Submission to the Australia Energy Market Commission's East Coast Wholesale Gas Market and Pipelines Framework Review

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Contents

Key Points

- Pipeline investment has supported the evolution of the Eastern Australian Gas Market.
- The pipeline sector is responding to changing conditions with new services, increased willingness to take on medium-term risk in investment decisions and initiatives to facilitate market development.
- Further investment will be required to support the future growth of the market.
- The circumstances of Australia are unique. In particular, the number of participants in the Eastern Australian Gas Market and the relatively small gas demand are the major limiting factors to developing a deep and liquid gas market.
- In the short-term, improvements that can support markets include:
    - Aligning market parameters;
    - Improving transparency of production and export capacity and activity; and
    - Implementing the information measures arising from the CoAG Energy Council Process to enhance pipeline capacity trading.
- Improvements to facilitated markets are not a credible catalyst for driving material improvements in gas market liquidity or consumer prices. However, measures to address or accelerate gas supply are capable of addressing these particular policy aims.
- It is vital for effective market development that initiatives are subject to robust cost-benefit analysis prior to any implementation decision. Effective initiatives also allocate the costs of implementation and operation to the market participants that accrue the benefits.

1. APGA's comments on the Eastern Australian Gas Market and the Review

Introduction

The Australian Pipelines and Gas Association, as the peak body representing Australia's gas transmission industry and advocating the role of gas in Australia, has views on many of the issues raised in the Study. APGA's members build, own and operate the gas transmission infrastructure connecting the disparate gas supply basins and demand centres of Eastern Australia, offering a wide range of services to gas shippers, producers, retailers and users.

In this submission APGA will provide comments on the Eastern Australian Gas Market, the CoAG Gas Market Vision and the AEMC's Review, before addressing the questions posed by the AEMC in its Discussion Paper.

Transmission pipeline investment has created the interconnections in the east coast gas market

Since 2000, APGA's members have invested in and built over $2.2billion of new infrastructure providing 4000km of coverage across 10 new gas transmission pipelines[1] in eastern and northern Australia. These new pipelines have been built to meet the demand of Eastern Australia's gas markets.

Since 2010, at least $850 million has been spent expanding existing infrastructure and there is more investment anticipated with APGA's members continuing to actively seek out new investment opportunities.

It is this investment that has led to the evolution of a pipeline network across eastern Australia's gas markets, promoting basin-on-basin competition and underpinning the emergence of trading hubs in the demand centres of Eastern Australia. It is this network that will facilitate the next evolution in trading and increased flexibility across these markets.

Importantly, this investment has occurred across a mix of regulated and unregulated assets and has been facilitated through bilateral negotiation and contracts, as envisaged under the regime established in the National Gas Law.

[1] AER State of the Energy Market 2014, p112

While a relatively small contributor to total delivered gas costs, the transmission sector sees itself as a critical part of a successful gas market. Historically, the role of transmission has been to provide shippers with point-to-point access to upstream and downstream markets. In the interconnected and currently rapidly changing gas market conditions, transmission ncreasingly provides tailored services to a broad range of parties so that they can effectively participate in gas markets. Bilateral negotiation and flexible contractual arrangements are essential for innovation and bespoke service delivery.

Transmission pipeline investment and services are responding to changing market conditions

The Australian gas transmission industry is changing rapidly in response to changing market conditions and the needs of shippers. Tailored contractual arrangements, both long and short term, are providing increased flexibility for shippers to respond, adapt and take advantage of the changing market dynamics. At the same time, pipeliners are offering new and innovative services that respond to the structural changes under way in gas markets, and provide a platform for potential future market development.

Capacity Trading

The gas transmission industry has actively pursued measures to enhance secondary capacity trading and has proactively participated in CoAG's Capacity Trading Regulation Impact Statement process by:

- working with Government and other stakeholders to develop viable, low-cost proposals for enhanced capacity trading, such as the publishing of forward spare primary capacity; and
- implementing industry-led solutions to facilitate increased trading and reduce the transaction costs of trading. The operational capacity transfer service was developed in cooperation across pipeline companies to ensure consistency. It has been available on pipelines around Wallumbilla since commencement of the Gas Supply Hub and is being implemented on the majority of other transmission pipelines.

APGA looks forward to working with the AEMC on the imminent COAG Energy Council rule change proposal for enhanced information provisions to facilitate capacity trading. It is important that this rule change proposal is integrated and sequenced appropriately with any other recommendations arising from the Review.

Market development and new services

Pipeline companies are actively investigating options for further transparency of available capacity and trades, including opportunities for increased tariff transparency, capacity trading platforms and alternative capacity allocation mechanisms. APGA considers that this work should be industry-led and respond to the specific needs of market participants to maximise confidence in pipeline investment. In this manner, it can be expected that initiatives will be timely, appropriate and low-cost.

Pipeline companies are also offering and developing new services. The suite of services being taken up by market participants is changing. There is increasing demand for storage, park and loan, interruptible and As Available services, all of which improve a shipper's ability to respond flexibly to changing market conditions[2]. A new service, ranked priority firm, is being offered on some fully contracted pipelines to provide a firm service on all days outside of those of peak demand.

New services offered under a contract-carriage regime allow market participants to exercise their universal preference for bespoke arrangements that reflect their specific business needs while increasing flexibility and opportunities for trade.

Investment

Pipeline businesses are responsive to customer needs. Customers seek a range of pipeline services:

- some long term to support matching long-term customer investments in plant or infrastructure (such as a gas-fired generator or a chemical plant); and
- some shorter term to fill gaps in a gas portfolio or to take advantage of market opportunities.

The costs and risks involved in long- and short-term projects differ, having a direct impact on project financing costs (and therefore on the tariffs charged).

Recently there have been a number of short-tenure contracts signed that involve significant infrastructure investment. These include recent announcements by APA Group to spend over $160 million to increase the capacity for gas transportation between Victoria and New South Wales for three different shippers for contracts spanning between four and six years. Historically, such an investment would have been made on the basis of contracts well in excess of ten years.

[2] Due to shippers' confidentiality requirements, pipeline owners are very limited in their ability to announce new contracts or modifications to existing contracts.

It is important to note that, contrary to perception, pipeline investments almost always retain some risk for the investor. It is very rare that a pipeline investment's foundation contracts will cover the full cost of capital expenditure and debt servicing. Pipeline investors have to make decisions regarding long-term viability of gas markets being served by new investments and the likelihood they will remain in place over the 80-year design life of an asset. The shorter terms of the contracts referred to above suggests that the pipeline operator is taking on increased recontracting risk associated with this investment.

The prevalence of shorter-term contracting is a function of both shipper demand and the cost and risk of the particular project. For example, single customer laterals carry greater recontracting risk than capacity expansions in an interconnected pipeline grid. At the same time, shippers seeking to connect new facilities to the pipeline through laterals are usually seeking longer-term capacity commitments to provide security of gas supply and satisfy their own project financing needs.

The market framework for Australia's transmission pipelines (except for the Declared Wholesale Gas Market), commonly called the contract carriage framework, has successfully provided timely investment and is demonstrating its ability to respond to customer needs whilst effectively managing project and financing risk.

The risks inherent in infrastructure investment will decline with the maturity of the market, and this will in turn drive changes in the contracting approach for both shippers and infrastructure investors. In contrast, during times of transition, such as those currently being experienced, the risks in infrastructure investment increase due to customer preference for shorter contracts and flexibility. This has a direct impact on the bankability of a project. This has already seen some additional risk transferred to infrastructure investors.

From a policy perspective, it is therefore important to focus on the basic drivers of contracting behaviour, such as the depth and liquidity of the market, in order to facilitate change. This is best done by focussing on reform that will address and accelerate gas supply development.

Pipeline tariffs

There is a range of information available to market participants regarding pipeline tariffs for pipelines both covered and uncovered under the NGL. This information can be used to infer other transportation costs and secondary capacity pricing.

TABLE 1: Eastern Australian Transmission Pipeline Tariff Information

Pipeline	Owner	Covered	Information location
MSP	APA Group	Light regulation - Marsden-Wilton section	APA website
MSP	APA Group	No regulation – Moomba-Marsden section	APA website
RBP	APA Group	Full regulation	APA website
VTS	APA Group	Full regulation	APA website
AGP	APA Group	Full regulation	APA website
CRP	APA Group	Full regulation	APA website
CGP	APA Group	Light regulation	APA website
CWP	APA Group	Light regulation	APA website
EGP	Jemena	No regulation	Jemena Website
QGP	Jemena	No regulation	Jemena Website

APA Group has also published a number of short-term firm transportation offers (duration of 1 week) on its capacity trading website with posted tariffs. These offers cover both regulated and unregulated pipelines.

It should be noted that the revenue generated by the gas transmission industry is the lowest contributor to the final cost of gas supply to consumers. The Australian Energy Regulator[3] has estimated that transmission charges contribute from 3% to 8% to delivered retail gas prices across Australia. This suggests that reforms focussed on the gas transmission sector are unlikely to deliver significant price outcomes to gas consumers.

[3] AER State of the Energy Market 20014 p117

The CoAG Gas Market Vision

The CoAG Gas Market Vision can essentially be summarised as:

- increase transparency;
- increase trade;
- increase competition; and
- provide appropriate regulation.

These goals are similar to the guiding principles for gas market development set out by the Ministerial Council on Energy (MCE) in May 2004. The MCE principles were:

- the provision of publicly available, up-to-date information on market and system operations and capabilities at all stages of the gas supply chain (subject to recognition of existing contractual confidentialities);
- the structure of the gas market should facilitate a competitive market in all sectors;
- gas market participants should be able to freely trade between pipelines, regions and basins;
- there should be regulatory certainty and consistency across all jurisdictions; and
- market design and institutional requirements should be responsive to and reflective of the needs of the market and market participants.

These are ambitions that apply to any market and APGA supports a transparent, competitive and liquid gas market in Eastern Australia.

APGA has some overarching comments to make on the Gas Market Vision and hopes the AEMC will be able to give consideration during its review to the issues raised.

The Gas Market Vision should recognise the link between gas market growth and gas market development.

The Gas Market Vision should articulate a clear statement in support of a strong and growing domestic gas market. In APGA's view, the past and current contemplation of gas market reform has not sufficiently recognised the role that the size and depth of the market plays in fostering an environment for desirable market characteristics to be enhanced.

A gas market that has more producers; more supply basins; more connections between supply and demand; more users; and, most importantly, more gas usage, will be deeper, be more liquid and drive more transparency. There would be more transactions for market participants to observe; more parties to transact with; more marginal gas to transact under shorter-term arrangements; and more demand for services that promote transparency.

The lack of an explicit link between a market's size and its transparency, trade and competition can lead policy makers and market participants to solutions that may not be appropriate for this Australian context.

The Gas Market Vision should be supported by specific goals

APGA supports a market that is more transparent, more competitive and more liquid. The Gas Market Vision is necessarily broad in its objectives and APGA would like to see the AEMC attempt to articulate specific, measureable goals when developing the long-term reform agenda. This will ensure genuine progress can be made and reforms can be assessed more effectively.

Whilst it can be difficult to articulate such goals, it is an important action that must be undertaken to allow the best analysis of each reform option for Australia's gas markets and assessment of its contribution to the desired goals.

Pipeline market regulation is not the 'silver bullet' to unlocking transparent, liquid and competitive wholesale gas markets

Transmission pipelines have a critical role to play in the fostering of more transparent, liquid and competitive wholesale markets. APGA contends the pipeline industry has been more proactive than any other sector of market participants in delivering industry-led initiatives, such as trading platforms, which can be leveraged to support market evolution over time.

Transparent, liquid and competitive markets require efficient investment in, and efficient use and operation of, gas infrastructure. Gas infrastructure is recognised as including three distinct categories: transportation, processing and storage. Each of these categories is represented on the National Gas Bulletin Board. The Gas Market Vision fails to mention processing infrastructure. Storage is mentioned only in relation to transparency.

Attention needs to be given to increasing the availability of commercial processing and storage services.

As APGA notes throughout this submission, the primary focus of reforms aimed at increasing the transparency, liquidity and competition in the Eastern Australian Gas Market must be on increasing both the number of participants in and the size of the market.

The Scope of AEMC's East Coast Wholesale Gas Market and Pipeline Frameworks Review

The title of the review as provided in the Terms of Reference (ToR), set out by the CoAG Energy Council, refers to the wholesale gas market. Unfortunately, this is not in fact the scope of the review – the review is instead being asked to review only the facilitated gas markets.

APGA considers that the east coast facilitated markets cannot be accurately described as wholesale markets. The use of the term 'wholesale' to describe these markets is a misunderstanding of their purpose, design and role in gas supply arrangements. The facilitated markets represent only a very small portion of the wholesale gas market that is primarily conducted through bilateral contracting.

APGA is concerned that a focus confined to the facilitated markets might lead some market observers to draw inappropriate conclusions on the state of the wholesale gas market on the basis of only a partial review of the market.

The role and design of all facilitated markets in Eastern Australia is twofold:

- for the STTMs and the DWGM it is to ensure that there are adequate mechanisms to allow retail markets to balance in a full retail competition environment. These markets do this through valuing and allocating shortfall gas. This retail-centric purpose is most clearly demonstrated by the STTM in Adelaide, which specifically excludes the largest, most volatile users of gas in the state - power generators.
- for the Wallumbilla GSH it is to increase the liquidity of short-term surplus gas in the Bowen/Surat Basin, particularly the anticipated volumes of gas resulting from LNG operation in Gladstone.

None of these markets has a role in primary gas supply arrangements, which are transacted through bilateral contracts in the gas wholesale market.

If the Eastern Australian Gas Market was larger in its total demand, the surplus gas in the market on any given day might be sufficient to provide an alternative source of primary gas supply for some participants and be a genuine component of the wholesale market. This is not the case in Australia due to both the relatively small total gas demand combined with a small number of participants, many of which have large individual demand, and a large geographic spread.

Only at the Wallumbilla GSH, proximate to the supply flows into the demand of the LNG export facilities, is there real potential for evolution to a source of gas supply complementary to the bilateral contracting market.

Review assessment and analysis of reform options

APGA considers the AEMC criteria for assessing existing arrangements, as set out in the discussion paper, a useful measure for conducting the Review and are very important in framing the real and perceived issues with facilitated markets and pipeline frameworks. This assessment, however, must be made in the context of the broader wholesale gas market that includes bilateral contracts for supply, in order to be effective.

Criteria for AEMC assessment of existing arrangements
The framework will build on factors previously identified and used by the AEMC and others, including whether arrangements:
- *impose inefficient or unnecessary costs on parties;*
- *expose parties to risks that are not allocated efficiently or cannot be effectively managed;*
- *impede efficient investment decisions;*
- *act as a barrier to entry or otherwise deter competition; and*
- *fail to provide timely and accurate information required by the market.*

Further, it is vital for effective market development that initiatives are subject to robust cost-benefit analysis prior to any implementation decision. Effective initiatives also allocate the costs of implementation and operation to the market participants that accrue the benefits. As demonstrated below, the cost of the STTMs is borne by all market participants, whether or not they use the balancing service provided.

Gas supply

It is clear that the major concern of many industrial gas users and retailers in the Eastern Australian Gas Market is the availability and well-head price of natural gas. Equally, major gas producers are concerned with the current government moratoriums limiting their ability to bring new supply to market. This is evidenced through submissions to the Energy White Paper process and other reviews, the public comments by participants at the AEMC's Advisory Group meeting and Public Forum, the media commentary and elsewhere on the gas market. Whilst it is outside the scope of this Review to consider measures to address this fundamental issue, APGA believes it will beuseful if the AEMC articulates the relationship between the facilitated gas markets, pipeline capacity markets and the bi-lateral gas wholesale market in Eastern Australia.

There are very few, if any, market participants who have advocated reform of facilitated markets or pipeline markets as a priority to address gas supply issues. It is vital AEMC's recommendations arising from this Review are not presented to market participants and observers as solutions to gas supply issues.

Immediate actions that can improve facilitated markets

APGA considers there are three immediate actions that can be undertaken to improve operation of facilitated markets and pipeline markets.

1. Align market parameters

The various facilitated markets operate under different parameters, including timing of the gas day, market price caps etc.

An alignment of these parameters is likely to:

- improve efficiencies of managing activities in multiple markets;
- reduce the complexity of operating in multiple markets, making it easier to enter markets; and
- begin the process of improving the interoperability of facilitated markets, leading to increasing opportunity for trade across markets.

A further potential alignment is the prudential requirements for participation in each facilitated market.

2. Improve transparency of gas supply and export activity on the National Gas Bulletin Board

It is clear that the actions of gas producers and exporters will have increasing influence over the Eastern Australian Gas Market and the availability of gas to facilitated markets and market participants. This is particularly true for facilitated markets if there are to be large volumes of gas available sporadically at the Wallumbilla GSH. Market participants need greater transparency around the dynamics of export (and associated production) operations to better understand the timing, availability and risks associated with a more flexible gas supply.

In considering increased transparency in the gas market, there is a need to distinguish between the types of information required for short- and long-term decision making as a result of the current rapid changes in the market. There is a real risk that current uncertainty over gas availability and price will lead to inefficient short-term decisions in the market, in

particular on the demand side. This could manifest through the downsizing and foregone investment in new manufacturing plant in response to short-term gas supply shortages and prices, where longer term, gas supply and prices could be expected to normalise at a level that would have allowed the plant to stay in operation. In the worst case, the Eastern Australian Gas Market may experience large permanent demand destruction due to the closure of major manufacturing facilities.

To address these short-term market inefficiencies, APGA considers that is important for the following information to be available to the market:

- Aggregate LNG processing facility ramp-up rate;
- Aggregate LNG-CSG production ramp rate against contractual commitments; and
- Aggregate LNG commercially committed ramp rates.

This information would allow the market to assess possible short-term gas availability issues, and likely duration. Of special interest will be sufficient forewarning of large volumes of gas becoming available to the market.

The following information is more relevant and useful for long-term planning and gas market transparency:

- 1P, 2P and 3P reserves of each project;
- Production plant capacity and utilisation;
- Committed (Contracted) reserves;
- Aggregated production forecasts and performance against these forecasts;
- Contracted and available processing capacity; and
- A list of contracted gas users and relevant contact details for trades.

This data would provide important information about the availability of gas across the medium and long term, yet are currently unknown to gas market participants who are trying to make critical decisions about gas supply options and long term plant investments. However, the relevant data is known to each gas producer and, in particular, each LNG development on the east coast of Australia. Given that each LNG development has a gas demand roughly equivalent to the entire Eastern Gas Market, a shortfall in supply of any development has major implications for the Eastern Gas Market and its participants.

3. Enhance gas transmission capacity trading arrangements

One of the two major gas market policy processes of the last three years has been the CoAG Energy Council's analysis and assessment of measures to enhance the trading of gas transmission pipeline capacity[4]. This process, which formally commenced with a directive

[4] The other has been the development and implementation of the Wallumbilla GSH.

from the CoAG Energy Council in December 2012, has followed the best practice policy development process outlined by the Office of Best Practice Regulation. This includes a regulatory impact analysis and cost-benefit analysis. The process resulted in a recommendation, endorsed by the CoAG Energy Council at its December 2013 meeting, to pursue three measures:

1. Mandate the provision of enhanced capacity trading information for publishing on the National Gas Bulletin Board (NGBB).
2. Improve the functionality and usability of the NGBB and develop an eastern market capacity listing service.
3. Develop and publish voluntary standard contractual terms and conditions for Eastern Australia Gas Market secondary capacity trade

The rule change proposal that will give effect to Measure 1 is anticipated to be submitted to the AEMC by the end of this month, March 2015. Measure 2 has been substantially completed and Measure 3 has been completed.

These measures, deemed most suitable through a comprehensive, best practice process, will, in conjunction with the industry-led initiatives outlined above, provide a proportionate approach to improving information to the market that will support additional capacity trading and reduce the transaction costs of trading.

APGA notes that the CoAG Energy Council process explicitly considered alternative initiatives including voluntary trading platforms and use-it-or-lose-it options and found there were no net benefits arising from their implementation.

Long-term market development goals

In attempting to set out specific goals and a long-term vision in the Review, the AEMC must consider what is appropriate for a market with the characteristics of the Australian market.

What is the Australian context?

For the purpose of this Review, the specific context is the Eastern Australian Gas Market. This is a market that is undergoing structural change; a market where an Australian demand of 687PJ in 2012[5] that has developed in a predictable and steady manner, is now dealing with

[5] Eastern Australian Domestic Gas Study 2014

the implications of around 1200PJ of additional export demand being introduced into the system over a period of 18 months.

In terms of the physical characteristics of the Eastern Australian Gas Market, there are 12 major pipelines (as defined by the NGBB) linking six capital cities, two industrial demand centres (one of which has all three export facilities) with three supply regions dispersed over roughly four million square kilometres. There are two storage facilities registered on the BB, one underground storage facility and one LNG peak shaver. There are five facilitated markets across Eastern Australia.

Given the geographical spread of supply and demand centres, there is one transportation option between any two points. In transporting gas from Victoria to Sydney, there are two transportation options. In transporting gas from Moomba to Victoria (and vice versa), there are up to three transportation options. Some investment is required to establish further bi-directional capability and the contract carriage model prevalent across Australia's gas markets will deliver this investment when genuine demand arises.

In terms of participants the Eastern Australian Gas Market has three major producers, three exporters[6], around a dozen large users, three major retailers and four pipeline companies. In terms of facilitated markets, there are 43[7] unique trading participants registered across five markets.

It should be noted that AEMO reports there are 22 participants in the DWGM once cross-ownership is taken into consideration[8]. This would remove 13 participants in the DWGM from APGA's chart below, making a total of 30 unique participants registered across all five markets.

[6] Two of which are included in the major producer count also.
[7] This number does not take into account all cross-ownership of participants.
[8] AEMO presentation to the AEMC Public Forum 25 February 2015

TABLE 2: Registered Trading Participants in Facilitated Markets

PARTICPANT	DWGM	SUPPLY HUB	ADL STTM	BNE STTM	SYD STTM
Adelaide Brighton Cement	■		■		
AETV Power	■				
AGL	■	■	■	■	■
Alinta	■		■	■	
APLNG	■				
Aurora	■				
The Australian Steel Company	■				
BHP	■				■
Bluescope					■
Boyne Smelters	■				
BP	■	■		■	
Braemer Power Project	■				
Coogee Energy	■				
Covau	■				■
Delta Electricity					■
Energy Australia	■		■		■
Ergon					
ERM	■	■		■	
Esso					■
Go Energy					■
Incitec Pivot	■	■		■	
International Power	■				
Lumo	■		■		■
MMG	■				
Mt Isa Mines	■				
One Steel	■		■		■
Orica	■				
Origin	■	■	■	■	■
Pelican Pt Power	■		■		
Qenos	■				■
QER	■				
Queensland Alumina	■				
Red Energy	■				
Santos	■	■	■	■	■
Snowy Hydro					■
Southern Natural Gas Development	■				
Simply Energy	■		■		
Synergen	■				
SA Water Corp	■		■		
Stanwell	■	■		■	
Tas Gas Retail	■				
Visy	■			■	■
Walloons CSG		■			
Total participants	35	8	10	9	15

As Table 1 shows:

- three participants are registered in all five markets;
- none is registered in four markets;
- nine are registered in three markets; and
- seven are registered in two markets[9]. All of these are registered in the DWGM and either Sydney or Adelaide. It is likely that most of these seven participants are registered in the DWGM solely because they contract Victorian gas for use in NSW or SA operations.

Clearly, the majority of participants operate only in a particular region of the market. This is likely to reflect the predominant gas supply contracting approach for market participants which is simple, single supply point contracting for gas used as a business input. Most market participants are not engaged in any trading activity for gas. For these participants, registration in these markets is more likely to reflect the compulsory nature of these markets, than the desire of these shippers to undertake significant trade of gas.

How will the Australian context change over time?

Many of the gas market reform actions undertaken by policy makers and advocated by some market participants seem to be in response to the specific conditions being experienced or perceived to be prevalent today. It is critical that the AEMC consider what is the most likely normal market state into the future when undertaking this review.

The Eastern Australian Gas Market is in a state of structural change at present. As the LNG facilities ramp up to full capacity there are periods where volumes of spare gas are available in Queensland. These periods have not been as frequent and the volumes not as large as anticipated by many market forecasters. Some market participants would like to access this gas and claim there are difficulties in achieving transportation arrangements. APGA notes that very few market participants are actually registered at the Wallumbilla Supply Hub, which is presumably the first step a market participant must take to acquire gas from the Hub.

When the three LNG facilities reach full capacity, as much gas as possible will be flowing north to Gladstone. Key pipelines are highly likely to be fully utilised in this market environment. It is assumed that from time-to-time large volumes of gas will be available at the Wallumbilla GSH as LNG facilities shut down for periodic maintenance or other events. However, this may not be the case in practice. LNG exporters have interconnected pipelines

[9] The number of participants registered in three and two markets would be less if cross-ownership is taken into consideration.

and agreements in place to swap gas between each other as these maintenance events occur. This has been reported widely in the media.

"The interconnect points will enable gas to flow from one project to the other when necessary, for example to allow for LNG plant downtime and planned maintenance to occur without interrupting either project's gasfield operations," Mr Duke said.[10]

This suggests that large swings at the Wallumbilla GSH may not be as significant or prevalent as previously anticipated. Therefore gas market development should not put unrealistic emphasis facilitating anticipated transactions that may never materialise.

What is the context of international markets that we compare ourselves to?

Comparisons are often made between Australian market frameworks and those in Europe and the US. When doing so, there are a number of questions that must be asked:

- Are there any Australian market failures to address?
- What were the market failures being addressed when international frameworks were introduced?
- What options were considered and why was the implemented measure selected in an international market?
- Are the international market conditions and characteristics (size, number of participants, level of competition, structures etc) prevailing at the time of reform comparable to current Australian conditions?
- What results are observable? Can similar results be expected in Australia?

APGA offers the following observations in regard to the final two points.

The entire domestic demand of the Australian east coast is roughly equivalent to a single large US city.

New York City had an annual gas demand of 500PJ in 2010[11]. It is the single largest city located in the Northeast Region of the US. This region covers the States of Connecticut, Delaware, Massachusetts, Maine, New Hampshire, New Jersey, New York, Pennsylvania, Rhode Island, Virginia, and West Virginia. The Region has an area of 520,000 square kilometres (sized half-way between Victoria at 227,000 and NSW at 800,000 square

[10] Rod Duke, Santos Vice-president GLNG Downstream, quoted in the Australian newspaper on 5 July 2013.
[11] Assessment of New York City Natural Gas Market Fundamentals and Life Cycle Fuel Emissions, ICF International 2012.

kilometres). In 2013 the Northeast Region had an annual gas demand of 5,110PJ. This gas demand is served by 20 major pipelines with a peak capacity of 47.3PJ/day[12].

Chicago had an annual gas demand of 600PJ in 2009[13]. It is the single largest city in the Midwest Region of the US. This Region covers the States of Illinois, Indiana, Michigan, Ohio and Wisconsin. It has an area 954,800 square kilometres (slightly smaller than South Australia at 970,000 square kilometres). In 2013 the Midwest Region had an annual gas demand of 4,627PJ. This gas demand is served by 34 major pipelines with a peak capacity of 39PJ/day. [14]

The load factor swing in these regions is huge, with peak winter demand exceeding median demand by around factor of three[15]. This massive swing in demand has major impacts of infrastructure utilisation in times of peak demand, so it is critical that access to storage, processing and transportation infrastructure is managed closely.

These are just 2 of the 6 gas regions defined by the US Energy Information Administration. The continental US has a total gas demand of 27,710PJ in 2013. This gas demand is served by a grid that comprises:

- More than 210 natural gas pipeline systems.
- 500,000 kilometres of interstate and intrastate transmission pipelines.
- More than 1,400 compressor stations that maintain pressure on the natural gas pipeline network and assure continuous forward movement of supplies
- More than 11,000 delivery points, 5,000 receipt points, and 1,400 interconnection points that provide for the transfer of natural gas throughout the United States.
- 24 hubs or market centres that provide additional interconnections.
- 400 underground natural gas storage facilities
- 49 locations where natural gas can be imported/exported via pipelines.
- 8 LNG import facilities and 100 LNG peaking facilities. Export facilities are under construction.

The EU consists of 28 members states. Belgium, with an area of 30,000 square kilometres (the Greater Sydney area is 14,000 square kilometres) and a population of 11.2 million, consumed 652PJ of gas in 2013[16]. Belgium is bordered by France, Germany and the Netherlands. In 2013 these three neighbours consumed 6,717PJ of gas.[17] The load factor swing for these countries would be comparable to North America. The combined surface area of these four

[12] US Energy Information Administration
[13] Chicago Regional Energy Snapshot, CNT Energy, 2009
[14] Us Energy Information Administration
[15] Eastern Interconnection States Planning Council, Study on long-term electricity and natural gas infrastructure requirements, September 2014
[16] Eurogas stats 2014.
[17] Eurogas stats 2014

countries, with its gas consumption of over 7,300PJ, is 1,070,000 square kilometres. This is about the same size as South Australia (which has annual consumption of around 100PJ).

TABLE 3: Comparison of Eastern Australian Gas Market with US and European regional markets

	Eastern Australian Gas Market	Midwest Region (US)	Northeast Region (US)	Belgium, France, Germany, Netherlands
Area (sq km)	3,813,110	954,800	520,000	1,070,000
Annual gas demand (PJ)	640 domestic 1200 export	4,627	5,110	7,369
Pipelines (#)	15[18]	34	20	19[19]
Nameplate capacity (PJ/day)	3.5[20]	39	47.3	16.3[21]
Annual pipeline capacity utilisation [22]	52%	32%	30%	

The Eastern Australian Gas Market is miniscule in terms of gas demand and transportation options in comparison to these markets whilst being massive in terms of geographic coverage. It does not seem likely to APGA that it is appropriate to directly transplant frameworks from these markets into Australia. Nevertheless, there is potential for some insights to be gained in examining international frameworks.

[18] Including the 3 LNG export pipelines in Queensland which are not yet deemed to be BB facilities

[19] This is number of cross border reference points between these countries as define by ENTSOG (the European Network of Transmission System Operators for Gas) – each of these points represents an alternate transportation option within and across these counties.

[20] Not including the 3 LNG export pipelines in Queensland as the nameplate capacity of these pipelines is not published anywhere

[21] This number is indicative only, many of these points are enabled for bi-directional flow and have different capacities in each direction. Importantly, this figure represents only the interconnector capacity between these four countries, there are many more internal pipelines and interconnectors with other countries that play a role in transporting gas.

[22] Annual gas demand divided by annual pipeline nameplate capacity. This analysis cannot be used for the European example, as gas enters these four countries through many other points that the interconnections between these countries.

In Summary

- Pipeline investment has supported the evolution of the Eastern Australian Gas Market.
- The pipeline sector is responding to changing conditions with new services, increased willingness to take-on medium-term risk in investment decisions and initiatives to facilitate market development.
- Further investment will be required to support the future growth of the market.
- The circumstances of Australia are unique. In particular, the number of participants in the Eastern Australian Gas Market and the relatively small gas demand are the major limiting factors to developing a deep and liquid gas market.
- In the short-term improvements that can support markets include:
    - Aligning market parameters;
    - Improving transparency of production and export capacity and activity; and
    - Implementing the information measures arising from the CoAG Energy Council Process to enhance pipeline capacity trading.
- Improvements to facilitated markets are not a credible catalyst for driving material improvements in gas market liquidity or consumer prices. However, measures to address or accelerate gas supply are capable of addressing these particular policy aims.
- It is vital for effective market development that initiatives are subject to robust cost-benefit analysis prior to any implementation decision. Effective initiatives should also allocate the costs of implementation and operation to the market participants that accrue the benefits.

2. Facilitated markets

2.1 Question 1

Given their performance to date, are the existing markets able to facilitate transactions required to manage current conditions?

The facilitated markets appear to be doing an adequate job of providing balancing arrangements in Victoria, Adelaide, Sydney and Brisbane and facilitating the sale of short-term volumes of surplus gas at the GSH. Trade in balancing gas ranges from 13 per cent of the market in Victoria, to three per cent in Brisbane.

According to market participants' comments, it appears their greatest difficultly is securing new contracts for gas supply for those participants whose contracts expire over the next two to three years. The facilitated markets are unlikely to help with this issue.

Some participants suggest that there is an increasing need for access to secondary pipeline capacity to manage current conditions. Shippers have had a long-standing ability to trade pipeline capacity on the basis of both bare transfers, and contract assignments. APGA understands that such trades do occur, however they are not widely reported. In addition access to contracted but unutilised capacity on a day is provided by pipeline operators through As Available or Interruptible services and APGA members have seen an increasing demand for such services in response to increased volatility in the market.

APGA members have developed products and websites to support capacity trading for firm services, in particular to reduce transaction costs and other barriers to trade associated with the administration of nominations, amongst other things. These products and services are relatively new, as is the Wallumbilla GSH that they have been initially designed to support.

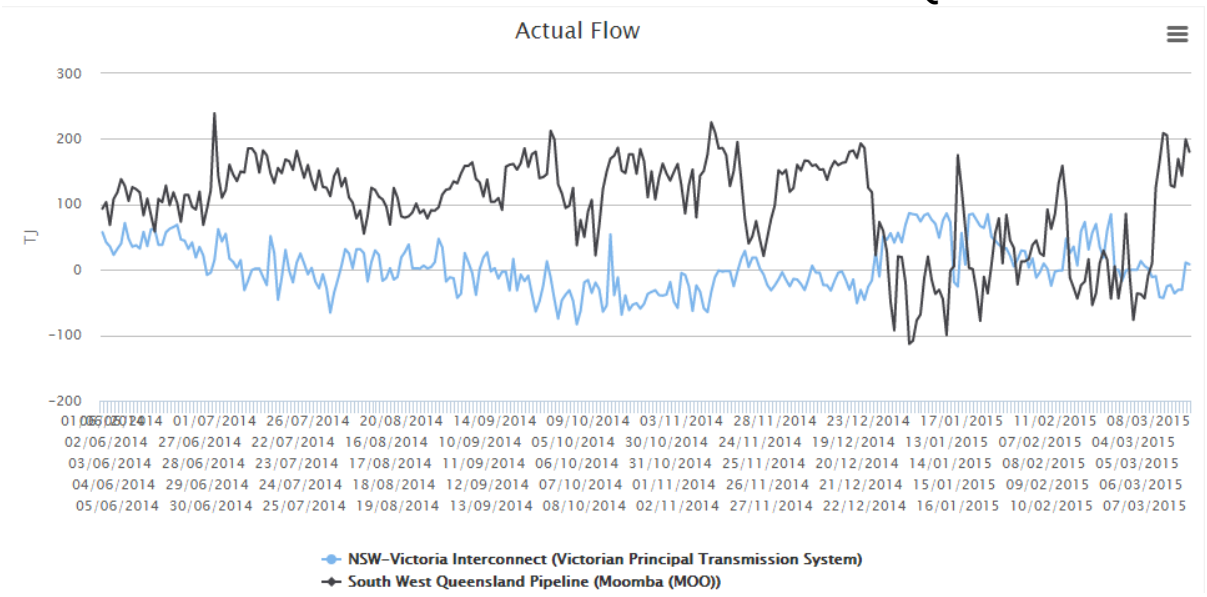
Given their relative immaturity, it is too early to determine whether the GSH model with facilitated capacity trading services offered will be successful in developing the secondary gas and capacity markets. In particular, many shippers have existing contractual positions in place that meet their current needs and have no immediate need to purchase additional gas or capacity via a trading mechanism. This situation may change as existing contracts roll off and more gas and capacity is offered to the secondary market. The full start-up on the three LNG facilities is also likely to provide a boost to this market.

Further, reforms that might support the GSH and pipeline capacity trading (for example, through the development of hub services and the listing of shippers on each pipeline with contact details), have not yet been completed. This means that the success of these recent market interventions have not yet had opportunity to be fully tested.

There have been observations that gas is not flowing to its region of highest value and that this is evidence that markets and pipeline frameworks are not working. APGA offers the following comments on this matter:

- For the most part, gas is flowing to its highest value. This is clearly evidenced through the historical flows provided on the National Gas Bulletin Board. These show that gas flowed north in response to the commencement of LNG shipments from Gladstone and subsequently changes flow from north to south and vice versa. Presumably, this is in response to the requirements of the one operational facility (e.g. ramp gas effect during later part of 2014 where flows were predominantly southwards). Inclusion of these facilities on the NGBB would allow confirmation of this presumption.

CHART 1: Gas flows on the NSW-Victoria Interconnect and the SWQP[23]



Positive numbers on the NVI represent gas flowing north from Victoria to NSW. Positive flows on the SWQP represent gas flowing from Wallumbilla to Moomba. As the chart shows, as LNG shipments from Gladstone commence in late December 2014, gas flows on both the NVI and the SWQP switch toward Gladstone. Since then, they have fluctuated. These two pipelines have been selected as they both have bi-directional flow capability.

- STTMs are not spot markets, they are balancing mechanisms. The price shown at the STTMs is not a true 'commodity supply' price; it is the price of imbalance on the day, in that retail market with most of the "trading" occurring between related entities who are ambivalent on the actual posted price. The STTMs (and to a lesser extent the DWGM) are illiquid and hence subject to substantial potential price volatility which limits their attractiveness for use in either hedging or arbitrage purposes.
- The market coverage of STTMs is different for different states (eg Adelaide STTM excludes power generation) so cannot be taken to reflect the full value of balancing gas, let alone commodity gas) on that day for the market as a whole. At best, they and the DWGM are balancing mechanisms for the retail sector.

[23] AEMO National Gas Bulletin Board

- Transportation costs must be taken into account. Some observers do not seem to be taking the cost of transportation into account when considering gas flows. For example, if gas was to be purchased in the STTM in Sydney for use in Victoria it must be transported to Victoria before it can be used. If the cost of transportation is factored in, the price differentials that are observed from time to time decrease.
- Examples of gas flowing from a higher priced DWGM into lower price STTM in Sydney is not an example of market inefficiency but merely an indication of how participants are managing their gas portfolios, and could be an indication of efficiency where the gas in Victoria is cheaper than contract price at Moomba shifting supply ex-Victoria.

2.2 Question 2

Will the current market framework be able to facilitate transactions that may be required to meet future conditions?

First and foremost, APGA considers there does not seem to be a large number of participants to underpin the development of a liquid and flexible East Coast Gas Market. In particular, there does not appear to be a sufficiently large number of participants as to make identifying trading opportunities and executing trades so overwhelming that complex market frameworks need to be imposed through government intervention. There appears to be sufficient capability for the existing market to evolve as required as has been demonstrated by the introduction of industry-led initiatives by the pipeline industry.

The primary requirement of market participants appears to be securing long-term secure supply. The facilitated markets are not designed or intended to facilitate such transactions, and most transactions for supply and capacity are 'long-term' in nature.

APGA notes that is apparent the market's perception of 'long-term' is also changing. In the past such a long-term contract may have covered a period of more than 10 years. Now, it is more likely the market will see a much greater proportion of contractual transactions covering a period of around five years.

As noted in response to Question 1, there are a number of reforms currently being implemented that can be included within the 'current market framework'. For example, policy decisions have been made, and significant policy work undertaken to achieve the following:

- Improved information provision on the Bulletin Board, through a redesign of zones to more clearly show pipeline and market flows;
- Publishing additional information on the Bulletin Board, to support capacity trading (Rule change proposal pending); and
- Development of hub services at Wallumbilla to integrate the existing three trading nodes into one.

APGA considers that these three initiatives will significantly improve the operation of the market and are expected to be in place within the next 12 -18 months (some earlier).

2.3 Question 3

Are there barriers to using the wholesale markets, for instance for new entrant retailers or for large users wishing to participate directly in the markets?

As noted above, APGA considers that there are some information and alignment-related barriers to using facilitated markets. These improvements will improve the ease of participations but APGA does not believe there are significant barriers to using facilitated markets. In particular, APGA disputes claims that access to pipelines is a barrier.

The primary capacity market is the market for services between shippers and pipeline operators. Amongst a range of services offered, there two principal types of transportation services for shippers, Firm capacity (guaranteed access) and As Available/Interruptible capacity.

The secondary capacity market is the market where shippers can trade Firm capacity to third parties.

Both As Available/Interruptible services and the secondary capacity market offer capacity that is not currently utilised by shippers. How these offerings occur varies across pipelines.

Primary Firm capacity is equally on offer to all market participants at time of investment. Pipeline companies actively pursue potential shippers prior to Final Investment Decision in order to secure the largest investment opportunity possible. Once an investment is made, primary capacity can be made available as existing contracts expire or through investment in increased capacity. There are also a range of flexible arrangements potentially available that use a combination of Firm capacity, storage and As Available/Interruptible capacity to meet shippers' needs.

With regard to the secondary capacity market, every holder of primary Firm capacity is free to trade their unutilised capacity on any basis they choose fit. Particularly in a fully contracted capacity environment, the effective ownership of the spare Firm capacity on any day sits with the Shipper and it is their right to trade that capacity at whatever price they deem economic.

There are implemented industry-led initiatives and under-development CoAG Energy Council initiatives to improve the environment for the trading of secondary capacity. These developments responded to concerns raised by some participants around access to pipelines. These measures make it easier to find trading partners, reduce the transaction costs of trades and help establish a market price for secondary capacity.

It should also be remembered that pipeliners offer As Available and Interruptible services that effectively makes unutilised capacity available to the market. While this offering is in the Primary capacity market, it is offered in competition to capacity that is traded in the secondary market. There is increasing interest in As Available and Interruptible capacity arrangements and there is evidence some market participants have been able to put arrangements in place enabling flexible, short-term access to pipelines to meet their needs.

APGA considers most of the participants currently raising access to pipelines serving facilitated markets as an issue are actually attempting to influence the price of these services through regulatory and market interventions as they seek to gain similar market capabilities to those participants that have taken on risk and enabled asset construction through primary Firm contracts.

Some participants appear to believe it is appropriate for primary Firm capacity to be subject to use-it-or-lose-it type arrangements; and then made available for access at or near its marginal cost. This ignores the relationship between the Firm and As Available/Interruptible markets (both services are offered in the same market) and the importance of recovering the sunk costs of infrastructure in order to ensure future investment. It also ignores the value Firm capacity holders place on being able to manage uncertainty in load forecasting and maintaining flexibility, and the damage marginal cost pricing can cause in infrastructure service markets.

Disagreements between parties about price are not a sign of market failure requiring government intervention. APGA will address this issue in more detail in the Transmission section.

2.4 Question 4

What opportunities are there for improved integration between the markets?

There are a number of opportunities for improved integration. Firstly, market parameters should be aligned to remove discrepancies between markets. These parameters include timing of the gas day, price caps in each market and some areas of terminology. The removal of such inconsistencies can reduce the administrative burden of market participants and reduce complexity, lowering the overall barrier to entry.

APGA considers it absolutely critical that better information on export and production capability is provided to market participants. Market participants cannot make full use of facilitated markets without an improved understanding of the operations of the three LNG facilities at Gladstone. Each of these facilities has an annual demand not much less than the entire domestic demand in the Eastern Australian Gas Market and has great ability to influence gas supply. APGA's views on specific information requirements are detailed above. Further areas of consideration include:

- A simplification and harmonisation of the STTMs to better recognisetheir primary purpose as balancing mechanism would improve integration. This will be addressed below.

- The unique market framework in Victoria is likely to be limiting integration across South-eastern Australia. This will also be addressed below.

- An increase in the availability of commercially provided storage facilities, particularly large-scale underground storage, would enhance flexibility and allow market participants to better access seasonal arbitrage opportunities in facilitated markets.

APGA also considers that the focus on transportation ignores the existing ability of shippers to enter into gas swapping arrangements between markets. Development of this market could enable participants to swap gas across markets without transportation requirements and may assist in improving access to the GSH for some participants.

Finally, APGA notes that there are few participants active in multiple markets. This is not because of difficulty in accessing markets, the complexity of operating in multiple markets or the lack of integration between existing markets. Quite simply, there are not many market participants in Australia. Many of the participants that are present have major facilities concentrated in a single region or just a single major facility and do not see gas trading as part of their business.

3. The STTM

3.1 Question 1

Are the original objectives for the STTM still relevant and compatible with the new Council vision? How have stakeholders' experience with the STTM corresponded to initial expectations?

The original STTM objective, as set out in the Gas Market Leaders Group National Gas Market Development Plan delivered to the then Ministerial Council on Energy in June 2006 was:

The STTM will establish a mandatory price based balancing mechanism for gas delivered to, and withdrawn from, defined market hubs, replacing existing gas balancing arrangements applicable at delivery points within the hubs.

The distinction between a balancing mechanism and a spot wholesale market appears to have been confused by many market observers and participants. Since 2006, references to the STTM have tended to label it a 'wholesale' or 'spot' market. It is a very important distinction – there should be very different expectations for a balancing market and for a wholesale market.

For example, APGA has observed market participants and AEMO express confusion as to why gas that is available in the Sydney STTM for $1/GJ is not being purchased and transported to other markets. The price shown at an STTM is not a 'commodity supply' price; it is the price of imbalance on the day, in that market. In essence, $1/GJ gas in Sydney means all Sydney STTM participants were very accurate with their nominations on a particular day. If any participant attempted to acquire a meaningful quantity of gas on that day, the price would rapidly escalate as there is not an underlying large surplus of commodity gas that is driving the low price. **It is a lack of demand for balancing services that drives the low price, not a surplus of commodity.**

Further, the Commonwealth's 2014 Eastern Australia Domestic Gas Market Study stated:

Gas market reform in Australia has aimed to improve liquidity and transparency in the wholesale gas market. Spot markets have been introduced in Victoria (the Declared Wholesale Gas Market), as well as Adelaide, Brisbane and Sydney (the short-term trading markets, or STTMs).

These markets were designed to complement long-term gas contracts and provide an option for making up short-run supply and demand shortfalls. However, ***they currently trade insignificant gas volumes and may have only a limited relevance to the price of the long-term gas contracts.***[24]

To state the STTMs and the DWGM trade insignificant gas volumes is to ignore their primary purpose – that of a balancing mechanism - and ignores the fact they were designed to complement, not inform or replace, long-term contracting arrangements. If a market observer was to assess the volume of gas traded at the STTMs in this context, they would be deemed to be trading the appropriate levels of gas.

TABLE 4: Traded volumes in the STTMs[25]

	SYDNEY	**ADELAIDE**	**BRISBANE**
Percentage of throughput traded in market	4%	7%	3%

APGA considers the need for liquid and transparent balancing mechanisms still remains relevant and compatible with the new Council vision. The STTMs do provide a liquid balancing mechanism for gas market participants in Sydney, Adelaide and Brisbane. They are unlikely to provide further liquidity as an alternative source of gas supply. The liquidity

[24] EADGMS, page 64
[25] ESAA 2013

required to provide a balancing service is much less than that to provide a genuine source of supply.

There is an important question as to whether the STTMs provide an efficient and effective balancing mechanism. Many market participants report they are overly costly and complex.

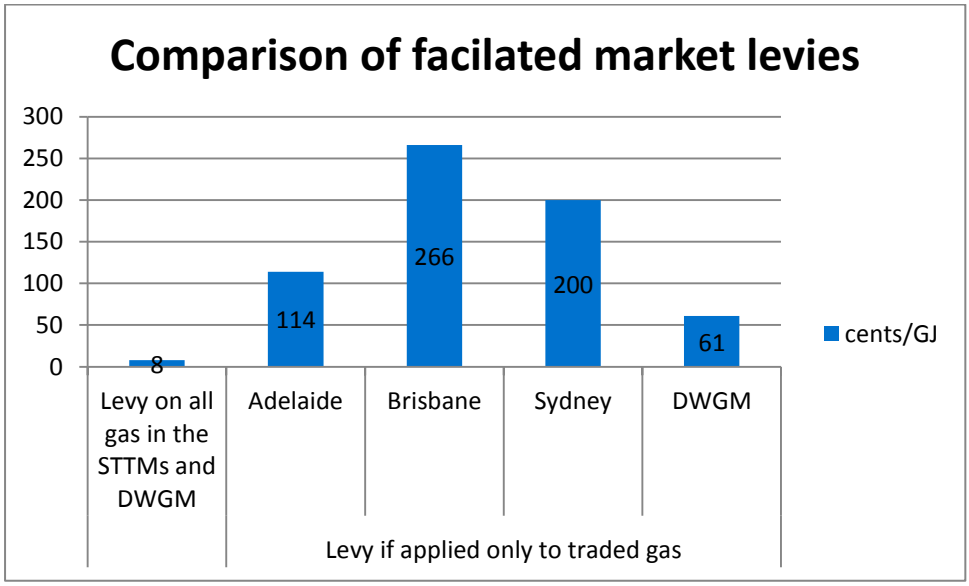
3.2 Question 2

Are all STTM hubs (Sydney, Adelaide and Brisbane) delivering value to market participants?

APGA does not believe the STTM hubs deliver value to market participants. The STTM is a gross market, charges apply to all gas that passes through each hub regardless of whether the market participant that owns the gas requires the services of the hub.

The current AEMO STTM (and DWGM) charge is slightly more than 8c/GJ of gas in each hub. If this charge was applied only to traded volumes of gas in each market the charge would be much higher.

CHART 2:



Effective reforms and initiatives appropriately allocated the costs associated with implementation and operation to the beneficiaries. If that was to be done in the case of the STTM, it is unlikely the balancing service would be used at all. As it currently stands, participants that do not need to use the service are subsidising those that do.

Further, the 8c/GJ is a fixed cost of participating in a market served by an STTM hub; it does not compare favourably to the transportation costs associated with participating in a market. Taking Sydney as an example, an additional 8c/GJ added to the transportation costs of

around a $1/GJ from either Moomba or Longford represents a substantial increase to the costs of delivering gas to the Sydney market.

The considerable costs incurred by market participants and pipeline operators in establishing internal systems to manage interaction with the STTM and mitigate risks in the market must also be considered when determining value.

Given that effective, if less transparent, balancing mechanisms were in place prior to the implementation of the STTMs, it must be asked whether the STTM-related costs borne by the market to date have resulted in significant improvements in efficiency or outcomes.

3.3 Question 3

What design features of the STTM could be improved to reduce costs and improve efficiency? (eg is there a role for intra-day trading?)

Counteracting MOS has been an issue in Sydney and Adelaide since the commencement of the STTM and is raised by some participants as a fault in the current design. Counteracting MOS arises due to the assumption in the STTM design that there are no physical limitations to delivering gas into the networks of Sydney and Adelaide. Rather than being a fault, counteracting MOS is providing a price signal for change. This change has given rise to the provision of some small MOS balancing services and, if significant enough, would warrant investment to provide free flow. In this regard the 'Facilitated Markets dilemma' for the STTM participants is now the same as those in the DGWM. i.e. who makes the investment to improve market capability and who shares in the benefit. The 'no physical constraint' assumption has also caused significant issues in the establishment and operation of the Brisbane STTM.

APGA also has concerns about the inability of the market operator to correct STTM prices in the event of pipeline information error or failure. If pipeline information error causes a 'price event' there is no mechanism to retrospectively correct price. For example, after a high-price event in the Sydney STTM caused by pipeline error in 2010, a deliberate decision was taken to not enable AEMO to retrospectively correct market prices. It was decided that pipeline operators would not have sufficient incentive to deliver accurate and timely data if mistakes could be corrected.

Further, the data validation process that was implemented in the wake of the high price event chose to institute a process whereby data that fails its automated validation and receives no confirmation from a pipeline will still be used to set prices.

The most likely scenario in such an event is that pipeline systems have suffered major failure and the data should not be used. Not only will it be used, there has been a deliberate decision not to provide the ability to retrospectively correct prices if a high-price event results from its use.

This issue was raised by APGA (then APIA) in our submission to the rule change process initiated by AEMO to change the daily data delivery times to allow for data validation in April 2011.

This contrasts with the ability of AEMO to place the market into administration when its own errors or system failures create issues.

3.4 Question 4

Given that most gas supply is bilaterally contracted, is it realistic to expect that prices in the STTM will signal underlying supply and demand conditions? If not, what is the role and value of STTM within the broader gas market framework?

It is not realistic to expect that prices in the STTM will signal underlying supply and demand conditions because it is a balancing mechanism for the retail segment of the market, not a source of gas supply. The price signal provided by the STTM is not relevant to bilateral contracting of gas supply. The belief that the STTM should provide a price signal on underlying supply and demand conditions can be attributed to its continual mislabelling as a wholesale market.

APGA considers there is an important question regarding the ongoing role and value of the STTMs. In a market where there are multiple supply hubs and enhanced capacity trading, balancing hubs may not be necessary.

4. Wallumbilla Gas Supply Hub

4.1 Question 1

Is Wallumbilla adding value to the way participants manage their gas portfolios and what directions should the development of the market take?

It does appear that Wallumbilla is adding value to the way participants manage their gas portfolios. It appears that some of the concerns raised by market participants about their ability to take advantage of Wallumbilla stem from their desire to access Wallumbilla on the same or better terms as participants that have made significant long term investments in pipeline capacity or hub compression services. Market participants that have made long-term investments have taken on the capacity risks associated with those investments and are now benefiting from those investments.

4.2 Question 2

How does trading at Wallumbilla impact on trading in other wholesale markets?

APGA considers the ability of Wallumbilla to impact trading in other facilitated markets to be overestimated, particularly as it is the only market with a wholesale role. If an observer considers the primary balancing role of other markets, there is little reason to expect Wallumbilla to impact trading elsewhere.

This impact is further reduced when an observer considers the distance Wallumbilla is from other markets. Adelaide, Sydney and Victoria are between 2,200 and 3,200km by pipeline away from the GSH. These are vast distances to traverse by pipeline and the cost of transportation services needs to be taken into account when looking at market price differentials.

4.3 Question 3

Would the establishment of a GSH at Moomba facilitate additional trade? Would a Moomba GSH impact on liquidity at Wallumbilla?

APGA does not have an opinion to offer with regard to a GSH at Moomba.

4.4 Question 4

How useful is the information provided by the Wallumbilla hub to market participants and what additional information could be provided to improve accuracy and transparency at the GSH?

As APGA has outlined above, production and export facility information is required so that market participants can reasonably forecast the availability of gas at the Wallumbilla GSH.

It is not sufficient to consider these facilities in aggregate; each export facility alone has a gas demand that is comparable to the entire Eastern Australian domestic gas market.

5. The DWGM

5.1 Question 1

Are the original objectives and rationale for the DWGM relevant and compatible with the Council's vision?

The original objective of DWGM reflected market conditions at the time of its establishment. At the time of the DWGM's establishment, the Victorian Gas Market was not connected to any other market. In essence, it was an isolated market that had significant excess capacity at market start. This has changed substantially. The construction of the Tasmanian Gas Pipeline, SEA Gas Pipeline and the Eastern Gas Pipeline, as well as the construction and subsequent significant expansion of the Victorian Northern Interconnect, have increase the linkages between Victoria and the entire Eastern seaboard.

5.2 Question 2

Is investment in the DTS occurring in an efficient and timely manner? Or are there limitations with the current investment and/or regulatory framework?

Investment does not appear to be occurring in a timely manner. Certainly APGA considers the regulatory framework means investment is delayed until it can be approved during the five yearly access arrangement process. There are documented occasions where necessary investment has been proposed and rejected during an Access Arrangement determination and then approved five years later in the next determination. The delays to investment caused through regulation have implications for efficiency and market welfare.

In contrast, pipelines that have full coverage and are tariff regulated under the contract carriage model have less difficulty in investing outside the regulatory cycle as they can offer Firm capacity rights.

APGA notes that the DWGM, like the STTMs, is a mandatory balancing market that market participants in Victoria must use and pay for, whether there is intent to use the balancing service or not,. The 2014-15 levy of 8c/GJ applies to all gas. Whilst the DWGM has more liquidity than other balancing mechanisms, largely due to the high winter peak demand in Victoria, the costs associated with it are not insignificant for those that don't require its services. The 13% traded volume of gas[26] in the DWGM would attract a charge of 61c/GJ if costs were attributed only to traded volumes.

5.3 Question 3

Do the DWGM arrangements inhibit the transportation of gas between the DTS and interconnected pipelines?

Historic issues that inhibited transportation of gas from the DWGM into contract-carriage pipelines have recently been addressed through an AEMO Procedure change. The change allows the matching of allocated AMDQ to Firm capacity rights at system withdrawal points,

[26] [26] ESAA 2013

such that shippers can be assured they can access their contracted Firm capacity rights on interconnected pipelines where they are scheduled in the DWGM.

As outlined in response to the previous question, APGA understands that there remain issues associated with securing timely investment in the DWGM that would support additional transportation of gas into and out of the DWGM.

5.4 Question 4

How could the market design be amended to provide additional tools for participants to manage price and volume risk in the DWGM?

Market participants with direct experience in the DWGM are best placed to address this question.

6. Transmission pipelines

6.1 Question 1

Are the original objectives of the gas access regime still relevant and compatible with the Council's vision?

As the Discussion Paper provides, the original objectives of the gas access regime were to:

> *a) facilitate the development and operation of a national market for natural gas;*
> *b) prevent abuse of monopoly power;*
> *c) promote a competitive market for natural gas in which customers may choose suppliers, including producers, retailers and traders;*
> *d) provide rights of access to natural gas pipelines on conditions that are fair and reasonable for both service providers and users; and*
> *e) provide for resolution of disputes.*

APGA considers thatthe existing gas access regime has allowed these objectives to be met. As they are open ended objectives, they are all still directly relevant to various outcomes of the CoAG Gas Market Vision.

6.2 Question 2

Is the current low number of covered transmission pipelines a cause for concern or a measure of competition?

The coverage criteria for transmission pipelines as set out in the National Gas Law assess not only the effects of coverage on competition, they also assess the efficiency of regulating an asset and whether regulation would result in materially improved outcomes for consumers.

The move away from fully regulated pipelines to lightly or unregulated pipelines should be seen as both a sign of increasing competition in the transportation market and the ability of the market to achieve efficient outcomes without regulatory intervention.

The access regimes under the Gas Code and the National Gas Law have applied alongside significant pipeline investment that has promoted competition between gas supply basins. As this competition increases, the costs of pipeline transportation services are a factor in the decision making process of market participants. Pipelines must remain competitive to ensure they remain a viable choice for supply options. As interconnection increases, pipelines have an increased driver to remain competitive as alternative sources of supply and transportation become available.

APGA considers the evidence of investment that has driven the increased interconnectivity of the Eastern Australian Gas Market is a sign the access regime is working. It allows market participants to enter into the arrangements necessary to achieve timely investment that is well-sized to market demand. The oversight and prospect of regulatory intervention provided by the access regime provide market participants with confidence in the resulting market outcomes.

It should be noted that the revenue generated by the gas transmission industry is the lowest contributor to the final cost of gas supply to consumers. The Australian Energy Regulator[27] has estimated that transmission charges contribute from 3% to 8% to delivered retail gas prices across Australia. This suggests that reforms focussed on the gas transmission sector are unlikely to deliver significant price outcomes to gas consumers.

Notwithstanding these observations, there are significant shortcomings with access regulation that need to be recognised. Access regulation significantly affects the incentives of pipeline investors to invest in spare capacity, and can lead to incentives for longer term 'underpinning' contractual arrangements for pipeline capacity investments in order to avoid the risk that regulated prices are insufficient to recover the costs of incremental investment. This can occur where additional capacity is added to an older and significantly depreciated pipeline, where 'average' tariffs applying to the full capacity of the pipeline would not recover the higher incremental costs of expansion.

APGA's key message is that timely investment can occur under contract-carriage with access regulation, but regulation does entail distortions and should only be imposed where there is a clear economic benefit in doing so. By contrast, market carriage *requires* access regulation and stifles the ability for timely private investment, therefore imposing significant costs on the community.

[27] AER State of the Energy Market 20014 p117

APGA contends that the market would benefit from a similar level of access oversight being extended to processing and storage facilities rather than changing the access regime for pipelines.

6.3 Question 3

Are there impediments to short term trading of pipeline capacity trading? (ie why is secondary trading not occurring?) If so, how should these best be addressed?

APGA notes that trading and swapping of transmission capacity and commodity gas is occurring and has occurred throughout the development of the Eastern Australian Gas Market. The trading may not be as visible as some policy makers and market participants would like, but it is occurring.

Additionally, APGA notes that short-term capacity is not only made available to market participants through trading, it is also available to all market participants on a non-discriminatory basis as AA and/or Interruptible capacity.

Despite this, there seems to be a prevailing view that there is insufficient short-term capacity trading occurring. No information has been provided regarding what the sufficient (or efficient) level of capacity trading would be.

Part of the driver for increased capacity trading seems to be the view held by some that pipelines are underutilised. Utilisation of a pipeline is first and foremost driven by the demand profile of the region being served. The primary way to increase a pipeline's utilisation is to increase non-peak demand. No amount of capacity trading can increase non-peak demand. As demonstrated in Table 2, the average annual utilisation of pipelines in the US and Europe is much lower than that in the Eastern Australian Gas Market. Despite the 'sophisticated' primary and secondary capacity access frameworks of these regions, they do not have greater pipeline utilisation than Australian pipelines because the demand profiles of these regions are concentrated on winter heating loads.

However, with the view that enhanced capacity trading is desirable, APGA considers the first impediment to increased short-term trading of pipeline capacity trading is the historical lack of harmonised contractual arrangements for trading. This impediment has been addressed.

AEMO has developed standardised terms and conditions (T&Cs) for bare capacity transfers at the Wallumbilla Hub. These T&Cs can be readily applied to bare capacity transfers on any pipeline and are available on the NGBB.

The pipeline industry has also responded to concerns by developing the operational capacity transfer service, providing standard T&Cs for trading of operational capacity; allowing traders to reduce transaction costs, trade the responsibilities associated with the capacity and take positions on pipelines they have no firm capacity rights on but may wish to acquire traded capacity on.

To support this harmonisation, capacity listing services have been introduced by industry and AEMO, providing a visible location to place bids and offers for capacity. If utilised, these platforms would establish market values for secondary capacity on each pipeline.

These services were developed in close consultation with market participants and APGA has published a Guideline for the offering of operational capacity transfer services that should see a more harmonised approach in the Eastern Australian Gas Market.

In reality, very little activity has occurred over the 12 months some of these services have been in place.

The second impediment to short-term trading of pipeline capacity may be related to the limited number of market participants, where parties with capacity to trade at particular receipt or delivery points cannot find a willing counterparty at those points. Pipeline companies can offer delivery point flexibility to shippers (and potential shippers) to address this problem. Variations to delivery points can affect deliverability to other delivery points and these impacts must be accounted for.

Arrangements can be developed for inclusion in contracts, but shippers need to request them.

Over the medium to longer term, increased delivery and receipt point flexibility should be facilitated by the expansion of existing and construction of new infrastructure, but more demand for flexibility would be needed to facilitate this.

Highly relevant to the issue of capacity trading is the CoAG Energy Council Capacity Trading Regulatory Reform Process that commenced in December 2012 and is still underway. The findings of the CoAG Decision Regulation Impact Statement (RIS) should not be ignored.

Economic consultancy NERA conducted the Cost-Benefit Analysis (CBA) that informed the Decision RIS. In its 82 page document, NERA assessed the costs and benefits of the four options proposed by CoAG, which were:

1. Status Quo.
2. Enhanced information.
3. Voluntary trading platform.
4. Mandatory trading obligations.

The CBA was informed by direct market participant interviews and also examined arrangements in Europe and the US. Some of NERA's findings include:

That said our discussions with stakeholders provided little evidence to suggest that there was currently large unmet demand for pipeline capacity during periods where capacity was currently available.[28]

In the context of the Australian market we have not found any evidence that would support a conclusion that shippers are withholding pipeline capacity for the purpose of achieving a competitive advantage in a related market.[29]

Pipeline operators have strong incentives to sell unutilised capacity that has been already contracted to other parties so as to earn additional revenue on a non-firm basis. That said, shippers generally prefer firm capacity more than non-firm capacity, because non-firm capacity is subject to the utilisation of other shippers contracted capacity. As a result, the demand for non-firm capacity will likely be limited.[30]

We have not received any information from stakeholders, nor identified any unusual characteristics in historical patterns of pipeline usage that would support a conclusion that capacity is being withheld from the market in an anti-competitive manner[31]

In light of the CBA, the CoAG Energy Council decided to progress Option 2. As detailed above, that process is still underway and about to culminate in the submission of a rule change proposal to the AEMC. It seems logical and appropriate that the improvements offered through this process, enhanced by the industry-led initiatives already in place, are given time to work before further changes are contemplated.

Some market participants continue to ignore the findings of this comprehensive process investigating the need for enhanced capacity trading, are still claiming that major issues exist and are advocating for significant market intervention.

One such market intervention that has been advocated is the mechanism of oversell and buyback (OSBB). APGA offers the following observations on this mechanism:

- OSBB is use-it-or-lose-it with an auction mechanism. NERA's CBA, funded by the CoAG Energy Council, demonstrates there is no evidence of anti-competitive behaviour that would justify such an intervention and no clear benefit that would arise from its introduction.
- Based on the presentation to the AEMC's Public Forum, the primary driver for OSBB in Australia appears to be setting the price for secondary capacity at or near the marginal cost of capacity. As such, proponents of OSBB are looking to free ride on

[28] 2013 NERA CBA, piv
[29] 2013 NERA CBA, pvi
[30] 2013 NERA CBA, p9
[31] 2013 NERA CBA, p46

market participants that are funding the provision of pipeline infrastructure. Without this commitment there would be no infrastructure to access. APGA urges the AEMC to carefully examine the existing OSBB arrangements as implemented in Europe. APGA understands that:

  - Not all jurisdictions have implemented OSBB. OSBB is one of four congestion management instruments available for use. The prevailing instrument in Germany and Austria, Restriction of Renomination Rights, is remarkably similar to the As Available service offered by Australian pipelines.
  - The UK has implemented a price floor of marginal cost and the market has suffered unforeseen consequences.
  - Learning from the UK experience, other jurisdictions that have implemented OSBB have done so with price floors at or above the cost of firm capacity.

- Proponents of OSBB seek to have the advantage of flexibility at much lower cost than those market participants that have taken firm positions on a pipeline. In addition they seek to shift the peak-time capacity risk that they would experience if they took advantage of As Available capacity arrangements away from themselves and onto pipelines.
- It is not clear what effect OSBB would have on pipeline investment. In particular, it is unlikely market participants would agree to underwrite future capacity expansions (with associated expense and capacity risk) if other market participants will be able to free ride on this investment.
- Importantly, APGA believes OSBB has major implications for the contract carriage model and its advantages in delivering timely investment.
- The market issues that have led to the implementation of oversell and buyback are not being experienced in Australia. In particular, unlike Europe, Australia has no history of vertically integrated pipeline owners that are also retail gas sellers with substantial reason to withhold capacity from competitors.
- APGA is researching the current broader European experience and notes that its structure is less than 18 months old.

In short, OSBB appears to be a high risk strategy that addresses a claimed market failure for which no evidence has been found in Australia and ignores the initiatives that are already being put in place to address some participants concerns.

6.4 Question 4

Does the increasingly interconnected nature of gas pipelines and markets on the east coast form a driver for greater harmonisation of regulatory arrangements (eg a single carriage model or greater integration of market and pipeline frameworks)?

Yes, the increasingly interconnected nature of gas pipelines and markets is relevant to the regulatory arrangements that set out pipeline access frameworks. Interconnectivity has increased under the contract carriage model and the investment required by the market has been delivered in a timely manner that efficiently attributes the cost of capacity to participants that want it.

Only one carriage model applies across the Eastern Australian Gas Market, the contract carriage model. A consistent national gas access framework overseen by a single regulator (for the east coast) ensures arrangements for access are consistent, while also reflecting the nature of the market and appropriate scope for unregulated provision of pipeline services.

A different approach has been applied in one jurisdiction that is inconsistent with the rest of the market.

Market carriage only applies to internal Victorian gas flows on the Victorian Transmission System and its application is historical (pre-dating much of the recent Energy reform in Australia). Market carriage forces a 'one size fits all' approach on market participants and results in investment delays and uncertain access rights for market participants that would otherwise be willing to fund timely investment. If applied across more pipelines it would stifle pipeline-on-pipeline competition and innovation.

APGA considers that the market carriage framework, as it is currently structured, is no longer appropriate for the Victorian market as this market is no longer isolated and is likely to require significant investments in coming years. In the current environment, it is more appropriate to consider how the carriage framework on the VTS can evolve to the same standard as the rest of the market in recognition of this new level of interconnectivity and to improve flows across borders.

Market participants have demonstrated a preference under the contract-carraige framework for bespoke service arrangements. Negotiated third-party access allows market participants' needs to be met. Innovation and competition is encouraged by service delivery across pipelines. This innovation has been amply demonstrated by the actions of the gas transmission industry over the last 18 months.

APGA believes that negotiated third-party access is working and will continue to work in the Eastern Australian Gas Market, particularly as market requirements can change very rapidly, requiring new investment and new services to be offered. Notwithstanding these changing conditions, the Eastern Australia Gas Market does not, and will not foreseeably have, the complexity of the markets in Europe and the US related to highly meshed pipelines that may warrant more complex market designs.

6.5 Question 5

How useful is the information provided on the Bulletin Board to market participants and what additional information could be provided to facilitate secondary trading?

There are some information improvements that can be made to the Bulletin Board to facilitate secondary trading. Importantly, this is not merely the publishing of new information; there is much more than can be done with existing information.

APGA has given this issue thorough consideration and can offer the AEMC the overview of information proposed in our submission to the CoAG Energy Council in July last year. The full

detail is available in the submission accessible from the CoAG Energy Council and APGA websites.

APGA considers that additional transparency on available firm primary capacity would assist capacity trading. This is because available secondary capacity is offered in competition with primary capacity, and having an outlook of available primary capacity would indicate the nature of the capacity market for each pipeline, and the degree of contractual congestion.

This information would be supported by the enhanced presentation of existing information in regard to physical pipeline congestion. Any parties interested in capacity trading will need an understanding of the likely demand in the relevant time periods. This can be provided using two sets of information already held by AEMO:

- *A graphical representation of historical daily flow data against pipeline capacity. Such graphs were developed and published at Attachment B to the Decision RIS and provide a clear indication of the seasonal flows and utilisation for each Bulletin Board pipeline. Publishing these graphs on the BB would be an effective means of delivering of this information.*
- *An analysis of historical flows in each day of the year. The Bulletin Board now has over five years of data, and for each day of the year on each pipeline it could publish data for average flow, highest flow and lowest flow. This will provide a reasonable basis from which to assess the anticipated pipeline utilisation, and therefore the potential for capacity trading.*

(APGA notes that our first proposal for historical information has been largely been implemented the BB redesign. An ability to graph against pipeline capacity has not yet been implemented)

APGA proposes that the most appropriate way to publish pipeline contractual information is by publishing available firm capacity by pipeline each month, with a 12 month forecast. This approach gives the market a clear indication of current and future available capacity. The frequency of publication also matches the potential frequency that contracted capacity changes – in general contracted capacity does not change on a day-to-day basis and changes are generally resolved in advance of their implementation. This is a consequence of the relatively long terms of gas supply and transport agreements, and the relatively small number of shippers in the market. It is therefore a lower cost option compared to providing a 365-day outlook (as discussed in the Consultation Paper) for information that does not change with that degree of regularity. This approach also addresses any confidentiality concerns that shippers may have in regard to publishing actual shipper contractual positions.

APGA agrees that there should be transparency with regard to the identity of shippers that have contractual positions on each pipeline. APGA therefore proposes to provide to AEMO, also on a monthly basis, a list of current shippers on each pipeline. By publishing contact details for those shippers (provided directly by shippers to ensure they remain up to date) a potential buyer of capacity would have sufficient detail to understand the likely market for pipeline capacity, and how to gain access to capacity, without disclosing sensitive commercial information on individual shipper contractual positions.

In summary, APGA's proposal is for gas transmission companies to provide the following information to AEMO, on a monthly basis:

- *A list of shippers with whom the pipeline has a contract (where the initial start date for that contract has passed) on the day of submission; and*
- *The available firm capacity with the pipeline for each National Gas Market Bulletin Board pipeline, on the first day of the month for the next 12 months.*

These measures, in conjunction with the capacity listing service being developed for the Bulletin Board, will provide an increased level of information on pipeline available firm capacity, historical demand, shippers and trading opportunities in a low-cost approach to facilitate pipeline capacity trading. In the absence of clear net benefit or demonstrated unmet demand for capacity trading, this is the appropriate step to take at this point in time.

Such enhanced measures will allow market observers and participants to test the demand for capacity trading on pipelines around the Wallumbilla hub, and through Eastern Australia, without imposing unjustifiably higher costs on some market participants.

Finally, APGA notes that pipeline operators and shippers will have to work together to increase flexibility in contractual arrangements in order to facilitate increased capacity trading. The gas transmission industry is committed to working with shippers to make these changes as efficiently and effectively as possible.