# VPA - Proposed price path for NSW regulated gas prices from 1 July 2014 to 30 June 2016 – public submission

Date: 11 February 2014

# Table of Contents

# Executive Summary

## Introduction

In June 2013, AGL Retail Energy Limited (***AGL***) and IPART agreed to Voluntary Pricing Arrangements (***VPA***) for the supply of natural gas to small customers from 1 July 2013 to 30 June 2016. The VPA set out the changes in the Retail and Carbon Components for 2013/14 only.

This pricing proposal has been prepared in accordance with the process outlined in the VPA to set the Retail and Carbon Components for remaining two years of the VPA, namely, 2014/15 and 2015/16.

## Wholesale gas market developments

The transformation of the Australian east coast gas market due to the development of large reserves of coal seam gas for export via LNG trains at Gladstone in Queensland has been well reported over the past year. Gas supply to NSW is currently sourced predominantly from the Cooper Basin (Moomba, Queensland) and the Gippsland Basin (Longford, Victoria).

Gas prices in Queensland are already reflecting the transition to export parity or LNG netback pricing. Supplies from Moomba are similarly reflecting export parity pricing.

Limited sources of new gas supply to the NSW domestic market has increased reliance on Gippsland Basin gas to supply NSW market demand. However, there is currently limited pipeline capacity on the Eastern Gas Pipeline from Longford, keeping Longford prices below export parity pricing during the VPA Period.

## Retail market developments

The churn in the NSW gas market has trended down in recent months to a rate of about 10%. Given that the NSW gas market is a separate market as distinct to a dual fuel market and the slowing churn rate, AGL considers that it is appropriate to adopt a similar approach to customer acquisition costs as in the 2013 NSW electricity review.

Given the AEMC recommendation on the removal of price regulation, regulated prices should be set at a level which will allow a successful transition to a market where prices are determined by competing retailers without a regulated price cap.

## Proposed Retail Component

The Retail Component comprises of the wholesale gas costs, retail operating costs and retail margin. Wholesale gas costs are referenced to a market benchmark assessed by AGL's consultants, The Brattle Group and MDQ Consulting, while retail costs and margin allowance are referenced to IPART's benchmarks in the 2013 electricity and gas reviews.

The benchmark proposed for retail costs includes direct and indirect acquisition costs, consistent with the 2013 NSW electricity price review.

Retail margin in the 2013-16 review was assessed to be 6.3% to 7.3% by IPART's consultant, Strategic Finance Group (***SFG***). AGL's proposal is based on a retail margin of 7%.

AGL's proposed Retail Component includes a transitional path for wholesale gas costs and customer acquisition costs.

| $/GJ in 2013/14$ | 2013/14 | 2014/15 | 2015/16 |
|---|---|---|---|
| **Wholesale gas costs** | | 10.94 | 11.95 |
| **Retail costs** | | | |
| **ROC** | | 3.69 | 3.69 |
| **CARC** | | 1.57 | 3.15 |
| **Retail margin** | | 2.28 | 2.39 |
| **Retail Component (R)** | 14.43 | 18.52 | 21.18 |
| **Change in R (real)** | | +28.3% | +14.4% |

## Proposed Carbon Component

In this pricing proposal, AGL assumes that the carbon pricing mechanism (***CPM***) will be removed as intended by the Federal Government from 1 July 2014. The Carbon Component for 2013/14 is $1.72/GJ. If the CPM is removed as intended by the Federal Government from 1 July 2014, the Carbon Component for 2014/15 and beyond will be set to zero.

In Annexure A, AGL has outlined the impact on the Carbon Component and retail price changes if the removal of the CPM is delayed by one year to 1 July 2015.

## Proposed retail price path

Assuming the removal of CPM from 1 July 2014, CPI of 2.7% and an increase in network charges of 11.1%, the average regulated retail price will increase as follows:

| Nominal (CPI = 2.7%) | 2014/15 | 2015/16 |
|---|---|---|
| **Change in regulated retail gas price** | 14.7% | 10.6% |

Subject to tariff rebalancing considerations, final network charges and CPI, the annual bill of a typical residential gas customer using 23 GJ a year of about $901 including GST in 2013/14 is expected to increase by $2.54 per week in 2014/15 and $1.98 per week in 2015/16.

# 1 Introduction

## 1.1 Transformation of the East Australian Gas Market

Demand for gas in the east Australian market is increasing substantially due to the development of LNG export facilities in northern Queensland. Due to these LNG exports, demand for gas in eastern Australia will double in 2015 from what was in 2012. Recently developed unconventional coal seam gas fields are being reserved solely for export as LNG. Coupled with this, some conventional gas from sources such as the Cooper Basin, is also being reserved, under contract, for supply as LNG exports. This is driving intense competition for what gas there is available and accessible to the LNG trains, with LNG producers paying export parity prices for LNG, with pipeline transportation, liquefaction and other costs netted off (the ***Netback Price***) in order to secure gas supplies to satisfy committed LNG contracts. Public information in respect of recent Gas Sales Agreements (***GSAs***) makes clear that gas from Moomba, which can readily flow from field to LNG facilities, is already being sold at LNG Netback Prices. Retailers seeking to secure supplies out of Moomba for its domestic customer base would need to compete for that supply at this price

In recent times, NSW has sourced its gas supply from Moomba via the Moomba Sydney Pipeline (***MSP***), and out of Longford via the Eastern Gas Pipeline (***EGP***). As supply from Moomba and the northern CSG fields becomes more difficult to secure in competition with LNG producers, NSW will become increasingly reliant on southern gas producers. At present, any additional supply from Victoria to NSW is restricted due to the constraints on the Eastern Gas Pipeline and the Victorian Interconnect at Culcairn, and these constraints will be in effect until at least mid-2015. While market prices have previously been at levels of $4.70/GJ[1]it is apparent from public information on recent GSAs that the market price is currently between $6 to $7/GJ.

AGL is proposing a staged increase across the period of the VPA. As noted by IPART and its consultants previously, in order for there to be effective competition regulated prices must be high enough to incentivise retailers to compete for customers. AGL has also provided IPART with an analysis of the likely post-VPA market conditions, as a means of assuring IPART that the price increases are not transitory in nature, but are the result of market conditions that will prevail beyond the VPA period. While it is possible that prices may soften in the long term as the market responds and new supplies come online, it is unlikely that there will be a significant shift away from LNG netback prices at Moomba at any time before 2020.

## 1.2 Voluntary Pricing Arrangements

AGL is the standard retailer with the largest supply area in NSW which covers Sydney, Wollongong, Newcastle, Dubbo, Orange, Parkes and parts of the Riverina. AGL Sales (Queensland) Pty Ltd also supplies to the border regions of NSW and Queensland under arrangements which are not regulated by IPART and therefore not included in this proposal.

---

[1] ACIL found the market price of gas out of Longford for 2013/14 to be $4.68/GJ in 'Cost of gas for the 2013 to 2016 regulatory period – A report on the wholesale cost of gas for the review of standard retailers in NSW, 13 June 2013, ACIL Tasman, p 25

In June 2013, AGL and IPART executed the VPA for regulated gas retail prices from 1 July 2013 to 30 June 2016. This arrangement covers residential and small business customers who use up to 1 TJ of gas per year in the supply areas in NSW where AGL is the standard retailer.

Regulated gas retail prices are made up of the weighted average of three components, R + N +C, where:

R = Retail Component

N = Network Component, and

C= Carbon Component.

Although the VPA covers a three year period from 1 July 2013, the VPA has outlined the price path for the Retail Component (R) and Carbon Component (C) for 2013/14 only. This was because price arbitrations and contract negotiations on wholesale gas supply agreements were proceeding during the period of the VPA review. Any statement, public or confidential, on the expected outcomes of these GSA price reviews would have likely become evidence in the review process and could have disadvantaged AGL and its customers.

Under the VPA, a further review is to be undertaken during 2013/14, or beyond, if required, to finalise the price path for the Retail Component and Carbon Component for the final two years of the current regulatory period. This proposal has been prepared in accordance with the process outlined in the VPA for setting regulated retail gas prices for 2014/15 and 2015/16.

The arrangements for Miscellaneous Charges for the three year period from 1 July 2013 have been outlined in the VPA and will continue to apply.

## 1.3 Form of Regulation

IPART has stated its preference for a light handed approach to regulating gas prices for residential and small business customers in NSW. IPART has consistently expressed the view that the most appropriate form of regulation is to seek to achieve a level of pricing which permits new entry and encourages customers to seek out better offers in the competitive market[2]. In 2013, IPART included in its scope of work provided to ACIL Tasman the following:

> "*The benchmark range should reflect costs incurred by a prudent and efficient retailer supplying gas to small retail customers in each supply area*."[3]

In the 2013 gas review, IPART considered the need to balance two potentially conflicting objectives[4]:

---

[2] Review of regulated retail prices and charges for gas from 1 July 2013 to 30 June 2016, Gas – Final Report, June 2013, IPART, p 25

[3] Cost of gas for the 2013 to 2016 regulatory period – A report on the wholesale cost of gas for the review of standard retailers in NSW, 13 June 2013, ACIL Tasman, p 1

[4] Review of regulated retail prices and charges for gas from 1 July 2013 to 30 June 2016, Gas – Final Report, June 2013, IPART, p 25

- To encourage efficiency and protect customers from prices that are higher than efficient levels in the short term by setting regulated prices that reflect the efficient cost of supply.
- To support the interests of customers in the long term by setting regulated retail prices that create sufficient incentives for retailers to compete and customers to participate in the market

AGL has considered IPART's objectives carefully and has interpreted this to mean prices should be set at a level that would enable a prudent new entrant retailer to efficiently secure gas supplies to serve the demand of residential and small business customers over the Review Period and beyond, in a similar manner to the direction IPART provided to ACIL Tasman in 2013. It is important to consider the prudent new entrant retailer beyond the duration of the VPA Period as gas contracting arrangements (be they supply or transportation arrangements) most often require multiple year commitments

AGL also notes in this respect its proposed inclusion of Customer Acquisition and Retention Costs (***CARC***) as calculated with reference to the methodology implemented by IPART in its 2013 Electricity Review[5] . In including the CARC in the regulated electricity price, IPART stated that it "*creates an incentive for retailers to compete in the market and for customers to seek out a better market offer".* IPART also recognised that without the inclusion of the CARC, there is 'little incentive' for retailers to compete for customers. AGL agrees with this, and believes that the inclusion of the CARC is similarly necessary in the regulated gas price in order to foster competition, and it is this competition, rather than regulation, that is best able to ensure prices are at efficient levels.

In formulating its proposal, AGL has also sought to consider the short-term interests of consumers as required by IPART, and structured its proposal to achieve what it believes to be a reasonable balance between the need to increase prices to support efficient new entry and competition, and the desire to mitigate the impact of these price rises on consumers. AGL has sought to do this by:

- continuing to adopt a multiple region pricing proposal of 50% of supply originating from Moomba and 50% from Longford, notwithstanding that transportation constraints on gas from Longford in effect prevent a new entrant from sourcing gas from Longford until mid-2015; and

- transitioning the step change in wholesale gas prices and the CARC over the two years of the price path.

## 1.4 Expert reports commissioned by AGL

To provide an independent view of the benchmark wholesale gas cost for the remaining period of the current VPA, AGL has engaged The Brattle Group (***Brattle***)[6]. To support Brattle's analysis, AGL has also engaged MDQ Consulting (***MDQ***)[7], an expert on the Australian gas industry, to provide an assessment of the prevailing wholesale gas market conditions in NSW and forecast the likely pricing conditions over the period of the VPA.

[5] Final Report – Review of Regulated Retail Prices for Electricity – From 1 July 2013 to 30 June 2016, IPART, 17 June 2013, p 109

[6] Brattle's report is titled, "*Wholesale Gas Price for AGL's VPA Proposal for 2014-16, February 2014*"

[7] MDQ's report is titled, "*NSW Wholesale Gas Market Report, February 2014*"

## 1.5 Structure of this proposal

The Retail Component comprises wholesale gas costs, retail operating costs (including customer acquisition costs) and retail margin. Discussions on these components are outlined in Sections 2 to 6 of this proposal:

- Section 2 reviews the developments in the wholesale gas market which affect the market price for 2014/15 and 2015/16.
- Section 3 considers the developments in the retail gas market including churn, the AEMC review of competition and the inclusion of customer acquisition costs.
- Section 4 discusses the wholesale gas costs,
- Section 5 discusses the retail costs and margins,
- Section 6 combines the preceding components to assess the Retail Component.
- Section 7 considers the Carbon Component,
- Section 8 shows the likely change in the total retail price and the impact on customers' bills, and
- Annexure A outlines the changes in the total retail price and the impact on customers' bills if the removal of the carbon pricing mechanism is delayed by one year.

# 2 Wholesale gas market developments

## 2.1 Developments in the wholesale gas market in east coast Australia

The eastern Australian gas market is in a significant state of change due primarily to the impending export of gas via LNG facilities currently under construction in northern Queensland.

**Historic supply into NSW**

Historically, the NSW domestic gas market has been serviced by the Cooper Basin via the MSP. From 2000, the EGP enabled gas from the Gippsland Basin via Longford to be delivered into the NSW market, creating competition between the northern Cooper Basin producers and the southern ~~Gippsland~~ producers to supply NSW demand. Coincident with this, production from Moomba began to decline as the Cooper Basin entered the 'tail gas' phase. Given retailers had options with regard to supply, it was prudent to diversify sources of gas and previous regulated pricing determinations reflected this with an assumption that gas sources were split 50/50 between Moomba and Longford.

In recent years, the advent of substantial quantities of unconventional CSG in Queensland has added to the competitive pressure on the Cooper and Victorian producers for the supply of gas to NSW. However, the commitment of large LNG projects in Queensland has driven intense competition for available gas between domestic customers and LNG projects as the CSG reserves have been committed to LNG projects in order to underwrite their development. These facilities will redirect substantial quantities of gas previously used for domestic supply to export markets, thereby reducing the availability of gas for domestic use. This reduction in available supply is leading to supply scarcity and consequently increasing the price at which domestic gas retailers are able to source gas.

**LNG projects driving intense demand for supply**

The transformation of the gas market due to the development of large reserves of coal seam gas for export via LNG trains at Gladstone in Queensland has been well reported over the past year by many sources[8] including IPART and ACIL reports in the 2013 gas price review.

ACIL[9] has acknowledged that a key driver in the determination of pricing outcomes is the influence of the LNG projects due to their substantive size. It is anticipated that first export from LNG facilities will occur in late 2014, and thus a sharp increase in demand for east coast gas will subsequently occur. The step change in demand due to LNG, commencing in 2014, has been forecasted by ACIL[10] as shown below:

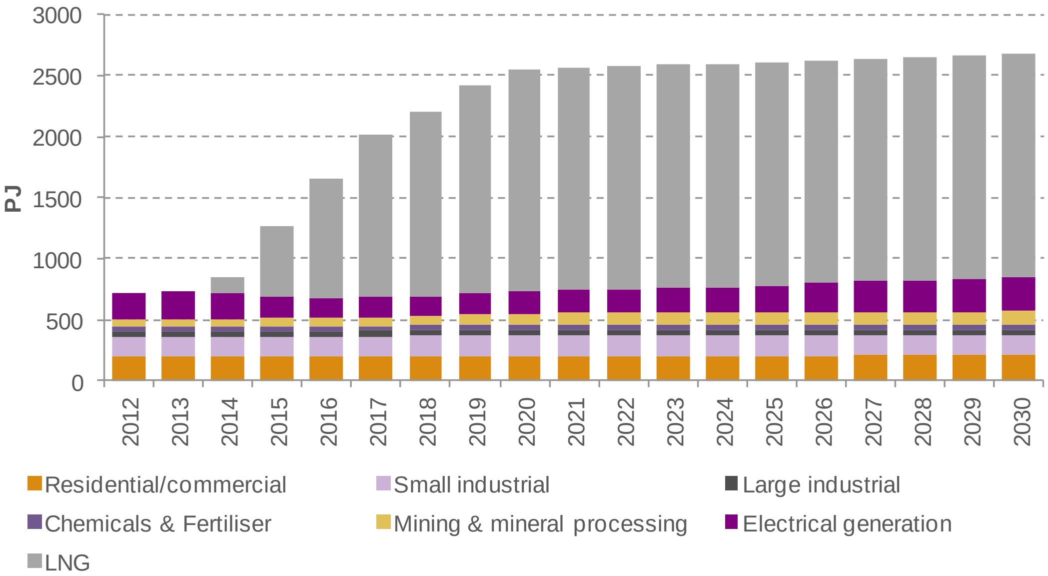
---

[8] See "Ensuring domestic supplies of natural gas for Australian businesses and households", APPEA Journal 2013, T. Nelson, p 178-183

[9] Cost of gas for the 2013 to 2016 regulatory period – A report on the wholesale cost of gas for the review of Standard Retailers in New South Wales, 13 June 2013, ACIL Tasman p 21

[10] Presentation at Ai Group AGL Gas Summit, ACIL Allen, 12 July 2013

**Figure 1 Eastern Australia gas demand forecast**




The ACIL Report makes an important point in relation to the fact that gas can only be used once[11], and thus, even though LNG facilities are not yet operational, gas is currently being reserved for these facilities to ensure sufficient reserves are available for LNG export once operation commences. The gas being reserved is therefore not being supplied into the domestic market at the current time, nor will it be in the future. At the Ai Group AGL Gas Summit in July 2013, ACIL pointed out that in an interconnected east coast gas market:

- producers have options where they sell,
- producers will seek the best price, and
- price trends are reflected throughout the interconnected market.

This analysis is consistent with the analysis conducted in the MDQ Report.

**Detailed supply and demand analysis by MDQ**

For the purpose of this pricing proposal, AGL commissioned MDQ to further detail the supply and demand and pricing conditions that will be in effect during the VPA period. In summary, MDQ has concluded:

- Queensland LNG projects will continue to have incentives to acquire gas at LNG netback prices:
    - GLNG is materially short long term reserves and deliverability and as a consequence has been active in the market purchasing large quantities of third party gas at a long run Wallumbilla LNG netback price. GLNG has been the

[11] Cost of gas for the 2013 to 2016 regulatory period – A report on the wholesale cost of gas for the review of standard retailers in NSW, 13 June 2013, ACIL Tasman, p 21

largest gas buyer in the east coast market for the last 3 years, competing against existing domestic customers for available reserves and production[12]; and

  - Even beyond the issue of requirements for contracted LNG quantities, the opportunity for sale of spot cargoes provides a further incentive for LNG producers to enter the domestic market for additional gas purchases at LNG netback prices. Throughout the term of the LNG projects and especially in the early years of production (2015-2020), the LNG producers have excess plant capacity compared to their firm LNG sales commitments providing an opportunity to sell additional LNG on a spot basis. Given the LNG producers' difficulties to satisfy their firm LNG contracts and the limited availability of domestic gas, it is not likely that the LNG producers will engage in spot sales. However, should additional gas become available, the opportunity to sell to the LNG spot would be further incentive to acquire gas at LNG netback prices and beyond.

- Queensland gas prices are already at LNG netback:
  - the combination of the LNG producers withdrawing as suppliers of new gas to the Queensland domestic market and LNG producers such as GLNG acting as large gas buyers, has transformed the Queensland market into a short, high price market;
  - GLNG has set the market price for gas in Queensland by its large gas purchases from Origin (May 2012 and Dec 2013) estimated at $US8/GJ/$A9.40/GJ (based on $US100/bbl oil price) at Wallumbilla.
  - GLNG's ongoing requirement for additional gas, and LNG spot sale opportunities, strongly suggest Queensland gas prices will remain at LNG netback for the VPA period and beyond.
- As evidenced by the latest sale by Beach Energy to Origin (April 2013), Cooper Basin sale prices are linked to the prevailing price of gas in Queensland netted back to Moomba. NSW customers will need to pay the Cooper Basin gas price that it can achieve by selling gas into Queensland;
- High gas demand in Queensland has reduced the availability of new northern gas supply to NSW and increased reliance on Gippsland Basin JV to supply the NSW market:
  - Cooper Basin JV has a substantial production challenge to satisfy its existing contractual arrangements up to the end of 2016 as gas is directed to the high price Queensland market; and
  - Other than AGL's Gloucester basin project, which will not become operational within the VPA Period, material quantities of NSW CSM or other unconventional gas production is subject to an extended period of appraisal and development and unlikely to be available prior to the end of this decade.
- Transportation constraints will limit the extent that Gippsland Basin JV can increase supply to NSW prior to mid-2015 at the earliest, and additional new southern gas into NSW is subject to further expansion of the Eastern Gas Pipeline or the Vic/NSW interconnect; and
- Southern gas prices are increasing in response to the changing northern market conditions. As evidenced by the recent purchase of gas by Origin from Gippsland Basin JV, ex-Longford gas prices are in a transitional phase of increasing gas price

---

[12] This has been discussed in the media, see Annexure B for a recent example.

during 2014 to 2016. The Origin GSA and other recent sales suggests the indicative Gippsland Basin JV ex-Longford price for new supply during the VPA Period is in the range of $A6.25 - $A6.50/GJ ($2013).

## 2.2 Wholesale gas prices during the period of the VPA

This section outlines the analysis conducted by AGL's economic expert, The Brattle Group and compares that with the range produced by ACIL for IPART last year, and public data in respect of recent contracts.

**The Brattle Group**

According to Brattle, a retailer seeking incremental gas supply at Moomba in order to enter the NSW market to supply small customers has to compete with other buyers prepared to pay high prices. Across the three LNG export projects currently under construction, in aggregate the exporters are short of gas relative to their contractual commitments. The shortage of gas is even greater if spot LNG sales opportunities, particularly in the ramp phase of the export projects, are taken into account. Therefore a retailer seeking new supplies for NSW would have to compete for the gas with the exporters, and one way to think about this is that the retailer would have to "bid away" the gas from the exporter, paying an LNG netback price as a result.

LNG netbacks represent the price that an exporter is willing to pay to obtain feedstock. The netback is the expected export price for the gas as LNG (which is related to the price of oil), minus pipeline transportation, liquefaction and other costs. Netback prices are different at different locations, because of pipeline transportation costs. Further details are provided in Brattle's report.

<u>Moomba</u>

Brattle has estimated an LNG netback price at Moomba of $9.73/GJ (long-run netback basis). This is equivalent to $11.38/GJ at Gladstone or $10.83/GJ at Wallumbilla. Brattle also note that the lack of surplus gas production capacity and the LNG exporters' need to purchase additional third-party gas to fulfill contract obligations suggests LNG producers could pay above $9.73/GJ and still earn incremental profits. This would mean in turn that domestic customers could be required to pay in excess of $9.73/GJ.

<u>Longford</u>

Brattle has concluded that, on the basis of transportation constraints, prices at Longford are not accessible to NSW new entrant retailers prior to mid-2015 at the earliest.

However, notwithstanding their view that Longford should be disregarded for the purpose of establishing new entrant price for the period of the VPA, Brattle's assessment of the Longford price, based on the recent GSA prices out of Longford, is $6.50/GJ.

**ACIL (2013)**

In ACIL's report to IPART, ACIL agreed that the main sources of gas into NSW are Moomba and Longford. Given that a prudent retailer is likely to contract at multiple sources, ACIL has estimated wholesale gas costs for 2013/14 to 2015/16 using the average of Moomba and Longford costs.

In estimating the wholesale gas costs, ACIL developed projections of wholesale gas prices for three scenarios:

- A high price scenario driven by a netback price reflecting production constraints from CSG projects in QLD and the short run export parity price,
- A medium price scenario driven by the netback price of LNG over the longer term, and
- A low price scenario driven by the long run marginal cost of domestic gas supplies as the price of LNG is not sufficient to lift domestic gas prices to LNG export parity.

Prices at Moomba and Longford for the high and medium price scenarios were based on LNG netback prices at Gladstone less the cost of transporting gas from Moomba and Longford respectively to Gladstone. The prices which exclude transmission costs are reproduced below. ACIL has proposed wholesale gas costs based on the low price scenario for 2013/14 and the medium price scenario for 2014/15 and 2015/16.

**Table 3 ACIL projected prices**

| 2013/14$/GJ | 2013/14 | 2014/15 | 2015/16 |
|---|---|---|---|
| **Moomba** | 5.57 | 10.27 | 9.99 |
| **Longford** | 4.68 | 7.90 | 7.94 |

**Public data on recent GSA prices**

Brattle's report has summarised prices of recent wholesale gas contracts, which have been publicly reported on. Recent transactions for supply in Queensland (including Moomba) are about $8 to $10/GJ while at Longford, prices are about $6 to 7/GJ for supply over the 2014-16 period.

**Table 4 Recent GSAs**

| | Seller | Buyer | Date Announced | Total Volume (PJ) | Start | End | Reported Price ($/GJ) | Priced At | Source for Price |
|---|---|---|---|---|---|---|---|---|---|
| [a] | Santos | GLNG | Oct-10 | 750 | 2014 | 2029 | $7.00 to $8.00 | Wallumbilla | IES |
| [b] | Origin Energy | GLNG | May-12 | 365 | 2015 | 2025 | $8.00 | Wallumbilla | ACIL |
| [c] | Origin Energy | GLNG | Dec-13 | 100 | 2016 | 2021 | $9.40 - $10.60 | Wallumbilla | MDQ Consulting |
| [d] | AGL | Xstrata | Oct-11 | 138 | 2013 | 2023 | $6.00 | Ballera | ACIL |
| [e] | Origin Energy | MMG | Dec-12 | 22 | 2013 | 2020 | $9.00 | Ballera | ACIL |
| [f] | AGL or Origin | Incitec Pivot | Dec-13 | 18 | 2015 | 2016 | $10.00 | Ballera | MDQ Consulting |
| [g] | Beach Energy | Origin Energy | Apr-13 | up to 173 | mid-2014 | 2022-2023 | $8.00 to $9.00 | Moomba | IES |
| [h] | BHP-Esso | Lumo Energy | May-13 | 22 | 2015 | 2018 | $7.00 | Longford | IES |
| [i] | BHP-Esso | Origin Energy | Sep-13 | 432 | 2014 | 2023 | $6.00 - $6.42 | Longford | MDQ Consulting |

Sources & Notes:

[a], [g] - [h]: See Study on the Australian Domestic Gas Market, IES, November 2013, p. 69.
[b], [d] - [e]: See Cost of gas for the 2013 to 2016 regulatory period, ACIL, June 2013, p. 27.
[c], [f], [i]: See MDQ Consulting Report. Note that the MDQ Report shows the Origin GLNG GSA in USD/GJ. This has been converted to AUD using the 0.85 USD/AUD exchange rate.

Notes:

Some of these contracts are reported by both ACIL and IES, in which case we take the IES price because the IES report is more recent.

# 3 Retail market developments

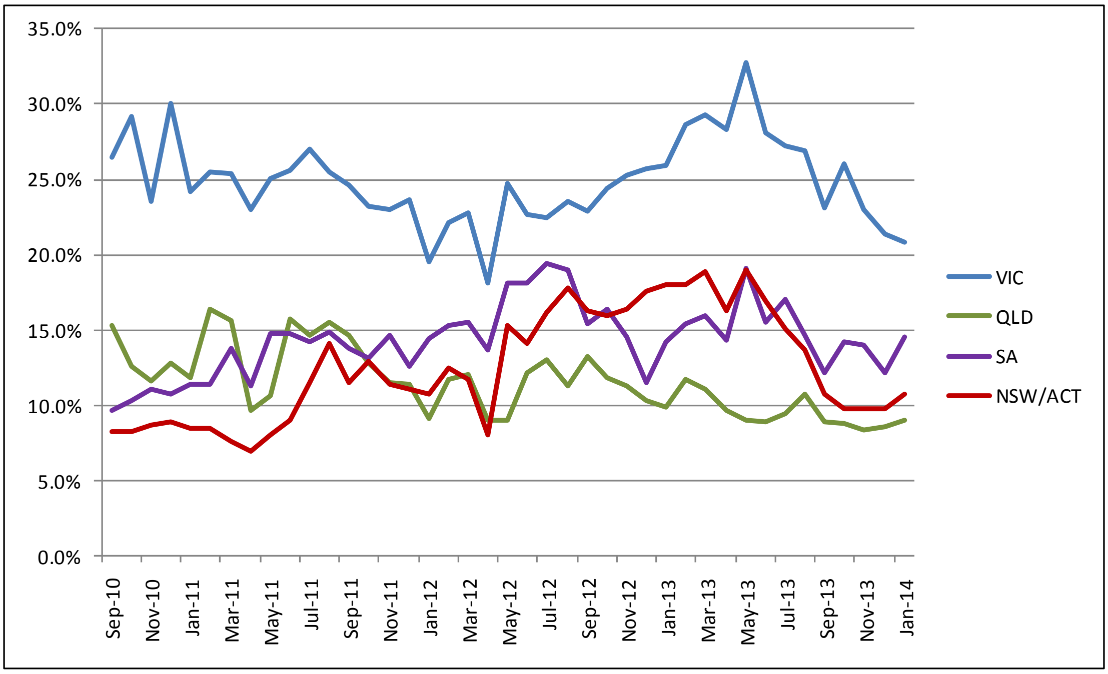
## 3.1 Retail market competition

Over the past 3 years, annualised monthly churn for NSW gas varied from 10% to 20% and is similar to the churn rate in South Australia and Queensland. Over this period, the three government-owned energy retailers were privatised and competition intensified particularly from unsuccessful bidders.

The annualised monthly churn rate in the NSW gas market is currently about 10%. Although this can be considered a high churn rate compared with other industries such as insurance and banking products, this churn rate has trended lower particularly in recent months, most likely reflecting the cessation of door to door sales activity in the residential market by the three largest retailers.

Related to the churn activity, an increasing number of customers have also participated in the competitive market and by January 2014, AGL estimates that less than 20% of gas customers in NSW remain on regulated prices.

**Figure 2 Historical Monthly Annualised Transfer Rate to January 2014 – gas retail markets**



## 3.2 AEMC review of competition in NSW

In October 2013, the AEMC released its Final Report on its review of competition in the retail electricity and natural gas markets in NSW. In the Final Report, the AEMC found that "competition in the gas market is delivering discounts and other benefits to the majority of small gas consumers through effective choice of their retailer and gas product" and that there is "evidence of effective competition in areas serviced by the Jemena distribution network (of which AGL is the main standard retailer)." The AEMC considered that removing price regulation for all consumers will improve competition.

Another important point is that, in the Final Report, the AEMC concluded that there is a separate market for gas as distinct from a dual fuel market. Although there are no gas-only retailers in NSW, all retailers that offer gas also sell a gas product separately, not just a dual fuel product. In addition, there are no additional discounts for dual fuel products. The AEMC noted that approximately one third of consumers in NSW have their electricity and gas supplied by different retailers. The AEMC concluded in the short term, the cost of changing appliances are likely to be high enough for a sufficient number of consumers that the retail supply of gas constitutes a separate market to the retail supply of electricity. AGL agrees with this view.

## 3.3 CARC allowance

In the 2013 electricity price review, IPART used a new approach to estimate the level of incentives and the extent to which costs associated with customer acquisition and retention (CARC), are included in regulated prices to promote competition. This approach is also more transparent and explicit.

AGL supports IPART's view of CARC that:

> *Including this CARC allowance in regulated prices at a level that creates an incentive for retailers to compete in the market and for customers to seek out a better market offer is the 'price' of promoting further competition and driving efficiency improvements in the longer term. Without this, there would be little incentive for retailers to enter the market and compete for customers. It also provides an incentive for customers to engage in the market and seek out a product that best suits them.*
>
> *Our approach necessarily means that the regulated price in a supply area is unlikely to be the lowest price in the market. Rather, it is a price for customers who have not taken up a competitive, unregulated market offer. It is important to note that the inclusion of an additional incentive in prices does not provide a subsidy from regulated customers to market customers. Customers can avoid this cost by taking up a better market offer* [13]

In developing this gas pricing proposal for 2014 to 2016, AGL considers that, given the slowing churn rate, it is appropriate to incorporate this approach for the CARC allowance. This is consistent with the objects under Section 3 of the Gas Supply Act 1996 which, amongst others, are to "encourage the development of a competitive market in gas..." and

---

[13] Review of regulated retail prices and charges for electricity from 1 July 2013 to 30 June 2016, IPART, June 2013, p 10

to “protect the interests of customers and to promote customer choice in relation to gas supply”.

Despite over a decade of full retail contestability in NSW, the retail gas market in NSW is the only jurisdiction in the National Electricity Market where prices continued to be regulated. Given the AEMC recommendation on the removal of price regulation, regulated prices should be set at a level which will allow a successful transition to a market where prices are determined by competing retailers without a regulated price cap.

# 4 Wholesale gas costs

Wholesale gas costs comprise of the following components:

- gas commodity costs
- cost of additional deliverability
- market charges, and
- transportation costs

The wholesale gas costs used to assess the price path for 2013/14 under the current 2013-16 VPA and the previous 2010-13 VTPA have been based on a gas market benchmark developed on the basis that gas in the NSW market is sourced equally from Moomba (Cooper Basin) in South Australia and Longford (Gippsland Basin) in Victoria. Gas transportation and peak demand management (additional deliverability) costs have been assessed using the 1 in 25 year load profile of the small customer market.

In the 2013 gas review, IPART had engaged ACIL Tasman (now ACIL Allen) to provide an independent expert's view of the market benchmark for wholesale gas costs from 2013 to 2016 for a prudent and efficient retailer supplying gas to small customers in NSW.

In late 2013, AGL engaged The Brattle Group to provide an independent view of the benchmark wholesale gas cost for the remaining period of the current VPA. To support Brattle's analysis, AGL has also engaged MDQ Consulting, an expert on the Australian gas industry, to provide an assessment of the prevailing wholesale gas market conditions in NSW and forecast the likely pricing conditions over the period of the VPA. Brattle's assessment will form the basis of AGL's proposed wholesale gas cost for 2014/15 and 2015/16 with respect to gas commodity costs and the cost of additional deliverability.

The proposed wholesale gas costs are considered in this section. These costs exclude any carbon cost because this is considered separately in the Carbon Component.

## 4.1 Gas commodity cost

In considering the benchmark gas commodity cost for NSW, AGL has noted the following:

- Moomba gas prices are already reflecting LNG netback prices,
- There is currently a shortage of gas for long term supply in the east coast such that Moomba prices are at risk exceeding long run netback prices,
- There is limited incremental gas supply from Longford due to pipeline constraints,
- Longford prices are expected to transition to LNG netback prices in the long run, and
- Beyond mid 2016, wholesale gas prices at Moomba and Longford will continue to remain high.

In preparing this pricing proposal for 2014 to 2016, AGL has adopted the market prices which Brattle has assessed for Moomba and Longford for the period to 30 June 2016, applying these prices to 2015/16.

AGL has sought to balance the short and medium term interests of consumers and retailers in several ways:

- Consistent with the 2010 and 2013 reviews, AGL has assumed that gas is supplied 50:50 from Moomba and Longford despite issues with gas availability and pipeline capacity,
- The benchmark gas cost at Moomba is based on the long run netback price even though the price at which LNG exporters are prepared to release gas exceed this, and
- For 2014/15, AGL has provided a transition between the 2013/14 benchmarks assessed by ACIL (2013) using the low price scenario and Brattle's market prices for 2015/16.

This provides small customers with a transition to higher prices. AGL acknowledges that this will be lower than a new entrant's cost in 2014/15 but it will approach the appropriate level in 2015/16. AGL's proposed gas costs are provided below:

**Table 5 Gas commodity cost**

| 2013/14$/GJ | 2014/15 | 2015/16 |
|---|---|---|
| **Moomba** | 8.65 | 9.73 |
| **Longford** | 5.59 | 6.50 |
| **AGL proposed – 50:50** | 7.12 | 8.12 |
| **ACIL 2013** | 9.09 | 8.97 |

Compared with ACIL's estimate, AGL's proposed gas commodity costs are lower by 22% in 2014/15 and 9% in 2015/16.

## 4.2 Cost of additional deliverability

In addition to the ex-plant gas commodity cost, a retailer also has to contract for other services to manage the variability of gas demand referred to as 'additional deliverability'.

Base supply contracts provide limited flexibility to manage peak demand. Base gas supply contracts are generally premised on a supply load factor of 80% to 95%. A retailer supplying a small customer load therefore needs to determine the likely shape of that load (ie demand load factor), and ensure that its supply arrangements are sufficient to cover the high level of demand.

Due to the shortfall in the base supply contracts, additional gas is required to meet peak demand. There are a number of ways of providing this additional supply, such via additional supply contracts, specific tranches of gas, storage facilities etc. However, AGL considers that reference to storage at the Iona Gas Plant (in Victoria) is a reasonable approach to determining the additional deliverability for benchmarking purposes. This approach was adopted by ESCOSA in its 2008-11 and 2011-14 determination of SA gas retail prices.

In the 2013 gas review, ACIL settled on "... the current value of the midpoint of the range of $160 to $240/GJ MDQ/year originally quoted in respect of the Victorian underground gas storage... "[14], consistent with AGL's 2010-13 proposal. In 2013-14$, this amounts to $221/GJ MDQ/year.

Brattle has considered and agreed with ACIL's approach to assess the cost of additional deliverability. This assumes that the cost of storage at Iona is an appropriate proxy for the cost of managing demand. Furthermore, this is based on the small customer load factor of 38.7% which was applied in the 2010 and 2013 gas reviews, and a supply load factor of 90%.

**Table 6 Cost of additional deliverability**

| 2013/14$/GJ | 2014/15 | 2015/16 |
|---|---|---|
| **AGL proposal** | 0.89 | 0.89 |
| **ACIL 2013** | 0.74-1.10 | 0.74-1.10 |

## 4.3 Market charges

Market charges are levied by the market operator, AEMO. These charges are consistent with AGL's 2013 proposal and ACIL's estimates.

**Table 7 Market charges**

| 2013/14$/GJ | 2014/15 | 2015/16 |
|---|---|---|
| **AGL proposal** | 0.08 | 0.08 |
| **ACIL 2013** | 0.08 | 0.08 |

## 4.4 Transportation cost

Transportation cost is based on published and forecast pipeline tariffs on the MSP and the EGP:

- MSP tariffs are expected to increase, in addition to CPI, by a further $0.02/GJ per year in the capacity charge from 1 January 2014 for three years,
- EGP tariffs are expected to increase at the rate of CPI on 1 January each year.
- System use gas and odorisation costs are also included.

The transportation cost takes account of the 1 in 25 demand load factor (38.7%) and assumes that gas is sourced equally from Moomba and Longford.

The transportation cost assessed by AGL is consistent with the cost estimated by ACIL in 2013.

[14] ACIL 2013, p 39

**Table 8 Transportation cost**

| 2013/14$/GJ | 2014/15 | 2015/16 |
|---|---|---|
| **AGL proposal** | 2.84 | 2.87 |
| **ACIL 2013** | 2.69-3.07 | 2.69-3.07 |

## 4.5 Summary of wholesale gas costs

In total, the wholesale gas cost proposed by AGL is about 15% lower than ACIL's assessment for 2014/15 and 6% lower for 2015/16.

**Table 9 Summary of wholesale gas costs**

| 2013/14$/GJ | 2014/15 | 2015/16 |
|---|---|---|
| **Commodity gas** | 7.12 | 8.12 |
| **Additional deliverability** | 0.89 | 0.89 |
| **Market charges** | 0.08 | 0.08 |
| **Transportation** | 2.84 | 2.87 |
| **Total – AGL proposed** | 10.94 | 11.95 |
| **ACIL 2013** | 12.81 | 12.68 |

# 5 Retail costs and margin

In this section, retail costs and retail margin are considered. Retail costs comprise of two components – retail operating costs and customer acquisition costs.

## 5.1 Retail operating costs

In the 2013 gas review, IPART formed the view that a range for retail operating costs to be $91 to $110 per customer (2012/13$)[15]. This does not include costs associated with acquiring and retaining customers. In the 2013 electricity review[16], IPART had determined retail operating costs (***ROC***) of $110 per electricity customer in 2012/13$ or $112.75 in 2013/14$.

AGL has reported in its 2012/13 annual report, an average cost to serve[17] of $62.24 per customer across its electricity and gas customers nationally[18]. This amount represented costs which are directly related to the retail business and do not include operating costs related to Merchant Energy, involved in managing the wholesale energy portfolio, and Corporate Costs. The wholesale operating costs and corporate costs would amount to about $30 to $40 per customer. Including these overhead costs, AGL's ROC will fall within the range of $91 to $110 per customer referred to by IPART. As AGL is one of the largest energy retailers, AGL's cost reflects some economies of scale. A benchmark for ROC should allow other retailers which may not have a similar scale to compete.

For 2014/15 and 2015/16, AGL proposes a benchmark for ROC of $101 per gas customer (2013/14$) which is within the reasonable range considered by IPART. This is about $11 lower than that the benchmark for an electricity customer. The lower benchmark for ROC proposed for gas is to account for lower average gas bills which will generally result in lower costs, particularly bad debts[19].

**Table 10 Retail operating costs (ROC)**

| 2013/14$/customer | 2014/15 | 2015/16 |
|---|---|---|
| **ROC** | 101 | 101 |

15 Review of regulated retail prices for gas, 2013 to 2016, Gas-Final Report, June 2013, IPART, p 80.
16 Review of regulated retail prices for electricity, 2013 to 2016, Electricity-Final Report, June 2013, IPART, p 98.
17 Cost to serve is equivalent to IPART's definition of retail operating cost. It does not include customer acquisition and retention costs.
18 From a cost to serve perspective, there is no special consideration for dual fuel customers. Although dual fuel customers are generally more "sticky", it is difficult to identify material operating cost savings, for instance, a dual fuel customer is billed separately for electricity and gas due to different meter reading cycles and therefore incurs the same costs as separate electricity and gas customers.
19 This based on an average bad debt rate of 1% and an average residential electricity bill of $2,000 compared with a typical residential gas bill of $900. The average bad debt rate of 1.0% was disclosed on page 29 of AGL's presentation on its full year results to 30 June 2013.

## 5.2 Customer acquisition and retention costs

In the 2013 electricity review, in addition to ROC, IPART has also allowed for customer acquisition and retention costs (***CARC***). In the 2013 gas review, however, IPART did not adopt the same approach in relation to CARC as, under the light handed intent of the VPAs, IPART's approach was to assess the standard retailers' overall proposals and to decide whether they were reasonable and balanced the longer and shorter term objectives for the price review[20].

In the 2013 electricity review, IPART had set the CARC allowance "... to reflect our view of the additional incentive (on top of the other cost allowance) required to promote competition in the NSW retail electricity market. That is, we explicitly used the CARC allowance as the mechanism for ensuring we set regulated prices at a level that facilitates the continued development of competition in the long-term interests of consumers of electricity."[21]

AGL supports IPART approach to CARC in the electricity review and proposes that this approach be adopted for regulated retail gas prices. Although gas is most often marketed on a dual fuel basis, it is important to note that retailers also offer gas market contracts separately. Marketing channel and processing costs are incurred separately for each electricity and gas account acquired. In addition, not all gas users have a gas account with their electricity retailer. The inclusion of this allowance is important to allow competition to further develop in the NSW gas retail market and is consistent with the AEMC's view that the retail gas market is separate to the retail electricity market.

Therefore, in setting the Retail Component for 2014/15 and 2015/16 for this pricing proposal, AGL has included a specific allowance for CARC which is consistent with the approach that IPART has taken in the 2013 electricity review.

In the 2013 electricity review, IPART had considered that it was reasonable to allow for direct and indirect acquisition costs below:

- a direct acquisition cost of around $150 per new customer or approximately $40 per customer per annum, and
- an indirect cost (in terms of ongoing market discounts) of around 8% off regulated prices, or approximately $150 per customer a year for a typical NSW customer.

AGL has publicly reported in its 2012/13 annual results that cost per lead sale amounted to $220.68 for a NSW electricity customer[22]. This measure, which is similar to the direct acquisition cost, is higher than the cost which IPART has assessed to be reasonable. IPART's benchmark for direct acquisition cost of $150 per customer is likely to be at the low end of the range of reasonable costs.

The discounts offered in market contracts i.e. the indirect costs, can vary over a period of time for a number of reasons including the level of competitive activity. Since July 2012, AGL has offered a range of products with guaranteed discounts as high as 10% off the energy usage charges for NSW gas customers. Currently, AGL offers guaranteed

---

[20] 2013 gas review, p 83.
[21] 2013 electricity review, p 108
[22] AGL Energy Ltd, Preliminary Final Report for the year ended 30 June 2013, ASX Appendix 4E, p 14

discounts of up to 6%.[23] For this gas pricing proposal, AGL considers the indirect cost of 5% to be reasonable for gas.

In line with IPART's approach in the 2013 electricity review, AGL proposes the following allowance for CARC, comprising of direct and indirect acquisition costs:

- direct acquisition cost of $40 per customer per annum, and
- indirect cost of 5% off regulated prices, i.e. $1.40/GJ, or about $32 per customer a year for a typical NSW gas customers24 compared with $150 for an electricity customer

The total CARC allowance amounts to $3.15/GJ (in 2013/14$). However, AGL proposes to transition this cost by including 50% of this allowance in 2014/15 and the balance in 2015/16.

**Table 11 Customer acquisition costs (CARC)**

| 2013/14$ | 2014/15 | 2015/16 |
|---|---|---|
| **Direct CARC $/customer** | 20 | 40 |
| **Indirect CARC %** | 2.5% | 5% |
| **Total CARC $/GJ** | 1.57 | 3.15 |

## 5.3 Retail margin

In the 2013 gas review, IPART found that a "reasonable range of 6.3% to 7.3% of EBITDA is consistent with the margin that would prevail in a competitive market"[25]. This range is lower than the range of 7.3% to 8.3% which IPART had previously assessed in the 2010 gas review.

AGL proposes that a retail margin, within the reasonable range, of 7% be applied for the remainder of the VPA.

**Table 12 Retail margin**

| | 2014/15 | 2015/16 |
|---|---|---|
| **Retail margin** | 7% | 7% |

---

[23] As at 11 November 2013
[24] A market discount of 5% off the usage rate only for a 23 GJ pa customer is based on an average usage rate of 2.81 c/MJ.
[25] Review of regulated retail tariffs and charges for gas 2010-13, Gas – Final Report, June 2010, IPART, p 32

# 6 Proposed Retail Component

## 6.1 Summary of benchmarks

A summary of the benchmarks for 2014/15 and 2015/16 in relation to wholesale gas costs, retail costs and margin is provided below:

**Table 13 Summary of retail benchmarks**

| 2013/14$ | 2014/15 | 2015/16 |
|---|---|---|
| **Wholesale gas costs $/GJ** | 10.38 | 11.88 |
| **Retail costs** | | |
| **ROC ($/customer)** | 100 | 100 |
| **Direct CARC ($/customer)** | 20 | 40 |
| **Indirect CARC ($/GJ)** | 0.70 | 1.40 |
| **Retail margin** | 7.0% | 7.0% |

## 6.2 Retail Component for 2014/15 and 2015/16

The benchmarks above results in the following price paths for the Retail Component for 2014/15 and 2015/16 (in real terms):

**Table 14 Changes in the Retail Component**

| $/GJ in 2013/14$ | 2013/14 | 2014/15 | 2015/16 |
|---|---|---|---|
| **Wholesale gas costs** | | 10.94 | 11.95 |
| **Retail costs** | | | |
| **ROC** | | 3.69 | 3.69 |
| **CARC** | | 1.57 | 3.15 |
| **Retail margin** | | 2.32 | 2.39 |
| **Retail Component (R)** | 14.43 | 18.52 | 21.18 |
| **Change in R (real)** | | +28.3% | +14.4% |

# 7 Proposed Carbon Component

In this pricing proposal, AGL assumes that the CPM will be removed as intended by the Federal Government from 1 July 2014. If the CPM is removed as intended by the Federal Government from 1 July 2014, the Carbon Component for 2014/15 and beyond will be set to zero.

**Table 15 Changes in the Carbon Component**

| $/GJ in 2013/14$ | 2013/14 | 2014/15 | 2015/16 |
|---|---|---|---|
| **Wholesale gas costs** | 1.72 | 0 | 0 |

In Annexure A, AGL has outlined the impact on the Carbon Component and retail price changes if the removal of the CPM is delayed beyond 1 July 2014. Until the repeal of the CPM is passed by both Houses of Parliament, AGL will charge retail prices which are inclusive of the Carbon Components.

# 8 Proposed retail price path

In this section, the likely impact on retail gas prices and customers' bills are considered. Due to the uncertainty in relation to the removal of the CPM, AGL has outlined two scenarios. If the legislated changes differ from either of these scenarios, AGL will work with IPART to assess the appropriate impact on regulated prices.

The change in regulated retail gas prices is based on the change in the weighted average price cap (WAPC) assessed under the R + N + C approach.

## 8.1 Network charges

Jemena Gas Networks is the distribution business in the regions in NSW where AGL is the standard retailer. The price path in Jemena's current access arrangement will expire on 30 June 2015. For 2014/15, these network charges will increase on average by CPI + 8.39%.

A review of Jemena Gas Networks' access arrangement from 1 July 2015 to 30 June 2020 will be undertaken by the Australian Energy Regulator from 2014. For the purpose of assessing the impact on customers' bills, it is assumed that network charges for 2015/16 will increase, on average, by CPI.

## 8.2 Retail price changes

If the CPM is removed from 1 July 2014, the WAPC will increase from $31.04/GJ in 2013/14 to $34.66/GJ in 2014/15 and $37.32/GJ in 2015/16 (in 2013/14$). On average, regulated retail gas prices are expected to increase by CPI + 11.7% for 2014/15 and CPI + 7.7% for 2015/16. If CPI is 2.7%[26], the nominal increases in retail gas price under this scenario will be 14.7% for 2014/15 and 10.6% for 2015/16.

**Table 16 Average retail price increase**

| $/GJ in 2013/14$ | 2013/14 | 2014/15 | 2015/16 |
|---|---|---|---|
| **R** | 14.43 | 18.42 | 21.18 |
| **N** | 14.89 | 16.14 | 16.14 |
| **C** | 1.72 | 0 | 0 |
| **WAPC = R + N + C** | **31.04** | **34.66** | **37.32** |
| **% change (real)** | | +11.7% | +7.7% |
| **% change (nominal)** | | +14.7% | +10.6% |

[26] Annual change in CPI up to December 2013 quarter

Based on a CPI of 2.7% and subject to the actual network charges and any rebalancing, the change in a customer's bill (including GST) under this scenario is expected to be as follows:

**Table 17 Average weekly change in customer's bill (in nominal $, GST inclusive)**

| | 2013/14 Annual bill | 2014/15 Bill increases | 2015/16 Bill increases |
|---|---|---|---|
| **Residential** | | | |
| 5 GJ/year | $370 | $1.37 | $0.96 |
| 23 GJ/year | $901 | $2.54 | $1.98 |
| 40 GJ/year | $1,259 | $3.31 | $2.84 |
| **Business** | | | |
| 184 GJ/year | $4,621 | $13.06 | $10.81 |

The typical bill for a residential gas customer using 23 GJ of gas each year is expected to increase by $2.54 per week in 2014/15 and $1.98 per week in 2015/16 including GST over the next two years.

# Annexure A – Retail price path if carbon pricing continues in 2014/15

Under existing legislation, the carbon price will increase from $24.15 per unit in 2013/14 to $25.40 in 2014/15. The Federal Government has introduced legislation to repeal the carbon pricing mechanism from 1 July 2014 but currently, there is uncertainty whether the current Upper House will allow passage of this legislation. This Annexure outlines the Carbon Component and retail price change if the repeal of the carbon legislation is deferred beyond 1 July 2014. It is assumed that carbon pricing will be removed from 1 July 2015, and no carbon price for the year commencing 1 July 2015 has been proposed (see below).

For 2014/15, the Carbon Component is established on a similar basis to that agreed with IPART when the carbon pricing mechanism was introduced from 1 July 2012.

The Carbon Component for 2013/14 is $1.72/GJ. This was based on the National Greenhouse Account Factors.

For 2014/15, the updated factors using the July 2013 publication will result in a Carbon Component of $1.75/GJ. This is an increase of only 1.7% compared with the change in carbon price of 5%. This is due to the reduction in the upstream emission factors in the latest publication.

**Table 18 Carbon Component for 2014/15 if CPM continues for one year**

| Nominal $/GJ | NGA Factor kgCO2e/GJ | 2014/15 |
|---|---|---|
| **Carbon price $/unit** | | 25.40 |
| **Upstream**[27]<br>**Downstream**[28] | 13.15<br>51.33 | 0.33<br>1.30 |
| **Retail margin** | | 0.12 |
| **Carbon Component** | | 1.75 |
| **Carbon Component (2013/14$)** | | 1.71 |

With carbon pricing under existing legislation, the average increase in regulated retail gas prices for 2014/15 will be 5.6% higher or 20.3% instead of 14.7% (in nominal $).

If carbon pricing is removed from 1 July 2015, the average increase in regulated retail gas prices for 2015/16 will be 5.4% instead of 10.6% (in nominal $).

[27] Based on the average of the metro and non-metro natural gas emission factors for scope 3, NGA Factors, July 2013, Table 37, p 71

[28] NGA Factors, July 2013, Table 2, p 14.

**Table 19 Average retail price increases if CPM continues for one year**

| $/GJ in 2013/14$ | 2013/14 | 2014/15 | 2015/16 |
|---|---|---|---|
| **R** | 14.43 | 18.52 | 21.20 |
| **N** | 14.89 | 16.14 | 16.14 |
| **C** | 1.72 | 1.71 | 0 |
| **WAPC = R + N + C** | **31.04** | **36.37** | **37.34** |
| **% change (real)** | | +17.2% | +2.7% |
| **% change (nominal)** | | +20.3% | +5.5% |

Based on a CPI of 2.7% and subject to the actual network charges and any rebalancing, the change in a customer's bill (including GST) under this scenario is expected to be as follows:

**Table 20 Average weekly change in customer's bill (in nominal $, GST inclusive)**

| | 2013/14<br>Annual bill | 2014/15<br>Bill increases | 2015/16<br>Bill increases |
|---|---|---|---|
| **Residential** | | | |
| 5 GJ/year | $370 | $1.55 | $0.78 |
| 23 GJ/year | $901 | $3.39 | $1.13 |
| 40 GJ/year | $1,259 | $4.79 | $1.36 |
| **Business** | | | |
| 184 GJ/year | $4,621 | $18.04 | $5.88 |

The typical bill for a residential gas customer using 23 GJ of gas each year is expected to increase by $3.39 per week in 2014/15 and $1.13 per week in 2015/16 including GST over the next two years.

### Carbon price beyond 1 July 2015

It is assumed that carbon pricing will be removed from 1 July 2015, and no carbon price for the year commencing 1 July 2015 has been proposed. In the event the CPM has not been repealed by 31 December 2014, AGL proposes to provide an application under clause 10.2 of the VPA to include a Carbon Component for 2015/16.

# Annexure B

## Concern as Qld LNG export projects eye local gas supplies

Angela Macdonald-Smith

**BG Group** has revealed it expects to rely on third parties for up to a fifth of the gas initially needed for its $US20.4 billion ($22.5 billion) LNG export project in Queensland, highlighting the extent to which the project will draw on supplies that would otherwise be available for local use.

Chief executive **Chris Finlayson** told investors in a Tuesday briefing in London that in 2014-16, gas bought externally would make up "some 10 per cent to 20 per cent of supply to the plant."

He said once the two-train project had ramped up fully, the share of third-party gas would fall to about 5 per cent.

BG's comments are set to revive concerns about Queensland LNG ventures' need to dip into supplies that were expected to be on offer for industrial users. That demand is pushing prices up well beyond the $3.50-$4 a gigajoule level typical of recent years.

The first train at BG's Queensland Curtis LNG project is due to start exports in the December quarter. China's CNOOC owns half of the first train.

Santos's GLNG project under construction in Queensland is also set to rely heavily on third-party supplies, at least in the initial years. The third project, **Origin Energy**'s Australia Pacific LNG venture, is not expected to be so affected.

BG's QGC business in Queensland has already sealed deals with AGL Energy and with the APLNG venture for gas. It is not clear whether it requires additional supplies.

Mr Finalyson said BG was pursuing other exploration plays to increase gas available for QCLNG, including shale gas in the Cooper Basin and other gas in the Bowen and Surat Basins.

But he played down the likelihood of any early move to expand QCLNG, pointing instead to opportunities to "debottleneck" the project, which would involve bolt-on investments to modestly lift capacity, rather than an adding a third processing unit.

"At the moment, I would not anticipate us taking a decision on that in the near future," he said. "Our focus is on delivering what we have."

"Quite clearly the most capital-efficient thing that we can do is to carry through that debottlenecking, fill those trains and make sure that they're kept full for longer," Mr Finlayson said.

Mr Finlayson, who took over as CEO at the British company a year ago, confirmed BG is considering the sale of gas pipelines and water treatment facilities at QCLNG to free up capital.

"We will make disposal at the optimum time to capture the best value," he said.

Commonwealth Bank of Australia analyst Luke Smith estimates the likely sale price for the 540-kilometre QCLNG pipeline at $US2 billion to $US3 billion.

APA Group, Duet Group and AMP Capital are among those that have voiced interest in pipelines that the Queensland LNG ventures may sell.

**Quite clearly the most capital-efficient thing that we can do is ... fill those trains and make sure that they're kept full.**

Chris Finlayson, BG Group CEO

The Curtis Island LNG project is due to start exports in the December quarter. PHOTO: GLENN HUNT

Source: Australian Financial Review, 6 February 2014