

IN THE AUSTRALIAN COMPETITION TRIBUNAL

of 2014

**AGL Energy Limited**

**RE: PROPOSED ACQUISITION OF MACQUARIE GENERATION (A CORPORATION ESTABLISHED UNDER THE ENERGY SERVICES CORPORATIONS ACT 1995 (NSW))**

Statement of: Anthony Garth Fowler

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Occupation: Group General Manager, Merchant Energy

Date: 23 March 2014

**Contents**

Document number	Details	Paragraph	Page
1	Statement of Anthony Garth Fowler in support of AGL's proposed acquisition of Macquarie Generation affirmed on 23 March 2014	1	5
2	Annexure AF-1, being a copy of the curriculum vitae of Anthony Fowler	12	6
3	Annexure AF-2, being a copy of AGL's 2013 Annual Report	22	7
4	Annexure AF-3, being extracts of AEMO's Glossary	26	7
5	Annexure AF-4, being a copy of the "Generators and Scheduled Loads" tab of the AEMO Registration and Exemption List (dated 3 March 2014)	35	9
6	Annexure AF-5, being a summary of AGL's electricity generation assets, power purchase agreements and joint venture interests	36	9
7	Annexure AF-6, being a summary of AGL and Macquarie Generation's "customers" and supply arrangements	37	10
8	Annexure AF-7, being a Delta Electricity media statement dated 3 July 2012	42	10
9	Annexure AF-8, being an overview of AGL's competitors	43	11

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Document number	Details	Paragraph	Page
10	Annexure AF-9, being a table summarising acquisitions and entry and expansion in electricity generation since 2008	63	14
11	Annexure AF-10, being a copy of the State of the Energy Market Report (2013)	63	14
12	Annexure AF-11, being tables identifying a limited sample of firms which may develop new wind or solar generation projects	79	17
13	Annexure AF-12, being AGL's Wholesale Energy Risk Management Policy	91	18
14	Annexure AF-13, being a copy of the 1992 form of the ISDA Master Agreement	97(a)	22
15	Annexure AF-14, being a copy of the 2002 form of the ISDA Master Agreement	97(a)	22
16	Annexure AF-15, being a copy of AGL ASX announcement dated 15 December 2010	135	30
17	Annexure AF-16, being a copy of AEMO's 2013 National Transmission Network Development Plan	193	46
18	Annexure AF-17, being a copy of the initial report of the technical due diligence team to the Board on 17 January 2014	221(a)	52
19	Annexure AF-18, being a copy of written materials presented to the Board by Anthony Fowler on 22 January 2014	221(b)	52
20	Annexure AF-19, being a copy of the due diligence presentation given to the AGL Board in January 2014	222	52
21	Annexure AF-20, being a copy of the Information Memorandum issued by the State of NSW in relation to the sale of the Macquarie Generation assets	223	52
22	Annexure AF-21, being an overview of Macquarie Generation	224	52
23	Annexure AF-22, being a copy of the Macquarie Generation 2013 Annual Report	224	52
24	Annexure AF-23, being a bundle of documents referred to in Annexure AF-8		






## CONTENTS

	PAGE
<b>BACKGROUND</b> .....	5
<b>AGL's business and the Merchant Energy Group</b> .....	6
<b>GENERATION AND SUPPLY OF ELECTRICITY IN THE NEM</b> .....	7
<i>The National Electricity Market</i> .....	7
<i>Current dynamics in the National Electricity Market</i> .....	7
<b>AGL's generation portfolio</b> .....	7
<b>AGL's competitors in the NEM</b> .....	10
<b>Potential for new entry in electricity generation</b> .....	11
<i>Key inputs</i> .....	11
<i>Registration</i> .....	11
<i>Development approvals</i> .....	12
<i>Capital costs</i> .....	13
<i>Access to appropriate site and inputs</i> .....	13
<i>Hedge contracts</i> .....	13
<b>Substantial investment in new generation capacity since the commencement of the NEM</b> 14	
<b>Current and future investment in response to the Renewable Energy Target</b> .....	14
<b>Recent examples of new entry by generators in the NEM</b> .....	14
<b>Potential for expansion by existing generators</b> .....	15
<b>Potential for establishment of new generation capacity</b> .....	16
<b>AGL's competitors in the supply of retail electricity to business customers</b> .....	17
<b>RISK AND RISK MANAGEMENT ASSOCIATED WITH THE GENERATION AND SUPPLY OF ELECTRICITY</b> .....	18
<i>Development of AGL's integrated business</i> .....	18
<i>The risks associated with the wholesale supply and purchase of electricity</i> .....	19
<i>Tools for managing wholesale risk</i> .....	20
<b>HOW AGL ALLOCATES AND MANAGES RISK</b> .....	23
<i>Allocation of risk within AGL's business: internal transfer pricing</i> .....	23
<i>How AGL manages risk</i> .....	25
<i>Corporate risk management framework</i> .....	25
<i>Risk management in practice</i> .....	26
<i>Responsibility for portfolio management</i> .....	26
<i>AGL's approach to managing its portfolio</i> .....	26
<i>AGL's risk management from its perspective as a retailer (ie an acquirer of wholesale electricity)</i> 27	
<i>AGL's risk management from its perspective as a generator (ie a supplier of wholesale electricity)</i> 29	
<b>How AGL established a contract position to support its retail load in NSW</b> .....	30
<b>RESPONSE TO QUESTIONS ABOUT TRADING OTC CONTRACTS AND ETFS WITH COUNTERPARTIES</b> .....	34
<i>Whether the need to obtain hedge coverage is a barrier to entry by independent or new entrant retailers</i> .....	35
<b>AGL's approach to dealing with counterparties</b> .....	36
<i>OTC Contracts</i> .....	37
<i>Counterparties AGL is willing to trade with</i> .....	37
<i>AGL's current risk management arrangements (including counterparties to OTC contracts)</i> .....	39
<i>Exchange-traded contracts</i> .....	45
<b>Availability of hedge contracts to independent retailers from sources other than AGL</b> ...	46
<i>Supply of contracts from generators which are not base load, coal fired power stations</i> .....	46
<i>Hedge contracts with financial intermediaries</i> .....	46
<b>Liquidity of supply of hedge contracts</b> .....	47
<i>Has the volume of OTC and ETF trades decreased over time due to reduced trading by physical market participants?</i> .....	47
<i>Are the causes of any reduction in volumes traded independent of a reduction in trading by physical market participants?</i> .....	49
<b>Hedge contracts currently purchased by AGL would be available for others to purchase</b> 51	
<b>AGL'S PROPOSED ACQUISITION OF MACQUARIE GENERATION</b> .....	51
<i>My role in the due diligence process</i> .....	52
<b>Macquarie Generation's Bayswater and Liddell power stations</b> .....	52
<i>Historical reliability of the Bayswater and Liddell power stations</i> .....	52
<i>Future reliability of the Bayswater and Liddell power stations</i> .....	54
<i>Macquarie Generation's hedge contract portfolio</i> .....	55



AF

**Incorporating the Macquarie Generation assets into AGL's portfolio ..... 55**  
*The impact of incorporating the Bayswater and Liddell power stations (including the Tomago Hedge Contracts) into AGL's generation portfolio ..... 55*  
*Benefits to AGL from acquiring the Macquarie Generation assets..... 56*  
*AGL will have an internal hedge for AGL's NSW retail load..... 56*  
*Portfolio benefit..... 57*  
**Other conclusions from the technical due diligence ..... 57**  
*AGL's plans regarding employment of staff currently employed by Macquarie Generation ..... 57*  
**AGL's bidding and dispatch following the acquisition of the Macquarie generation assets 58**  
*AGL's incentives not to retire generation capacity..... 59*  
**AGL's incentives not to maintain a "net generation" position following the proposed acquisition of Macquarie Generation ..... 59**  
*The conditions in which AGL might be able to influence the NEM price are rare and difficult to predict 61*  
*Conclusion..... 65*  
**A RECENT EXAMPLE OF AGL'S MANAGEMENT OF ITS PORTFOLIO DURING EXTREME WEATHER EVENTS ..... 65**

AF



**I Anthony Garth Fowler affirm:**

1. I am the Group General Manager of Merchant Energy of AGL Energy Limited ACN 115 061 375 (**AGL**) and I am authorised to make this statement on AGL's behalf.

**BACKGROUND**

2. I am the Group General Manager, Merchant Energy of AGL and a member of AGL's Executive Team. I have held this position since approximately October 2010.
3. AGL is a vertically integrated energy retailer listed on the Australian Securities Exchange (**ASX**). AGL:
  - (a) develops and operates electricity generation and gas production assets;
  - (b) operates a gas and electricity retail business in each of NSW, Victoria, Queensland and South Australia
  - (c) has coal seam methane (**CSM**) production and exploration interests in NSW and Queensland.
4. AGL produces and supplies gas and electricity for sale in wholesale and retail markets. One of the ways in which AGL manages the risk associated with fluctuations in the wholesale price of electricity is by supplying and buying risk management instruments such as hedge contracts. AGL also buys credits and other risk management instruments required to manage, and manage risks associated with changes in, AGL's liability for carbon emissions produced in the course of its business.
5. The Merchant Energy division is one of AGL's core operational businesses. The Merchant Energy division manages and develops AGL's diversified portfolio of electricity generation and wholesale gas arrangements. Merchant Energy also manages relationships with AGL's large commercial and industrial customers.
6. I hold the following qualifications: a Bachelor of Science (Honours) and a Master of Applied Finance. I have also attended and completed the Harvard Advanced Management Program, and am a Fellow of the Financial Services Institute of Australasia.
7. I have been employed by AGL since November 2002, when I held the position of Manager Risk Policy. Before I became the Group General Manager of Merchant Energy, I held the role of General Manager of Energy Portfolio Management (**EPM**) from approximately January 2008 to October 2010.
8. As Group General Manager, Merchant Energy, I report to Michael Fraser, who is the Chief Executive Officer and Managing Director of AGL.
9. 4 people report directly to me:
  - (a) the General Manager of EPM, who manages AGL's bidding and dispatch of generation in the NEM, and AGL's hedge contracting;
  - (b) the Chief Operating Officer of Merchant Operations, who is relevantly responsible for managing AGL's portfolio of electricity generation assets;
  - (c) the General Manager of Power Development and General Manager of Business Customers (these are two separate positions, which are currently held by the same person); and
  - (d) the Head of Operational Excellence.
10. I am responsible for a further approximately 1,200 people in Merchant Energy through those direct reports.



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11. During 2013, my responsibilities as the Group General Manager of Merchant Energy included responsibility for reporting to the AGL Board on AGL's technical due diligence on the assets of Macquarie Generation being offered for sale by the State of NSW. A team lead by AGL's Chief Engineer, who reports to the Chief Operating Officer of Merchant Operations, conducted the technical due diligence, and prepared a report which was provided to the Chief Operating Officer of Merchant Operations. The Chief Operating Officer of Merchant Operations and I presented that report to the Board.
12. A copy of my curriculum vitae is attached as Annexure AF-1.
13. I give the evidence set out in this statement based on my own knowledge and experience unless stated otherwise.
14. Some of the information set out in this statement was produced by or under the direction of the General Manager of EPM (who reports to me) and his team. That information was prepared in support of support of AGL's application to the Australian Competition and Consumer Commission for informal clearance to acquire the assets of Macquarie Generation. Where in this statement I refer to something done by the General Manager of EPM, this should be read as referring also the General Manager of EPM having caused that thing to be done by the EPM team. Where I have adopted in this affidavit information and analysis undertaken by or under the direction of the General Manager of EPM I have made inquiries into the source of the data and the analysis undertaken and I believe the information to be true.
15. Where I use the term "generation" in this statement, this should be read as a reference to "electricity generation".

***AGL's business and the Merchant Energy Group***

16. AGL's business is divided into three core operational businesses:
  - (a) **"Merchant Energy"**: the Merchant Energy division manages and develops AGL's diversified portfolio of electricity generation and wholesale gas arrangements. Merchant Energy also manages relationships with AGL's large commercial and industrial customers.
  - (b) **"Upstream Gas"**: the Upstream Gas division manages and develops AGL's upstream gas assets located in Queensland and New South Wales.
  - (c) **"Retail Energy"**: the Retail Energy division sells and markets natural gas, electricity and energy related products and services to more than 3.8 million residential and small business customer accounts across NSW, Victoria, South Australia and Queensland.
17. There are four groups within Merchant Energy:
  - (a) Merchant Operations;
  - (a) Energy Portfolio Management (or EPM);
  - (b) Business Customers; and
  - (c) Power Development.
18. Merchant Operations is responsible for the physical operation and maintenance of AGL's portfolio of wind, water, gas and coal fired generation plant.
19. EPM is responsible for managing the risks associated with procuring gas, electricity and environmental market certificates, for administering AGL's hedge contract portfolio, and for bidding AGL's electricity generation into the NEM.



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20. The Business Customers group manages AGL's approximately 20,000 Business Customer energy accounts, but not individual smaller industrial and commercial customers or consumer market customers.
21. Power Development develops generation assets, including wind, solar and thermal generation assets.
22. Annexure AF-2 contains a copy of AGL's Annual Report for 2013. The Merchant Energy business is described at pages 15 to 18 of that report.

## **GENERATION AND SUPPLY OF ELECTRICITY IN THE NEM**

### ***The National Electricity Market***

23. I have read, agree with, and adopt the description of the National Electricity Market (**NEM**), and recent developments in that market, which is contained in part A of the report by Frontier Economics titled "Industry Background", attached to the statement of Danny Price (**Frontier General Industry Report**).

### ***Current dynamics in the National Electricity Market***

24. My commercial experience as Group General Manager of Merchant Energy, and my time before that as General Manager of EPM, is that AGL faces intense competition in the supply of electricity in the NEM, from a wide range of competing generators.
25. I have read, agree with, and adopt the description of decreased demand, increased supply and excess generation in the NEM which is contained in section 7.1 of the Frontier General Industry Report. In particular, the following observations in that report are consistent with my commercial experience as Group General Manager of Merchant Energy, and my time before that as General Manager of EPM has been that:
  - (a) there is currently significant excess capacity in the NEM;
  - (b) this excess capacity reflects the significant decrease in demand (including because of the closure of large scale energy intensive industries), and the significant investment in generation capacity (particularly generation produced from renewable energy sources);
  - (c) generators in the NEM currently face uncertainty in the NEM as a result of the introduction of significant wind and solar powered generation, output from which is intermittent and unpredictable, and makes demand conditions more volatile for other generators; and
  - (d) average wholesale pool prices have been lower than most reasonable estimates of the long run marginal cost of generation (such that prevailing wholesale pool prices are insufficient to compensate investors for investment in new generation).

### ***AGL's generation portfolio***

26. AGL's Merchant Operations business unit manages and maintains AGL's portfolio of electricity generation assets. AGL's portfolio includes base load generators, intermediate or peaking generators, and intermittent generators. I use these terms in a way that is consistent with the way that those terms are used by the Australian Energy Market Operator (**AEMO**), as set out in Annexure AF-3 - that is:
  - (a) **Base load generators** - this refers to are generators which are "designed to run almost constantly at near maximum capacity levels, usually at lower cost than intermediate or peaking generating systems". Base load generators typically have high sunk costs and relatively low variable costs. Coal fired power stations such as Bayswater, Liddell and the Loy Yang A power station are examples of base load generators.



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- (b) **Intermediate or peaking generators** – this refers to a generator which typically minimises generation when the pool price is below the generator's marginal cost of generation. AGL but not Macquarie Generation owns intermediate or peaking generators – AGL's Torrens Island Power Station is an example of this type of generator.
- (c) **Intermittent generators** – this refers to generators "whose output is not readily predictable, including, without limitation, solar generators, wave turbine generators, wind turbine generators and hydro-generators without any material storage capability". Further, a generator will also be described as "intermittent" where the energy released by that generator is determined by other requirements not listed above (for example, by requirements that available water be released for irrigation, rather than for generation purposes).
27. In this statement I use the terms "scheduled", "semi-scheduled" and "non-scheduled" to describe classes of generators. A "scheduled" generator bids capacity into the NEM based on an instruction provided by Australian Energy Market Operator (**AEMO**) which is given based on its anticipated level of demand. This generally refers to base load generators. A "non-scheduled" generator is a generator whose output is not scheduled by AEMO. This generally refers to smaller generators whose output is committed to a particular customer. "Semi-scheduled" generators have their output regulated by AEMO only at certain times. This generally refers to generators with intermittent capacity such as wind generators.
28. AGL has scheduled generation assets in Victoria, South Australia and Queensland, but not in NSW.
29. In Victoria, AGL's generation portfolio comprises the following scheduled generators:
- (a) the Loy Yang A power station, which is a 2,210MW brown coal fired, base load generator located adjacent to the Loy Yang A coal mine (which AGL also owns);
  - (b) the Somerton power station, which is a 160MW open cycle gas turbine (**OCGT**), peaking generator; and
  - (c) several hydro generation assets (total registered capacity of 697.4MW), the largest being the Bogong / McKay (300MW), Dartmouth (150MW), Eildon (120MW) and West Kiewa (62MW) power stations, each of which are scheduled generators; and
- the following semi-scheduled and non-scheduled generators:
- (d) the Macarthur (420MW) and Oaklands (67MW) wind farms both of which are semi-scheduled generators. AGL operates and dispatches these wind farms under long-term power purchase agreements with the asset owners; and
  - (e) a number of non-scheduled generators, each with a registered capacity of 30MW or less.
30. In South Australia, AGL's generation portfolio comprises:
- (a) the Torrens Island power station, which is a 1,280MW gas fired, scheduled peaking generator; and
  - (b) several wind farms (total registered capacity 441.45MW) – these are:
    - (i) the North Brown Hill (132.3MW), Hallett 1 (94.5MW), Hallett 2 (71.4MW) and The Bluff (52.5MW) wind farms, all of which are semi-scheduled; and
    - (ii) the Wattle Point wind farm (90.75MW), which is non-scheduled.






AGL operates and dispatches these wind farms under long-term power purchase agreements with the asset owners.

31. In Queensland, AGL's generation portfolio comprises:
- (a) the Oakey power station, which is a 282MW OCGT, scheduled peaking generator. AGL dispatches Oakey's output under a power purchase agreement with Oakey Power Holdings Pty Ltd (a subsidiary of ERM Power). AGL's contract to operate the Oakey power station is due to terminate at the end of 2014, and there is no option in that contract for either party to renew the contract for a further term;
  - (b) the Yabulu power station, which is a 242MW OCGT scheduled peaking generator located in Townsville. AGL dispatches the Yabulu power station under a long term power purchase agreement with RATCH Australia; and
  - (c) several non-scheduled generators with registered capacities of 25MW or less.
32. AGL also has a 50% interest in the 302MW Diamantina power station development at Mount Isa, which is due to become operational in FY2014,<sup>1</sup> but will not be connected to the NEM grid.
33. AGL does not own, operate or dispatch any generation assets in NSW which are scheduled or semi-scheduled generation assets. AGL's generation portfolio in NSW comprises a number of non-scheduled hydro and landfill methane / gas generators, each with a registered capacity of 24MW or less. AGL also owns the Broken Hill (53MW) and Nyngan (102MW) solar projects, both of which are in development, and the proposed Silverton wind farm (300MW for Stage 1).<sup>2</sup>
34. AGL faces constraints on the extent to which it can economically operate its generation assets during any particular period, and in particular constraints on the operation of its gas, hydro and wind assets. In particular:
- (a) OCGT and closed cycle gas generation (**CCGT**) assets (which are types of generator that use gas as the primary source of fuel, and typically have a high variable cost but a low initial capital cost, as compared with base load coal generators) operate at a higher marginal cost than other forms of generation, and so it may not be economic to dispatch generation from these assets during periods of lower pool prices;
  - (b) hydro generation assets are constrained by restrictions on the availability of water to operate those assets; and
  - (c) generation from wind assets is constrained by the intermittent availability of, and impossibility of storing, wind.
35. I base my summary above on my own knowledge of AGL's portfolio, on the AEMO Registration and Exemption List (dated 3 March 2014) (a copy of which is contained in Annexure AF-4), and on AGL's 2013 Annual Report (a copy of which is contained in Annexure AF-2).
36. I have caused to be produced the summary in Annexure AF-5 of:
- (a) the electricity generation assets that are owned by AGL, or for which AGL operates the generator or has electricity dispatch rights; and
  - (b) AGL's power purchase agreements; and

<sup>1</sup> Source: AGL, Annual Report 2013, page 21, a copy of which is contained in Annexure AF-2.

<sup>2</sup> AGL, Annual Report 2013, page 6, a copy of which is contained in Annexure AF-2.




(c) AGL's joint venture interests.

37. I have also caused to be produced, based on AGL's records and the information disclosed to AGL during due diligence for the Macquarie Generation sale process, the tables contained in Annexure AF-6, which identify a representative selection of:
- (a) the "customers" of Macquarie Generation and AGL Merchant Energy (both counterparties to OTC contracts and commercial and industrial retail electricity customers); and
  - (b) Macquarie Generation's and AGL's suppliers.
38. I also note that AGL is a "customer" of Macquarie Generation, to the extent that it is party to OTC contracts with Macquarie Generation.

***AGL's competitors in the NEM***

39. I have read, agree with and adopt the description of the NEM pricing and dispatch arrangements, including the merit order, in section 3 of the Frontier General Industry Report.
40. The consequence of the pricing and dispatch arrangements in the NEM, including the merit order approach to pricing and dispatch, is that all generators which supply electricity in the NEM are potential competitors of AGL in relation to the supply of electricity in the NEM. This is because, absent any constraints on the interconnectors between NEM regions (which I address in paragraph 41 below), any generator in the NEM which submits a lower bid than AGL during a particular trading interval could potentially "displace" AGL from being dispatched during that period. Depending on another generator's available generation portfolio, costs and trading practices, AGL's bids could be displaced in the merit order by generators with similar or different characteristics to AGL.
41. Interconnectors are "wires" or transmission lines that connect two regions of the NEM. For example, there are interconnectors between New South Wales and Queensland and between New South Wales and Victoria. All interconnectors have a maximum capacity. Significant quantities of electricity can be transferred using interconnectors. For example, in the absence of constraints, approximately 1,250MW can be transferred from Queensland to New South Wales. AGL has used these interconnector flows to support the hedging of its retail load in New South Wales for many years.
42. In my view, each of the following generators which AGL competes with in the NEM is a vigorous and effective competitor of AGL:
- (a) Origin Energy, which AGL estimates owns approximately 12.6% of all registered capacity, and supplied approximately 9.4% of generation output, in the NEM in FY13;
  - (b) EnergyAustralia, which AGL estimates owns approximately 11.8% of all registered capacity, and supplied approximately 13.2% of generation output, in the NEM in FY13;
  - (c) Snowy Hydro, which AGL estimates owns approximately 10% of all registered capacity, and supplied approximately 2.7% of generation output, in the NEM in FY13 - Snowy Hydro's Victorian assets have a total registered generation capacity of 2,112MW, and its NSW generation assets have a total registered generation capacity of 2,261.1MW;
  - (d) CS Energy, which AGL estimates owns approximately 8.6% of all registered capacity, and supplied approximately 9.5% of generation output, in the NEM in FY13;



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- (e) Stanwell, which AGL estimates owns approximately 8.2% of all registered capacity, and supplied approximately 9.5% of generation output, in the NEM in FY13;
- (f) GDFSuez (formerly International Power), which AGL estimates owns approximately 7.4% of all registered capacity, and supplied approximately 11.8% of generation output, in the NEM in FY13;
- (g) Hydro Tasmania, which AGL estimates owns approximately 4.6% of all registered capacity, and supplied approximately 5.3% of generation output, in the NEM in FY13;
- (h) Delta Electricity, which AGL estimates owns approximately 4.3% of all registered capacity, and supplied approximately 3.9% of generation output, in the NEM in FY13 – Delta Electricity owns three power stations, all located in NSW:
  - (i) the Colongra power station – an OCGT power station with four 181MW units (total registered generation capacity of 724MW);
  - (ii) the Vales Point "B" power station – a black coal fired power station with two 660MW units (total registered generation capacity of 1,320MW); and
  - (iii) the Munmorah power station – a black coal fired power station with two 300MW units registered with AEMO for dispatch (total registered generation capacity of 600MW), however on 3 July 2012 Delta Electricity announced the decommissioning of the Munmorah power station;<sup>3</sup>
- (i) Intergen, which AGL estimates owns approximately 2.8% of all registered capacity, and supplied approximately 4.7% of generation output, in the NEM in FY13; and
- (j) Alinta, which AGL estimates owns approximately 2.2% of all registered capacity, and supplied approximately 2.0% of generation output, in the NEM in FY13.

43.

44. I have caused to be produced the summary in Annexure AF-8, which provides an overview of the competitors I have identified above.

45. AGL estimates that Macquarie Generation owns approximately 10.2% of all registered capacity, and supplied approximately 12.0% of generation output, in the NEM in FY13.

#### **Potential for new entry in electricity generation**

##### *Key inputs*

46. I discuss below the key inputs that a new entrant generator would require in order to establish a business to generate and supply electricity in the NEM.

##### Registration

47. The electricity wholesale industry is regulated under (among other things) the National Electricity Law (**Law**) and the National Electricity Rules (**Rules**), and electricity generators must be registered with AEMO as a market participant under the Rules in order to participate in the NEM.

<sup>3</sup> Source: Delta Electricity, media statement, "Munmorah Power Station to close after 45 years of operation" (3 July 2012). A copy of that statement is contained in Annexure AF-7.



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### Development approvals

48. A developer of a new generation asset requires government planning, environment and other regulatory approvals. These approvals can take a significant period of time to obtain – for example, I would expect that the process to acquire approvals from the NSW government equivalent to those currently in place for Macquarie Generation's Bayswater B development site would take approximately two to four years.
49. The development and approvals process for wind generation assets can also be lengthy, and in my experience typically involves a significant period of community engagement. The duration of the approval process for gas fired generation will depend upon its location. If the proposed site is near residential areas the process is likely to be lengthy but if the site is not located near residential areas the period is likely to take approximately 2 years. The approvals process for solar generation developments may be shorter than for other generation projects.
50. I have caused to be prepared the following table summarising planning approval timing for recent gas fired generation developments in NSW based on publicly available information concerning those planning approvals from the NSW Department of Planning & Infrastructure website.<sup>4</sup>

**Figure 1 – Planning approval timing for NSW gas fired generation**

Project	DGRs <sup>5</sup> Issued	Exhibition period	Determination	Total
Dalton Station Power	19/04/2010	17/08/2011 – 19/09/2011	19/07/2012	27 months <sup>6</sup>
Marulan	03/03/2008	10/09/2008 – 13/10/2008	26/10/2009	19 Months <sup>7</sup>
Burronga	10/08/2007	11/08/2008 – 12/09/2008	06/09/2009	25 months
Wellington	31/01/2007	21/05/2008 – 23/06/2008	04/03/2009	26 months
North West Parkes	28/10/2006	21/11/2007 – 21/12/2007	10/07/2008	21 months
Bamarang	18/08/2005	19/05/2006 – 19/06/2006	27/02/2007	18 months <sup>8</sup>
Uranquinty	18/07/2003	February 2004	04/04/2005	21 months

51. This information shows that the planning approval processes for recent gas fired generation projects in NSW have taken between 18 and 27 months. Consistent with my experience, this information suggests that a new entrant would need to allow approximately 2 years for planning approval in NSW.

<sup>4</sup> <http://majorprojects.planning.nsw.gov.au/page/>

<sup>5</sup> Director-General's requirements (or their equivalent in jurisdictions outside NSW) are the requirements that a proponent of a development or project is required to address in an environmental assessment.

<sup>6</sup> Note that AGL spent at least a year on site acquisition prior to the planning approval process.

<sup>7</sup> Note that this development is located next to an existing substation with very few neighbours.

<sup>8</sup> Note that this was a NSW government-owned site.



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Capital costs

52. There are sunk capital costs associated with the development and construction of new generation assets, as well as the supporting infrastructure. The extent of those costs varies depending on the type of generation asset being developed.
53. Based on my experience and current market conditions, I consider that:
- (a) OCGT generators are typically the most cost-effective, in terms of the cost of development on a per MW of capacity basis;
  - (b) wind generation is the lowest cost renewable generation option, and is the most economic form of new generation, partly because of the subsidy it attracts under the Renewal Energy Target (**RET**) regime; and
  - (c) the sunk capital cost associated with new coal fired generation are large (and greater than the capital cost associated with developing a new OCGT generator).

Access to appropriate site and inputs

54. A new entrant generator would need to identify a suitable site for their new development, having regard to factors such as the following:
- (a) **Site location** – appropriate sites for electricity generation assets must typically be located proximate to demand centres (eg significant population centres and/or commercial and industrial operations) and to appropriate transmission infrastructure.
  - (b) **Access to fuel and other inputs** – Generation developments require long-term access to fuel. Access to appropriate fuel can influence site location. Coal fired power plants require access to significant volumes of thermal coal and water (including appropriate transport).
  - (c) **Compatibility with community** – Generation developments need to be located sensitively with regard to surrounding communities.

Hedge contracts

55. I have read, agree with and adopt the description of the NEM pricing and dispatch arrangements, including the merit order, in section 3 of the Frontier General Industry Report.
56. In order to establish an electricity generation business, a new entrant would need to be able to sell hedge contracts, to manage their exposure to the financial risks associated with volatility in the NEM pool price. In the case of new thermal generation assets with substantial capacity, a new entrant generator would also be likely to need to either have an associated retail business of some size or to have one or more "foundation" customer contracts in order to secure financing.
57. Two options for managing that risk are entering into over the counter (**OTC**) hedge contracts, and trading in exchange traded futures (**ETFs**) – I describe these types of contracts in further detail from paragraph 97 below.
58. In order to trade OTC hedge contracts, a new entrant generator would need to:
- (a) obtain an Australian Financial Services Licence (**AFSL**) – this involves an application to the Australian Securities & Investments Commission demonstrating that the applicant has the necessary knowledge, experience, financial/human/system resources and compliance programs to provide the relevant financial service, and payment of an application fee;
  - (b) maintain the AFSL – this involves complying with the obligations and conditions imposed by the AFSL, including meeting financial adequacy metrics;



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- (c) negotiate and execute International Swaps and Derivatives Association (**ISDA**) Master Agreements with counterparties;
  - (d) satisfy the credit requirements set by their counterparties – typical credit requirements are either an investment grade rating, or provision of a corporate or bank guarantee, and subsequent credit requirements could include the provision of additional bank guarantees under credit margining arrangements;
  - (e) put in place banking and payment systems for the settlement of the contracts;
  - (f) implement an Anti-Money Laundering and Counter-Terrorism Financing (AML-CTF) compliance program, and meet associated requirements, as regulated by AUSTRAC;
  - (g) obtain access to data about prices of OTC contracts – this is typically available through an information service such as those provided by Reuters or Bloomberg; and
  - (h) obtain an executing broker service (or, alternatively, engage staff to execute OTC contracts directly).
59. In order to trade ETFs on the ASX, a new entrant generator would need to:
- (a) enter into an agreement with a futures clearer;
  - (b) put in place banking and payments systems for the payment of trade initial margins and daily variation margins
  - (c) have adequate financial liquidity to pay daily margin calls;
  - (d) obtain access to price data – this is typically available through an information service such as those provided by Reuters or Bloomberg; and
  - (e) obtain an executing broker service.
60. OTC contracts and ETFs are readily available from a variety of businesses who trade those instruments, including NEM participants (eg generators and retailers), financial institutions (including international and Australian banks, hedge funds and private investment funds), large industrial customers (for example, aluminium smelters), and energy companies (such as major oil companies or international utilities). I address this further from paragraph 151 below onwards.

***Substantial investment in new generation capacity since the commencement of the NEM***

61. I have read, agree with and adopt the description of the substantial investment in new generation capacity since the commencement of the NEM set out in section 4.2 of the Frontier General Industry Report.

***Current and future investment in response to the Renewable Energy Target***

62. I have read, agree with and adopt the description of the Renewable Energy Target (**RET**) in section 5.2.3 of the Frontier General Industry Report, and the impact of the RET on current and future investment in renewable generation capacity in the NEM in section 7.1.5 of the Frontier General Industry Report. In my opinion investment in generation capacity in the NEM will continue, and a substantial component of that future investment will be in renewable capacity (wind and solar) driven by the effective subsidies available as a consequence of the RET.

***Recent examples of new entry by generators in the NEM***

63. I have caused to be produced the tables contained in Annexure AF-9, which show:



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(a) details of acquisitions made in the wholesale electricity sector in the last 5 years; and

(b) entry and expansion in electricity generation since 2008,

based on reports published by the Australian Energy Regulator (**AER**) over the past 5 years and my knowledge of new generation development in the NEM. A copy of the AER's 2013 State of the Energy Market Report is contained in Annexure AF-10.

64. I am not aware of any firms which have recently entered the wholesale electricity market and whose business has failed after entering. I am aware that investors look at opportunities in the wholesale electricity market from time to time, and in some cases choose not to pursue a particular opportunity, but I am not aware of any such investors which I would consider to have "tried and failed" to enter.
65. I am however aware that the following financial intermediaries have exited from, or are no longer actively, trading in derivatives:
- (a) BP Energy (in late 2009);
  - (b) Societe Generale (in 2009);
  - (c) Goldman Sachs (in mid-2013);
  - (d) JP Morgan (in August 2011);
  - (e) DE Shaw (in 2010);
  - (f) Optiver (in April 2012); and
  - (g) Noble (I am not aware of Nobel having traded since early 2013).
66. I am also aware that Deutsche Bank is expected to cease trading in derivatives in the near future.

**Potential for expansion by existing generators**

67. I am aware that in the last two years several NEM generators have announced plans to withdraw or "mothball" generation capacity which has the potential to be reintroduced in future.
68. I am aware that the General Manager of EPM reviewed public announcements by the firms concerned and other publicly available information (in particular, information published by AEMO), and prepared a table summarising instances of withdrawal or "mothballing" of generation capacity over the last two years. The table below sets out the results of that review.

**Figure 2 – Withdrawal/mothballing of generation**

	Station (owner; node)	Volume	Off date	Return date
1.	Swanbank E (Stanwell; Qld)	385MW	1/10/2014	~3 years
2.	Tarong units 2 and 4 (Stanwell; Qld)	2 x 350MW	Unit 2: October 2012 Unit 4: December 2012	Unit 4: late 2014 Unit 2: mid 2015
3.	Wallerawang unit 8 (Energy Australia; NSW)	500MW	Unit 8: Late March 2014	Unit 8: three month recall if conditions change
4.	Yallourn (1 unit, cycled over time) (Energy Australia; VIC)	380MW	23/10/2012	Returned to 4 units 4/01/2013



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	Station (owner; node)	Volume	Off date	Return date
5.	Northern (Alinta Energy; SA)	2 x 265MW	01/04/2012, winter only with three week recall	1/10/2014
6.	Playford (Alinta Energy; SA)	240MW	20/04/2012	No set date, available on 70 day recall

69. I understand, based on my experience, that the period of time required to return a mothballed generator to service depends on the way in which the generator is mothballed, and the type and extent of ongoing maintenance that is undertaken while the generator is mothballed (for example, the extent to which auxiliary electronics and control systems are maintained).
70. I understand that generators can be mothballed in such a way as to allow their return to service in relatively short periods, by which I mean a period of weeks or months. For example, as the table set out above shows, the Northern Power Station (row 5) and Wallerawang unit 8 (row 3) are able to be reintroduced on 3 weeks' and 3 months' notice respectively, and the Yallourn unit (row 4) was reintroduced less than 3 months after it was mothballed.
71. I note that it is also possible for a generator or generating unit to be "turned off", from which state it typically can be returned to service on a much shorter timeframe. However, this is not what I would consider to be true "mothballing" of a generator.
72. I consider that the fact that significant volumes of base load electricity generation have recently been "mothballed" from the NEM, but are capable of being reintroduced in response to a change in market conditions, means that the barriers to expansion in the wholesale supply of electricity are low.

**Potential for establishment of new generation capacity**

73. I have read, agree with, and adopt the description in section 7.1 of the Frontier General Industry Report in relation to the prevailing circumstances of oversupply of electricity generation in the NEM. The examples of "mothballed" generation capacity I identified in paragraph 68 above reflect those prevailing conditions.
74. I would expect that a potential new entrant generator would have regard to these prevailing conditions in the NEM, including the potential for expansion by existing operators (by reintroduction of withdrawn capacity) when considering whether to invest in new generation capacity.
75. Further, as I noted above, the capital costs associated with the development of wind and solar generators are lower in absolute terms than the capital costs associated with base load power stations.
76. In this context (assuming no material change to the current conditions of oversupply and the cost relativities referred to above), I would expect that if new entry is to occur in the NEM in the short to medium term, it is most likely to occur through the establishment of new wind powered generation, and in particular in large scale wind generation installations (ie units with capacity greater than 2MW and wind farms with capacity greater than 100MW).
77. However new entry is also likely to be possible in solar generation, particularly for large scale solar projects (capacity greater than 1MW), which can be established in a short period of time. I am aware that several large scale systems have recently been installed or committed (for example in Royalla ACT, Nyngan and Broken Hill), with the benefit of significant government subsidies.
78. There are several classes of firms that would be potential developers of new wind generation projects.






- (a) Developers – parties which identify suitable sites for wind generation development, and seek to enter into land access arrangements with landowners. Numerous developers have been active since the commencement of the RET scheme.
- (b) Original Equipment Manufacturers (**OEMs**)/Constructors – most or all of the major wind generation OEMs are represented in Australia. OEMs typically become involved in project construction in Australia (due to a local preference for turnkey construction), and also frequently supply ongoing operation and maintenance services to developers/owners.
- (c) Investors – Developers frequently work with investors to produce an ownership group for projects.

79. The tables in Annexure AF-11 identify a limited sample of firms which:

- (a) I would expect may be interested in participating in the development of new wind generation projects in the NEM (this list does not include owners of existing major wind generation developments, such as Origin Energy, EnergyAustralia, Meridian, CWP Renewables, Infigen Energy, GE and Goldwind); and
- (b) may be potential investors in new large scale solar generation projects in the NEM.

***AGL's competitors in the supply of retail electricity to business customers***

- 80. As I noted in paragraph 20 above, Merchant Energy's responsibilities include the supply of electricity to AGL's business customers.
- 81. I have been asked to identify the major competitors of AGL in relation to the supply of electricity to such customers.
- 82. In my experience, the competitors of AGL in the supply of electricity to commercial and industrial customers are:
  - (a) Alinta Energy Retail Sales Pty Ltd;
  - (b) Aurora Energy Pty Ltd;
  - (c) Click Energy Pty Ltd;
  - (d) CS Energy Limited;
  - (e) EnergyAustralia Pty Ltd;
  - (f) ERM Power Retail Pty Ltd;
  - (g) Momentum Energy Pty Limited;
  - (h) Origin Energy Electricity Limited;
  - (i) Pacific Hydro Retail Pty Ltd;
  - (j) Qenergy Pty Ltd;
  - (k) Red Energy Pty Limited;
  - (l) Simply Energy; and
  - (m) Stanwell Corporation Limited.



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**RISK AND RISK MANAGEMENT ASSOCIATED WITH THE GENERATION AND SUPPLY OF ELECTRICITY**

***Development of AGL's integrated business***

83. AGL has established its integrated business by taking a business which was principally focussed on retail operations, and developing generation assets to support those operations. The acquisition of Macquarie Generation would mean that, on an aggregate view across AGL's entire NEM operations, it will change AGL from being a net retail business to a net generation business.
84. I have read, agree with, and adopt the description in section 3.4 of the Frontier General Industry Report concerning the variation in the NEM pool price, and section 6.1 of the Frontier General Industry Report concerning the differing exposure to pool price volatility faced by generators and retailers.
85. In my experience, generators and retailers in the NEM (and vertically integrated generators/retailers) face different types of risk in relation to their exposure to the NEM pool price.
86. The principal risk that a NEM generator faces is that the NEM pool price will be lower, in any particular period, than the price the generator forecasted or expected when it invested in its generation portfolio. NEM prices which are lower than forecasted or expected can prevent a generator from recovering the costs of, and/or achieving its expected return on, its investment in its generation assets.
87. Another key risk faced by thermal generators is uncertainty in relation to fuel costs.
88. The principal risk that a NEM retailer faces is that the NEM pool price will be higher, in any particular period, than the price the retailer forecasted or expected when it entered into contracts to supply its retail customers with electricity. NEM prices which are higher than forecasted or expected can prevent a retailer from recovering the costs of, and/or achieving its expected return on, its investment in connection with the supply of electricity to retail customers. Retailers' exposure to variations in the NEM pool price arises from the fact that they typically supply retail customers on fixed (or substantially fixed) tariffs, which are based on the periods in which electricity is consumed, but which do not vary to reflect changes in the NEM pool price.
89. Accordingly, on an aggregate basis, the Macquarie Generation acquisition would change AGL's net risk profile, from being exposed as a retailer (on a net basis) to the risks that NEM prices will be higher than expected, to being exposed as a generator (on a net basis) to the risks that NEM prices will be lower than expected.
90. However in practice a vertically integrated generator and retailer faces both types of risk on an ongoing basis: even though on an aggregate basis AGL may at any one point be a net retailer or a net generator, this position can and does change from time to time. For example, in periods of particularly low demand AGL may be a net generator (that is, generating at a higher level than its retail load demand), whereas in other periods of higher demand, plant outages or fuel constraints it may be a net retailer (that is, its retail load demand exceeds its generation level).
91. The extent to which AGL is a net generator or retailer on a portfolio basis (ie having regard to AGL's physical and contract position in combination) will also vary from time to time, having regard to AGL's risk management practices and external constraints in a particular period. This is reflected in the fact that AGL's Wholesale Energy Risk Management Policy (**WERMP**) sets the tolerances within which AGL's Merchant Energy business must manage all of AGL's wholesale risks - both AGL's risks as a generator and AGL's risks as a retailer. A copy of the WERMP is contained in Annexure AF-12.
92. The WERMP does not assume that AGL is either a net generator or a net retailer during any particular period. The WERMP applies equally to AGL's practices in selling physical generation and hedge contracts as it does to AGL's practices in buying electricity and hedge contracts.






93. While the price risks I describe above are the principal risks faced by generators and retailers, they are one of a range of risks that NEM participants face and manage on a daily basis.
94. My description below of AGL's risks and risk management practices necessarily reflects AGL's experience to date as a net retailer, but in doing so I consider the risks AGL faces from its perspective both as a retailer and as a generator.

#### The risks associated with the wholesale supply and purchase of electricity

95. In my view, the key risks that generators and retailers face in the NEM are as follows.
- (a) Price risk, which refers to uncertainty as to the price at which energy (or the inputs required to generate energy) can be bought and sold. There are three key types of price risk:
- (i) pool market price risk: the risk from a NEM participant's exposure to fluctuations in the pool price - ie, for a retailer, the risk that the pool price will be higher than forecast by the retailer (thereby increasing their costs of servicing their retail customer load), and for a generator, the risk that the pool price will be lower than forecast (thereby decreasing the return they earn on investments in their generation assets).
  - (ii) contract price risk: the risk that the price of hedge contracts will move against the NEM participant - ie:
    - (A) between the price a retailer forecasts when they commit to supply a customer (and so create their exposure to the NEM price) and the price at the time when the retailer can actually buy contracts to hedge that exposure (and so "close out" its exposure); or
    - (B) between the price a generator forecasts when they invest in their generation assets, and the price at the time when the generator can sell contracts to hedge their generation.
  - (iii) fuel cost risk: the risk generators face from exposure to fluctuations in the price of key inputs to generation assets, such as coal and gas. Generators can mitigate this risk in part by entering long term supply agreements for critical fuels, or by owning key fuel sources.
- (b) Volume risk, which refers to two types of risk:
- (i) Customer Load Volume Risk: the risk that a retailer's customers will consume a greater or lesser quantity of electricity than the retailer expected or forecast when it entered into its retail sales contracts (**Customer Load Risk**), or will or comprise a different mix of "peak" and "off peak" demand than the retailer forecast (**Load Shape Risk**). Customer Load Risk is a function of customer numbers and consumption; Load Shape Risk is a function of consumption patterns, rather than solely volume. Both types of risk are affected by factors such as prevailing weather conditions, alternative energy sources, time of day and time of week.
  - (ii) Generation volume risk: the risk that a particular power station or generation unit will be unavailable or unable to dispatch its full generation capacity into the NEM during a particular period - for example, because the unit experiences a planned or unplanned outage, is subject to fuel or other constraints, or is "derated" (meaning that output capacity is reduced due to a mechanical, safety or other reason).
- (c) Regional price differentiation / basis risk, which refers to the risks raised by the divergence of between pool prices in different regions of the NEM as may occur during periods in which interregional interconnects are constrained.






- (d) Risks associated with contracting or trading futures, including:
- (i) Liquidity risk: the risk associated with availability of competitively priced OTC contracts or ETFs
  - (ii) Margining Risk: the risk that arises from entering into margined exchange-traded hedging agreements which require a party to meet margin calls on short notice if settlement prices move against their position.
  - (iii) Credit risk: the risk that the counterparty to a contract (such as a hedge contract or power purchase agreement) may become insolvent and so be unable to meet their payment obligations.
- (e) "Carbon price risk", which is effectively a combination of price risk and regulatory risk (which I describe in paragraph (f) below), regarding the cost to AGL as a generator of meeting its liability to surrender carbon permits under the Clean Energy Policy, and the uncertainty regarding whether and when the legislation creating that liability will be repealed. This risk also affects AGL as a retailer, including because it affects the level of NEM pool prices, and can also affect the prevailing price for hedge contracts. I note that standard form OTC contracts use a carbon "uplift" clause which is not used in ETF contracts – due to the differing treatment of carbon price pass-through under these contract types, the carbon price affects the price of these contracts to a differing extent).
- (f) Regulatory risk, which is the risk that a change in laws or regulations will materially impact a security, business, sector or market, for example, in a way that increases the costs of operating a business, reduces the attractiveness of an investment and/or changes the competitive landscape.
- (g) Operational risk, which relates to the operational risks involved in the use of physical plant, environmental risks and health, safety and environment requirements, as well as the operational risks that are typical of any company which trades or operates in financial markets, such as the risk of IT failures, and fraud.

#### **Tools for managing wholesale risk**

96. In my experience, AGL and other generators and retailers use a wide range of risk management instruments and techniques to manage the types of risks I have described above, including the following.
- (a) **Physical integration of generation and retail:** retailers can manage risk by building, purchasing or acquiring physical electricity generation assets, so that the retailer is paid at the prevailing pool price for their dispatched generation, and thereby the retailer's cost of servicing a customer load equivalent to the volume and shape of their generation output is effectively offset. Similarly, generators can manage risk by acquiring retail customers, because this effectively provides them with guaranteed demand for a portion of their generation (ie it is effectively a substitute for selling hedge contracts against their generation). However in practice, no generator's output ever perfectly matches the volume and composition (ie shape) of a retail customer load, so vertical integration of generation and retail businesses is an incomplete solution to managing NEM participants' risk. Further, vertical integration in fact introduces additional risks: for example, for generators it introduces risks associated with retail customer load shape, and for retailers it introduces risks such as fuel cost and generation volume risk.
  - (b) **Contractual integration of generation and retail:** NEM participants can also achieve a form of vertical integration by entering into contracts such as Power Purchase Agreements (**PPAs**), which are private bilateral agreements between the owner of a generation asset and a retailer, and provide the owner of the PPA (for example, a retailer) with the right to the economic benefit of all of the






output of a plant, or a unit within a plant. A PPA may also include bid and dispatch rights. In this way, a retailer can effectively acquire generation load, and a generator can effectively transfer price risks associated with their dispatch of electricity into the NEM to a retailer in return for payments under the PPA. PPAs are typically long term agreements which run for between 5 and 25 years. PPAs are also known as "off-take agreements". PPAs involve significantly less upfront cost for the retailer than building or acquiring generation; for the generation owner, they pass the price and volume risk associated with NEM dispatch to the retailer, and secure a steady income stream for generation bid by the retailer. Similarly to physical integration, the volume of electricity contracted under a PPA is unlikely to perfectly match the volume and shape of a retail customer load. PPAs also introduce additional forms of risk, including counterparty risk. I consider that smaller retailers with significant commercial and industrial loads could hedge that customer load using a PPA, as an alternative to using hedge contracts.

- (c) **Contractual hedging of NEM price risk:** both generators and retailers can trade swaps, caps, options and other forms of electricity derivative by entering into OTC contracts, or by trading ETFs on the ASX. Specifically, retailers can buy these types of contracts, and generators can sell these types of contracts. These mechanisms allow counterparties to "substitute" the variable NEM price for a contractual price mechanism. Other variations of OTC contracts are also available such as Asian calls, collar contracts, swaptions, reallocation arrangements and load following arrangements. I described the hedges contracts in more detail in paragraph 97 below.
- (d) **Purchasing insurance products:** market participants also acquire weather derivative products as a form of insurance in relation to the variability of weather conditions and their impact on the NEM spot price. For example, market participants may acquire insurance which provides coverage in relation to the occurrence of extreme temperatures (often sustained over a defined period) to manage short term impacts of those weather events on retail customer load (ie demand) and/or NEM spot prices. These products may be triggered by, for example:
- (i) rainfall conditions - to manage the risks associated with hydro generation assets availability and generation volume;
  - (ii) wind conditions - to manage the risks associated with wind turbines availability and generation volume;
  - (iii) extreme temperatures (often sustained over a defined period) - to manage short term impacts on retail customer load and/or NEM pool prices;
  - (iv) average temperature over a whole season (for example, due to a hotter or cooler than average summer or winter) - to manage longer term impacts on retail customer load and/or NEM pool prices; or
  - (v) the coincidence between the loss of generation availability (for example, the unplanned outage of one or more generation units at a specified power station) and specified extreme temperature events - to manage short term impacts on retail customer load and/or NEM pool prices.

Weather derivative products are generally referenced to weather conditions in the capital city a particular NEM region. In my experience, weather derivative products referenced to multiple regions are traded less frequently.

I consider that it is likely that most (if not all) vertically integrated retailers and financial intermediaries use weather derivatives as a standard risk management tool. I consider that it is likely that Origin Energy, EnergyAustralia, ERM Power and Westpac use weather derivatives in their



risk management portfolios. Weather derivatives (when used in conjunction with other risk management tools) are a cost effective tool to manage the risk of coincident high temperature demand conditions in multiple NEM regions, thereby reducing the volume of firm hedge contracts that a market participant needs to support its hedge position in those regions. This reflects the fact that market participants (like AGL) establish hedge positions having regard to their NEM wide position, rather than considering their position in each NEM region in isolation. Financial intermediaries use weather derivatives to support their trading in firm hedge contracts, and accordingly I consider that the trade in weather derivatives increases liquidity in hedge contracts.

- (e) **Actively managing customer load:** retailers can also actively manage the size and composition of their customer base, and/or the volume and shape of the electricity consumed by their customers. For example, retailers can limit the number of electricity supply agreements they sell and/or the types of customers they sell contracts to; in some cases retailers can also enter into agreements with customers (such as large commercial and industrial customers) under which customers agree to modify their electricity consumption in certain circumstances, in return for payment by the electricity retailer.

97. I describe the typical forms of hedges contracts and their features below.

- (a) **OTC contracts:** OTC contracts are bilateral contracts which are referenced to (and settled against) the spot price at a regional node in the NEM (ie with reference to the spot price in a particular region). OTC contracts are generally based on the ISDA standard form OTC agreements published by the Australian Financial Markets Association (**AFMA**). Copies of the 1992 and 2002 forms of the ISDA Master Agreement are contained in Annexure AF-13 and Annexure AF-14. OTC contracts may be negotiated directly between the parties (in which case the contract may be standard form or tailored). Alternatively, parties may be matched through a broker (in which case the OTC contract is generally executed in standard form). Types of standard form OTC contract include:
- (i) **Swaps** - an agreement to exchange a future NEM spot price (the "floating" price) for an agreed fixed price, with settlement based on the difference between the future spot price and the agreed fixed price;
  - (ii) **Caps** - contracts that place a ceiling on the buyer's exposure to the future spot price in any half hour period within the contract period for an agreed premium;
  - (iii) **Options** - contracts that create a right (but not an obligation) to enter into a transaction to acquire (call) or sell (put) an electricity derivative contract (ie a swap or a cap) at an agreed price in future, for an agreed premium.
  - (iv) **Asian calls** (or Asian options) - a form of option contract in which the payoff is linked to the average spot price over a defined period; and
  - (v) **Collar contracts** - which are contracts that impose both a cap and a floor on the price to be paid to acquire electricity in future.

OTC contracts are "referenced" to a period determined at the date the contract is entered into, and that period is generally a quarter, half year or year (either calendar or financial). Additionally, OTC contracts are classified as "peak" (which means that the contract applies to all dispatch intervals between 7am and 10pm on business days), "off-peak" (which means that the contract applies to all dispatch intervals which are not "peak" dispatch intervals), or "flat" (which means that the contract applies during all dispatch intervals). Parties can modify a standard form OTC contract, including by agreeing to include:






- (vi) **a load following arrangement:** this refers to an OTC contract under which the generator accepts its obligations under the contract with respect to the volume of electricity actually consumed by the retailer's customers during the relevant period, rather than with reference to a particular absolute volume. This means that the generator assumes the risk associated with changes in the retailer's customer load. These contracts are typically priced at a premium to contracts which do not have this feature, to reflect the additional risk assumed by the generator.
- (vii) **Reallocation arrangement,** this refers to an OTC contract under which one NEM participant agrees to acquire electricity on behalf of another party (eg a generator agrees to acquire electricity on behalf of a retailer); this removes the need for the second party to make payments to AEMO (typically reducing a retailer's working capital requirements) and to satisfy AEMO's prudential requirements for transacting in the NEM.
- (b) **Exchange-traded contracts** (or exchange-traded futures, **ETFs**): ETFs are standardised electricity derivative contracts which are traded on an exchange platform. In Australia electricity derivatives are currently traded on the ASX, and may in future also be traded on a competing platform which is currently being developed by a number of industry participants (see paragraph 187 below). The types of ETFs able to be traded on the ASX include swaps, caps and options. When parties trade ETFs, they bid to buy or sell the relevant product, and trades are executed, without the trading parties knowing or ever discovering the identity of the counterparty to their trade.
98. NEM participants also trade a range of other products related to managing the risk associated with electricity generation and consumption. For generators, these include Renewable Energy Certificates created under the *Renewable Energy (Electricity) Act 2000* (Cth), and products relating to generators' liability for carbon emissions.
99. Traders of risk management products such as those described above include generators, retailers and financial intermediaries which do not own retail and/or generation businesses, but trade these products on a speculative basis, without any underlying physical exposure to the Pool Price. For example, the firms granted admission as a Trading Participant by the ASX in relation to ETFs for electricity include ANZ Banking Group, Castleton Commodities, Commonwealth Banking Group, Macquarie Bank, RWE and Westpac Banking Group.

## **HOW AGL ALLOCATES AND MANAGES RISK**

### ***Allocation of risk within AGL's business: internal transfer pricing***

100. As a large publicly listed company, AGL engages in contracting according to AGL's internal risk management protocols, which seek to manage the financial risk, earnings volatility and risk to AGL's BBB investment grade rating which might otherwise be created by AGL's exposure to the pool price.
101. AGL Retail and Merchant Energy are separate business divisions of AGL. They are also separate, standalone cost and profit centres, and AGL reports to the capital and financial markets on that basis.
102. Within Merchant Energy, the EPM group is responsible for managing AGL's exposure to the pool including through managing the dispatch of AGL's generation and trading in risk management tools.
103. In general terms:
- (a) the EPM group pays the settlement bills issued by AEMO to AGL for the physical consumption of electricity by AGL's retail customers; and




- (b) in return for EPM's payment of the AEMO settlement bills:
- (i) AGL's Retail group pays EPM an internal "wholesale transfer price" in relation to electricity consumed by AGL's residential and small business electricity customers; and
  - (ii) the Business Customers group in Merchant Energy pays EPM the internal transfer price for electricity consumed by AGL's large commercial and industrial customers.
104. The internal wholesale transfer price does not purport to reflect the actual or total cost associated with procuring the electricity consumed by AGL's retail customers. Rather:
- (a) in respect of Business Customers – it is an approximation of the competitive wholesale cost of supply (ie the market price, rather than costs actually incurred by EPM), which at best forms only a part of the total cost of supply; and
  - (b) in respect of AGL Retail – it is generally set in accordance with the wholesale energy allowance permitted by jurisdictional regulators (in jurisdictions which are subject to retail price regulation).
105. EPM calculates the internal transfer price having regard to its assessment of NEM pool prices, an estimate of the cost associated with managing variations in AGL's retail customer load, a "validity premium" which is an estimate of the cost of holding a quote open for a customer (ie offering a particular fixed price during a period in which actual wholesale costs vary), contract prices, and, where applicable, an allowance for the time value of money.
106. These internal arrangements mean, among other things, that the Retail Energy and Business Customers groups are not exposed to the actual price and/or volume risks associated with the procurement of the electricity consumed by AGL's customers. Rather, those risks are borne and managed by EPM, as a standalone cost and profit centre in AGL.
107. In other words, the effect of this internal transfer price is to transfer the risk of buying and selling electricity in the NEM to EPM. These arrangements are reflected in the financial reporting and accountability arrangements adopted for EPM.
108. Under those arrangements:
- (a) receipts for pool payments for electricity dispatched into the NEM, and for AGL's internal transfer price for electricity (described below) are treated as revenue items for EPM;
  - (b) payments made by EPM to acquire electricity in the NEM are treated as costs to EPM;
  - (c) payments made by AGL and to AGL under OTC contracts and ETFs are treated as costs and revenue to EPM (respectively); and
  - (d) EPM is also financially responsible for variable costs associated with the operation of AGL's physical generation assets – for example, variable costs associated with:
    - (i) AGL's liability to surrender carbon permits;
    - (ii) the amounts paid by AGL for fuel (and in particular, the costs associated with procuring gas for AGL's gas fired power stations); and
    - (iii) AGL's payments to power station owners under AGL's PPAs (which I refer to in paragraph 36 above),






are all recorded as costs incurred by EPM. The effect of these arrangements is that EPM is financially responsible for those variable costs associated with AGL's portfolio (both physical and financial) over which EPM has control when managing that portfolio, and that individuals in EPM are incentivised to manage those costs efficiently as part of their overall management of AGL's portfolio.

### **How AGL manages risk**

109. In very simplified terms, EPM manages the risks associated with AGL's exposure to the NEM spot price, both as a generator and as a retailer, by:
- (a) entering into hedge contracts and making use of other risk management instruments, which is the responsibility of the Wholesale Electricity Desk (**WED**) within EPM; and
  - (b) controlling the physical operation of AGL's generation assets and maximising the contracts able to be sold against AGL's generation (including the making of offer or rebid decisions referable to AGL's generation assets), which is the responsibility of the Wholesale Operations team (**Wholesale Ops**) within EPM,
- within the parameters established by the risk management protocols set by the AGL Board.
110. In practice, managing AGL's exposure in this way is a highly complex, interdependent, dynamic and information intensive task. It involves the making of complex commercial decisions based on data about a wide range of factors relevant to the risks I described above – for example, actual and forecast conditions in the NEM (eg as to pool price, output, demand and contract prices), and about factors that influence those conditions (such as technical constraints, weather and fuel availability). Decisions about AGL's contract position are made constantly throughout a day by the team of 5 full time traders who comprise the WED; decisions about dispatch of AGL's generation are made and communicated to AEMO for every 5 minute increment of every day. In each case, decisions are taken and revised as additional information and analysis becomes available.
111. In the following sections I describe the corporate risk management parameters within which EPM undertakes these portfolio management activities, and the manner in which EPM undertakes these activities.

### *Corporate risk management framework*

112. The Merchant Energy Group manages risk in accordance with the WERMP.
113. A separate and subsidiary document, the *AGL Wholesale Energy Risk Management Framework* (**Framework**), sets out details for the implementation of the requirements of the WERMP in relation to the trading related operations of Merchant Energy. The Framework is the responsibility of, and is approved and administered by, the Risk Management Committee (**RMC**). The Framework is subject to the WERMP.
114. AGL's business units are required to maintain the operational procedures set out in the Framework for all of their activities, and to prepare technical documentation that details their analytical methodologies. The RMC's duties include the review of and decision whether to approve high-level strategies proposed by Merchant Energy.
115. Within EPM, there is a Wholesale Strategy Committee (**WSC**) which has the role of:
- (a) considering and endorsing any wholesale strategy presented for the purpose of increasing wholesale revenue and/or reducing wholesale risk and/or costs;
  - (b) reviewing the appropriateness and effectiveness of previously approved wholesale strategies and where necessary their continuation;
  - (c) monitoring financial forecasts and results; and



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- (d) monitoring energy forecasts and results.
116. Wholesale energy transactions in excess of RMC limits require Managing Director, or (depending on the value involved) Board, approval, and should be first endorsed by the RMC.
117. Wholesale energy risk management is monitored and reported on within AGL through a number of avenues, which include:
- (a) regular meetings of the RMC, WSC and Marketing Strategy Committee (which includes the General Managers of the relevant operational groups within AGL);
  - (b) distribution of a weekly report to EPM and RMC members – this provides a more frequent update of the movement in the financial risk positions of the portfolios held by AGL;
  - (c) credit risk monitoring and reporting is also conducted on a weekly basis – this involves a recalculation of the exposures to wholesale electricity counterparties based on the latest movements in forward prices and new trades entered into;
  - (d) monitoring of AGL's overall hedge portfolio structure over the forward period by the traders in the WED within EPM, which occurs daily and is managed on a day to day basis by the Head of WED;
  - (e) daily dispatch of generation assets and electricity purchases from the NEM are completed by the traders in Wholesale Ops within EPM, which is managed on a day to day basis by the Head of Wholesale Ops; and
  - (f) other informal communications within EPM, which occur on a continuous basis.

#### *Risk management in practice*

#### Responsibility for portfolio management

118. As I noted above, AGL's hedge contracting and NEM trading (ie bidding and dispatch) activities are significantly interdependent. For example, while Wholesale Ops manages the bidding and dispatch of AGL's generation, it does so during each contract quarter having regard to AGL's entire portfolio, which comprises both its physical generation assets and its position under PPAs, hedge contracts, futures, insurance products and other risk management measures adopted by AGL. Similarly, while WED largely develops much AGL's portfolio of risk management instruments, it does so within the parameters of AGL's generation portfolio, including the generation capacity, costs, technical and other constraints associated with that portfolio. Accordingly, Wholesale Ops and WED liaise closely on an ongoing basis, and AGL's physical trading and other activities within EPM occur in combination, not in isolation. As I noted above, on a day to day basis, both activities occur in a dynamic and information intensive environment, and require swift assessment of information and analysis on a wide range of commercial and technical information.

#### AGL's approach to managing its portfolio

119. As I noted above, AGL can never entirely neutralise the risks it faces from its participation in the NEM. The WERMP and associated framework recognise this, in that they require AGL to hedge and otherwise manage its risk exposure within acceptable levels – they do not require AGL to eliminate all such risk. In particular, they are designed to achieve an outcome whereby AGL is prevented from distributing to shareholders ██████████ of projected net profit after tax in a maximum of 1 year out of 10 (ie AGL applies a 10% probability of exceedence (**POE**) threshold). They are not designed to ensure that AGL is always able to achieve this level of distribution; instead, they are designed with the aim of ensuring that AGL is only unable to make this level of distribution in one year out of every 10.






120. This risk tolerance reflects the commercial realities of AGL's business. In particular, AGL cannot perfectly match its generation precisely to the volume and composition of its retail customer load. Similarly, there is no product (or willing counterparty) which would allow AGL to contract to perfectly and completely transfer AGL's entire price and volume risk to a counterparty. Accordingly, what EPM does is to manage, and not to eliminate, AGL's commercial exposure to the risks it faces. At a conceptual level, AGL does that by taking actions which have a risk profile which is more acceptable to AGL than AGL's next best alternative.
121. At a very simplified level, AGL's approach to managing its risk exposure involves:
- (a) applying business parameters about the level of risk it is prepared to assume in relation to particular tranches of its portfolio (ie a process whereby AGL analyses the level of risk associated with a particular activity, and compares it to the level of risk to the relevant risk limit); and
  - (b) using a combination of its own physical generation and contractual and other mechanisms to achieve its desired level of risk.
122. At a practical level, this involves AGL making decisions and trade-offs about its portfolio position on a long, medium and short term basis.

AGL's risk management from its perspective as a retailer (ie an acquirer of wholesale electricity)

123. Managing AGL's pool price exposure that arises from the demand of its customers is a complex task. Decisions are made over a variety of time horizons and involve complex analysis and decision making over a wide variety of market variables and business inputs.
124. There are two main concepts of demand that AGL utilises in order to effectively manage its price and volume risk associated with customer demand effectively:
- (a) Average peak demand - the simple average of AGL's forecast of its customer demand across all peak periods (being defined as 7am to 10pm on working weekdays); and
  - (b) Capacity demand - this represents for each calendar month the maximum forecast of AGL's customer demand in any given half hour during that month. This forecast is referenced to a 50% Probability of Exceedence (50POE) forecast, which means that one in two years it is expected that this maximum demand will be exceeded. The capacity demand (to a 50POE) is the difference between the maximum demand and the average demand.
125. AGL generally hedges its average peak demand using a combination of:
- (a) Swap contracts (whether OTC contracts or EFTs); and
  - (b) Its available generation assets that are capable of generating at a relatively high capacity factor (a general rule of thumb is 65%, however, intermediate plant (with a capacity factor between say 30% and 65%) can also be used) for the relevant period of time.
126. This is, however, not a hard and fast rule, and depends to a large extent on the alternatives available to AGL. As an example, if AGL's view of forward pool prices for a given period did not accord with the rest of the market, and thus AGL considered the price of swap contracts to be inconsistent with its own view of forward prices for a particular period, AGL may choose to manage its customer demand differently. Alternative options available to AGL in this instance could include:
- (a) relying on lower capacity factor generation assets (such as Torrens Island Power Station (**TIPS**) or hydro plant) that may be ordinarily be constrained by fuel supply or reliability issues in lieu of purchasing swap contracts considered to be "over priced"; or






- (b) purchasing different types of derivative contracts which may have a different relative value to the "over priced" swap contract. This may include cap contracts and could occur in instances where AGL considers the swap price to be too high, but considers the market view of the level of expected volatility in the pool price to be consistent with its own view; or
  - (c) leaving the customer demand exposed to the pool price if AGL's view of the pool price continued to remain below the price at which swap contracts were trading in the market. Any such strategy would need to be consistent with AGL's WERMP; or
  - (d) Using a combination of inter-regional settlement reside units (**IRSRs**, which are a financial product which allows the holder to hedge based on differences between spot prices in different regions within the NEM and which are auctioned by AEMO on a quarterly basis) together with derivative contracts referenced to the pool price in another region, or generation assets located in another region. AGL may consider this in instances where the swap prices in the region in which the customer demand is located are (according to AGL) unexpectedly higher than the equivalent contract referenced to the pool price in an adjacent region.
127. AGL generally hedges its capacity demand using a combination of:
- (a) cap contracts (whether OTC or EFTs); and
  - (b) its available generation assets that tend to be lower capacity plant. This plant includes fuel constrained plant, or plant with high fuel costs, and plant with lower reliability.
128. Again, this is not a binding rule, but rather a starting point, and giving consideration to a broad range of factors AGL may chose alternate methods to manage capacity demand. Some of these might include:
- (a) Using a combination of IRSR units together with cap contracts referenced to the pool price in another region, or generation assets located in another region. AGL may consider this in instances where the cap prices in the region in which the customer demand is located are (in AGL's view) unexpectedly higher than the equivalent contract referenced to the pool price in an adjacent region;
  - (b) Using a combination of IRSR units together with generation assets located in another region even where those generation assets may be required to manage capacity demand in the region in which they are located. AGL may consider this in instances where the coincidence of maximum demand in both regions is improbable, thereby creating a greater level of utilisation of AGL's generation capacity across its portfolio;
  - (c) Acquiring insurance products related to weather conditions (which may be in the form of a simple financial payout if certain weather conditions prevail, or may be directly referenced to the pool price in a particular region if certain weather conditions prevail). AGL would typically use such products to hedge its maximum demand for a 10POE event (that is, demand conditions that would be expected to occur only one year in every ten).
129. In practice, as explained above, AGL constantly refines and updates its risk management arrangements in relation to its retail load. This reflects the fact that the size and shape of that load can change on an ongoing basis, due to variations in customer numbers and consumption patterns. For example, in any particular period AGL may sign up new customers, may experience customer leaving to join a different retailer, and may experience customers consuming electricity in a manner different to AGL's forecasts (eg because consumer preferences, weather or other factors were different to those AGL forecast). In each case, these variations may affect AGL's view of the preferable approach to managing its portfolio, and AGL responds by adjusting its approach to managing that portfolio.






AGL's risk management from its perspective as a generator (ie a supplier of wholesale electricity)

130. However AGL has regard to different considerations when seeking to manage the exposure of its generation assets to the NEM pool price – here, AGL seeks to manage the risk of earning the NEM pool price, in circumstances where contract prices, or potentially not generating at all, would be the preferable outcome.
131. For example, where AGL expects to have generation output which exceeds its retail load during a particular period, it faces a range of choices about how to manage that exposure, from doing nothing and accepting the risk from that exposure (eg if AGL expects that pool prices will exceed its costs of generating in that period), to selling OTC contracts backed by its generation, to reducing its generation (eg by reducing use of, retiring or mothballing generation units) to the extent that AGL believes that its costs of generating will exceed the potential revenue from generating. Similarly, AGL may change the *type* of contracts that it sells against its generation portfolio, depending on the relative attractiveness to AGL of the prevailing prices that counterparties are willing to pay for particular contract types.
132. As this discussion illustrates, AGL faces a range of possibilities for managing its exposure to the pool price.
- (a) The **nature and range** of these possibilities varies depending on the time frame under consideration.
- (i) Decisions which are made on a longer term basis (ie having regard to a period of 2 years or more from the decision date) include strategic decisions about the composition, capacity and availability of generation assets owned by AGL, and generation assets AGL bids into the NEM under PPAs. For example, these would include decisions on matters such as what new investments AGL will make in generation plant, whether and to what extent it will acquire, expand, maintain, mothball or retire generation assets, and whether and in what form it will seek to enter into PPAs in future.
- (ii) Decisions which are made on a medium term basis (ie having regard to a period of 1 to 2 years from the decision date) include decisions about what types of hedge contracts and ETFs AGL will buy and sell to establish coverage, whether to customise those products, and to what extent AGL will buy or sell those contracts having regard to AGL's view of likely pool prices in a particular period, compared to the prevailing contract price for that period. These decisions also include decisions on how major plant outages will be managed, and how AGL will manage procurement of fuel and/or the impact of fuel shortages.
- (iii) Decisions which are made on an immediate or short term basis (ie having regard to a period of up to a calendar year or quarter in advance of the decision date) include an extremely wide range of decisions on matters such as:
- (A) how much energy to bid into the NEM and at what price for a particular, week, day or trading interval;
- (B) whether to adjust the output from a particular asset in response to factors such as price, fuel constraints or other dynamics;
- (C) adjusting AGL's contract or other risk management position for the coming quarter having regard to updated information in relation to likely conditions in that quarter – for example, buying contracts for the coming period at a price lower than AGL's forecast of the NEM pool price for that period, or selling contracts at prices higher than AGL's forecast; and






- (D) whether and how to rely on a range of other risk management instruments AGL has in place from time to time – for example, negotiating with commercial and industrial customers to modify their consumption in a particular period, or relying on a weather derivative product in a particular period.
- (b) The **desirability** of a particular risk management tool depends on AGL's risk preference and alternatives at that point in time. To take one example, if fuel (eg gas) costs are low and contract prices are high, AGL may prefer to increase its generation rather than buy caps to hedge its retail load; alternatively, it might seek to rely on agreements with customers to reduce their consumption, or might decide to bear the exposure to the pool price if it judges that the cost and risk of doing so is more attractive than the available alternatives. There is a close connection between expectations about NEM pool prices and the prices of contracts sold by generators and bought by retailers. For example, if pool prices were generally low but high for short periods of time, this might translate into moderate strike prices for swap contracts and higher premiums for cap contracts. However, if the pool price was generally high for large periods during the year this may result in higher strike prices for swap contracts and relatively lower premiums for cap contracts. AGL may also increase or decrease the extent to which it relies on a particular type of contract, having regard to its own view of future pool prices, and the prevailing prices available under different contract types. It may do this by using more or one type of contract than another, and/or by increasing or decreasing its overall use of hedge contracts (and, for example, accepting a greater exposure to the pool price, or adjusting its position in other ways). Over a longer term decision making horizon, AGL might manage the exposure of its generation to the pool price by deciding not to renew a PPA or to reduce the availability of plant; but if the forward contract price was high, AGL might prefer not to take those steps and to sell contracts against its generation portfolio instead.
- (c) Ultimately, the **efficacy** of a particular option depends on actual outcomes – in the NEM, in relation to AGL's generation assets, and under AGL's contracts and other arrangements. AGL necessarily makes decisions about management of its portfolio on the basis of its forecasts about those matters. Accordingly, there can be significant discrepancy between the forecast conditions on the basis of which AGL makes decisions about managing the risks facing its portfolio, and actual outcomes in the NEM. For example, if AGL adopts a particular risk management parameter which assumes a 10% POE, but AGL's forecasts underpinning that parameter are imperfect, outcomes AGL assumed had a 10% POE may in fact have a higher POE (eg 20%, 30%). This may mean that AGL in fact faces a substantially different risk profile to that it assumed when making decisions about managing its portfolio.

***How AGL established a contract position to support its retail load in NSW***

133. As I stated above, AGL does not apply any "hard and fast" rules about how it manages its portfolio, and adapts its approach in light of the available alternatives and market variables. This is illustrated by the way that AGL has hedged its exposure to the NEM pool price in connection with its NSW retail customer load.
134. AGL does not have any scheduled generation assets in NSW which it can use in combination with swap contracts to hedge its retail customer load in NSW in this way. However, AGL has been able to establish a hedge position to support its NSW retail business (and the retail business of ActewAGL), which represents over 800,000 retail electricity customers in NSW (including the ACT) and a retail "load" of 9.1TWh.
135. In December 2010, following AGL being unsuccessful in its bid to acquire one of the NSW retail businesses during the NSW privatisation process that was underway at the time, AGL announced to the market its intention to seek to acquire an additional 400,000 to 500,000 customers through organic growth over a 3 year period. A copy of AGL's ASX announcement dated 15 December 2010 is contained in Annexure AF-15. AGL already had a substantial retail electricity customer base of approximately 400,000

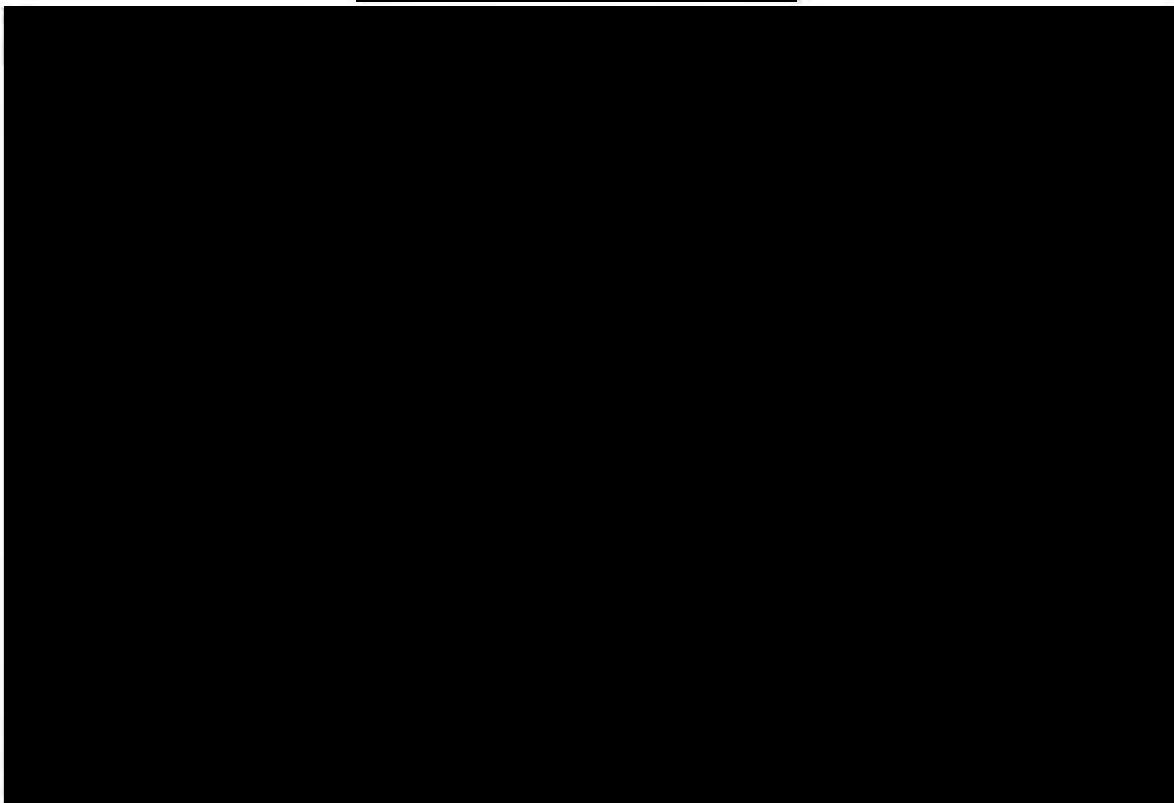





customers. Following that announcement, AGL managed its wholesale portfolio so as to support that growing retail load in NSW.

136. As the graphs showing AGL's hedge position which I discuss in the paragraphs below demonstrate, AGL established its NSW hedge position:
- (a) principally by entering into hedge contracts referenced to the NSW RRP with generators located in NSW (in particular, with [REDACTED] and [REDACTED];
  - (b) by entering into hedge contracts referenced to the NSW RRP with generators located in other regions of the NEM (in particular Queensland generators); and
  - (c) by utilising hedge contracts referenced to other regions of the NEM and/or physical generation located in other regions (in particular Victoria and Queensland), supplemented by IRSRs.
137. I have reviewed a number of graphs (which I describe below) showing AGL's NSW hedge position, and AGL's purchases of swap contracts from [REDACTED], [REDACTED] and Queensland generators, based on data on AGL's contracting activity stored in AGL's internal financial and contracting systems. These systems are used on a day-to-day basis to manage AGL's business, and are also used for management reporting.
138. The graph set out below shows data stored in AGL's systems relating to AGL's contract book for contracts covering its NSW retail load over the period from January 2008 to January 2018, plotted against AGL's actual and forecast average and maximum demand over that period.

[REDACTED]



139. I know from my understanding of AGL's contracting practices that where the graph shows that AGL's position is "short" in NSW, this is because AGL usually also holds:

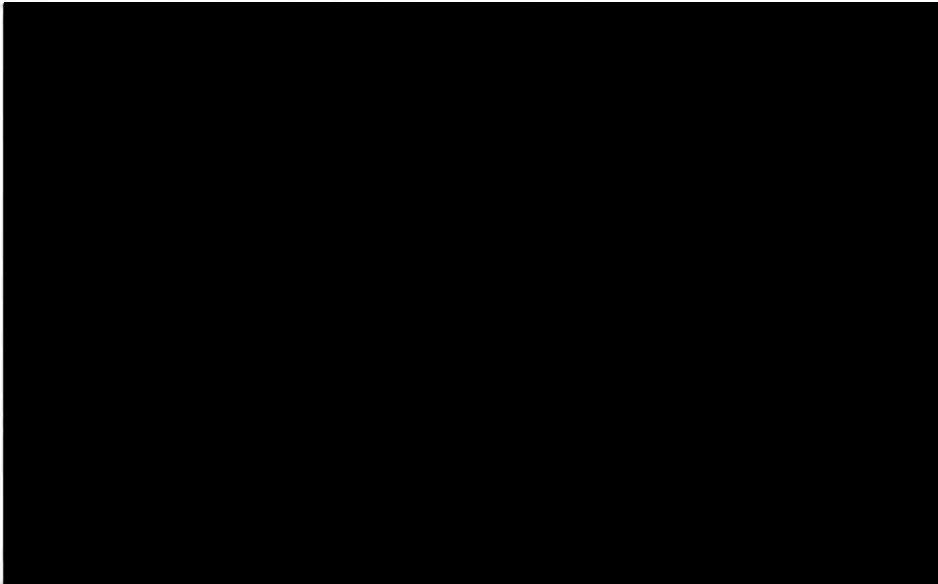
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- (a) IRSRs, to allow AGL to hedge NSW retail load using generation located in regions other than NSW; and/or
- (b) weather derivatives (and has maintained a residual exposure to the pool price).
140. This graph shows that AGL "built" a contract book to provide coverage for volumes in excess of 2,500MW, in order to hedge its NSW retail load.
141. Notably:
- (a) AGL contracted substantial volumes with [REDACTED] including both swaps and caps. Based on my experience, I consider the physical generation from a generator with 65% or greater capacity factor to be (in general) an effective alternative to the supply of swap contracts. [REDACTED], not being a base load power station, has a significantly lower capacity factor than 65%. This demonstrates that generators can and do offer swap contracts, backed by a lower capacity factor generation assets.
- (b) AGL contracted substantial volumes with [REDACTED] (included along with [REDACTED] in the "NSW Coal" volumes).
- (c) AGL contracted substantial volumes with Queensland generators under contracts referenced to the NSW nodal price.
- (d) AGL contracted on average only [REDACTED] directly with [REDACTED] (ie a standalone baseload generator located in NSW).
- (e) the remaining volumes were contracted under both OTC contracts and ETFs (referred to as "SFE" in the graph above).
142. While I consider that base load (ie high capacity factor) generators do supply swap contracts, I also consider that generators with lower capacity factors (for example, hydro or OCGT peaking generators) also sell swap contracts in significant quantities. In my experience, generators will seek to sell types of contracts to maximise their revenues. As such, a generator with a lower capacity factor may sell swap contracts (rather than cap contracts) where this will maximise their revenues, and even though selling swap contracts potentially increases their risk profile as compared to selling cap contracts. A generator's decision whether to sell swap contracts largely depends on prevailing market conditions as to the extent of risk, as well as the relative pricing of swap contracts as against cap contracts. I consider that it would be a relatively low risk strategy for a lower capacity generator with a rapid ramp rate (being the rate at which the generator can change generation output) to sell swap contracts in market conditions where substantial excess generation capacity exists.
143. The graph set out below shows data from AGL's systems regarding AGL's purchase of swap contracts from [REDACTED] covering the contract period from July 2009 until March 2015. The blue areas of this graph show AGL's purchases of swap contracts from [REDACTED] which are priced with reference to the NSW RRP.



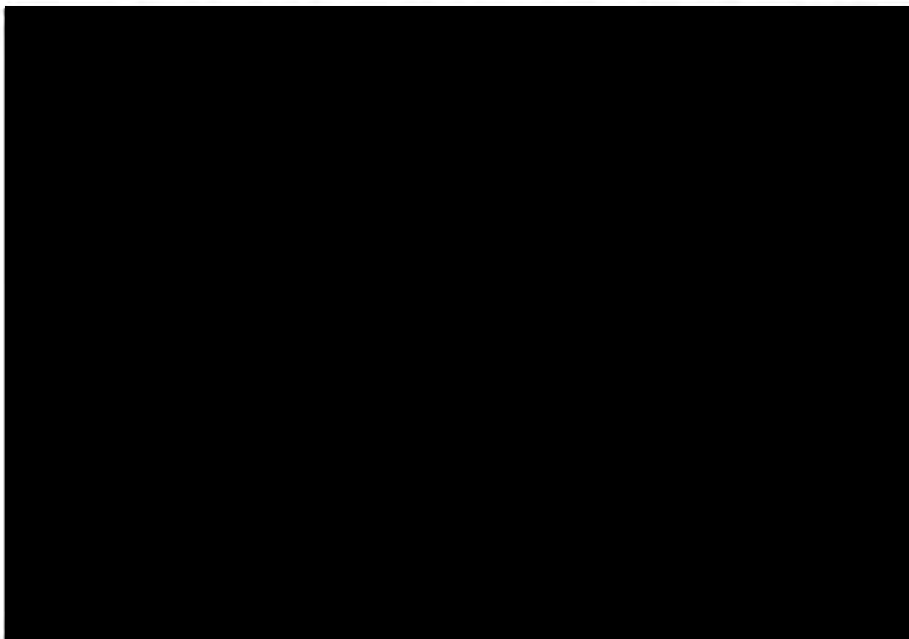



**Figure 4 - AGL Swap Purchases from [REDACTED]**



144. The graph set out below shows data from AGL's systems regarding AGL's purchase of swap and cap contracts from Queensland generators where the contract price was based on the NSW RRP, for the period from July 2009 to March 2015.

**Figure 5 - AGL Contract Purchases from QLD Generators**



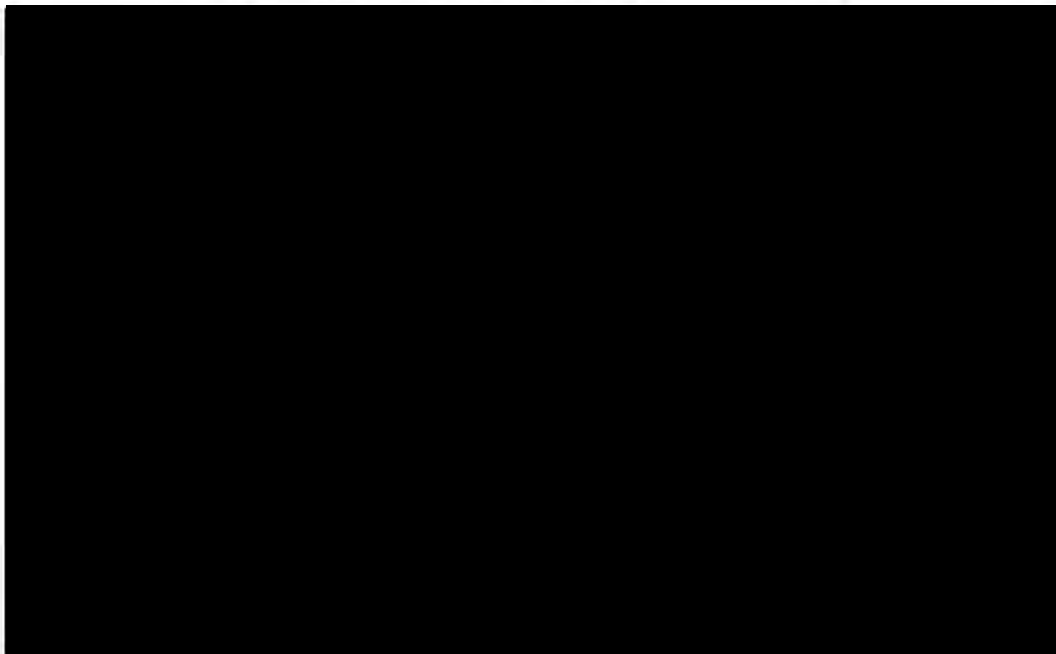
145. This graph shows that AGL has contracted with Queensland generators to provide substantial hedge contract coverage for AGL's retail load in NSW, using contracts priced with reference to the NSW RRP.
146. Based on my experience, I consider that interconnector flows from Queensland into NSW are robust (ie all or the majority of the interconnector maximum nominal capacity is generally available), predictable and significant in terms of volume. Interconnector flows from Queensland to NSW typically occur when the price in where the RRP in NSW exceeds the RRP in Queensland, and the maximum import capacity exceeds 1,250MW (with a corresponding volume of IRSRs therefore being available in Queensland). AEMO's summer peak estimated nominal interconnector capacity limit for the

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interconnector from Victoria into NSW, which takes into account thermal rating considerations, is 1,500MW.<sup>9</sup>

147. I know from my experience that AGL uses (and has for many years used) as a standard risk management tool a combination of IRSRs covering interconnector flows from Queensland into NSW and hedge contracts with Queensland generators referenced to the Queensland RRP (or output from the Oakey power station). I consider that this combination of IRSRs and hedge arrangements creates a hedge position which is broadly equivalent to a hedge contract referenced to the NSW RRP. I consider that this combination of hedge arrangements is an important hedging tool for AGL (in the sense that AGL frequently uses or considers using it), and AGL's use of this combination of hedge arrangements adds liquidity to the supply of NSW contracts.
148. This graph also shows that AGL's hedge coverage for its NSW retail load during the period July 2009 to March 2015 included hedge contracts with [REDACTED], and for at least the period March 2011 until June 2014, included hedge contracts from those generators covering at least 100MW of AGL's NSW retail load.
149. The graph set out below shows data from AGL's systems regarding AGL's purchase of swap and cap contracts from [REDACTED] for the period from January 2009 to June 2015.

**Figure 6 - AGL Purchases from [REDACTED]**



**RESPONSE TO QUESTIONS ABOUT TRADING OTC CONTRACTS AND ETFS WITH COUNTERPARTIES**

150. I am aware that the ACCC published a "Statement of Issues" in relation to AGL's proposed acquisition of Macquarie Generation (**SOI**). The SOI states as follows:
61. *The ACCC's preliminary view is that the proposed acquisition is likely to substantially lessen competition in the retail supply of electricity in NSW as a result of:*

<sup>9</sup>. Source: AEMO, Interconnector Performance Report: Quarter September to November 2013, page 5.



- *A significant reduction of liquidity in the supply of hedge contracts due to the reduced volume of hedge contract trading as AGL's retail load will be supported with a natural hedge. This may potentially increase the risk of spot price exposure for independent retailers and, in turn, discourage participation in those markets and/or increase risk premiums in forward hedge contracts.*
  - *The increased ability and incentive of AGL to withhold competitively priced and customised hedge contracts to independent retailers. This would occur as a result of the changed incentives that AGL would have in the supply of hedge contracts backed by Macquarie Generation to independent retailers that compete with its retail arm.*
62. *Following the proposed acquisition, the three major vertically-integrated retailers would have approximately 70 per cent of electricity generation capacity and approximately 80 per cent of electricity generation output in NSW as well as over 85 per cent of the retail electricity load in NSW (supplied to both mass market and large customers) in NSW. The ACCC is concerned that independent and new entrant retailers may find it difficult to gain the hedge contracts they need to compete aggressively in the retail supply of electricity in NSW.*
151. I have been asked to consider this passage, and address the following questions:
- (a) whether the need to acquire hedge coverage is a barrier to entry to independent and new entrant retailers;
  - (b) whether and how AGL makes hedge contracts available to independent and new entrant retailers;
  - (c) what other sources of hedge contracts exist for independent and new entrant retailers; and
  - (d) whether vertical integration of generators and retailers in the NEM has caused a reduction in the liquidity of hedge contracts.
152. As a preliminary point, based on my experience I consider that any significant reduction in hedge contract liquidity would have a negative influence on AGL's ability to appropriately manage risk, and on AGL's electricity business overall. This is because AGL's position with respect to the NSW RRP is variable and dynamic – AGL's net position with respect to the NSW RRP can change from being net long to net short based on a range of factors both within and outside of AGL's control. AGL's position is rarely, if ever, balanced. As a result, AGL transacts in the hedge contract market to manage that risk. If there was a significant reduction in hedge contract liquidity, then I consider that AGL would face increased difficulty in appropriately managing the financial risks associated with its electricity business.

***Whether the need to obtain hedge coverage is a barrier to entry by independent or new entrant retailers***

153. As I described in paragraph 107 above, AGL's transfer pricing mechanism means that the Merchant Energy group (specifically, EPM) manages AGL's price risk as a generator and as a retailer in the NEM. Accordingly, my experience as Group General Manager of Merchant Energy and my previous role as General Manager of EPM comprised experience managing the types of risks faced by a retailer as well as by a generator.
154. Two of the key means by which new entrant retailers could establish hedge contract coverage are by trading OTC contracts and by trading ETFs. The registration, costs and prudential requirements that a retailer would face in order to trade these products are the same as those I described in paragraphs 58 and 59 above.
155. As I describe in the following section:
- (a) OTC contracts and ETFs are traded by a wide range of commercial parties;




- (b) AGL trades with a number of independent and standalone retailers; and
- (c) I am aware that independent and standalone retailers use a number of sources aside from AGL to obtain contract coverage for their retail load.

156. Based on these matters, I consider that although retailers, like generators, need to incur establishment costs in order to be able to trade OTC and ETF contracts, those costs are not so significant as to amount to a barrier to entry.

#### **AGL's approach to dealing with counterparties**

157. In my experience, hedge contracts are typically traded at a premium to expected pool prices (and to actual pool price outcomes). In addition, customised hedge products, which include load following arrangements and/or reallocation arrangements (which I discuss in paragraph 97(a) above), trade at an additional premium, to reflect the additional risk that a generator takes on under those arrangements. Accordingly, AGL has a commercial incentive to supply those hedge contracts, and to supply customised hedge contracts, where the price of those arrangements includes a premium commensurate with the risk that AGL takes on in supplying the relevant hedge contract.
158. I have caused to be prepared a graph (which I describe below) showing the level and changes in prices of electricity ETFs, using data produced by the ASX. For each year shown below, the graph shows the prices for contracts covering the following calendar year period, as reported by the ASX, for contracts priced with reference to NSW, Queensland, South Australia and Victoria.

**Figure 7 – Year-ahead futures prices 2002-2014 by NEM region**



159. AGL's approach to hedging is to hedge with any market participant on commercial terms and in accordance with AGL's risk management policy (that is, the WERMP and the associated risk management framework, which I described in paragraphs 112 to 116 above). In practice, this policy determines the acceptable exposures AGL is able to incur by contracting with third parties – relevantly, including the credit rating AGL requires a counterparty to have in order for AGL to trade with it, and the extent of financial exposure AGL will tolerate to any one counterparty having regard to their



financial standing. When AGL identifies opportunities to trade OTC and ETF contracts to manage AGL's exposure to the NEM pool price, it does so in a manner which is consistent with those limits.

#### *OTC Contracts*

160. There are two ways in which AGL enters into OTC contracts with retailers:
- (a) by trading directly with the retailer (direct trades constitute between 50 and 75% of all of AGL's OTC hedge contracting); and
  - (b) by giving instructions to a broker to enter into a particular contract type, for a specified volume and price (between 25 and 50% of AGL's OTC hedge contracting is transacted through a broker).

#### Counterparties AGL is willing to trade with

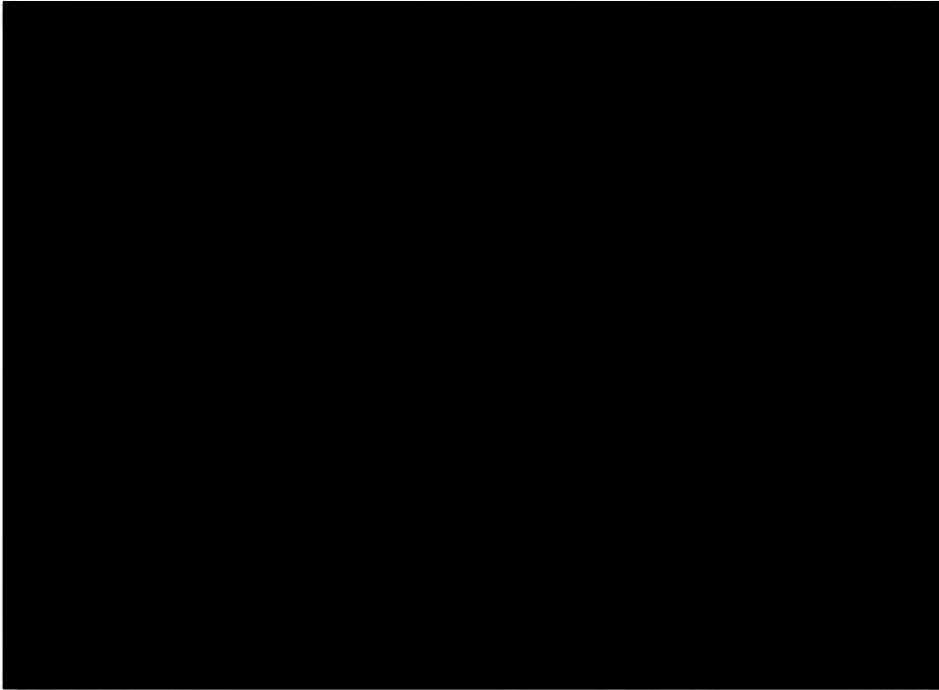
161. In order for AGL to trade OTC contracts in either of these ways consistently with the risk management framework outlined above, the Wholesale Energy Risk Group develops what AGL refers to internally as a "good names" list – that is, a list of counterparties with whom AGL can trade consistently with AGL's risk management policies and protocols.
162. When AGL trades OTC contracts directly with counterparties, AGL either checks that a potential counterparty is on the "good names" list, or takes steps to have them included on the "good names" list, before trading with them (ie by obtaining information from them to demonstrate that they satisfy AGL's requirements as to creditworthiness).
163. When AGL uses brokers to transact a sale of an OTC contract, AGL gives instructions to its broker to "place" that volume with any counterparty who is currently on the "good names" list, at the price indicated (or a price more favourable to AGL). AGL does not otherwise give instructions to the broker regarding the identity of the counterparty to the trade. Provided that the broker faithfully executes AGL's instructions, AGL is bound by the trade before it knows, and regardless of, the identity of the counterparty.
164. The 32 entities named on AGL's "good names" list (as at February 2014) are set out below.







**Figure 9 – Macquarie Generation contracts with independent retailers (as at 31 January 2014)**



169.

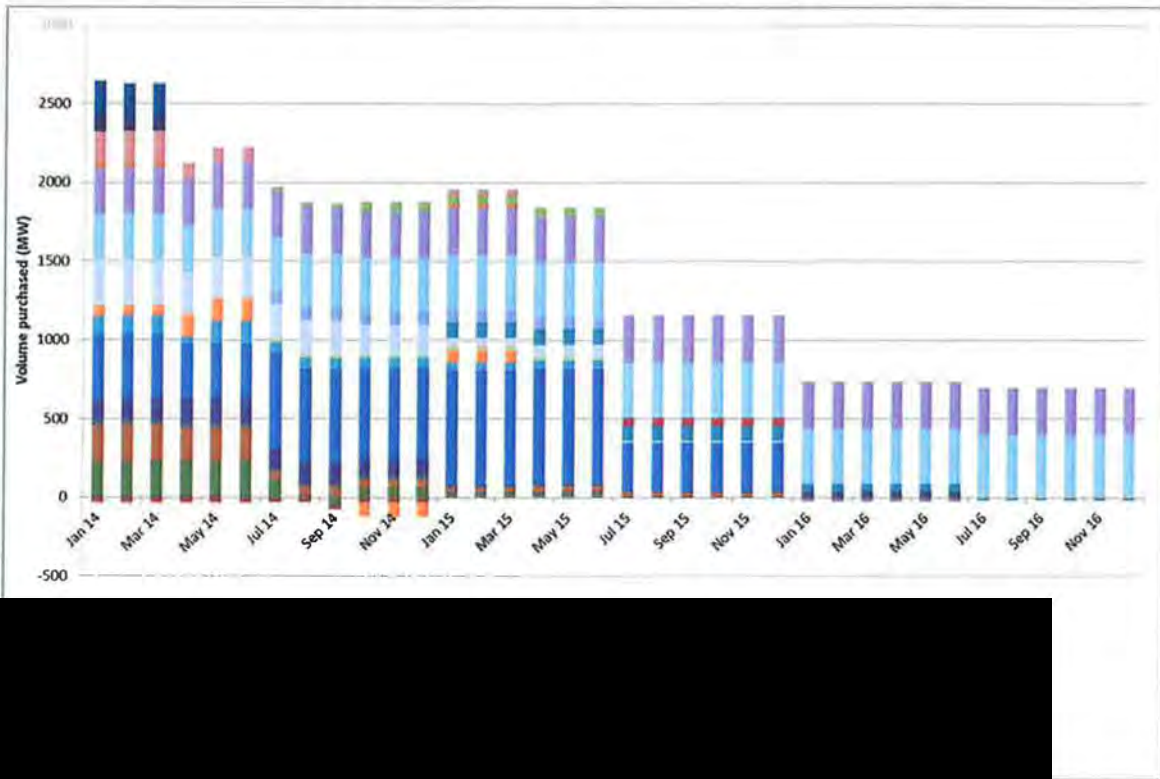


AGL's current risk management arrangements (including counterparties to OTC contracts)

170. In my experience, AGL trades with a diverse range of counterparties, and has consistently taken that approach to hedging for at least the period since I became General Manager of EPM in December 2007 (and, for the avoidance of doubt, including since I became Head of Merchant Energy).
171. I have caused a number of charts (which I describe below) showing AGL's hedge position (including OTC contracts, ETFs and related products) for contracts referenced to the regional node for each of the States in which AGL operates to be produced. The information in those charts is derived from the AGL systems which I refer to in paragraph 137 above.
172. The graph below shows that for NSW (where AGL does not own scheduled NEM generators), for the period covering 2014 onwards, AGL has used a range of risk management products, including OTC contracts (swaps, caps, swaptions, callable caps), and ETFs (described here as "SFE"). The counterparties to AGL's OTC contracts include generators based in NSW (eg [redacted], [redacted]) and outside of NSW (eg [redacted], as well as vertically integrated generators [redacted] and [redacted]). AGL has also contracted with financial intermediaries (eg [redacted] and [redacted]), and traded ETFs (referred to in the graph as "futures").

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Figure 10 – AGL hedge position (NSW)

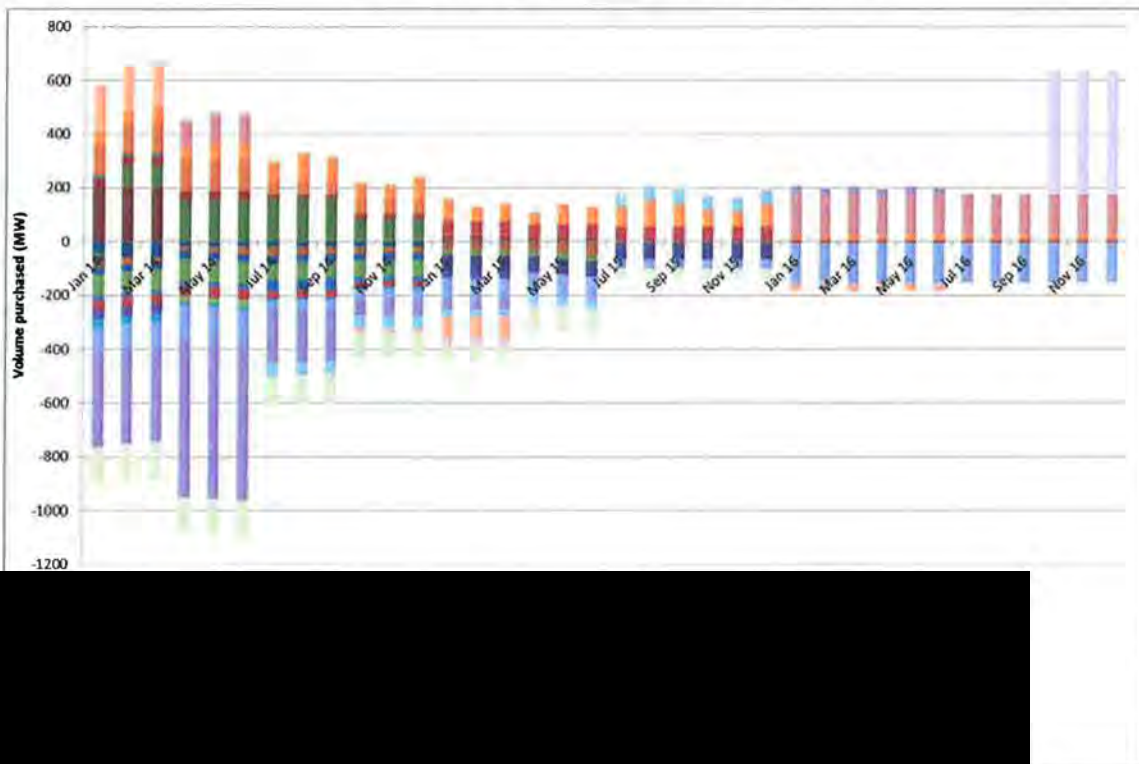


- 173. This graph shows that AGL has bought contracts from [redacted] [redacted] and [redacted] in order to manage the risks associated with its NSW retail load, as well as other counterparties.
- 174. The graph below shows the equivalent information in relation to Victoria.

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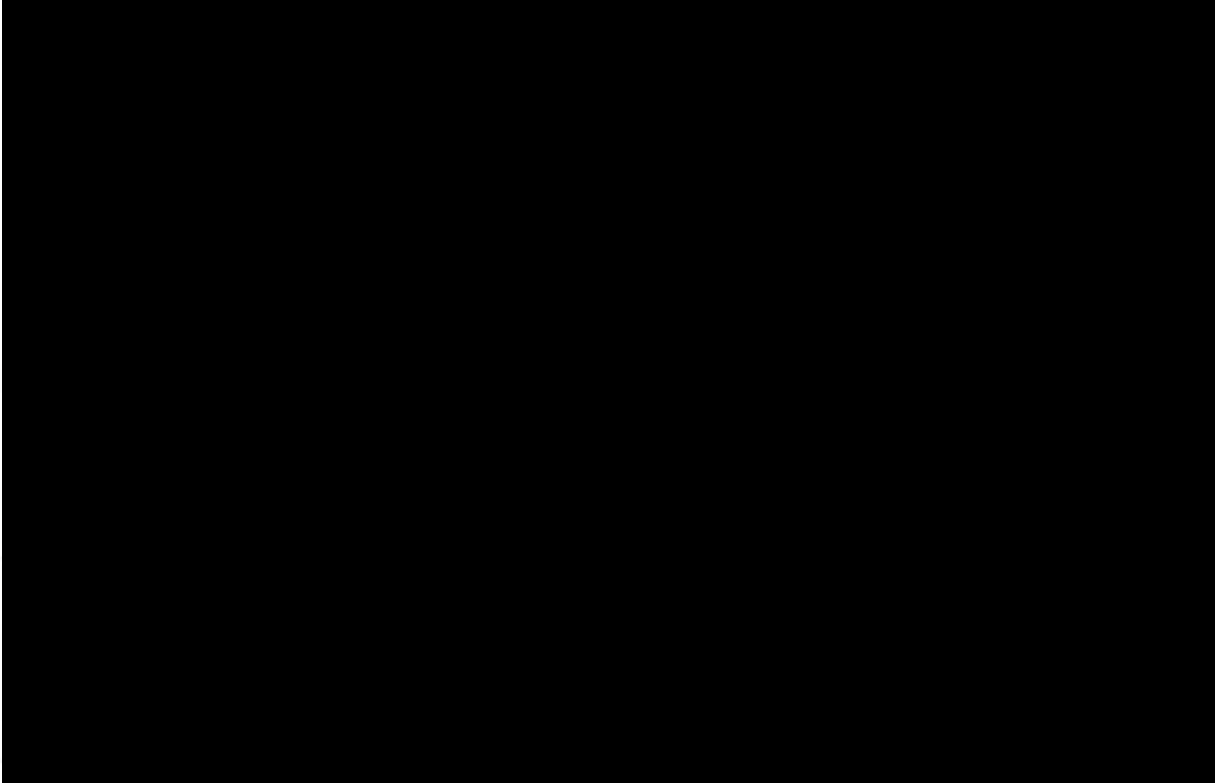


Figure 11 – AGL hedge position (Victoria)



175. This graph shows that for Victoria (where AGL owns NEM scheduled generators), for the period covering 2014 onwards, AGL has entered into a range of risk management products, including OTC contracts (swaps, caps, swaptions), ETFs (described here as "SFE" products), power purchase agreements (described here as PPAs) and weather insurance (described as [REDACTED]). The counterparties to AGL's OTC contracts include standalone and vertically integrated retailers, such as [REDACTED] (a standalone retailer), [REDACTED] (a standalone retailer in Victoria), [REDACTED], [REDACTED] and [REDACTED], as well as financial intermediaries (eg [REDACTED] and [REDACTED]). I am also aware that AGL previously entered into contracts with Australian power & Gas (APG), a standalone retailer in Victoria, before APG was acquired by AGL.
176. The graph below shows the equivalent information in relation to Queensland.

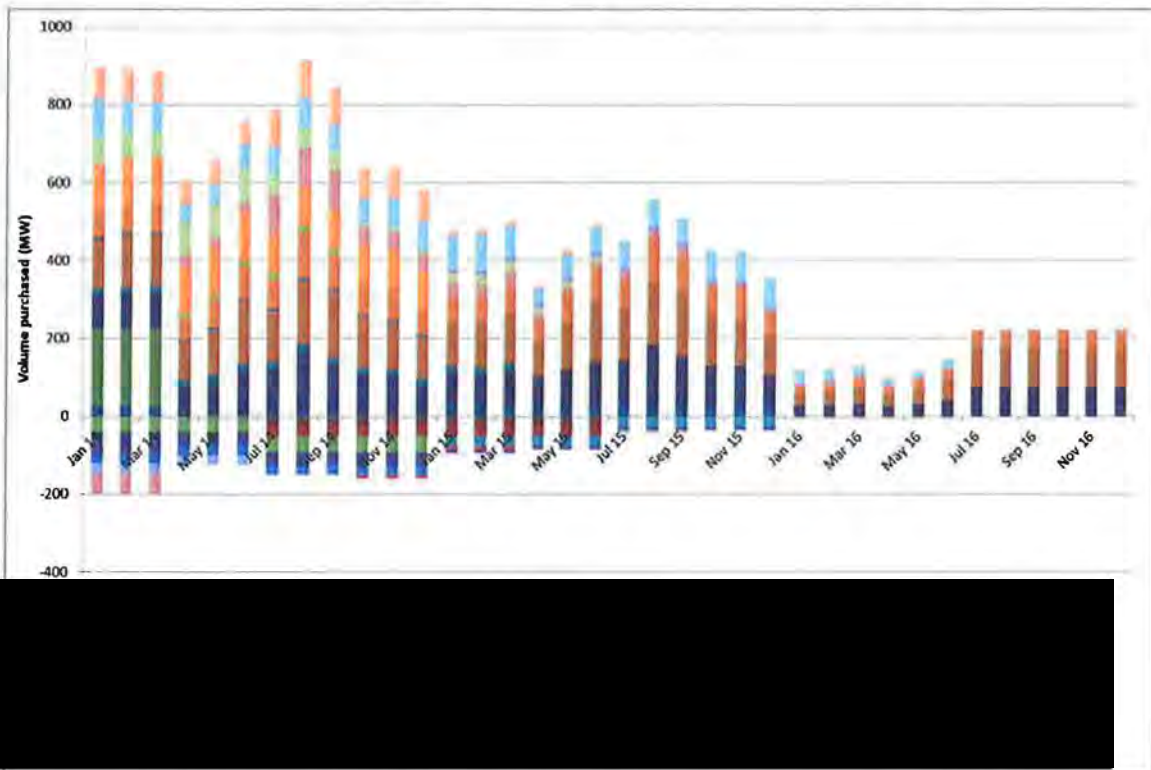
**Figure 12 – AGL hedge position (Queensland)**



177. This graph shows that for Queensland, for the period covering 2014 onwards, AGL has used into a range of risk management products, including OTC contracts (swaps, caps, swaptions, collars), ETFs (described here as "SFE") and weather insurance. The counterparties to AGL's OTC contracts include standalone generators located in Queensland (eg [REDACTED]) and outside of Queensland (eg [REDACTED]), as well as a range of AGL's competitors, including [REDACTED] and [REDACTED].
178. The graph below shows the equivalent information in relation to South Australia.



**Figure 13 – AGL hedge position (South Australia)**



179. This graph shows that for South Australia (where AGL owns NEM scheduled generators), for the period covering 2014 onwards, AGL has entered into a range of risk management products, including OTC contracts (swaps, caps, swaptions), ETFs (described here as "SFE" products), PPAs and weather insurance. The counterparties to AGL's OTC contracts include competing retailers such as [REDACTED], [REDACTED] and [REDACTED].
180. In addition to the above, I am aware that AGL has sold hedge to contracts to retailers that do not own generation in other regions of the NEM, namely:
- in New South Wales, AGL has sold swap contracts to [REDACTED] and [REDACTED];
  - in Queensland, AGL has sold swaps, options and caps to [REDACTED], [REDACTED], [REDACTED] and [REDACTED]; and
  - in South Australia, AGL has sold swaps and caps to [REDACTED], [REDACTED] and [REDACTED].
181. One example of a competing retailer who is a counterparty to OTC contracts with AGL is [REDACTED]. I am aware that the General Manager of EPM caused to be prepared the following graphs, setting out data from AGL's internal database which records trades between AGL and AGL's associated entities, which identifies what hedge contracts AGL has sold to [REDACTED].

Figure 14 - Victorian MWs sold to [REDACTED] by AGL

Figure 15 - SA MWs sold to [REDACTED] by AGL

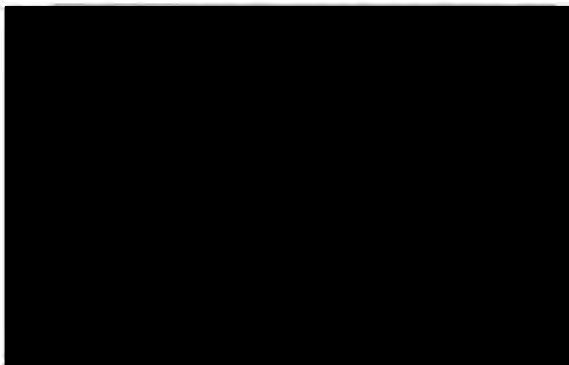
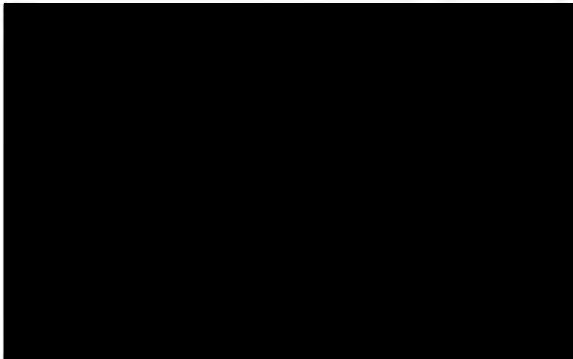


Figure 16 - NSW MWs sold to [REDACTED] by AGL

Figure 17 - Queensland MWs sold to [REDACTED] by AGL



182. The graphs show that AGL has sold hedge contracts (swaps, swaptions, caps and Asian caps) to [REDACTED] for each of Victoria, SA, NSW and Queensland, and that in total, those contracts provide coverage over the period from January 2010 until July 2015.

183. As I note in paragraph 58 above, one requirement for a retailer to trade OTC hedge contracts is for the retailer to entry into an ISDA Master Agreement with the relevant counterparty. In my experience, once an ISDA Master Agreement is in place, entering into standard hedge contracts under that agreement (assuming the parties are able to agree on price, volume and other basic terms) is a relatively straight forward process. I understand that entering into a customised product can, by comparison, require more involved negotiations due to the more complex nature of those products.

184. I have made relevant enquiries of my team, and based on those enquiries believe that AGL's business records show that AGL has engaged in communications with a number of other smaller retailers about the supply by AGL of hedge contracts to those retailers since 2012, including:

- (a) [REDACTED]
- (b) [REDACTED]
- (c) [REDACTED]
- (d) [REDACTED]
- (e) [REDACTED]
- (f) [REDACTED]
- (g) [REDACTED]
- (h) [REDACTED]
- (i) [REDACTED]; and

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(j) [REDACTED]

185. In addition AGL:

- (a) currently has customised hedge contracting arrangements with [REDACTED] and is negotiating the supply of a further customised product to support [REDACTED] entry into South Australia;
- (b) prior to acquiring APG, AGL had both customised and standard hedge contract arrangements with APG (AGL acquired a customised "reallocation" arrangement with APG when it acquired the Loy Yang A power station); and
- (c) is currently engaging with [REDACTED] in relation to the supply of a reallocation arrangement with [REDACTED].

*Exchange-traded contracts*

186. AGL does not need to develop a "good names" list or equivalent in order to trade exchange-traded contracts. This is because AGL does not bear the risk of a counterparty defaulting on an ETF trade. When AGL trades ETF products it has no knowledge of let alone control over the identity of the final counterparty to that trade, as AGL transacts through its clearer. In fact, AGL does not even find out the identity of the final counterparty to an ETF trade after the trade has been executed.

187. AGL currently trades ETFs on the ASX, but AGL and a number of other industry participants are also involved in the development of the LeClair platform, which is intended to be a platform for trading electricity derivatives, and will operate in competition with the existing ASX platform. It is intended that the LeClair platform will facilitate exchange-based trading of both carbon inclusive and carbon exclusive electricity derivatives (ie it will allow listing of exchange-traded carbon exclusive products which are similar to the carbon exclusive over the counter contracts traded by physical market participants).

188. [REDACTED]

- (a) [REDACTED]
- (b) [REDACTED]
- (c) [REDACTED]
- (d) [REDACTED]
- (e) [REDACTED];
- (f) [REDACTED]
- (g) [REDACTED]; and
- (h) [REDACTED]

189. [REDACTED]

190. [REDACTED]

**Availability of hedge contracts to independent retailers from sources other than AGL***Supply of contracts from generators which are not base load, coal fired power stations*

191. I am aware that independent retailers use a range of hedge contracting methods to hedge their exposure to the NEM pool price, aside from contracting with AGL or other owners of base load power stations.
192. For example, as I mentioned in paragraph 143 above, AGL has bought significant volumes of swaps from [REDACTED] (which owns only hydro, and not base load, generators) to hedge its NSW retail load. I am also aware that AGL has a long term contract with [REDACTED], which includes both a simple cap product and a complex cap product, one component of which is a "callable peak swap component". I am also aware that hedge contracts are currently being offered by owners of wind powered generation:
- (a) AGL has previously purchased wind-backed swap contracts from [REDACTED] – specifically, a standard fixed price swap contract for South Australia, for [REDACTED] for Q1 2012, and a flat contract for Victoria for [REDACTED] for FY 2013/14 (both acquired in 2011) – AGL uses these swap contracts in combination with either its own natural peaking capacity load, or with additional cap products; and
  - (b) [REDACTED] also sought to sell wind-backed contracts to AGL in June 2012 and December 2012 (Victoria), and April 2013 (South Australia).
193. Since AEMO estimates that significant volumes of wind generation capacity will be built in NSW by 2016, rising to 3,962MW by 2021,<sup>10</sup> in my view it is reasonable to expect that some of those wind powered generators may be prepared to offer swaps similar to those outlined above.

*Hedge contracts with financial intermediaries*

194. In my experience, standalone and new entrant retailers can also enter into hedge contract arrangements with financial intermediaries rather than physical market participants.
195. Prior to AGL acquiring APG in October 2013, AGL undertook a due diligence process, which was conducted by a member of my team and for which I was ultimately responsible and I am aware that:
- (a) APG had a range of electricity hedge contract arrangements in place, including with [REDACTED] and [REDACTED] and a number of those electricity hedges included reallocation arrangements; and
  - (b) [REDACTED] also provided APG finance and guarantee facilities.
196. I am also aware of other examples where retailers have acquired "reallocation" arrangements from financial intermediaries rather than physical market participants. For example, I am aware that:
- (a) [REDACTED] and [REDACTED] have, and APG had (before its acquisition by AGL) reallocation arrangements with [REDACTED] and
  - (b) AGL has a reallocation arrangement with [REDACTED]
197. I am aware that reallocation arrangements offered by intermediaries are often more competitively priced than reallocation arrangements offered by generators, due to the fact that intermediaries may have lower costs of funding, and may have sufficiently

<sup>10</sup> Source: AEMO 2013 NTNDP, a copy of which is contained in Annexure AF-16.



high short-term credit ratings that they are an acceptable credit risk to AEMO, and do not need to provide credit support.

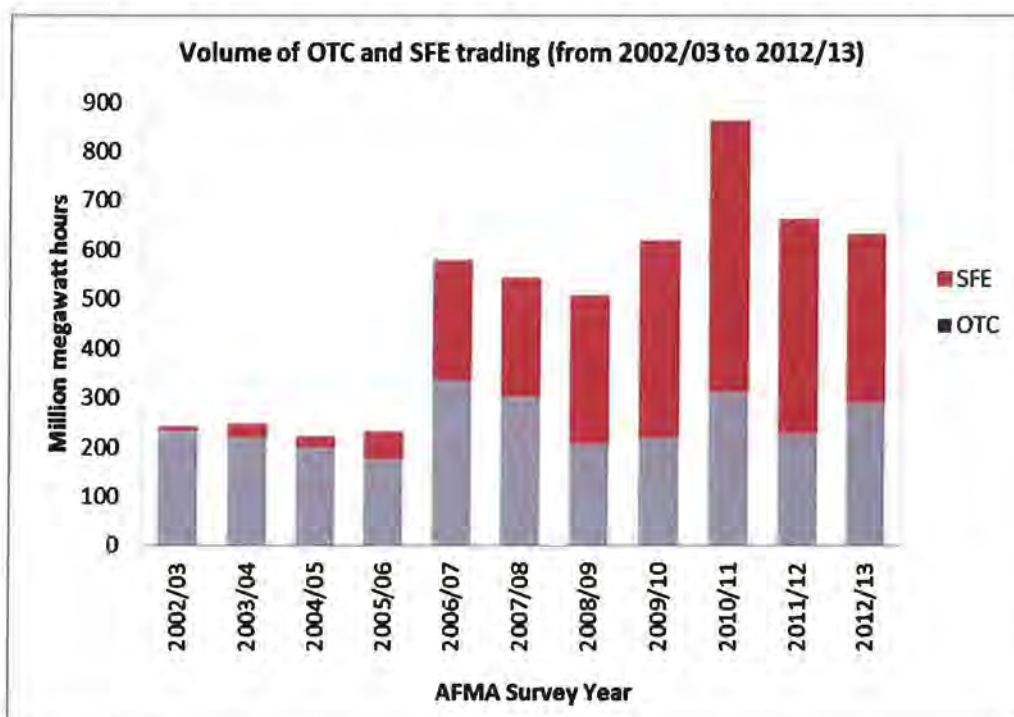
**Liquidity of supply of hedge contracts**

198. I do not agree with the proposition that there has been an overall reduction in the liquidity of trading of hedge contracts available to retailers.
199. There is publicly available data published by the ASX and AFMA regarding the volumes of OTC and ETF contracts traded from 2000 until 2011-2012. If there had been an overall reduction in the liquidity of trading of those products, then I would expect that:
- (a) the volume of trades had decreased over time (ie as vertical integration of NEM participants increased); and
  - (b) the reduction in the volume of trades:
    - (i) would be characterised by a reduction in volumes traded by physical market participants; and
    - (ii) would not be driven by factors independent of any such reduction by physical market participants.

*Has the volume of OTC and ETF trades decreased over time due to reduced trading by physical market participants?*

200. I am aware that the General Manager of EPM caused to be prepared the following graph setting out data published by AFMA regarding OTC trades, and by the ASX regarding trading in ETF contracts, for the period from 2008-2009 until 2012-2013.

**Figure 18 – Volume of OTC and ETF/SFE trading (until 2012/13)**



201. Analysis of this data reveals that in FY2012/13:
- (a) the volume of OTC trades increased by 28% and the volume of ETF trades decreased by 22% compared to FY2011/12;

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- (b) the volume of OTC trades increased in all regions compared to FY2011/12, with the exception of Victoria, where the volume of trades fell by just 0.4%; and
- (c) the volume of ETF trades decreased in all regions of the NEM compared to FY2011/12.

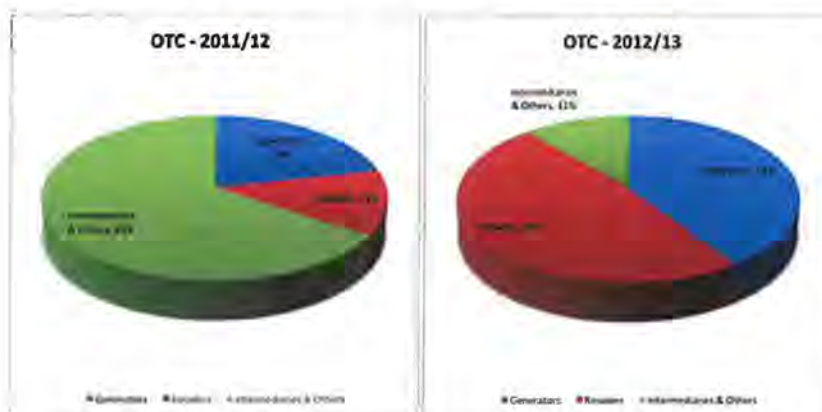
202. These results are consistent with my experience that:

- (a) there has not been a significant reduction in overall volumes of electricity derivatives traded – aside from a spike in volumes in 2010/11, volumes have been relatively stable since around 2006; and
- (b) in recent years there has been an overall decrease in trading of ETF contracts, but an overall increase in trading of OTC contracts.

203. Since Victoria was the one NEM region in which this data showed that OTC trades had decreased, I caused further information published by AFMA on OTC trades to be reviewed to identify whether this reduction was due to a reduction in trading by physical market participants – specifically, by those entities AFMA classes as "generators" and "retailers".<sup>11</sup> The results of this further task are reported in the following table and graphs:

**Figure 19 – Victorian OTC trading**

VIC OTC Annual Turnover (TWh)	2008-09	2009-10	2010-11	2011-12	2012-13
Generators & Retailers	23.8	31.5	23.4	18.0	46.4
Financial Intermediaries & Others	24.6	29.2	21.8	34.5	6.0
Total	48.5	60.7	45.2	52.6	52.4



204. This Victorian data is consistent with my experience and understanding that there has not been an overall reduction in the extent to which physical market participants (including vertically integrated market participants) participate in OTC trading. In particular, this data shows that:

- (a) during the period from FY08/09 until FY12/13, there was no consistent reduction in the extent to which physical market participants traded OTC products; rather, there has been significant volatility in volumes traded by these participants and by non-physical participants (such as financial intermediaries);
- (b) most recently, during the period from FY11/12 to FY12/13:

<sup>11</sup> The AFMA definition of a retailer is an entity "whose predominant business is selling electricity", and its definition of a generator is an entity "whose predominant business is producing electricity".

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- (i) physical market participants have increased the extent of their participation in total OTC trades, from 35% of total trades to 89% of total trades; and
- (ii) non-physical participants (intermediaries and others) have reduced their participation in OTC trades from 66% to 11%.

205. As I set out in paragraph 65 above, I am aware of a number of financial intermediaries that have exited from, or are no longer actively, trading in derivatives.

*Are the causes of any reduction in volumes traded independent of a reduction in trading by physical market participants?*

206. I am aware, and the above data illustrates, that there has not been a significant reduction in overall volumes of electricity derivatives traded, and that in recent years there has been an overall decrease in volumes of ETF contracts traded, but an overall increase in volumes of OTC contracts traded.

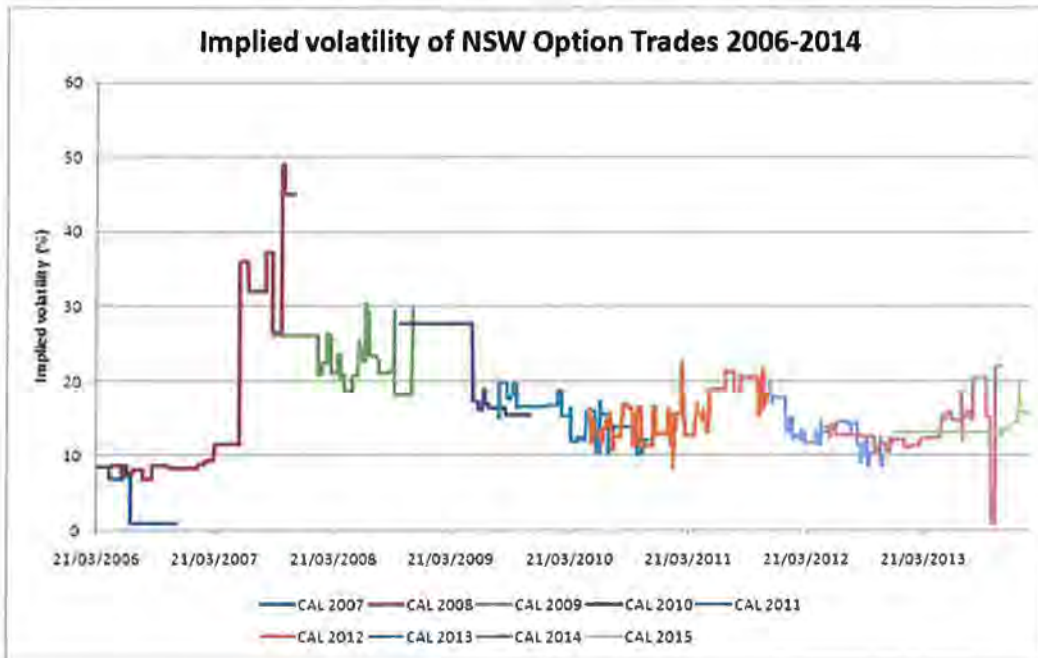
207. One of the key developments relevant to the volumes of ETF and OTC contracts traded is the fact that several financial intermediaries who previously traded Australian electricity derivatives have ceased these activities (ie ceased both OTC and ETF trading). I understand that the following intermediaries have each ceased trading Australian electricity derivatives: Deutsche Bank, BP Energy, Societe Generale, Goldman Sachs, JP Morgan, DE Shaw, Optiver, Noble and Duke (see paragraph 65 above).

208. In my view, one of the key developments which is likely to make trading of Australian electricity derivatives less attractive to financial intermediaries such as those listed above is the fact that there has been a significant reduction in volatility of NEM pool prices, and associated contract prices. Financial intermediaries trade as "speculative" investors (as distinct from physical market participants, who trade to hedge their physical exposure to the NEM pool price). As such, the level of volatility in contract prices is critical to intermediaries' ability to make money by trading electricity derivatives - reduced volatility reduces the opportunities to profit from derivatives trading.

209. I am aware that the General Manager of EPM caused to be prepared the following graph showing data on the implied volatility of "at the money" ETF options (which reflects the volatility of ETFs over time) published by D-Cypha.

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**Figure 20 – Volatility in NSW ETF prices**

210. Consistent with the information in this graph, I consider that there has been reduced volatility in contract prices for electricity derivatives in recent years.
211. These results are consistent with my experience that, aside from temporary "spikes" in contract price volatility associated with the potential introduction of carbon pricing legislation (July 2012) and with the potential repeal of carbon pricing legislation (which may occur during the period July – December 2014), volatility of NSW contract prices in recent years has been low relative to historical levels.
212. I consider that further reasons why these intermediaries have ceased trading electricity derivatives include that:
- (a) for several intermediaries, Australian electricity derivatives trading operation have been closed as part of rationalisation of the intermediary's international operations; and
  - (b) increased prudential requirements applied to these intermediaries under US financial regulations make it more difficult for them to obtain internal approval to trade Australian electricity derivatives.
213. I am not aware of any financial intermediary ceasing their trading of electricity derivatives for the reason that there has been, or that they expect, a material decrease in the liquidity of OTC derivatives.
214. In my experience, three of the further significant reasons why there has been a reduction specifically in the trading of ETF contracts are that:
- (a) AGL and other physical market participants who are currently liable to pay a legislated carbon price in relation to carbon dioxide omissions, and who face the risk that the current carbon pricing legislation will be repealed, often consider that OTC contracts provide a better means to manage carbon price liability than ETFs (this reflects the fact that standard form OTC contracts use a carbon "uplift" clause which is not used in ETF contracts);
  - (b) for some physical market participants, such as the Loy Yang A power station before AGL acquired a 100% interest in that station in 2012, the need to maintain significant working capital reserves in order to be able to pay an



upfront cash margin to the relevant clearinghouse at the time of entering into an ETF contract, and to meet margin calls as ETF settlement prices vary over time, can discourage physical market participants from trading ETF contracts, particularly given that there is no equivalent requirement in order to be able to trade OTC contracts; and

(c) the quantum of the fees charged by the ASX.

215. Based on my understanding of AGL's involvement in the development of the LeClair platform (which I describe in paragraph 187 above), I understand that AGL expects that the quantum of fees for transacting on that platform will be lower than those charged by the ASX, and that this is one of the reasons for AGL's involvement in establishing LeClair.

216. In summary, and as illustrated by the analysis presented above:

- (a) there has not been a significant reduction in overall liquidity in trading of electricity derivatives;
- (b) to the extent that liquidity in trading of electricity derivatives has decreased, this decrease has largely occurred in relation to trading in ETF rather than OTC contracts; and
- (c) to the best of my knowledge, the reduction in volumes of electricity contracts traded described above has occurred due to factors which are independent of the existence and extent of vertical integration in the NEM.

***Hedge contracts currently purchased by AGL would be available for others to purchase***

217. It is also my opinion that if the Macquarie Generation transaction were to proceed, then the generation capacity supporting the hedge contracts that AGL would otherwise purchase will be available to support hedge contracts with other market participants. As set out in paragraphs 125 to 128 above, AGL presently purchases a range of hedge contracts including:

- (a) hedge contracts referenced to the NSW RRP with generators located in NSW (in particular, with [REDACTED] and [REDACTED]);
- (b) hedge contracts referenced to the NSW RRP with generators located in other regions of the NEM (in particular Queensland generators); and
- (c) hedge contracts referenced to other regions of the NEM and/or physical generation located in other regions (in particular Victoria and Queensland), supplemented by IRSRs.

218. The proposed acquisition of Macquarie Generation would reduce the need for AGL to purchase these hedge contracts. If that occurred, it would be open to other market participants (including smaller retailers) to purchase those hedge contracts.

**AGL'S PROPOSED ACQUISITION OF MACQUARIE GENERATION**

219. As I stated in paragraph 11 above, I was responsible for reporting to the Board on the technical due diligence undertaken by AGL's Chief Operating Officer and his team regarding the assets of Macquarie Generation, and responding to the board's questions and requests for further analysis in relation to that report.

220. In this section I:

- (a) describe my role in the due diligence process;
- (b) describe the current state of Macquarie Generation's Bayswater and Liddell power stations;



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- (c) describe Macquarie Generation's current hedge contract portfolio;
- (d) consider the impact of incorporating those assets into AGL's business; and
- (e) respond to questions regarding statements in the ACCC's SOI regarding AGL's conduct if it acquires the Macquarie Generation assets.

**My role in the due diligence process**

221. My key responsibilities in relation to the due diligence process undertaken by AGL regarding its proposed acquisition of the Macquarie Generation assets were:
- (a) I presented the initial report of the technical due diligence team to the Board on 17 January 2014 - a copy of the written materials I presented is attached at Annexure AF-17; and
  - (b) I was responsible for commissioning and reporting back to the Board on questions raised by Board members on 17 January 2014 - a copy of the written materials I presented to the Board in response to those questions, on 22 January 2014, is contained in Annexure AF-18.
222. A copy of the due diligence presentation given to the Board in January 2014 is contained in Annexure AF-19.

**Macquarie Generation's Bayswater and Liddell power stations**

223. Through my involvement in the due diligence process for AGL's acquisition of the Macquarie Generation assets, I am familiar with the Information Memorandum issued by the State of NSW in relation to the sale of those assets (**Information Memorandum**), a copy of which is contained in Annexure AF-20.
224. I have caused to be produced the overview of Macquarie Generation which is contained in Annexure AF-21, which is based on that Information Memorandum, and on information contained in Macquarie Generation's annual report for 2013, a copy of which is attached in Annexure AF-22.

*Historical reliability of the Bayswater and Liddell power stations*

225. [REDACTED]
- (a) [REDACTED]
  - (b) [REDACTED]
  - (c) [REDACTED]

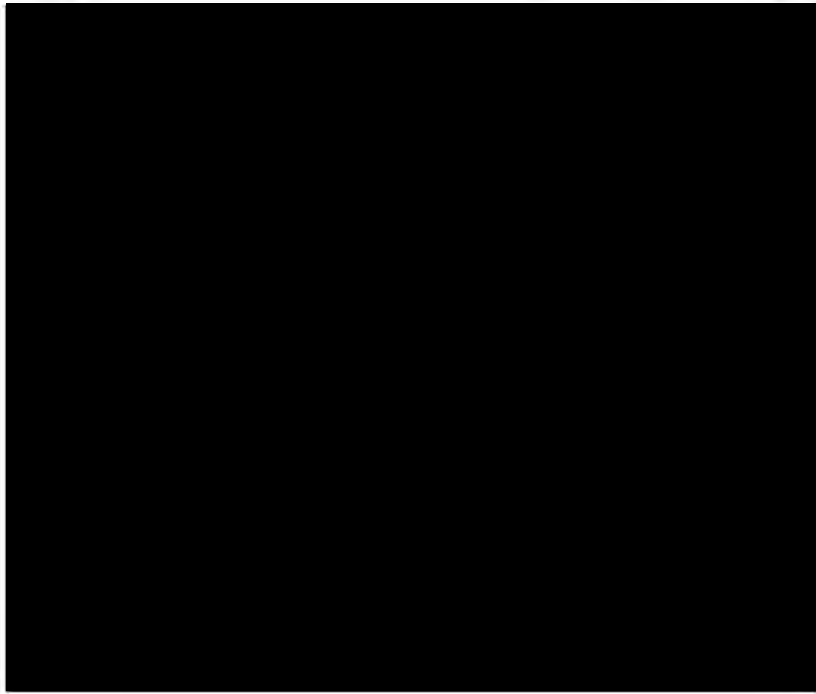
<sup>12</sup> Source: Information Memorandum, pages 27 and 36-37.



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Figure 21 - [REDACTED]



226. [REDACTED]

Figure 22 - [REDACTED]



227. [REDACTED]

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[REDACTED] and

- (e) AGL's technical due diligence team reported that AGL would need to incur incremental expenditure on the Bayswater and Liddell power stations of \$345 million above Macquarie Generation's own forecast level of expenditure in order for those power stations to perform to a standard and in a manner acceptable to AGL.

*Macquarie Generation's hedge contract portfolio*

231. [REDACTED]

(a) [REDACTED]

(b) [REDACTED]

232. [REDACTED]

233. [REDACTED]

234. I make this observation based on my experience relating to AGL's Loy Yang A power station. AGL has similar incentives in relation to dispatching generation from that power station. AGL owns the Loy Yang A coal mine which is the fuel source for the Loy Yang A power station. As a result, the Loy Yang A power station has a low fuel cost and a low short run marginal cost of generation. This creates incentives for AGL to operate the Loy Yang A power station with a high capacity factor.

***Incorporating the Macquarie Generation assets into AGL's portfolio***

*The impact of incorporating the Bayswater and Liddell power stations (including the Tomago Hedge Contracts) into AGL's generation portfolio*

235. Based on my own knowledge of and involvement in the Macquarie Generation due diligence process and my experience of AGL managing its risk management portfolio in accordance with the WERMP, I believe that:

(a) AGL intends to operate the Bayswater power station until the end of its economic life in 2035 with an availability factor equivalent to between [REDACTED], and to hedge [REDACTED] of its available capacity;

(b) AGL intends to operate the Liddell power station until 2017, and to maintain options to continue to operate it until the end of its economic life in 2022 [REDACTED] and to hedge up to [REDACTED] of its capacity during periods of high demand and/or price; and

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- (c) AGL will make an incremental investment of \$345 million, comprising \$304 million in Bayswater power station and \$41 million in Liddell power station, to facilitate these operations.

236. As set out in the Due Diligence Presentation given to the Board in January 2014 and the Project Hunter Technical Due Diligence Information Paper given to the Board on 17 January 2014:

- (a) AGL intends to operate the Bayswater power station until the end of its economic life in 2035 with an availability factor equivalent to between [REDACTED] and [REDACTED]. Based on Bayswater power station's target availability factor, AGL intends to hedge [REDACTED] of its capacity. AGL intends to manage the low cost, high ash coal that will be used at the Bayswater power station through incremental investment of \$304 million in accordance with AGL's asset management systems.
- (b) AGL intends to operate the Liddell power station until 2017, maintaining options to operate it until 2022 (the end of its economic life) if Tomago remains open [REDACTED]. Given that the Liddell power station is nearing the end of its economic life, expenses would be minimised and lower levels of capacity and reliability accepted resulting in its available capacity only being up to [REDACTED] hedged. AGL intends to make incremental investments of \$41 million in process safety and asset management improvements to avoid significant outages at the Liddell power station. However, AGL may also at some point in the future retire the worst performing generation unit at the Liddell power station in order to harvest assets to ensure that the remaining generation units continue to be available.

237. In the following paragraphs I discuss the consequences for AGL's management of its generation portfolio, and its contracting practices, of owning the Macquarie Generation assets.

*Benefits to AGL from acquiring the Macquarie Generation assets*

238. Based on my own knowledge of and involvement in the Macquarie Generation due diligence process, I understand that AGL expects that the acquisition will:

- (a) exceed AGL's internal rate of return;
- (b) provide AGL with an internal hedge for its NSW retail load;
- (c) provide a cost advantage to AGL's generation portfolio, based on the low cost of fuel for, and low short run costs of, the Bayswater and Liddell power stations;
- (d) improve AGL's ability to manage its load across all region of the NEM; and
- (e) lower AGL's cost of funding, assist AGL to grow its balance sheet and improve AGL's near term earnings.

239. I provide further explanation of some aspects of these benefits which are relevant to the management of AGL's portfolio below.

*AGL will have an internal hedge for AGL's NSW retail load*

240. If AGL owns the Macquarie Generation assets, then AGL will be able to use the generation from those power stations as one part of its management of the risk associated with its NSW retail customer load.

241. I expect that this will produce benefits to AGL for the following reasons.

- (a) OTC contracts and ETFs trade at a price which reflects a premium to market expectations about the NEM pool price in the relevant contract period.






- (b) Accordingly, when AGL purchases OTC contracts and ETFs to hedge its NSW load (such as the OTC contracts and ETFs depicted in paragraph 138 above), it pays a price premium in order to obtain the reduced price risk it achieves by entering into such contracts.
  - (c) By reducing the number of OTC contracts and ETFs AGL purchases to hedge its NSW retail load, AGL will reduce the extent to which it pays this premium to third parties.
242. In my view, there are financial efficiencies in vertical integration as compared to contracting with third parties. However, I note that AGL's financial modelling of the AGL's proposed acquisition of Macquarie Generation did not seek to quantify the value of those efficiencies in this case.
243. As I noted above, AGL will be a "net" generator if it acquires the Macquarie Generation assets. I expect that, in order to both earn the premiums associated with hedge contracts relative to the pool price and to comply with AGL's WERMP and associated risk management policies, AGL will sell OTC and ETF contracts to retailers and trade ETFs, and seek to sign up additional retail electricity customers, among other measures, to manage the exposure AGL's exposure to the NEM pool price from this net length.
244. In my opinion, based on my knowledge of the matters referred to in paragraph 230, if AGL acquires the Bayswater and Liddell power station, and spends the incremental \$345 million I referred to above, then all else being equal, the effect of the operations that I described in paragraph 235 is that:
- (a) AGL will be able to operate those power stations to a higher standard of reliability than will be possible on Macquarie Generation's proposed investment case; and
  - (b) AGL will be able to use generation from those power stations to provide hedge coverage for a greater volume of retail load (including both "natural" hedge coverage for AGL's retail load and coverage under OTC and ETF contracts) than if those power stations continued to be owned and operated by the State of NSW.

*Portfolio benefit*

245. The acquisition of an additional eight units of thermal generation totalling 4600MW will significantly improve AGL's ability to manage its load across all states in the NEM, including its obligation to supply ActewAGL in the ACT (which is part of the NSW region in the NEM). Factors such as temperature, planned and unplanned outages and variations in wind and solar generation output influence supply and demand and control of Bayswater and Liddell will enhance AGL's risk management capability.

***Other conclusions from the technical due diligence***

246. I make the following observations about certain other features of AGL's technical due diligence on the acquisition of the Macquarie Generation assets.

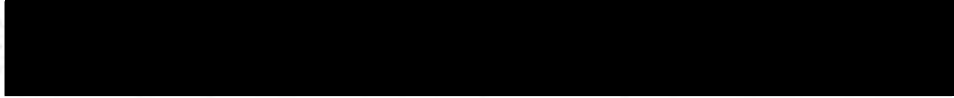
*AGL's plans regarding employment of staff currently employed by Macquarie Generation*


247. The model that AGL adopted to value the acquisition of the Macquarie Generation assets, and which AGL used to determine the amount it would bid for those assets, made certain assumptions about the numbers of staff required to operate the assets.
248. These assumptions are described on slide 22 of the document contained in Annexure AF-18. These assumptions are that, if AGL acquires the Macquarie Generation assets:
- (a) there will be no reduction in the number of staff Macquarie Generation employs in operation, maintenance or engineering roles in connection with the Macquarie Generation assets; and



AF

(b)



249. I am also aware from my involvement in the due diligence process that the term of sale of the Macquarie Generation assets significantly limit the potential for redundancies of Macquarie Generation staff following the proposed acquisition by AGL, as set out in clause 15 of the Asset Sale and Purchase Agreement.
250. I am aware from my involvement in the technical due diligence process and my attendance at meetings of the AGL Board that AGL expects that following the proposed acquisition of Macquarie Generation, AGL will:
- (a) invest approximately \$345 million in the maintenance of, and capital expenditure on, the Bayswater and Liddell power stations over the projected life of those assets, in addition to the planned levels of future investment in Bayswater and Liddell of current Macquarie Generation management;
  - (b) apply  AGL's technical capability and expertise to the maintenance and operation of the Bayswater and Liddell power stations; and
  - (c) capture annual cost savings in labour costs, and improve Macquarie Generation staff engagement to create value.
251. I consider that this is likely to have the following impacts:
- (a) increase levels of likely availability to generate electricity for supply into the NEM of each of the Bayswater and Liddell power stations, which will increase reliability of electricity supply for NSW;
  - (b) as a consequence of (a), and also because AGL has a broader portfolio of assets than Macquarie Generation, AGL will be able to hedge Macquarie Generation to a greater extent and so increase the volume of NSW hedge contracts that AGL would sell;
  - (c) reduce overall cost in maintaining the efficient operation of each of the Bayswater and Liddell power stations, over its remaining operational life (to 2035 in the case of Bayswater and to 2022 in the case of Liddell);
  - (d) increase potential for the Bayswater power station to operate effectively beyond 2035.

**AGL's bidding and dispatch following the acquisition of the Macquarie generation assets**

252. I am aware that the ACCC's SOI contains the following passage.
77. *Market participants have raised concerns that because AGL has a large portfolio of generation assets across the NEM, including the largest share of generation in Victoria and South Australia, a withdrawal of electricity supply that causes an increase in wholesale spot prices may be a more profitable strategy for AGL compared to other potential acquirers of Macquarie Generation with less generation assets in the NEM. This is because the benefits of the higher prices caused by a withdrawal of supply would be spread across a larger generation portfolio.*
78. *In addition, the ACCC is considering whether AGL would have an incentive (compared to a different purchaser or the status quo) to operate the Liddell*

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*power station less often, mothball generation units<sup>13</sup>, or otherwise prematurely retire the Liddell power station altogether in order to withhold supply. Such a strategy would reduce any excess generation capacity of AGL in NSW and may result in a tightening of the supply and demand balance in NSW with flow on impacts which benefit AGL's positions in Victoria and South Australia.*

253. I have been asked to consider these paragraphs, and comment on whether I would expect that AGL would seek to engage in withdrawal of electricity supply in the NEM, for the purpose of causing an increase in NEM pool prices, following its acquisition of the Macquarie Generation assets.
254. In order to implement and benefit from a withdrawal strategy such as that outlined above, AGL would need to do two things:
- (a) to withdraw or retire capacity (eg from the Liddell power station or elsewhere in its portfolio); and
  - (b) to maintain a "net" generation position (ie which was not required to back AGL's retail load and in relation to which AGL had not sold hedge contracts), in order to take advantage of increased NEM prices achieved by the strategy.
255. In summary, I think that AGL would be unlikely to engage in such a strategy following the acquisition for the Macquarie Generation assets, for the reasons I describe below.

*AGL's incentives not to retire generation capacity*

256. I am aware that, if AGL's proposed acquisition of Macquarie Generation proceeds, AGL will acquire the Tomago Hedge Contracts (representing approximately 900 MWs). I am also aware that AGL already has a substantial retail load in NSW, representing almost 2500MW at its forecast of maximum demand (based on current customer numbers and composition). The need to meet the obligations under those contracts [REDACTED], will give AGL strong incentives not to withdraw capacity from the NEM.
257. Further, if AGL did withdraw Liddell or other generation capacity, it would face significant financial risk if it experienced significant outages in its generation plant during high demand periods in which capacity had been withdrawn – ie, AGL would assume the risk of being a net purchaser, rather than a net generator, of electricity in those periods. AGL's experience in January 2014, which I describe below, illustrates how plant outages can change AGL from being a net generator to being a net purchaser of electricity, and so expose AGL to significant financial losses, during high demand periods.

***AGL's incentives not to maintain a "net generation" position following the proposed acquisition of Macquarie Generation***

258. As I described in paragraph 157 above, I expect that AGL will sell OTC contracts and ETFs, and to acquire additional retail electricity customers, in order to manage the exposure to the NEM pool price which it would otherwise face from being "long" to the pool price. In doing so, AGL will take advantage of opportunities to trade OTC contracts and ETFs at a premium to forecast future pool prices.
259. I do not expect that AGL would maintain a significant net position of length to the NEM pool (ie net having regard to AGL's portfolio of physical and contract positions), because in order to do so:

<sup>13</sup> By way of example, Energy Australia has announced that it will be retiring capacity at its recently acquired Wallerawang power station in NSW. The ACCC understands that EnergyAustralia will be removing Unit 7 and Unit 8 will shortly be placed on a three month recall should market conditions change.

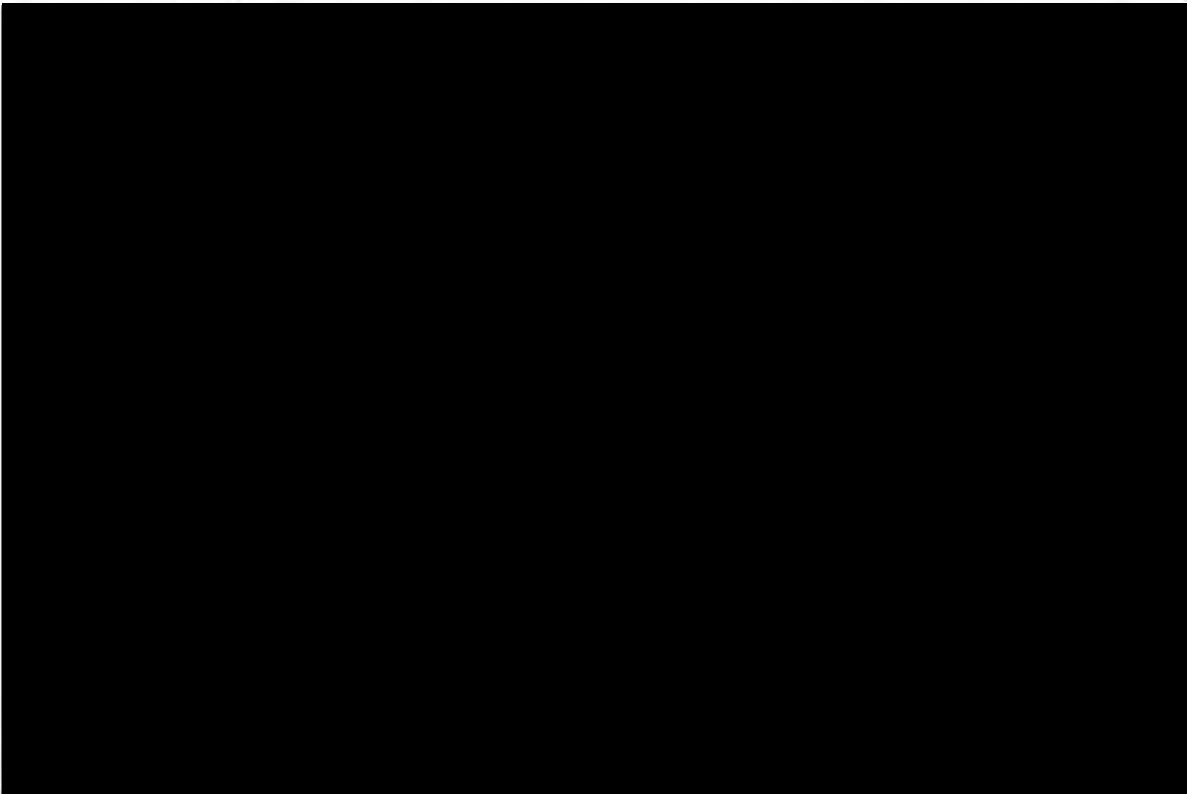



- (a) AGL would need to maintain exposure to NEM pool prices to an extent that I expect may not comply with AGL's WERMP and associated risk management policies;
- (b) AGL would need to forego profitable opportunities to sell forward contracts at a premium to estimated future electricity prices; and
- (c) AGL would need to assume significant financial exposure associated with being a net generator (ie seller) of electricity in a period of prevailing low NEM pool prices.

260. AGL's internal analysis shows that AGL will be a net generator in NSW by between approximately 800MW and 1,000MW until 2018<sup>14</sup> - that is, that AGL's generation output in NSW is likely to exceed the electricity consumption by AGL's NSW retail customers.

261. In February 2014 the General Manager of EPM directed members of his team to extract data regarding AGL's wholesale portfolio in New South Wales and combine it with information obtained during the due diligence process in relation to Macquarie Generation's wholesale portfolio in order to construct a combined portfolio of what AGL's net position would be post Transaction.

In addition the EPM team were directed include in the combined position the 500 MWs that was the subject of the undertaking AGL offered to the ACCC as part of the process of seeking clearance for the Transaction. The following graph sets out the results of that analysis.



262. I have made inquiries of the General Manager of EPM and I have been informed and believe that the key assumptions upon which this analysis is based are:

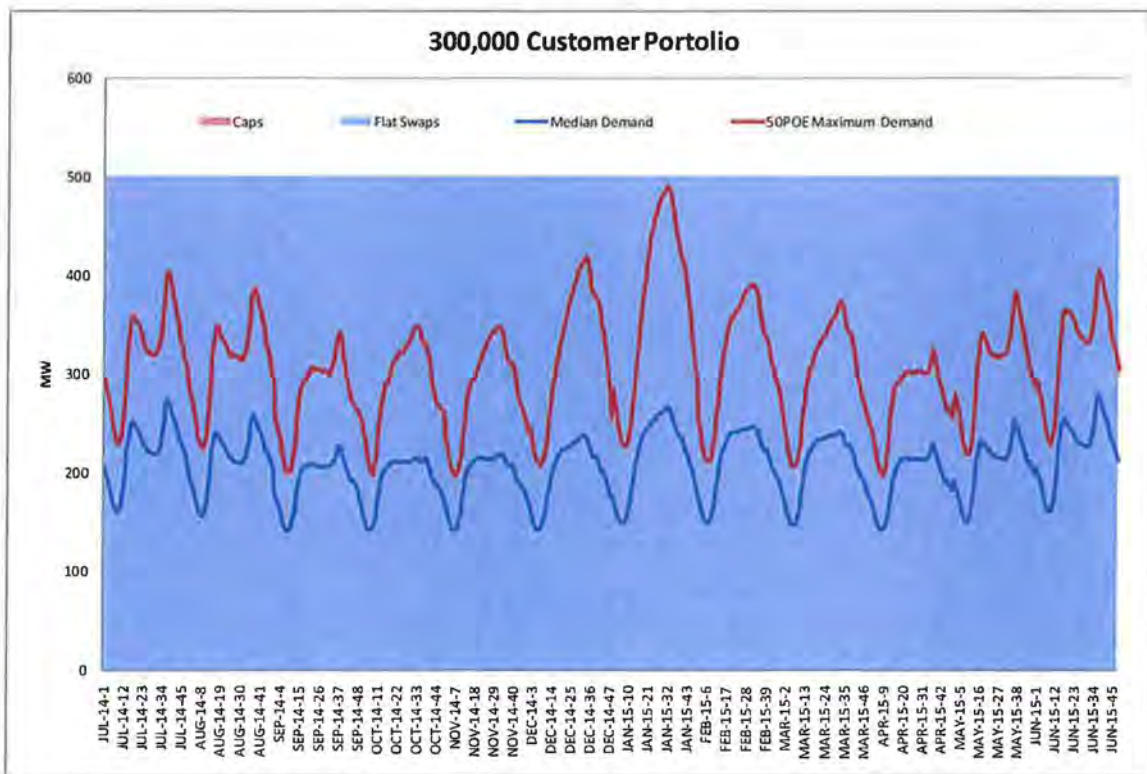
<sup>14</sup> I note that, for the purposes of analysing the proposed acquisition of Macquarie Generation, AGL has assumed an 85% availability factor for Bayswater and a 65% availability factor for Liddell. However, I consider that this estimate is likely to overstate the extent to which AGL is long generation [REDACTED]



- (a) 50% probability of exceedence in respect of the level of maximum demand;
- (b) no loss of commercial and industrial customers;
- (c) 85% and 65% availability for Bayswater and Liddell respectively; and
- (d) adjustments for in house use and transmission losses to the reference node.

263. I understand that AGL is making this application to the Australian Competition Tribunal on the basis that it proposes conditions be imposed on any authorisation in relation to AGL making available 500MWs in hedge contracts to small retailers for a period of 7 years. While I consider that for the reasons set out in the preceding paragraph that AGL will trade its net position of length to the NEM pool I understand that the proposed conditions may address any concerns about AGL's future conduct.
264. I consider that the trading of 500MWs of hedge capacity is a significant volume, and that a retailer could supply a significant number of average residential customers with the benefit of hedges in that order.
265. The following graph shows a typical forecast demand profile comprising 300,000 residential customers in NSW with a load factor of 42% and an annual consumption of 6MWh per annum against 500MW of flat swap contracts.

**Figure 24 – typical forecast demand of 300,000 residential customers in NSW against 500MW flat swaps**



266. I consider that this graph demonstrates that 500MW of capacity is sufficient to hedge the demand associated with 300,000 average residential customers. In fact, the graph shows that for the majority of the time 500MW would exceed that level of demand.

*The conditions in which AGL might be able to influence the NEM price are rare and difficult to predict*

267. The statements in the SOI quoted above appear to assume that if AGL retired the Liddell power station or other generation capacity, this would achieve such a tightening

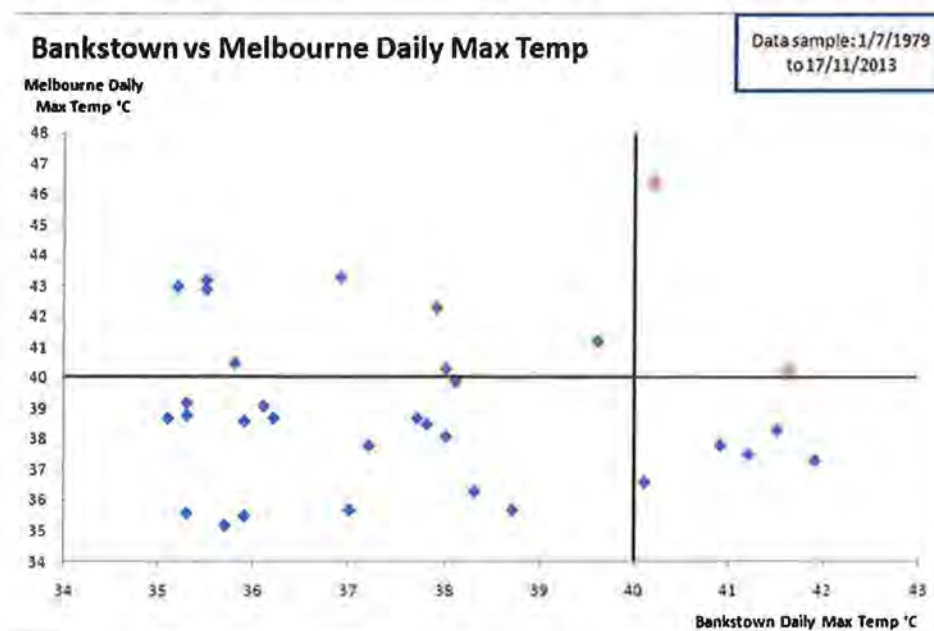
of the supply and demand balance that AGL would have the ability to influence NEM pool prices.

268. I have read, agree with, and adopt the description in section 7.1 of the Frontier General Industry Report about that in prevailing conditions of oversupply in the NEM, and agree with the analysis showing that there is sufficient generation capacity in the NEM that in the majority of trading intervals, such that demand can be met without the combined output of AGL and Macquarie Generation.
269. Accordingly, I would expect that if AGL attempted to withdraw capacity in order to increase prices (as contemplated by the SOI), this would generally not result in a tightening of demand and supply conditions in the NEM such as would increase NEM prices. This is because, since AGL/Macquarie Generation's output is not essential to meet demand in the NEM, I expect that AGL's bids to dispatch that electricity which it did not withdraw could well be displaced in the NEM merit order by other generators, without necessarily affecting NEM prices. I would also expect that if there was a temporary increase in NEM prices as a result of any such withholding strategy by AGL, owners of "mothballed" generation capacity (such as that I described from paragraph 67 above) would rationally respond by returning some or all of that generation to the NEM.
270. Nonetheless, I would expect that a combined AGL/Macquarie Generation might be able to influence prices in the NEM in the manner contemplated by the SOI in conditions where:
- (a) there was extremely high demand for electricity in the adjacent South Australian, Victorian and NSW regions of the NEM; and
  - (b) the flow of electricity over the interconnects into those NEM regions was constrained.
271. In my experience, these conditions may occur during periods in which extremely high temperatures during work day peak periods occur at the same time in adjacent NEM regions.
272. I am aware from my experience that the occurrence of coincident high temperatures in adjacent NEM region is rare, and extremely difficult to predict.
273. The graph below shows the coincidence of temperatures exceeding 34°C in the major demand centres of Victoria and NSW, being Melbourne and Sydney (Bankstown) over the last 34 years, based on data published by the Bureau of Meteorology.






**Figure 25 – Coincident temperature analysis for Victoria and NSW over last 34 years**



274. As this graph shows, in the last 34 years there have been:
- only 14** occasions on which very high temperatures ( $>37^{\circ}\text{C}$ ) have been recorded in both Melbourne and Sydney (ie an average of less than one occasion every 2.5 years); and
  - only two** occasions on which extreme temperatures ( $>40^{\circ}\text{C}$ ) have been recorded in both Melbourne and Sydney (ie an average of one occasion every 17 years).
275. I am also aware that the results of my teams analysis shows that there has been only one occasion in the last 34 years on which extreme temperatures ( $>40^{\circ}\text{C}$ ) have been recorded in Melbourne, Sydney and Adelaide (Kent Town).
276. I have caused to be prepared the tables below showing the average daily pool price over the last five years where that price has exceeded \$300/MWh and the corresponding maximum daily temperature at the relevant measurement point for that region (Melbourne for Victoria and Bankstown for NSW).

**Figure 26 – Melbourne temperature on days with Victorian average daily pool price over \$300/MWh**

Date	Temp (C°)	Average Daily Pool Price
29/01/2009	44.3	\$ 2,376.45
22/04/2010	30.1	\$ 1,276.84
11/01/2010	43.6	\$ 1,152.99
29/11/2012	39.6	\$ 722.57
15/01/2014	41.7	\$ 498.42
31/01/2011	32.5	\$ 494.70

17/03/2008	38.4	\$	475.77
9/02/2010	32.1	\$	470.74
28/01/2009	43.4	\$	404.09
8/02/2010	35.3	\$	365.15
1/02/2011	40.2	\$	323.67
<b>Average</b>	<b>38.3</b>		

**Figure 27 – Sydney (Bankstown) temperature on days with NSW average daily pool price over \$300/MWh**

Date	Temp (C°)	Average Daily Pool Price
31/10/2008	35.8	\$ 1,394.20
1/02/2011	41.6	\$ 1,281.93
2/02/2011	34.2	\$ 1,207.56
7/12/2009	36.2	\$ 1,185.51
20/11/2009	41.5	\$ 1,135.54
17/12/2009	41.2	\$ 824.05
27/11/2009	33.6	\$ 545.28
22/01/2010	41.2	\$ 537.42
31/01/2011	39.5	\$ 364.83
19/11/2009	31.4	\$ 363.19
12/02/2010	37.1	\$ 318.81
20/12/2013	40.1	\$ 303.10
4/02/2010	27.8	\$ 300.93
<b>Average</b>	<b>37.0</b>	

277. The information in these tables shows that the average maximum temperature for each of these days where the average daily pool price exceeded \$300/MWh is 38.3C° for Melbourne, and 37.0C° Bankstown.
278. The fact that there are coincident high temperatures in adjacent NEM regions may but will not necessarily produce conditions with the two features I described in paragraph 270 above.
279. I have read and agree with section 7.1 of the Frontier Report, and in particular the conclusions in section 7.1.5 that the increase in renewable generation capacity means that there is considerable uncertainty regarding the availability of wind both at any






given time (including at times of peak demand) and in terms of correlation across regions of the NEM, and accordingly considerable uncertainty regarding residual demand to be met with non-wind generation.

280. I would expect that, as a result of these factors, a generator seeking to engage in economic withholding would assess that there was very significant risk and uncertainty involved in pursuing that strategy, including because:
- (a) the occurrence of coincident very high temperatures in adjacent NEM regions, such as would give rise to extremely high demand for electricity in the NEM, is rare and difficult to predict; and
  - (b) even in periods of extremely high demand, an economic withholding strategy could be undermined if those periods of high demand coincided with periods in which substantial volumes of wind generation was available for dispatch at low or zero prices; and
  - (c) the occurrence of wind, and hence the likelihood of substantial volumes of wind generation being available for dispatch, is extremely difficult to predict.
281. I would not expect a prudent generator to engage in such a strategy unless that generator had a very high appetite for risk, and was able to sustain extensive commercial losses in the event that they were not able to implement the strategy as planned. This is because economic withholding involves placing potentially large volumes of capacity in high price bids, and if the strategy is unsuccessful the generator earns no revenues in respect of that volume.

#### *Conclusion*

282. In summary, I think it is unlikely that AGL would seek to withhold generation capacity in order to seek to achieve higher NEM pool prices in the manner described in the SOI, for the following reasons:
- (a) AGL has strong incentives not to retire generation plant, in order to be able to meet its contractual obligations, including under the Tomago Hedge Contracts;
  - (b) AGL also has strong incentives not to maintain a net generation position, since this would involve maintaining its financial exposure to prevailing low pool prices in circumstances where AGL could instead sell contracts against its generation portfolio at a premium to estimated future pool prices;
  - (c) the occurrence of demand and supply conditions which are so tight that a combined AGL/Macquarie Generation may be able to influence NEM pool prices rarely occur, are very difficult to predict in advance, and even when they do occur can be readily altered by the presence of wind powered generation; and
  - (d) accordingly, I expect that the "benefit" to AGL of seeking to achieve increased NEM pool prices in those rare and uncertain periods when AGL has an ability to influence such prices would not justify the cost and risk to AGL of pursuing such a strategy.

#### **A RECENT EXAMPLE OF AGL'S MANAGEMENT OF ITS PORTFOLIO DURING EXTREME WEATHER EVENTS**

283. In this affidavit I have described:
- (a) the risks AGL faces, as both a generator and a retailer of electricity, from its exposure to the NEM pool price;
  - (b) the complex nature of AGL's decision making about risk management for its portfolio; and
  - (c) AGL's ongoing readjustment of its portfolio position.






284. In the following paragraphs I describe my recent experience of AGL's portfolio management during the week commencing 13 January 2014, to provide a practical illustration of some of these matters.
285. During the week beginning 13 January 2014, both South Australia and Victoria experienced consecutive days of extremely hot weather: Victoria experienced 4 consecutive days where the temperature reached above 40°C, and South Australia experienced 5 consecutive days where the temperature reached around 42°C.
286. At the beginning of that week, AGL considered its ability to use its generation portfolio and contract positions to maintain adequate hedge coverage for its retail load during the period in which high prices were expected to accompany the forecast high temperatures. In my view, AGL was adequately covered provided that its generation assets were running and could provide "a natural hedge" for AGL's retail load during this period.
287. On Tuesday 14 January, I formed the view that the combination of AGL's generation portfolio and contract position meant AGL would be "long" to the NEM pool price provided that all of its generating units were available. This meant that AGL would be "long" to expected "price spikes" (ie periods when the NEM pool price exceeded \$1,000/MWh). However, in practice:
288. In South Australia there were 4 five minute price spikes; AGL was "square" to 2 of those price spikes (ie neither long nor short); AGL was "long" by approximately 100MW to the third price spike and by approximately 200MW to the fourth price spike. In Victoria there were only 2 five minute price spikes; AGL was long by approximately 100MW to the first spike, and "square" to the second spike.
289. At around 2:00pm AGL's Loy Yang A unit 3 (representing 560MW of AGL's available generating capacity) experienced a fault and tripped out of service. It was temporarily restored to service at around 5:00pm but failed again at around 7:30pm and remained out of service until Thursday morning. At around 8:00pm TIPS unit 3 (representing 200MW of AGL's available generating capacity) tripped, and as a result was out of service from Tuesday evening until Thursday afternoon.
290. I expected that these units would remain out of service on Wednesday 15 January 2014, and that AGL would therefore be short to the high NEM pool prices expected on Wednesday (ie AGL would have to buy electricity at those high prices in order to service its retail load). Accordingly, on Tuesday afternoon, AGL purchased 129MW of exchange-traded contracts for Q1 2014 (caps and swaps) at a cost to AGL of around ██████████ to assist AGL to cover this "short" position.
291. On Wednesday 15 January 2014, AEMO's pre dispatch data forecasted around 6 hours of prices above \$12,000 (from 1:00pm until 7:00pm). AGL forecasted that it would lose ██████████ to ██████████ as a result of being "short" during that period.
- (a) In South Australia there were 10 price spikes during the day; AGL was "square" to each price spike, but was otherwise short approximately 200MW to high underlying prices (ie prices greater than \$300/MWh) during the day.
- (b) In Victoria there were 10 price spikes; AGL was around 150MW short to all price spikes and was approximately 150MW short to high underlying prices during the day. In order to assist it to manage its short position in Victoria, AGL contacted three of its commercial and industrial customers with whom it has load containment agreements, and reached agreement with two of those customers to reduce their electricity usage during that day. This assisted AGL to manage its position, but did not stop AGL from being short as described above.
292. On Thursday 16 January 2014, the Loy Yang A unit 3 and TIPS unit 3 returned to service. In South Australia there were 3 price spikes and AGL was square to each, but 200MW short to underlying high prices during the day. In Victoria there were 3 price spikes and AGL was square to each, but short to high underlying prices during the day.



