Energy in action.

2011 Full Year Results

12 Months to 30 June 2011

Michael Fraser, Managing Director and CEO
Stephen Mikkelsen, Chief Financial Officer | 25 August 2011

Disclaimer

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.

Before making or varying any investment in securities in AGL Energy Limited, all investors should consider the appropriateness of that investment in light of their individual investment objectives and financial situation and should seek their own independent professional advice.

Agenda

- **Result Highlights** — Michael Fraser
- **Group Financials** — Stephen Mikkelsen
- **Operational Review** — Michael Fraser
- **Supplementary Information**

IMPORTANT NOTE:
This presentation should be read in conjunction with the AGL Energy Limited ASX Appendix 4E for the 12 months ended 30 June 2011.

FY11 Highlights

Organic growth strategy delivers strong initial success.

- Flat Underlying Profit constrained by weather and Loy Yang A
- Strong underlying operating cash flow before tax at $676 million
- 95,959 new NSW electricity customers contracted in 2HFY11
- Retail Energy Operating EBIT increased by $54 million (17%)
- Merchant Energy Operating EBIT declined 2%
- Sale of Oaklands Hill wind farm (67 MW) completed
- Acquisition of Mosaic Oil NL completed October 2010
- Conditional approval
  - Dalton gas-fired power station (500 MW)
  - Newcastle Gas Storage facility

Final 2011 Result

Strong operational cash flow further strengthens financial metrics.

FINANCIAL

Revenue:	$7,072.5m	↑ 7.0%
Statutory Profit:	$558.7m	↑ 56.9%
Underlying Profit:	$431.1m	↑ 0.5%
Underlying EPS:	94.4 cps	↓ 1.3%
DPS: (final dividend 31.0 cents - 100% franked)	60.0 cps (Jun 10: 59.0 cps)	↑ 1.7%
EBITDA / Net Interest:	21.5x (Jun 10: 16.6x)	↑ 4.9x
Statutory operating cash flow after tax	$569.3m	↑ $179.3m
Underlying operating cash flow before tax	$676.0m	↑ $45.7m

HIGHLIGHTS

- Strong cash flow reflected in key financial ratios
- Revenue increases largely driven by rising transmission & distribution charges
- Statutory Profit increase reflects favourable movements in fair value of financial instruments
- Underlying Profit up marginally as severe weather events and Loy Yang A (LYA) offset operational improvements
- Resumption of 100% franking with 2011 final dividend

Group Financials

Stephen Mikkelsen
Chief Financial Officer

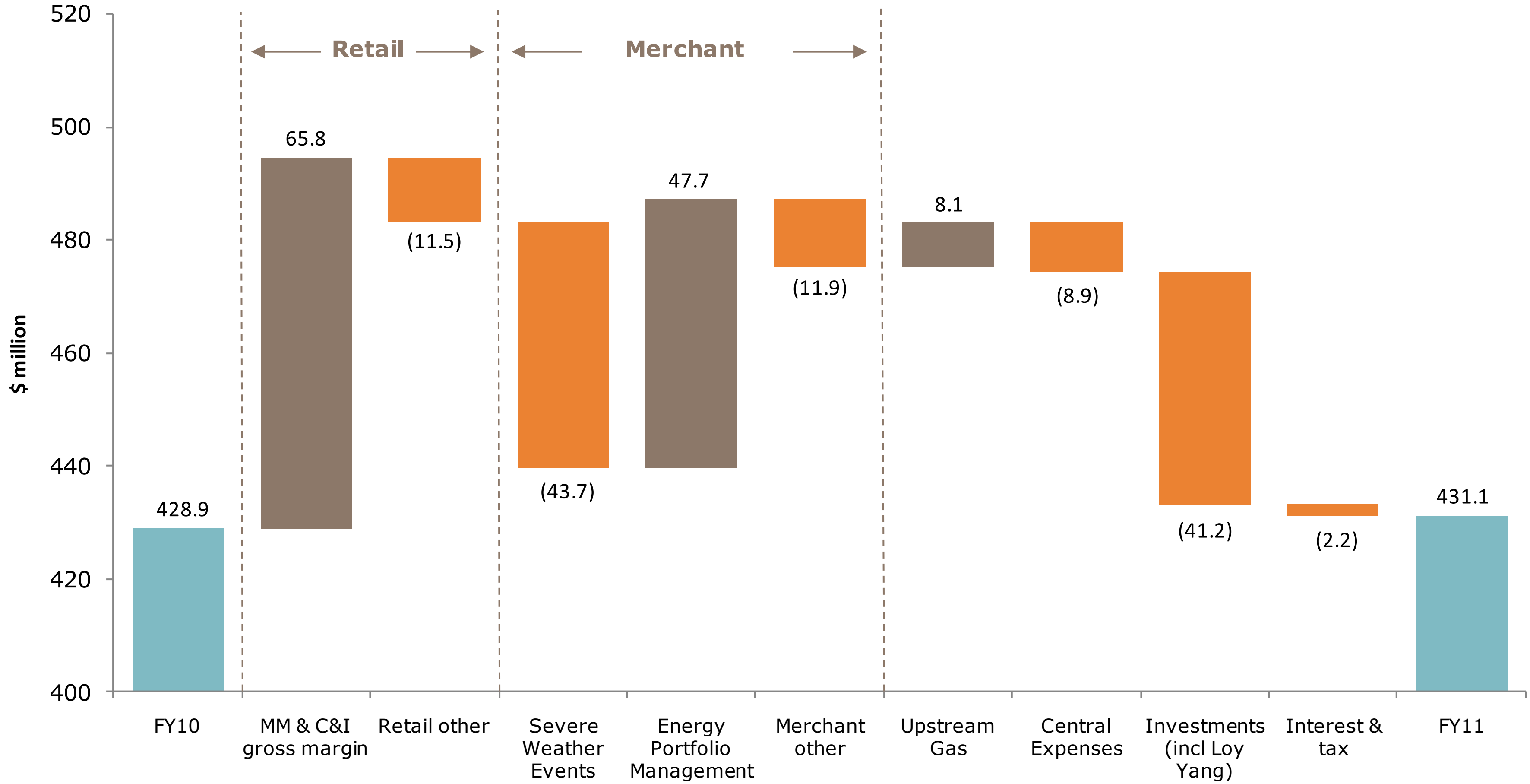
Profit & Loss (excluding significant items & fair value movements)

Flat Underlying Profit - constrained by weather events and Loy Yang A.

12 months to $m	30 Jun 2011	30 Jun 2010	Change
Revenue	**7,072.5**	6,610.7	7.0%
Operating EBITDA	**804.5**	789.6	1.9%
Operating EBIT			
Retail	**373.0**	318.7	17.0%
Merchant	**378.2**	386.1	(2.0%)
Upstream Gas	**13.6**	5.5	147.3%
Energy Investments	**40.5**	81.7	(50.4%)
Centrally managed expenses	**(148.8)**	(139.9)	6.4%
Total operating EBIT	**656.5**	652.1	0.7%
Less: Net finance costs	**(37.4)**	(47.5)	(21.3%)
Underlying Profit before tax	**619.1**	604.6	2.4%
Less: Income tax expense	**(188.0)**	(175.7)	7.0%
Underlying Profit	**431.1**	428.9	0.5%

Group Underlying Profit

Continued improvement in Retail offset by LYA and weather events.



Retail – Key Financial Metrics

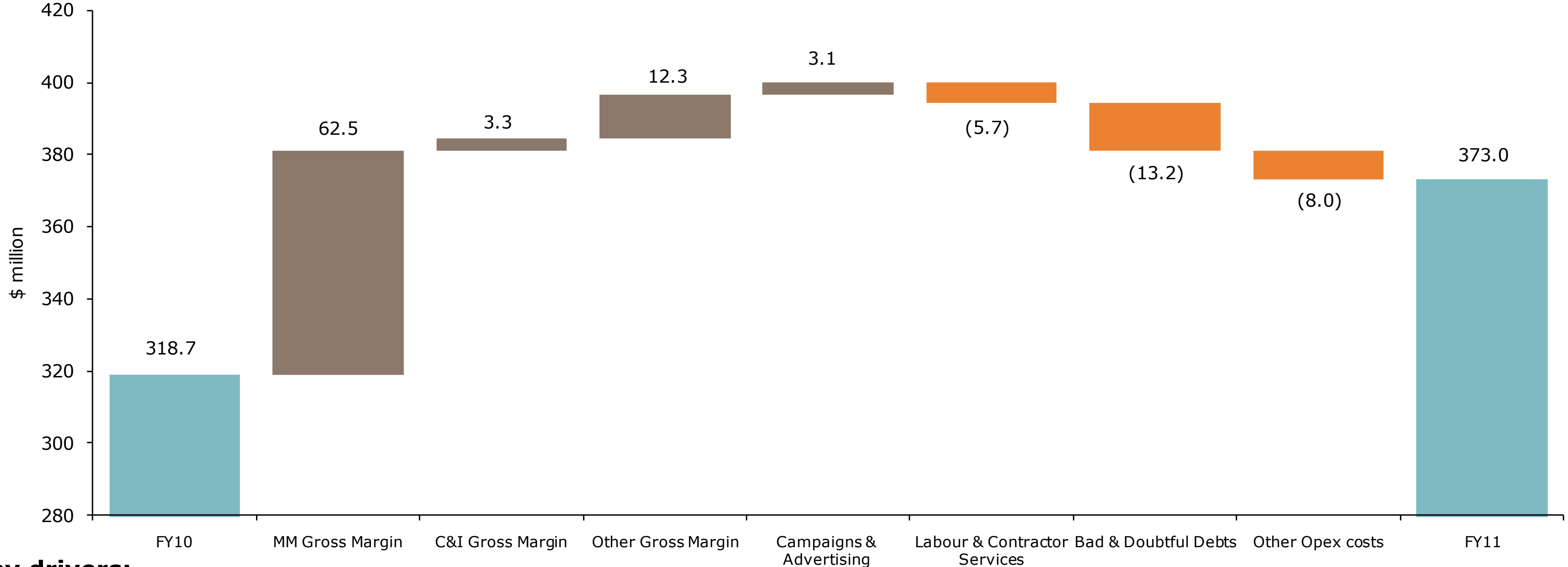
Continued margin improvement against a backdrop of subdued demand.

12 months to $m	30 Jun 2011	30 Jun 2010	Change
Electricity Revenue	**4,349.4**	4,010.0	8.5%
Gas Revenue	**1,665.7**	1,511.9	10.2%
Other Revenue (Fees & Charges)	**76.0**	63.7	19.3%
Total Revenue	**6,091.1**	5,585.6	9.1%
Cost of Sales[1]	**(5,317.7)**	(4,890.3)	8.7%
Gross Margin	**773.4**	695.3	11.2%
Operating Costs (excl. D&A)	**(356.6)**	(335.1)	6.4%
Operating EBITDA	**416.8**	360.2	15.7%
D&A	**(43.8)**	(41.5)	5.5%
Operating EBIT	**373.0**	318.7	17.0%
Operating EBIT / Sales (%)	**6.1%**	5.7%	0.4 ppts

1. Includes $2,393.9m electricity COGS ($2,324.6m Jun 10) & $822.9m gas COGS ($725.5m Jun 10) transferred from Merchant.

Retail – EBIT Drivers

Strong improvement in mass market.



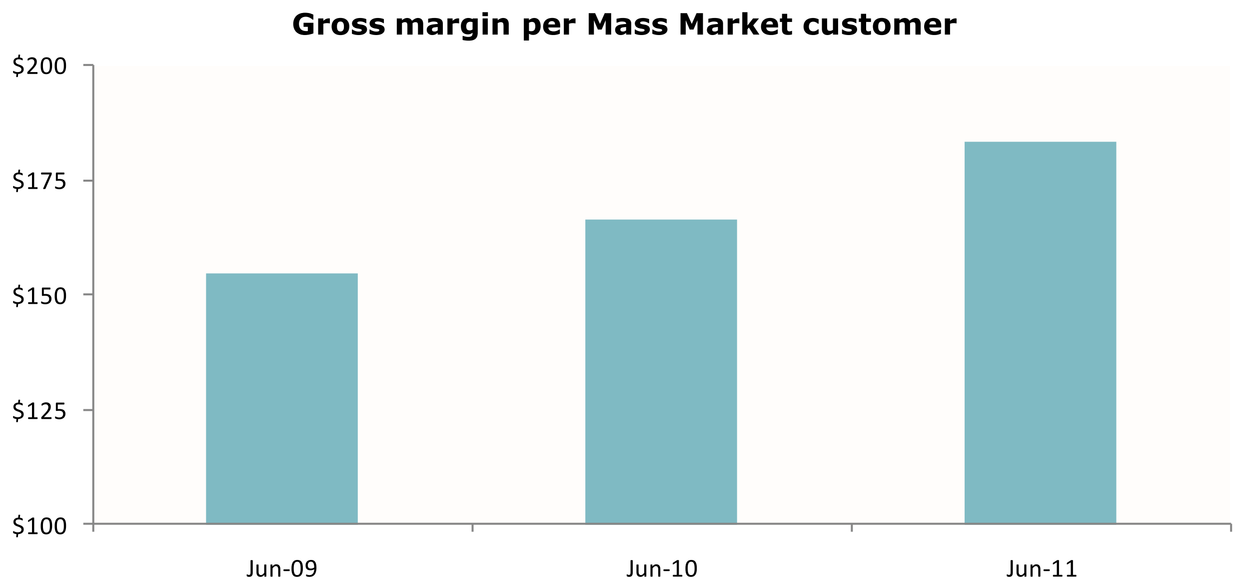
Key drivers:

- Mass market gross margin higher mainly due to higher current year mass market tariffs
- Other gross margin higher than prior year mainly due to increased bad debt recoveries (offsetting bad debt expenses), late payment fees and merchant service fees
- Campaigns and advertising lower than prior year partially due to the capitalisation of New South Wales campaign costs
- Labour and Contractor Services is higher than prior year driven by higher customer services costs to deal with higher call volumes, and additional sales staff to generate lead sales activities
- Other costs higher than prior year mainly due to higher training and travel, printing and computer costs, third party agency collection fees, and higher amortisation in FY11 relating to the treatment of directly attributable New South Wales campaign costs

Retail – Key Operating Metrics

Continued growth in gross margin per customer.

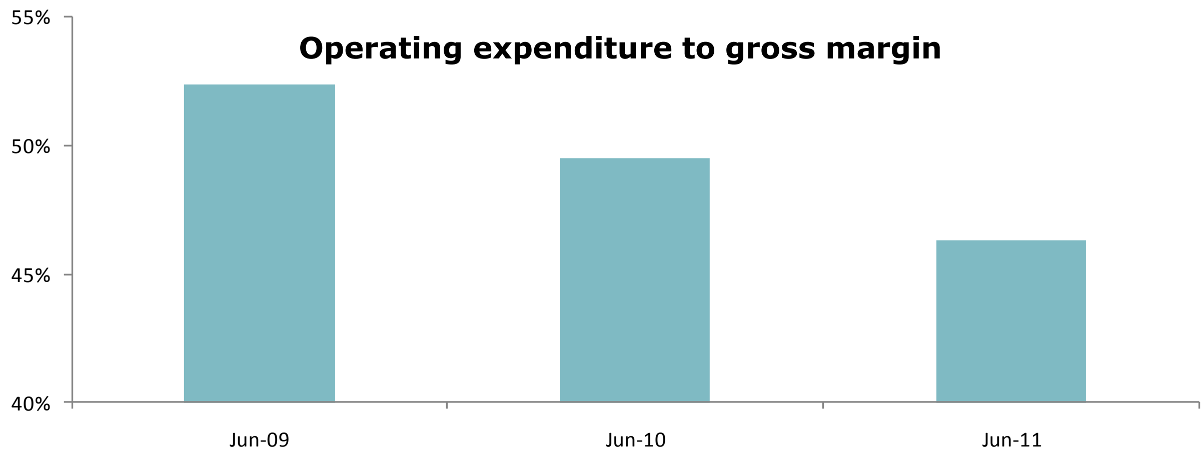
12 months to	30 Jun 2011	30 Jun 2010	Change
Mass Market gross margin ($m)	**595.8**	533.3	11.7%
Avg Mass Market customer numbers (‘000)	**3,254.2**	3,205.6	1.5%
Gross margin per Mass Market customer	**$183.08**	$166.35	10.1%



Retail – Key Operating Metrics

Opex to Gross Margin on track to meet target of low 40s.

12 months to $m	30 Jun 2011	30 Jun 2010	Change
Operating costs	**356.6**	335.1	6.4%
Depreciation and amortisation	**43.8**	41.5	5.5%
Less fees and charges	**(76.0)**	(63.7)	19.3%
Net operating costs	**324.4**	**312.9**	**3.7%**
Gross margin	**773.4**	695.3	11.2%
Less fees and charges	**(76.0)**	(63.7)	19.3%
Gross margin excluding fees and charges	**697.4**	**631.6**	**10.4%**
Operating expenditure to gross margin ratio	**46.5%**	49.5%	3.0 ppts



Merchant – Key Financial Metrics

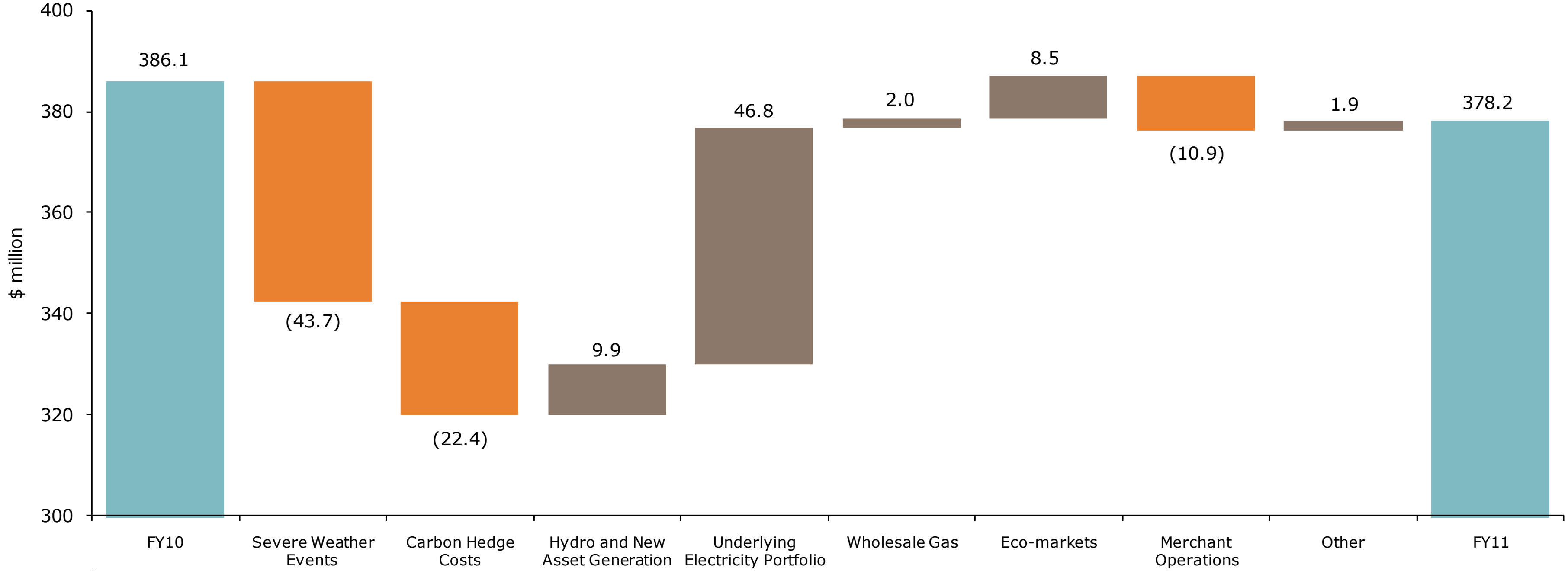
Operating EBIT down 2%.

12 months to $m	30 Jun 2011	30 Jun 2010	Change
Operating EBITDA	**447.3**	449.8	(0.6%)
D & A	**(69.1)**	(63.7)	8.5%
EBIT Energy Portfolio Management (EPM)			
Wholesale Electricity Gross Margin	**304.3**	313.7	(3.0%)
Wholesale Gas Gross Margin	**104.3**	102.3	2.0%
Eco-markets Gross Margin	**44.4**	35.9	23.7%
EPM Operating Expenses (including D&A)	**(22.9)**	(25.8)	(11.2%)
Merchant Operations	**(114.7)**	(103.8)	10.5%
Energy Services	**17.8**	17.3	2.9%
Power Development[1]	**56.3**	56.9	(1.1%)
Sundry Expenses	**(11.3)**	(10.4)	8.7%
Operating EBIT	**378.2**	386.1	(2.0%)

1. Includes development fees of $61.0m (Jun 10: $57.0m).

Merchant – EBIT Drivers

Strong underlying Electricity performance impacted by one-off events.



Key Drivers:

- January/February 2011 severe weather events in Queensland, New South Wales and South Australia affected Wholesale Electricity underlying performance
- Wholesale Electricity hedging costs – the inclusion of costs associated with hedges which implicitly included anticipated carbon costs
- Underlying Electricity Portfolio – effective portfolio management, including managing generation to benefit from depressed pool prices
- Eco-Markets – increased renewable generation and favourable transfer price movements in green certificates
- Merchant Operations – additional costs associated with new plant coming on line and increased depreciation driven by higher hydro generation

Significant Items

AGL lowers cost base. FY12 savings approximately $20 million.

12 months to 30 Jun 2011 $m	Pre Tax	Tax	After Tax
Redundancy, termination and restructuring costs	**(27.0)**	7.3	**(19.7)**
Merger and acquisition related costs	**(17.3)**	4.2	**(13.1)**
Tax consolidation adjustment	**-**	5.5	**5.5**
Total significant items	**(44.3)**	17.0	**(27.3)**

- Redundancy, termination and restructuring costs
  - Majority associated with redundancy costs
  - Redundancy costs for 300 people includes offshoring of 190 back office roles
- Merger and acquisition related costs
  - Privatisation of New South Wales energy assets bid costs and the acquisition of Mosaic Oil NL
- Tax consolidation adjustment
  - Attributable to a change in tax law allowing AGL to claim deductions in the 2007 to 2010 tax years for the tax values allocated to certain derivative transactions in place at the time of the Alinta merger / demerger

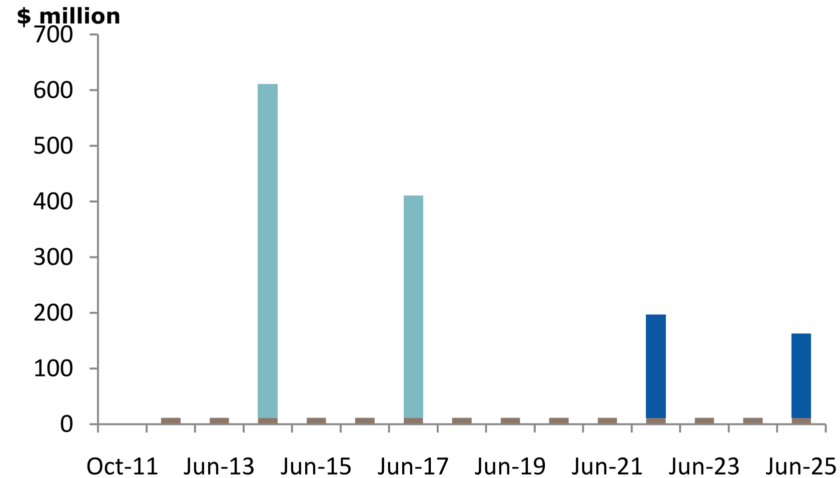
Debt Position

Net debt only increased $50 million to $471 million.

- Refinancing of existing $886m syndicated bank loan signed 20 July 2011
  - Replaced with $1,000m self-arranged syndicated loan facility
    - $600m - 3 year Term facility; $400m - 5 year Revolving facility
- $200m Export credit agency facility to partially finance Macarthur (18-year amortising loan)

Facilities at 30 June 2011	Limit $m	Usage $m
Current		
Term facilities Tranche C	886.7	886.7
Non Current		
US Private Placement	337.8	337.8
Total debt facilities	**1,224.5**	**1,224.5**
Cash	**-**	**753.1**
Net Debt	**-**	**471.4**

Debt Maturity Profile post $1.2bn refinancing



Financial Ratios

Continued improvement across all key financial coverage metrics.

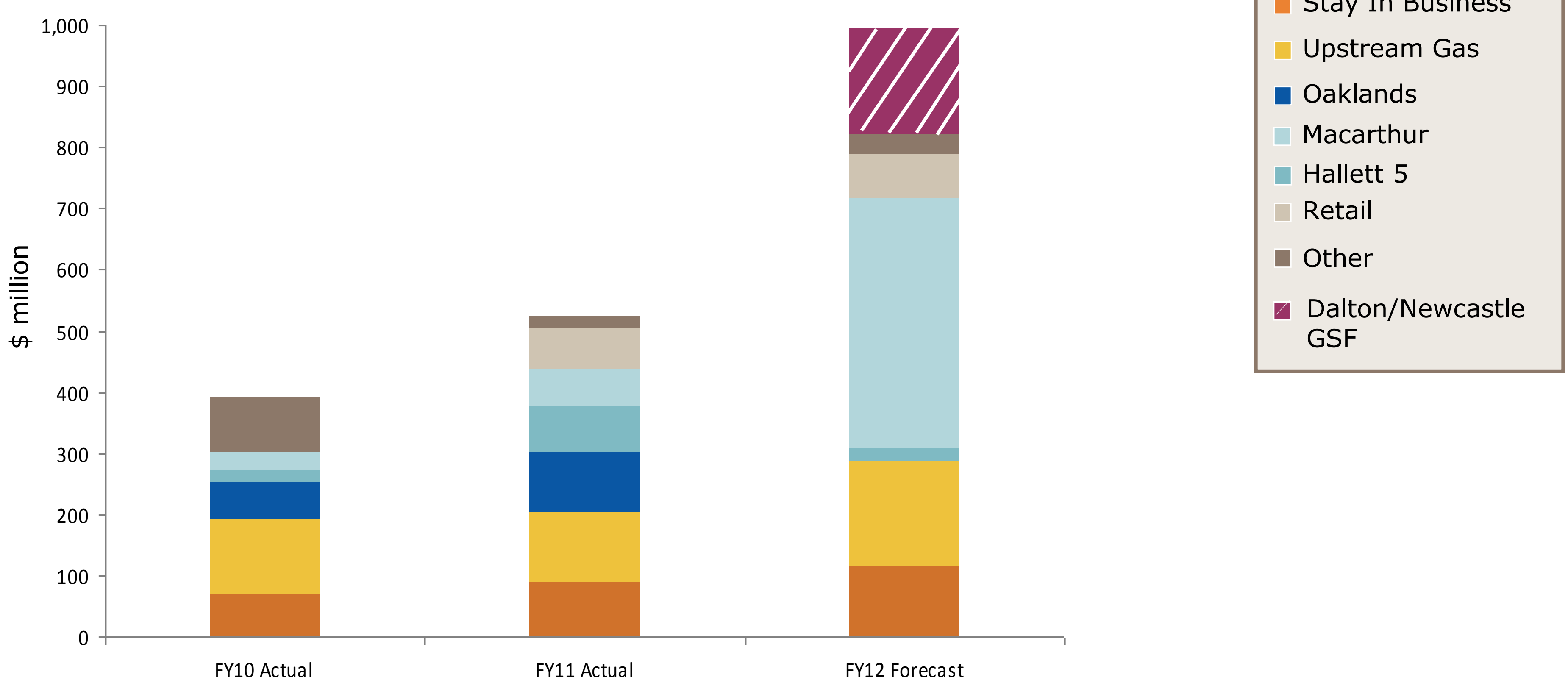
- BBB stable credit rating
- Rating reaffirmed by S&P in August 2011

	30 Jun 2011	30 Jun 2010
FFO / Interest cover (times)[1]	**12.2**	7.5
FFO / Interest cover S&P Adjusted (times)[2]	**7.9**	5.4
Net Debt ($m)	**471.4**	420.4
Net debt / (Net debt + Equity)	**6.9%**	6.7%
EBITDA / Net Interest (times)	**21.5**	16.6

1. Adjustments as applied by Standard & Poor's excluding the notional adjustment for Operating Lease Agreements and wind-farm off-take agreements.
2. Adjustments as applied by Standard & Poor's.

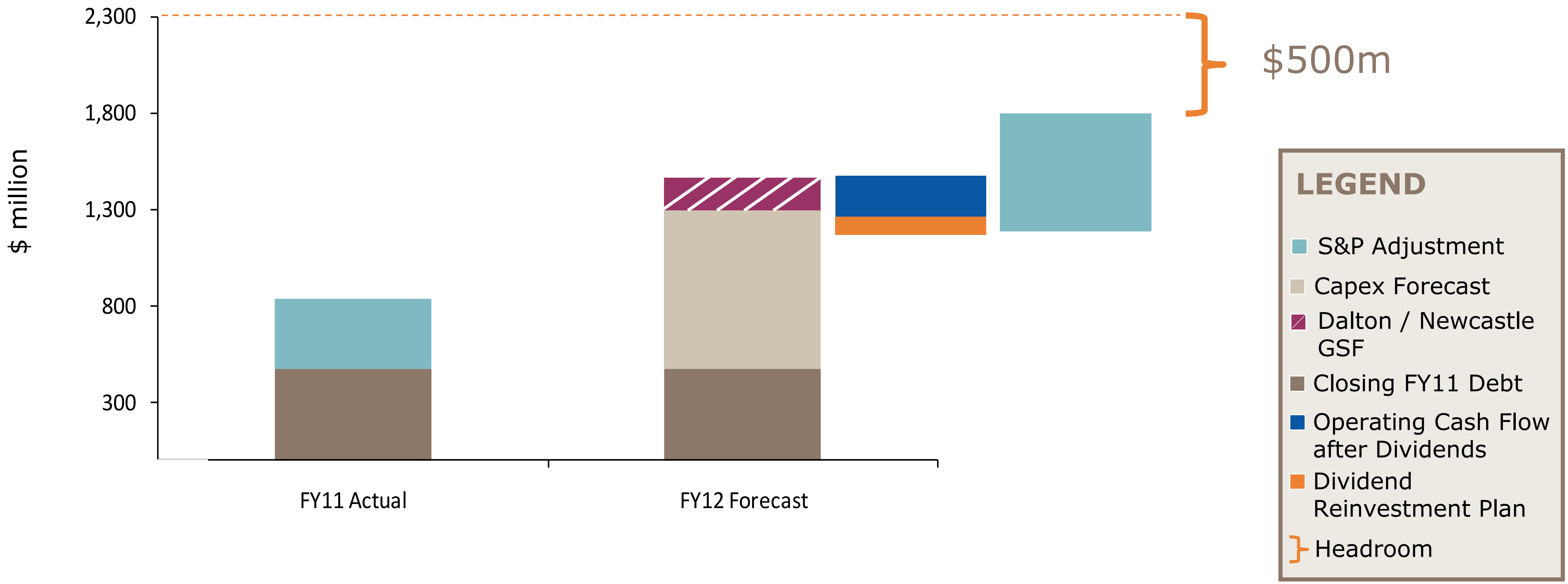
Capital Expenditure

Macarthur represents ~40% of committed FY12 capital spend.



Debt Capacity

$500 million of headroom to fund future capex.



Return on Funds Employed

Flat results impacted returns.

12 months to $m	30 Jun 2011	30 Jun 2010	30 Jun 2009
Operating EBIT	**656.5**	652.1	643.1
Average Funds Employed	**7,403.0**	6,953.8	6,644.4
EBIT / Funds Employed	**8.9%**	9.4%	9.7%
Operating EBIT	**656.5**	652.1	643.1
Less: Upstream Gas EBIT	**(13.6)**	(5.5)	(4.9)
Less: Divested EBIT	**-**	-	(35.6)
EBIT Adjusted	**642.9**	646.6	602.6
Average Funds Employed	**7,403.0**	6,953.8	6,644.4
Less: Assets under construction	**(164.4)**	(220.6)	(228.1)
Less: Upstream Gas Funds Employed	**(1,086.0)**	(993.2)	(747.1)
Less: Divested Funds Employed	**-**	-	(215.6)
Average Funds Employed Adjusted	**6,152.6**	5,740.0	5,453.6
EBIT / Funds Employed Adjusted	**10.4%**	11.3%	11.0%

Underlying Operating Cash Flow

Solid uplift in cash flow.

12 months to $m	30 Jun 2011	30 Jun 2010	Change
Statutory net cash provided by operating activities	**569.3**	390.0	
Cash flow relating to significant items	**41.9**	27.8	
Futures margin calls	**(30.0)**	5.9	
Increase in net green position	**94.1**	17.6	
Underlying operating cash flow	**675.3**	441.3	
Income tax paid	**0.7**	189.0	
Underlying operating cash flow before tax	**676.0**	630.3	↑ 45.7

Operating cash flow

Strong working capital management.

› Unbilled customers continue to reach new lows

  » Oldest mass market unbilled customer aged 52 days

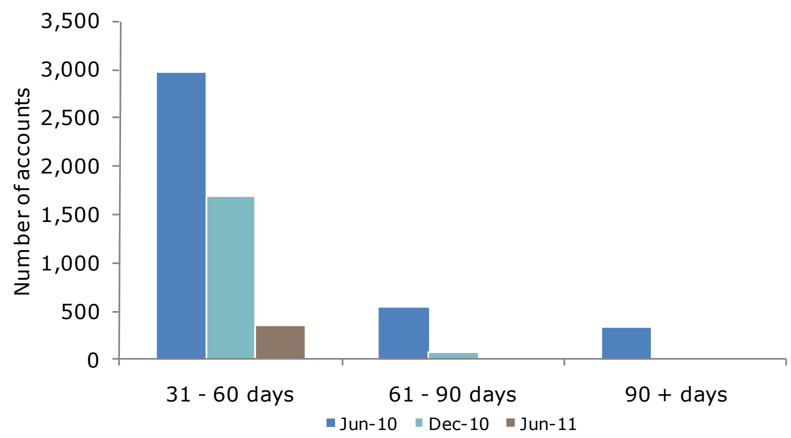
› Mass market days sales due continuing to reduce driven by increasing system functionality and business focus

› Robust mass market and C&I aged debt management amidst growing revenue streams

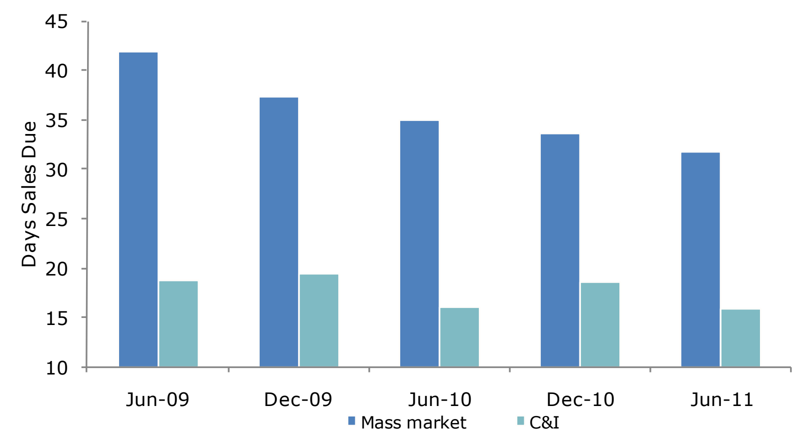
  » Reduction in Retail aged debt (30+ days) despite mass market and C&I revenue increasing 12.1% and 4.5% respectively

› Greater operating cash flow outcomes fund current and future growth

Aged Unbilled Accounts – improving across all categories



Days Sales Due – consistent improvement over 2 years



Operational Review

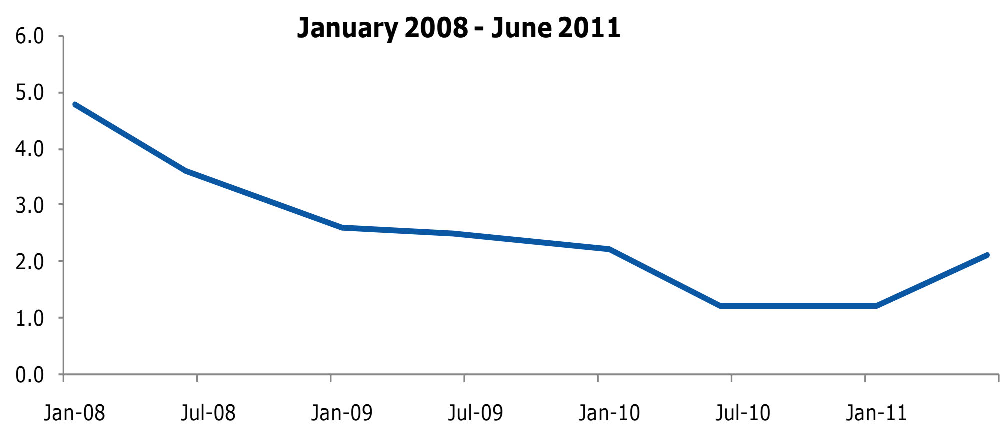
Michael Fraser
Managing Director & CEO

Safety & People

Safety metrics require on-going focus.

- Key safety statistics
  - 4.2 million hours worked
  - 9 Lost Time Injuries
  - 21 Total Injuries
- Embedding a safety culture across employees and contractors
- Key people initiatives
  - Talent sourcing to enable growth
  - Employees as customer advocates
  - Streamline People & Culture processes

Lost Time Injury Frequency Rate

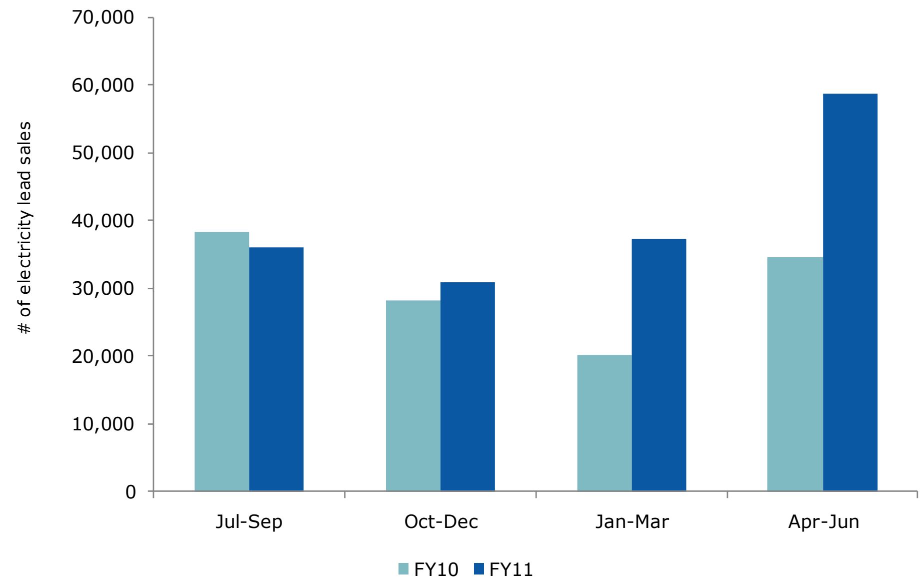


NSW growth – Electricity customer acquisition

Lead sales in 2HFY11 up 75% on pcp.

- NSW Lead sales of +96,000 in 2HFY11
  - Strong 2H performance given Jan-Feb activity traditionally slow
- Net Growth versus Lead sales
  - Reflects average 45-day lag between contract signing and switching over to become a customer
- Net Growth in NSW electricity customers
  - FY11: +87,000 (FY10: +52,000)
  - July 2011: +12,000
- AGL's NSW churn declines as market churn increases
- Target marketing sees significant increase in dual fuel accounts in NSW

NSW Electricity Lead Sales FY11 vs. FY10



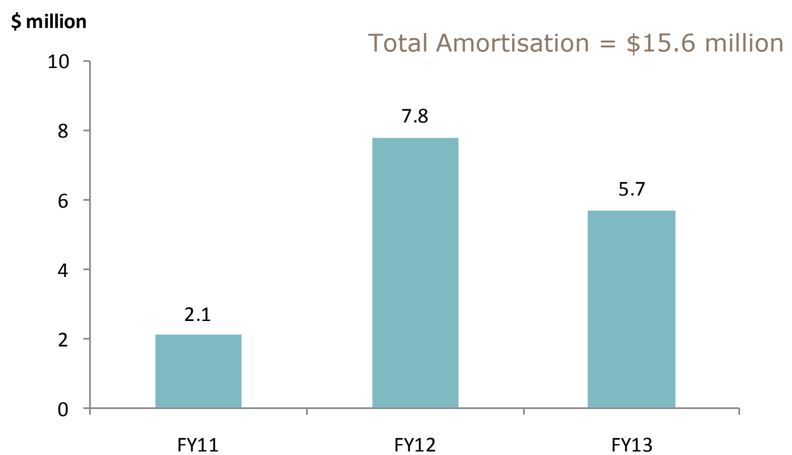
NSW Electricity Churn Rate	FY10	FY11
AGL	19.5%	17.0%
Market	12.8%	14.1%

NSW growth – Electricity customer acquisition

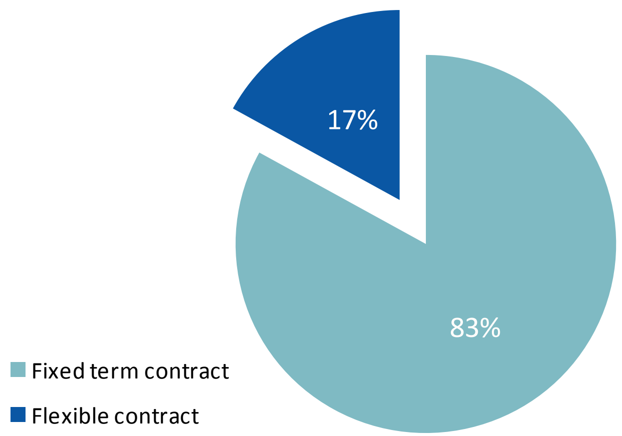
Attractive cost to acquire creates shareholder value.

- Average acquisition cost per customer - $170
  - Amount amortised over life of contracts - $162
- High proportion of new customers entering into fixed-term contracts (83%)
- Capitalised cash outlay in FY11 was $15.6 million to contract 96,000 customers

Amortisation profile – NSW customer acquisition costs



NSW Lead sales by contract type – 2HFY11

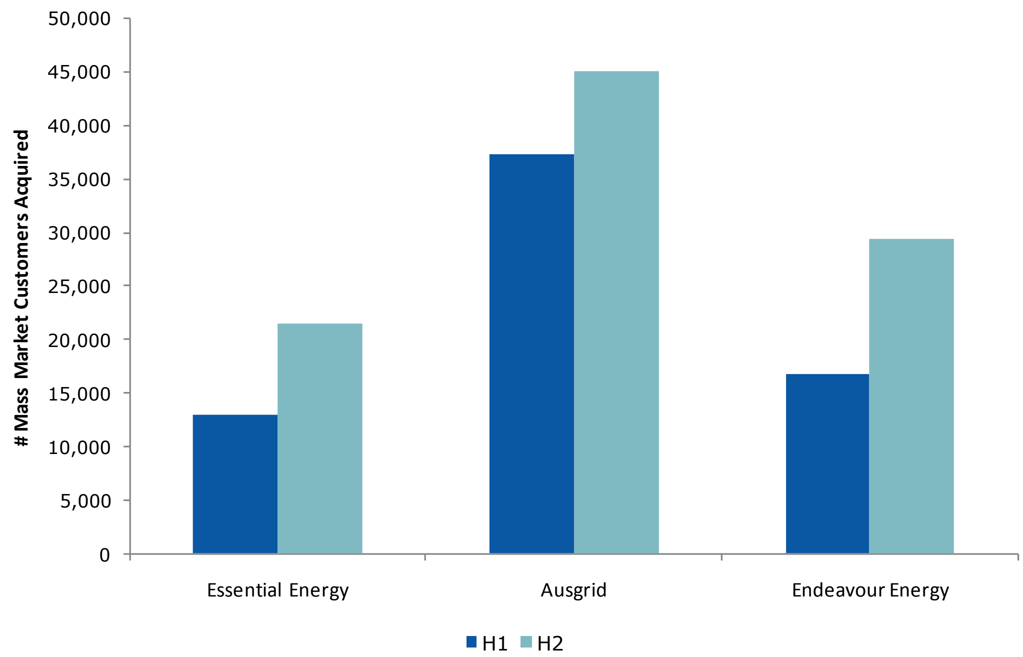


NSW growth – Electricity customer acquisition[1]

All regions responding to increased activity and AGL's product offering.

- Prior to completion of NSW privatisation
  - Churn primarily occurred in Ausgrid patch
- AGL Sales activity in 2HFY11 broadened
- Multiple distribution channels deployed
- Essential and Endeavour patches up 72% in 2HFY11
- Ausgrid patch up 21% in 2HFY11

AGL Electricity Lead Sales by Distributor Patch[1]– FY11



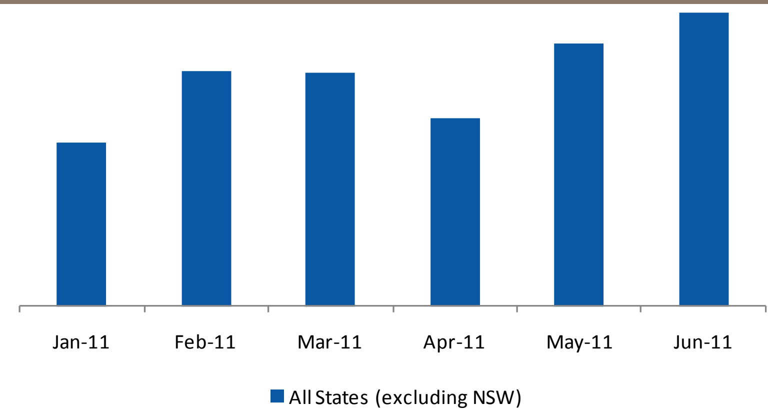
1. Incumbent distributor patch based on postcode.

Retail competition in other States

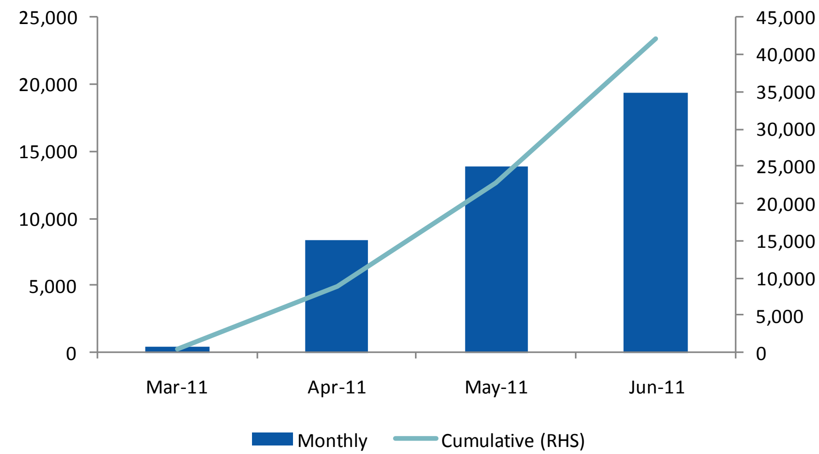
Competitive activity remains high in benign wholesale market conditions.

- Changes to Consumer Laws in January 2011, re: hours of operation for door-to-door sales
- AGL over-estimated likely downturn in sales activity in States outside NSW from changes to legislation
- Second tier competitors have significantly increased field sales resources (estimated +25%)
- Margin expansion has driven competitive activity
- AGL response has been to increase activity, launch new channels boosting lead sales in Q4FY11
- AGL Energy Online launched with over 42,000 registrations in four months

New Customer Lead Sales - Qld, VIC & SA (2HFY11)



AGL Energy Online - Customer Registrations



Customer growth

Strategies to improve retention & sales in Queensland/South Australia.

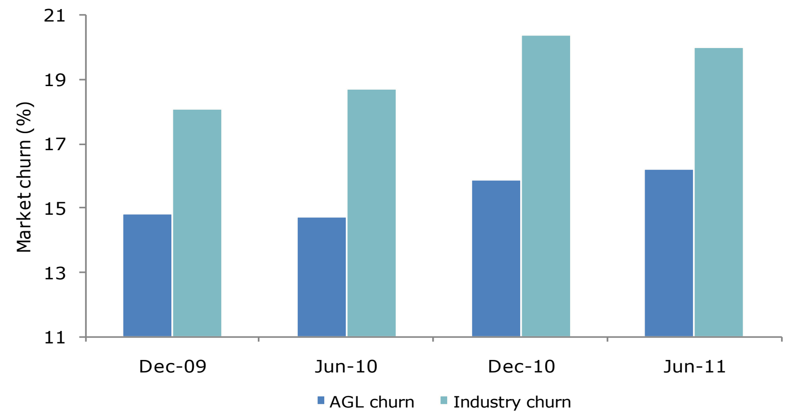
Customer Numbers ('000)	30 Jun 2010	31 Dec 2010	30 Jun 2011	FY11 vs FY10
Electricity				
New South Wales	381	423	**468**	87
Queensland	371	362	**350**	(21)
South Australia	478	475	**468**	(10)
Victoria	643	646	**639**	(4)
	1,873	1,906	**1,925**	52
Gas				
New South Wales	727	717	**718**	(9)
Queensland	77	75	**74**	(3)
South Australia	97	102	**104**	7
Victoria	468	474	**473**	5
	1,369	1,368	**1,369**	0
Total	3,242	3,274	**3,294**	52
Dual fuel accounts	1,362	1,431	**1,472**	110

Improving customer service

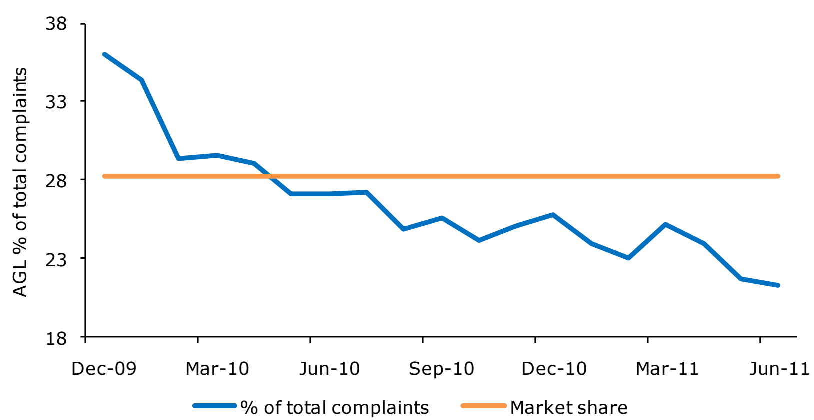
Industry outperformance.

- AGL continues to outperform industry despite increasing competition
  - AGL customer churn 3.8 ppts below industry average
  - AGL churn reduced in NSW
- Combination of retention and increased dual fuel focus has reduced the impact of churn
- Strong customer focus
  - Focus on first call resolution
  - Regular engagement between Senior Leadership Group and customers embedding service culture throughout the organisation
  - Helping to further reduce AGL's share of Ombudsman complaints

AGL churn much lower than industry



Share of total Ombudsman complaints continues to decrease

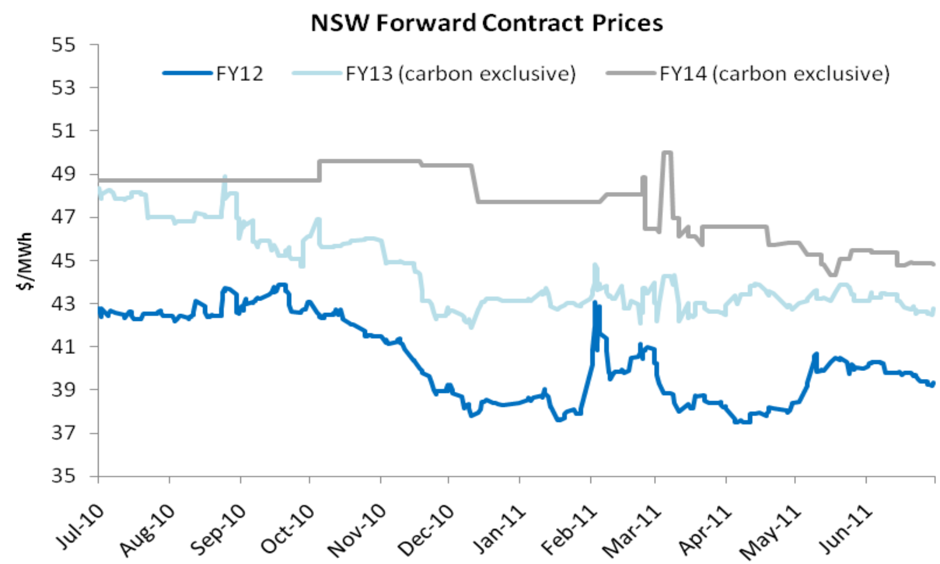


Managing NSW electricity load

Generators provide additional hedge cover.

- Unaligned NSW generation available to support AGL's NSW growth strategy
- AGL has been able to procure significant volumes of hedge cover for multiple years to support its retail business post completion of NSW electricity privatisation
- Additional contracts out to FY18
- Continued low spot prices in NSW and other NEM regions resulting in a reduction in forward contract prices

Entity	Capacity (MW)	% of Region
Macquarie Generation	4,839	28.8%
Snowy Hydro	2,516	15.0%
Delta Coastal	2,588	15.4%
Total	9,943	59.2%



Building scale in generation

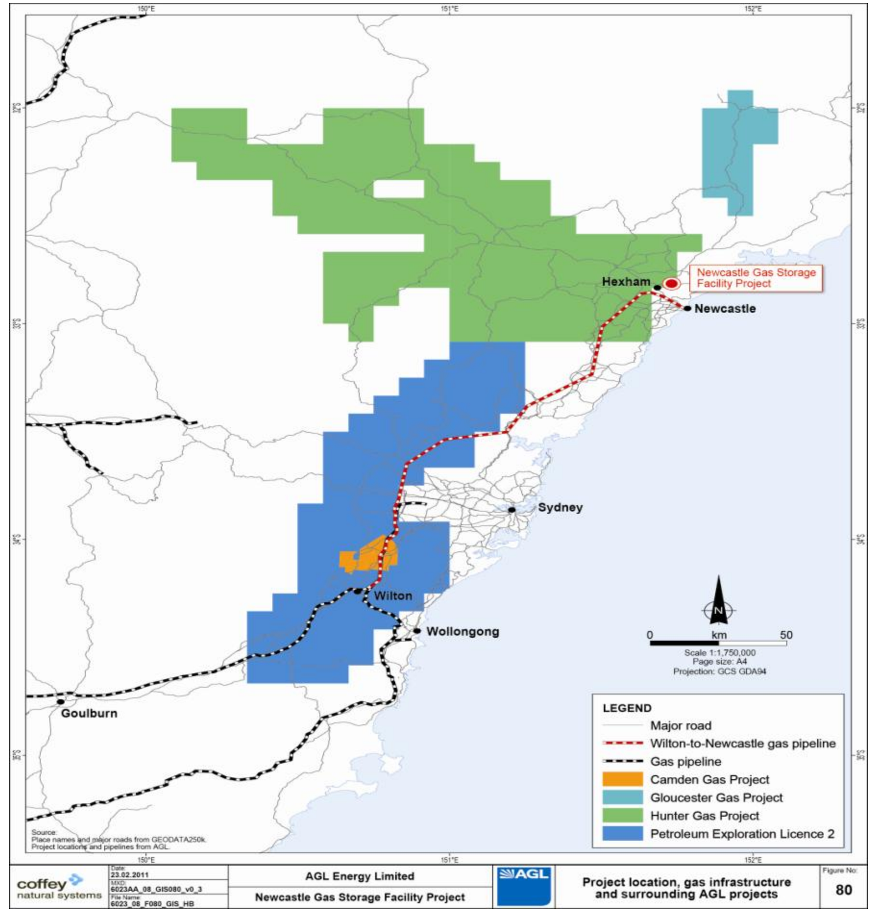
Dalton to deliver cost-competitive capacity and portfolio flexibility.

- Initial 500 MW peaking capacity
- EPC contract signed
  - Leighton Contractors/GE consortium
  - Conditional upon planning approval, transmission and gas connection
  - Planning approval expected within next six months
- Attractive pricing reflects:
  - Low demand for gas turbines post-GFC
  - Recent A$ strength
- Completion expected Summer 2013/14

Newcastle Gas Storage Facility

Storage to deliver cost-competitive capacity and portfolio flexibility.

- EPC contractor selected
  - Conditional upon NSW and Commonwealth government approvals
- Approvals expected Q2FY12
- Managing peak gas demand (daily and hourly)
- Storage capacity 1.5 PJ
- Peak supply rate 120 TJ per day
- Expected completion/commissioning in 2014



Project location, gas infrastructure and surrounding AGL Projects

New QGC gas sales contract

Gas sale of between 54 PJ and 74 PJ.

- Binding agreement executed with QGC
  - Reshapes the contractual volumes in AGL's existing gas purchase agreement
  - Reduces AGL's front-end purchase obligations and increases volumes available for sale to QGC post January 2014
  - AGL to sell gas to QGC over a three-year period
  - Flexible start date commencing January 2014
  - Final gas sales volume determined by timing of start date
- Contract rationale
  - Manages AGL's wholesale gas portfolio inventory
  - Assists QGC with its QCLNG project ramp-up
  - Attractive oil-linked selling price

Mosaic acquisition

Emerging gas storage business provides new platform for growth.

Silver Springs underground gas storage project

- Underpinned by QGC gas storage services agreement for first 7 years
- Stage 1 in commissioning
- Injection commenced August 2011
- Current injection/extraction rate of 30 TJ per day
- Investigating Stage 2:
  - Expansion to 40 TJ per day injection/extraction
  - Aim to be operational in 2HFY12

Upstream Gas – Creating long-term value

Total 2P reserves entitlement increased by 511 PJ during FY11.

- Initial Hunter gas reserves booked (2P: 142 PJ)
- Total Bowen Basin 2P reserves up 310 PJ despite 131 PJ decline at Moranbah
- Arrow Energy commits to FEED. ATP 1103 gas likely to be committed to LNG export project
- Initial resource estimates booked for Galilee (2C: 259 PJ)

AGL share of CSG reserves	As at 30 Jun 11		As at 30 Jun 10		Change	
PJ	**2P**	**3P**	**2P**	**3P**	**2P**	**3P**
Gloucester (100%)	**669**	**832**	669	832	-	-
Moranbah (50%) – Bowen Basin	**370**	**700**	501	1,022	(26.1%)	(31.5%)
Camden (100%)	**148**	**195**	154	201	(3.9%)	(3.0%)
Hunter (100%)	**142**	**271**	-	-	na	na
Silver Springs (various)	**65**	**137**	-	-	na	na
Spring Gully (various, small)	**8**	**10**	8	10	-	-
Sub-Total	**1,402**	**2,145**	**1,332**	**2,065**	**5.3%**	**3.9%**
ATP 1103 rights (50%) – Bowen Basin*	**687**	**1,495**	246	1,307	179.3%	14.4%
Total	**2,089**	**3,640**	**1,578**	**3,372**	**32.4%**	**7.9%**

* 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. Past costs are anticipated to be less than $0.05/GJ.

Renewables

Projects remain on track.

- Macarthur (420 MW) wind farm construction commenced November 2010
  - $1 billion project (AGL 50%) remains on track for Q1 2013 completion
  - AGL's 50% interest is being partly funded by $200m export credit facility
- Oaklands Hill (67 MW) wind farm sold in June 2011
  - Development profit of $38 million ($30 million recognised in FY11)
- Hallett 5 (52 MW) wind farm on-time and budget to be sold in FY12
- AGL buys solar installation business (Rezeko) in July 2011
  - $15 million acquisition cost
  - Expands customer product offering
- Development pipeline
  - Ready-to-develop – wind 700 MW
  - Feasibility – wind/solar 1,200 MW

AGL

Carbon price proposed from 1 July 2012

Market-based mechanism will achieve lowest cost.

- Government committed to 1 July 2012 start date
  - Legislation scheduled to be passed in 1HFY12
- AGL well-positioned for a low carbon environment
  - Generation fleet average emissions intensity 58% below NEM
  - Pipeline of low-emission gas and renewable power development projects
  - Skilled resource base to assist customers – Energy Services
- Preparation underway to manage obligation
  - Emissions obligation anticipated approximately 10 million tonne
  - Australian Energy Market Agreement – States committed to full pass through of carbon costs
- Loy Yang A expected to receive transitional assistance over the first five years

Summary

Good start to NSW organic growth strategy.

- Retail Energy continues to perform well
  - Ongoing improvement in customer service
  - Good growth in NSW electricity customer acquisitions
  - NSW acquisition costs per customer substantially less than $200
- Merchant Energy delivers flat result
  - Severe weather event
  - Higher hedge costs
- Loy Yang A contribution declined reflecting lower wholesale electricity prices
- Upstream Gas continues to create long-term value and develop strategic optionality
- Strong balance sheet, strong cash flows and strong growth pipeline

Outlook

- Strong growth in Merchant Energy reflecting:
  - Assumed absence of costs associated with 2011 weather events
  - Favourable wholesale electricity markets
  - Increased contribution from hydro assets
  - Initial contribution from South Australia desalination contract
  - Partially offset by reduced wind farm development fees, soft demand and more conservatively positioned hedge book
- Solid growth in Retail earnings despite intense competition
  - Continuing strong growth in NSW electricity customers
- Construction expected to commence on Dalton/Newcastle GSF
- No improvement in contribution from LYA expected
- Profit guidance at AGM - 27 October 2011

Sales / Information / Contacts

Sales

Switch to AGL electricity and gas:	**www.agl.com.au**
Register for AGL Online:	**https://aglenergyonline.agl.com.au**
Call Customer Service:	**131 245**

Information

Refer to AGL's website:	**www.agl.com.au**

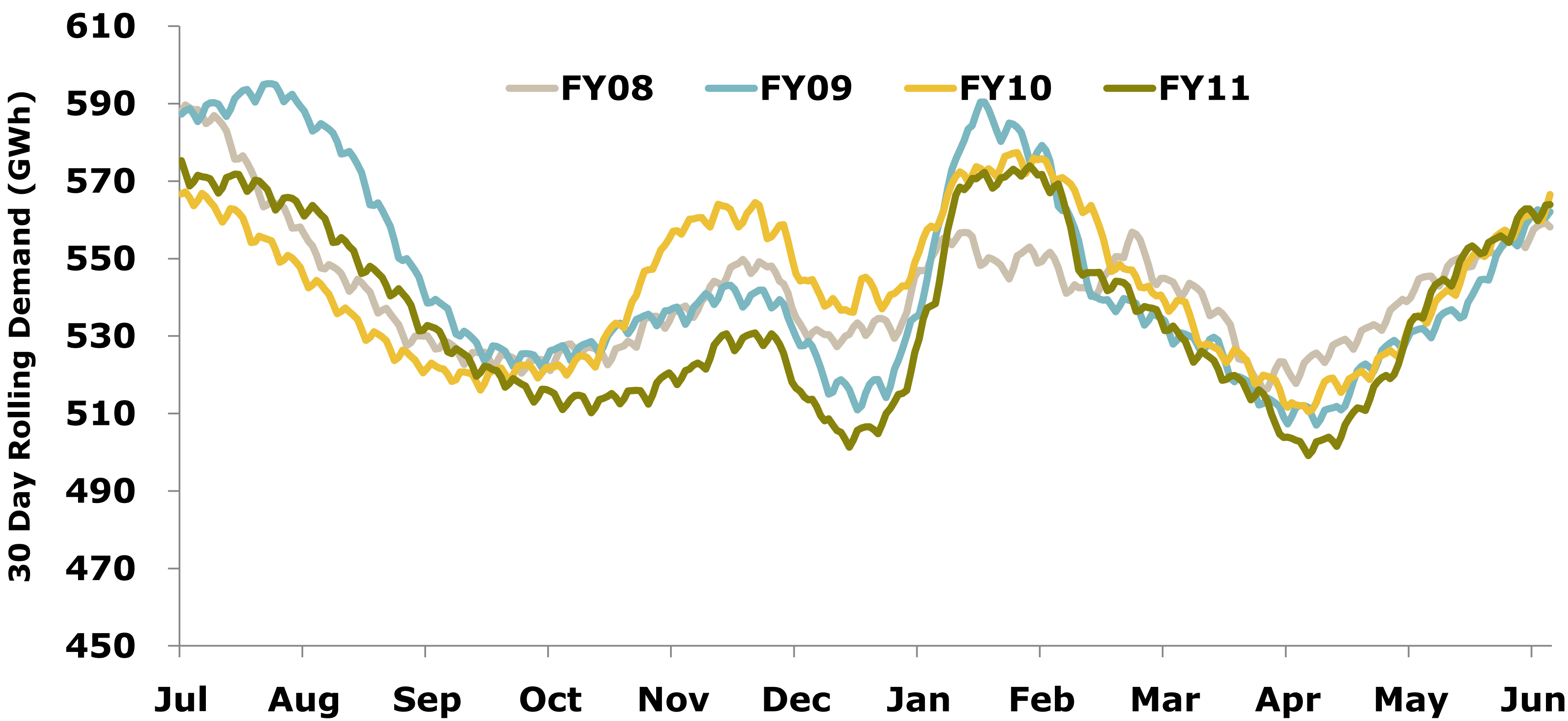
Contacts

INVESTORS
John Hobson
Head of Capital Markets
phone: +61 2 9921 2789
mobile: +61 (0) 488 002 460
e-mail: john.hobson@agl.com.au

MEDIA
Nathan Vass
Head of Corporate Communications
phone: +61 2 9921 2264
mobile: +61 (0) 405 040 133
e-mail: nvass@agl.com.au

Supplementary Information

Electricity Demand - NEM



Source: AEMO (excludes Tasmania)

Electricity Sales Volume

12 months to GWh	30 Jun 2011	30 Jun 2010	Change
Mass Market			
VIC	**4,747**	4,931	(3.7%)
SA	**3,233**	3,404	(5.0%)
NSW	**3,859**	3,338	15.6%
QLD	**2,835**	3,406	(16.8%)
Mass Market Total	**14,674**	15,079	(2.7%)
C & I			
VIC	**6,156**	6,097	1.0%
SA	**3,563**	3,196	11.5%
NSW	**5,538**	5,397	2.6%
QLD	**2,833**	4,593	(38.3%)
C & I Total	**18,090**	19,283	(6.2%)
Total (excl. ActewAGL)	**32,764**	**34,362**	**(4.7%)**
Purchased volume ActewAGL	**3,029**	3,014	0.5%

Gas Sales Volume

12 months to PJ	30 Jun 2011	30 Jun 2010	Change
Mass Market			
VIC	**30.8**	28.1	9.6%
SA	**2.6**	2.0	30.0%
NSW	**26.3**	25.0	5.2%
QLD	**2.9**	3.2	(9.4%)
Mass Market Total	**62.6**	58.3	7.4%
C & I			
VIC	**26.0**	25.8	0.8%
SA	**9.4**	7.3	28.8%
NSW	**39.9**	39.0	2.3%
QLD	**13.8**	14.6	(5.5%)
C & I Total	**89.1**	86.7	2.8%
Wholesale Customers & Generation[1]	**64.5**	65.9	(2.1%)
Total	**216.2**	**210.9**	**2.5%**

1. Includes volumes sold to TIPS during full year Jun 11 26.3 PJ (Jun 10 23.4 PJ). Increase due to higher generation.

Retail – Mass Market Key Indicators (includes SME)

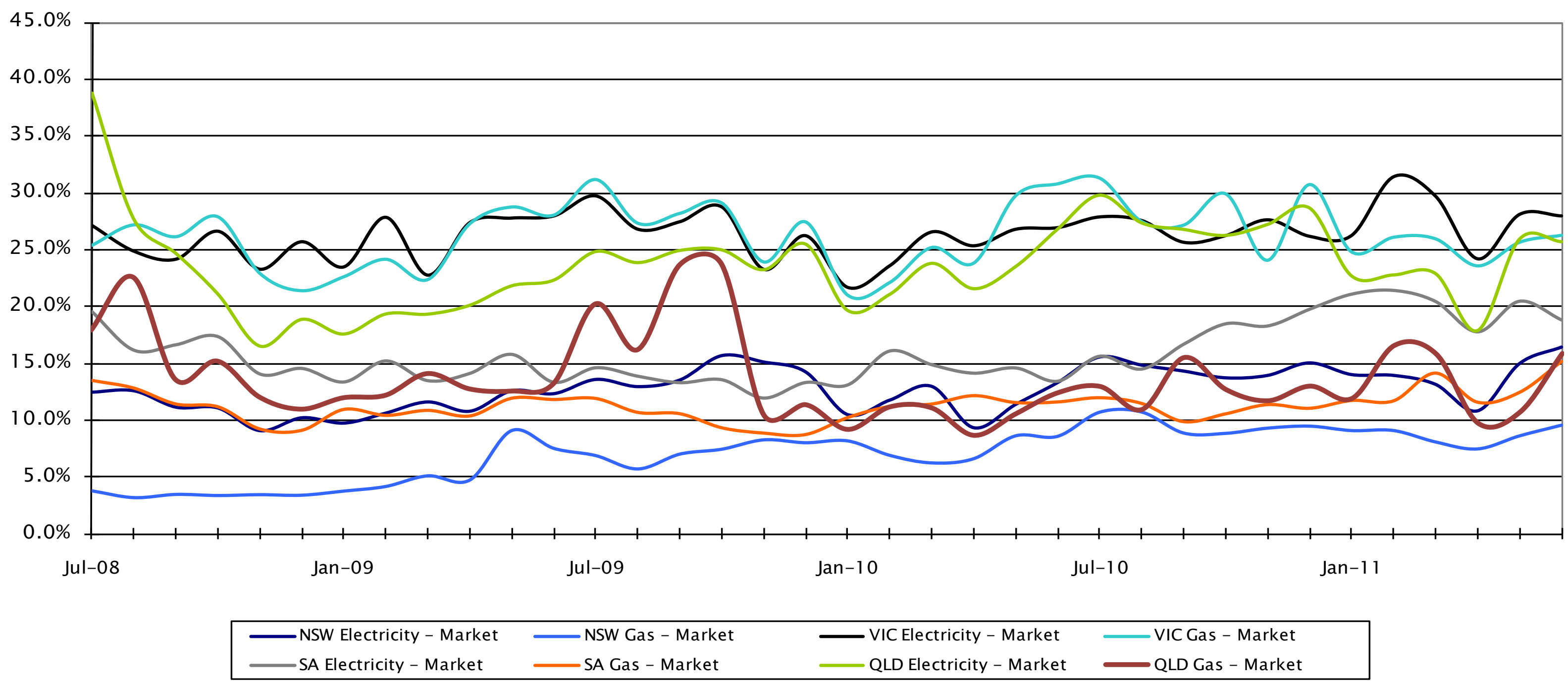
12 months to Electricity	30 Jun 2011	30 Jun 2010	Change
Volume (GWh)	**14,674**	15,079	(2.7%)
Avg. Mass Market Accounts ('000)	**1,886**	1,856	1.6%
Revenue ($m)	**2,479.4**	2,208.9	12.2%
Gross Margin ($m)	**388.1**	345.0	12.5%
Gross Margin	**15.7%**	15.6%	0.1 ppts
Gross Margin per customer	**$205.81**	$188.93	8.9%
12 months to Gas			
Volume (PJ)	**62.6**	58.3	7.4%
Avg. Mass Market Accounts ('000)	**1,368**	1,368	0.0%
Revenue ($m)	**1,111.9**	993.9	11.9%
Gross Margin ($m)	**207.7**	188.3	10.3%
Gross Margin	**18.7%**	18.9%	(0.2) ppts
Gross Margin per customer	**$151.80**	$136.47	11.2%

Retail – C & I Key Indicators

12 months to Electricity	30 Jun 2011	30 Jun 2010	Change
Volume (GWh)	**18,090**	19,283	(6.2%)
C & I Accounts ('000)	**19.6**	16.5	18.8%
Revenue ($m)	**1,870.0**	1,801.1	3.8%
Gross Margin ($m)	**61.0**	49.6	23.0%
$ / MWh	**$3.37**	$2.57	31.1%
12 months to Gas			
Volume (PJ)	**89.1**	86.7	2.8%
C & I Accounts ('000)	**1.0**	1.0	0.0%
Revenue ($m)	**553.8**	518.0	6.9%
Gross Margin ($m)	**40.6**	48.8	(16.8%)
$ / GJ	**$0.47**	$0.56	(16.1%)

Retail – Market Churn

AGL churn 3.8 ppts below Market (16.2% vs Market at 20.0%)



Retail – Cost to Serve

12 months to	30 Jun 2011	30 Jun 2010	Change
Net operating expenditure	**$324.4m**	$312.9m	3.7%
Net operating cost per customer account	**$99.12**	$97.11	2.1%
Cost to grow/retain	**$75.9m**	$77.5m	(2.1%)
Cost to grow per account acquired/retained[1]	**$84.08**	$86.84	(3.2%)
Cost to serve	**$248.5m**	$235.4m	5.6%
Cost to serve per customer account[2]	**$75.93**	$73.06	3.9%

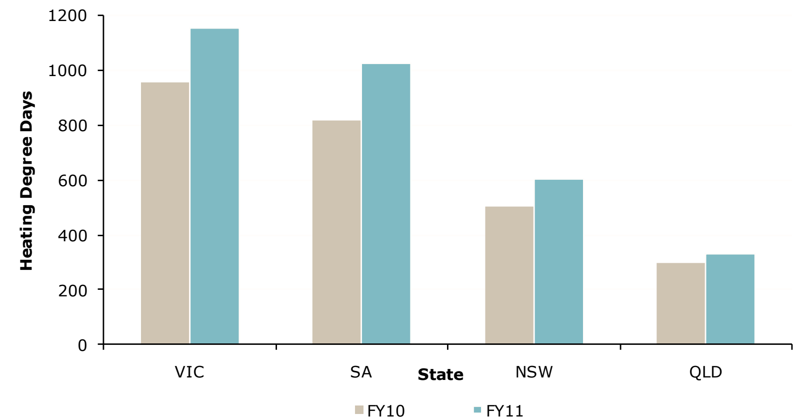
- Cost to grow per acquisition / retention remained largely flat. More efficient SAP sales processing and lead conversion has been offset by higher broker costs due to increasing market competition
- Cost to serve per customer account up – labour cost increase due to maintaining low unbilled levels and continuing to improve customer service. Higher bad debt expenses in line with mass market tariff increases

1. Cost to grow 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.

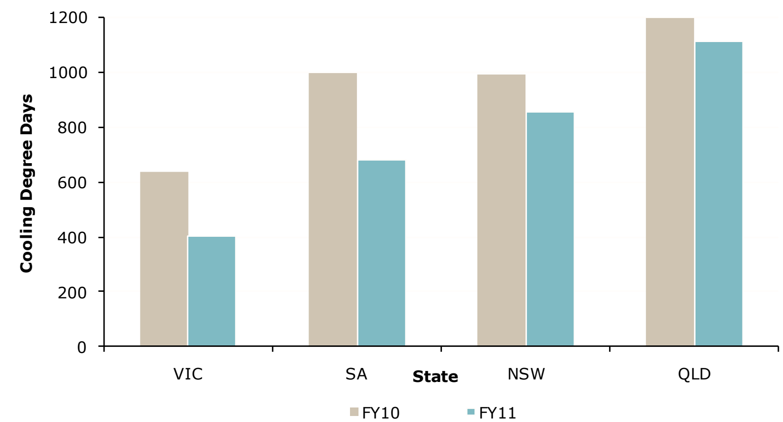
Retail – Weather

- Winter months
  - Victoria experienced 6th wettest August 2010 on record with exceptionally low daytime temperatures
  - South Australia July and August 2010: 1 - 3°C below average temperatures; second coolest Autumn on record in 2011
  - New South Wales August 2010 the coldest August for maximum temperatures since 1990, and sixth coldest Autumn on record (especially May 2011)
  - Queensland experienced cooler daytimes and warmer minimum temperatures than average
- Summer months
  - Record Summer rainfall in Victoria kept average temperatures low compared to prior year
  - South Australia experienced average day time temperatures in Summer 2011, a lack of severe heat compared to 2010
  - New South Wales experienced 5th coldest December on record in 2010. In early-February Sydney experienced record-breaking heat wave of 7 days above 30°C and 5 nights with minimum temperatures exceeding 24°C
  - Record or near record Queensland rainfall impacted Summer temperatures across the state

Heating Degree Days



Cooling Degree Days



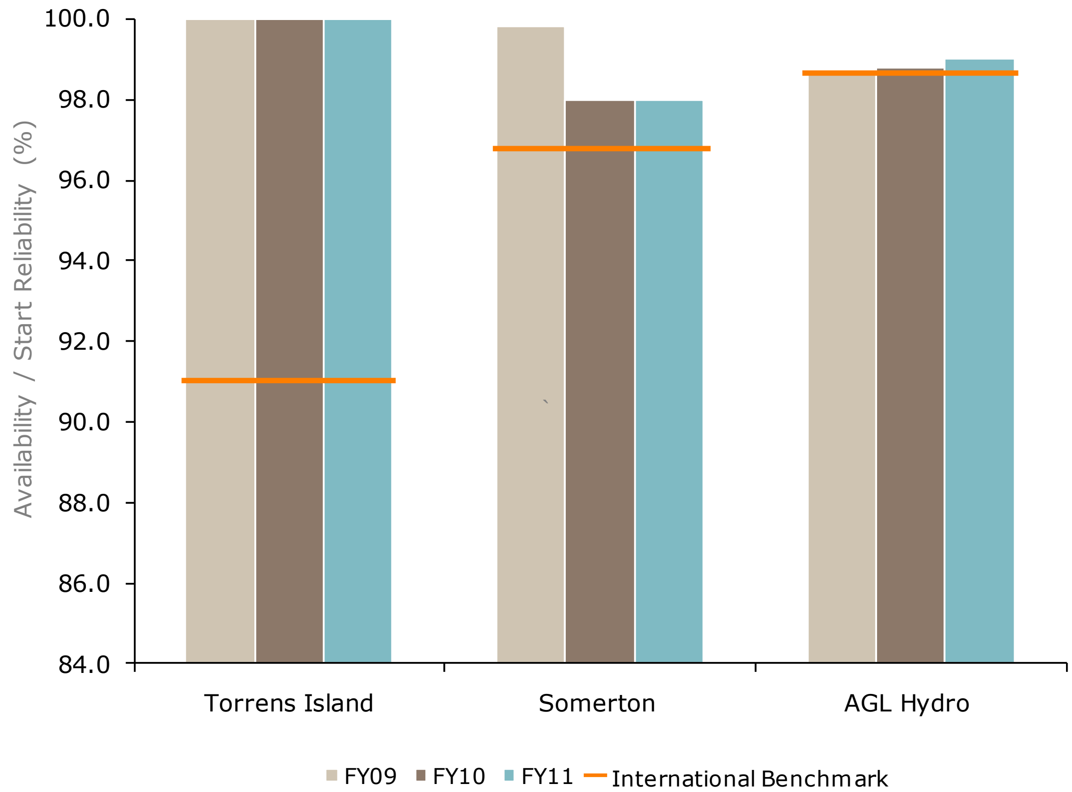
Merchant – EBIT Analysis

12 months to $m	30 Jun 2011	30 Jun 2010	Change
Revenue from Retail Business			
- Electricity (COGS transfer price)	**2,393.9**	2,324.6	3.0%
- Gas (COGS transfer price)	**822.9**	725.5	13.4%
External Revenue			
- Generation Revenue[1]	**256.5**	361.5	(29.0%)
- ActewAGL[2]	**284.3**	253.9	12.0%
- External (3rd Party) Revenue[3]	**364.5**	361.0	1.0%
- Wind Farm Development Fees	**61.0**	57.0	7.0%
Total Merchant Revenue	**4,183.1**	4,083.5	2.4%
Cost of Goods Sold			
- Electricity COGS[4]	**(1,896.1)**	(2,606.1)	(27.2%)
- Electricity CFD's	**(391.9)**	93.4	(519.6%)
- Gas COGS	**(928.8)**	(863.0)	7.6%
- Green Certificates	**(410.9)**	(155.7)	163.9%
Gross Margin	**555.4**	552.1	0.6%
Operating Costs	**(108.1)**	(102.3)	5.7%
EBITDA	**447.3**	449.8	(0.6%)
D&A	**(69.1)**	(63.7)	8.5%
EBIT	**378.2**	386.1	(2.0%)

1. Generation revenue is pool revenue from owned generation assets.
2. ActewAGL Jun 11: Electricity sales 60%, Gas sales 28%; Other sales 12%; Jun 10: Electricity sales 63%, Gas sales 30%; Other sales: 7%.
3. External revenue Jun 11: Gas sales 35%, Green Certificate Sales 49%, Other sales 16%; Jun 10: Gas sales 45%, Green Certificate Sales 36%, Other sales 19%.
4. Electricity COGS includes $110.8m (Jun 10: $113.5m) of gas costs for gas fired generation (TIPS, Oakey, Somerton and Yabulu) which is reported in Wholesale Electricity EBIT.

Merchant – Generation: Operational performance

Commercial Availability / Start Reliability (%)

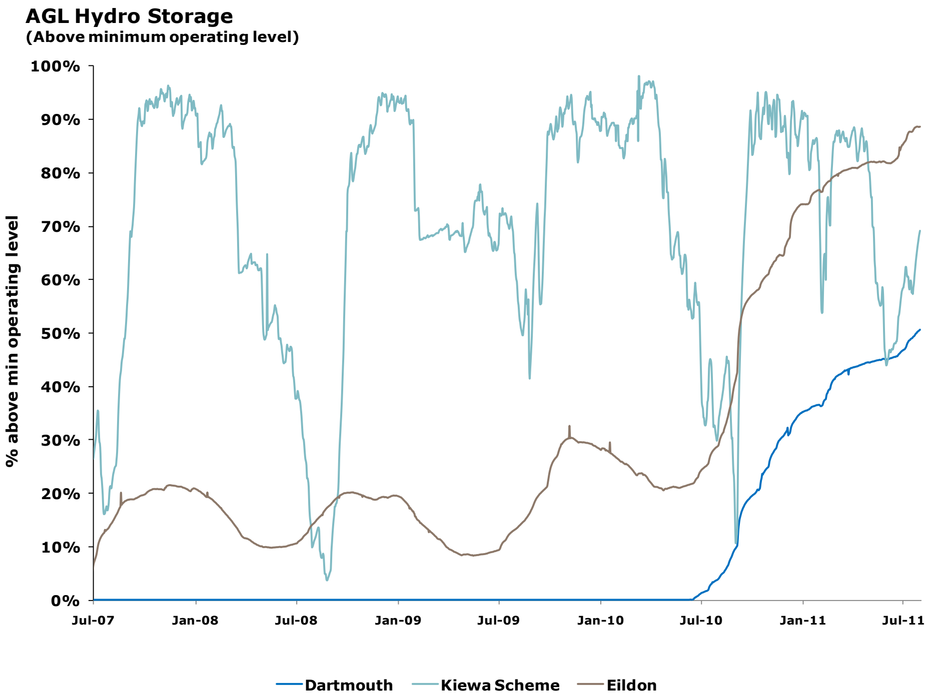


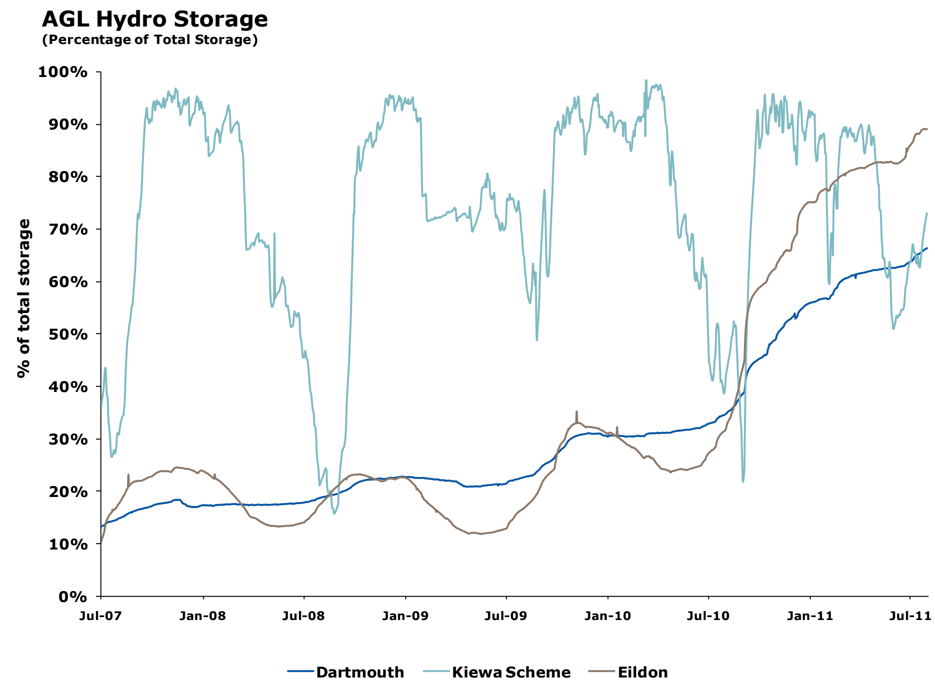
Operational performance of generation assets continues to meet or exceed international benchmarks.

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 Council 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.

Merchant – Hydrology

- 52.6% of Hydro capacity is now linked to drought-resistant Kiewa Scheme
- Eildon is operational and at full capacity (120MW)
- Dartmouth continues to get good inflows and is operational at 145MW (out of a total 180MW)





Merchant – Generation: Carbon intensity

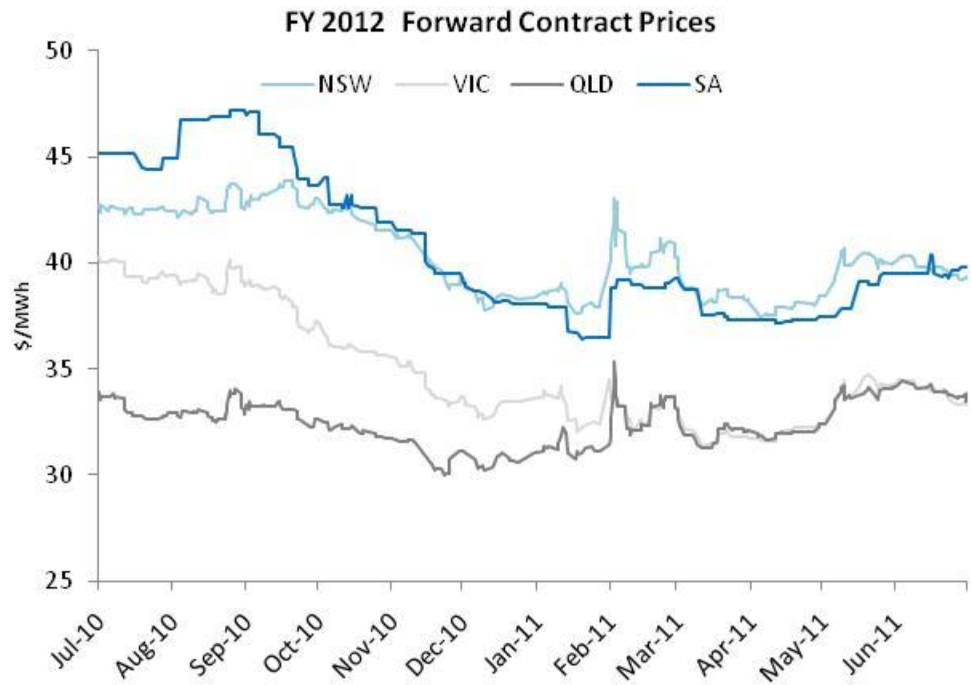
Asset	Location	Type	Status	Capacity (MW)	Capacity Factor (%)	Output 2010/11 (GWh)	Carbon intensity (tonnes CO2e/MWh)
Torrens Island	SA	CCGT	Owned	1,280	20	2,211	0.6
Angaston	SA	OCGT	Control dispatch	49	0	1	1.0
Wattle Point	SA	Wind	Control dispatch	91	32	252	0.0
Hallett 1	SA	Wind	Control dispatch	95	39	320	0.0
Hallett 2	SA	Wind	Control dispatch	71	39	245	0.0
Hallett 4	SA	Wind	Control dispatch	132	38	301	0.0
Oaklands Hill	SA	Wind	Control dispatch	67	NA	0	0.0
Somerton	Vic	OCGT	Owned	150	4	56	0.7
Vic Hydro	Vic	Hydro	Owned	733	11	731	0.0
NSW Hydro	NSW	Hydro	Owned	62	12	64	0.0
Moranbah	Qld	OCGT	Owned	12	81	85	0.6
Oakey	Qld	OCGT	Control dispatch	282	1	26	0.6
Yabulu	Qld	CCGT	Control dispatch	121	42	443	0.4
Other	Various	Biomass & Cogen	Various	101	42	203	0.2
AGL Total				**3,246**			**0.4**
Industry Average							**0.9**

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
- Counter party 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

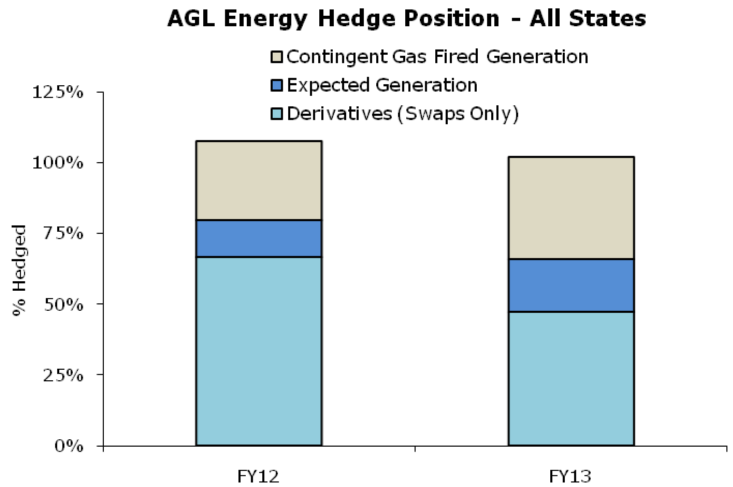
Merchant – Wholesale Electricity Prices

- Financial Year 2012 contract prices fell significantly in the second half of Calendar Year 2010 and January 2011 following a prolonged period of flat spot prices across the National Electricity Market
- Forward prices then spiked in February 2011 in response to spot price volatility driven by severe hot weather in New South Wales
- Financial Year 2012 prices increased steadily during the first half Q2 Calendar Year 2011, driven by the early onset of cold weather in April and May 2011 and uncertainty around the contract positions of New South Wales generators following privatisation



Merchant – Electricity Hedging: Position

Physical

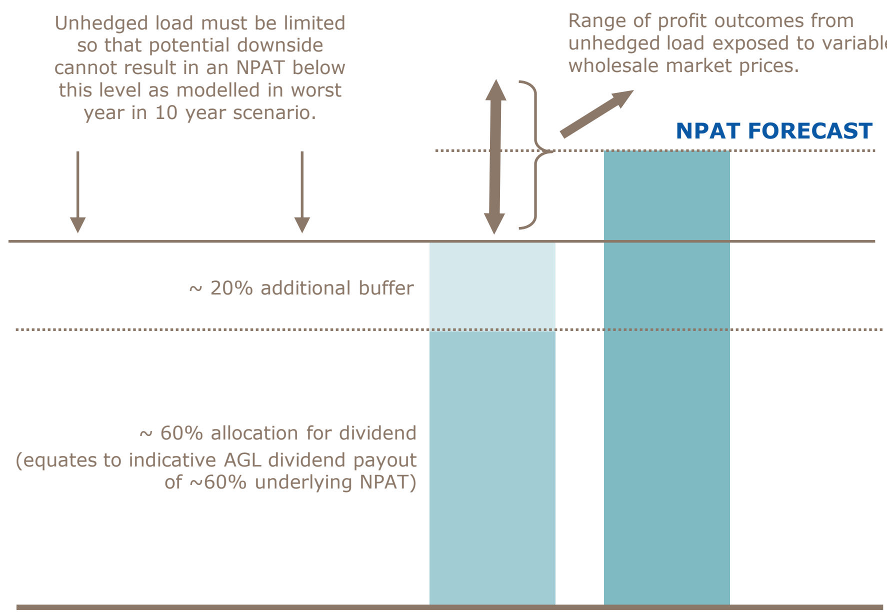


Key Points

- 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
- Position does not include AGL's passive investment in Loy Yang A

Financial

Satisfying Financial Risk Limits



Upstream Gas – Key Financial Metrics

12 months to $m	30 Jun 2011	30 Jun 2010	Change
Operating EBITDA	**35.1**	26.6	32.0%
D & A	**(21.5)**	(21.1)	1.9%
EBIT			
Upstream Gas			
Queensland / South Australia	**16.2**	4.7	244.7%
New South Wales	**4.2**	4.3	(2.3%)
Equity Investments	**(0.4)**	(2.2)	(81.8%)
Sundry	**(6.4)**	(1.3)	392.3%
Operating EBIT	**13.6**	5.5	147.3%

Upstream Gas Interests – Permit Details

Basin	Project	Permits: Exploration (Area km²)	Permits: Production (Area km²)	Working Interest
Sydney	Camden Gas Project	PEL 2 (6,708)	-	100%
		PEL 5 (401)	-	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)	-	100%
Gloucester	Gloucester Gas Project	PEL 285 (1,021)	-	100%
Cooper/Eromanga	Conventional oil and gas	ATP 934P (1,466)**a**	-	20%
	Conventional oil and gas	ATP 1056P (3,917)	-	40%**f**
	Innamincka JV (oil and gas)	PEL 101 (154)	-	35%**f**
		PEL 103 (177)	-	37.5%**f**
		PEL 103A (56)	-	37.5%**f**
		PRL 17 (64)	-	37.5%**f**
		PRL 18 (65)	-	37.5%**f**
		-	PRL 14 (22)	37.5%
Galilee	Galilee JV	ATP 529P (5,930)	-	50%**f**

Basin	Project	Permits: Exploration (Area km²)	Permits: Production (Area km²)	Working Interest
Surat	Silver Springs (oil and gas)	ATP 471P (703)**r**	-	28.71-100%
		ATP 709P (146)	-	100%
		-	PL 1 (55)	15%
		-	PL 15 (259)	75%
		-	PL 16 (259)	100%
		-	PL 30 (37)	10%
		-	PL 46 (33)**r**	100%
		-	PL 48 (6)**r**	100%
		-	PL 49 (21)**r**	100%
		-	PL 56 (18)**r**	100%
		-	PL 66 (125)	10%
		-	PL 74 (18)**r**	16%
		-	PL 192 (91)	100%
		-	PL 202 (91)	100%
		-	PL 213 (46)	100%
		-	PL 441 (43)	75.252%
Bowen	Moranbah Gas Project	ATP 1103 (4,135)	-	99%**p**
		-	PL 191 (219)	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 (256)	0.75%
		-	PL 203 (259)	0.75%
		-	PL 204 (219)	0.0375%
Taranaki (New Zealand)	Conventional oil and gas	PEP 51149 (636)	-	18.575%
		PEP 51151 (482)	-	50%
		PEP 52181 (172)	-	15%
		PEP 53247 (6)	-	75%

a Under application.
f Subject to farm in; working interests reflect AGL's final position after farm.
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.

Operating Cash Flow to Statutory Cash Flow Reconciliation

12 months to $m	30 Jun 2011	30 Jun 2010	Movement
Operating EBITDA	**804.5**	789.6	14.9
Equity accounting	**(6.0)**	(39.1)	33.1
Onerous gas contract	**(20.9)**	(20.9)	-
Receivables	**(42.3)**	(25.4)	(16.9)
Net movement in green assets / liabilities	**(94.1)**	(17.6)	(76.5)
Inventories	**(30.4)**	(42.9)	12.5
Creditors	**22.9**	26.5	(3.6)
Futures margin calls	**30.0**	(5.9)	35.9
Net derivative premiums paid / roll-offs	**(29.2)**	6.7	(35.9)
Net movement in GST recoverable / payable	**7.5**	(6.4)	13.9
Other	**9.2**	(14.0)	23.2
Total working capital movements	**(126.4)**	(79.0)	(47.4)
Operating cash flow before interest, tax & significant items	**651.2**	650.6	0.6
Net finance costs	**(39.3)**	(43.8)	4.5
Tax paid	**(0.7)**	(189.0)	188.3
Cash flow relating to significant items	**(41.9)**	(27.8)	(14.1)
Statutory net cash provided by operating activities	**569.3**	390.0	179.3

Energy Investments

12 months to $m	30 Jun 2011	30 Jun 2010	Change
EBIT			
ActewAGL	**29.8**	30.4	(2.0%)
Loy Yang	**10.7**	45.1	(76.3%)
Investments Other	**-**	6.2	(100.0%)
Total EBIT	**40.5**	81.7	(101.7%)

Capital Expenditure

12 months to 30 Jun 2011 $m	SIB	Discretionary	Total
Merchant Energy	61.8	254.8	316.6
Upstream Gas	-	114.1	114.1
Retail Energy	-	64.4	64.4
Corporate Other	27.5	-	27.5
Total	**89.3**	**433.3**	**522.6**

- SIB capital expenditure relates predominantly to:
  - Torrens Island Power Station Project Gateway and major survey on the B1 and B2 units
  - Refurbishment of Generators 2 and 3 at the West Kiewa Power Station
  - Somerton noise reduction project
  - SAP upgrade for non-billing applications

Balance Sheet

As at $m	30 Jun 2011	30 Jun 2010
Current assets	**2,730.4**	2,208.5
PPE, E&E and oil & gas assets	**3,400.9**	2,997.1
Other non current assets	**3,564.4**	3,485.3
Total Assets	**9,695.7**	8,690.9
Current liabilities	**1,570.4**	1,532.5
Total debt	**1,171.2**	900.8
Other non current liabilities	**612.6**	457.7
Total Liabilities	**3,354.2**	2,891.0
Net Assets	**6,341.5**	5,799.9
Contributed equity	**4,244.6**	4,066.7
Reserves	**(97.1)**	(159.4)
Retained earnings	**2,194.0**	1,892.6
Total Equity	**6,341.5**	5,799.9

Fair Value Reconciliation

As at $m	Net Assets (Liabilities) 30 Jun 2011	 30 Jun 2010	 Change
Electricity derivative contracts	**(89.7)**	(474.3)	384.6
Interest rate swap & foreign currency derivative contracts	**(148.5)**	(7.2)	(141.3)
Total net liabilities for derivative contracts	**(238.2)**	(481.5)	243.3
Change in derivative net liability	**243.3**		
Premiums paid	**(175.0)**		
Equity accounted Loy Yang fair value	**5.8**		
Premium roll off	**145.9**		
Total change in fair value	**220.0**		
Recognised in equity hedge reserve	**64.7**		
Recognised in borrowings	**(63.5)**		
Recognised in profit and loss	**218.8**		
Total change in fair value	**220.0**		

Loy Yang A: Financial Performance

12 months to $m	30 Jun 2011	30 Jun 2010	Change
Generation Volume (GWh)	**15,174**	15,518	(2.2%)
Average Price ($/MWh)[1]	**$37.62**	$42.62	(11.7%)
Generation revenue	**570.9**	661.4	(13.7%)
Other revenue	**77.8**	76.0	2.4%
Expenses	**(271.1)**	(264.7)	2.4%
Depreciation	**(117.1)**	(112.7)	3.9%
Borrowing costs	**(266.3)**	(252.4)	5.5%
Income tax benefit	**5.8**	-	- %
Profit (loss) after tax before fair value changes	**0.0**	107.6	(100.0%)
AGL share of profit (loss) after tax before fair value	**0.0**	35.0	(100.0%)
Interest on loan note	**10.7**	10.1	5.9%
Operating EBIT	**10.7**	45.1	(76.3%)

1. Weighted average price based on Generation Revenue and Generation Volume.