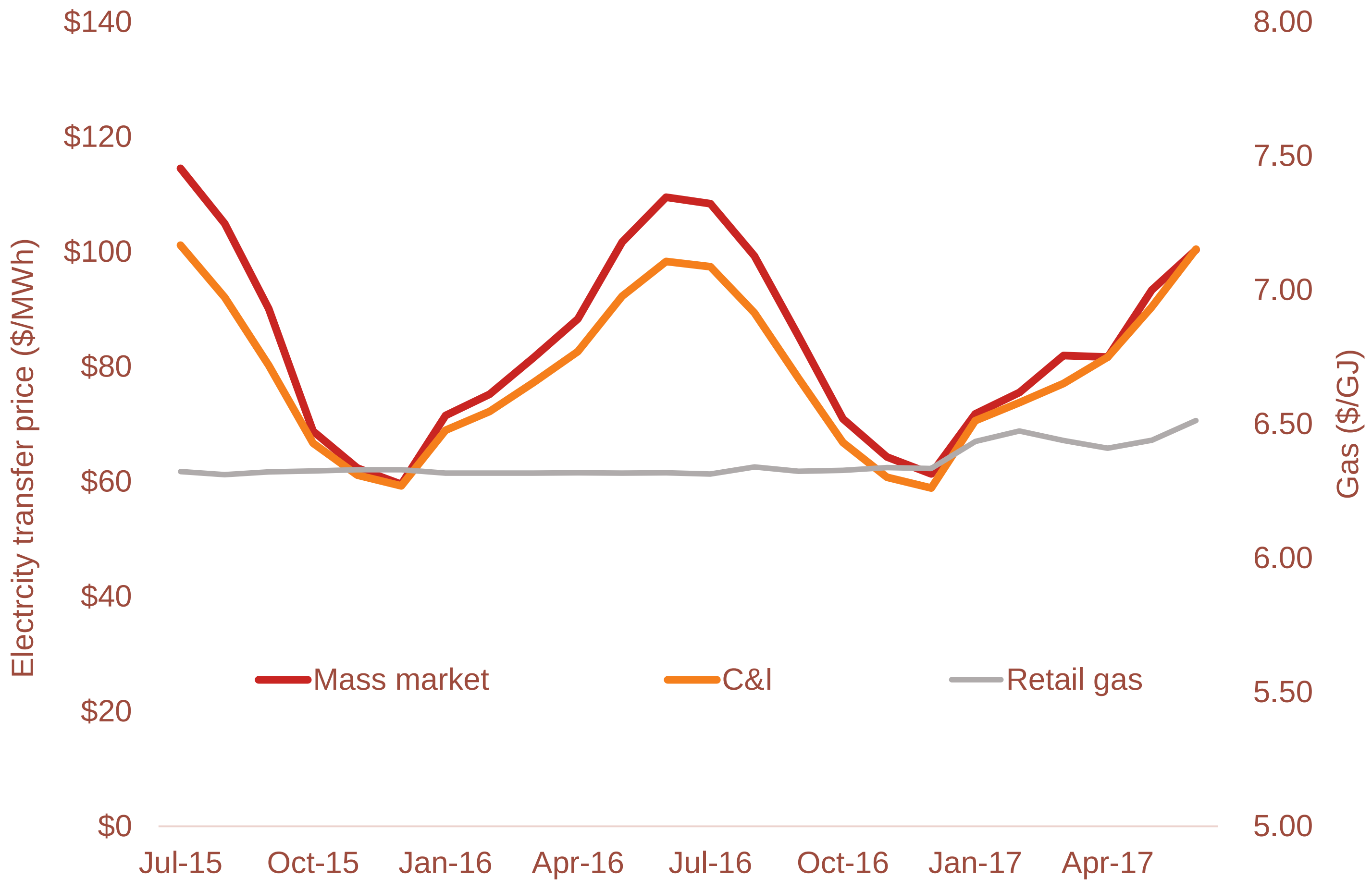
C&I electricity

» The price path agreed between Generation and Customer at the time of contracting with the C&I customer

Gas sales

» Market price for flexible gas including a carbon cost component

Inter-segment electricity transfer price



EBITDAF down $29m due to unfavourable hydrology

Customer segment

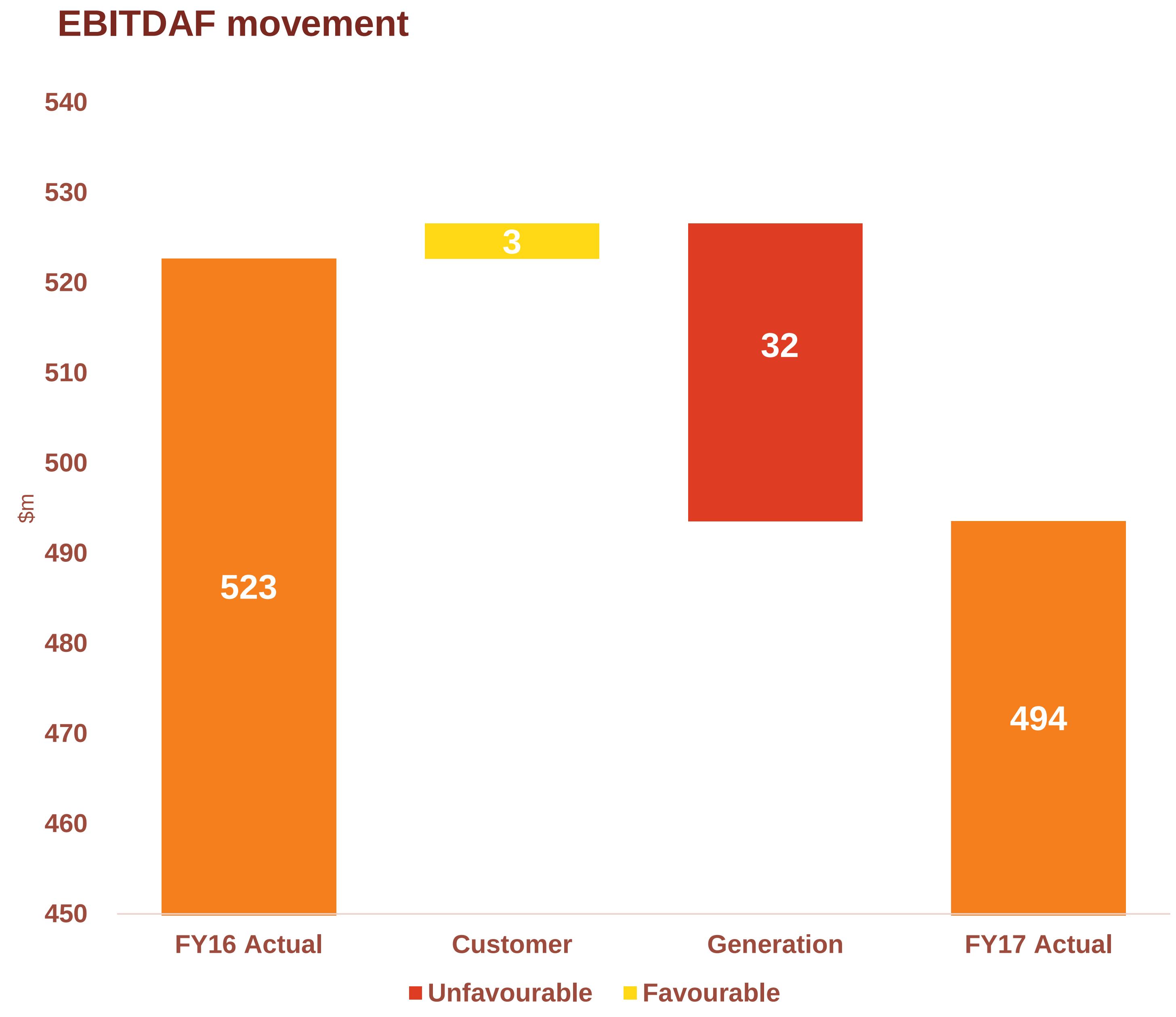
» Customer EBITDAF was $3m (4%) higher than FY16 as the Customer business expanded retail margins in a competitive market

- Electricity and gas netback was down $13m (2%) to $730m with reduced sales to SME customers and the delay in recovering residential network cost increases since April
- Electricity purchase costs reduced further than the decline in netback (+$20m) with the lower electricity transfer price and reduced electricity sales volumes (-72 GWh). Retail gas purchase costs where (-$1m) higher.
- LPG, meter and other revenue margin was down on the prior period (-$1m). LPG was up $1m and was offset by the continued decline in meters revenue (-$2m).

Generation segment

» Generation EBITDAF was $32m lower than FY16

- Cost of energy was up by $14m, to $258m, with significantly lower hydro generation in the final quarter resulting in increased thermal generation and purchase of market hedges, while weak wholesale market conditions during the first 9 months limited returns on thermal generation plant
- Electricity sales to the Customer business reduced by $20m on lower ASX pricing and reduced sales volumes

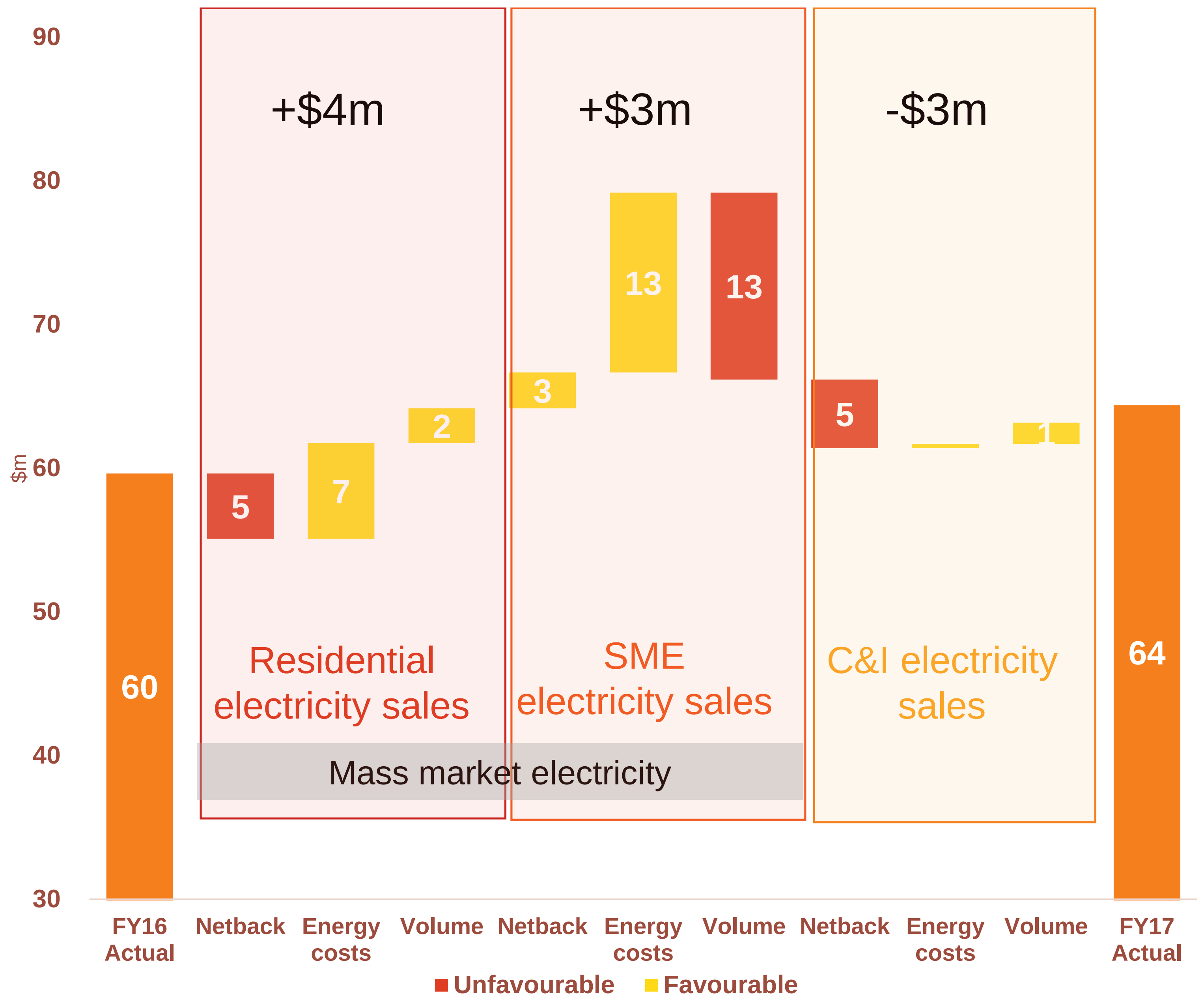


Customer EBITDAF up $3m on margin expansion across key sales channels

EBITDAF from electricity sales totaled $64m in FY17, up $4m (6%) from the prior period

- Mass market electricity sales EBITDAF increased by $7m in the period despite a 90 GWh decrease in sales volumes
  - Residential electricity sales volumes were up 25 GWh to 2,628 GWh. Netback ($/MWh) was down 2% as network cost increases were absorbed in 2H17. With ASX futures weaker, the energy cost declined by 4%. Increased sales volumes and net margin expansion / MWh saw EBITDAF up $4m to $21m.
  - SME electricity sales volumes were 115 GWh down (-10%) to 1,074 GWh. Netback ($/MWh) up 2% driven by an increase in tariff of 3%. With ASX futures weaker, the energy cost declined by 3%. While sales volumes were lower, net margin expansion by 3%. While sales volumes were lower, net margin expansion / MWh saw EBITDAF up $3m to $23m.
- C&I electricity sales EBITDAF declined by $3m in the period despite a 17 GWh increase in sales volumes
  - C&I electricity sales volumes were up 17 GWh with a 215 GWh increase in Customer CfD sales. Netback ($/MWh) was down 1% , more than the decline in the intersegment energy cost with a higher proportion of sales to lower margin CfD customers. C&I EBITDAF reduced by $3m to $20m.

Customer segment EBITDAF movements



Strong increases in gas and LPG sales volumes, meters revenue continues to decline

EBITDAF from gas, LPG and meters totaled $47m in FY17, down $1m on declining meters revenue

» Retail gas sales EBITDAF of $11m was flat on the prior period

  » Residential gas sales volumes up by 1 GWh, netback and energy costs in line with FY16, FY17 EBITDAF was unchanged at $6m

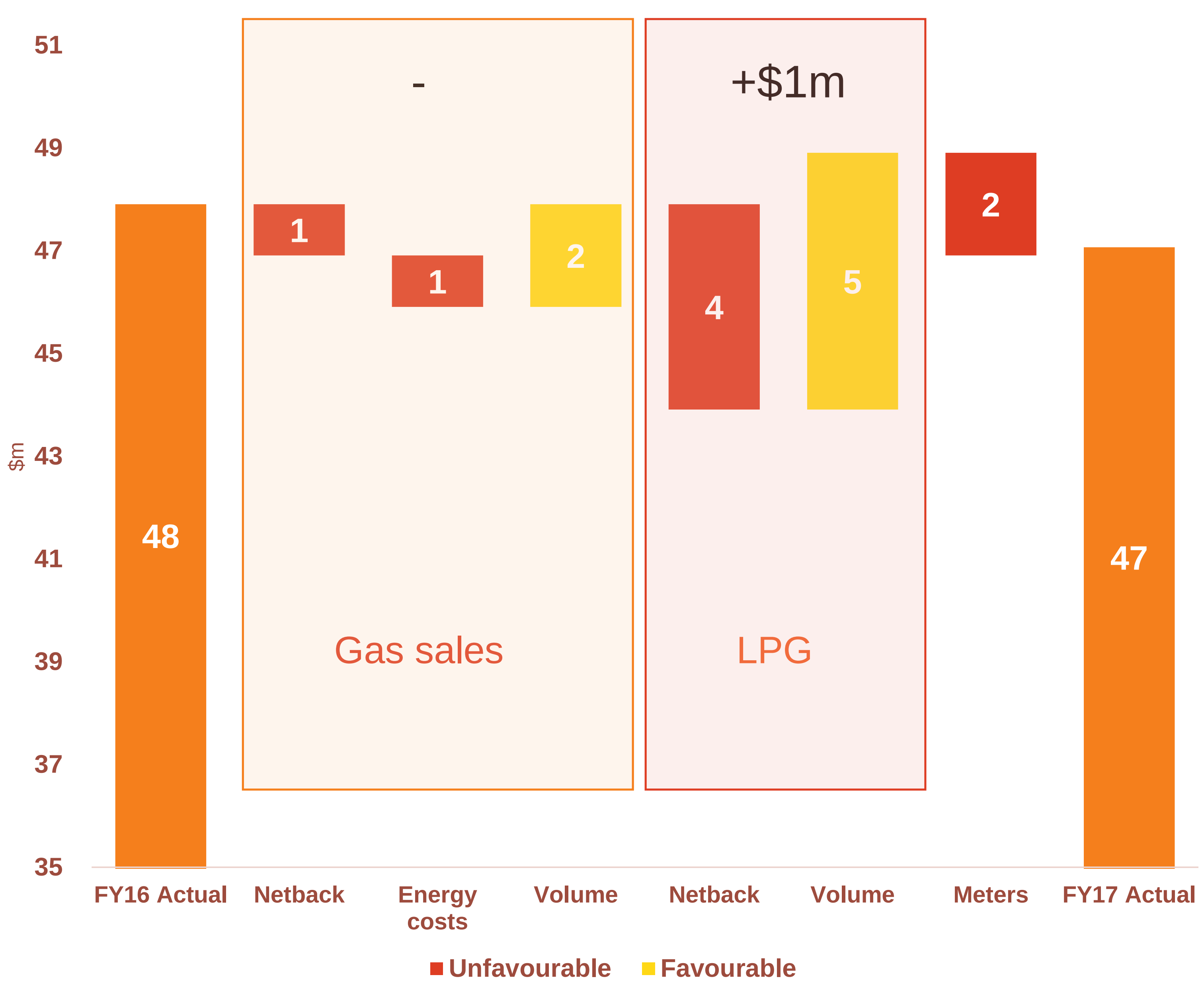
  » SME and C&I gas sales were up 65 GWh (+36%) to 245 GWh. Netback ($/MWh) down 14% with tariff down 5% and network costs up 22%. EBITDAF of $5m was unchanged on FY16

» LPG EBITDAF was up $1m in the period to $33m

  » LPG sales volumes were up 3,000T as Contact added over 4,000 new LPG customers. Netback ($/T) was flat on the prior period as tariff increases were offset by an increase in operating costs. Product costs increased by 1% on the back of summer imports and higher international prices between January and March.

» Meters EBITDAF was down $2m in the period to $3m

Customer segment EBITDAF movements continued



Renewable generation volumes and energy price impacted Generation EBITDAF

Generation EBITDAF down by $32m (8%). Led by a $14m (6%) increase in the cost of energy and a $20m (3%) reduction in electricity sales revenue from Customer

» Fuel mix unfavourable by $27m with an 8% (593 GWh) reduction in renewable generation

- » Hydro generation of 3,562 GWh, was down 529 GWh (13%) on FY16 and significantly below the annual mean of 3,900 GWh
- » Geothermal generation was down 64 GWh, or 2% to 3,233 GWh, after an extended Te Mihi outage

» Wholesale spot market returns down $16m as low wholesale prices limited the opportunity for economic thermal generation

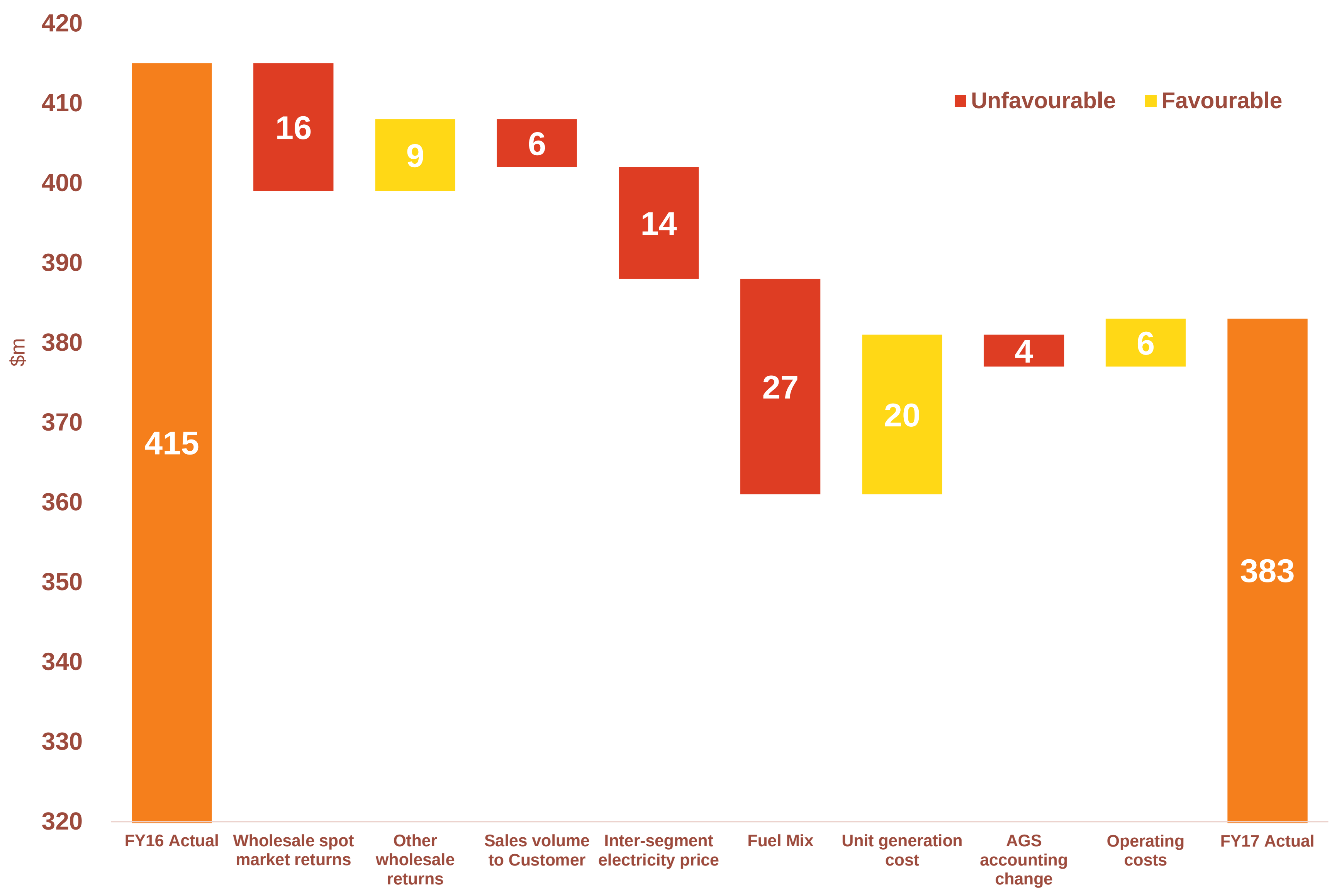
» Wholesale financial market returns up $9m on increased CfD sales

» Electricity sales to the Customer business reduced by $20m with lower ASX pricing ($14m) and reduced sales volumes ($6m)

» Unit generation cost favourable by $17m with lower unit gas costs and lower gas transmission ($20m) partially offset by increasing carbon costs (-$3m)

» The change in accounting treatment in FY17 for the costs incurred in operating Ahuroa gas storage reduced EBITDAF by $4m over FY16

Generation segment EBITDAF movement



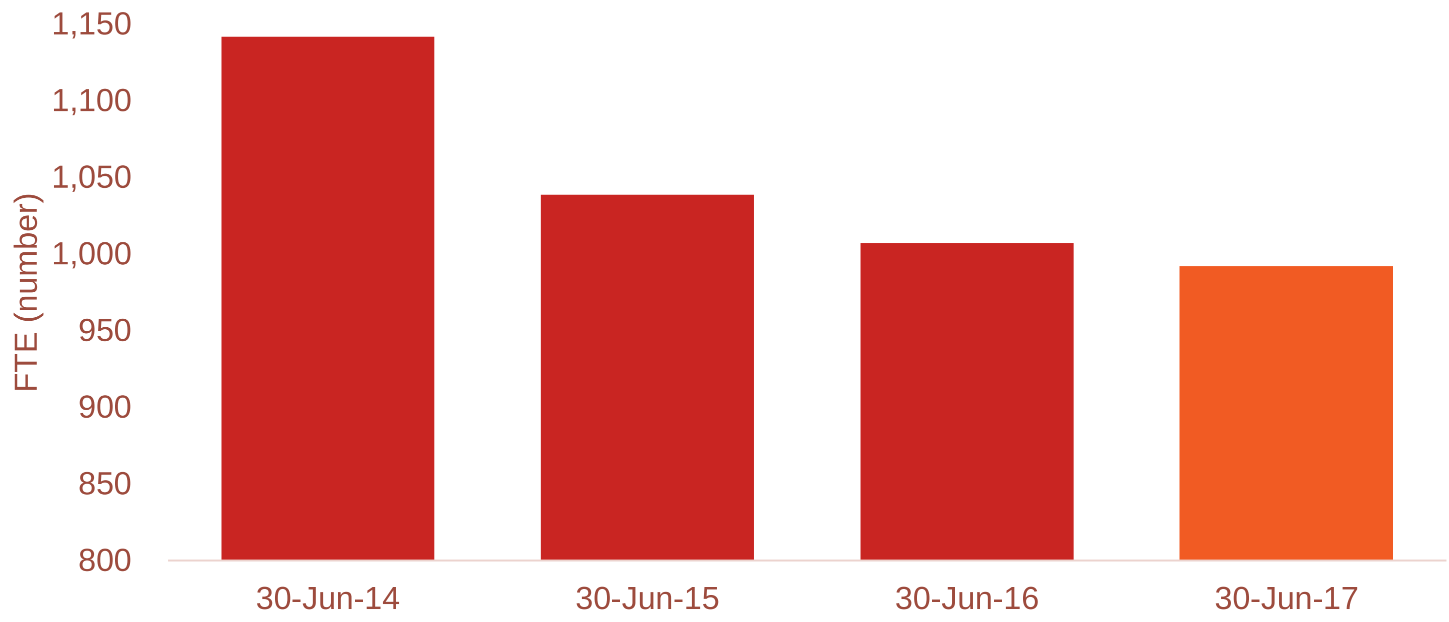
Focus continues on the reduction of both operating and capital expenditure

Other operating expenses

» FY17 other operating expenses were in line with FY16 but down $11m on a like-for-like basis (after excluding Ahuroa gas storage and strategy review and restructure costs)

- Labour costs down primarily due to reduced FTE and lower incentive payments ($4m)
- Continued improved debt management with lower bad debt write-offs ($3m)
- Lower insurance and ACC costs ($4m)

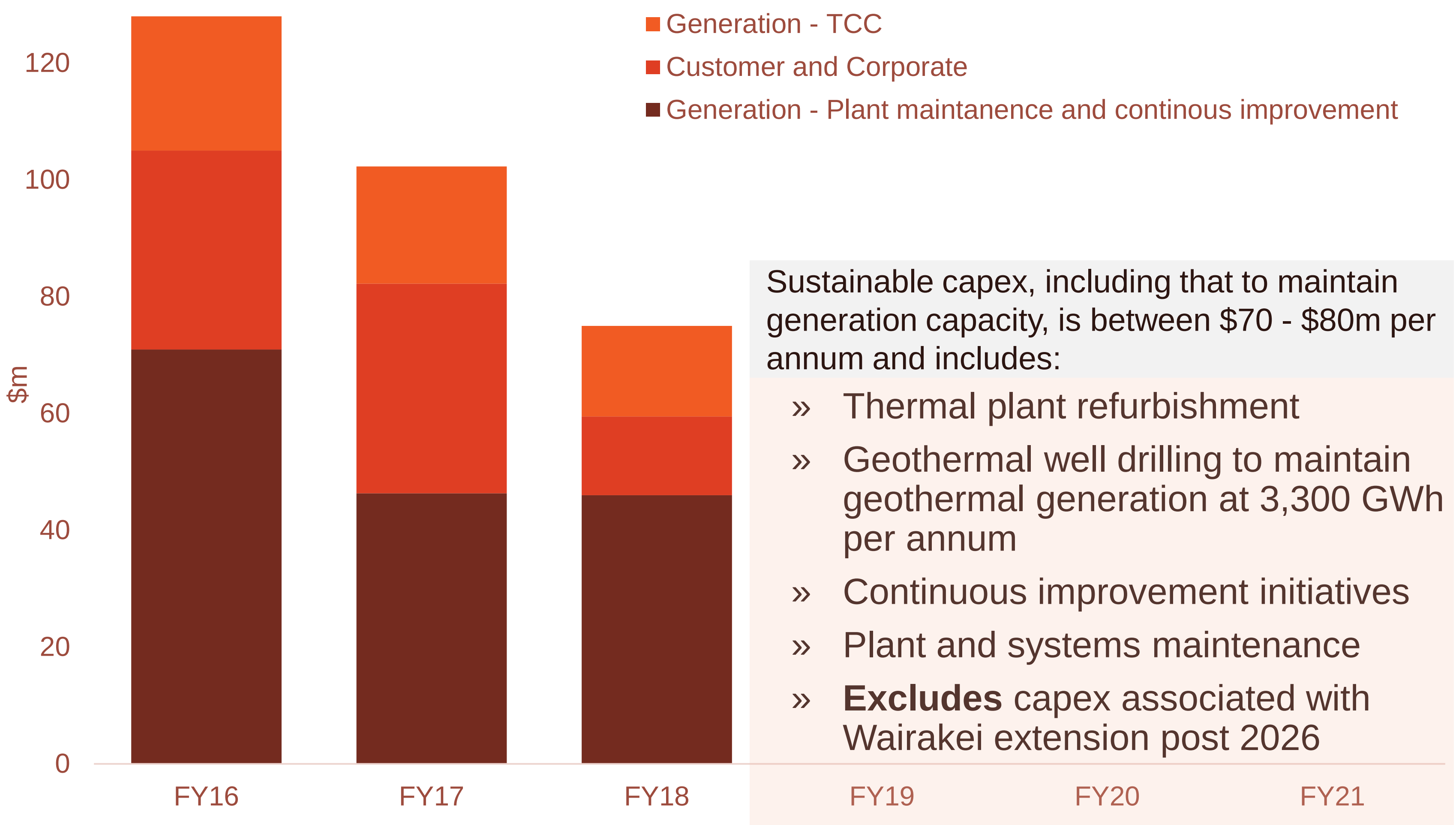
Contact FTE as at 30 June



Capital expenditure and targets

» FY17 capex $102m, $26m lower than FY16

» FY18 capex expected to be $75m, including $15m to complete TCC refurbishment



Sustainable capex, including that to maintain generation capacity, is between $70 - $80m per annum and includes:

» Thermal plant refurbishment

» Geothermal well drilling to maintain geothermal generation at 3,300 GWh per annum

» Continuous improvement initiatives

» Plant and systems maintenance

» **Excludes** capex associated with Wairakei extension post 2026

Operating free cash flow per share down 14%

Following the normalisation of tax paid and lower operating earnings compared to the prior year

» The definition of stay in business capital expenditure was refined during the year to include spend on restoration / environmental rehabilitation and capital expenditure to increase revenue from existing assets. This increases the hurdle for capital expenditure to be excluded from operating free cash flow.

$m	Year ended 30 June 2017	Year ended 30 June 2016	Variance on FY16 $m	%
EBITDAF	**494**	**523**	**(29)**	(6%)
Tax (paid)/received	(37)	1	(38)	
Change in working capital net of non-cash, investing and financing activities	41	22	19	86%
Non-cash items included in EBITDAF	12	20	(8)	(40%)
Significant items, net of non-cash amounts	(8)	(10)	2	20%
Operating cash flows	**502**	**556**	**(54)**	(10%)
Net interest paid	(86)	(93)	7	8%
Stay in business capital expenditure	(116)	(111)	(5)	(5%)
Operating free cash flow	**300**	**352**	**(52)**	(15%)
Proceeds from sale of assets	9	27	(18)	(67%)
Free cash flow	**309**	**379**	**(70)**	(18%)
Operating free cash flow per share (cents)	**41.9**	**48.5**	**(6.6)**	(14%)

» EBITDAF down $29m

» Tax paid increased by $38m on FY16, with a tax refund relating to FY15 tax payments and tax benefits from the Otahuhu closure impacting the tax paid in FY16

» Favourable working capital movements of $19m following the increased use of storage gas from Ahuroa gas storage

» The cost of the $10m Stratford super core recognised in FY16, was paid in FY17. This asset was previously financed via a lease arrangement with instalment payments. Contact settled this liability with a one-off payment on favourable terms in the period.

Strong free cash flow directed to debt repayment ensures robust balance sheet

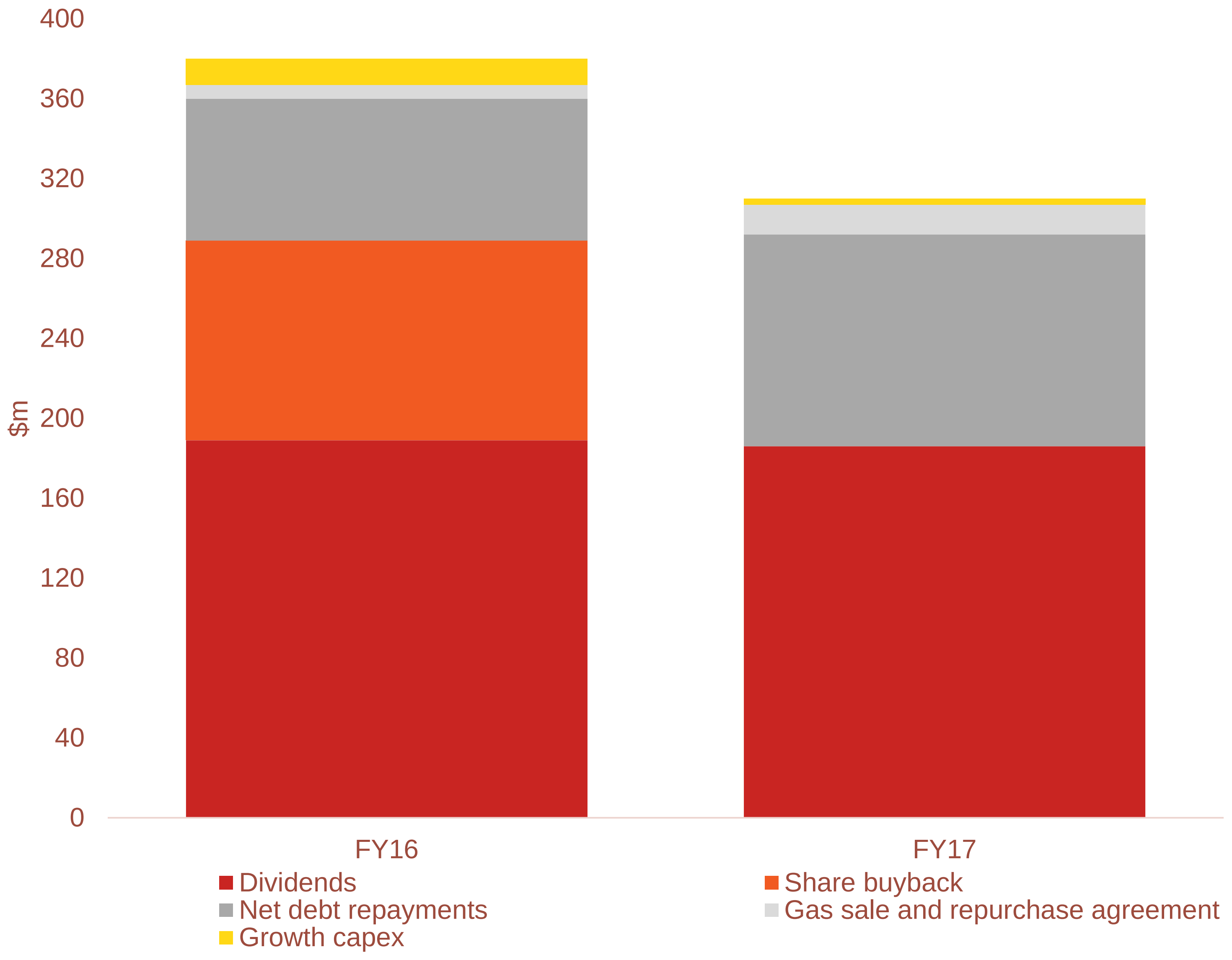
Debt reduced by $106m in FY17

- Face value of net borrowings reduced by $106m to $1,523m as surplus cash was applied to debt repayment
- Gearing reduced to 36% at 30 June 2017, down from 38% at 30 June 2016
- $177m in debt repayment since 30 June 2015

Final dividend for FY17 held stable at 15 cents per share

- 15 cents per share is fully imputed reflecting a change to the FY18 interim dividend payment date to April 2018
- Record date 31 August 2017; payment date 19 September 2017
  - The NZD/AUD exchange rate used for the payment of Australian dollar dividends will be set in early September

Uses of free cash flow



Outlook

Dennis Barnes

Strongly positioned in a competitive market

Customer

» High-performing, efficient retailer with the lowest CTS and best customer experience of the tier 1 retailers in New Zealand, with an ability to execute consistently

Generation

» Focusing on operational excellence and investment in digital approaches with clear payback will accelerate continuous improvement

Focus areas

Customer

- Sustainable cost reduction
- Digitalisation/streamline highest-priority customer journeys
- Optimise and automate processes
- Adapt IT operating model to better serve customer needs

Generation

- Sustainable cost reduction
- Innovating to lead the world in lowering the cost of geothermal energy
- Initiatives to support further decarbonisation of our energy sector

Leaner corporate centre with aligned support functions and IT programme in line with business requirements

Short-term performance impacts and opportunities

01 Mass market price changes effective from 1 August 2017

02 C&I load to be re-contracted at higher futures prices

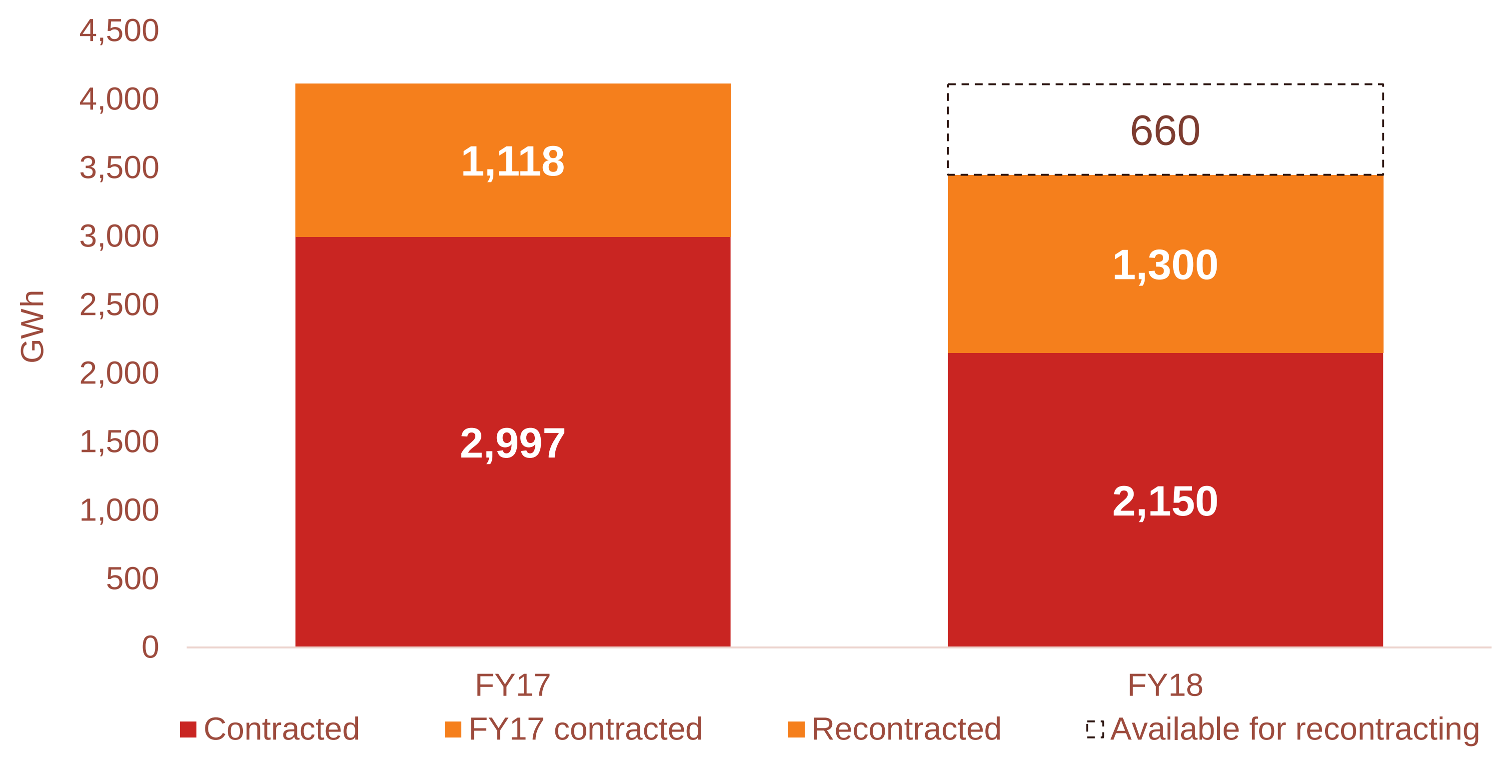
03 C&I load contracted during the summer of FY16 reflecting lower near term ASX pricing

04 Full year supplying 80MW to Meridian in support of Tiwai

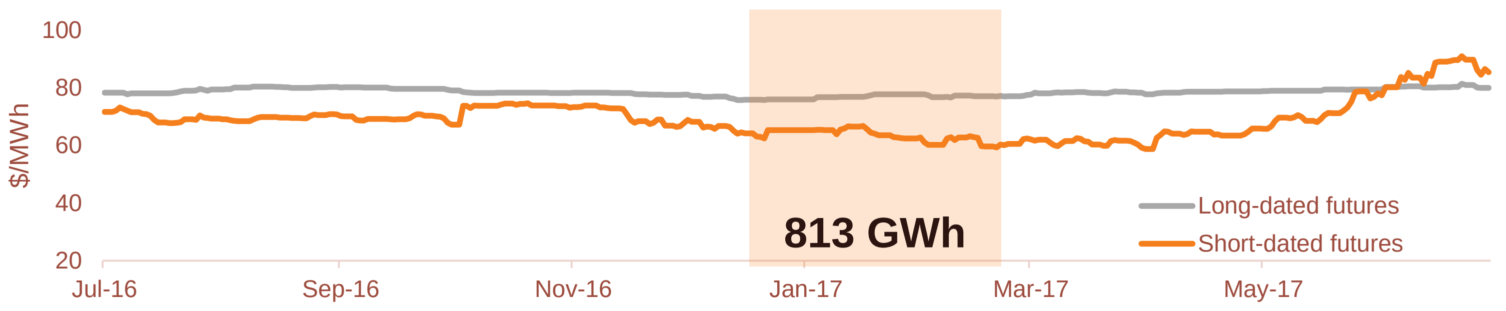
05 Record low hydro inflows, with an opening available storage of 29 GWh

06 Increasing carbon costs on higher NZU cost, transition to 1 for 1 and higher expected thermal usage

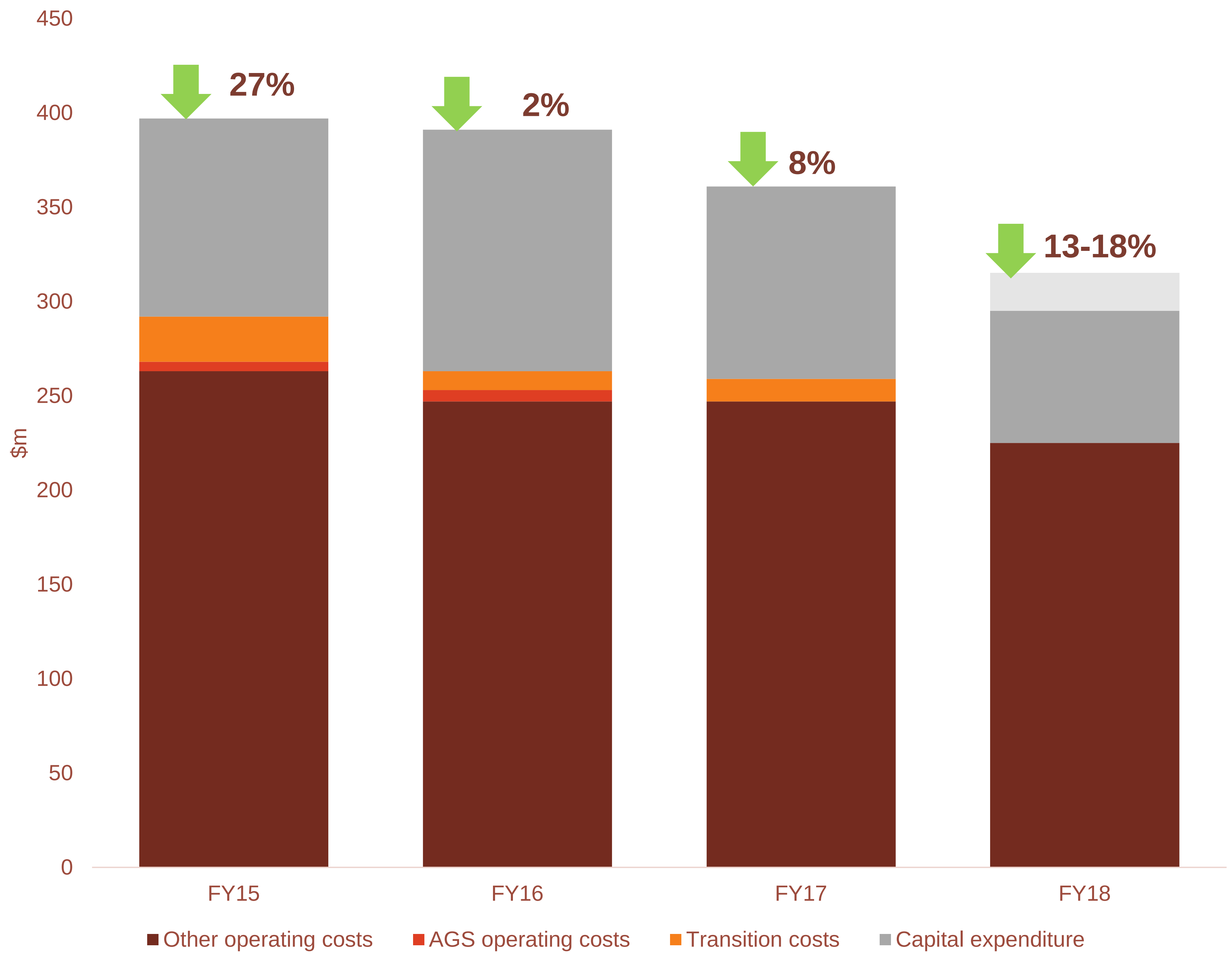
C&I load contracting profile



Bulk of FY17 load contracted during Summer



Continue to improve operating free cash flow by driving cost efficiency



	FY15	FY16	FY17	FY18
Other operating costs	$263m	$247m	$247m	$225 - 235m
Costs excluded from underlying	$24m	$10m	$12m	-
AGS operating costs	$5m	$6m	-	-
Capital expenditure	$105m	$128m	$102m	$70 - 80m
Controllable costs	**$397m**	**$391m**	**$361m**	**$295 - 315m**
Improvement on prior year	$146m	$6m	$30m	$66 - 46m

New distribution policy reflects confidence in the strength of cash flow generation

Contact will target distributions of between 80 – 90% of operating free cash flow as an ordinary dividend, on average over time, once the S&P net debt / EBITDAF ratio is below 2.8x

» Contact will provide the market with the targeted distribution for the following financial year

» Distributions are expected to be split into an interim dividend paid in April, targeting 40% of the total expected dividend, with the remainder paid as a final dividend in September

» Imputation credits will be attached to dividends to the extent that they are available

26 cps

FY17 declared dividend

62% of operating free cash flow

up +23%

32 cps

FY18 dividend target

With net debt / EBITDA currently above 2.8x, FY18 will see a transition to the new distribution policy

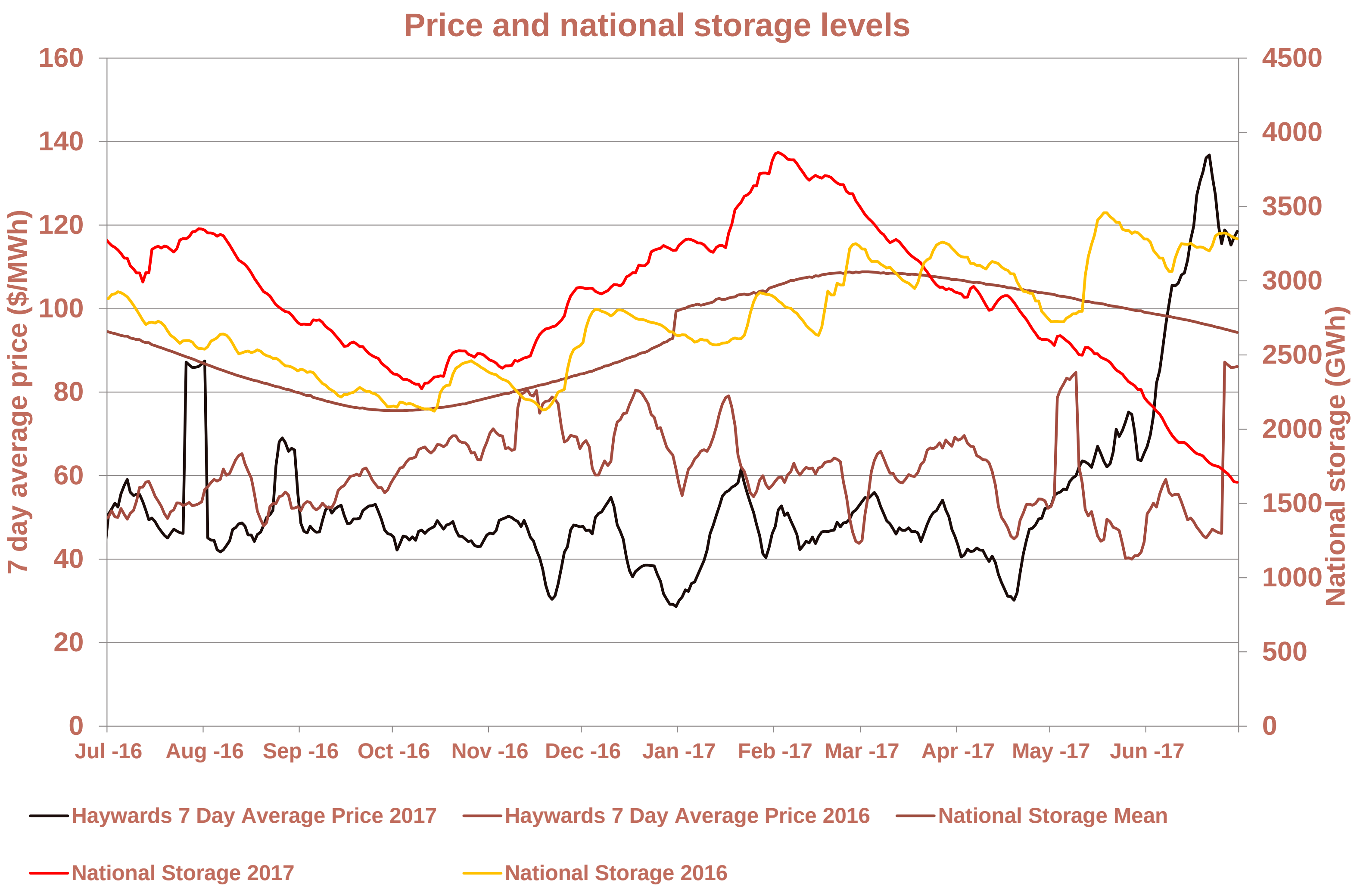
» For FY18, Contact will target to pay a dividend of 32.0 cents per share, with an interim dividend to be paid in April

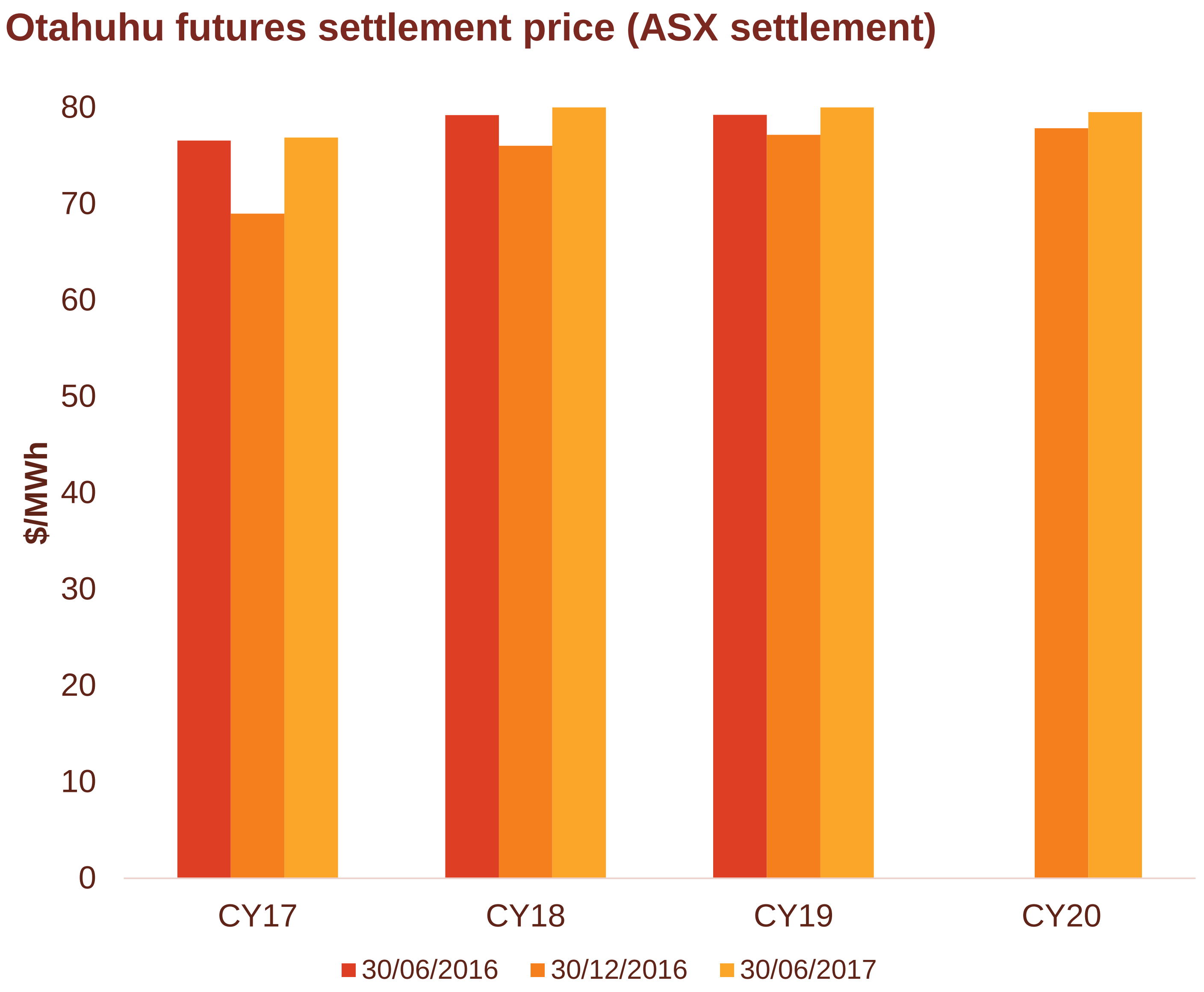
» Once the S&P net debt / EBITDAF ratio is below 2.8x, distributions will increase to target between 80 – 90% of operating free cash flow

» If the new policy were in operation for FY17 and net debt / EBITDA was below 2.8x, the ordinary dividend would be between 34 and 38 cents per share

Supporting material

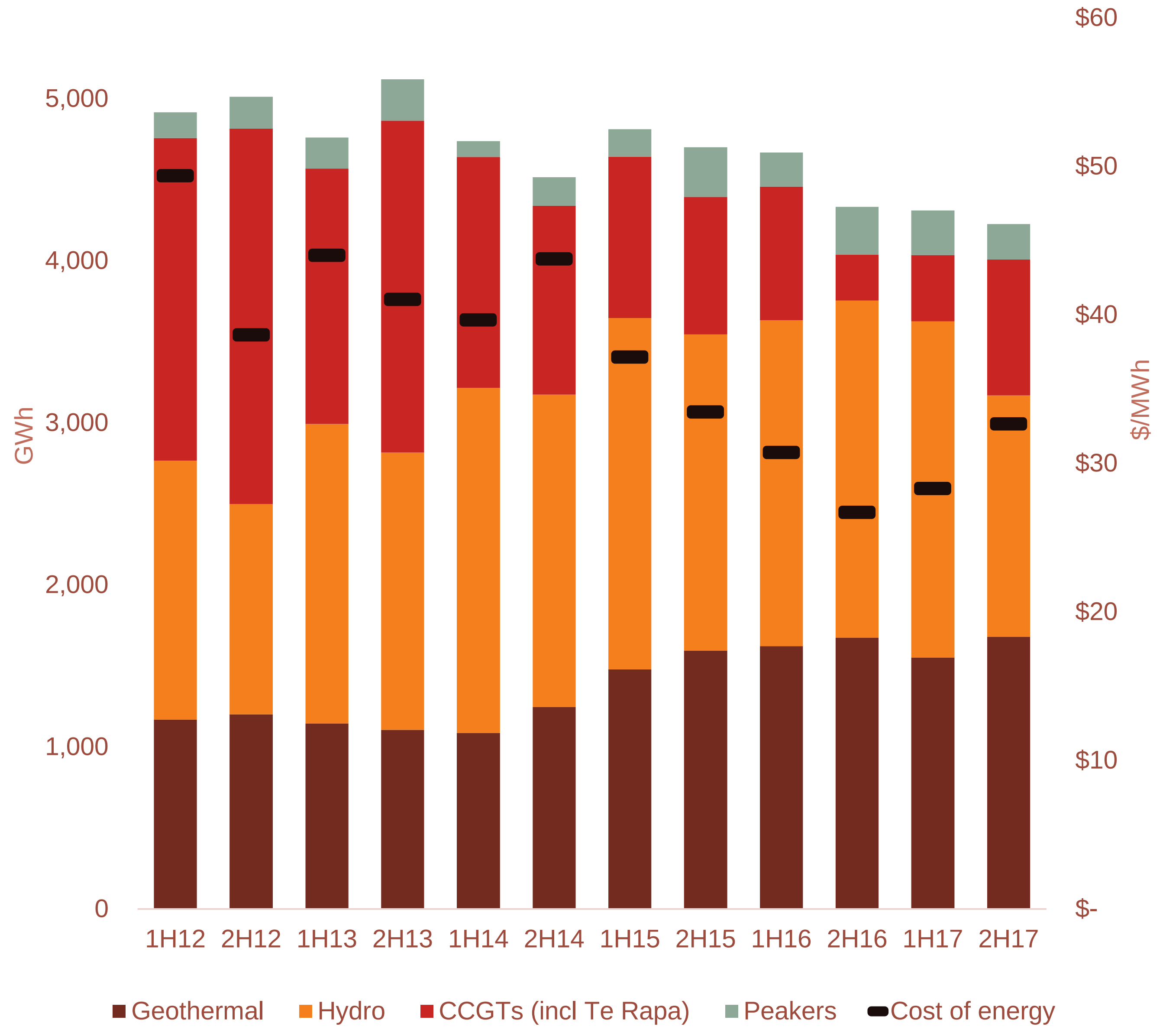
Electricity market conditions





Plant availability improved in FY17

Generation by sources



Plant reliability and generation revenue

	Gross output (MW)	Plant availability[1] FY17 (%)	Plant availability[1] FY16 (%)	Capacity factor (%)	Electricity output (GWh)	Pool revenue ($/MWh)	Pool revenue ($m)
Hydro	784	92%	89%	52%	3,562	47	169
Geothermal	429	91%	93%	86%	3,233	55	177
CCGTs	377	90%	89%	31%	1,021	64	65
Te Rapa (spot only)	41	98%	94%	63%	226	58	13
Peakers (incl Whirinaki)	360	95%	89%	16%	495	73	36
Total	**1,991**	**92%**	**90%**	**49%**	**8,537**	**54**	**460**

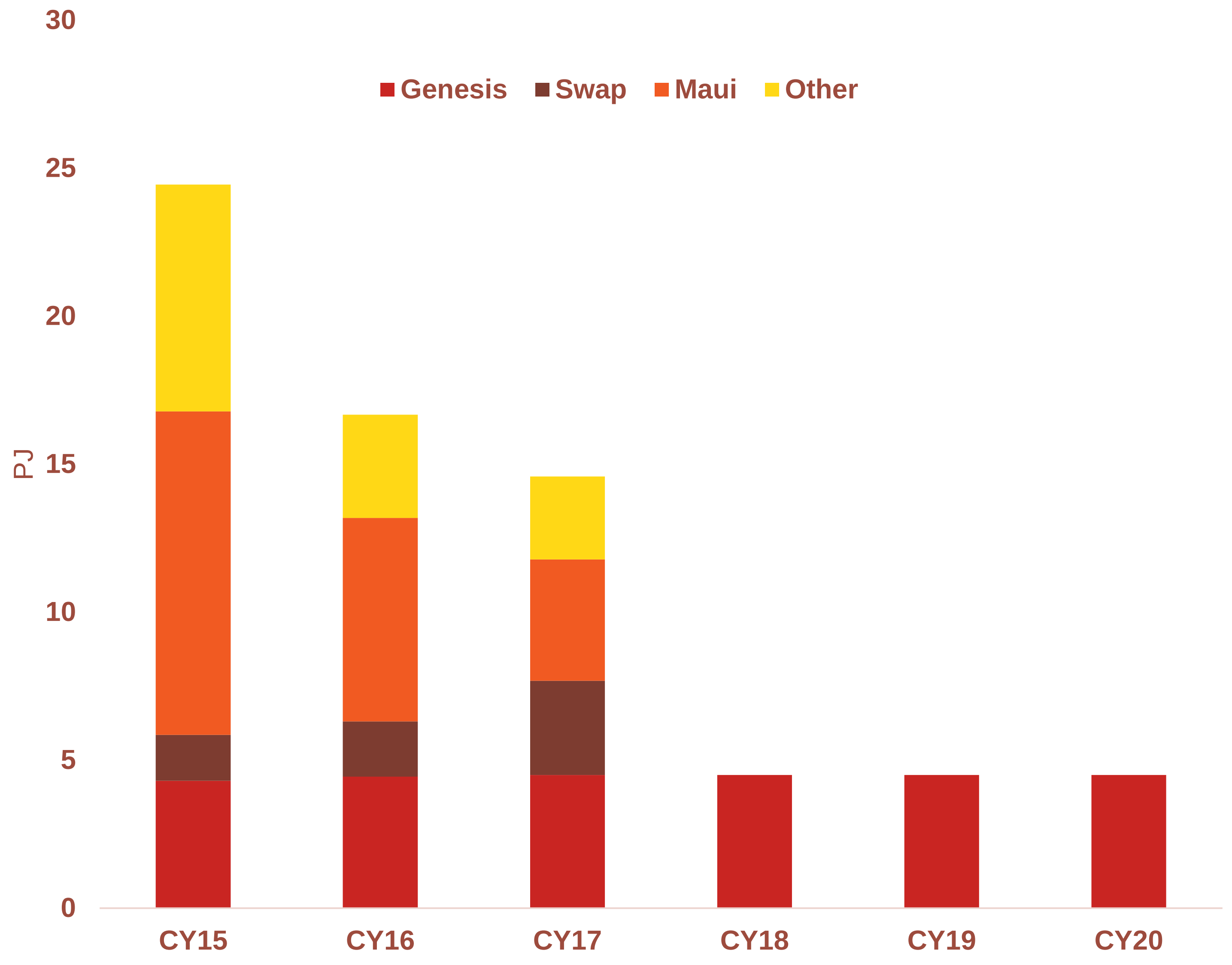
	FY17	FY16
Wairakei geothermal fluid extracted (kT)	86,793	88,700
Wairakei geothermal fluid consented (kT)	89,425	89,670
% of geothermal fluid extracted	**97%**	**99%**
Wairakei, Poihipi and Te Mihi generation (GWh)	2,710	2,764
Efficiency (MWh/kT)	31.22	31.17

[1] Measures reliability of our generation plants

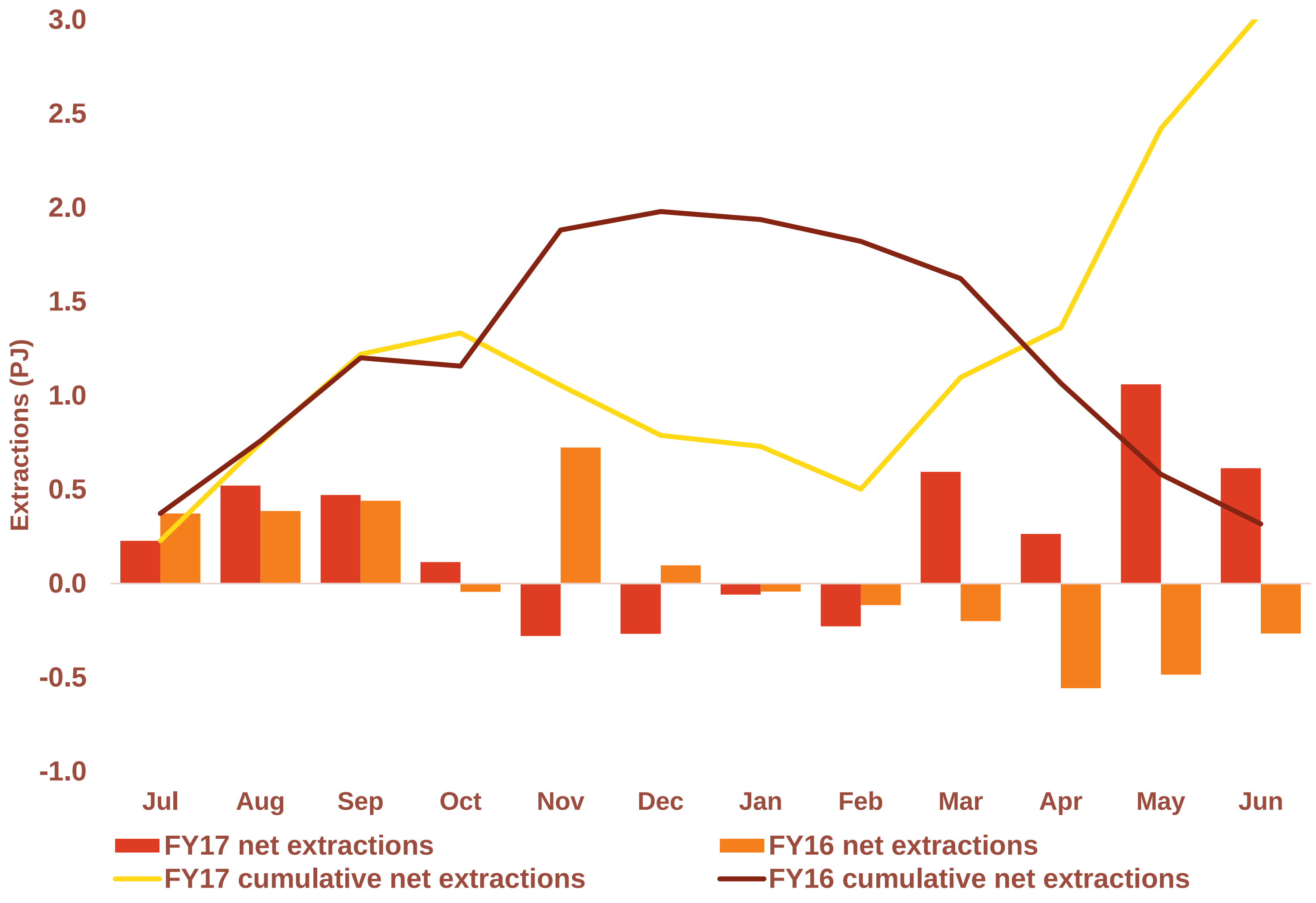
* Otahuhu last day of operation 21 September 2015

No change in contracted gas volumes with support provided by gas storage

Contracted gas volumes



Ahuroa gas storage monthly injections and extractions



» Working volume in Ahuroa gas storage at 30 June 2017 was 7.9 PJ

Contact's Green Borrowing Programme is aligned with its commitment to a low carbon future

Contact's funding portfolio has been certified as "Green" based on the Green Bond Principles and the current Climate Bonds Standard V2.1

- Contact has adopted an innovative approach to Green certification, providing debt investors and lenders exposure to a broad range of Green Debt Instruments that have been certified by the Climate Bonds Initiative (CBI) and assured by EY.
- Use of Proceeds: The Programme will be supported by Green Assets, initially comprising geothermal assets that meet the CBI criteria. Once criteria have been finalised for hydro assets, Contact will seek to include these as Green Assets.
- Green Debt Instruments in the Programme include all debt instruments in Contact's funding portfolio except overdrafts, finance leases and USPP Notes and Wholesale Bonds maturing in 2018.
- Management of Proceeds: Contact is committed to ensuring that its Programme is always at least 1.0 times covered by the value of its Green Assets (the "Green Ratio"), currently 1.03x

Certification

Climate Bond Certified

"ANZ is delighted to have assisted Contact with creation of a green borrowing programme. Advancing environmental sustainability through our key clients is core to our purpose, and Contact's approach is absolutely pioneering. Their debt investors and lenders now have exposure to a wide range of green certified debt instruments that fund low carbon activity and align to New Zealand's commitments to the Paris Agreement. That's a first, and we applaud them."

Katharine Tapley, Head of Sustainable Finance, ANZ

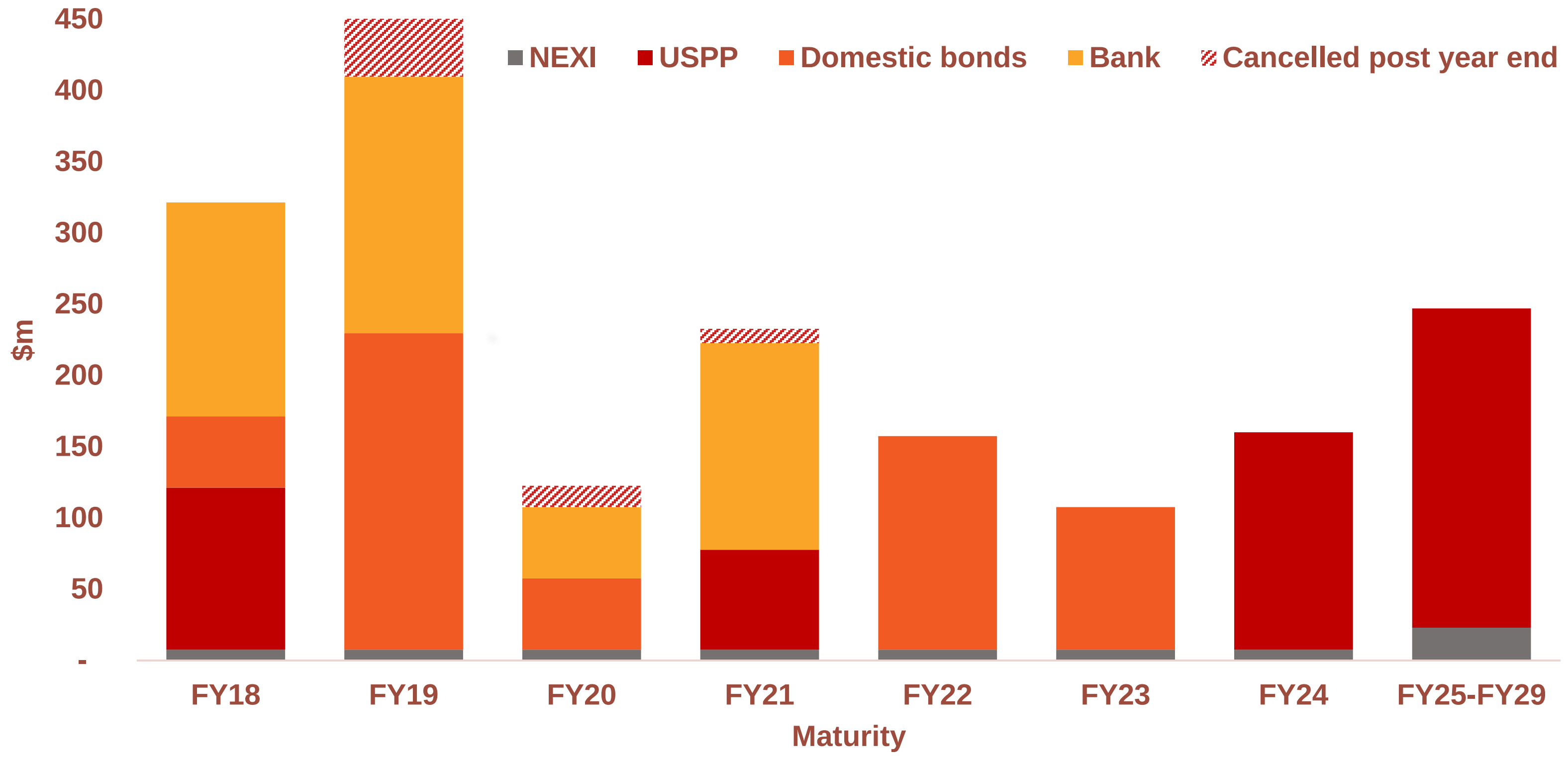
"Brilliant! NZ has now joined the global green debt market! Thank you Contact Energy for showing the way. Tumeke!"

Sean Kidney, CEO, Climate Bond Initiative

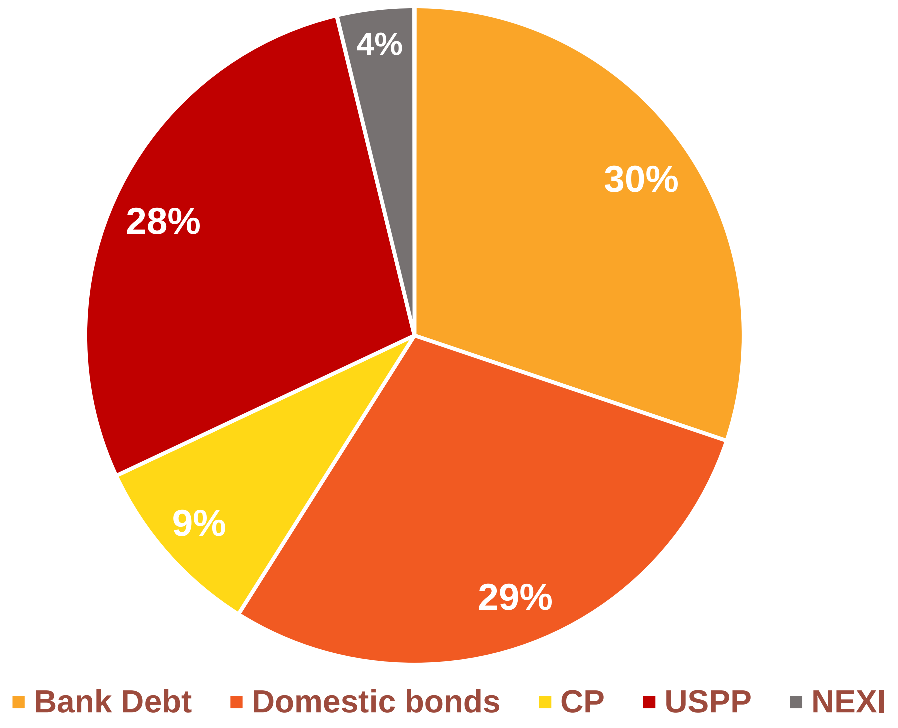
All capitalised terms are defined in the Green Borrowing Programme Framework, available on Contact's website

Contact's balance sheet is supported by a robust funding portfolio

Funding maturity profile



Funding sources



» Contact benefits from a funding portfolio that is flexible, efficient, diverse and has a manageable maturity profile:

- $600m total committed bank facilities ($113m drawn as at 30 June 2017) and $180m commercial paper
- Weighted average tenor of funding facilities 3.7 years

» Average weighted cost of borrowings down 0.3% from FY16 to 5.0% in FY17

Climate Bond Certified

Non-GAAP profit measure - EBITDAF

- EBITDAF is Contact's earnings before net interest expense, tax, depreciation, amortisation, change in fair value of financial instruments and other significant items
- EBITDAF is commonly used in the electricity industry so provides a comparable measure of Contact's performance at segment and group levels
- Reconciliation of EBITDAF to statutory profit/(loss):

$m	Year ended 30 June 2017	Year ended 30 June 2016	Variance $m	Variance %
EBITDAF	**494**	**523**	**(29)**	**(6%)**
Depreciation and amortisation	(204)	(201)	(3)	(1%)
Significant items	11	(327)	338	
Net interest expense	(92)	(101)	9	9%
Tax expense	(59)	40	(99)	
Profit/(loss)	**150**	**(66)**	**216**	

- Forecast depreciation for FY18 is estimated to be between $215 and $220m following the changes to the operating lease standard and a broad review of asset useful lives, including accelerated depreciation on geothermal wells and technology assets.

- Depreciation and amortisation, change in fair value of financial instruments, net interest and tax expense are explained in the following slide

Explanation of reconciliation between EBITDAF and profit

» The adjustments from EBITDAF to reported profit/(loss) are as follows:

- Depreciation and amortisation: Costs increased by $3m (1%) due to higher depreciation on TCC resulting from higher thermal generation
- Change in fair value of financial instruments: the balance of $23m reflecting a favourable movement in interest rate derivatives over the period
- Other significant items: these are detailed on the next two slides
- Net interest expense decreased $9m (9%) to $92m in FY17 due to reduced debt level and lower average interest rates
- Tax expense for FY17 is $59m compared to $40m credit for FY16. The difference in tax expense is driven by the FY16 impairments. There are no significant impairments or non-taxable income amounts in FY17. Tax expense represents an effective tax rate of 28%. There is little variance from the statutory rate as a result of non-deductible expenditure being fully offset by non-assessable income derived on the sale of land.

Non-GAAP profit measure – underlying profit

- Underlying profit provides a consistent measure of Contact's ongoing performance
- Underlying profit excludes the effect of significant items from reported profit / (loss). Significant items are determined based on principles approved by the Board of Directors
- Other significant items are determined in accordance with the principles of consistency, relevance and clarity. Items considered for classification as other significant items include impairment or reversal of impairment of assets; business integration, restructure, acquisition and disposal costs; and transactions or events outside of Contact's ongoing operations that have a significant impact on reported profit
- Reconciliation of statutory profit for the year to underlying profit:

$m	Year ended 30 June 2017	Year ended 30 June 2016	Variance $m	Variance %
Profit/(loss)	**150**	**(66)**	**216**	
Change in fair value of financial instruments	(23)	21	(44)	
Transition costs	7	10	(3)	(30%)
Remediation for Holidays Act non-compliance	5	-	5	100%
Asset impairments	-	36	(36)	(100%)
Write down of inventory gas	-	43	(43)	(100%)
Otahuhu thermal power station closure and sale	-	217	(217)	(100%)
Tax on items excluded from underlying profit	2	(100)	102	
Reinstatement of tax depreciation on powerhouse	-	(4)	4	100%
Underlying profit	**141**	**157**	**(16)**	**(10%)**

Explanation of reconciliation from reported profit to underlying profit

» The adjustments from reported profit / (loss) to underlying profit are as follows:

- Change in fair value of financial instruments: Movements in the valuation of interest rate and electricity price derivatives that are not accounted for as hedges, hedge accounting ineffectiveness and the effect of credit risk on the valuation of hedged debt and derivatives
- Transition costs: incurred as a result of the ICT Change and Transition programme that will significantly change Contact's ICT infrastructure and service delivery. Included in the cost is $1m of accelerated depreciation
- Remediation for Holidays Act non-compliance: At 30 June 2016, Contact disclosed a contingent liability for non-compliance with aspects of the Holidays Act 2003. At 31 December 2016, a provision representing the best estimate of the cost to resolve the issue, including payments to current and previous employees, was recognised. Actual payments may differ to the estimate and the cost recognised will be adjusted accordingly.

Costs to operate Ahuroa gas storage, reconciliation of accounting treatment change

- Contact changed the accounting treatment for the costs incurred in operating the Ahuroa Gas Storage (AGS) facility. While there are no cash implications, this change reduced FY17 EBITDAF by $4m with other operating costs $6m higher on a like-for-like basis on FY16.
- Fixed costs to operate the facility have all been included under other operating costs, which improves the transparency around Ahuroa gas storage costs, variable operating costs including gas transmission costs continue to be included in cost of energy

Ahuroa gas storage costs – 12 months ended 30 June 2017 ($m)	**Historically**	**FY17 change**	**Change**
Inventory (Balance sheet)	4	-	(4)
Gas transportation and purchase costs (Profit and Loss – Cost of energy)	4	2	(2)
Other operating expenses (Profit and Loss – Other operating expenses)		6	6
Total Ahuroa gas storage costs to operate	8	8	-
EBITDAF impact	**(4)**	**(8)**	**(4)**

Customer segment

Customer segment $m	Year ended 30 June 2017	Year ended 30 June 2016	Variance $m	%
Mass market electricity	893	903	(10)	(1%)
Commercial and industrial electricity	510	520	(10)	(2%)
Gas	66	62	4	6%
LPG	122	117	5	4%
Other income	3	5	(2)	(40%)
Total revenue and other income	**1,594**	**1,607**	**(13)**	**(1%)**
Inter-segment electricity purchases	(641)	(661)	20	3%
Gas purchases	(15)	(14)	(1)	7%
LPG purchases	(71)	(68)	(3)	(4%)
Electricity networks, levies & meter costs	(590)	(596)	6	1%
Gas networks, levies & meter costs	(36)	(33)	(3)	(9%)
Emission costs	(2)	(1)	(1)	(100%)
Total direct costs	**(1,355)**	**(1,373)**	**18**	**(1%)**
Other operating expenses	(128)	(126)	(2)	(2%)
EBITDAF	**111**	**108**	**3**	**3%**
Mass market electricity sales (GWh)	3,702	3,792	(90)	(2%)
Commercial & industrial electricity sales (GWh)	4,116	4,099	17	0%
Retail gas sales (GWh)	685	618	67	11%
Total retail sales (GWh)	**8,503**	**8,509**	**(6)**	**(0%)**
LPG sales (tonnes)	72,700	69,617	3,083	4%
Average electricity sales price ($/MWH)	179.36	180.37	(1.01)	(1%)
Electricity direct pass through costs ($/MWh)	(75.47)	(75.51)	0.04	0%
Electricity and gas cost to serve ($/MWh)	(13.22)	(13.22)	-	0%
Electricity and gas netback ($/MWh)	85.90	87.41	(1.51)	(2%)
Actual electricity line losses (%)	5%	5%	0%	0%
Retail gas sales (PJ)	2.4	2.2	0.2	9%
Electricity customer numbers (closing)	423,000	425,000	(2,000)	(0%)
Retail gas customer numbers (closing)	64,000	62,000	2,000	3%
LPG customer numbers (closing)	80,000	72,500	7,500	10%

Generation segment

Generation segment $m	Year ended 30 June 2017	Year ended 30 June 2016	Variance $m	 %
Wholesale electricity	483	539	(56)	(10%)
Inter-segment electricity sales	641	661	(20)	(3%)
Gas	-	1	(1)	(100%)
Steam	25	25	-	0%
Te Mihi compensation	6	6	-	0%
Total revenue and other income	**1,155**	**1,232**	**(77)**	**(6%)**
Electricity purchases	(494)	(528)	34	6%
Gas purchases	(100)	(108)	8	7%
Electricity networks & levies	(42)	(41)	(1)	(2%)
Gas networks & levies	(8)	(12)	4	33%
Carbon emissions	(9)	(7)	(2)	(29%)
Total cost of goods sold	**(653)**	**(696)**	**43**	**6%**
Other operating expenses	(119)	(121)	2	2%
EBITDAF	**383**	**415**	**(32)**	**8%**
Thermal generation (GWh)	1,742	1,614	128	8%
Geothermal generation(GWh)	3,233	3,297	(64)	(2%)
Hydro generation (GWh)	3,562	4,091	(529)	(13%)
Spot market generation (GWh)	**8,537**	**9,002**	**(465)**	**(5%)**
Spot electricity purchases (GWh)	8,144	8,231	(87)	(1%)
CfD sales/(purchases) (GWh)	254	81	173	214%
GWAP ($/MWh)	53.94	58.49	(4.55)	(8%)
LWAP ($/MWh)	(60.03)	(64.05)	4.02	6%
LWAP/GWAP (%)	(111%)	(110%)	(1%)	(1%)
Gas used in internal generation (PJ)	17.1	16.0	1.1	7%
Steam sales (GWh)	602	626	(24)	(4%)
Gas storage net movement (PJ)	3.0	0.3	2.7	(900%)
Unit generation costs ($MWh)	(32.3)	(31.7)	(0.6)	(2%)
Cost of energy ($MWh)	(30.39)	(28.94)	(1.45)	(5%)