2017 Interim Results Presentation

Six months ended 31 December 2016

13 February 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 and 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

Strategy	» Optimise the Customer and Generation businesses to deliver strong cash flows • Deliver value by providing customers with choice, certainty and control • A low cost, long life and flexible generation portfolio with a continuous improvement programme focusing on safety, reliability and resource utilisation • Disciplined and transparent approach to expenditure
Performance highlights against 1H16	» EBITDAF up 3%, Underlying profit per share up 15%, Free cash flow per share strong at 20c » Other operating expenses down $4m, or 3% to $128m. On a like for like basis other operating expenses down $7m » Contact grew electricity market share with sales volumes down 1% against national electricity demand which declined by 2%, Mass market electricity netback per MWh up 1% » Cost of energy improved by 7% as high national hydro generation and lower sales volumes saw thermal generation replaced with lower cost supply contracts » Total recordable injury frequency rate down to 1.2 from 3.1
Capital management	» Interim dividend stable at 11 cents per share; 8 cents per share imputed » $21m reduction in debt in the six months ended 31 December 2016 » $75m domestic retail bond (with oversubscriptions up to $100m) launched today
Focus on structural efficiency	» Tiwai's new higher priced electricity contract, which Contact is supporting with an 80 MW supply agreement with Meridian, commenced on 1 January 2017 » Completion of TCC major maintenance deferred and no new gas purchases » Regulatory changes around transmission pricing and network charging are critical to ensure the right incentives are in place for customers and industry participants. Network charging regulation reform has been slow and fragmented to date » Retail competition expected to continue, despite elevated marketing costs to acquire and retain
Outlook	» Operational performance improvements will support ongoing strong cash flow » On track to reduce the net debt / EBITDA ratio to our target range

Statutory profit of $96m

Underlying profit per share up 15%; EBITDAF up 3%

	6 months ended 31 December 2016	Comparison against 1H16
EBITDAF[1]	$261m	up 3% from $254m
Profit/(loss)	$96m	up 183% from ($116m)
Earnings per share (cents)	13.5 cps	up 185% from ($15.9 cps)
Underlying profit[1]	$82m	up 12% from $73m
Underlying profit per share (cents)	11.5 cps	up 15% from 10.0 cps
Interim dividend (cents)	11.0 cps	no change from 11.0 cps
Free cash flow[2]	$141m	down 31% from $203m
Free cash flow per share (cents)[2]	19.7 cps	down 29% from $27.7 cps
Capital expenditure	$63m	down 11% from $71m

[1] Refer to slides 31-34 for a definition and reconciliation of EBITDAF and underlying profit

[2] Refer to slide 20 for a definition and reconciliation of free cash flow

[3] Refer to slide 35 for a reconciliation of the AGS 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 1H17 EBITDAF by $2m with other operating costs $3m higher on 1H16 on a like-for-like basis[3]
- Free cash flow for the period remained strong at $141m, with the reduction on 1H16 primarily related to:
  - Tax paid up by $33m on 1H16 due to a tax refund relating to FY15 tax payments and tax benefits from Otahuhu closure received in 1H16
  - Unfavourable working capital movements of $22m as less storage gas was used with lower thermal generation and a reduction in retail debtor receipts on the collection of late bills in 1H16

Market dynamics and strategy

Dennis Barnes

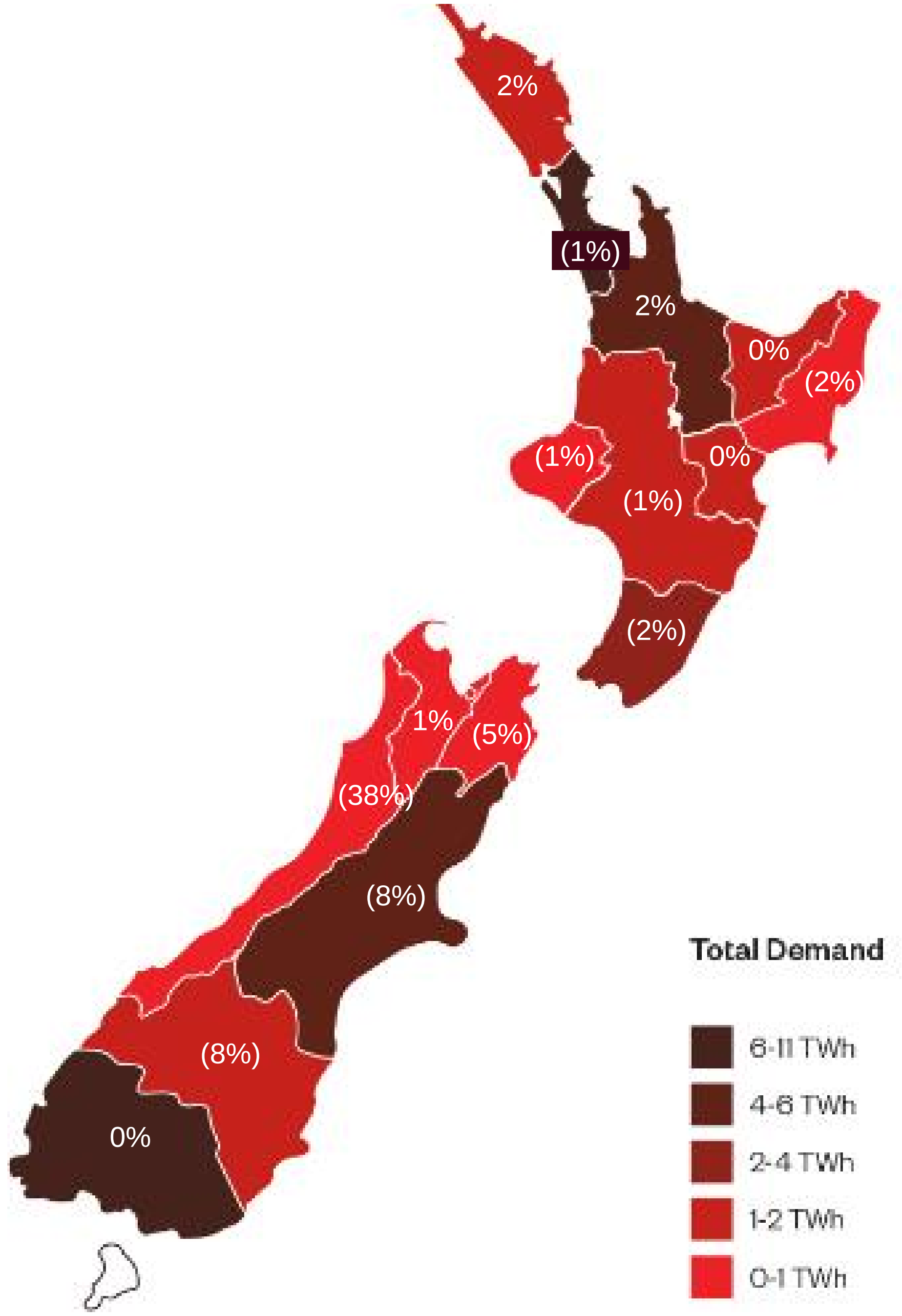
1H17 Results Presentation

13 February 2017
Contact Energy Limited

National electricity demand down 2% compared to 1H16, on warmer wetter weather

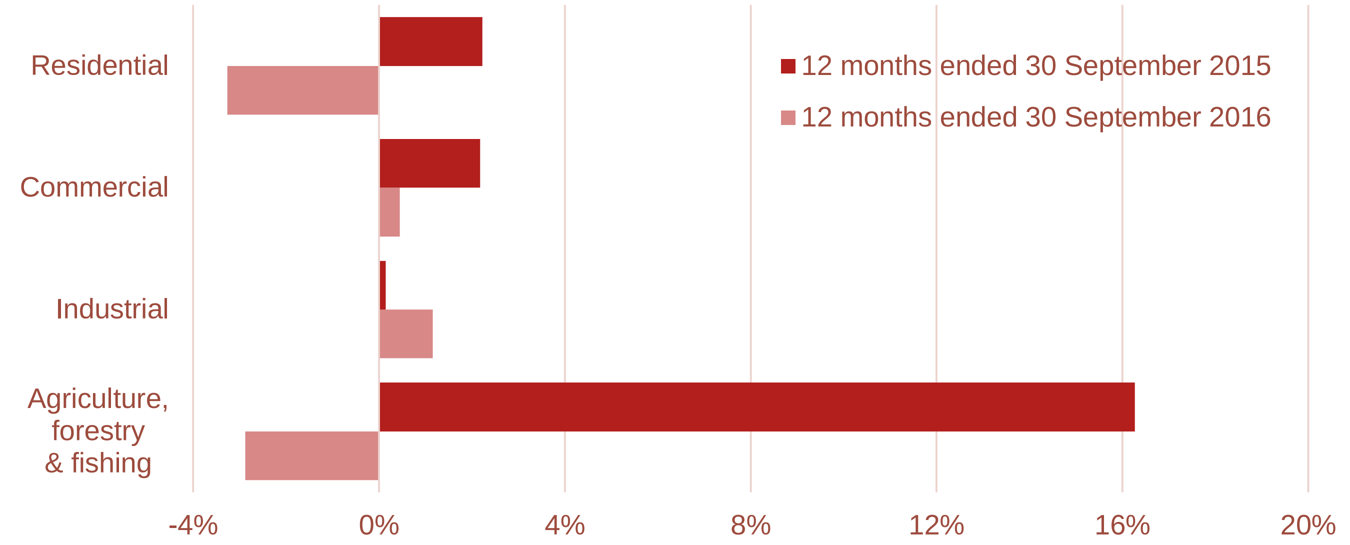
Regional changes in demand 1H17 vs 1H16

Source: Transpower / Contact



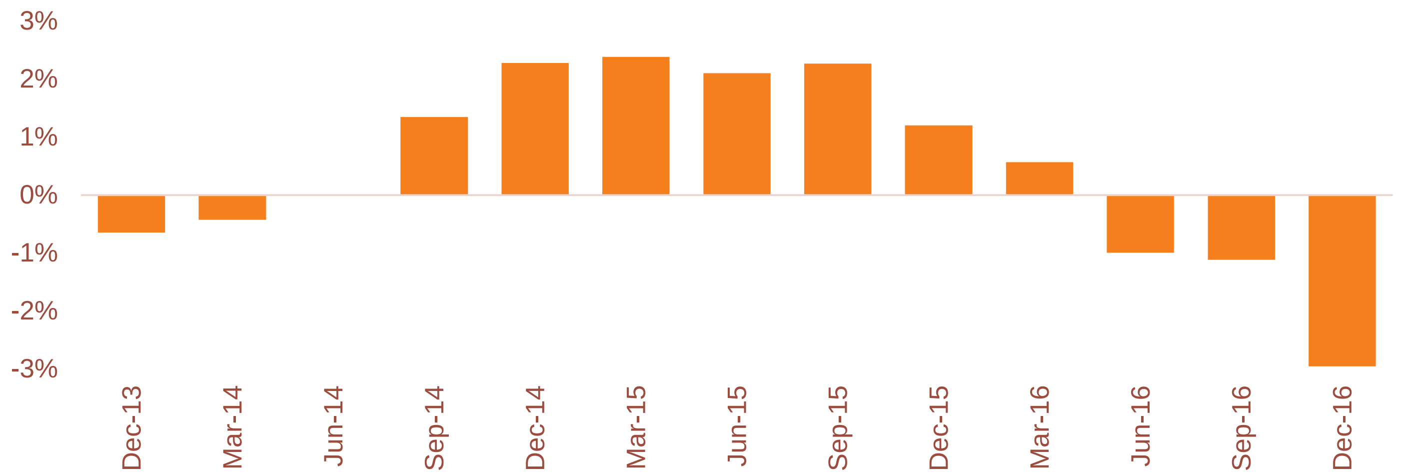
12 month change in electricity consumption

Source: *MBIE*



Year on year quarterly change in electricity consumption

Source: EA reconciled demand data



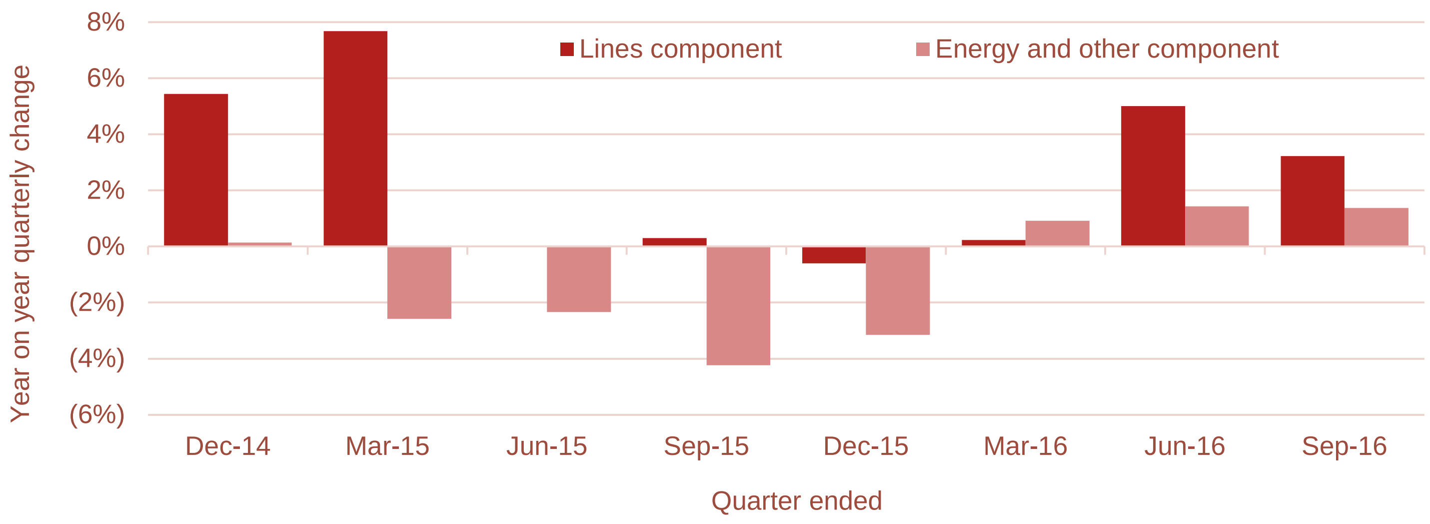
Retail electricity market trends

Electricity pricing up in a competitive retail market

- Price increases from Tier 1 retailers implemented
  - Residential prices rose in the September quarter by 2.2% (3.2% line costs and 1.4% energy related)
- 1H17 customer switching activity remains near historic highs with the 12 month rolling switch rate at 20.1%
  - Tier 2 retailers continued to gain customers (market share by ICP up 0.6% to 9.4%), 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
  - Tier 1 competition remains intense requiring pricing response to ensure we remain competitive

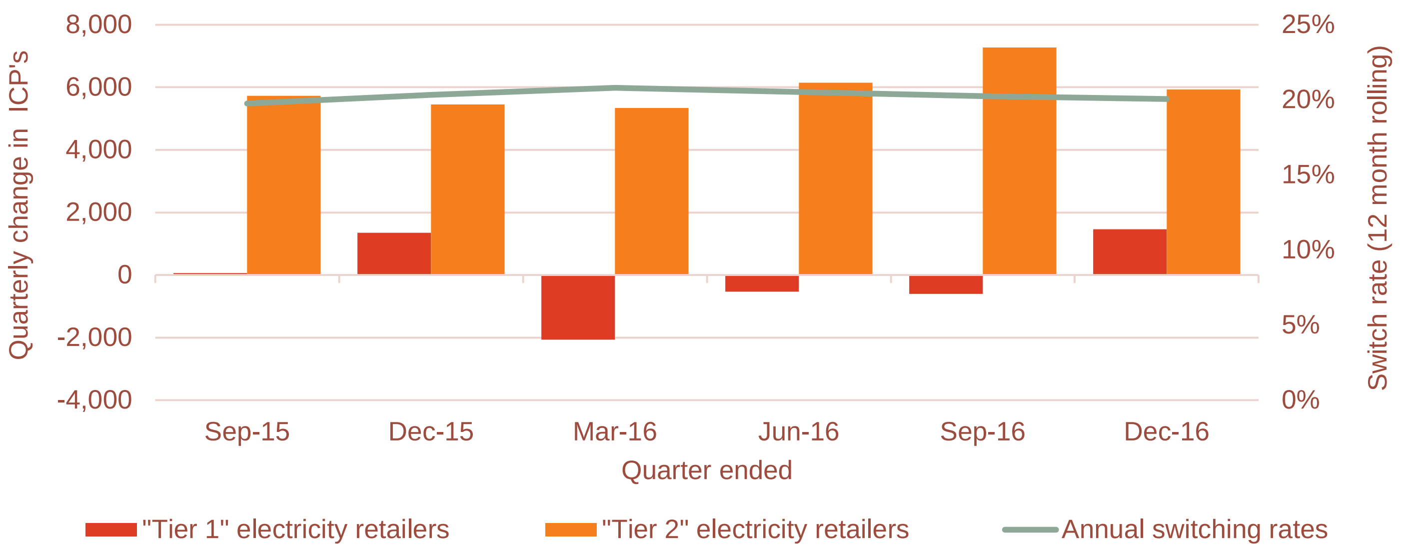
Year on year quarterly change in residential electricity prices

Source: MBIE Quarterly Survey of Domestic Electricity Prices



Tier 2 retailers continue to gain market share

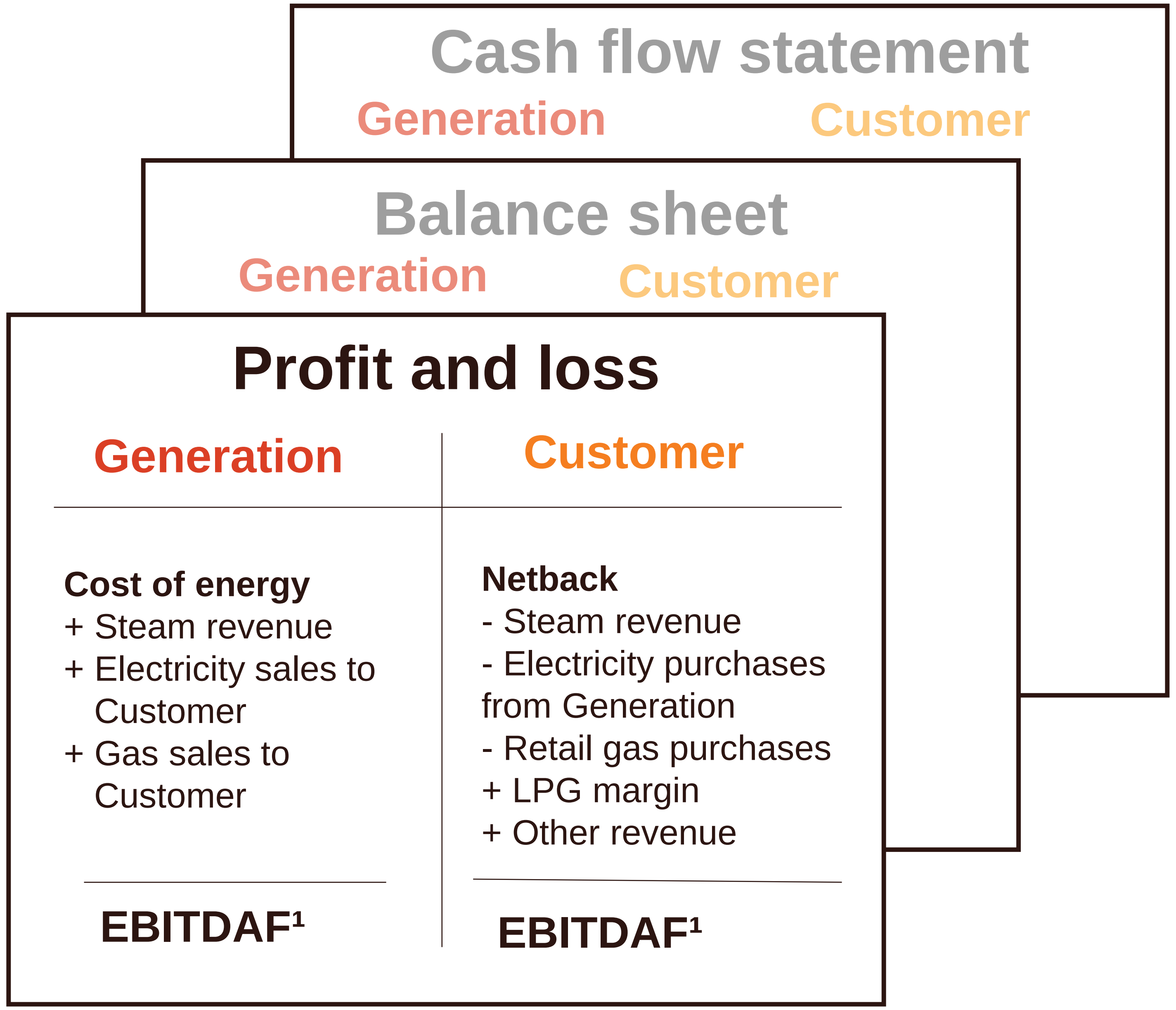
Source: EA, ICP market share



Looking forward, the transparency of performance will drive our focus

New reporting segments

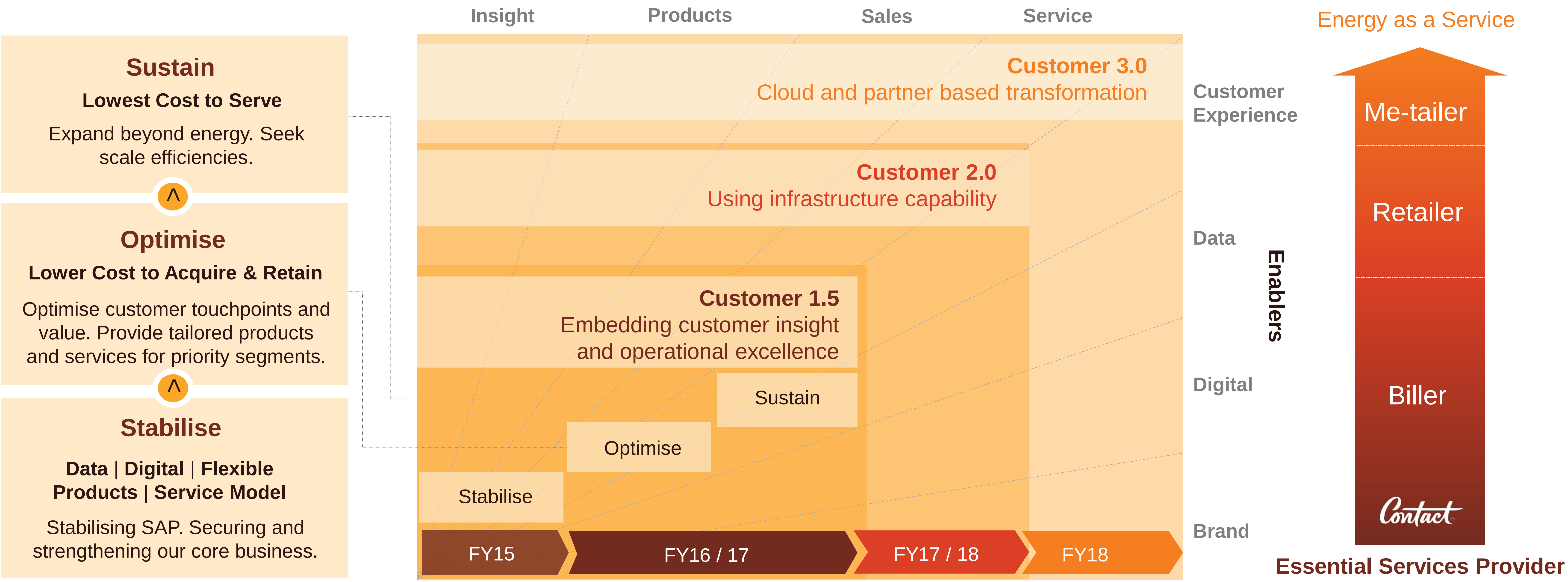
- » Capturing customer inspired value will require innovation and discipline
- » A transfer price has been introduced between the Customer and Generation businesses
    - » The Customer business purchases electricity from the Generation business at an electricity price that is set in a similar manner to transactions with third parties
- » Transparency of performance will drive focus
    - » Enables view of profitability for the Customer and Generation businesses
    - » The allocation of volume risk between the two segments enhances performance comparison metrics



[1] Refer to slide 38 for a reconciliation of previously reported operating statistics and EBITDAF

The Customer business is evolving from an Essential Services business to a Living Services business

Deliver value by providing customers with choice, certainty and control

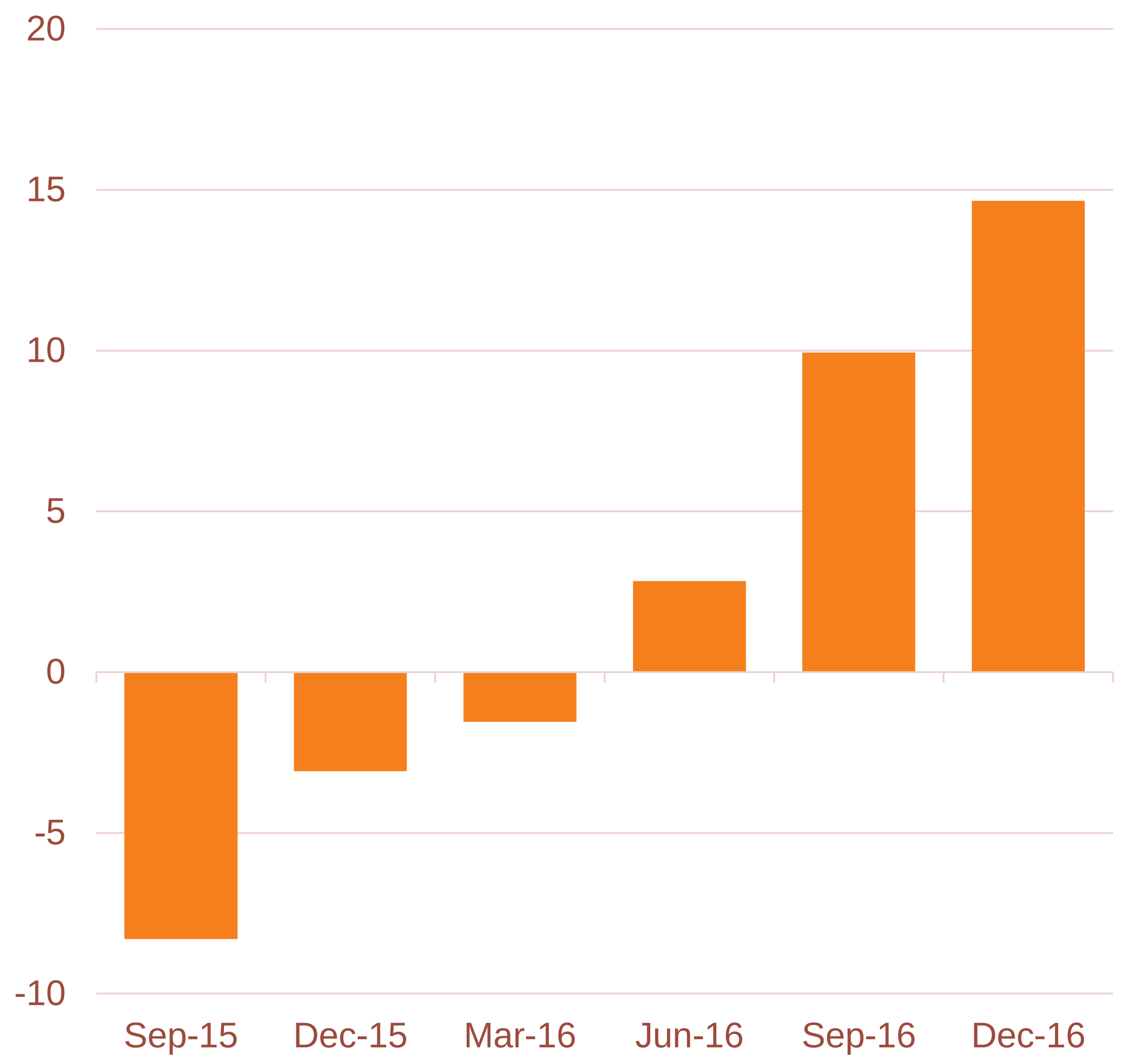


Operational improvement momentum is continuing

	1H15	2H15	1H16	2H16	1H17
Change in customer numbers	-7,300	-1,600	-9,800	+5,380	-3,100
Average time to answer (seconds)	220	268	222	141	128
Churn (variance to market)	+2.9%	-0.2%	+1.1%	-1.3%	-0.3%
% of residential customers on >10% discount	63%	70%	76%	82%	84%
% on a fixed term product	9%	10%	11%	24%	28%
% with MM dual fuels or products	18%	20%	20%	22%	22%
Cost to serve per customer	$113	$124	$122	$106	$118
Number of vacant properties	12,800	11,500	10,000	4,500	3,900
Average late bills >30 days	12,000	5,000	2,000	1,100	850
Bad debt expense (net) as a % of retail revenue	0.55%	0.70%	0.67%	0.52%	0.49%

Net promoter score continues to improve quarter-on-quarter

Source: Contact, relational NPS



The Generation business is on a continuous improvement path

Low cost, long life and flexible generation portfolio

01 » Strong earnings performance from core renewable business, firmed by Ahuroa Gas storage and Stratford Peakers

02 » Discretionary thermal generation available if it delivers margin on commercial and industrial sales

03 » Market balanced short-term with some uncertainty long-term

04 » Contact well positioned to manage risks in all conditions

A continuous improvement programme focusing on safety, reliability and resource utilisation

01 » Safety and operational reliability improvement

02 » Engagement improvement

03 » Cost of energy improvement

04 » Wholesale market that supports a return on capital

Trading for Value

Continuous improvement

Sustainable new revenue

1H17 performance

Graham Cockroft

1H17 performance highlights

Financial performance compared to 1H16

$261m

EBITDAF up 3% from $254m on improved operational performance

$96m

Profit for the period, $212m higher due to 1H16 impairments

$4m

Or 3% reduction in other operating expenses, down $7m (5%) on a like for like basis

2%

Decline in national electricity demand over 1H16, Contact volumes declined by less than 1%

$1/MWh

Netback improvement in the mass market electricity sales channel

$21m

Debt reduction in the six months ended 31 December 2016

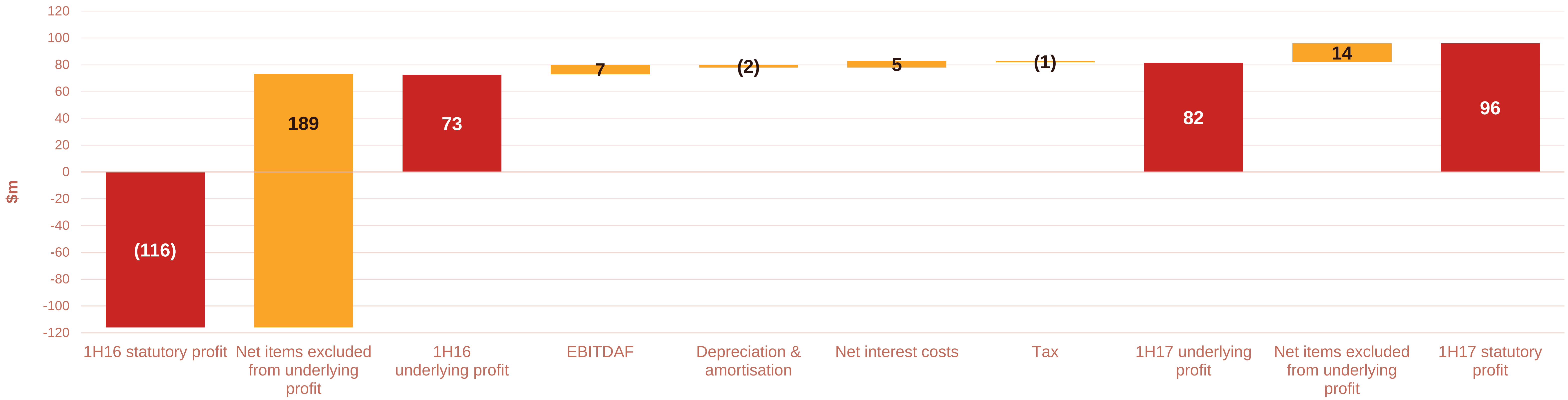




Statutory profit $96m

Underlying profit up 12% from $73m in 1H16 to $82m

Contact's statutory profit



Financial performance compared to 1H16

» Underlying profit of $82m, was up $9m (12%) reflecting the improvement in operating earnings with EBITDAF up by $7m

» Depreciation remained steady as the closure of Otahuhu and lower depreciation from TCC on the back of lower thermal generation was offset by accelerated depreciation on geothermal wells

» Net interest costs reduced by $5 million on lower average interest rates

» The net significant items excluded from underlying profit in the current period were the increase in the fair value of financial instruments ($30m), transition costs relating to the ICT change and transition programme ($7m), an estimate to address historic non-compliance with the Holidays Act ($5m), and $1m relating to the closure of the Otahuhu power station. The tax expense associated with these significant items was $5m

Transfers of value between the two segments appropriately reflect market conditions

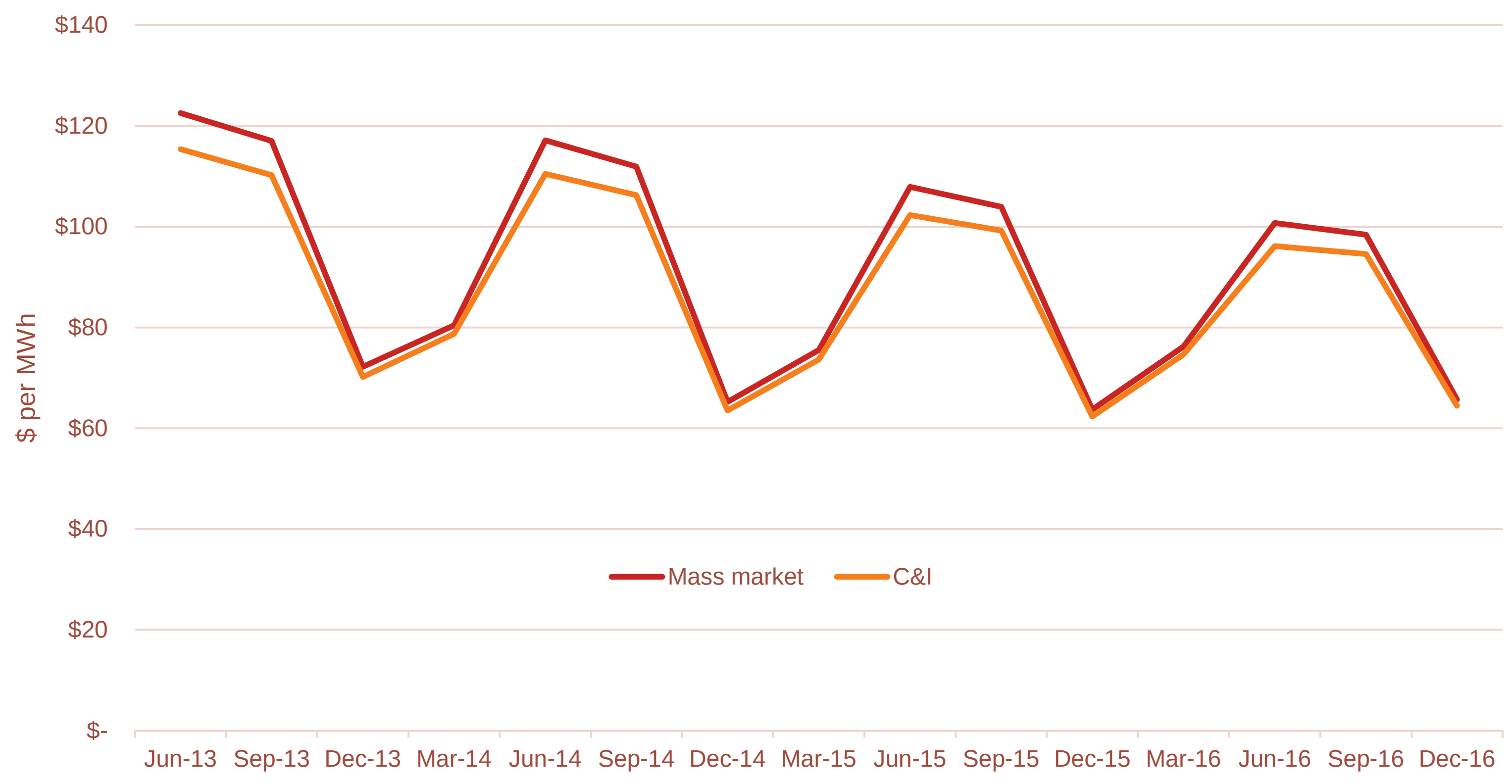
Inter-segment electricity transfer price

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

» A prudent retailer, offering fixed price variable volume products would contract their forecast load incrementally up until the start of the contract period. For the Customer business, 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 which are based on the Customer business load profile for preceding 12 months

Inter-segment electricity transfer price



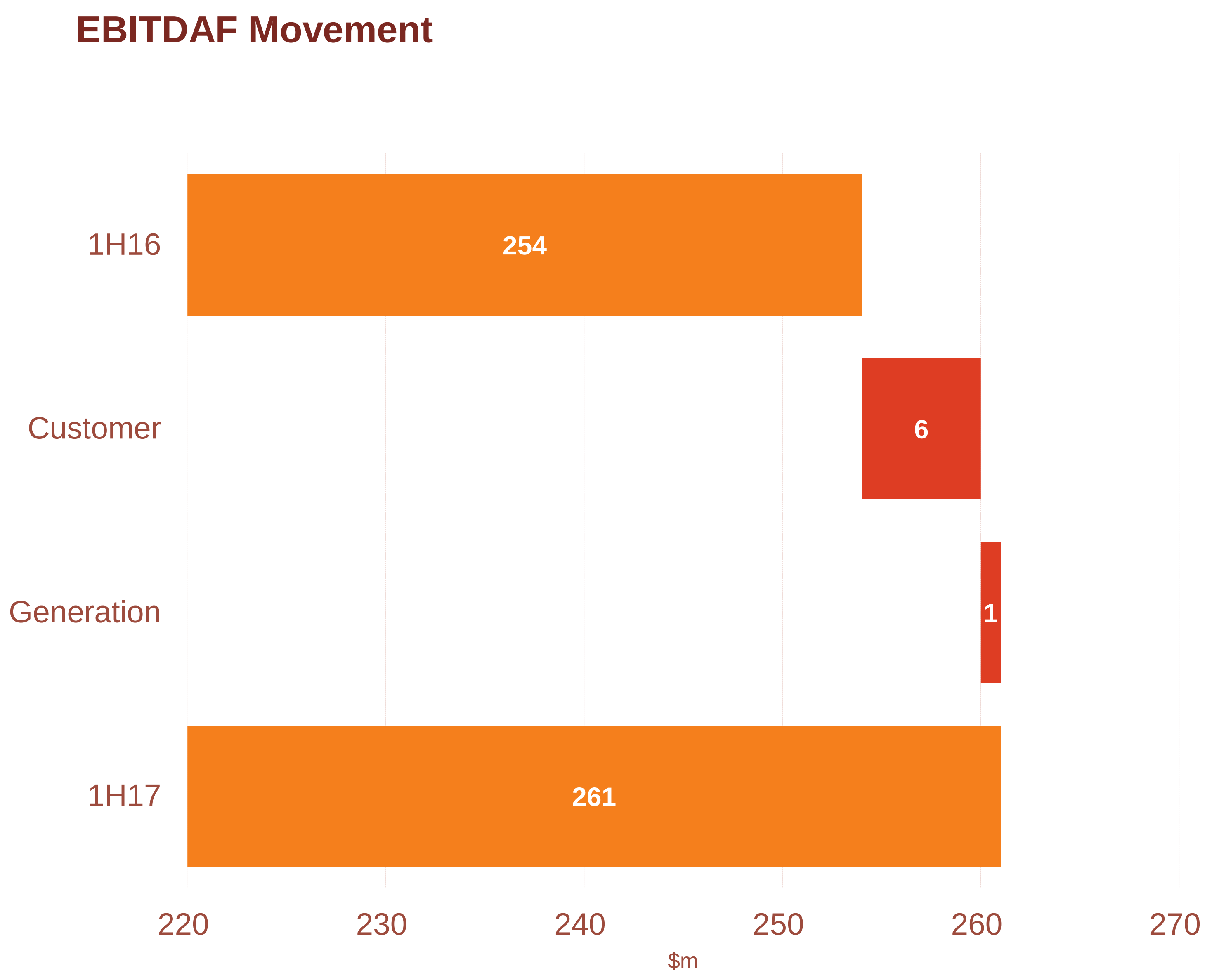
EBITDAF up 3% on operational performance improvement

Customer segment

» Customer EBITDAF was $6m (12%) higher than 1H16
  - Netback down $5m (1%) to $371m on lower mass market sales volumes, partially offset by an increase in sales to lower margin C&I customers
  - Electricity purchase costs reduced $9m (3%) due to lower sales volumes and a lower electricity transfer price reflecting reductions in ASX prices
  - LPG, meter and other revenue margin was up $2m due to lower product costs and higher sales volumes

Generation segment

» Generation EBITDAF was $1m higher than 1H16
  - Cost of energy was favorable by $10m, to $125m on lower thermal generation as hydro conditions allowed increased purchases of lower cost electricity supply contracts
  - Electricity sales to the Customer business reduced by $9m on lower pricing and sales volumes



Customer EBITDAF up $6m on lower electricity purchase costs

Netback reduction on lower mass market sales volumes and C&I pricing; offset by reduction in electricity purchase costs

» 1H17 sales volume was down 25 GWh to 4,001 GWh
- Mass market sales volumes reduced by 5% primarily due to lower usage per customer
  - Residential usage per ICP was down 3% on warmer temperatures
  - Business customer usage per ICP was down 9% as customers acquired used less energy than those replaced
  - Mass market customer connections were on average 1,100 lower as we lost re-priced fixed term customers, saw continued price discounting by larger competitors and benign wholesale conditions supported new entrants
- Commercial and Industrial (C&I) sales volumes were up 85 GWh

» Mass market electricity netback was up $1/MWh
- Tariff up 3% or $6/MWh with prices increased on new products launched
- Network costs increased by $4/MWh or 4%

» C&I electricity netback was down $2/MWh with the prices of new contracts tracking ASX prices down

» Electricity purchase costs were $9m (3%) lower on reduced sales volumes and a lower electricity transfer price

» Retail gas volumes and netback marginally up on 1H16

» LPG gross margin up $3m on lower product costs and higher volume

» The Customer business operating costs to serve our customers reduced by $2m

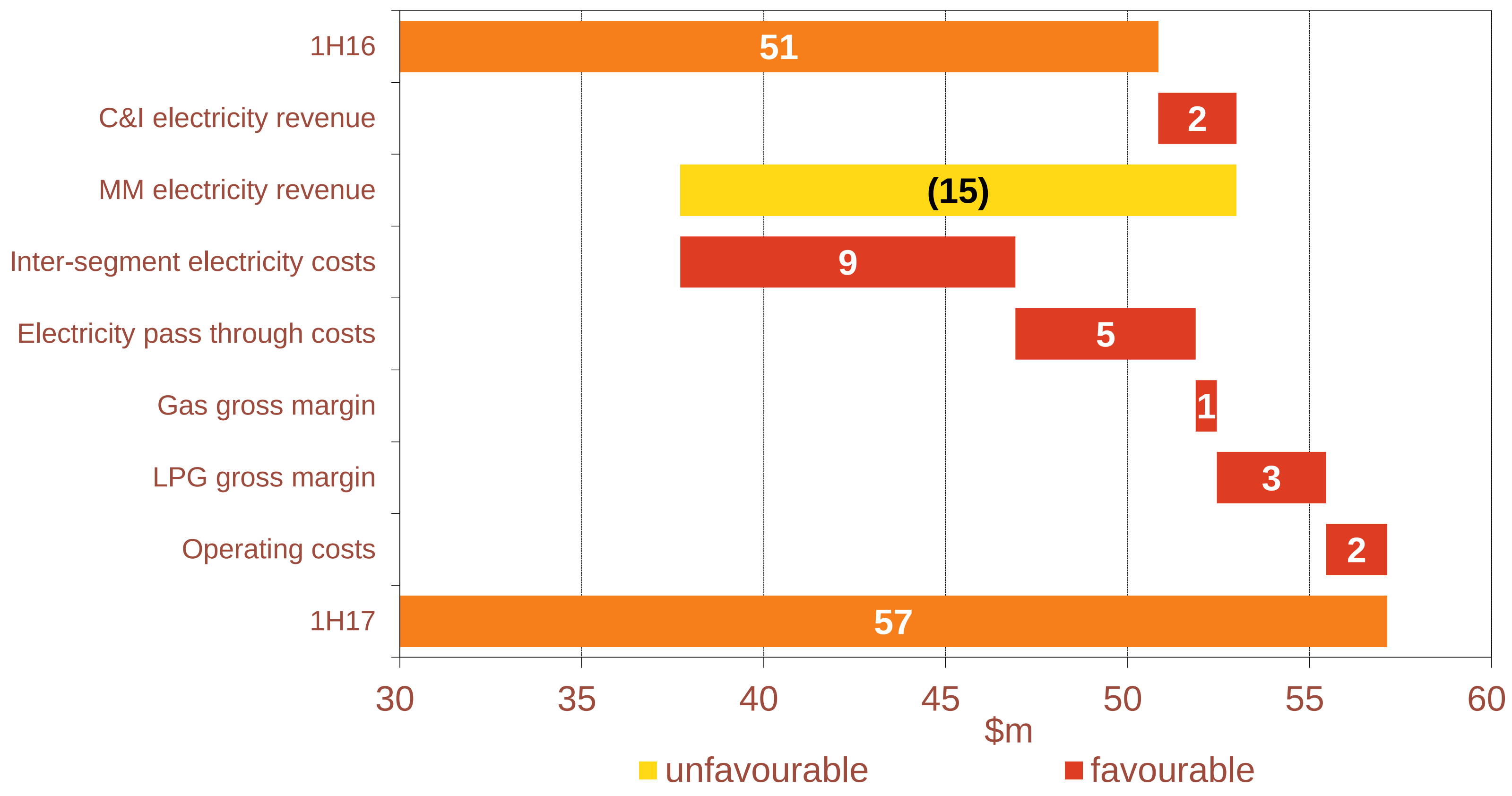
4,001 GWh

Electricity sales volume; down 1% as lower mass market sales were offset by an increase in C&I sales

$84/MWh

Netback down $1/MWh with a higher proportion of C&I sales

Customer segment EBITDAF movements



Generation EBITDAF up $1m to $204m

84%

Renewable generation up from 78% in 1H16

4,156 GWh

30 GWh decrease in electricity purchase volumes

$10m (7%) improvement in cost of energy was offset by a $9m reduction in electricity sales revenue from the Customer business

» Wholesale spot market revenue down $14m
  - Merchant sales volumes were 145 GWh, 329 GWh lower than 1H16 with low wholesale prices in the period

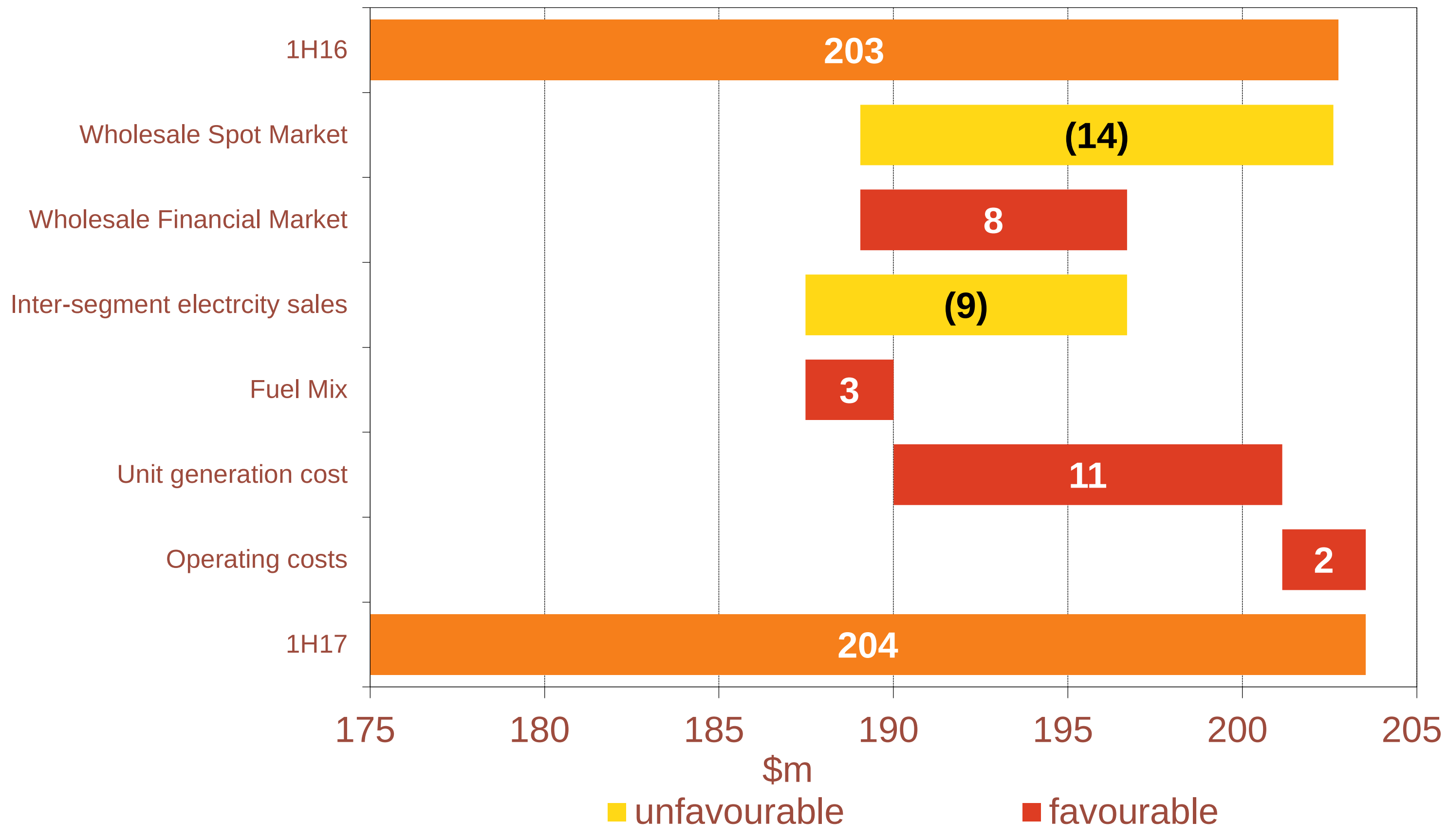
» Wholesale financial market revenue up $8m on higher CfD sales

» Fuel mix favorable $3m with renewable generation increasing from 78% to 84%
  - Thermal generation was down by 416 GWh reducing gas purchases by 3 PJ
  - Geothermal generation was down 71 GWh on an extended Te Mihi outage in the period which was offset by a 63 GWh increase in hydro volume

» Unit generation cost favourable $15m with lower unit gas costs and lower gas transmission and operating costs due to the closure of Otahuhu more than offsetting increased carbon costs and plant maintenance expenses

» The change in accounting treatment in 1H17 for the costs incurred in operating the Ahuroa Gas Storage (AGS) facility reduced EBITDAF by $2m over the prior comparative period

Generation segment EBITDAF movement



Focus continues on the reduction of both operating and capital expenditure

Other operating expenses

» 1H17 other operating expenses were down $4m, 3% lower than 1H16
- Labour costs down primarily due to reduced FTE's
- Reduced bad debt write-offs
- Lower insurance costs
- AGS facility costs were re-classified in the period, increasing other operating expenses by $3m over 1H16 (full year impact on prior period comparison is $6m) [1]

» Savings to continue
- IT systems simplification move to the cloud
- Reduced churn costs and an increase in digital self-service

[1] Refer to slide 35 for a reconciliation of the impact of this change

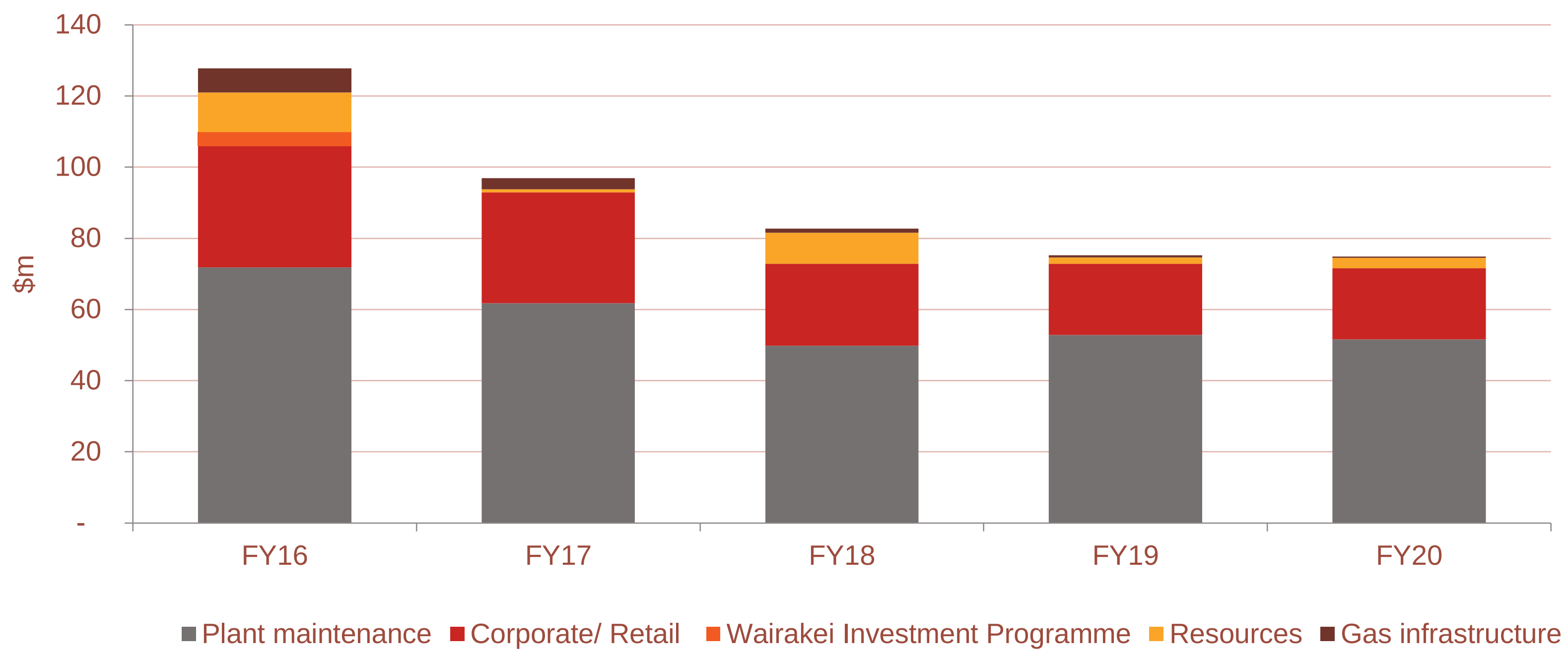
Capital expenditure

» 1H17 capex $63m, $8m lower than 1H16

» The reduction in thermal generation in the period has allowed for the partial deferral of TCC major maintenance with $9m moved from FY17 to FY18

» Capex expected to be $70 - $80m per annum from FY18

Capital expenditure



Free cash flow down 31%

Due to higher tax paid and unfavourable working capital movements

» Free cash flow measures the cash generating performance of the business and represents cash available to reduce debt, fund distributions to shareholders and fund capital expenditure for growth

$m	6 months ended 31 December 2016	6 months ended 31 December 2015	Variance $m	Variance %
EBITDAF	**261**	**254**	**7**	**3%**
Tax received/(paid)	(25)	8	(33)	(413%)
Change in working capital	4	26	(22)	(85%)
Other	6	9	(3)	(33%)
Significant items	(6)	(5)	(1)	(20%)
Operating cash flows	**240**	**292**	**(52)**	**(18%)**
Stay in business capital expenditure	(57)	(46)	(11)	(24%)
Net interest paid	(44)	(46)	2	4%
Proceeds from asset sales	2	3	(1)	(33%)
Free cash flow	**141**	**203**	**(62)**	**(31%)**

» Tax paid increased by $33m on 1H16 due to a tax refund relating to FY15 tax payments and tax benefits from Otahuhu closure in 1H16

» Unfavourable working capital movements of $22m as less storage gas was used with lower thermal generation and a reduction in retail debtor receipts on the one-off collection of late bills in 1H16

» The cost of the $10m Stratford super core recognised in FY16, was paid in 1H17. This asset was previously financed via a lease arrangement with installment payments. Contact settled this liability with a one-off payment on favourable terms in the period

» Partially offset by favourable EBITDAF and lower net interest paid

Our financial framework

» Our focus is on free cash flow generation and ensuring a robust balance sheet

Free cash flow

» Operating cash flow
- *Less* net interest paid
- *Less* stay in business capex
- *Add* proceeds from asset sales

Balance Sheet

» Investment grade credit rating
- Net debt / EBITDA ratio of 2.6 – 3.0

Distributions

» Ordinary dividend equal to 100% underlying profit

» Special dividend where imputation credits available

» Share buyback

Investment in growth

» Returns greater than risk adjusted cost of capital

» Focus on areas of strength

Financial framework prioritises a robust balance sheet, with strong free cash flow currently directed to debt repayment

Debt reduced by $21m in 1H17

» Face value of net borrowings reduced by $21m to $1,610m as surplus cash was applied to the debt repayment

» Gearing remained stable at 36.1%

» $122m in debt repayment since peak debt in March 2016

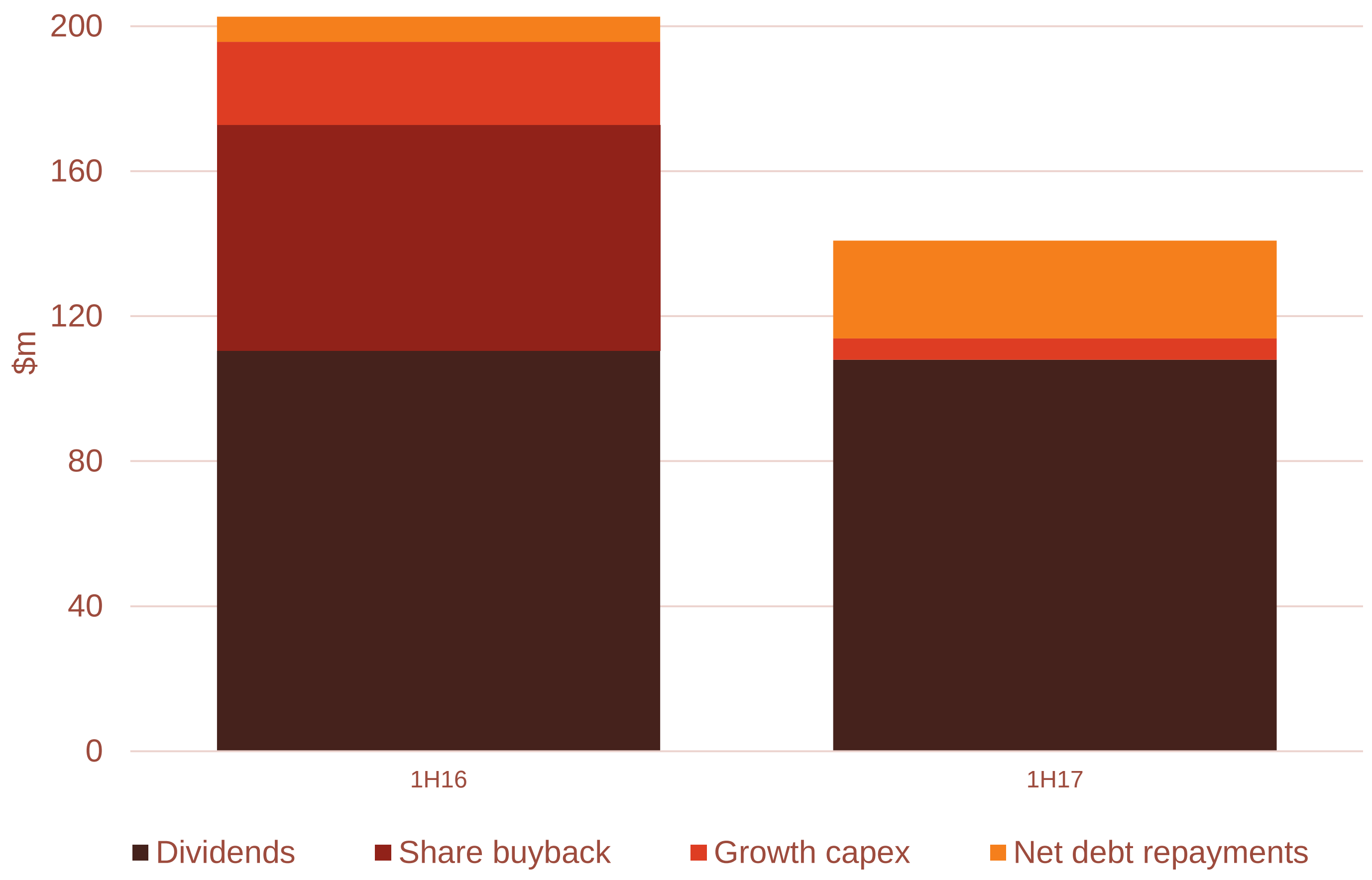
Interim dividend for 1H17 held stable at 11 cents per share

» 8 cents per share is imputed reflecting available imputation credit balance following the payment of the fully imputed special dividend in June 2015

» Record date 28 Feb 2017; payment date 17 March 2017

- The NZD/AUD exchange rate used for the payment of Australian dollar dividends will be set in early March

Uses of free cash flow



Summary

Dennis Barnes

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Outlook	» Operational performance improvements will support ongoing strong cash flow » On track to reduce the net debt / EBITDA ratio to our target range

Outlook

» In a competitive market, turning improving operational performance into value remains the focus

» Growing capability in retail supported by systems investment may provide opportunities to expand our offering and/or consolidate

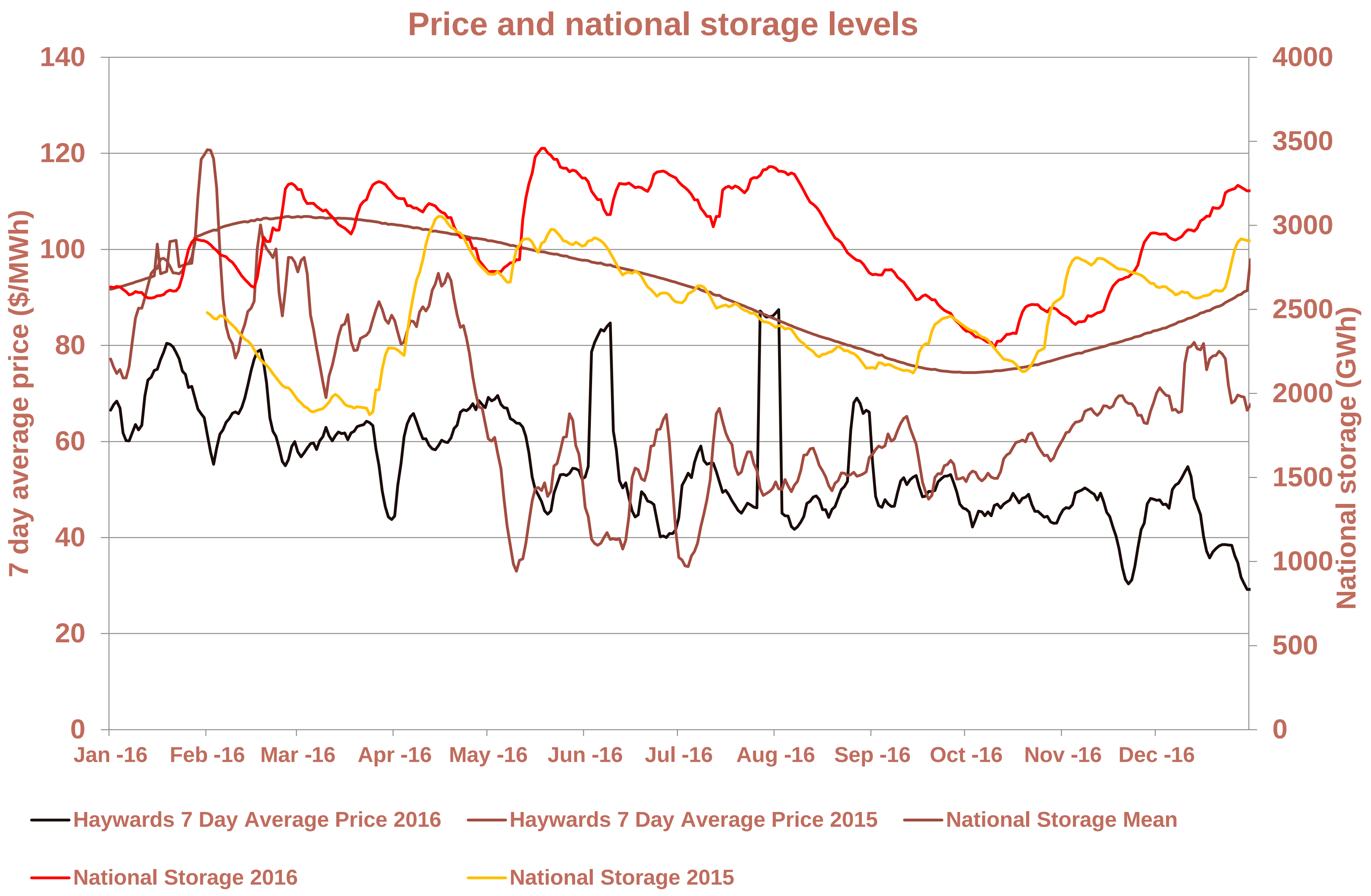
» Transition to new technologies likely to be slow but will deliver opportunities for customer-led businesses

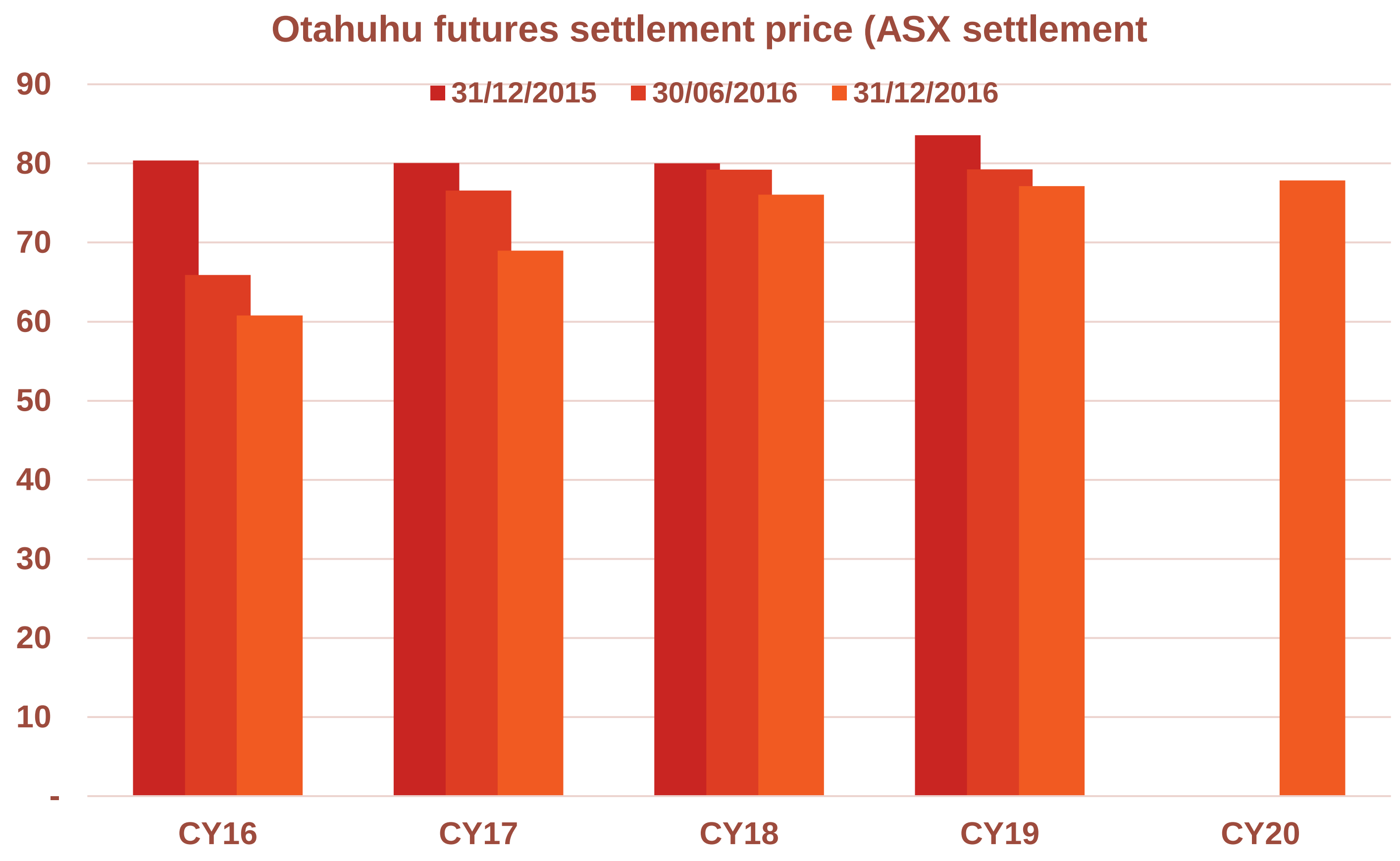
» Slow demand growth unlikely to require additional generation to be built in the near term. Tiwai exit likely to remain a risk, although increasingly manageable

» Our quality portfolio of long life generation assets will continue to lower the cost of energy through fuel substitution, electricity trading and gains realised through the efficient execution of our continuous improvement programme

Supporting material

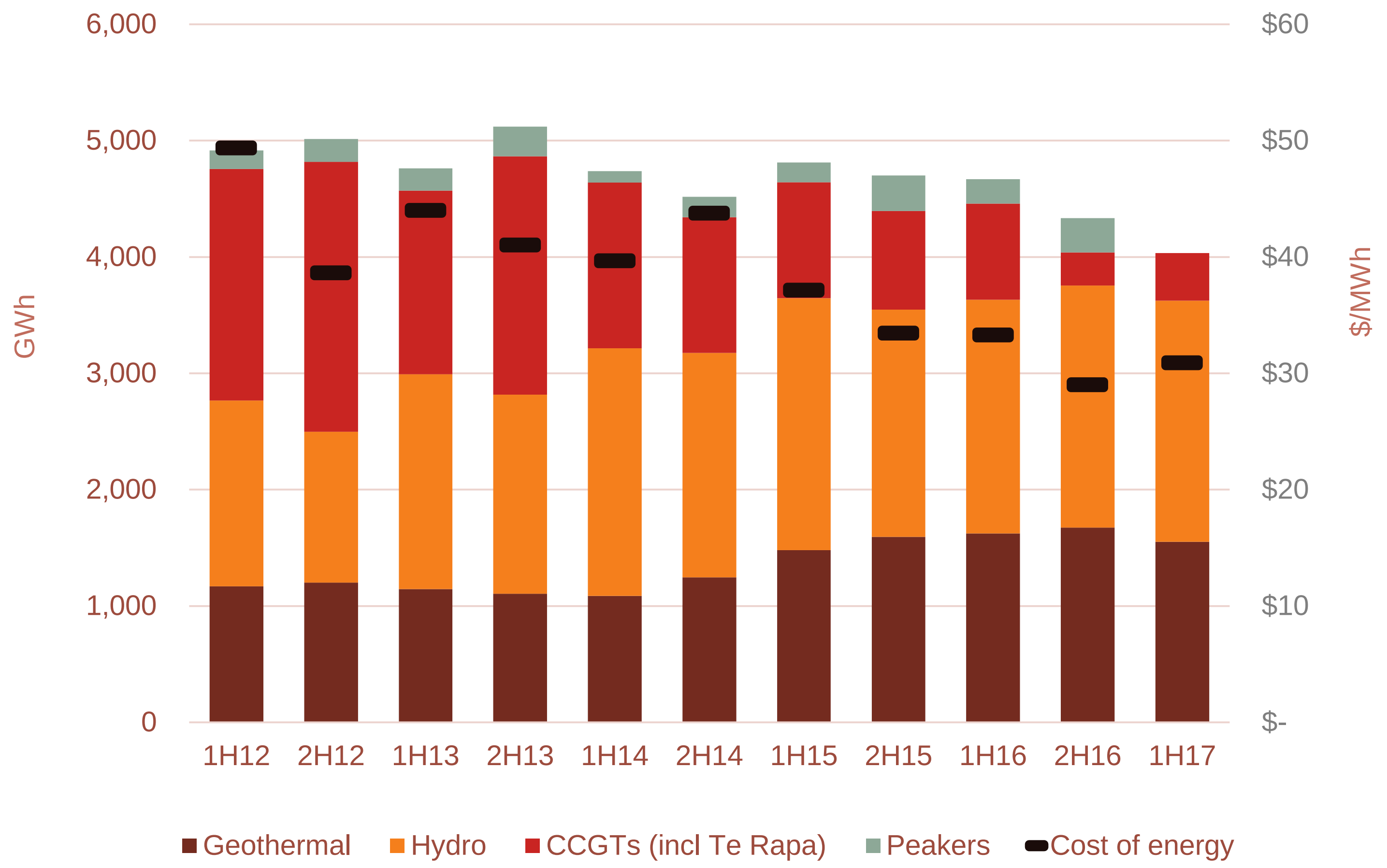
Electricity market conditions





Plant availability improved in 1H17

Generation by sources

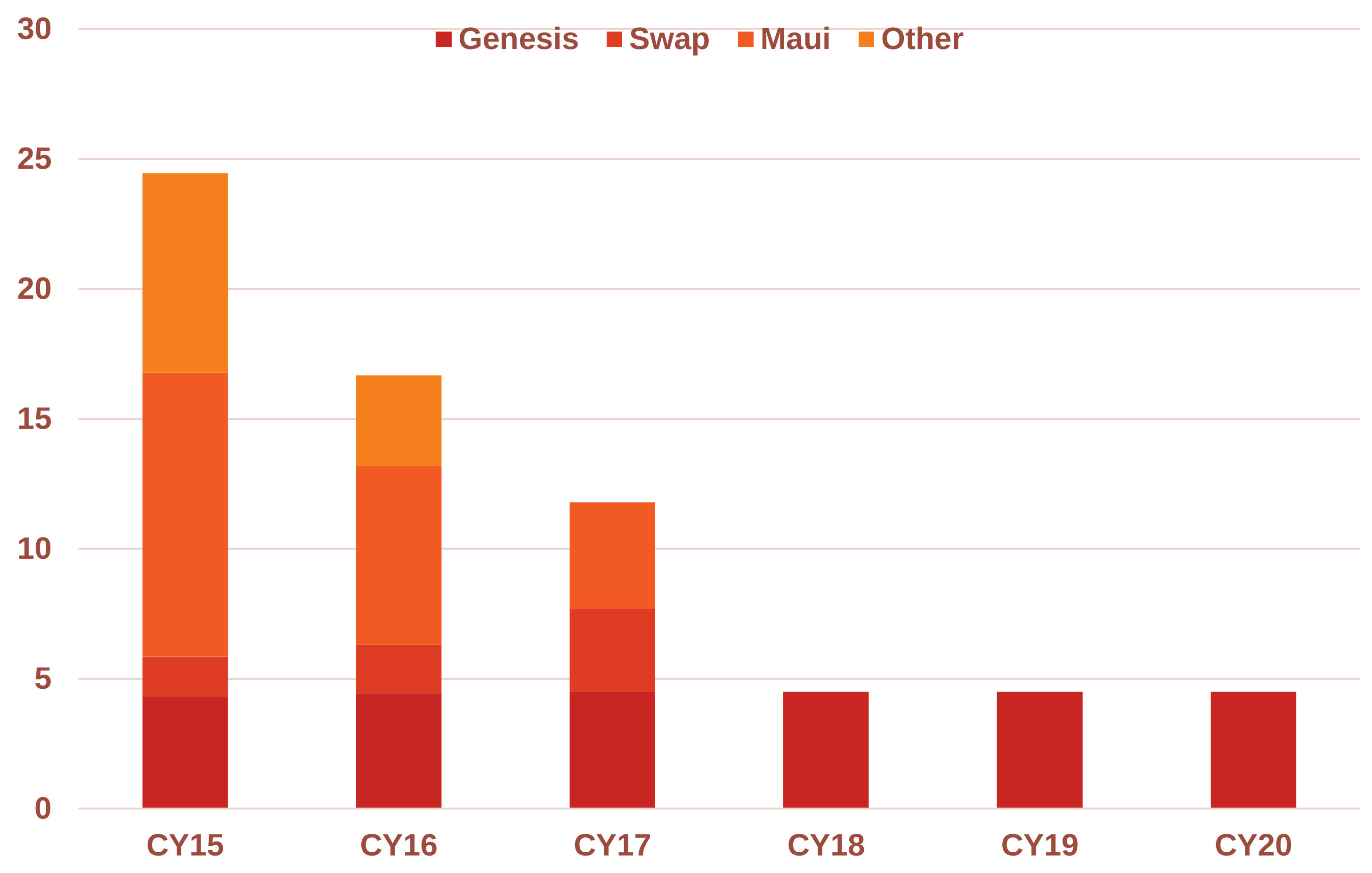


Plant reliability and generation revenue

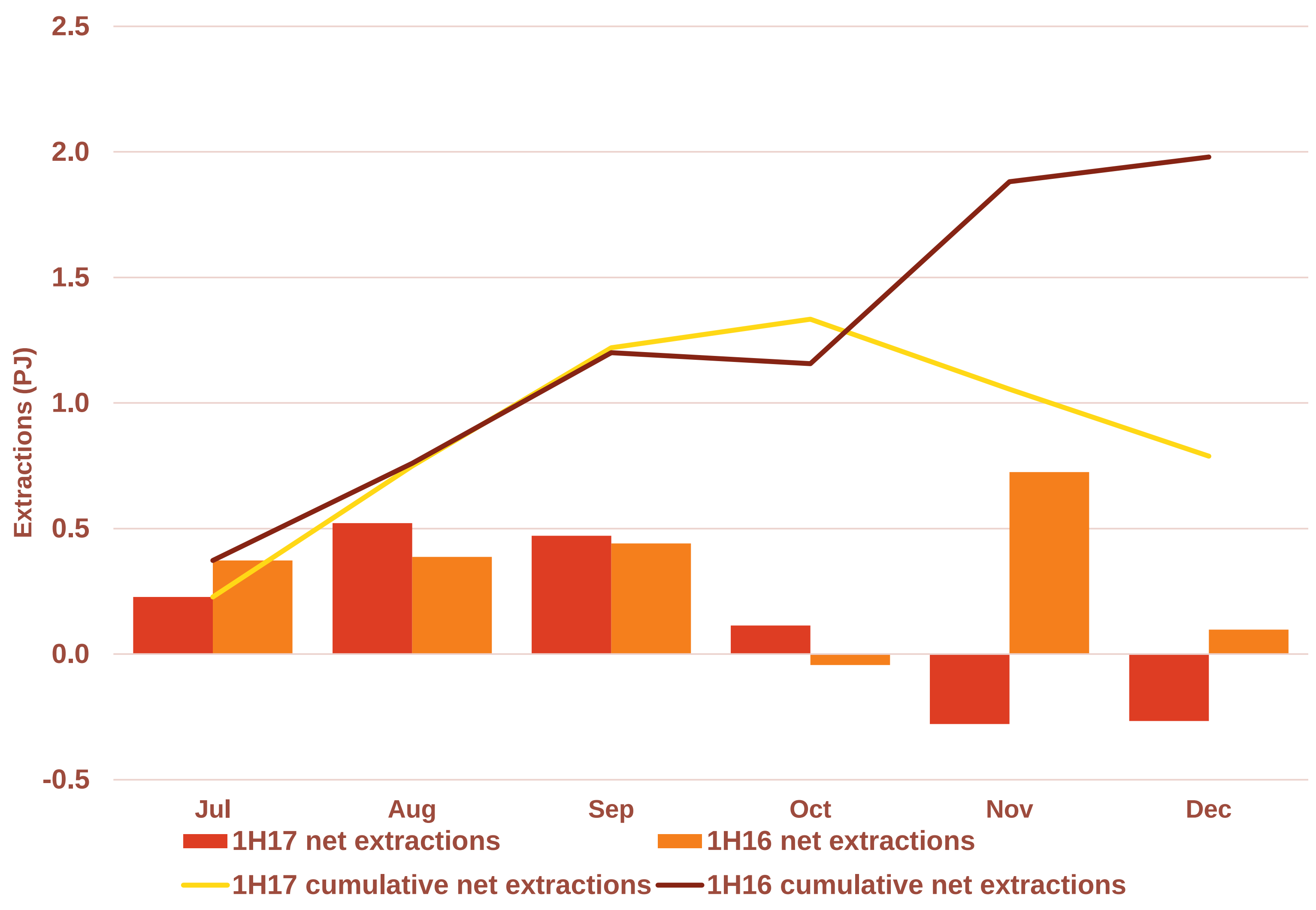
	Gross output	Plant availability		Capacity factor	Electricity output	Pool revenue	
		1H17	1H16				
	(MW)	(%)	(%)	(%)	(GWh)	($/MWh)	($m)
Hydro	752	91%	84%	60%	2,073	42	87
Geothermal	431	89%	91%	82%	1,552	50	78
CCGTs	377	95%	97%	18%	298	52	15
Te Rapa (spot only)	44	100%	100%	61%	111	53	6
Peakers (incl Whirinaki)	365	96%	93%	17%	276	60	17
Total	**1,969**	**92%**	**91%**	**49%**	**4,310**	**47**	**203**

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

Contracted gas volumes



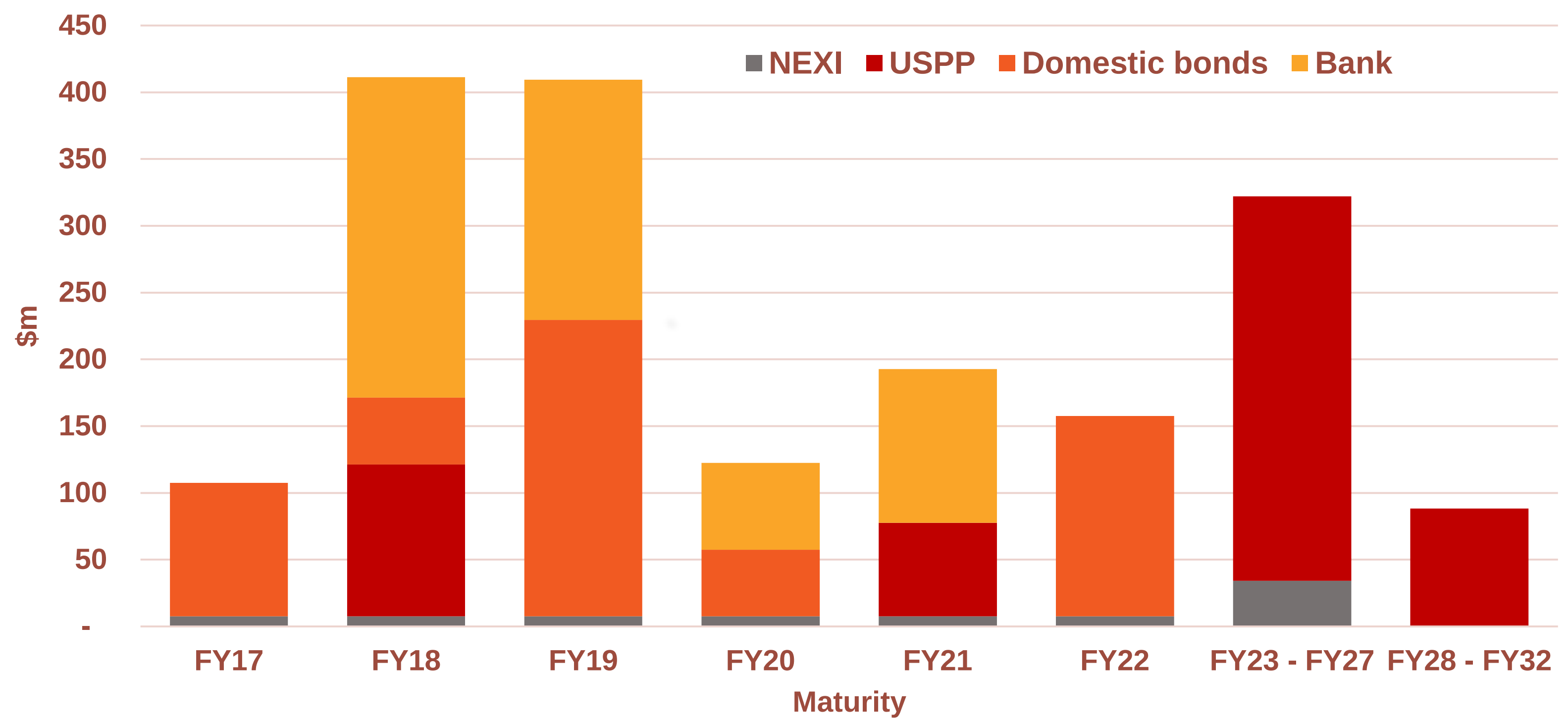
Ahuroa gas storage monthly injections and extractions



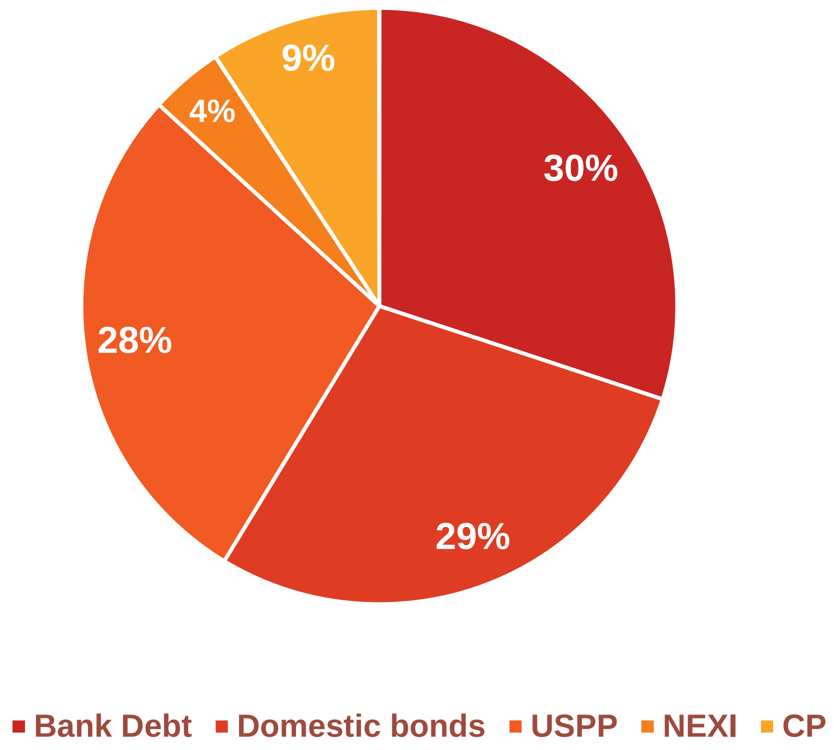
» Working volume in Ahuroa gas storage at 31 December 2016 was 10.1PJ

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 ($187m drawn as at 31 December 2016) and $185m commercial paper
- Weighted average tenor of funding facilities 3.9 years

» Average weighted cost of borrowings down 0.4% from 1H16 to 5.1% in 1H17

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	6 months ended 31 December 2016	6 months ended 31 December 2015	Variance $m	Variance %
EBITDAF	**261**	**254**	**7**	**3%**
Depreciation and amortisation	(99)	(97)	(2)	(2%)
Change in fair value of financial instruments	30	(9)	39	433%
Other significant items	(11)	(263)	252	96%
Net interest expense	(47)	(52)	5	10%
Tax expense	(38)	51	(89)	(175%)
Profit/(loss)	**96**	**(116)**	**212**	**183%**

- 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 $2m (2%) due to accelerated depreciation on geothermal wells being decommissioned in FY17
- Change in fair value of financial instruments: the balance of $30m 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 $5m (10%) to $47 million in 1H17 due to reduced debt level and lower average interest rates
- Tax expense for 1H17 is $38m compared to $51m credit for 1H16. The difference in tax expense is driven by there being no significant impairments or non-taxable income amounts in 1H17. Tax expense represents an effective tax rate of 28.2 per cent. 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:

	6 months ended	6 months ended	Variance	
$m	**31 December 2016**	**31 December 2015**	**$m**	**%**
Profit/(loss)	**96**	**(116)**	**212**	**183%**
Change in fair value of financial instruments	(30)	9	(39)	(433%)
Transition costs	7	5	2	40%
Remediation for Holidays Act non-compliance	5	-	5	100%
Asset impairments	-	35	(35)	(100%)
Otahuhu thermal power station closure and sale	(1)	223	(224)	(100%)
Tax on items excluded from underlying profit	5	(83)	88	106%
Underlying profit	**82**	**73**	**9**	**12%**

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.
- Otahuhu thermal power station closure and sale: Remaining costs and proceeds from asset sales relating to the Otahuhu power station sale that occurred during the year ended 30 June 2016

Costs to operate AGS, 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 1H17 EBITDAF by $2m with other operating costs $3m higher on a like-for-like basis on 1H16.

» Current run-rate can be extrapolated for full year impact

» Fixed costs to operate the facility have all been included under other operating costs, which improves the transparency around AGS costs, variable operating costs including gas transmission costs continue to be included in cost of energy

AGS costs – 6 months ended 31 December 2016 ($m)	Historically	1H17 change	Change
Inventory (Balance sheet)	2	-	(2)
Gas transportation and purchase costs (Profit and Loss – Cost of energy)	2	1	(1)
Other operating expenses (Profit and Loss – Other operating expenses)		3	3
Total AGS costs to operate	4	4	-
EBITDAF impact	**(2)**	**(4)**	**(2)**

Customer segment

Customer segment $m	6 months ended 31 December 2016	6 months ended 31 December 2015	Variance $m	 %
Mass market electricity	466	481	(15)	(3%)
Commercial and industrial electricity	251	249	2	1%
Gas	36	35	1	3%
LPG	64	63	1	2%
Other income	1	2	(1)	(50%)
Total revenue and other income	**818**	**830**	**(12)**	**(1%)**
Inter-segment electricity purchases	(328)	(337)	9	3%
Gas purchases	(8)	(8)	-	0%
LPG purchases	(34)	(38)	4	11%
Electricity networks, levies & meter costs	(305)	(310)	5	2%
Gas networks, levies & meter costs	(19)	(18)	(1)	(5%)
Emission costs	(1)	-	(1)	(100%)
Total direct costs	**(695)**	**(711)**	**16**	**(2%)**
Other operating expenses	(66)	(68)	2	3%
EBITDAF	**57**	**51**	**6**	**12%**
Mass market electricity sales (GWh)	1,942	2,052	(110)	(5%)
Commercial & industrial electricity sales	2,059	1,974	85	4%
Retail gas sales (GWh)	392	377	15	4%
Total retail sales (GWh)	**4,393**	**4,403**	**(10)**	**(0%)**
LPG sales (tonnes)	38,112	37,379	733	2%
Average electricity sales price ($/MWH)	179.42	181.31	(1.89)	(1%)
Electricity direct pass through costs ($/M	(76.27)	(77.02)	0.75	1%
Electricity and gas cost to serve ($/MWh)	(13.24)	(13.75)	0.51	4%
Electricity and gas netback ($/MWh)	84.46	85.41	(0.95)	(1%)
Actual electricity line losses (%)	5%	7%	(2%)	(29%)
Retail gas sales (PJ)	1.3	1.3	-	0%
Electricity customer numbers (closing)	421,000	421,000	-	0%
Retail gas customer numbers (closing)	62,500	60,500	2,000	3%
LPG customer numbers (closing)	76,500	72,500	4,000	6%

Generation segment

Generation segment $m	6 months ended 31 December 2016	6 months ended 31 December 2015	Variance $m	 %
Wholesale electricity	217	276	(59)	(21%)
Inter-segment electricity sales	328	337	(9)	(3%)
Gas	-	1	(1)	(100%)
Steam	14	16	(2)	(13%)
Te Mihi compensation	-	2	(2)	(100%)
Total revenue and other income	**559**	**632**	**(73)**	**(12%)**
Electricity purchases	(219)	(263)	44	17%
Gas purchases	(45)	(70)	25	36%
Electricity networks & levies	(21)	(20)	(1)	(5%)
Gas networks & levies	(4)	(8)	4	50%
Carbon emissions	(4)	(4)	-	0%
Total cost of goods sold	**(293)**	**(365)**	**72**	**20%**
Other operating expenses	(62)	(64)	2	3%
EBITDAF	**204**	**203**	**1**	**(0%)**
Thermal generation (GWh)	685	1,036	(351)	(34%)
Geothermal generation(GWh)	1,552	1,623	(71)	(4%)
Hydro generation (GWh)	2,073	2,010	63	3%
Spot market generation (GWh)	**4,310**	**4,669**	**(359)**	**(8%)**
Spot electricity purchases (GWh)	4,156	4,186	(30)	(1%)
CfD sales/(purchases) (GWh)	(41)	39	(80)	(205%)
GWAP ($/MWh)	47.04	57.80	(10.76)	(19%)
LWAP ($/MWh)	(52.78)	(62.34)	9.56	15%
LWAP/GWAP (%)	(112%)	(108%)	(4%)	(4%)
Gas used in internal generation (PJ)	7.4	9.8	(2.4)	(24%)
Steam sales (GWh)	349	377	(28.0)	(7%)
Gas storage net movement (PJ)	(0.8)	(2.0)	1.2	60%
Unit generation costs ($MWh)	(31.16)	(35.13)	3.97	11%
Cost of energy ($MWh)	(28.41)	(30.62)	2.21	7%

Customer and Generation segments reconciliation to previously reported operating statistics

	6 months ended 31 December 2016			6 months ended 31 December 2015			12 months ended 30 June 2016		
	$m	GWh	$/MWh	$m	GWh	$/MWh	$m	GWh	$/MWh
Customer EBITDAF									
Mass market electricity sales	466	1,942	240.25	481	2,052	234.28	903	3,792	238.23
Commercial & industrial electricity sales	251	2,059	122.07	249	1,974	126.25	520	4,099	126.84
Retail gas sales	36	392	91.43	35	377	93.35	62	618	100.92
Steam sales	14	349	39.76	16	377	41.33	25	626	40.46
Total retail sales	**768**	**4,741**		**781**	**4,780**		**1,511**	**9,134**	
Electricity networks, transmission, levies and meter costs	(305)	4,001	(76.27)	(310)	4,026	(77.02)	(596)	7,890	(75.51)
Gas networks, transmission, levies and meter costs	(19)	392	(49.42)	(18)	377	(48.82)	(34)	618	(54.26)
Electricity and gas cost to serve	(58)	4,393	(13.24)	(61)	4,403	(13.75)	(112)	8,509	(13.20)
Electricity, Gas and Steam Netback	**385**	**4,741**	**81.18**	**392**	**4,780**	**81.94**	**769**	**9,134**	**84.21**
Less: Steam sales transferred to Generation	(14)	(349)	39.8	(16)	(377)	41.33	(25)	-626	40.46
Electricity and Gas Netback	**371**	**4,393**	**84.46**	**376**	**4,403**	**85.42**	**744**	**8,509**	**87.43**
Electricity purchases from Generation	(328)	4,001	(81.99)	(338)	4,026	(83.85)	(675) [1]	7,890	(85.57)
Gas purchases	(8)			(9)			(14)		
LPG revenue	64			63			117		
LPG purchase costs	(34)			(38)			(69)		
LPG other operating expenses	(8)			(7)			(14)		
Other income	1			2			5		
Customer EBITDAF	**57**	**4,393**	**13.00**	**51**	**4,403**	**11.55**	**94**	**8,509**	**11.01**
Generation EBITDAF									
Cost of Energy	**(146)**	**4,741**	**(30.88)**	**(159)**	**4,780**	**(33.27)**	**(285)**	**9,134**	**(31.23)**
Transfer retail gas purchase costs	8			9			14		
Add: Steam sales	14			16			25		
Cost of Energy	**(125)**	**4,393**	**(28.41)**	**(135)**	**4,403**	**(30.62)**	**(246)**	**8,509**	**(28.93)**
Electricity sales to Customer	328			338			675[1]		
Generation EBITDAF	**204**			**203**			**429**		
Contact EBITDAF	**261**			**254**			**523**		

Unit generation cost definition unchanged (Generation gas purchases + electricity networks, transmission, levies and meter costs + carbon emissions + other operating expenses)/(spot market generation volumes)

[1] Inter-segment electricity purchases as per the Financial Statements for the six months ended 31 December 2016, which supercedes the pro-forma segment note that was released on 8 February 2017

Monthly operating statistics restated to include reporting segment changes

		Measure	Jul-15	Aug-15	Sep-15	Oct-15	Nov-15	Dec-15	Jan-16	Feb-16	Mar-16	Apr-16	May-16	Jun-16	Jul-16	Aug-16	Sep-16	Oct-16	Nov-16	Dec-16
Customer	Mass market electricity sales	GWh	418	404	359	309	283	278	251	245	279	284	321	360	396	393	330	301	261	260
	Commercial & industrial electricity sales	GWh	328	334	325	333	327	327	344	341	364	361	372	343	339	357	345	348	344	327
	Retail gas sales	GWh	87	84	69	56	44	37	26	25	32	40	51	67	81	72	77	72	50	39
	Total electricity and gas sales	GWh	833	822	754	698	654	643	622	611	674	685	744	770	816	822	753	720	655	627
	Average electricity sales price	$/MWh	193.94	191.87	183.77	174.45	168.96	169.85	170.33	170.88	174.94	177.55	186.12	193.32	193.48	189.04	178.85	173.85	164.61	171.65
	Electricity direct pass thru costs	$/MWh	(79.09)	(76.49)	(77.45)	(76.78)	(77.17)	(74.76)	(74.42)	(72.45)	(72.84)	(71.23)	(71.96)	(80.21)	(77.64)	(76.35)	(76.03)	(76.06)	(74.81)	(76.48)
	Electricity and gas cost to serve	$/MWh	(12.77)	(13.79)	(14.62)	(16.07)	(13.60)	(11.61)	(13.94)	(13.78)	(14.44)	(13.15)	(10.58)	(10.47)	(11.93)	(12.47)	(13.74)	(12.82)	(13.86)	(15.17)
	Electricity and Gas Netback	$/MWh	93.74	94.29	85.57	78.09	74.62	82.03	80.33	82.97	85.66	89.65	98.66	96.95	96.46	93.80	82.96	79.57	72.44	76.59
	Actual electricity line losses	%	8%	5%	4%	4%	6%	3%	4%	8%	3%	3%	8%	7%	6%	4%	5%	5%	5%	5%
	Retail gas sales	PJ	0.3	0.3	0.2	0.2	0.2	0.1	0.1	0.1	0.1	0.1	0.2	0.2	0.3	0.3	0.2	0.2	0.2	0.1
	LPG sales	tonnes	7,677	7,158	6,502	5,451	5,265	5,327	4,269	4,533	4,984	5,472	5,976	7,005	7,433	7,334	6,477	5,623	5,882	5,363
	Electricity customer numbers	#	428,500	427,000	424,500	423,000	422,000	421,000	420,500	421,000	422,000	423,500	424,000	425,000	425,500	423,500	423,000	423,000	422,500	421,000
	Gas customer numbers	#	61,500	61,500	61,000	61,000	61,000	60,500	60,500	60,500	61,000	61,500	61,500	62,000	62,000	62,000	62,500	62,500	62,500	62,500
	LPG customer numbers (includes franchises)	#	70,577	70,947	71,307	71,755	72,149	72,581	72,969	73,250	73,447	73,873	74,486	75,251	75,774	75,488	76,053	75,380	75,795	76,380
Generation	Thermal generation	GWh	231	236	254	89	170	56	90	74	137	65	86	126	148	171	148	128	54	37
	Geothermal generation	GWh	276	293	264	262	239	290	295	268	269	274	284	285	293	294	257	205	208	295
	Hydro generation	GWh	384	339	250	357	314	366	252	298	358	351	420	401	395	319	260	343	369	388
	Spot market generation	GWh	890	868	768	708	723	712	638	639	764	691	790	812	835	783	664	676	632	720
	Spot electricity purchases	GWh	807	763	703	658	641	614	609	628	656	657	744	751	779	770	698	670	628	610
	CfD sales	GWh	12	7	15	(12)	16	1	8	(2)	52	(11)	(15)	9	13	(9)	(78)	(5)	(15)	53
	Steam sales	GWh	38	70	67	69	66	67	59	50	44	46	36	14	34	69	66	65	60	55
	GWAP	$/MWh	51	53	57	56	64	68	68	64	57	62	54	53	54	51	50	45	42	38
	LWAP	$/MWh	(56)	(56)	(60)	(61)	(70)	(76)	(73)	(70)	(63)	(69)	(61)	(61)	(63)	(56)	(54)	(50)	(47)	(44)
	LWAP/GWAP	%	108%	105%	106%	109%	109%	111%	108%	110%	111%	110%	112%	115%	115%	109%	107%	110%	114%	118%
	Gas used in internal generation	PJ	2.0	2.0	2.2	1.1	1.7	0.8	1.1	0.9	1.3	0.8	1.0	1.1	1.4	1.7	1.5	1.3	0.7	0.6
	Wholesale gas sales	PJ	0.0	0.0	0.0	0.0	0.0	0.0	0.0	-	-	-	-	-	-	-	-	-	-	-
	Gas storage net movement	PJ	(0.4)	(0.4)	(0.4)	0.0	(0.7)	(0.1)	0.0	0.1	0.2	0.6	0.5	0.3	(0.2)	(0.5)	(0.5)	(0.1)	0.3	0.3
	Unit generation cost	$/MWh	(35.17)	(36.94)	(43.45)	(29.98)	(37.82)	(26.30)	(30.05)	(29.90)	(30.81)	(26.26)	(25.58)	(26.26)	(27.80)	(33.37)	(35.46)	(33.45)	(32.22)	(25.55)
	Cost of Energy	$/MWh	(34.00)	(32.11)	(38.76)	(23.98)	(36.22)	(16.25)	(30.29)	(30.69)	(26.44)	(26.02)	(27.68)	(22.82)	(25.34)	(30.27)	(31.81)	(30.35)	(30.74)	(21.24)

[1] Data has been rounded to the nearest 500 and reflects numbers as at month end.