175 YEARS SUPPORTING THE COMMUNITY

AGL

FY13 Interim Results

6 Months to 31 December 2012

Michael Fraser, Managing Director and CEO
Brett Redman, Chief Financial Officer | 27 February 2013

Disclaimer and important information

The information in this presentation:

- Is not an offer or recommendation to purchase or subscribe for securities in AGL Energy Limited or to retain any securities currently held.
- Does not take into account the potential and current individual investment objectives or the financial situation of investors.
- Was prepared with due care and attention and is current at the date of the presentation.

Actual results may materially vary from any forecasts (where applicable) in this presentation.

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Statutory Profit and Underlying Profit

Statutory Profit is prepared in accordance with the Corporations Act 2001 and the Australian Accounting Standards, which comply with the International Financial Reporting Standards.

Underlying Profit is the Statutory Profit adjusted for significant items and changes in fair value of financial instruments.

Underlying Profit has been presented with reference to the Australian Securities and Investment Commission Regulatory Guide 230 “Disclosing non-IFRS financial information” issued in December 2011. AGL’s policy for reporting Underlying Profit is consistent with this guidance and the Directors have had the consistency of the application of the policy reviewed by the external auditors of AGL. For more information refer to slide 7 and the Appendix 4D.

Agenda

› **Result Highlights**	Michael Fraser
› **Group Financials**	Brett Redman
› **Operational Review / Summary**	Michael Fraser
› **Supplementary Information**	

IMPORTANT NOTE:
This presentation should be read in conjunction with the AGL Energy Limited ASX Appendix 4D for the 6 months ended 31 December 2012.

Half year FY13 highlights

Integrated strategy drives strong earnings and cash flow growth.

- Underlying Profit up 20% to $279.4 million
- Underlying Operating Cash Flow before interest and tax up $492.4 million
- Merchant Operating EBIT up $204.5 million (+82%) primarily reflecting Loy Yang A contribution
- Retail Operating EBIT down by $41.8 million (-23%)
  - Timing differences reduced earnings by $68 million, will reverse in second half
- Queensland regulatory pricing decision reduced Operating EBIT by $29 million
- Continued strong NSW electricity customer growth (+64,220)
- Macarthur wind farm (420 MW) commenced generating September 2012
- $2.7 billion of Loy Yang A debt restructured in August 2012

Interim FY13 result

Strong growth in Statutory and Underlying Profit.

FINANCIAL

› Revenue:	$4,970.2m	↑ 37.5%
› Statutory Profit:	$364.7m	↑ 211.7%
› Underlying Profit:	$279.4m	↑ 20.0%
› Statutory EPS:	66.5 cps	↑ 171.4%
› Underlying EPS:	51.0 cps	↑ 4.7%
› Dividends Per Share (100% franked):	30.0 cps (Dec 11: 28.1 cps[1])	↑ 6.8%
› Operating EBITDA / Net Interest:	5.9x (Dec 11: 18.8x)	↓ 12.9x
› Gearing (Net Debt / Net Debt + Equity):	26.2% (Jun 12: 26.1%)	↑ 0.1 ppt
› Statutory operating cash flow after tax:	$364.8m	↑ $337.0m
› Underlying operating cash flow before interest and tax:	$644.8m	↑ $492.4m

OPERATIONAL

- Strong growth in Merchant reflects:
  - Successful integration of Loy Yang A into AGL's portfolio of generation assets
  - 100% increase in electricity generated by AGL owned/controlled assets
  - Macarthur wind farm contributes 127.7 GWh of generation since 30 September 2012
- Retail EBIT growth of 14.7%, excluding impact of carbon and transfer price timing differences
- Higher operating cash flow reflects higher earnings and a working capital benefit from carbon as payment of 75% of the carbon liability is not required until H2

[1] Adjusted for bonus element of 2012 rights entitlement offer

Group Financials

Brett Redman
Chief Financial Officer

Statutory Profit to Underlying Profit reconciliation

Volatility of non-cash items highlights value of focus on Underlying Profit.

6 months to $m	31 Dec 2012	31 Dec 2011	Change
Statutory Profit	**364.7**	117.0	↑ 247.7
Adjust for the following after tax items:			
Significant items	**-**	-	
Changes in fair value of financial instruments	**(85.3)**	115.9	↓ 201.2
Underlying Profit	**279.4**	232.9	↑ 46.5

› Changes in the fair value of financial instruments arise from an accounting standard requirement to value certain components of AGL's derivative portfolio differently to the value of the underlying asset to AGL's business. This is a non-cash accounting entry

› AGL believes Underlying Profit provides a better understanding of its financial performance because it:

  » removes significant items that are material items of revenue or expense that are unrelated to the underlying performance of the business thereby facilitating a more representative comparison of financial performance between financial periods

  » removes changes in the fair value of financial instruments recognised in the income statement to remove the volatility caused by mismatches in valuing derivatives and the underlying asset

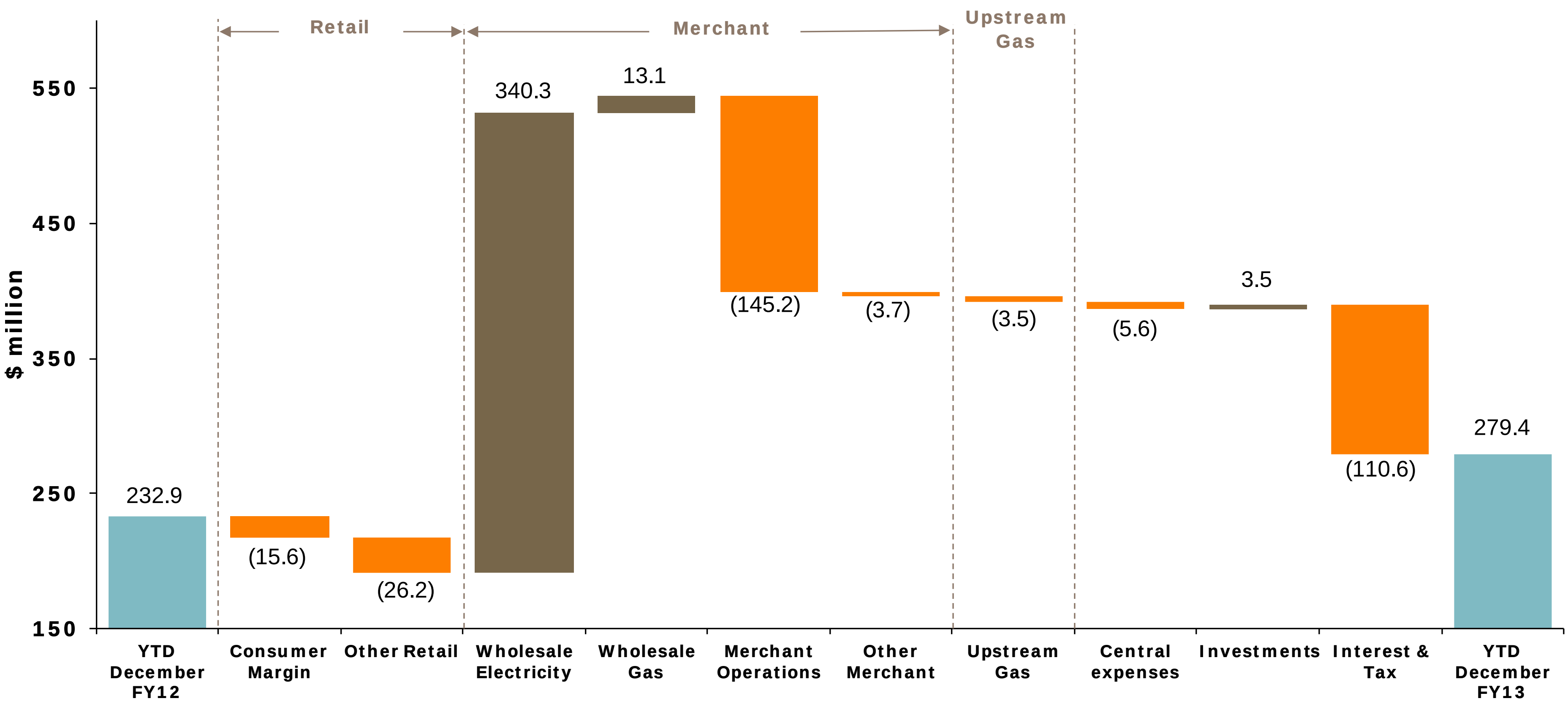
Underlying Profit

Generation portfolio drives step change in Operating EBITDA.

6 months to $m	31 Dec 2012	31 Dec 2011	Change
Revenue	**4,970.2**	3,615.3	37.5%
Operating EBITDA	**650.0**	438.9	48.1%
Operating EBIT			
Retail	**136.4**	178.2	(23.5%)
Merchant	**453.3**	248.8	82.2%
Upstream Gas	**(2.5)**	1.0	(350.0%)
Energy Investments	**15.9**	12.4	28.2%
Centrally managed expenses	**(91.4)**	(85.8)	6.5%
Total Operating EBIT	**511.7**	354.6	44.3%
Less: Net finance costs	**(109.4)**	(23.3)	369.5%
Underlying Profit before tax	**402.3**	331.3	21.4%
Less: Income tax expense	**(122.9)**	(98.4)	24.9%
Underlying Profit	**279.4**	232.9	20.0%

Group Underlying Profit

Loy Yang A and renewable portfolio lift Wholesale Electricity contribution.



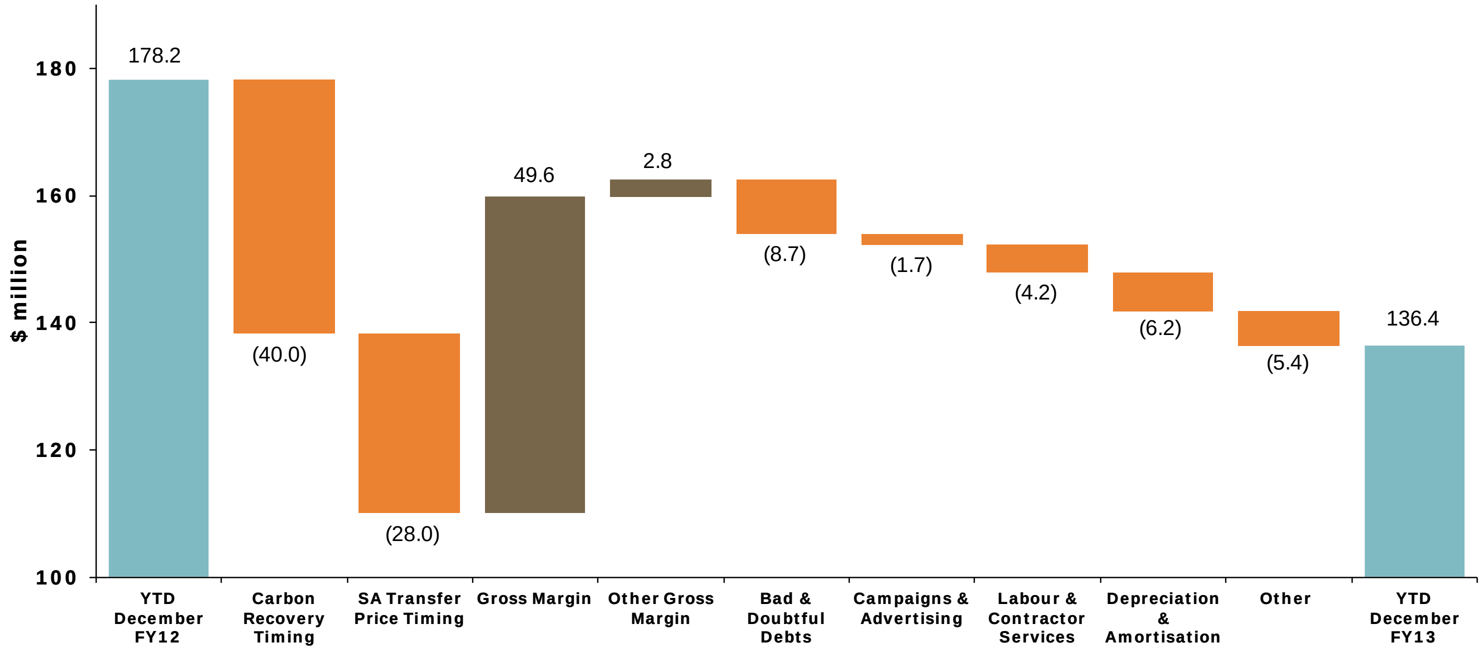
Retail – key financial metrics

Carbon and increased network charges drive higher revenue and costs.

6 months to $m	31 Dec 2012	31 Dec 2011	Change
Electricity Revenue	**1,774.3**	1,410.2	25.8%
Gas Revenue	**698.1**	582.8	19.8%
Other Revenue (Fees & Charges)	**41.2**	38.4	7.3%
Total Revenue	**2,513.6**	2,031.4	23.7%
Cost of Sales	**(2,156.0)**	(1,658.1)	30.0%
Gross Margin	**357.6**	373.3	(4.2%)
Operating Costs (excl. D&A)	**(186.7)**	(166.8)	11.9%
Operating EBITDA	**170.9**	206.5	(17.2%)
D&A	**(34.5)**	(28.3)	21.9%
Operating EBIT	**136.4**	178.2	(23.5%)

Retail – Operating EBIT drivers

Carbon timing and change in transfer pricing from Merchant impact gross margin.



Key drivers:

› Electricity and gas gross margin reduced by $40 million from timing differences between incurring carbon cost and pass through to customers. This will reverse in the second half

› SA transfer pricing from Merchant was updated to be based on a financial year, making it same basis as other states. This lifts transfer prices in the first half by $28 million. Effect will reverse in the second half

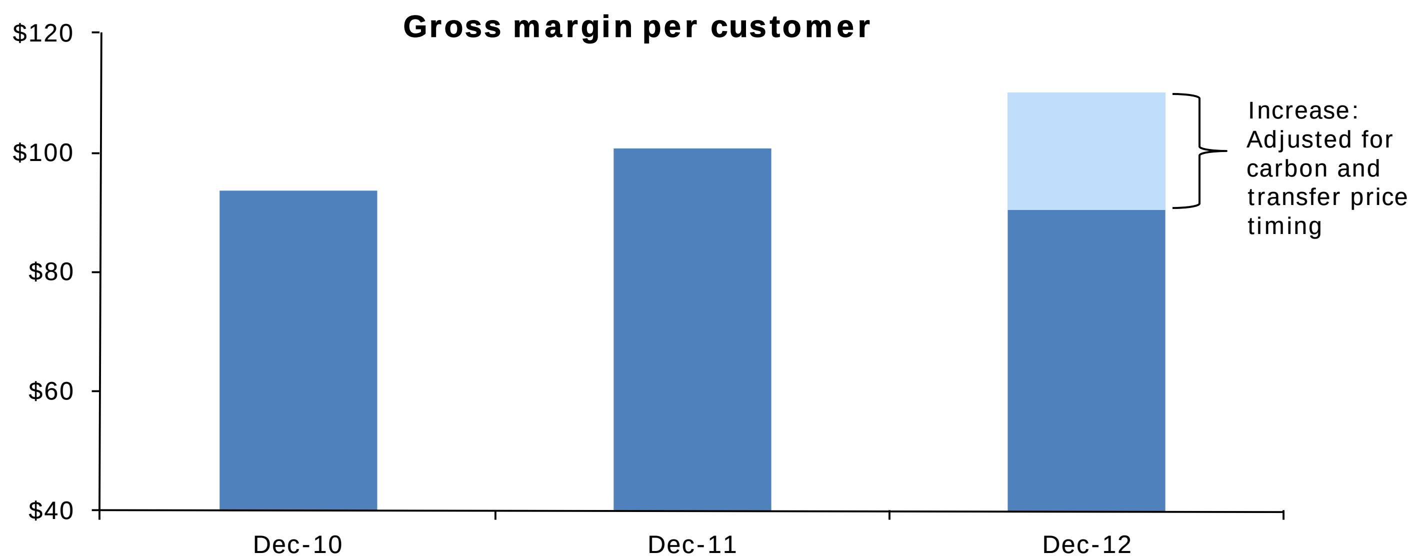
› Underlying gross margin improvement from customer growth in New South Wales, higher gas volumes and price management

› Increase in net bad debt expense consistent with higher revenue

Retail – key operating metrics

Normalised gross margin per customer at $110.

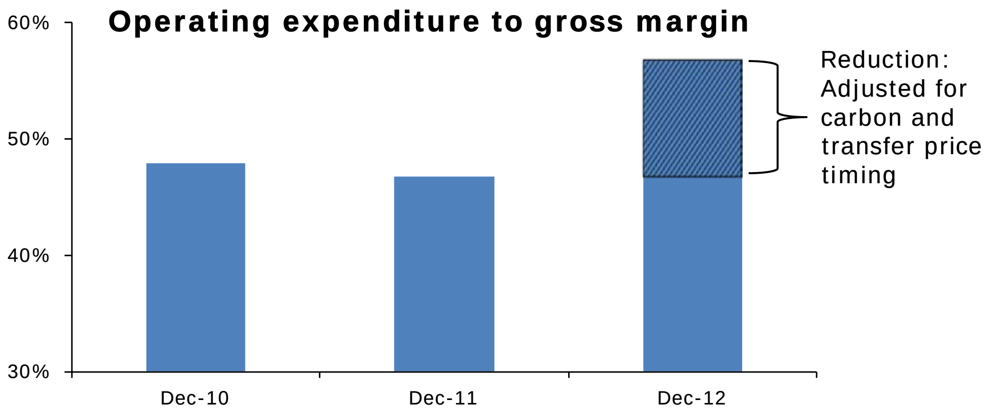
6 months to	31 Dec 2012	31 Dec 2011	Change
Consumer gross margin ($m)	**316.4**	334.9	(5.5%)
Average customer numbers (‘000)	**3,494.6**	3,322.3	5.2%
Gross margin per customer	**$90.54**	$100.80	(10.2%)
Gross margin per customer (excluding carbon and transfer price timing impact)	**$110.00**	$100.80	9.1%

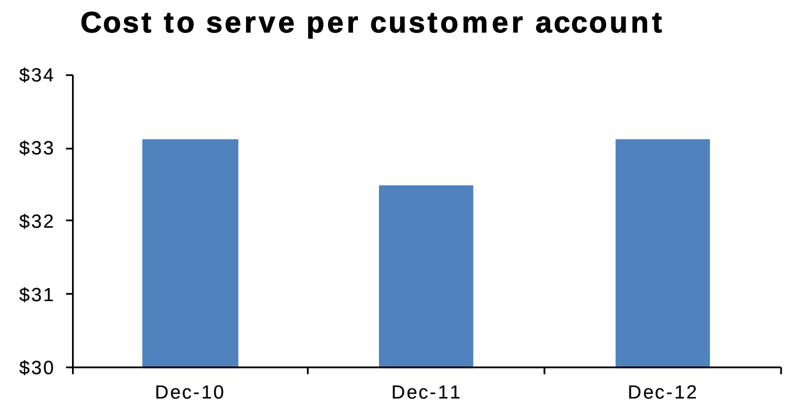


Retail – key operating metrics

Carbon and transfer price timing impacts key metrics.

6 months to $m	31 Dec 2012	31 Dec 2011	Change
Operating costs	**(186.7)**	(166.8)	11.9%
Depreciation and amortisation	**(34.5)**	(28.3)	21.9%
Less fees and charges	**41.2**	38.4	7.3%
Net operating costs	**(180.0)**	**(156.7)**	**14.9%**
Gross margin	**357.6**	373.3	(4.2%)
Less fees and charges	**(41.2)**	(38.4)	7.3%
Gross margin excluding fees and charges	**316.4**	**334.9**	**(5.5%)**
Operating expenditure to gross margin ratio	**56.9%**	46.8%	10.1ppts
Operating expenditure to gross margin ratio (excluding carbon and transfer price timing impact)	**46.8%**	46.8%	0.0ppts





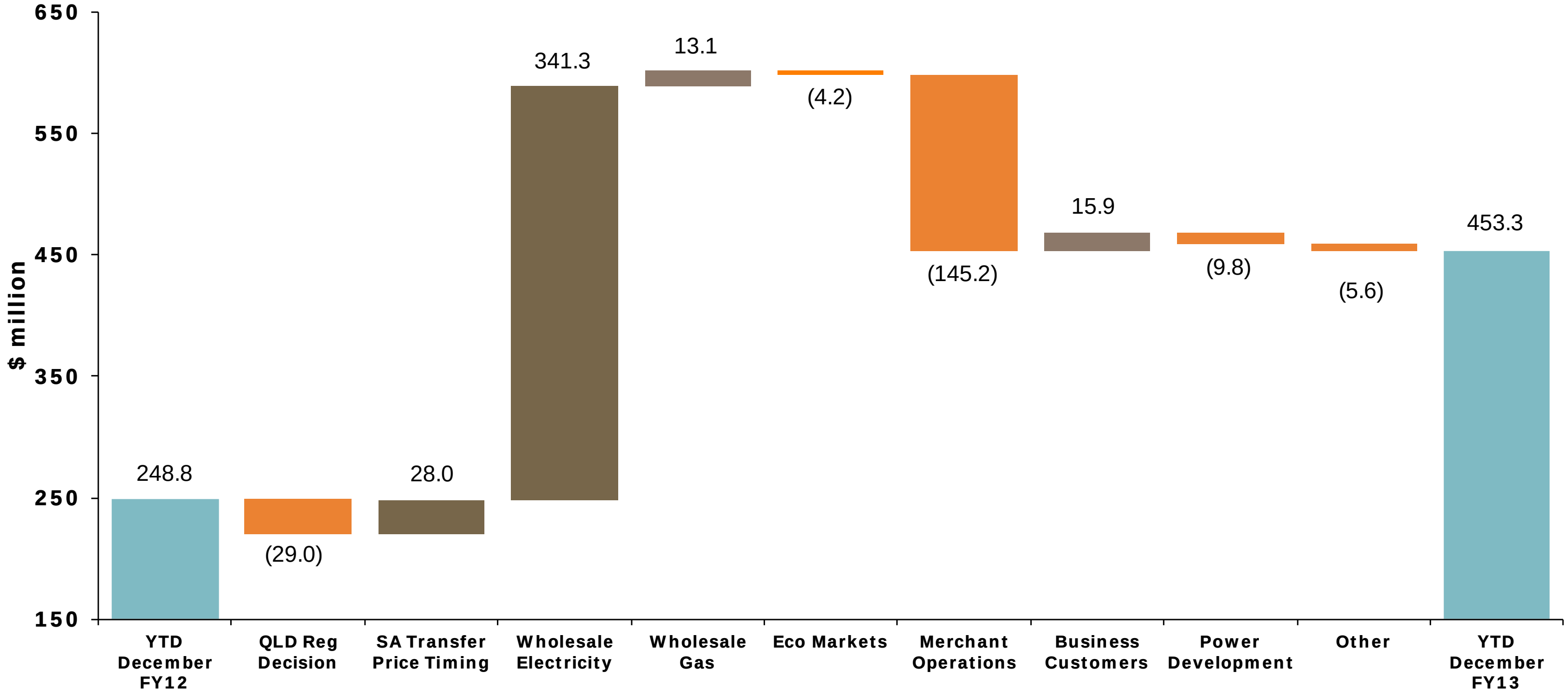
Merchant – key financial metrics

Loy Yang A drives growth in Operating EBIT.

6 months to $m	31 Dec 2012	31 Dec 2011	Change
Operating EBITDA	**535.7**	287.7	86.2%
Depreciation and amortisation	**(82.4)**	(38.9)	111.8%
EBIT			
Energy Portfolio Management (EPM)			
Wholesale Electricity Gross Margin	**518.9**	178.6	190.5%
Wholesale Gas Gross Margin	**71.8**	58.7	22.3%
Eco-markets Gross Margin	**28.9**	33.1	(12.7%)
EPM Operating Expenses (including D&A)	**(12.1)**	(11.0)	10.0%
Merchant Operations	**(203.6)**	(58.4)	248.6%
Business Customers			
Electricity Gross Margin	**32.2**	29.5	9.2%
Gas Gross Margin	**34.8**	20.7	68.1%
Operations, Sales and Customer Service	**(17.9)**	(16.6)	7.8%
Energy Services	**10.4**	10.0	4.0%
Power Development	**(0.4)**	9.4	(104.3%)
Sundry	**(9.7)**	(5.2)	86.5%
Operating EBIT	**453.3**	248.8	82.2%

Merchant – Operating EBIT drivers

Strong result in wholesale electricity driven by Loy Yang A and low carbon generation fleet.



Key drivers:

- Wholesale Electricity increases driven by Loy Yang A and balance of generation portfolio being below NEM average carbon intensity
- QCA regulatory decision reduced Wholesale Electricity EBIT by $29 million
- Wholesale Gas and Business Customers benefited from higher gas volumes compared to weaker winter last year
- Merchant Operations included costs of Loy Yang A generation
- No development fees in Power Development this year, compared with $10 million booked last year

Upstream Gas – key financial metrics

Gloucester project Stage 1 receives approval to proceed.

6 months to $m	31 Dec 2012	31 Dec 2011	Change
Operating EBITDA	**9.3**	11.1	(16.2%)
Depreciation and amortisation	**(11.8)**	(10.1)	16.8%
Operating EBIT			
Upstream Gas			
Queensland / South Australia	**1.3**	4.2	(69.0%)
New South Wales	**0.5**	1.0	(50.0%)
Equity Investments	**-**	(0.1)	(100.0%)
Sundry	**(4.3)**	(4.1)	4.9%
Operating EBIT	**(2.5)**	1.0	(350.0%)

Key drivers:

- Moranbah was adversely affected by lower gas bank income
- Silver Springs was negatively affected by lower storage injection income, higher operating expenses and higher depreciation and amortisation costs
- Camden incurred higher operating expenses from well workover activity and plant operating expenses

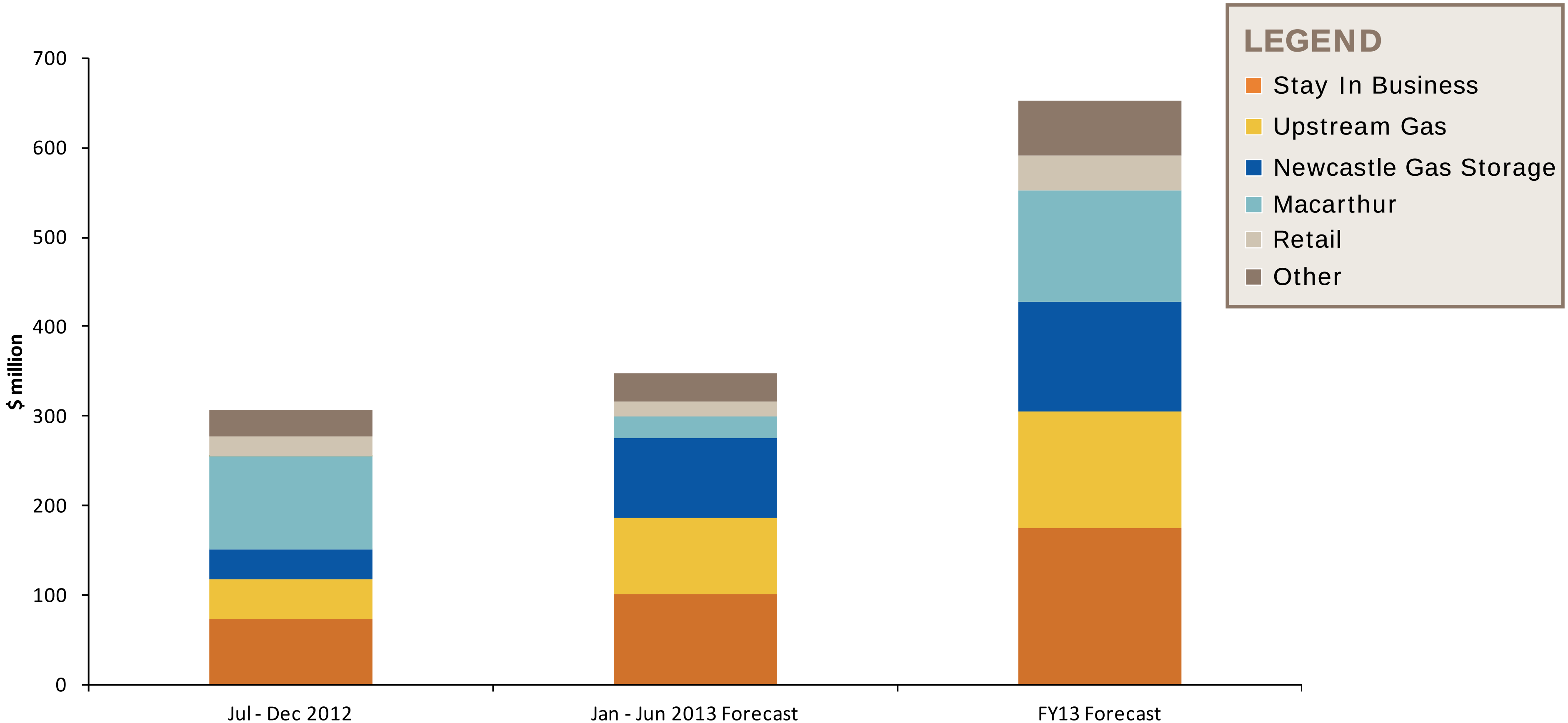
Underlying Operating cash flow

Higher earnings and working capital benefit from carbon lifts Operating cash flow.

6 months to $m	31 Dec 2012	31 Dec 2011	Change
Operating EBITDA	**650.0**	438.9	211.1
Equity accounted income	(2.9)	8.0	(10.9)
Onerous contracts	(26.4)	(10.4)	(16.0)
Receivables	(194.3)	(51.3)	(143.0)
Inventories	9.2	(7.5)	16.7
Creditors	(77.4)	(155.9)	78.5
Carbon Liability	295.5	-	295.5
Net derivative premiums paid / roll-offs	(13.6)	(44.5)	30.9
Net movement in GST recoverable / payable	17.3	(4.4)	21.7
Other	(12.6)	(20.5)	7.9
Total working capital movements	**24.1**	(284.1)	308.2
Underlying Operating cash flow before interest and tax	**644.8**	152.4	492.4

Capital expenditure

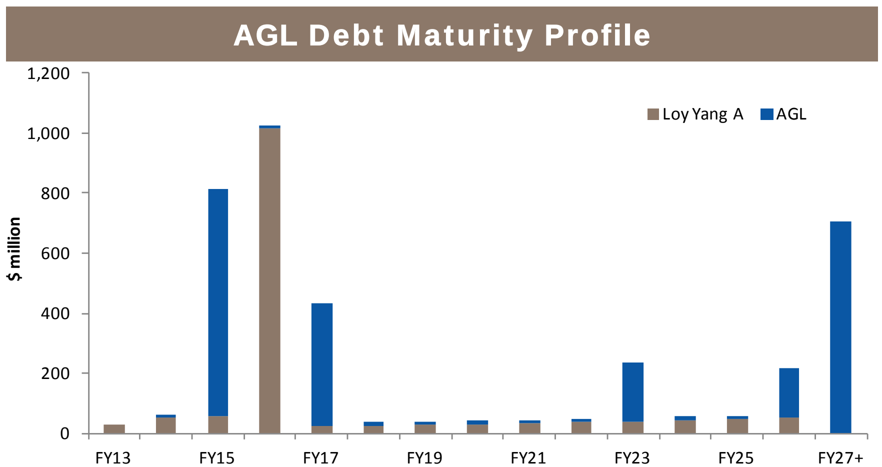
Stay in Business capital expenditure rises with Loy Yang A acquisition.



Debt structure

No major debt maturity until July 2014.

- Loy Yang A debt restructured in August 2012
- Standard & Poor's expected to lower equity credit content on $650 million hybrid
  - No impact on credit rating expected
- Entered into a $150 million working capital facility
- First carbon liability payment due 15 June 2013



Facilities at 31 Dec 2012	Limit $m	Usage $m
Current		
Loy Yang A Senior Debt	39.5	39.5
Export Credit Agency Facility	5.5	5.5
Non Current		
AGL – Term A	600.0	600.0
AGL – Term B	400.0	0.0
Working Capital Facility	150.0	0.0
AGL – US Senior Notes	337.8	337.8
Export Credit Agency Facility	194.5	194.5
Hybrid Subordinated Notes	650.0	650.0
Loy Yang A Senior Debt	1,439.9	1,439.9
Total Debt	3,817.2	3,267.2
Less: Cash		654.7
Net Debt		2,612.5

Operational Review

Michael Fraser
Managing Director & CEO

People and safety

Safety metrics require on-going focus.

Key safety statistics:

- Total injuries – 17 (Loy Yang A: 4)
- Lost time injuries - 7 (Loy Yang A: 2)

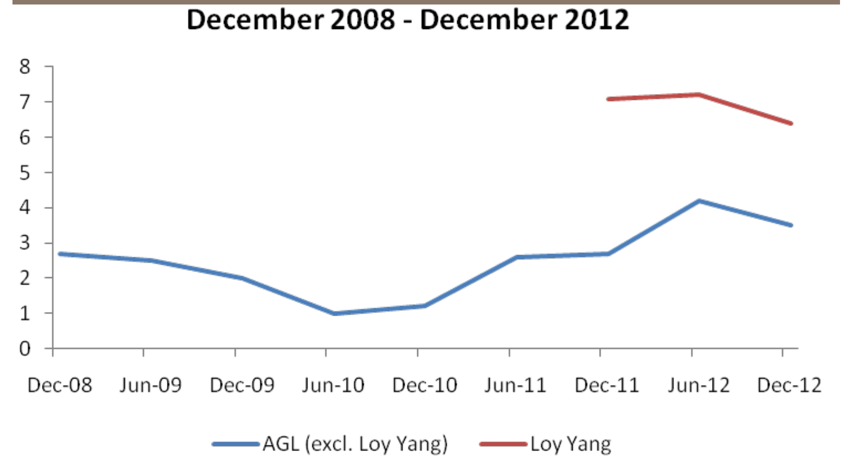
Key Health and Safety improvement initiatives:

- Increase safety leadership
- Strengthen management systems
- Mitigate H&S risks
- Manage non event related soft tissue injuries

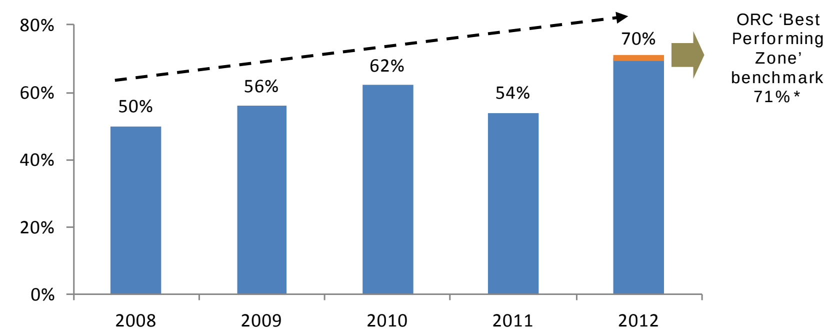
Key people initiatives:

- Improving employee and contractor safety
- Building capability in processes and people
- Sourcing talent to enable growth
- Develop employees as customer advocates

Employee Lost Time Injury Frequency Rate



Employee Engagement Score



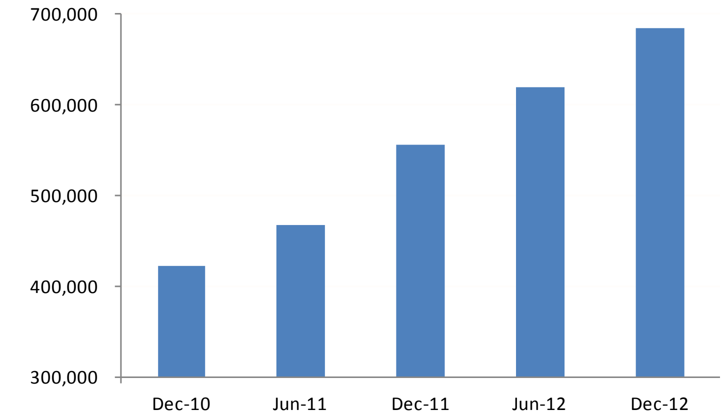
Note: 2008-2011 Engagement Score calculated using AON Hewitt methodology. 2012 Engagement Score calculated using ORC International methodology

AGL continues strong growth in New South Wales

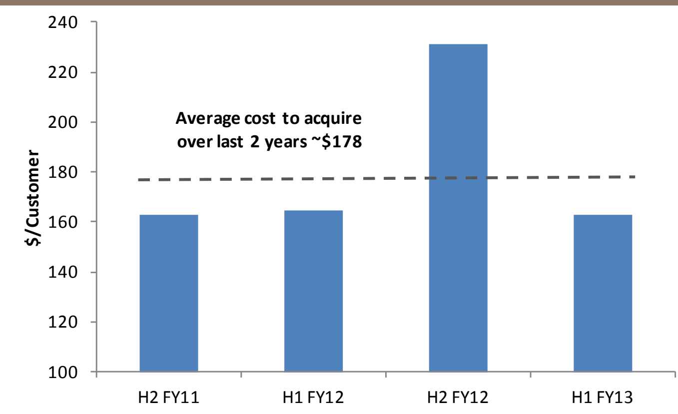
Organic growth strategy creates shareholder value.

- New South Wales electricity growth up 64,220
  - Net growth over 260,000 since 1 January 2011
  - NSW now AGL's largest electricity base with 684,140 customers
  - Capitalised cash outlay in H1 FY13 of $19 million
- Timing differences between campaign costs and customer acquisition
  - Average cost to acquire (FY12) $193
  - Average cost to acquire for H1 FY13 at $163
  - Full year FY13 customer acquisition costs expected to be similar to FY12
- Organic growth strategy continues to create significant shareholder value

NSW electricity customer numbers



NSW Average Cost to Acquire*



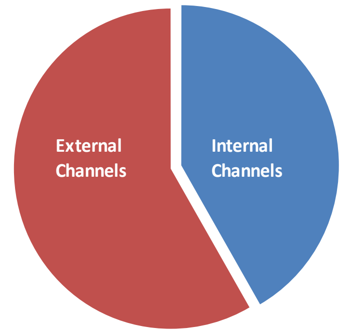
*Includes capitalised costs only

Net national customer growth of 56,711

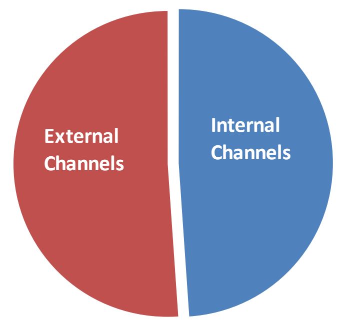
Competition intensifies and market dynamics continue to change.

- Net national customer growth of 56,711 (1.6%)
  - Dual fuel accounts up 50,948 (3.1%)
  - Significant competition in most states
- Customer growth in QLD electricity and SA gas was offset by a drop in VIC electricity and NSW gas
- Improved performance from internal sales channels
  - Door knocking accounts for ~20% of AGL's lead sales
- AGL lead industry by withdrawing from door knocking in QLD and SA
  - Positive consumer response sees AGL withdraw from door knocking in NSW and Victoria
  - Second tier retailers highly reliant on door-to-door selling
- Stable systems, low cost-to-serve and low cost-to-acquire underpin competitive position

Lead sales by channel type



H1 FY12



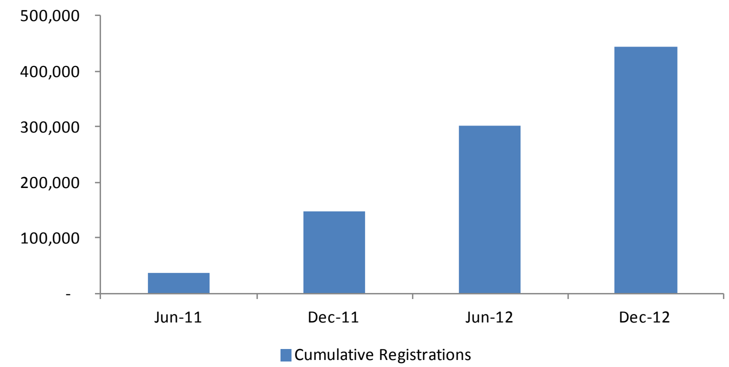
H1 FY13

AGL leading Australia's retail energy markets

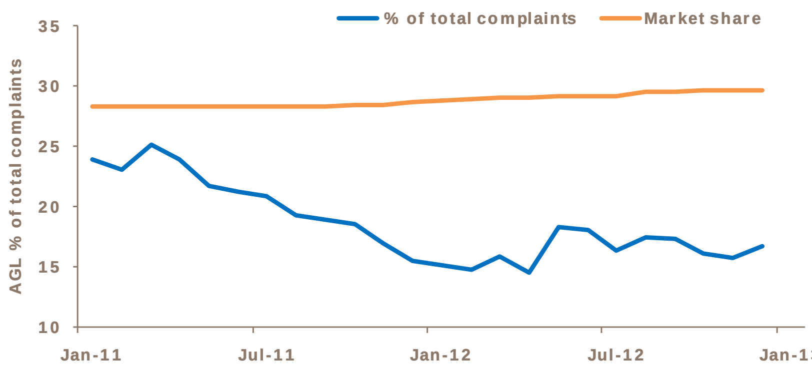
Customer engagement strategies underpin growth.

- AGL Smarter Living business model now fully integrated '*online, in store and in-home*'
- Online registrations grow steadily
  - AGL Energy Online registrations exceed 440,000
  - Over 500,000 e-billing accounts
- Over 300,000 AGL customers rewarded by linking their flybuys and energy accounts
- AGL maintains significant gap in national churn versus the rest of the market (18.9% versus 23.2%)
- Price rises and competitor activity increased Call Centre volumes
  - Additional resources added to maintain Average Speed of Answer and Handle Time
- Ombudsman complaints continue below market share
- AGL awarded Most Satisfied NSW Customers for Electricity and Gas Providers 2012 by Canstar Blue

AGL Energy Online - Customer Registrations



Share of Ombudsman complaints below market share



My AGL IQ™ launched

A world class offering – all customers, all states, all fuels and all meters.

- My AGL IQ™ launched 25 February 2013, enables customers to see, act and save on energy usage
- First major Australian retailer to deliver energy monitoring tools to all customers in all states
- More than 440,000 registered AGL Energy Online customers have access to My AGL IQ™
- My AGL IQ™ will enable customers to:
  - See and manage energy usage and spend
  - Receive alerts when usage is higher than plan[1]
  - Predict electricity consumption and spend[1]
  - Compare usage and spend with similar households
  - Get targeted energy advice and solutions
  - Set energy goals and track progress
- Designed in Australia for the Australian market
- World first implementation using SAP Smart Meter Analytics and HANA in memory computing

1. Function available for electricity Smart Meters only

Regulatory pricing

SA price deregulation is a positive step.

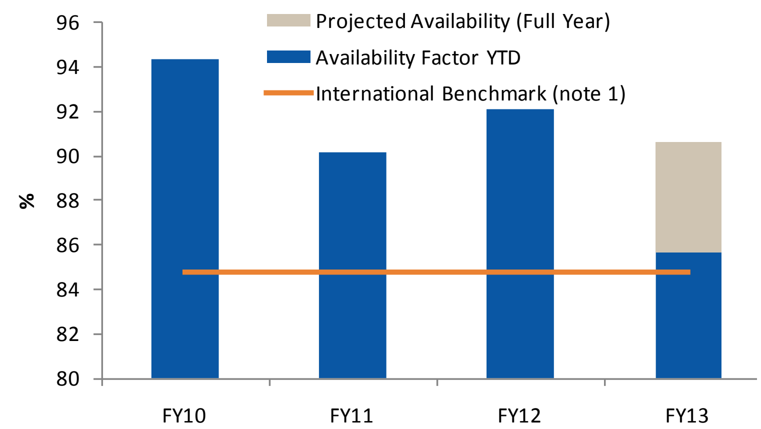
- SA government implemented price deregulation effective 1 February 2013
  - Increased levels of competition and investment expected in the SA electricity market
  - Guarantee residential and small business customers on standing contract price arrangements as at 31 January 2013 a 9.1% and 4.5% reduction respectively
  - Residential and small business customers moving to a standing contract price arrangement from 1 February 2013 receive a 4.5% reduction to the standing contract price
  - Expected to adversely impact Retail results by ~$15 million in second half
- QCA 2013/14 Draft Determination continues a market-based approach to set energy cost allowance
  - Pass-through of draft network tariff increase of 23% in South-East Queensland
  - Increase in 2013/14 energy cost does not reflect retailers' long-term energy costs
  - Persisting with short-run pricing approach is likely to further destabilise the industry
  - Reduction in retail competition expected to settle at historic lows
- NSW electricity pricing Draft Determination (2013-2016) expected to be released in April 2013
  - Strong levels of competition supports deregulation ahead of release of AEMC report due in September 2013
- NSW gas pricing Draft Determination (2013-2016) expected to be released in April 2013

Loy Yang A and Macarthur expand generation portfolio

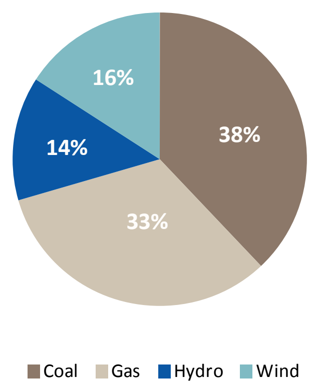
Plant availability reflects planned maintenance on Unit 1.

- Integration on track
- H1 FY13 operational performance
  - Availability factor - 85.7%
  - Capacity factor - 82.3%
  - Planned major outage on Unit 1 and control system upgrade
  - No major outages planned for the second half
  - Mine supplied 14.4 million tonnes of coal to Loy Yang A and Loy Yang B
  - Coal supply reliability - 99.2%
- Macarthur increases wind farm portfolio capacity by 83% to 924 MW
- Wind generation capacity now surpasses hydro capacity

Loy Yang A Availability Factor



Owned and / or Controlled Generation Portfolio Mix



Note 1: North American Electricity Reliability Corporation (NERC) 2006-2010 Historic Generation Unit statistics.

Continued growth in renewable portfolio

High wind farm capacity factors plus hydro storage near capacity.

› Total renewable portfolio capacity of 1,720 MW

› Strong track record of developing high performing wind projects on time and on budget

» Higher than average capacity factors

» Capacity factors of Hallett wind farms close to 40%

› Hydro dams near capacity

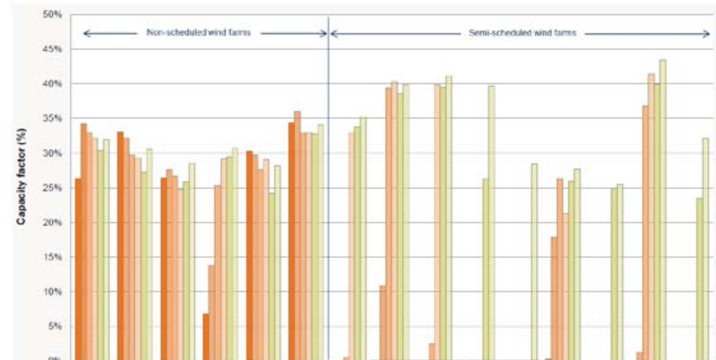
» Dartmouth capacity of 3,906 GL (6.7 times volume of Sydney Harbour)

» Eildon capacity of 3,334 GL

» Kiewa scheme (381 MW) runs off the Rocky Valley dam (28 GL) - generally refills around 3 times per annum

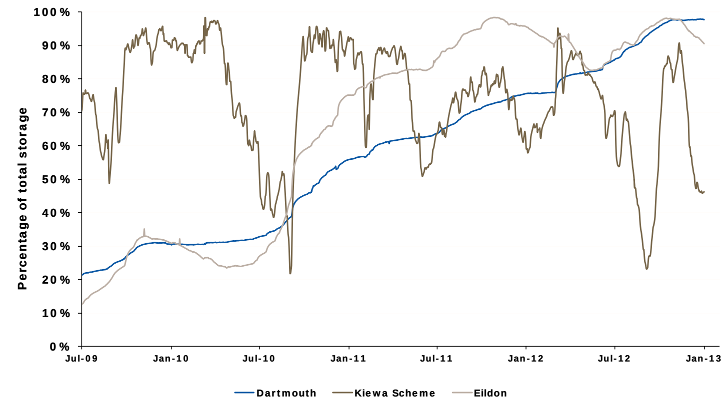
› Peaking capacity of hydro plants enable greater optimisation of portfolio

Wind Farm Capacity Factors



	Cathedral Rocks	Canunda	Lake Bonney 1	Mt Millar	Starfish Hill	Wattle Point	Clements Gap	Hallett 1 (Brown Hill)	Hallett 2 (Hallett Hill)	Hallett 4 (North Brown Hill)	Hallett 5 (The Bluff)	Lake Bonney 2	Lake Bonney 3	Snowtown	Waterloo
2006-07	26.4%	33.1%	26.5%	6.8%	30.3%	34.4%	0.0%	0.0%	0.0%	0.0%	0.0%	0.3%	0.0%	0.0%	0.0%
2007-08	34.3%	32.2%	27.6%	13.9%	29.7%	36.1%	0.0%	10.9%	0.0%	0.0%	0.0%	17.9%	0.0%	1.3%	0.0%
2008-09	33.0%	29.7%	26.7%	25.3%	27.6%	33.0%	0.6%	39.4%	2.5%	0.0%	0.0%	26.4%	0.0%	36.8%	0.0%
2009-10	32.2%	29.3%	24.7%	29.1%	29.0%	33.0%	32.9%	40.3%	39.8%	0.0%	0.0%	21.3%	0.0%	41.4%	0.0%
2010-11	30.4%	27.3%	25.8%	25.5%	24.3%	32.7%	33.8%	38.6%	39.5%	26.3%	0.0%	26.0%	24.8%	40.0%	23.5%
2011-12	31.9%	30.6%	28.6%	30.7%	28.2%	34.1%	35.2%	39.9%	41.1%	39.7%	28.4%	27.7%	25.5%	43.4%	32.1%

AGL Hydro Storage

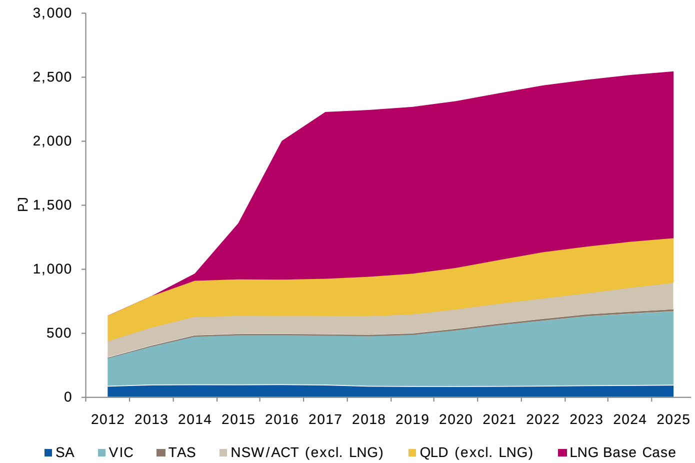


Subsequent events: NSW gas policy reversal

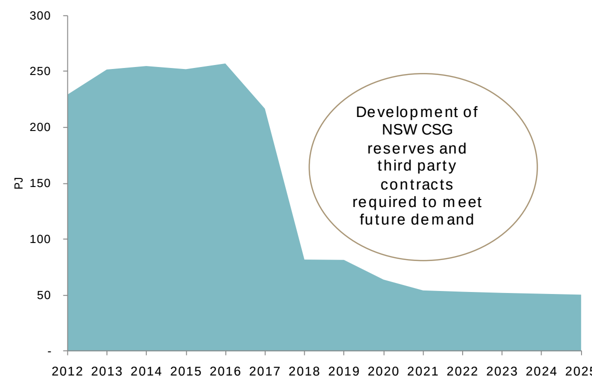
Likely asset impairment and future gas supply impacts.

- Book value of Camden (including the northern expansion) and Hunter gas projects of $325 million may be substantially impaired once rule changes finalised
- Further development of Gloucester may be impacted by proposed policy
- Arbitrary exclusion zones particularly around industry clusters will sterilise substantial resources
- Gladstone LNG exports increase to ~1,500 PJ/a co-incidentally with roll off of east coast domestic supply contracts
- Proposed policy will put significant upward pressure on future energy prices
- Industries most at risk are food processing, brick, cement, chemical and metal manufacturers
- Discussions underway with NSW Government around proposed policy

Eastern Australia Gas Demand



AGL Long-term Gas Supply Contracts



Gloucester Gas Project

State and Commonwealth approvals now in place for Stage 1.

- Approvals received for Stage 1 with a total of 128 conditions
  - State development approval 92 conditions
  - Federal EPBC 36 conditions
- Applications made for petroleum production licence and pipeline licence in December 2012
- Key exploration activities for 2013:
  - Drill 3 core holes
  - Test production from 4 wells drilled in October 2012
  - Test production at 2 pilot trials in the southern part of the basin
  - 3D seismic
  - Expand groundwater investigation program
- Final investment decision target mid 2014
  - First gas target Q4 2016; ~20 – 30 PJ/a

Aerial image of AGL's property near Gloucester

Newcastle Gas Storage and Diamantina Power Station

Construction well underway.

Newcastle Gas Storage Facility

- 120 TJ/day peaking capacity
- In-ground services are being installed including communications, water supply and temporary power
- Ground improvement under the LNG tank is complete and foundation works have started
- Completion targeted mid 2015

Diamantina Power Station – Mount Isa

- Financial close of project financing achieved December 2012
- 242 MW CCGT and 60 MW OCGT (dual fuel) power stations
- CCGT gas turbines installed
- CCGT operations targeted H1 2014
- 10.5 year gas supply contract commencing mid 2013 for 138 PJ

Aerial image of Newcastle Gas Storage Facility site (foreground)

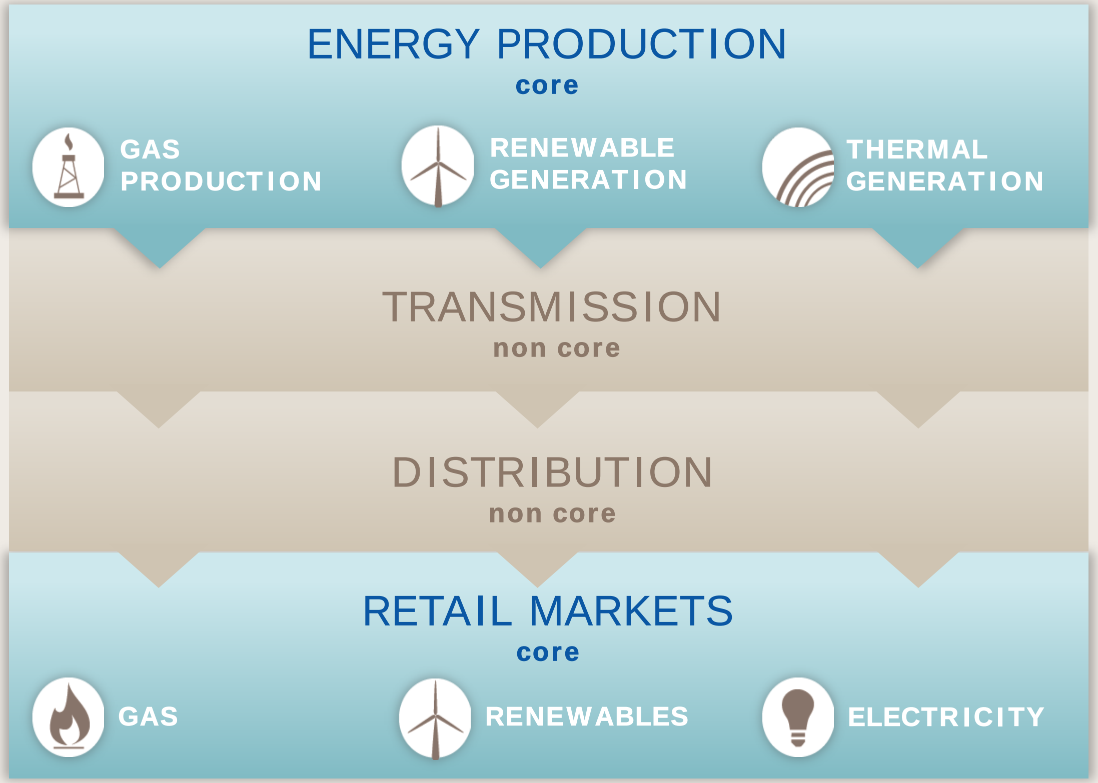
Aerial image of Diamantina Power Station site

Integrated strategy

Delivering growth and diversity of earnings.

Energy Production
Status

- 5,825 MW of operating capacity including 1,720 MW of renewable generation
- 10.2 TWh of self generation against sales of 15.7 TWh in H1
- 2,231 PJ of 2P gas reserves (including ATP 1103)
- 6.2 PJ of self production against sales of 80.1 PJ in H1
- Construction commenced on Newcastle gas storage
- Silver Springs gas storage capacity of 30 PJ

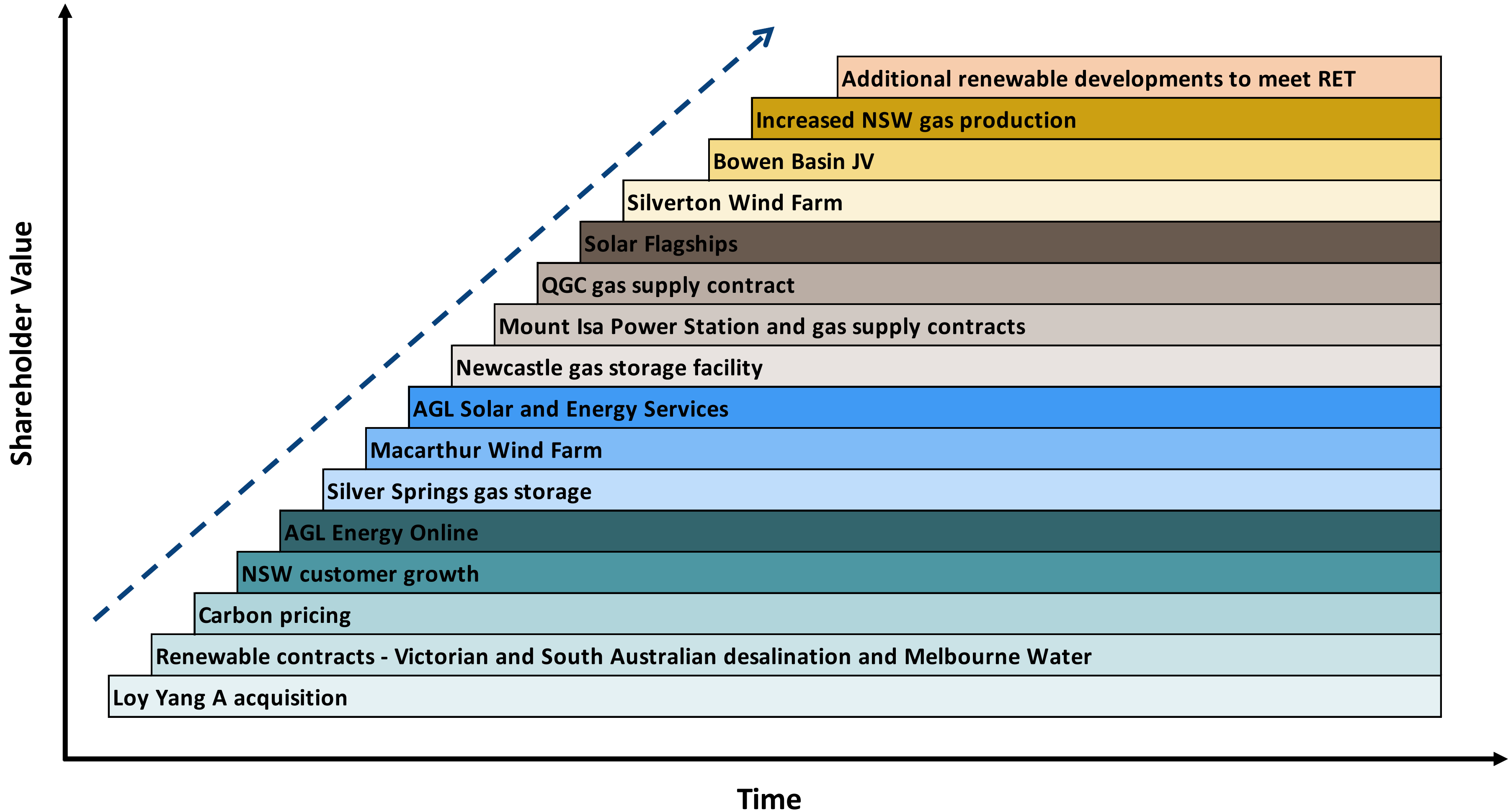


Retail Markets
Status

- 2.1 million electricity customers
- 1.4 million gas customers
- 1.7 million dual fuel customers
- 440,000 customers now online
- Over 500,000 e-billing accounts
- Over 300,000 customers linked to flybuys
- My Energy IQ launched
- AGL Smarter Living fully integrated

AGL growth pipelines

AGL's integrated strategy creating significant growth pipelines.



Summary

Loy Yang A and low carbon generation portfolio drive first half growth.

- Retail continues to perform well
  - Adverse QLD regulatory price determination begins to impact earnings
  - Continued strong growth in NSW electricity customer numbers
- Merchant delivers strong profit growth
  - Loy Yang A power station and mine successfully integrated
  - Electricity demand constrained by economic conditions
  - Macarthur wind farm (420 MW) delivered on-time and on-budget
- Increased operating cash flow driven by Loy Yang A and timing difference between payment of carbon liability and pass through to customers

Outlook FY13

Underlying NPAT guidance of $590 million to $640 million reaffirmed.

- Previous guidance of Underlying NPAT for FY13 of $590 million to $640 million confirmed subject to normal trading conditions
- Continued growth expected in second half despite:
  - Expectation that energy demand will remain subdued
  - Volatile Queensland wholesale electricity prices to adversely impact EBIT by ~$10 million in H2 FY13
  - SA price deregulation tariff reductions to adversely impact EBIT by ~$15 million in H2 FY13
- Retail contribution for FY13 expected to surpass FY12 following recovery of carbon costs and SA transfer pricing reversal in second half

Contact information

Sales - Electricity and gas	**www.agl.com.au**
Customer Service	**131 245**
AGL Energy Online / My AGL IQ™	**https://aglenergyonline.agl.com.au**
Corporate Information	**www.agl.com.au/about/Pages/Default.aspx**

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Supplementary Information

Electricity sales volume

6 months to GWh	31 Dec 2012	31 Dec 2011	Change
Consumer			
New South Wales	**2,746**	2,327	18.0%
Victoria	**2,214**	2,372	(6.7%)
South Australia	**1,416**	1,435	(1.3%)
Queensland	**1,393**	1,447	(3.7%)
Consumer Total	**7,769**	7,581	2.5%
Business			
New South Wales	**2,078**	2,583	(19.6%)
Victoria	**2,486**	2,841	(12.5%)
South Australia	**2,247**	2,332	(3.6%)
Queensland	**1,100**	1,347	(18.3%)
Business Total	**7,911**	9,103	(13.1%)
Total (excl. ActewAGL)	**15,680**	**16,684**	(**6.0%**)
Purchased volume ActewAGL	**1,361**	1,344	1.3%

Gas sales volume

6 months to PJ	31 Dec 2012	31 Dec 2011	Change
Consumer			
New South Wales	**13.9**	13.9	0.0%
Victoria	**17.2**	15.5	11.0%
South Australia	**1.6**	1.4	14.3%
Queensland	**1.5**	1.5	0.0%
Consumer Total	**34.2**	32.3	5.9%
Business			
New South Wales	**19.3**	14.0	37.9%
Victoria	**13.9**	12.5	11.2%
South Australia	**5.3**	4.5	17.8%
Queensland	**7.5**	7.3	2.7%
Business Total	**46.0**	38.3	20.1%
Wholesale Customers & Generation[1]	**25.0**	27.3	(8.4%)
Total	**105.2**	**97.9**	**7.5%**

1. Includes volumes sold to Torrens Island and Townsville power stations during half year to Dec 2012 of 13.5PJ (Dec 2011 of 13.9PJ).

Customer numbers

Customer Numbers	31 Dec 2011	30 Jun 2012	31 Dec 2012	Change since 30 Jun 2012
Electricity				
New South Wales	556,982	619,920	**684,140**	64,220
Victoria	637,505	637,708	**623,850**	(13,858)
South Australia	463,513	458,822	**458,125**	(697)
Queensland	354,645	367,482	**378,412**	10,930
	2,012,645	2,083,932	**2,144,527**	60,595
Gas				
New South Wales	716,386	711,185	**692,809**	(18,376)
Victoria	483,346	486,971	**490,652**	3,681
South Australia	108,322	117,271	**127,454**	10,183
Queensland	73,462	74,607	**75,235**	628
	1,381,516	1,390,034	**1,386,150**	(3,884)
Total	3,394,161	3,473,966	**3,530,677**	56,711
Dual fuel accounts	1,551,840	1,622,712	**1,673,660**	50,948

The above customer numbers include Business Customers.

Consumer market - key indicators

6 months to Electricity	31 Dec 2012	31 Dec 2011	Change
Volume (GWh)	**7,769**	7,581	2.5%
Avg. Consumer Accounts ('000)	**2,105.5**	1,951.5	7.9%
Revenue ($m)	**1,774.3**	1,410.2	25.8%
Gross Margin ($m)	**199.4**	217.5	(8.3%)
Gross Margin	**11.2%**	15.4%	(4.2 ppts)
Gross Margin per customer	**$94.72**	$111.44	(15.0%)
Gas			
Volume (PJ)	**34.2**	32.3	5.9%
Avg. Consumer Accounts ('000)	**1,389.1**	1,370.9	1.3%
Revenue ($m)	**698.1**	582.8	19.8%
Gross Margin ($m)	**117.0**	117.3	(0.3%)
Gross Margin	**16.8%**	20.1%	(3.3 ppts)
Gross Margin per customer	**$84.21**	$85.76	(1.8%)

Business customers – key indicators

6 months to Electricity	31 Dec 2012	31 Dec 2011	Change
Volume (GWh)	**7,911**	9,103	(13.1%)
Business Accounts ('000)	**19.5**	19.8	(1.5%)
Revenue ($m)	**1,081.9**	939.9	15.1%
Gross Margin ($m)	**32.2**	29.5	9.2%
Gross margin per MWh	**$4.16**	$3.24	28.4%
Gas			
Volume (PJ)	**46.0**	38.3	20.1%
Business Accounts ('000)	**0.9**	1.0	(10.0%)
Revenue ($m)	**342.5**	256.5	33.5%
Gross Margin ($m)	**34.8**	20.7	68.1%
Gross margin per GJ	**$0.76**	$0.54	40.7%

Retail – Cost to Serve

6 months to	31 Dec 2012	31 Dec 2011	Change
Net operating costs ($m)	**180.0**	156.7	14.9%
Net operating cost per customer account	**$51.43**	**$47.14**	**9.1%**
Cost to acquire/retain ($m)	**64.1**	48.8	31.4%
Cost to acquire/retain per account acquired/retained[1]	**$67.84**	**$67.75**	**0.1%**
Cost to serve ($m)	**115.9**	107.9	7.4%
Cost to serve per customer account[2]	**$33.12**	**$32.44**	**2.1%**

- Cost to acquire/retain per acquisition/retention decreased due to approximately 60% higher retention activities compared to the prior corresponding period
- Cost to serve per customer account increased due to higher bad debt provisioning in line with revenue increases and increased amortisation of New South Wales customer acquisitions

1. *Cost to acquire/retain per account acquired/retained = costs to win and retain market contracts and transfer customers to AGL DIVIDED by contracts acquired PLUS contracts retained.*
2. *Cost to serve per customer account = net operating costs LESS cost to grow DIVIDED by average customer accounts.*

Retail – weather

› **Winter months**

» Victoria: Average temperatures in winter 2012, winter 2011 second warmest temperatures on record

» South Australia: Overnight temperatures during winter 2012 were the coldest since 1997

» New South Wales: Last three winters have been mild with winter 2010 having lower mean temperatures

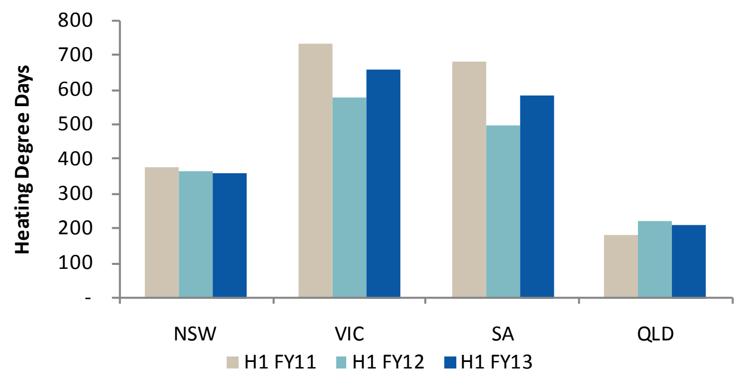
› **Summer months**

» New South Wales: Hot spell in late November 2012 with maximum temperatures eight degrees above normal

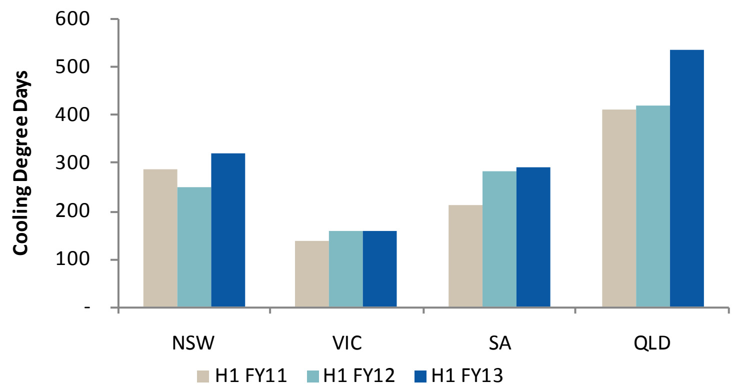
» South Australia: Above average temperatures in December 2012, fifth warmest December on record

» Queensland: Above average temperatures in November and December 2012

Heating Degree Days



Cooling Degree Days



Merchant – generation: operational performance

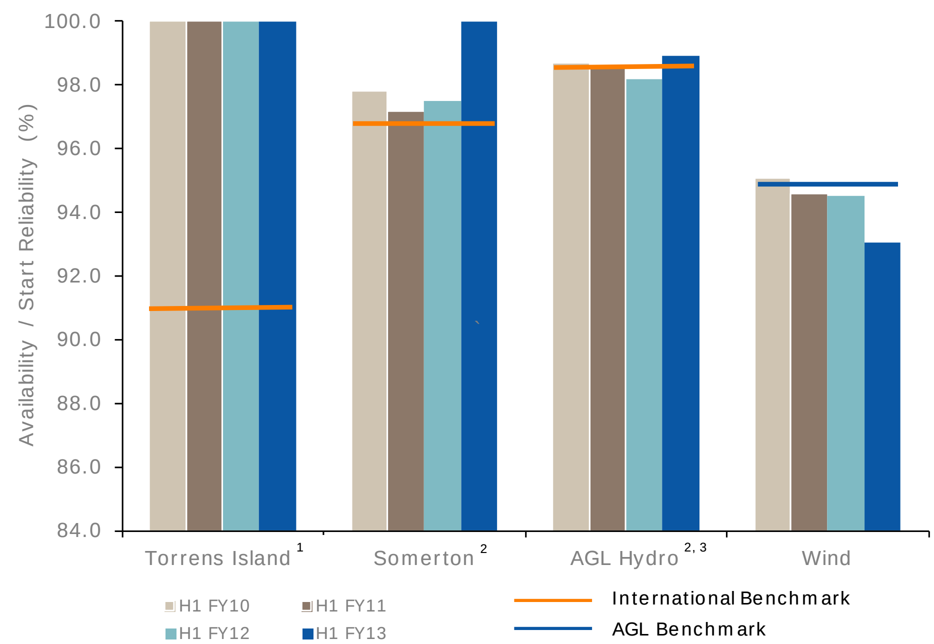
1. 'Commercial availability' is used to measure Torrens Island performance, and represents the percentage of times the plant is available to operate when required

2. 'Start reliability' is used to measure the performance of Somerton and AGL Hydro. Start reliability is the percentage of times the plant started successfully when asked to start

3. NERC – North American Electric Reliability Corporation's 5 Year average for hydro facilities adjusted for the difference in operating regime between the North American fleet and AGL's fleet which operate as peaking plant which increases the frequency of starts and stops

4. Availability weighted by plant capacity is used to measure wind farm performance. There is no international benchmark for wind farms, however AGL targets 95%

Commercial Availability / Start Reliability (%)

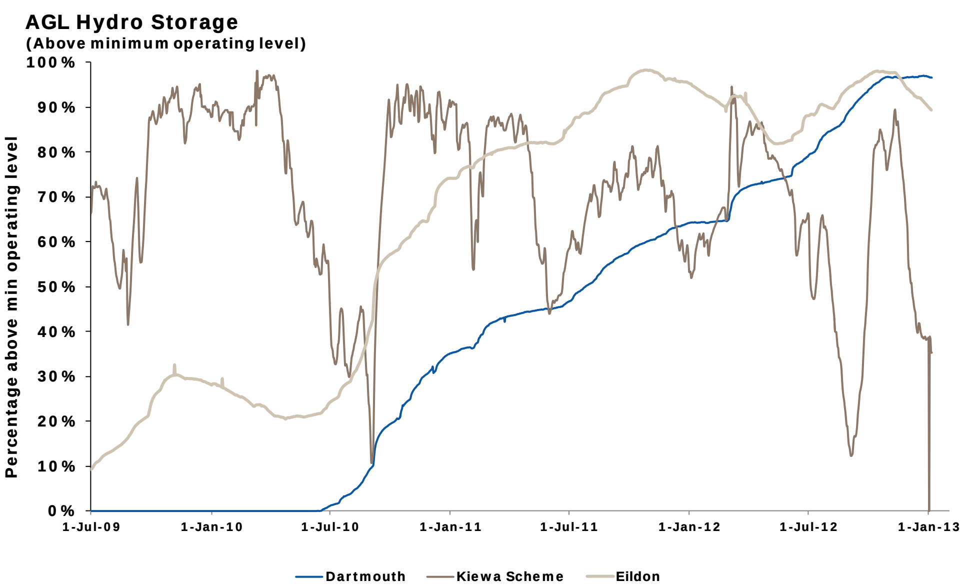


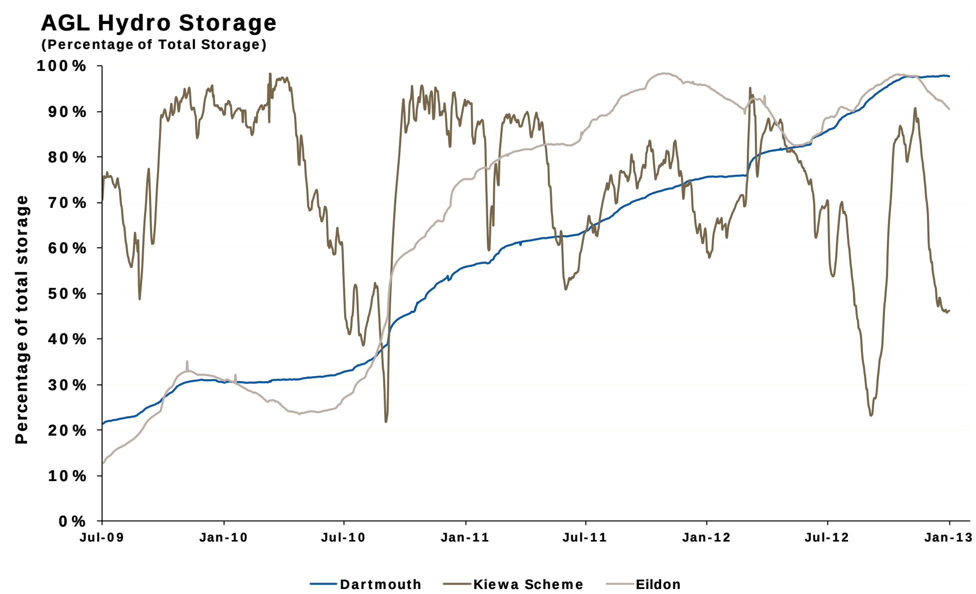
Merchant – hydrology

› 52.6% of hydro capacity is linked to drought resistant Kiewa Scheme

› Dartmouth is in service and currently available for 177MW. Dam is currently above 95% with the water authority planning releases over the next few months

› Eildon is currently available for full capacity (120MW), the water authority is currently releasing for irrigation requirements downstream





Merchant – generation: carbon intensity

Asset	Location	Type	Status	Capacity (MW)	Capacity Factor (%)	H1 FY13 Output (GWh)	Carbon intensity (tonnes CO2e/MWh)
Torrens Island	SA	CCGT	Owned	1,280	18%	1,024	0.6
Wattle Point	SA	Wind	Control dispatch	91	30%	120	0.0
Hallett 1	SA	Wind	Control dispatch	95	44%	183	0.0
Hallett 2	SA	Wind	Control dispatch	71	46%	143	0.0
Hallett 4	SA	Wind	Control dispatch	132	40%	231	0.0
Hallett 5	SA	Wind	Control dispatch	52.5	37%	85	0.0
Oaklands Hill	VIC	Wind	Control dispatch	63	30%	83	0.0
Somerton	VIC	OCGT	Owned	150	1%	8	0.7
VIC Hydro	VIC	Hydro	Owned	733	16%	510	0.0
NSW Hydro	NSW	Hydro	Owned	62	30%	83	0.0
Moranbah	QLD	OCGT	Owned	12	70%	37	0.6
Oakey	QLD	OCGT	Control dispatch	282	0.1%	2	0.6
Yabulu	QLD	CCGT	Control dispatch	121	33%	175	0.4
Loy Yang A	VIC	Coal	Owned	2,210	76%	7,299	1.3
Other	Various	Biogas & Cogen	Various	50	39%	86	0.2
Macarthur	VIC	Wind	Control dispatch	420	N/A*	128	0.0
Total at 31 Dec 2012				**5,824.5**		**10,196**	**1.0**
Industry Average							**0.9**

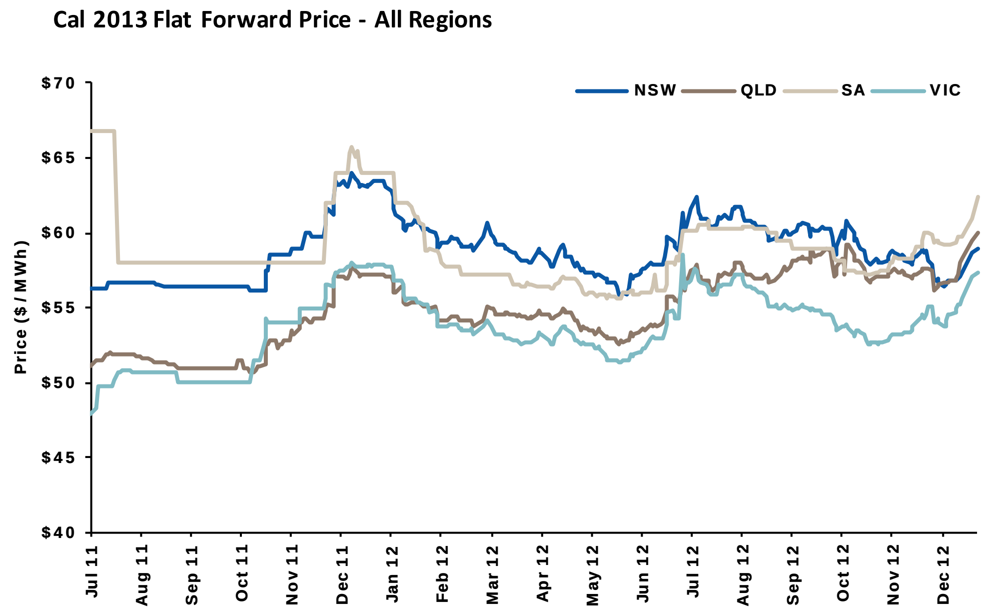
* Actual capacity factor not applicable as Macarthur was in commissioning phase as at 31 December 2012.

Merchant – electricity hedging policy

- AGL Risk Management Policy is set by the Board and establishes the requirements for the management of wholesale risk
- Clearly defined and approved commodity and transaction limits
- Counterparty credit limit tier allocation
- Market price risk is contained with requirements for hedging based upon physical limits and financial limits:
  - **Physical Limits**: Appropriate hedges to meet minimum fraction of expected energy load
  - **Financial Limits**: Additional limits defined on basis of detailed economic analysis of portfolio dynamics of load, hedge contracts, generation and volatile prices:
    - Earnings at Risk limits are established as the worst outcome expected 1 year in every 10 years

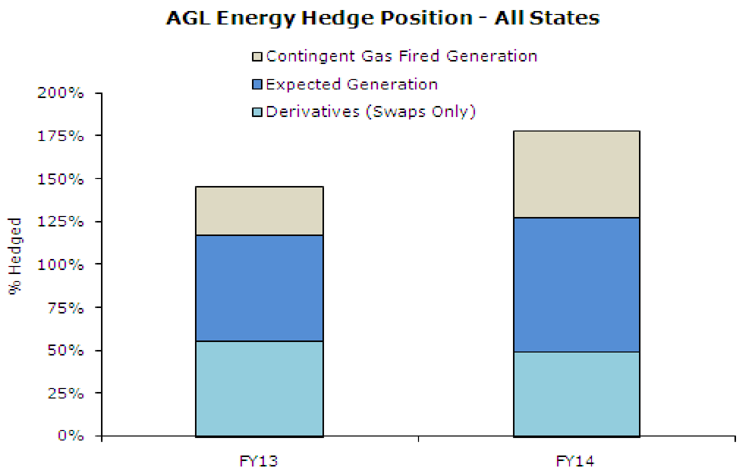
Merchant – wholesale electricity prices

- Forward prices rallied across the NEM through December 2011 following the successful passage of the Clean Energy Act through both houses of parliament, and the full price of carbon was factored into electricity prices
- Prices fell across the first six months of 2012 due to a mild summer and prolonged periods of depressed prices in the physical market
- Prices recovered in the last six months of 2012 in response to higher physical market prices and ended the year stronger ahead of hot weather forecast in the early weeks of 2013



Merchant – Electricity Hedging: Position

Physical



Key Points

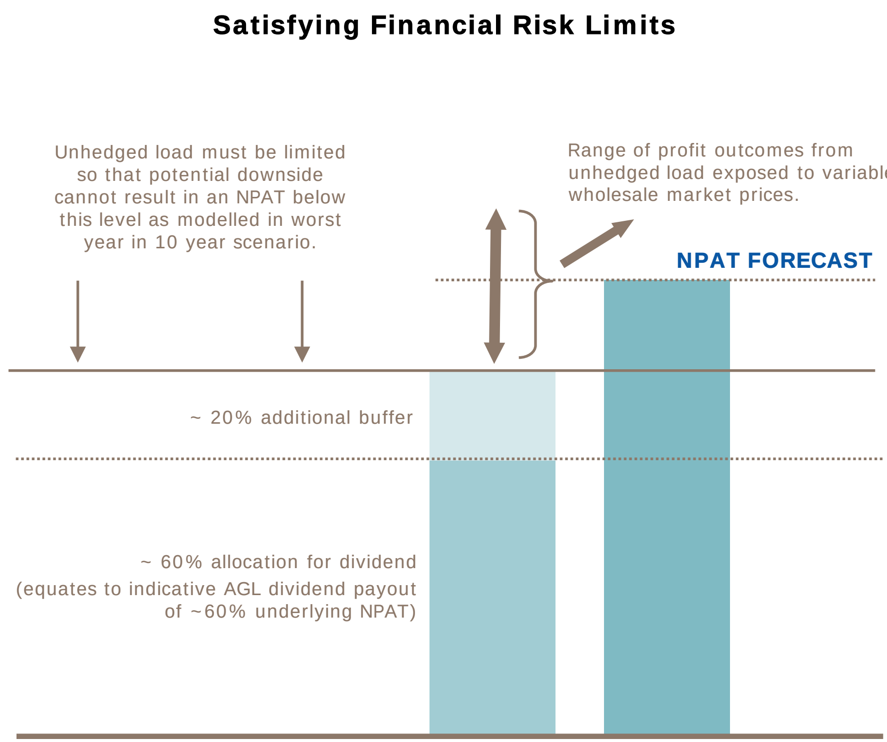
› Positions across all states and time periods have been aggregated

› Reference load is average annual energy (in MWh) for 100% of (C&I contracted load + expected mass market load)

› Expected Generation represents AGL's internal estimate of the amount of energy likely to be generated based on pool price, fuel cost and hydrology assumptions

› Contingent Gas Fired Generation is the maximum amount of energy that AGL's portfolio could generate if required

Financial



Upstream Gas - Reserves

AGL share of CSG reserves	31 Dec 2012		30 Jun 2012		Change	
PJ	**2P**	**3P**	**2P**	**3P**	**2P**	**3P**
Gloucester (100%)	**669**	**832**	669	832	-	-
Moranbah (50%) – Bowen Basin	**307**	**511**	376	862	(18.4%)	(40.7%)
Camden (100%)	**140**	**186**	142	189	(1.4%)	(1.6%)
Hunter (100%)	**142**	**271**	142	271	-	-
Silver Springs (various)	**61**	**158**	61	158	-	-
Spring Gully (various, small)	**8**	**10**	8	10	-	-
Sub-Total	**1,327**	**1,968**	**1,398**	**2,322**	**(5.1%)**	**(15.2%)**
ATP 1103 back-in rights (50%) – Bowen Basin*	**904**	**2,151**	768	1,660	17.7%	29.6%
Total	**2,231**	**4,119**	**2,166**	**3,982**	**3.0%**	**3.4%**

* Under a 50-year project agreement that commenced in 2000, AGL has no effective exploration rights (or ongoing cost obligations) within exploration tenement ATP 1103 as these were assigned to Arrow Energy Limited. However, AGL is entitled to participate up to a 50% interest in any commercial development by contributing its share of past costs.

Upstream Gas – Permits

Basin	Project	Permits		Working Interest
		Exploration (Area km^2)	Production (Area km^2)	
Sydney	Camden Gas Project	PEL 2 (6,708)**r**	-	100%
		PEL 5 (401)**r**	-	100%
		-	PPL 1 (48)	100%
		-	PPL 2 (1)	100%
		-	PPL 4 (55)	100%
		-	PPL 5 (103)	100%
		-	PPL 6 (7)	100%
	Hunter Gas Project	PEL 4 (5,081)	-	100%
		PEL 267 (4,925)**r**	-	100%
Gloucester	Gloucester Gas Project	PEL 285 (1,021)**r**	-	100%
Cooper / Eromanga	Conventional oil and gas	ATP 934P (1,466)**a**	-	20%
	Conventional oil and gas	ATP 1056P (3,917)	-	40%**f**
Galilee	Galilee JV	ATP 529P (5,930)	-	50%

a Under application.

f Subject to farm in; working interests reflect AGL's final position after farm in is completed.

r Under renewal.

p Under a 50-year project agreement that commenced in 2000, AGL has no effective exploration rights (or ongoing cost obligations) within exploration tenement ATP 1103 as these were assigned to Arrow Energy. However, AGL is entitled to participate up to a 50% interest in any commercial development by contributing its share of past costs.

Basin	Project	Permits		Working Interest
		Exploration (Area km^2)	Production (Area km^2)	
Surat	Silver Springs Project	ATP 471P (453)**r**	-	28.71-100%
		ATP 709P (146)	-	100%
		-	PL 1 (55)	15%
		-	PL 15 (259)	75%
		-	PL 30 (37)	10%
		-	PL 48 (6)**r**	100%
		-	PL 49 (21)**r**	100%
		-	PL 56 (18)	16%
		-	PL 66 (125)	100%
		-	PL 74 (18)**r**	16%
		-	PL 192 (92)	100%
		-	PL 202 (91)	100%
		-	PL 213 (46)	100%
		-	PL 446 (259)	100%
Bowen	Moranbah Gas Project	ATP 1103 (4,153)	-	99%**p**
		-	PL 191 (220)	50%
		-	PL 196 (38)	50%
		-	PL 222 (108)**a**	50%
		-	PL 223 (166)	50%
		-	PL 224 (70)	50%
	Spring Gully Project	ATP 592P (1,734)	-	0.75%
		-	PL 195 (257)	0.75%
		-	PL 203 (259)	0.75%
		-	PL 204 (220)	0.0375%
Taranaki (NZ)	Conventional oil and gas	PEP 53247 (6)	-	75%

Reconciling Statutory to Underlying cash flow

6 months to $m	31 Dec 2012	31 Dec 2011	Change
Statutory net cash provided by operating activities	**364.8**	27.8	
Increase / (decrease) in futures margin calls	**21.3**	(19.6)	
Increase / (decrease) in net green position	**(54.1)**	(15.2)	
Unwind of carbon assistance[1]	**120.0**	-	
Underlying operating cash flow	**452.0**	(7.0)	↑ 459.0
Net finance costs paid	**120.9**	37.8	↑ 83.1
Income tax paid	**71.9**	121.6	↓ 49.7
Underlying operating cash flow before interest and tax	**644.8**	152.4	↑ 492.4

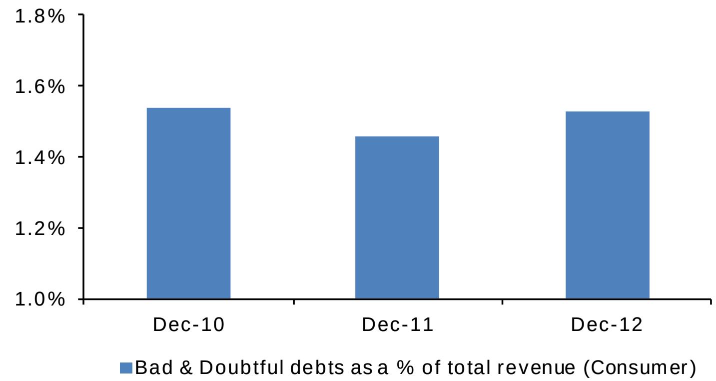
[1] Represents 50% of the carbon transitional assistance of $240.1 million received by GEAC in June 2012, which was not included in Operating Cashflow in FY12 as this cash was provided to partially offset the cost of carbon for FY13.

AGL

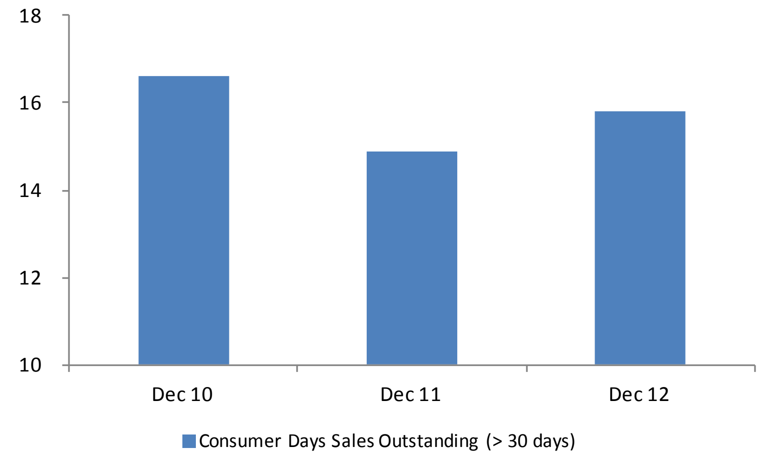
Retail debtors

- Introduction of carbon and network increases drive rises in gas and electricity prices
- Price rises phased in between July to October 2012 causing some initial customer bill shock
- As a result:
  - Consumer bad and doubtful debts increased by 29.3% against revenue increase of 23.7%
  - Days Sales Outstanding increased by 0.9 days

Bad and Doubtful Debts



Days Sales Outstanding



Energy Investments

6 months to $m	31 Dec 2012	31 Dec 2011	Change
ActewAGL	**15.9**	17.3	(8.1%)
Loy Yang A	**-**	(4.9)	(100.0%)
Total EBIT	**15.9**	12.4	28.2%

Capital expenditure

6 months to 31 Dec 2012 $m	SIB	Discretionary	Total
Merchant	67.6	128.6	196.2
Upstream Gas	-	75.2	75.2
Retail	-	22.2	22.2
Corporate Other	6.3	4.4	10.7
Total	**73.9**	**230.4**	**304.3**

Balance Sheet

As at $m	31 Dec 2012	30 Jun 2012
Current assets	**3,138.7**	4,131.9
PPE, E&E and oil & gas assets	**6,346.1**	6,323.5
Other non current assets	**4,507.4**	4,283.0
Total Assets	**13,992.2**	14,738.4
Current debt	**46.6**	616.0
Other current liabilities	**2,162.8**	1,993.8
Non current debt	**3,207.3**	3,696.0
Other non current liabilities	**1,221.7**	1,299.7
Total Liabilities	**6,638.4**	7,605.5
Net Assets	**7,353.8**	7,132.9
Contributed equity	**5,289.7**	5,227.3
Reserves	**(28.9)**	22.0
Retained earnings	**2,093.0**	1,883.6
Total Equity	**7,353.8**	7,132.9

Fair Value Reconciliation

As at $m	Net Assets (Liabilities) 31 Dec 2012	 30 Jun 2012	 Change
Electricity derivative contracts	**270.4**	208.7	61.7
Interest rate swaps and foreign currency derivative contracts	**(112.5)**	(224.9)	112.4
Total net assets (liabilities) for derivative contracts	**157.9**	(16.2)	174.1
Change in derivative net assets	**174.1**		
Premiums paid	**(67.1)**		
Settlement of interest rate swaps	**(105.1)**		
Premium roll off	**53.5**		
Total change in fair value	**55.4**		
Recognised in equity hedge reserve	**(69.7)**		
Recognised in borrowings	**(7.9)**		
Recognised in profit and loss (fair value – pre-tax)	**121.8**		
Recognised in profit and loss (interest – pre-tax)	**11.2**		
Total change in fair value	**55.4**		