



# **Regulation Impact Statement**

## **Gas Transmission Pipeline Capacity Trading**

### **DECISION PAPER**

**2 December 2013**

## EXECUTIVE SUMMARY

This regulation impact statement (RIS) examines the trade in natural gas transmission pipeline capacity in eastern Australia and tests options for possible changes to the way in which capacity is traded.

Australia's eastern market gas transmission pipelines experience differing levels of congestion. The focus of this paper is on trading opportunities relating to gas transmission pipelines that are said to experience contractual congestion. Contractual congestion occurs when market participants are unable to gain direct access to unused capacity on a pipeline because all of a pipeline's capacity is contracted. Capacity trading can reallocate this capacity, facilitating the delivery of additional gas to the market, making more efficient use of existing infrastructure and lowering transaction costs for those seeking to access to short-term pipeline services.

It is recognised that any short-term benefits that can be gained from improving the way in which pipeline capacity is traded are difficult to quantify. However, as international experience suggests, the benefits of improving capacity trading may go beyond the facilitation of more opportunistic access to pipeline services to also helping to build competition and liquidity in the wholesale market over time.

Pipeline capacity utilisation data indicates that there are periods during the year when some eastern Australian pipelines have significant volumes of unutilised capacity. The unused capacity on these pipelines is understood to be predominantly contracted to either gas retailers or industrial consumers. It is understood that seasonal demand variations largely account for the observed variations in capacity utilisation.

Although there is already some limited trade in unused capacity, anecdotal evidence suggests that the absence of a transparent and responsive market for trading unused pipeline capacity may be making such transactions more complex and costly than they need be. Over time, in a larger and more dynamic east coast market, these concerns may also become material to efforts to improve market transparency and liquidity. If undertaken efficiently, benefits from increased utilisation of existing infrastructure and lower costs of access, would be expected to be passed through to consumers.

In May 2013, the Standing Council on Energy and Resources' (SCER's) Senior Committee of Officials (SCO) published its consultation RIS that presented potential policy options that could improve the efficiency in the way natural gas transmission pipeline capacity is traded. These policy options included:

- Option 1: Status quo – no change;
- Option 2: Improved information – provision of additional information and the standardisation of contractual terms and conditions;
- Option 3: Voluntary trading platform – establishment of a capacity trading platform with market participants voluntarily offering up unused capacity for trade; or
- Option 4: Mandatory trading obligation – shippers or pipeliners are compelled to release unutilised capacity via a transparent market mechanism.

Considerable consultation with key stakeholders on these proposed policy options has been undertaken by SCER officials including the receipt of formal submissions against the consultation RIS and direct consultations with industry, the Australian Energy Regulator, the Australian Energy Market Commission and the Australian Energy Market Operator. No alternative options were identified. The results of these consultations is reflected in this decision RIS.

Given the likely demand for enhanced capacity trading services and the benefits to future market development are difficult to quantify, empirical analysis of these options is limited. Submissions on the consultation RIS provided little new empirical data, so SCO officials engaged a consultant to perform an independent cost-benefit analysis of policy options. This analysis suggests that the combination of low-cost implementation and a reasonable assumption that resulting benefits will grow over time supports SCO's preferred policy approach of implementing Option 2. Option 2 would also not preclude – indeed it would inform – consideration of other options over time.

SCO's recommended policy position has been reached in recognition that current market arrangements, involving the use of long-term gas transportation agreements and bilateral secondary capacity agreements, have resulted in a market that has limited transparency. This lack of publicly accessible and fundamental market information may make it very difficult for current and potential market participants to engage in secondary capacity trade. This information asymmetry may be acting as a barrier to entry, limiting competition in the sector and the utilisation of transmission pipeline infrastructure.

A key risk associated with Options 1, 2 and 3 is that existing market participants will not offer up adequate unutilised capacity to meet potential demand. Against this, it could be reasonably expected that under Options 2 and 3, holders of unutilised capacity would be motivated to offer capacity they do not need if the transaction costs were low. Option 2 measures to achieve this outcome involve:

- AEMO improving the capability of its National Gas Market Bulletin Board (BB) to better present existing data and enhance the useability of the information to market participants. This measure would not require regulatory change and could be implemented relatively quickly;
- AEMO establishing a capacity listing service on the BB;
- Pipeliners (and shippers via pipeliners) providing additional information concerning pipeline capacity utilisation and capacity trading activity. This measure would require the development and implementation of appropriate rule changes;
- AEMO publishing new data provided by pipeliners on the BB;
- developing standardised contractual terms and conditions applying to pipeline transport; and
- developing business tools and processes to expedite and ease the transfer of contractual rights to capacity.

While Option 2 represents a relatively low-cost option, it is recognised there is a degree of uncertainty concerning the potential net benefits of Option 2 that primarily reflect the unknown level of demand for utilised capacity. Regardless, Option 2 is a light-handed regulatory approach that has the potential to: reduce transaction costs; make fundamental information available to facilitate transactions and enable additional gas to be delivered to market; and better enable the decision making of policy makers. The timely provision of this information in a way that addresses substantive confidentiality issues appears to be in the interests of all market participants.

Although Options 3 and 4 have the potential to deliver higher net benefits than Option 2, they also involve considerably higher costs. For Option 3 and 4, a key risk is there may not be adequate demand to justify trading platform establishment and operation costs. Option 4B may raise sovereign risk issues due to intervening in established contractual agreements (see Appendix D for a list of costs, benefits and risks for all policy options).

SCER officials will develop a detailed implementation plan by mid-2014, with a view to fully implementing Option 2 as soon as possible.

It is proposed that two years after Option 2 initiatives have been implemented, a review will be undertaken into the usefulness and effectiveness of the proposed changes. The review will also assess the level of supply and demand for unused pipeline capacity at the Wallumbilla Gas Supply Hub (GSH) and whether or not adequate unused capacity has been offered to the market.

## ACRONYMS

AEMO	Australian Energy Market Operator
AER	Australian Energy Regulator
BB	(National Gas Market) Bulletin Board
CAM	Capacity Allocation Mechanism
CBA	cost-benefit analysis
CGP	Carpentaria Gas Pipeline
COAG	Council of Australian Governments
CMP	Congestion Management Procedures
DTS	Declared Transmission System
DWGM	Declared Wholesale Gas Market
EGP	Eastern Gas Pipeline
EU	European Union
FERC	Federal Energy Regulatory Commission
GJ	gigajoule
GSH	Gas Supply Hub
LMP	Longford to Melbourne Pipeline
MAP	Moomba to Adelaide Pipeline
MSP	Moomba to Sydney Pipeline
NEM	National Electricity Market
NGL	National Gas Law
NGO	National Gas Objective
NGR	National Gas Rules
NVI	New South Wales to Victoria Pipeline
PJ	petajoule
QGP	Queensland Gas Pipeline
QSN	QSN Link (Moomba to Ballera)
RBP	Roma to Brisbane Pipeline
RIS	Regulation Impact Statement
SCER	Standing Council on Energy and Resources
SCO	Senior Committee of Officials
SEA Gas	South East Australia Gas
STTM	Short Term Trading Market
SWQP	South West Queensland Pipeline
SWP	South West Pipeline
TSO	Transmission System Operator
TJ	terajoule
UIOLI	Use-it-or-lose-it
UIOSI	Use-it-or-sell-it

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## **1. PURPOSE OF THIS REGULATION IMPACT STATEMENT**

This regulation RIS represents the SCER's final policy position on possible changes to the way in which natural gas transmission pipeline capacity is traded.

Although there is already some limited trade in unused capacity, anecdotal evidence suggests that the absence of a transparent and responsive market for trading unused pipeline capacity may be making such transactions more complex and costly than they need be. Over time, in a larger and more dynamic east coast market, these concerns may also become material to efforts to improve market transparency and liquidity.

Consequently, at its December 2012 meeting, SCER Ministers agreed to consider more broadly whether there are appropriate mechanisms available to improve trade in gas transmission pipeline capacity in the eastern gas market. This RIS is part of that process.

## **2. INTRODUCTION**

Australia is experiencing a significant structural change in the domestic production, consumption and trade of natural gas. The continued expansion of liquefied natural gas (LNG) export capacity and the rapid growth of the east coast coal seam gas (CSG) industry are driving these changes. The development of Queensland's CSG-LNG projects will: require a significant expansion in production capacity and the development of large reserves; provide producers with the opportunity to access higher international gas prices; sharpen competition for gas; and drive market development for the next decade or longer.

Some domestic gas transmission pipelines are often operating at close to capacity and there are significant upfront costs involved in building new capacity. It may also be administratively complex and expensive for new entrants to access existing unutilised (although potentially contracted) capacity. Increasing the capacity utilisation of existing domestic gas transmission pipelines may provide an avenue to more efficiently allocate gas in the market and could also facilitate additional gas being delivered to the market.

### ***2.1 Gas Market Regulatory Framework***

The regulatory framework governing Australia's gas market is set out in the National Gas Law (NGL) and associated National Gas Rules (NGR). The NGL is underpinned by the National Gas Objective (NGO) which is:

“To promote efficient investment in, and efficient operation and use of, natural gas services for the long-term interests of consumers of natural gas with respect to price, quality, safety, reliability and security of supply of natural gas.”

Access to unutilised pipeline capacity has been raised by a number of stakeholders as an important issue for improving the efficiency of infrastructure, the operation of trading markets and the continuing evolution of Australia's gas markets.



In the eastern states, there is a potential risk of tight gas supply conditions occurring over the period 2015 to 2018 due to slower than expected ramp up of new CSG supply, coupled with significant new demand from LNG producers from 2014. These developments reinforce the need for the continued development of efficient domestic gas markets.

In recognition of these issues, and in the pursuit of improved transparency and efficiency of the market, SCER has agreed that Government efforts be focused on actively pursuing two policy principles:

- 1) ensuring supply can respond flexibly to market conditions; and
- 2) promoting market development.

These principles are being given effect through the implementation of an Australian Gas Market Development Plan, agreed to by SCER on 14 December 2012.

## **2.2 Gas Market Reforms**

The eastern Australian natural gas market has undergone substantial development over the past 20 years. The expansion of pipeline infrastructure has resulted in increasing interconnection between demand centres and gas consumption by industry, power generators and households has almost doubled. These changes have been accompanied by an extensive market reform agenda that has seen the introduction of wholesale and retail competition in many regions.

Australian gas markets have been subject to initiatives designed to support development in line with the long-term interests of consumers. To date, this reform has primarily focused on transmission and distribution competition and access issues and increasing market transparency and flexibility. This has led to the national regulation of pipeline infrastructure that has natural monopoly characteristics to facilitate more efficient investment in and operation of Australia's gas networks.

In the mid-1990s, the Council of Australian Governments (COAG) led the removal of barriers to the interstate trade in gas and the development, and eventual enactment in 2008, of nationally-consistent gas legislation, the NGL. The NGL includes provisions for third-party access to regulated (referred to as covered) pipelines that display natural monopoly characteristics.

In 2003, COAG agreed to the creation of the Australian Energy Market Commission (AEMC) and Australian Energy Regulator (AER). The AEMC is the rule maker and developer for Australian energy markets while the AER is the regulator for covered pipelines in Australia's eastern markets. In 2007, energy Ministers agreed to establish the Australian Energy Market Operator (AEMO) that operates Australia's eastern energy markets. The above changes were designed to create efficiencies through centralised rule-making, regulatory decision making and enforcement, market operation and planning.

In 2004, the Ministerial Council on Energy (MCE, now SCER) was given specific responsibility by COAG to accelerate development of a 'reliable, competitive and secure natural gas market'. The scope of the industry-led, eastern gas market reform

agenda has expanded from networks to facilitating greater provision of market information, including a BB and an annual Gas Statement of Opportunities, and the establishment of new, shorter-term trading market options. Spot markets now exist in the Victorian Declared Wholesale Gas Market (DWGM) and Short Term Trading Market (STTM) hubs in Adelaide, Sydney and Brisbane.

Most recently, SCER has tasked AEMO with implementing a 'Brokerage' model GSH to be located at Wallumbilla, Queensland by 2014 (see Box 1). The Wallumbilla GSH will be a liquid reference point for spot and forward trading and will support bilateral trading of unused pipeline capacity via a bulletin board style, web-based capacity listing service that will allow market participants to advertise a willingness to buy or sell gas transportation services. AEMO is also developing standardised terms and conditions for capacity transfer between shippers at the Wallumbilla GSH. This work complements, but is separate to, this RIS process.

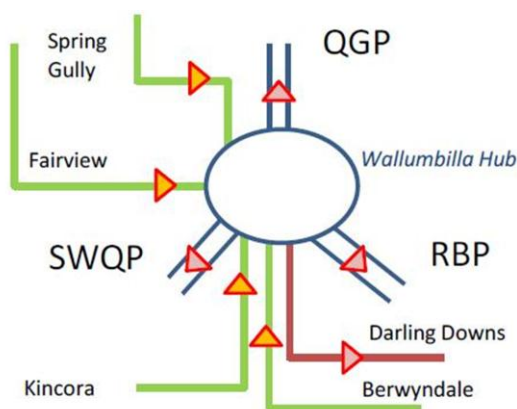
This initiative has acted as a trigger to further examine natural gas transmission pipeline capacity utilisation because GSH services will rely on market participants offering up unused pipeline capacity for trade.

While significant gas market reforms have been undertaken to date, the eastern Australian gas market is undergoing significant change, transitioning from an isolated and self-sufficient market to one linked to high-value international gas markets. Within this dynamic gas market environment, enhanced pipeline capacity trading may facilitate more opportunistic gas trading activity and ultimately help build competition and liquidity in the wholesale market over time.

### Box 1: Wallumbilla Gas Supply Hub

In 2011, the Queensland Government proposed implementing a GSH as part of its Annual Gas Market Review 2011. On 9 December 2011, the SCER agreed to request the AEMO to prepare a full project scoping and cost report on the development of a GSH model. At its December 2012 meeting, SCER agreed to task AEMO with implementing the ‘Brokerage’ hub model – for initial application in Wallumbilla in southern Queensland by early 2014.

Wallumbilla was selected for the Hub because it is the location where three gas transmission pipelines converge, namely the: Queensland Gas Pipeline (QGP); Roma to Brisbane Pipeline (RBP); and the South West Queensland Pipeline (SWQP). In addition, pipelines from several coal seam gas (CSG) fields meet at Wallumbilla.



The GSH represents an incremental step towards the development of an upstream gas market. Participation will be voluntary and trading will complement existing long-term contractual arrangements and provide flexibility for participants to buy or sell gas.

The GSH will establish an exchange to match and clear trades using existing physical infrastructure. Buyers and sellers will place bids and offers for a particular quantity of gas being delivered to the relevant hub location. If a bid and offer match on price, the trade will be cleared by AEMO. Buyers will then be responsible for arranging transportation of gas away from the Hub. The success of the Hub will be dependent on market participants accessing unused pipeline capacity to facilitate gas trades.

### 3. EASTERN GAS MARKET

The Australian domestic gas market consists of three distinct regional markets: the eastern market (comprising Queensland, New South Wales, Australian Capital Territory, Victoria, South Australia and Tasmania); the western market (Western Australia); and the northern market (Northern Territory). Due to the vast distances between each region, the construction of pipeline infrastructure to connect these markets is at this time uneconomic.

While transmission pipeline capacity trading is of interest to all Australian jurisdictions, the focus of this RIS is on the eastern gas market because the nature of the eastern market (i.e. a network of inter-connected gas transmission pipelines, some with unused capacity) lends itself to capacity trading opportunities. Further, capacity trading has the potential over time to become increasingly important to:

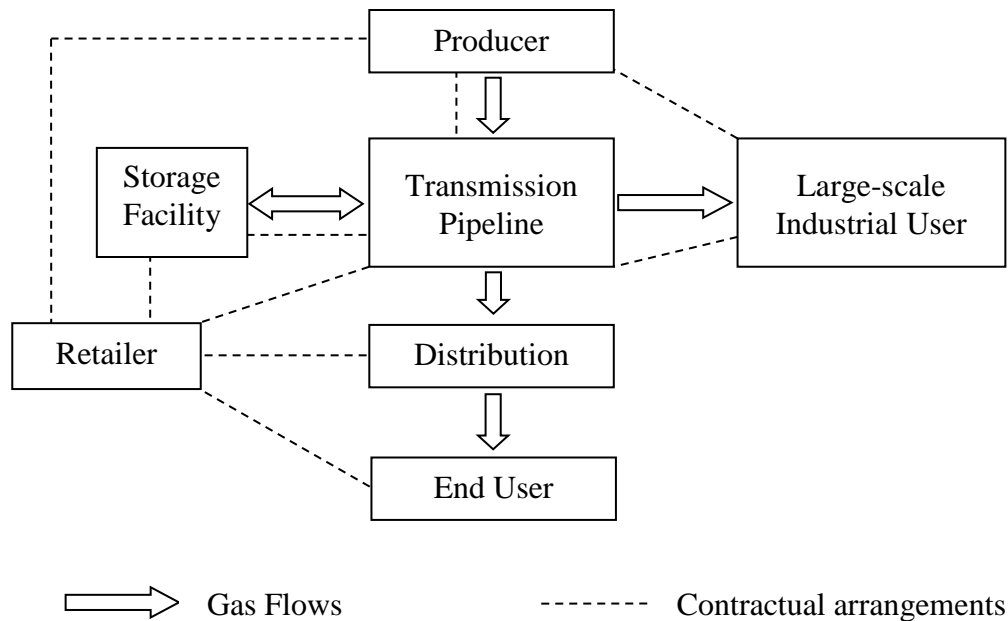
- efficiently re-allocate unused capacity and gas to higher-value uses;
- maximise the efficiency of capital stock;
- incentivise pipeline investment;
- create opportunities for gas trading, particularly at the Wallumbilla GSH;
- lower barriers to entry and increase competition; and
- assist with bringing additional gas to market.

#### 3.1 *Roles of Market Participants*

In Australia, the gas supply chain (Figure 1) consists of the following sectors:

- upstream gas production facilities: businesses extract gas and process it to a standard that enables it to be sold to domestic or international markets;
- transmission pipelines: transport natural gas from gas fields to demand centres;
- storage facilities: enhance security of supply by facilitating the injection of gas into the transmission system at short notice to better manage peak demand and emergencies;
- distribution networks: typically consists of high and medium pressure pipes (to transport gas within a demand centre) and low pressure pipelines (servicing end users); and
- gas retailers: sell a range of natural gas products to end users on varying terms.

**Figure 1: Gas Supply Chain**



### 3.2 Gas Supply

During the 12 months to June 2013, eastern Australian natural gas producers supplied 735 petajoules (PJ) of gas into the domestic market. The vast majority of eastern gas demand was met by 22 producers operating across several basins including the Cooper, Gippsland, Otway and Surat-Bowen basins. Of these producers, six accounted for approximately 77% of production with the remaining 16 producers holding between 0.1% and 3.8% of market share (see Table 1 for further details).

Gas producers sell gas in wholesale markets either directly to end users such as large-scale industrial consumers, mining and power generation consumers or to energy retailers. Large-scale industrial consumers include brickworks, fertiliser plants, petroleum refineries, paper mills, cement producers and explosives manufacturers. The terms under which this gas is sold are specified in gas supply agreements (GSAs). Retailers then sell to smaller commercial/industrial users and residential users.

**Table 1: Eastern Australia Supply Side Participants**

Gas Producers	Eastern Australia Production (12 months to June 2013)		Market Share	
BHP Billiton	153.8 PJ		20.9%	
ExxonMobil	131.2 PJ		17.9%	
Santos	96.3 PJ		13.1%	
Origin Energy	91.5 PJ		12.5%	
BG Group	51.2 PJ		7.0%	
ConocoPhillips	41.6 PJ		5.7%	
Other	169.1 PJ		23.0%	
<b>TOTAL</b>	<b>734.6 PJ</b>		<b>100%</b>	
Transmission Pipeline Owners	Pipeline	State	Covered	Capacity/Length
APA Group	LMP	VIC	Yes	1,030 TJ/d; 173 km
	SWP	VIC	Yes	353 TJ/d; 144 km
	NVI	VIC/NSW	Yes	90 TJ/d; 145 km
	SEA Gas (REST 50%)	VIC/SA	No	314 TJ/d; 680 km
	MSP	SA/NSW	Light <sup>a</sup>	439 TJ/d; 2,029 km
	RBP	QLD	Yes	233 TJ/d; 440 km
	CGP	QLD	Light	119 TJ/d; 840 km
	SWQP	QLD	No	404 TJ/d; 756 km
	QSN	QLD/SA/NSW	No	212 TJ/d; 180 km
Jemena	QGP	QLD	No	145 TJ/d; 629 km
	EGP	VIC/NSW	No	289 TJ/d; 795 km
EPIC <sup>d</sup>	MAP	SA	No	241 TJ/d; 1,185 km
Victorian Funds Managm't Corp	NQGP	QLD	No	108 TJ/d; 391 km
Palisade Investment Partners	TGP	VIC/TAS	No	129 TJ/d; 734 km
Gas Retailers (Active)	Markets		Customers	
Origin Energy <sup>b</sup>	NSW, QLD, VIC, SA		4.3 m <sup>c</sup>	
AGL Energy	NSW, QLD, VIC, SA		3.5 m <sup>c</sup>	
EnergyAustralia	NSW, VIC, SA, ACT		2.7 m <sup>c</sup>	
Lumo Energy	VIC		400,000 <sup>c</sup>	
Australian Power & Gas	QLD, VIC		341,000	
ActewAGL Retail	ACT, NSW		124,000	
Red Energy	VIC		n.a.	
Simply Energy	VIC, SA		n.a.	
Aurora Energy	TAS		n.a.	
Tas Gas Retail	TAS		6,000	
Dist. Network	Market	Owners	Customers	
Multinet	VIC	DUET Group	668,000	
SP AusNet	VIC	SP AusNet (Singapore Power International, 51%)	602,000	
Envestra	VIC	Envestra (APA Group, 33.4%; Cheung Kong Infra.18.9%)	587,400	
Jemena	NSW	Jemena (Singapore Power International)	1,050,000	
ACTEWAGL	NSW, ACT	ACTEW (ACT Gov't, 50%; Jemena, 50%)	124,000	
Wagga Wagga	NSW	Envestra (APA Group, 33.4%; Cheung Kong Infra.18.9%)	23,800	
Central Ranges	NSW	APA Group	7,000	
Envestra	QLD	Envestra (APA Group, 33.4%; Cheung Kong Infra.18.9%)	89,100	
Allgas Energy	QLD	APA Group (Marubeni 40%; RREEF 40%)	84,400	
Envestra	SA	Envestra (APA Group, 33.4%; Cheung Kong Infra.18.9%)	410,700	
Tas Gas	TAS	Tas Gas (Brookfield Infrastructure)	8,900	
<b>TOTAL</b>			<b>3,656,200</b>	

Sources: Australian Energy Regulator (2012) *State of the Energy Market 2012*  
 EnergyQuest (2013) *Energy Quarterly*, August Quarter  
 IBISWorld (2012) *Gas Supply in Australia*  
 Company websites  
 AEMO, National Gas Market Bulletin Board

Notes: a) Partially regulated b) including Country Energy and Integral Energy c) Electricity and gas customers  
 d) QIC Global Infrastructure

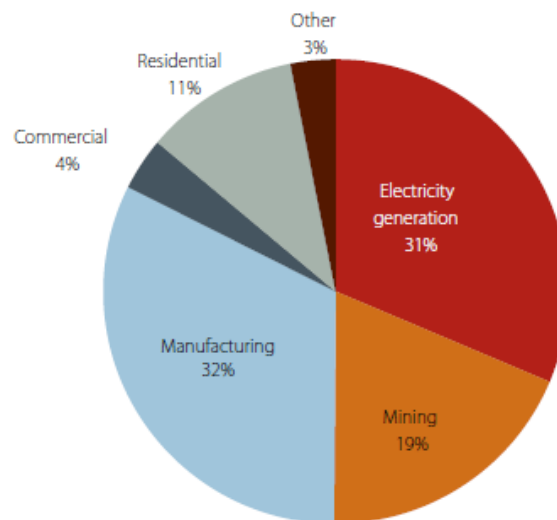
SWQP - South West Queensland Pipeline LMP - Longford to Melbourne Pipeline EGP - Eastern Gas Pipeline  
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 SEA Gas - South East Australia Gas MAP - Moomba to Adelaide Pipeline RBP - Roma to Brisbane Pipeline  
 SWP - South West Pipeline CGP - Carpentaria Gas Pipeline QSN - QSN Link  
 NQGP - North Queensland Gas Pipeline TGP - Tasmania Gas Pipeline n.a. - not available

### 3.3 Domestic Gas Demand

In 2011-12, 82% of Australia's domestic gas demand came from the manufacturing, electricity generation and mining sectors with residential demand only accounting for 11% as shown in Figure 2.

The gas demand profiles for manufacturing and mining operations tend to be relatively constant throughout the year while electricity generation and residential/commercial demand profiles tend to be subject to time-of-day/week and seasonal variations.

**Figure 2: Australian Primary Consumption of Gas by Sector (2011-12)**



Source: BREE (2013) *Gas Market Report*

### 3.4 Gas Demand by LNG Projects

On Australia's east coast, there are three CSG-LNG projects under construction in Gladstone, Queensland: Gladstone LNG (Operator – Santos); Queensland Curtis LNG (Operator – BG Group); and Australia-Pacific LNG (Operator – Origin Energy). These projects are expected to begin LNG production in 2014-15 and they will collectively require approximately 1,300 PJ of gas per annum (p.a.) to produce approximately 25.3 million tonnes of LNG per annum (mtpa). There is also a fourth project at the planning stage, the Arrow LNG Project (Operator – Shell). If the Arrow project is sanctioned, it could begin as a two production 'train' project with potential to expand to a 4 train project that could produce up to 18 mtpa of LNG. Arrow would require approximately between 400-800 PJ p.a. depending on the scale of the project.<sup>1</sup>

### 3.5 Transportation

Gas is 'shipped' from production centres to demand centres via large diameter (approximately 300-800mm) gas transmission pipelines. In the eastern market, gas is transported to consumers through a network of 14 major gas transmission pipelines as shown in Figure 3.

<sup>1</sup> The Arrow LNG Project is expected to make a final investment decision in late 2013.

**Figure 3: Eastern Australia Gas Transmission Network**



Source: Core Energy (2011) *Energy Outlook, Part 3: The Eastern Australian Gas Market*

Pipeline owners underwrite the construction of new pipelines, or major expansions in pipeline capacity, with long-term foundation contracts (typically 10-15 years). These contracts are known as gas transportation agreements (GTAs). Among other things, GTAs specify maximum daily quantities (MDQs) of gas that may be shipped under prescribed terms and conditions. Shippers nominate before each gas day how much of the MDQ they wish to transport.

Gas that is transported under long-term GTAs (usually under foundation contracts) is shipped on a ‘firm’ basis whereby operators are obliged to transport gas on a non-interruptible basis. However, the transportation of gas is always subject to planned and unplanned interruptions as well as *force majeure*<sup>2</sup> provisions, which allow pipeline operators to interrupt firm services without incurring liability.

<sup>2</sup> *Force majeure* is an event that occurs outside the control of parties to a contract and which could not have been foreseen, planned for or evaded through the exercise of due care (e.g. natural disaster).

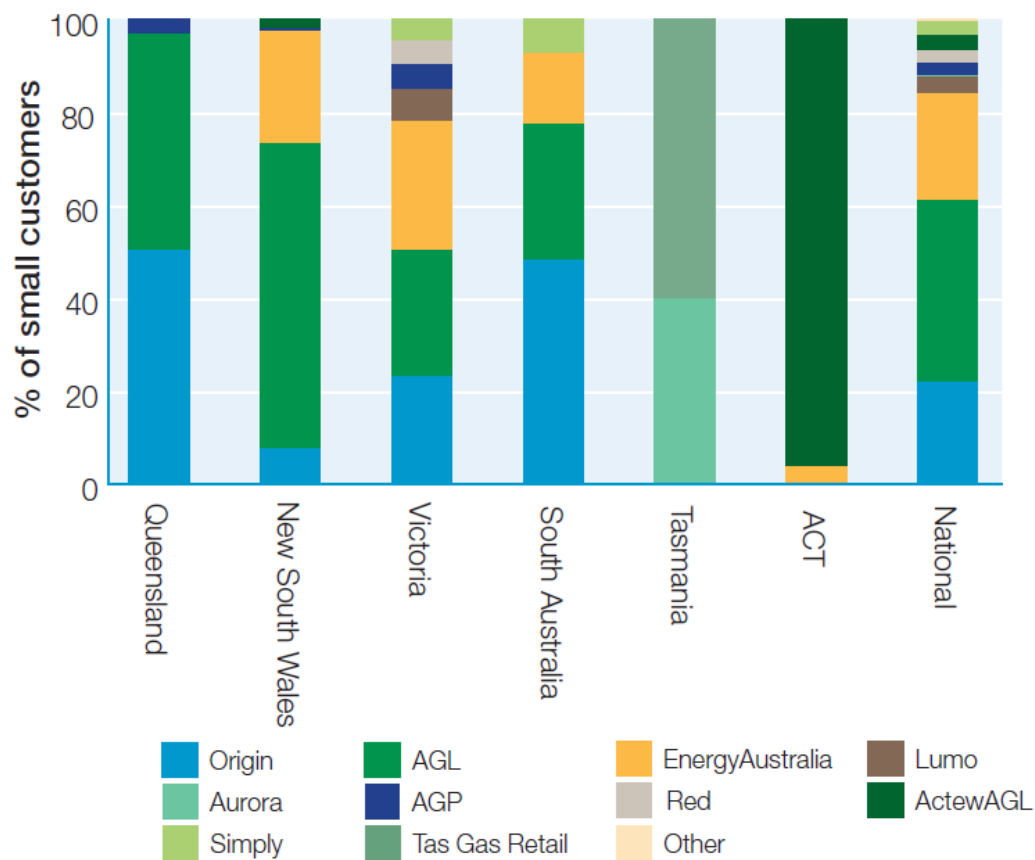


Operational management of pipelines is undertaken by pipeline operators who are generally the same business entities that own the asset, but in some cases, either a third party or one of the joint venture owners of the asset operates the pipeline on behalf of the owner/s. In this RIS, pipeline owners and operators are collectively referred to as pipeliners.

Pipeliners sell transportation capacity to retailers, large-scale industrial consumers and some producers (collectively known as shippers). In eastern Australia, retailers sell the overwhelming majority of gas and it is understood that retail sales account for more than 90% of the south-eastern gas market. Retailers' shipping arrangements are therefore the main determinant of capacity utilisation in this region. In contrast, Queensland is predominately a wholesale market with the majority of gas sold to industrial customers who take gas directly from transmission pipelines. Therefore, the main determinant of capacity utilisation in Queensland is industrial users. NSW has a similar market to Queensland with industrial and electricity generation consumption dominating.

Retailers arrange with gas distribution network operators to supply gas to end users via local gas distribution networks. There are 12 active gas retailers in eastern Australia with typically only 1-2 transmission pipelines servicing each demand centre. Figure 4 indicates that during 2012, AGL Energy, Origin Energy and EnergyAustralia supplied approximately 84% of small gas customers in eastern Australia.

**Figure 4: Eastern Australian Retail Market Share (small customers) 2012**



Source: Australian Energy Regulator (2012) *State of the Energy Market 2012*

Network operators own reticulated pipeline distribution networks within demand centres, providing the means for gas retailers to deliver gas to end users. In the east, there are 11 gas distribution networks (see Table 1 for details).

In Australia, pipeline capacity management is handled by either the contract carriage approach or the market carriage approach. Under contract carriage, pipeliners enter into bilateral GTAs with shippers. However, under the market carriage model, an independent system/market operator manages pipeline capacity through a pool approach. The pipeline owner makes the relevant pipeline system available to the system/market operator under contract (the service envelope agreement). Users of a market carriage pipeline are not able to reserve capacity on the pipeline.

Contract carriage is used for transmission pipelines in all states and territories except for Victoria where the market carriage model is used for the Victorian declared transmission system (DTS) that encompasses the SWP, LMP and NVI pipelines. AEMO manages the operation of DTS pipelines and also operates the Victorian DWGM which applies to the DTS.

The focus of this RIS is on pipeline capacity trade that relates to pipelines managed under the contract carriage approach.

### ***3.6 Concentration and Ownership***

During the past 10-15 years, some downstream market participants have strengthened their positions. The privatisation of Victoria's, South Australia's, Queensland's and NSW's electricity and gas retail markets have bolstered downstream market power, with AGL, EnergyAustralia and Origin the dominant entities. These companies are also employing vertical integration strategies in the gas and electricity sectors.

For the transportation component of the market, the overwhelming majority of pipeline assets are owned by only two companies; APA Group and Jemena.

Table 2 details the current state of activity in the major eastern Australian pipelines. It shows which pipelines tend to be retailer-dominated and those where some industrial customers have also entered into GTAs with pipeline owners.

**Table 2: Major Firm Shippers in Eastern Australian Pipelines**

Pipeline	Major Shippers	Comment
RBP	Mostly large industrial customers including Incitec, Stanwell (Swanbank E power station) and BP's refinery.  Retailers supply Brisbane market (only 15-20 PJ/a).	Diverse pipeline, with a variety of users. The RBP has a large number of delivery points, to which not all shippers have contractual access.
QGP	Mostly large industrial customers such as QAL and Comalco. AGL and Origin are also present.	Currently fully contracted. Some users have insufficient pipeline capacity and are curtailing gas supply.
SWQP and QSN	<i>Western bound flow</i> (current direction): Virtually 100% of capacity contracted to AGL and Origin.  <i>Eastern bound flow</i> (expected flow from 2015); Santos major shipper to GLNG and Origin.	Retailer domination of SWQP capacity limits competition for gas supply to NWQ and southern markets.
CGP	Mostly large industrial NWQ mining customers.  AGL became a significant shipper from May 2013.	NWQ customers purchase gas at Ballera. With Santos' SWQ Cooper Basin supply constrained, only AGL and Origin can supply at Ballera via the SWQP.
MSP	AGL is the dominant existing shipper.	
MAP	Origin and AGL are the major shippers. Several SA industrial customers are also shippers.	Retailers dominate MAP firm transportation.
EGP	Existing foundation EGP transportation by BHP has been on sold to retailers.	Retailers dominate EGP firm transportation.
SEA Gas	Retailers and GDF Suez Australian Energy.	Retailers dominate SEA Gas firm transportation.

Source: Industry consultations

### 3.7 Recent Market Outcomes

In the eastern states, there is potential risk that a tightening of gas supply may occur from 2015 to 2018 due to slower than expected ramp up of new CSG supply, coupled with significant new demand from LNG exporters from 2014. Gas prices are rising due to higher costs of production and competition for gas from LNG producers.

While the vast majority of producers have historically sold gas to retailers and large consumers under confidential, long-term contracts, recently there has been some growth in shorter-term contracts and spot market gas trades, although precise details concerning these sales and their quantum are not publicly known.

As discussed in Section 7.1, there have often been periods throughout the year when eastern pipelines have significant volumes of unutilised capacity (e.g. SWQP, MSP, MAP, Sea Gas, LMP and EGP). The unused capacity on these pipelines is predominantly contracted to retailers. There have also been periods when pipeline capacity in Queensland is not fully utilised (e.g. RBP, QGP and CGP). The unused capacity on these pipelines is predominantly contracted to industrial customers.

## 4. REGULATORY ENVIRONMENT

The NGL and subordinate NGR commenced 1 July 2008, bringing regulation of natural gas pipelines under the national energy framework. The NGL and NGR introduced regulatory and access arrangements for pipelines as discussed below. The NGL and NGR are applied in all jurisdictions, except Western Australia, through the passage of legislation in South Australia and application Acts in all other jurisdictions. Instead of an application Act, Western Australia enacted the NGL and NGR through complementary legislation on 1 January 2010.

### 4.1 *Regulated Transmission Pipelines*

Various tiers of regulation apply to pipelines, based on decisions of relevant energy ministers in the context of assessment of competition and significance criteria by the National Competition Council. Pipelines are either uncovered (i.e. not covered by regulation), lightly regulated, fully regulated or partially regulated (i.e. only a portion of the pipeline is regulated). Where regulated, this may apply to only a nominated subset of services on the pipeline.

Six of Australia's 14 major eastern gas transmission pipelines are covered by economic regulation (see Table 1 for further details). The rationale for the economic regulation of gas pipelines is that these assets are considered to be natural monopolies. Consequently, access and/or price regulations are applied to limit owners' market power and promote market efficiency.

In jurisdictions other than Western Australia<sup>3</sup>, the AER regulates certain pipelines under the NGL and NGR. Full regulation requires a pipeline owner to periodically submit to the AER an access arrangement for approval. On covered pipelines, pipeliners are obligated to offer capacity in accordance with an access arrangement that sets out the terms and conditions under which third parties can access available firm capacity. Access is dependent on the availability of uncontracted capacity. Regulations and rules have not been instituted to specifically maximise or optimise capacity utilisation and pipeliners or shippers are not compelled to offer contracted but unused capacity. Access arrangements must specify at least:

- one reference service likely to be sought by a significant part of the market;
- a reference tariff for that service;
- capacity trading requirements;
- queuing requirements (if applicable) to determine user priorities for spare capacity;
- how the pipeline is to be expanded or extended; and
- how access requests are to be dealt with.

The AER first assesses the revenues needed to cover efficient costs and provide a commercial return on capital, then it can derive reference tariffs for the pipeline. Access arrangements are periodically reviewed by the AER.

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<sup>3</sup> The Economic Regulation Authority regulates pipelines in Western Australia.

Under light regulation, the pipeline provider determines its own tariffs. The provider must then publish relevant access prices and other terms and conditions on its website. In the event of a dispute, a party seeking access to the pipeline may ask the AER to arbitrate.

Certain pipelines were automatically covered when the regulatory regime commenced. Pipelines may become covered if they meet certain criteria set out in the NGR. Covered pipelines may become uncovered if they no longer meet those criteria. Industry can also apply for a no coverage determination that provides for a 15-year exemption from regulatory coverage for greenfields pipelines in limited circumstances.

#### **4.2 Unregulated Transmission Pipelines – Negotiated Outcomes**

For uncovered pipelines (i.e. 8 of 14 eastern pipelines), third party access is negotiated bilaterally on commercial terms and conditions that may differ from those set through regulatory processes. Disputes are also resolved via commercial processes as set out in individual GTAs.

While GTAs or GSAs are not specifically mentioned in energy laws or rules, certain elements thereof are (e.g. access rights, *force majeure* and dispute resolution details).

GSAs generally include the following:

- parties' responsibilities and obligations;
- annual quantities (including seasonal variations);
- monthly estimates and daily nomination details;
- supply term;
- supply arrangements including permitted interruption and quantity variation details;
- price review mechanisms;
- billing and payment obligations and details;
- gas quality and measurement details;
- sufficiency of proved and probable gas reserves details;
- provisions in the advent of default or termination;
- resolution of disputes;
- confidentiality details;
- *force majeure* provisions; and
- credit provisions.

While GSAs typically include many of the above elements, the terms and conditions of individual contracts may differ considerably and are commercial-in-confidence.

GTAs generally include the following:

- forecast, nomination and scheduling;
- trading of MDQ (including trading by shipper and restrictions on trade details);
- receipt and delivery point details and obligations;
- system use gas and gas imbalance allowances;
- additional charges such as overrun, imbalance and daily imbalance charges;
- park and loan arrangements;
- rights and obligations of the transporter;
- shipper's warranty and linepack<sup>4</sup> details;
- prioritisation of delivery details;
- gas quality and measurement;
- access rights;
- data and information exchange details;
- transportation charges;
- insurance details;
- provisions in the advent of default or termination;
- resolution of disputes;
- confidentiality details;
- *force majeure* provisions; and
- credit provisions.

While GTAs typically include many of the above elements, they are commercial-in-confidence and the terms and conditions of individual contracts may differ considerably.

## **5. ECONOMIC RATIONALE FOR SECONDARY CAPACITY TRADING**

In Australia, the overwhelming majority of gas is transported under long-term GTAs that underpin investment in pipelines. This transportation capacity is sold by pipeliners and the trade in this firm capacity is referred to as primary capacity trade. Subsequent trade in this firm capacity is referred to as secondary capacity trade, which is the focus of this RIS.

In the context of upstream gas supply markets, it is important that pipeliners provide reasonable access to and pricing of gas transportation capacity services that can increase competition by facilitating basin-on-basin competition and allow the entry of independent new entrants. As such, more efficient access and pricing of transport services can facilitate upstream markets that are more competitive as a result of being both broader and deeper.

While primary capacity trade facilitates pipeliners' investment in new or expanded pipeline capacity, secondary trading provides a mechanism to re-allocate existing capacity that would otherwise lay idle for significant periods, such as periods of low seasonal demand.

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<sup>4</sup> Linepack is the quantity of gas contained in a pipeline and represents its storage capacity.

Accordingly, secondary trading mechanisms can promote access to infrastructure and improve efficiency by signalling the short-run marginal value of pipeline services. This is important to promote:

- allocative efficiency at any given point in time — that is, to ensure capacity is made available to shippers that value it most highly;
- dynamic efficiency, with the value of secondary trades signalling the value of investment (to resolve congestion) over the longer run and efficiently delaying the need for incremental pipeline investment;
- productive efficiency, by improving the capacity utilisation of the network; and
- competition in upstream and downstream supply by reducing barriers to entry.

Importantly, a transparent secondary trading mechanism utilising standardised transportation entitlements would not only improve short-run efficiencies, it can also significantly contribute to longer-term market development objectives including deepening market liquidity by providing improved access to transportation services for gas sold under shorter-term GSAs.

## **6. SOURCES OF TRANSMISSION PIPELINE CAPACITY**

The Australian pipeline industry is based on an investment model that minimises risk and it would be very rare for a pipeline owner to expand pipeline capacity without long-term commitments from users to underpin the capital investment.

This RIS concerns the trade in contracted, but unutilised, pipeline capacity and it is recognised that market participants seeking significant capacities are able to enter into contractual arrangements with pipeline owners that could underwrite investment to expand existing pipeline capacity.

### **6.1 Expansion**

In addition to building new pipelines as greenfield investments, over time, pipeline owners have the option to install additional compression units on their pipelines and therefore provide additional transportation capacity on a particular route. Another option to increase capacity is via ‘looping’ (duplicating part of, or all of) an existing pipeline, thereby increasing flow and storage capacities.

It is understood that the majority of eastern market pipelines could have their capacities expanded by way of installing additional compression.<sup>5</sup> This represents a relatively low-cost means to increase the amount of gas that could be shipped on a pipeline. However, it is recognised that beyond a point, there are diminishing marginal returns associated with the installation of additional compression capacity. Further, upgrades to compression facilities and pipeline infrastructure are generally required to be underwritten by long-term contracts.

However, there have been some recent announcements concerning shorter-term GTAs that underpin pipeline capacity expansion with one example involving three contracts

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<sup>5</sup> The next stage of EGP expansion is via looping, with most of the other pipelines via compression.

ranging in duration from 4½ years to 6 years.<sup>6</sup> These contracts will underpin capacity expansions by APA Group to deliver gas from Victoria into NSW through the NSW-Victoria Interconnect (NVI).

In the case of covered pipelines, access arrangements include queuing requirements that must contain a process or mechanism (or both) for establishing an order of priority between prospective users of spare or developable capacity (or both) in which all prospective users are treated on a fair and equal basis. In the case of uncovered pipelines, shippers seeking capacities above constructed capacity need to negotiate with pipeline owners to underwrite capacity expansions.

In some overseas markets when pipeliners are approached with queries concerning expanding capacity, there is a requirement for pipeliners to put forward a public ‘open season’ request seeking as many interested parties as possible to support the development of new pipeline infrastructure.<sup>7</sup> In Australia, the onus is on pipeliners to work with established and new customers to underpin new investments.

## **6.2 Unutilised Capacity**

It is understood that shippers may build in a margin to their MDQs to ensure that they will have adequate gas to cover expected peak gas demand throughout the year. Shippers who have nominated gas flows less than their MDQs are free to trade the unused portion of their MDQs, subject to the terms and conditions of their GTAs. Mechanisms for effecting such trades are discussed in detail below.

On a day-before basis, shippers provide final nominations to pipeline operators of the pipeline capacities they will require for the following day (the gas day).<sup>8</sup> Pipeline operators then aggregate nominated daily gas flows and determine the total volume of gas that will need to flow the following day.

In cases where the total MDQs for a particular pipeline equal the full capacity of a pipeline, the pipeline is fully contracted. On fully-contracted pipelines, unless unutilised capacity is traded, or additional pipeline capacity is constructed, no further firm capacity can be offered.

If firm shippers on a particular pipeline do not nominate their full MDQ entitlements, it is highly likely that gas flows will be less than the pipeline’s capacity on a given day. In these circumstances, pipeliners may offer gas transportation services on an ‘as available’ basis whereby gas is delivered on an interruptible basis, utilising the above free capacity. This class of transportation service is provided at the pipeliner’s discretion and will generally only be provided if the pipeliner is very confident that there will be adequate capacity to meet both firm and ‘as available’ requirements.

For example, a pipeline may have a nameplate capacity of 100 terajoules (TJ)/day. The pipeliner may have firm contracts in place that total 100 TJ/day but these shippers

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<sup>6</sup> <http://www.apa.com.au/investor-centre/news/asxmedia-releases/2013/apa-to-further-expand-vic-nsw-interconnect.aspx>

<sup>7</sup> Open season processes occur in the US and in Europe.

<sup>8</sup> For planning purposes, shippers are also required to provide pipeliners with detailed, longer-term forecasts for their daily gas transportation requirements.



only nominate a total of 65 TJ flow for the following day. If these shippers decide not to trade their unused capacities, the pipeliner may choose to offer up to the market, on an ‘as available’, interruptible basis, 35 TJ of pipeline capacity, depending on the original contract terms.

As a result, pipeliners can effectively sell some capacity twice, initially under the original contract, and again on an ‘as available’ basis if shippers do not use fully their MDQ entitlements. These services can be offered concurrently because pipeline operators can interrupt ‘as available’ services should firm shippers decide to re-nominate during the gas day (intra-day) and increase their capacity requirements above that previously nominated, up to their MDQs.

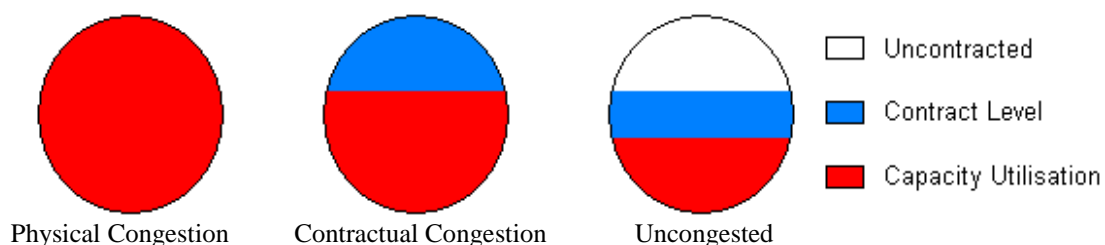
On pipelines that are fully contracted, if intra-day nominations result in all MDQs being fully used, ‘as available’ shippers may not have all their gas transported. In this way, ‘as available’ shippers bear all the risk of not being able to take delivery of gas on a given day.

## 7. CURRENT TRANSMISSION PIPELINE CAPACITY UTILISATION

Australia’s eastern market gas transmission pipelines experience differing levels of congestion ranging from ‘physical congestion’ to ‘contractual congestion’ to uncongested. Each of these states is explained below:

- **Physical congestion:** market participants are unable to gain access to capacity because there is a physical shortage of capacity in the pipeline. In this situation, the pipeline has all of its capacity contracted and capacity is being 100% utilised. The only way to deliver additional gas to the market would be to undertake new investment in additional capacity.
- **Contractual congestion:** market participants are unable to gain direct access to capacity on a pipeline because all of a pipeline’s capacity is contracted. Although all the capacity is contracted, the capacity is not being fully utilised. Capacity trading could deliver additional gas to the market and make more efficient use of existing infrastructure.
- **Uncongested:** a pipeline’s capacity is not fully contracted. Market participants can generally gain access to capacity via direct negotiation with pipeliner.

**Figure 5: Degrees of Pipeline Congestion**



The focus of this RIS is on trading opportunities relating to gas transmission pipelines that are contractually congested.

It is recognised that there are seasonal demand variations (particularly in the south) and unused capacities are generally higher in the warmer months when gas demand

for heating (both residential and commercial) is generally lower. On high demand pipelines such as the RBP, QGP, EGP and CGP, although there appears to be unused pipeline capacity during periods of lower demand, during periods of peak demand, there may only be small volumes of unused capacity, or none at all.

As at 1 November 2013, the MAP had uncontracted firm capacity available. However, uncontracted firm capacity may change over time as contracts expire and new contracts are negotiated. For example, as at 1 January 2014, the MSP and CGP will have uncontracted capacity available.

However, there is limited transparency concerning uncontracted and unutilised firm capacity and it is unclear exactly what unutilised firm volumes could be made available for secondary trade.

### **7.1 AEMO Data on Utilisation**

Some publicly-available information concerning aggregated pipeline capacity utilisation is accessible online via the BB.<sup>9</sup> Nominated daily flows and actual flow data are published daily on the BB. This data represents aggregated firm and 'as available' flow volumes. However, existing data only shows average daily flows and therefore does not provide information concerning intra-day peak flows.

The BB data shows that on all pipelines there have been volumes of unused pipeline capacity. During certain periods, the following pipelines had considerable volumes of unused capacity: SWQP; LMP; NVI, SWP, SEA Gas; MAP; and MSP. There are lesser volumes of unused capacity on the RBP; QGP; EGP; and CGP.<sup>10</sup>

It is understood that on pipelines that are subject to physical congestion (e.g. QGP) all the capacity has been fully contracted and is generally being fully utilised. The QGP is an example of a pipeline that predominantly services industrial customers whose demand profile remains reasonably constant throughout the year. Therefore, shippers on such pipelines may have limited capacity to participate in voluntary secondary trading. Further, to access capacity on these pipelines, market participants may need to buy capacity from the pipeliner, which may involve underwriting an investment in a capacity upgrade.

The above suggests that for some pipelines, including those experiencing contractual congestion (e.g. MSP), trading has the potential to increase utilisation of existing capacity. Even on uncongested pipelines (e.g. MAP) there may be an opportunity for existing shippers to compete with pipeline owners for the sale of firm capacity.

### **7.2 BB Data Limitations**

Caution needs to be exercised with some of the BB figures. For example, depending on the age of a pipeline and other engineering factors, the practical carrying capacity and the understood 'nameplate capacity' of a particular pipeline may differ considerably. The term 'nameplate capacity' is often used to describe the physical

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<sup>9</sup> <http://www.gasbb.com.au>

<sup>10</sup> Appendix B contains charts showing pipeline capacity utilisation data.

capacity of a pipeline on a medium to long-term basis. It is the intended technical full-load sustained capacity of the pipeline. ‘Operational capacity’ describes a pipeline’s physical capacity on a short-term basis and is subject to influences like discretionary maintenance.

For example, the BB notes the MSP (one of Australia’s oldest pipelines) has a capacity of 439 TJ/day. However, due to ongoing maintenance involving corrosion repair activities, the MSP’s operating pressure had been lower than its nameplate pressure and therefore it had not been operating at full capacity. This activity has since been completed and the MSP is now operating at normal pressure. Pipeliners typically schedule maintenance activities during periods of lower demand to minimise the impacts on gas transportation.

BB data shows that actual daily flows may be higher than nameplate capacities, as evidenced by historic flows on the EGP, QGP and SWP. However, these transitory, peak flows are above nameplate capacities and are not sustainable.

In summary, pipelines are designed to sustainably operate at nameplate capacities, however, due to seasonal demand variations or planned maintenance activities their operational capacities or actual flows may be greater or less than their nameplate capacities for transitory periods.

### ***7.3 Regulatory Coverage and Capacity Utilisation***

Regarding the effect that regulation has on pipeline capacity utilisation, there does not appear to be a correlation between the level of regulated access arrangements<sup>11</sup> and pipeline capacity utilisation. This is not surprising given that mandated access arrangements have been instituted to facilitate negotiations surrounding price and other conditions for the initial sale of primary capacity to shippers.

For example, the RGP and LMP are fully regulated and while the RGP consistently has high capacity utilisation, the LMP’s capacity utilisation varies widely throughout the year, largely a function of seasonal demand. Likewise, the QGP and MAP are unregulated and have quite different levels of capacity utilisation as discussed above.

### ***7.4 Are opportunities to trade being fully utilised?***

While virtually all pipeliners are likely to hold non-firm, or ‘as available’, interruptible gas transportation capacity, some market participants have suggested that pipeliners are generally more interested in negotiating longer-term transportation contracts for significant volumes rather than short-term contracts or deals for smaller or ad-hoc volumes. It is argued that this is because standalone short-term and/or small-quantity transactions represent low-value propositions for pipeliners and they may be more interested in pursuing other activities aimed at maximising revenue. There may also be significant transaction costs, for example it is understood that negotiations for ‘as available’ capacity can take between 2-4 weeks (or longer) to finalise. However, pipeliners refute this assertion noting they offer up smaller

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<sup>11</sup> As described in Section 4.1.

volumes of ‘as available’ capacity on a shorter basis.<sup>12</sup> It is understood that these low-value transactions may be undertaken if pursuing goals such as strategic relationship building.

Shippers that contract firm capacity on a long-term basis can negotiate ‘as available’ services as part of their larger deal with pipeliners. However, it may be time consuming and costly for small users to negotiate ‘as available’ services with pipeliners.

For firm capacity it is likely that, except for a few days a year when gas demand peaks (e.g. very cold days in Victoria), contracted retailers and possibly large-scale industrial customers are unlikely to fully utilise their MDQs, as discussed previously and evidenced by historic capacity utilisation data shown in Appendix B. Therefore, on any given day it is highly likely that unused firm gas transmission volumes will exist. This creates an opportunity, which is not necessarily exercised, for the trade in short-term, secondary firm capacity.

Gas transported via secondary capacity transactions could facilitate the establishment of gas storage investment and/or the more efficient utilisation of existing storage infrastructure. This could involve transporting and storing gas during periods of low capacity utilisation and then withdrawing and supplying that gas during periods of peak demand.

The availability of this class of firm transmission capacity will be dependent on whether or not existing shippers offer it up to the market. Ultimately, shippers with unused firm capacity will weigh up the costs and benefits of trading their unused capacities. However, there may be limited incentives to offer up this capacity, particularly in the absence of a timely and cost-effective capacity trading mechanism.

In summary, it appears likely that the level of trading activity is currently lower than it could be given the transaction costs involved and the possibility that the current market structure may mean there are limited incentives to bringing this capacity to market.

## **8. CAPACITY TRADING TRANSACTIONS**

### **8.1 *Transaction Types***

In Australia, secondary pipeline capacity trade occurs by either novation or bare transfer. In some overseas markets, capacity is also traded using the alternative mechanisms discussed below.

#### **8.1.1 *Novation***

Novation is a permanent transfer of capacity whereby a shipper assigns all or part of their firm capacity to a third party and the assignee must enter into a new GTA with the pipeliner for the assigned capacity.

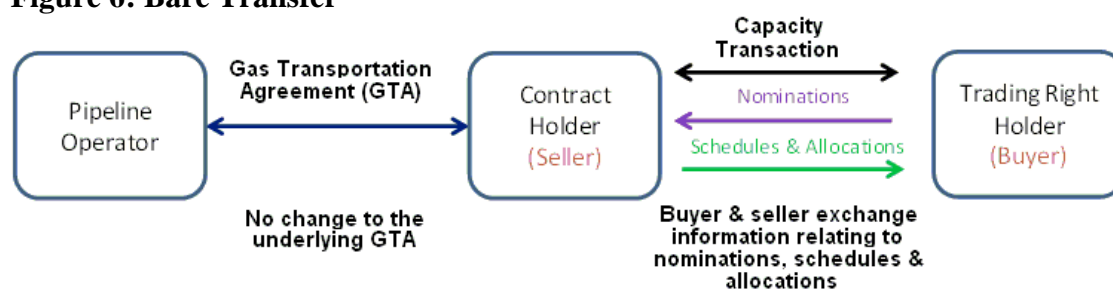
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<sup>12</sup> Australian Pipeline Industry Association, RIS submission, pp. 8-9.

### 8.1.2 Bare Transfer

A bare transfer is a temporary transfer of firm capacity from a contract holder (seller) to a trading right holder (buyer) where the contract holder continues to be responsible to the pipeline operator for all financial and operational obligations. As shown in Figure 6, there is no change to the underlying contractual agreement between the pipeline operator and the contract holder. As there is no relationship between the trading right holder and the pipeline operator, all of the operational requirements of the transportation service are managed through the contract holder. The pipeline operator is not involved with a bare transfer trade and the transaction is likely to be completed without the knowledge or consent of the pipeline operator.

**Figure 6: Bare Transfer**



### 8.1.3 Gas/Capacity Swap

Gas/capacity swaps are a type of bare transfer involving two transactions. For example, Producer A in the Gippsland Basin may want to ship 20 TJ of gas to a customer in Adelaide but does not have adequate capacity on the SEA Gas pipeline to effect a transaction. However, Producer B at Moomba has 20 TJ of uncontracted gas and also unused capacity on the MAP. Producer B also has an existing GSA (and an underlying GTA) to supply a customer in Sydney. Producer A agrees to a gas swap with Producer B whereby Producer A ships 20 TJ of gas to Producer B's customer in Sydney (assuming Producer A has unused capacity on the EGP) and Producer B ships 20 TJ of gas to Producer A's customer in Adelaide. In this way, an extra 20 TJ is delivered to market without Producer A's gas physically travelling to its customer in Adelaide.

Another type of swap can occur if Retailer A needs an extra volume of gas and strikes a deal with Retailer B to use some of Retailer B's capacity allocation. Retailer B provides required capacity to Retailer A and Retailer B agrees to provide Retailer A with the borrowed capacity at a later date and/or on a different pipeline.

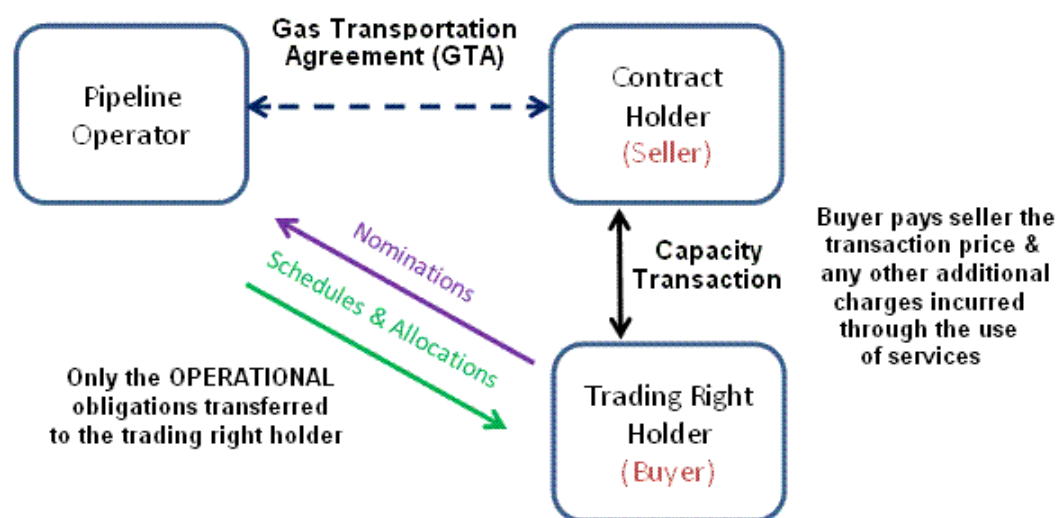
While bare transfer has been used for the temporary transfer of capacity in Australia, operational transfer and contractual transfer are being used in European markets and may also be suitable for the Australian market. These alternative trading options may hold potential to make capacity trading more attractive to shippers who hold unused capacity due to reduced operational and financial responsibilities.

### 8.1.4 Operational Transfer

Operational transfer involves the temporary transfer of capacity from a contract holder (seller) to a trading right holder (buyer) whereby only operational obligations (e.g. scheduling and delivery points) pass from the seller to the buyer. As shown in Figure 7, under an operational transfer the contract holding shipper continues to be

responsible for all financial obligations to the pipeline operator. At the end of the transaction, all of operational obligations return to the original contract holder.

**Figure 7: Operational Transfer**



Operational transfer is the basis for secondary trading of pipeline capacity on a short term-basis in European markets. Functionality within Australian markets can support this model of trading. However, there are likely to be system and process changes required by pipeline operators to give effect to and manage the transfers between shippers.

It is recognised that the APA Group is currently developing a ‘trade facilitator’ gas transmission pipeline capacity trading model that it proposes to implement on its RBP and SWQP.

It is understood the model would:

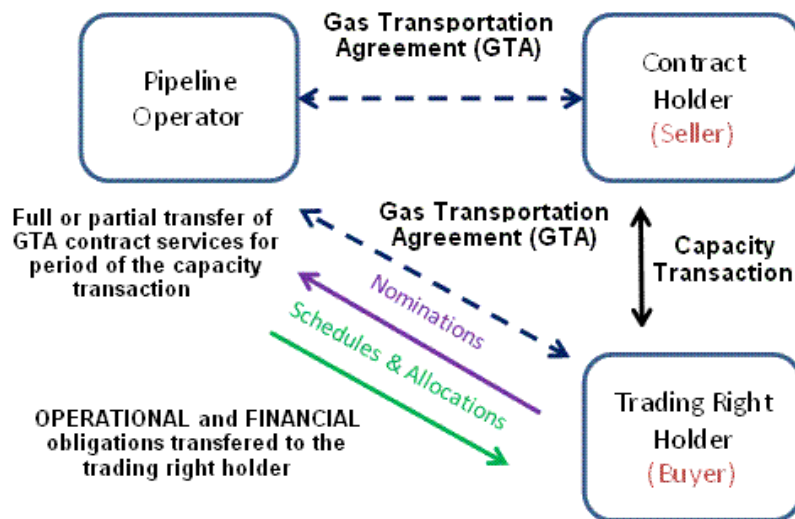
- employ operational transfer that could encourage capacity transactions due to streamlined capacity nomination procedures and hence reduced transaction costs;
- be open to all current and future market participants; and
- include publishing of trading information (volumes, bid and offer details, contracted and uncontracted capacities and capacity utilisation).

APA Group intends to establish this service on its RBP and SWQP pipelines by March 2014 to support capacity trading at the Wallumbilla GSH. APA Group will consider expanding this service to other pipelines if there is adequate demand.

### 8.1.5 Contractual Transfer

Contractual transfer involves the temporary transfer of capacity from a contract holder to a trading right holder whereby all financial and operational obligations pass from the seller to the buyer. As shown in Figure 8, a contractual transfer is similar to the permanent transfer of pipeline services, except that the transfer is only for the period of the transaction (where the transaction could be as short as a single gas day). At the end of the transaction, all financial and operational obligations return to the original contract holder.

**Figure 8: Contractual Transfer**



A contractual transfer is the basis for secondary trading of pipeline capacity products over medium to long-terms in European markets. As for operational transfer, implementation of this service in Australia is likely to require changes to pipeline management systems to give effect to and manage the contract transfers between shippers.

The buyer must be a party to the relevant allocation agreements prior to entering into a transaction. This could be achieved by substituting the buyer for the contract holder in the allocation agreement for the term of the transaction. This approach may also require changes to systems in existing markets to facilitate the transfer of contract capacity between shippers.

## 8.2 Capacity Trading Activity in Australia

The information on the quantum of capacity trade in Australia is very limited. It is understood that both unused firm and 'as available' capacity are currently being traded on a bilateral basis, but this trade is relatively rare. Further, there is:

- no requirement for participants to report capacity trades, even to the applicable pipeliners;
- very limited publicly-available data showing the quantum of this trade; and
- no transparent market mechanism to allocate unused pipeline capacity.

It is understood that this trade may be limited to those with existing market positions and often comes as a package deal with gas supply. This trade may be based around sellers' terms rather than what the buyer may be seeking. For example, a buyer may seek pipeline capacity for a week, but may actually need to purchase capacity for six months.

As discussed above, there is 'as available' pipeline capacity available on most pipelines and, subject to mutual agreement on required volume and contract duration, pipeliners may be able to provide transportation on an 'as available' basis. It is

understood that market participants who may be seeking ‘as available’ capacity would find it challenging to manage the combination of securing an ‘as available’ GTA and a non-firm GSA.

Regarding specifically the trade in unused *firm* capacity, as part of STTM operations, AEMO records the contract holders and trading right holder of capacity on which offers to supply gas to the Adelaide, Brisbane and Sydney STTM hubs are based. AER analysis indicates that as at March 2013, capacity transactions typically occurred whereby the contract holder of pipeline capacity and the trading participant were the same retailer, producer or industrial customer. Therefore, the AER notes there were only a few ‘trades’ of pipeline capacity. However, a large volume transaction on SEA Gas and some transactions on the RBP indicate some willingness of retailers/producers to on-sell capacity. Capacity trades have generally been between large retailers and large customers or between two large retailers. Generally, smaller gas retailers have not accessed capacity from other contract holders.

The above firm capacity trading observations only relate to the STTM and is the only publicly available data. It is recognised that other capacity trading may be occurring that does not relate to the STTM. However, the quantum of this trade is unknown.

Although shippers that hold unused firm capacity are free to trade this capacity, it is understood that short-term bare transfers, including gas swaps, may be rare. A lack of bare transfer trading may be due to a number of factors including:

- the lack of standard contract terms and conditions: this brings with it a significant management overhead than can make negotiations for trades, especially for short periods, administratively prohibitive;
- the contract holder is required to continue managing nominations, scheduling, allocations and the management of imbalances: this imposes an administrative overhead and may also increase operational risk for the seller;
- financial considerations including how and when settlement occurs, managing credit risk and the settlement of ad-hoc charges such as pipeline imbalances;
- potential impact on market position: retailers may consider that their release of unused capacity could enable their competitors to increase market share; and/or
- limited unmet demand for contracted but unused capacity because market participants who rely on gas/transportation already have contracts in place.

### **8.3 Demand for Capacity Trading**

It is recognised that large industrial consumers and gas powered generators (GPGs) either arrange their own shipping under long-term contractual arrangements or buy gas from a retailer. The types of businesses that may be interested in accessing unused capacity on a short to medium-term basis may include:

- industrial consumers who need unanticipated additional capacity;
- new entrants to the gas retail sector who wish to test the market;
- GPGs seeking additional volumes to optimise daily output;
- GPGs seeking to release unused volumes if they have excess gas on a given day/over a given period; and



- gas producers seeking discrete trading opportunities.

Anecdotal evidence from stakeholders suggests there is some demand from shippers to access unutilised capacity. Unfortunately the nature of this demand (including the shippers, quantity, duration and pipelines sought) is difficult to quantify.

#### 8.4 Gas Transportation Services

Capacity, as it has been referred to above, is not a homogeneous product and pipeliners can offer a range of transportation services for the delivery of gas. Being specific about these services would be important to any move to standardised or regulated capacity trade. It is understood that limited firm and ‘as available’ capacity trade occurs in Australia. The services that transportation capacity buyers may be interested in could include:

- **‘As available’**: non-firm service usually nominated and confirmed the day before but can be interrupted on the day. Generally, pipeline owners appear to be conservative in their assessment of ‘as available’ capacity and generally do not offer this service unless it is highly likely they can transport the gas;
- **Firm Spot**: in eastern Australia this service is not commonly offered, however, it is understood to have been used in Western Australia. A firm spot service is similar to ‘as-available’ where capacity is confirmed the day before, however, once parties agree on the quantity, it is a firm transport arrangement;
- **Firm Short-term**: a firm transport service but with a term applicable more than 1 day but up to 6 months;
- **Firm Long-term**: a firm transport service with a term applicable more than 6 months; and
- **Backhaul**: a service where gas transportation is in an opposite direction of the aggregate physical flow of gas in the pipeline (i.e. the capacity buyer is located upstream of the gas supply point).

Stakeholders may also be interested in accessing other types of capacity, including those listed above. While there is very little information about demand for such services, anecdotal evidence suggests that the market would be predominantly interested in a range of firm capacity services.

## 9. METHODS OF FACILITATING CAPACITY TRADING

Secondary transactions for accessing pipeline capacity can be facilitated through a market, which generally aims to reduce the transaction costs of accessing capacity for relatively short durations, but can also occur informally, including through bilateral negotiations.

The expansion of secondary pipeline capacity trading activity may require mechanisms to lower transaction costs, improve incentives, and/or remove disincentives for trade between buyers and sellers. There are a number of mechanisms that can be used to trade unused capacity including: bilateral negotiation; exchange-based trade; and auction.

## 9.1 *Bilateral Negotiation*

As previously outlined, bilateral trading refers to the direct negotiation of capacity transactions between a contract holding shipper (seller) and a trading right holder (buyer). The execution of trade and settlement and credit risk management arrangements are managed outside the market by the counterparts to the transaction.

As part of the detailed design for the Wallumbilla GSH, AEMO has proposed that the Wallumbilla GSH will support bilateral trading of unused pipeline capacity. AEMO will develop a bulletin board style, web-based information screen that will allow market participants to advertise a willingness to buy or sell specific gas transportation services.

This listing of spare capacity will be located alongside the exchange trading screens for the proposed physical gas products making it more convenient for participants to manage their trading requirements. Participants with an interest in trading unused gas transportation services will be able to manually upload details relating to the receipt and delivery points, term and their contact details to facilitate the commencement of a bilateral negotiation. Table 3 shows an illustrative snapshot of a capacity listing webpage.

**Table 3: Illustrative Trading Screen**

Receipt Point	Delivery Point	Qty (GJ)	From Date	To Date	Interest	Listing Party
Wallumbilla	Gladstone	2,000	01-May-14	14-May-14	Sell	Gas Trading Company
Longford	Sydney	5,000	28-Apr-14	29-Apr-14	Buy	Energy Retailer
Wallumbilla	Brisbane	2,500	01-Apr-14	31-Jul-14	Buy	Industrial Consumer

In the example above, the Gas Trading Company is offering firm gas transportation for 2,000 GJ of gas from Wallumbilla to Gladstone. Participants that have an interest in buying this service would be able to retrieve the contact details for the Gas Trading Company from the market system and then make contact to commence bilateral negotiation of the quantity, price and terms of a capacity transaction.

The above is being complemented by AEMO's work on developing standardised terms and conditions for bilateral capacity trading that will assist with making capacity trade easier.

## 9.2 *Exchange-Based Trade*

An alternative to bilateral negotiation is the exchange-based trading of capacity products. Exchange-based trading would simplify the trading process for participants, promote competition between potential buyers and sellers and complement the exchange trading of physical gas products. However, the realisation of the full trading efficiencies that exchange trading can offer requires the selection of transportation services that are of interest to a large number of potential buyers and sellers. Products for the transportation of gas between major supply and demand hubs (e.g. from Wallumbilla to the Brisbane STTM hub) are more likely to generate interest between buyers and sellers that is necessary to build trading liquidity.

However, this approach may not be a solution to the capacity trading concerns raised by all participants, in particular, shippers located upstream of existing demand hubs (i.e. shippers wanting backhaul services). In practice, the technically available backhaul capacity will vary from day to day: aggregate backhaul must be equal to or less than aggregate forward haul transactions and minimum pressure levels must be maintained within the pipeline for safety and security of supply reasons. Consequently, where pipeliners offer backhaul services, it will generally be on an ‘as available’ basis.

The exchange platform that is being implemented as part of the Wallumbilla GSH could be utilised to list products for the trading of pipeline capacity, however, a suitable pipeline capacity trading market operator would need to be established.

A capacity trading exchange jointly developed and operated by pipeline operators could realise greater market efficiencies than developments by individual operators for the following reasons:

- **Standardisation of terms:** joint development by pipeline operators is more likely to result in common terms and conditions across pipelines making it more efficient for shippers that operate nationally to trade;
- **Cost:** a single joint development by pipeline operators would avoid the duplication of the bulk of the costs associated the development of a trading exchange including the trading systems and legal drafting of the contract framework; and
- **Efficient trading:** the more exchanges that a participant needs to access and operate within the higher the transaction costs. The most efficient trading approach is one where physical gas and transportation trade in the same location, under similar terms and settlement frameworks.

An example of exchange trading of capacity products is shown in Table 4.

**Table 4: Illustrative Exchange Platform for Day-Ahead (1 May 2014)**

Spot Transport	Qty (GJ)	Bid	Ask	Qty (GJ)
Wallumbilla to Brisbane	5,000	0.85	1.25	4,000
Wallumbilla to Gladstone	2,000	0.61	0.88	3,000
Longford to Sydney	1,000	1.25	1.55	6,000

Buyers and sellers would need to be registered as trading participants. Participants would submit orders to buy or sell capacity for the defined transportation service as they would if they were trading a physical gas product. In the example above, a participant is willing to sell 4,000 gigajoules (GJ) of pipeline capacity for services between Wallumbilla and the Brisbane STTM hub for \$1.25/GJ for gas day 1 May 2014. When the buy and sell orders can be matched, a capacity transaction between the two participants would be created.

The capacity products listed would cover the same time periods as those for the physical gas products (e.g. day-ahead, balance-of-month and month-ahead). The alignment of products would allow participants to bundle together their gas and transportation requirements.

The exchange trading of capacity products is likely to improve the price discovery and trading process for shippers. However, there are a number of hurdles to the development of exchange traded products including the standardisation of terms and conditions, settlement and credit risk management.

- ***Standard Terms and Conditions:*** It would not be feasible to create and list products for many different combinations of receipt and delivery points. To develop the necessary trading liquidity it would be important to select a set of receipt and delivery points that can be accessed by many potential buyers and sellers.
- ***Management of Imbalances:*** The standard terms and conditions for a capacity trading product would need to include obligations on the buyer in relation to their use of the transportation service. The contract holding shipper would also require the ability to recover any additional charges levied by the pipeline operator due to an imbalance caused by the trading right holder. For example, if receipt or delivered volumes transported by the third party shipper vary from the pipeline schedule, then the contract holding shipper may incur an imbalance charge from the pipeline operator.
- ***Nomination Process and Information Exchange:*** The transfer of capacity services requires parties to a capacity transaction to exchange information relating to nominations, schedules and allocations. A standard set of processes would need to be developed and would then need to be incorporated into the exchange rules and the relevant product specifications.
- ***Settlement and Credit Risk Management:*** The centralised settlement and credit risk management model proposed for the Wallumbilla GSH could be extended to support the exchange trading of capacity products. However, the proposed settlement framework for the Wallumbilla GSH would require modification to cater for capacity transactions including the delivery of information and settlement of pipeline imbalances.

Bilateral settlement of capacity transactions cannot be supported within the exchange trading framework proposed for the Wallumbilla GSH. Bilateral settlement requires each trader to establish separate credit support arrangements with the participants it wishes to trade with. The exchange would then require the functionality to only match transactions for participants that have established credit support arrangements.

### **9.3 Auction**

The matching of purchase and sale orders could be conducted through an auction process similar in nature to existing energy markets (e.g. Settlement Residue Auction in the National Energy Market). An auction mechanism would require the standardisation of terms and conditions and can be seen as an alternative to the exchange trading of capacity products.

An auction process would be applicable in particular to a process for the allocation of spare capacity that would not involve a selling party. This could be the case where a shipper loses the right to pipeline capacity they are not using as described under a 'use-it-or-lose-it' scenario as described below.

Once a day, or at some other pre-defined time<sup>13</sup>, potential sellers would make their capacity available to the auction. Buyers of these services would submit bids for the services indicating the volume and price at which they would be willing to transact. The auction process would determine the quantity of capacity transactions and would set a price at which they are transacted at similar to the scheduling process within the existing gas markets.

The inclusion of physical dynamics in the auction and capacity allocation process could extend the model to cater for trading of capacity between various receipt or delivery points or where the pipeline or sections of the pipeline are physically congested. This type of model would be most valuable on a pipeline where there are many different receipt and delivery points. On a pipeline that is physically congested, this type of model could allocate capacity to parties that are able to derive the most economic benefit from the constrained set of transportation services.

## 10. INTERNATIONAL CONTEXT

Recognising the importance of access to pipeline infrastructure for broader market efficiency, overseas governments and regulators have implemented a variety of reforms to enhance pipeline capacity utilisation. The contractual and regulatory frameworks that underpin the gas transmission pipeline capacity markets operating internationally offer valuable insights into how pipeline capacity trading can be managed. It is recognised that different capacity trading markets have been developed to suit each country's unique market parameters and are not directly comparable to the Australian context.

### 10.1 United States of America

The United States of America's (US's) gas market is the largest, most liquid and transparent in the world. The US has ownership separation of pipelines from producers and distribution. The largest gas pipeline network in the world, the US has over 100 pipelines that span a distance of approximately 492,000 kilometres. Highly integrated, US pipelines are interconnected with Canada and Mexico. The pipeline network connects the major gas basins in the south-west US and Canada to the demand centres. Within the US there are many regional hubs at which gas is traded and where price indices are reported. In many instances, multiple pipeliners provide competing transportation services between the same supply and demand centres.<sup>14</sup>

Interstate gas pipelines are regulated by the national energy regulator, the Federal Energy Regulatory Commission (FERC), who determines the method for calculating rates of return, and authorises pipeline construction and expansion. Since the 1980s, FERC has implemented a range of regulatory interventions to encourage competition in the gas market and improve transparency (see Box 2).

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<sup>13</sup> Forward-dated trading products covering a month or quarter in the future could be auctioned less frequently. For example, settlement residue units in the National Energy Market are auctioned on quarterly basis.

<sup>14</sup> Much of the content of this section has been drawn from the Brattle Group's *International Experience in Pipeline Capacity Trading*, 2013, [online] [http://www.aemo.com.au/Gas/Market-Operations/Gas-Supply-Hub/~media/Files/Other/gas\\_supply\\_hub/International\\_Experience\\_In\\_Pipeline\\_Capacity\\_Trading\\_Brattle%20Group\\_August\\_2013.pdf.ashx](http://www.aemo.com.au/Gas/Market-Operations/Gas-Supply-Hub/~media/Files/Other/gas_supply_hub/International_Experience_In_Pipeline_Capacity_Trading_Brattle%20Group_August_2013.pdf.ashx) (accessed 13 November 2013).

## **Box 2 - Timeline of Relevant Regulatory Changes**

1985 – FERC Order 436: Established a voluntary program of pipeline capacity release and third-party access, encouraging unbundling by allowing end-users to contract directly with producers.

1988 – FERC Order 497: Established pipeline capacity release reporting requirements and standards of conduct for pipeliners regarding their interactions with marketing entities to prevent discriminatory sales.

1992 – FERC Order 636: Was expansive in its coverage and included:

- establishing mandatory unbundling that required the separation of gas sales and gas transport capacity access, prohibiting pipeliners from selling gas;
- creating a secondary capacity market by allowing shippers to sell excess capacity on a short (less than one year) and long-term basis;
- prohibiting direct capacity transfers between shippers (bare transfers), requiring the capacity release is conducted by pipeliners; and
- increasing bulletin boards and service level expectations to highlight the availability and trading of capacity and encourage the development of trading hubs.

2000 – FERC Order 637: Amended Order 636 to ensure capacity could not be resold at a price exceeding the maximum cost-based tariff set by FERC and removed the cap on transaction prices for short-term capacity release.

These regulatory changes instituted a third-party access regime, unbundled gas transportation services from gas supply services and introduced arrangements for capacity trading.

Similarly to eastern Australia, gas transmission pipeline capacity is traded under a point-to-point model. The production and expansion of pipelines is underwritten by long-term transportation contracts (often for terms of 15 years or more) between pipeliners and shippers.

Transportation contracts are largely standardised, following the same broad structure and central terms and conditions. Each pipeline has its own open access tariff that is publically outlined on the FERC website. Further, capacity contracts between pipeliners and shippers are also provided on the FERC website.

Similarly to a use-it-or-lose-it (UIOLI) model, in the US pipeliners are required to provide a mechanism for shippers to release capacity back to the pipeliner for resale. There are two kinds of capacity release transactions:

1. If the capacity released is for a short duration (less than one year) it must be advertised on the pipeliners' bulletin board, with no cap on price and made available to the highest bidder.
2. If the capacity released is for more than one year the price charged cannot exceed the maximum tariff. If the capacity is released at the maximum tariff rate, the transaction must be published for information but not made available for bidding on the bulletin board.

The shipper determines the terms and conditions under which the capacity is released. Further, the pipeline's tariff will outline the rules and procedures for capacity release.

Pipeline operators are required to operate an electronic bulletin board that publishes all capacity release transactions and post operational data, including available capacities and historical flow data for all receipt and delivery points of the pipeline. Planned and actual outage data must also be published. While specific kinds of secondary capacity trades can occur bilaterally, the details of the trade must be posted on the relevant bulletin board. As such, most secondary trades still occur bilaterally. The bulletin board requirement facilitates transparent secondary trade of pipeline capacity.

## **10.2 European Union**

A highly-complex and interconnected network, consisting of over 200,000 kilometres of gas transmission pipelines, extends across the European Union (EU). Similarly to the US, many Transmission Service Operators (TSOs) are in direct competition with each other to provide transportation services between the same supply basins and gas demand centres. Historically, pipeline and production assets were vertically integrated with capacity bundled with supply under long-term contracts.

Following a review of energy market competition in 2007, the European Commission imposed requirements to separate ownership of pipelines from gas supply affiliates. This separation process resulted in the unbundling of many contracts to establish separate gas supply and transportation contracts.

In 2009, the European Commission adopted stricter unbundling requirements, introduced an entry/exit model for capacity trading and required TSOs under legislation to develop capacity trading mechanisms. Under the entry/exit model, shippers independently contract capacity at pipelines' entry and exit points, allowing shippers to trade gas at a wide range of entry and exit combinations. Market participants trading capacity on a particular route using the same entry/exit point trade products with standardised terms and conditions, issued by the same TSO.

Concerned that contractual congestion on some pipelines represented a market failure, the European Commission revised gas regulations to provide for the development of network codes to enhance capacity utilisation at interconnection points between EU member states.

As a result of changes to the gas regulations in 2009, TSOs are obliged to publish online pipeline capacity information regarding:

- maximum technical capacity for flows in both directions;
- total contracted and interruptible capacity; and
- available capacity.

Additionally, TSOs are required to publish data on available capacities for a period of at least 18 months ahead and this information must be updated at least every month. TSOs also have to provide annual long-term forecasts (up to 10 year ahead) of available capacities as well as publish historical maximum and minimum monthly capacity utilisation rates and annual average flows at all relevant points for the past three years on a rolling basis.

Two of the key network codes included in the revised gas regulations are the Congestion Management Procedures (CMP) and the Capacity Allocation Mechanism (CAM).

The CMPs are designed to reduce contractual congestion on the European gas transmission pipelines. The CMP consist of four mechanisms, namely:

1. firm day-ahead UIOLI – restricting shippers ability to renominate – to be implemented from July 2016;
2. long-term UIOLI – obligating shippers to release capacity to TSOs where specific underutilisation criteria are met – implemented October 2013;
3. oversubscription and buy-back – incentivising TSOs to sell capacity and buy it back where demand is greater than technical capacity – implemented October 2013; and
4. surrender of contracted capacity – requiring TSOs to resell firm capacity released by shippers voluntarily – implemented October 2013.

The CMPs also require TSOs to publish particular information on the European Network of Transmission System Operators for Gas (ENTSOG) Transparency Platform, including:

- unsuccessful requests for firm capacity of a duration of one month or more;
- where firm capacity of a duration of one month or more has cleared at a price higher than the reserve price;
- where no firm capacity of a duration of one month or more was made available by a pipeline operator; and
- the amount of capacity made available to the market resulting from the application of the CMP.

Responding to problems with accessing primary capacity and the difficulties of secondary capacity trading in most EU member countries, the CAMs outline the rules that govern how capacity is sold at interconnect points between EU members. The CAMs calls for TSOs to provide a booking platform for allocation of primary capacity by auction and also for trading of secondary capacity for registered shippers. Key features of the CAMs include: standardisation of capacity products; rules for capacity auctions; and the bundling of entry and exit capacity. The CAM also proposes the development of an integrated, single EU-wide capacity platform by 2016.

While EU members will not be bound by CAMs until 2015, numerous platforms already exist to facilitate capacity trading through the implementation of standardised and bundled capacity products traded under auction mechanisms, settled bilaterally.

Separate mechanisms are now being consolidated in a single, EU-wide capacity trading platform called PRISMA, which commenced on 1 April 2013. Motivated by reducing the transaction costs associated with using multiple location-specific trading platforms, TSOs have pre-emptively developed PRISMA ahead of schedule. Given that costs are essentially fixed no matter how many TSOs participate, it is cost effective to have a single capacity trading platform.



The majority of the PRISMA trading activity is still based on primary capacity allocation. With regard to secondary trading, PRISMA is currently limited to re-packaging the pre-existing TRAC-X (German) and Capsquare (France/Belgium) capacity trading platforms.

### *10.3 Lessons from International Markets*

The US and European gas markets:

- are much larger than Australia's;
- are intra- and inter-connected with multiple gas transmission pipelines; and
- are well-developed and highly liquid with many competitors at all levels of the supply chain.

The US and EU gas pipeline capacity trading regulatory regimes have undergone significant changes to reflect broader policy reform agendas. However, there appears to be little empirical evidence available concerning the direct impacts of their altered capacity trading arrangements. It remains unclear whether regulatory changes made in the US and EU have directly increased pipeline capacity utilisation.

What is abundantly clear is that both the US and EU regulators have introduced measures to improve the transparency of pipeline capacity trading, far greater than those currently seen in any Australian gas market. Also in contrast to Australia, the EU requires its TSOs to publish detailed forward and backward pipeline capacity information, including on the ENTSOG Transparency Platform. While the majority of secondary capacity trades in the US continue to be conducted bilaterally, rather than through a use-it-or-lose-it capacity release model, the details of all trade must be posted on the relevant bulletin board.

## **11. STATEMENT OF THE PROBLEM**

This chapter identifies the nature of the underlying policy problem. In determining whether a regulatory response may be necessary, consideration needs to be given to whether or not a significant problem with the current pipeline capacity trading market exists.

### *11.1 Transmission Capacity Trading in Eastern Australia*

Australia's eastern gas market pipelines experience differing levels of congestion. As outlined previously, depending on the time of year, the LMP, SWP, SEA Gas, NVI, EGP, SWQP<sup>15</sup> and MSP have considerable volumes of contracted but unused capacity.

In periods of volatile peak demand, it is particularly important for retailers and power generators to have capacity in reserve to be capable of meeting demand. Therefore, during peak periods, the existence of unutilised capacity is not necessarily a sign of contractual congestion because there is likely an operational requirement for such

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<sup>15</sup> Post 2014-2015 considerable additional volumes of gas from Santos' portfolio will be transported on the recently expanded SWQP.

capacity. In contrast, during periods of low demand, larger volumes of unutilised capacity may not be required by the holders of that capacity and they could make it available for secondary trade.

Therefore, in periods of low demand, the above pipelines could be considered as contractually congested. These pipelines represent approximately 80% of the eastern market's total major transmission capacity.

The CGP, QGP and RBP tend to have high capacity utilisation rates and have much smaller volumes of unused capacity, depending on the time of year. These pipelines could be considered close to physically congested and represent approximately 14% of the eastern market's total major transmission capacity.

As at 1 November 2014, the only major eastern Australian pipeline that had uncontracted firm capacity was the MAP which could therefore be considered uncongested.<sup>16</sup> It represents approximately 7% of the eastern market's total major transmission capacity.

As previously indicated, the overwhelming majority of gas and transportation capacity is traded under confidential, long-term contracts and it is understood that very small volumes of gas and capacity are traded on a short-term basis. While there is no publicly-available price data for contracted volumes, gas prices for balancing trade at the STTM and the Victorian DWGM are available from the AER.<sup>17</sup> These figures show that there are significant price differentials between state markets. For example, over the period 17-23 March 2013, the following average prices were realised: Victoria \$4.34/GJ; Adelaide \$4.76/GJ; Sydney \$4.88/GJ; and Brisbane \$7.28/GJ. These differentials, which may only exist for relatively short periods of tight supply or unanticipated periods of higher demand, represent arbitrage opportunities for stakeholders who can offer up gas and have access to gas transportation capacity.

## **11.2 Stakeholder Concerns**

Industry consultations have identified that some stakeholders are interested in accessing short-term and/or long-term firm gas transportation capacity that could enable additional gas transactions to occur. Rather than enter into new contracts with pipeliners that would underpin an expansion of existing pipelines, these stakeholders are interested in accessing existing contracted, but unused, pipeline capacity.

As indicated above, on certain pipelines there are times during which considerable volumes of contracted but unused pipeline capacity exist. However, some stakeholders have highlighted difficulties in accessing this capacity. In summary, some stakeholders have suggested that:

- despite the existence of unutilised, but contracted, gas transmission pipeline capacity and demand for this capacity, some users have not been able to access unused capacity;

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<sup>16</sup> However, as stated at Section 7, uncontracted firm capacity may become available on other pipelines when current contracts expire.

<sup>17</sup> AER, *Wholesale Markets - Market Performance, Weekly Gas Market Report 17-23 March 2013*, <http://www.aer.gov.au/node/451>.

- gas spot trading is currently hindered by the ability of shippers to secure unused transportation capacity on a short-term basis;
- negotiations aimed at gaining access to unused capacity can be lengthy, complicated and expensive and therefore negotiation timeframes can be prohibitive;
- trading liquidity at the proposed Wallumbilla GSH will be significantly hindered without the complementary development of arrangements to facilitate the trading of spare transportation capacity; and
- incumbent shippers holding unused capacity should be compelled to offer this unused capacity to the market.

The RIS consultation process sought information from stakeholders to better understand the nature and extent of any problem. Thirteen organisations made written submissions and industry was also formally consulted following submissions and during the cost-benefit analysis stage. While providing useful qualitative information, submissions provided little by way of empirical evidence on existing capacity trading activity nor the expected level of demand for unused capacity.

### *11.3 Significance of the Problem*

There are a number of potential reasons why the market may not seek opportunities to supply unused capacity including:

- a. significant management overheads, especially those incurred while negotiating short-term capacity trading agreements, may make negotiations administratively prohibitive;
- b. the on-going management of nominations, scheduling, allocations and imbalances may impose prohibitive administrative overheads and may also increase operational risk for the seller;
- c. financial considerations including how and when settlement occurs, managing credit risk and the settlement of ad-hoc charges such as pipeline imbalances;
- d. potential impact on market position; and/or
- e. limited interest by holders of unused capacity due to perception that there is no demand for unused short-term capacity.

Regarding items (a) and (b), high transaction costs may result in incumbent shippers and/or pipeliners not pursuing negotiations for small-volume capacity trades or trades with parties lacking established market positions as discussed in Section 7.4. RIS consultations highlight divergent views on whether transaction costs are prohibitively high. While some incumbent shippers and pipeliners state they have not experienced difficulties regarding secondary capacity transactions, other stakeholders argue that existing capacity transactions are time-consuming, complex and costly.

Regarding item (d), this would be an indication that the current market structure may be resulting in competition failure whereby a limited number of incumbent shippers control unused capacity and are exercising market power to effectively either block the entrance of new market participants (e.g. new gas retailers) or limit the supply from producers (both existing and/or new participants) that would improve market

contestability. For example, incumbents could deliberately withhold unused capacity as a means of maintaining flexibility, avoiding disclosure of their market positions and/or restricting competitors' access in order to maintain their market positions.

Regarding item (e), this could indicate that market information failure/asymmetry may be occurring whereby either incumbents or parties seeking capacity lack adequate information concerning the demand for, or supply of, unused capacity and therefore trading activity is limited. Further, the lack of a centralised market clearing repository means there may not be an easy way for market participants who want to trade capacity to identify one another. Additionally, it is understood that the relatively small number of shippers in the market has not seen the establishment of shipping brokers that could offer standard contracts, post capacity prices or offer any services that a market would traditionally provide to reduce trading costs.

However, there may be other reasons why incumbents do not seek to mitigate costs and maximise their revenues via selling unused capacity. Factors, such as the existing market or regulatory environment, may be distorting the incentives for incumbents to offer up unused capacity.

Regarding regulatory gaps (i.e. whether current regulations are impeding capacity trade or whether additional regulation is necessary to promote market efficiency), it is recognised that the NGL/NGR are nationally consistent and there are no jurisdictional differences that could be inhibiting capacity trade. The intent of the current regulatory regime is not to specifically optimise or maximise capacity utilisation. The NGL/NGR does not explicitly deal with secondary capacity trade. For covered pipelines, current regulations only obligate pipeliners to offer capacity in accordance with an access arrangement that sets out the terms and conditions under which third parties can access uncontracted firm capacity.

Although it is not clear how strong the demand for unutilised capacity is, it is unlikely that the current market for gas transmission transportation is preventing wide-scale unmet demand for transportation capacity being filled. However, as outlined above, some market participants have stated they have not been able to secure access to unused pipeline capacity and there may be scope for the better utilisation of these assets.

Further, in the first instance, the potential volumes of additional gas supply that could be brought to market via improved secondary capacity trading are likely to be relatively small and are not expected to have an impact on retail gas prices.

#### ***11.4 A Case for Intervention***

Submissions and anecdotal evidence highlight divergent opinions about whether a problem exists with the way in which secondary capacity is traded (see Section 15 for a summary of stakeholders' views). However, firm data to support these positions is not readily available. Further, data on historical utilisation even if available may not capture the potential use of the capacity trading at a particular time. As international experience suggests, improving the way that capacity is traded may also help build competition and liquidity in the wholesale market, contributing to gas market development over the longer term.

The anticipated flow-on benefits from increasing trade in unused pipeline capacity may include:

- access to capacity to transport additional gas;
- opportunities for the manufacturing sector to transport discrete volumes of gas, including additional gas that could be purchased direct from producers;
- ability for electricity generators to optimise gas utilisation and generation capacity;
- scope for producers to undertake cross-border gas trades with resultant lost arbitrage opportunities; and
- opportunities for new retailers to enter market and improve competition.

The above circumstances are providing a new imperative to examine avenues for improvement of the efficiency of existing pipeline infrastructure and therefore maximise opportunities for gas trading between regions.

Given gas is an important fuel and chemical source, the reallocation of capacity achieved through improved secondary capacity trading could have flow on effects to other sectors. These include large industrial consumers, metals processors and refiners, chemicals and plastics producers, electricity generators, commercial and residential users.

The absence of clear data on demand for capacity trading, therefore leaves policymakers with a dilemma – either accept that no change to the status quo can be made without data, which the status quo is unlikely to generate, or to consider opportunities to build experience in capacity trading which are of lower cost and capture reasonable prospects of net benefits.

## **12. OBJECTIVES**

In line with the principles of the NGO, gas markets that incorporate transparent, flexible and well-functioning gas transmission pipeline capacity trading regimes can:

- provide an ability to go to market for price;
- ease the transfer of gas title;
- allow competitive access to unutilised pipeline capacity;
- reward for efficient pipeline investment;
- enhance participation by end users in spot markets; and
- improve consumer confidence in the gas market.

If it was found that a significant problem existed with the current transmission pipeline capacity trading market, changes consistent with the NGO could be made to support continued gas market development. Such changes could be made to improve:

- gas transmission network efficiency;
- market transparency; and
- market contestability.

## 13. OPTIONS

If a problem with the pipeline capacity trading market did exist, it would need to be determined whether a policy response was appropriate and, if so, what would be the most effective and efficient response to employ.

In the international context, there are numerous initiatives associated with pipeline capacity trading operating abroad, some of which are discussed in the Section 10 (see Appendix A for further examples). Although they offer insights into how pipeline capacity trading can be managed, it is recognised that each of the models listed have been developed to suit each country's unique market parameters (e.g. Great Britain's model is a balancing system rather than a trading platform).

The Wallumbilla GSH includes market-based initiatives to:

- list available pipeline capacity using a bulletin board approach that would allow participants to advertise a willingness to buy or sell transportation services; and
- develop standardised terms and conditions for secondary capacity trading that may help expedite gas transactions and facilitate the transfer of title.

These initiatives will assist with improving market transparency and can contribute to facilitating gas transactions. The Wallumbilla GSH capacity trading work complements, but is separate to, this RIS process and any policy options that may be adopted.

With respect to Australia, a spectrum of responses, ranging from a minimalist approach to full regulation, could be employed to encourage the trade in unused pipeline capacity. For the purpose of seeking feedback and assisting stakeholders to frame their responses, a range of policy options have been set out below. The options are:

Option 1: Status quo;

Option 2: Improved information provision and the standardisation of contractual terms and conditions;

Option 3: Voluntary trading platform and an incentive for incumbents to release capacity; or

Option 4: Mandatory trading obligations requiring incumbents to release unutilised capacity to all market participants on either an 'as available' or firm basis.

### *13.1 Option 1: Status Quo*

This option sees market participants who hold contracted, but unused, pipeline capacity not being obligated to offer up capacity to the market. If they choose, market participants can sell unused capacity by pursuing bilateral capacity trades.

Trading mechanisms may evolve organically in some circumstances. This option assumes that the development of the Wallumbilla GSH is completed on schedule by March 2014 and that APA Group's trade facilitator capacity trading model is introduced on the RBP and SWQP by March 2014.

### **13.2 Option 2: Information Provision**

A common concern regarding gas markets is the lack of transparency including the access to and timely provision of information that would better enable market participants to make more informed decisions. Access to better information can improve market efficiency and pricing outcomes. Many stakeholders have noted that while AEMO's BB is an appropriate place to publish pipeline capacity information, its current functionality is limited and existing data could be better presented.

This option involves:

- improvements to the presentation and capability of existing BB data and facilities to enhance the useability of the information to market participants;
- publishing of rolling data concerning unused pipeline capacity on the BB; and
- standardisation of contractual terms and conditions applying to pipeline transport, and the development of business tools and processes to expedite and ease the transfer of contractual rights to capacity.

Under the existing NGRs, pipeliners, storage providers and production facility operators are required to provide AEMO with the following information for publication on the BB:

- nameplate capacity;
- forecast available capacity for the following three days;
- forecast linepack/capacity adequacy for the following three days;
- actual and forecast aggregated delivery nominations, if forecasts have been provided by shippers;
- actual and scheduled aggregated injections less aggregate scheduled withdrawals; and
- actual deliveries of gas on the pipeline

Under Option 2, the NGRs would be amended to require pipeliners to collate and provide AEMO with additional historical, day-after and expected levels of:

- operational pipeline capacity, including any operational flow orders and maintenance;
- contracted firm capacity by shipper, including secondary capacity trades;
- contracted 'as available' capacity by shipper, including secondary capacity trades; and
- deliveries by shipper.

From this information it will be possible to derive historical, day-after and expected levels of:

- utilised and unutilised firm capacity by shipper;
- uncontracted firm capacity; and
- uncontracted 'as available' capacity.

Shippers would also be required to notify the applicable pipeliner/s of their secondary capacity trading activities. This would enable pipeliners to provide AEMO with complete capacity trading information.

To ensure that additional data is provided in a timely, accurate and complete manner, the AER would use existing powers of enforcement applied to the amended NGRs.

This option would also encompass AEMO making improvements to the presentation and capability of the BB to enhance the usability of new and existing information.

Further, this option would require AEMO to enhance its BB to include a voluntary east coast capacity listing service, similar to that being developed for the Wallumbilla GSH. Settlement between buyers and sellers would occur bilaterally either under a standardised transportation contract or a contract more tailored to the needs of the parties.

Under this option, AEMO would also work with pipeliners and shippers to create a publicly available contract containing standardised terms and conditions for the secondary trading of firm capacity. This contract would describe the transfer of rights and obligations from the original shipper to the replacement shipper. Settlement between buyers and sellers could occur bilaterally under the standardised transportation contract, or a contract more tailored to the needs of the parties. This standardised transportation contract would resemble that drafted by AEMO for the Wallumbilla GSH.

This option would require the upgrading of AEMO's and pipeliners' systems and procedures.

### ***13.3 Option 3: Voluntary Trading Platform***

This option would make use of Option 2's market information provisions and the development of standardised contractual terms and conditions. It would see the establishment of a capacity trading platform to allow market participants to voluntarily offer unused capacity for trade. The trading platform would be developed and operated by AEMO, similar to the platforms AEMO has developed for the STTM and the Victorian DWGM.

In addition to providing a matching service, the trading platform would be a cleared exchange and it would facilitate the trading of standardised products between pipeliners, existing shippers and prospective shippers. Building on the standardised contract developed as a component of Option 2, AEMO would develop an initial standardised product that could be transacted on the voluntary platform for a trial period. During that trial period, AEMO would receive feedback from pipeliners and shippers about preferred amendments and the attractiveness of developing additional standardised products. Should additional products be required, they would be developed in consultation with market participants, in a staged manner, to ensure that they are suitable instruments for trade and reflect the needs of potential traders.

The voluntary trading platform would not be the only option available for trade. Pipeliners and shippers would continue to be allowed to enter into bilateral agreements for capacity trade outside of the platform.



### 13.4 Option 4: Mandatory Trading Obligations

Introducing mandatory trading obligations would compel shippers or pipeliners to release unused capacity. Mandatory trading would require: making use of Option 2’s market information provisions; developing standardised contractual terms and conditions; and developing standardised products as discussed in Option 3. It would be a challenging option to progress and would require clear evidence of:

- a) a significant problem existing that materially affects the operation of the market (i.e. detrimental to the NGO); and
- b) inadequate effort being made by market participants to voluntarily address any significant identified issues.

Mandating the release of unused capacity could either involve compelling:

- pipeliners to transparently offer up unused capacity on an ‘as available’, interruptible basis, referred to in this RIS as UIOLI; or
- shippers to transparently offer up unused firm capacity, referred to in this RIS as use-it-or-sell-it (UIOSI).

It is recognised that in the international context the terms UIOLI and UIOSI may refer to differing concepts.

These options fall toward the full regulatory end of the policy spectrum and would require legislative changes to mandate the release of unused capacity.

Given that the AER only has a role in regulating relatively few covered pipelines, thought would need to be given to what changes to legislation would be need and what role the AER could play in a changed regime.

Consideration would also need to be given to the duration over which capacity rights would be offered (e.g. daily or longer term).

Regarding the potential application of UIOLI and UIOSI, Table 5 shows who would receive the revenue from the sale of contracted but unused capacity under each scheme, what type of capacity could be offered and why alternatives are not appropriate.

**Table 5: Revenue from Sale of Contracted but Unused Capacity**

Capacity \ Revenue	Firm	As Available
Pipeliners	<p><b>NOT APPROPRIATE</b></p> <ul style="list-style-type: none"> <li>• Property rights issues</li> </ul>	<p><b>UIOLI</b></p>
Shipper	<p><b>UIOSI</b></p>	<p><b>NOT APPROPRIATE</b></p> <ul style="list-style-type: none"> <li>• Not core business</li> <li>• Technical and operational issues</li> </ul>

### 13.4.1 Option 4A: UIOLI

This option would oblige pipeliners to offer up ‘as available’ capacity via a transparent trading platform if shippers did not nominate their full MDQ entitlements.

Mandating the trade of unused capacity on an ‘as available’ basis, would provide incumbent shippers with an option to undertake intra-day nominations and renominate up to their MDQs on a given gas day. Therefore, UIOLI would likely be the most acceptable mandatory option for incumbent shippers.

This option would operate on the basis of the following assumptions:

- On a given gas day, the quantity of ‘as available’ capacity a pipeline would be required to offer would be equal to the sum of each shipper’s MDQ minus nominations.
- The initial nominations of the existing shippers for a gas day occur in advance of the commencement of a gas day, and pipeliners would use those initial nominations to derive initial offers of ‘as available’ capacity for the following gas day.
- Prospective shippers would be able to bid for a proportion of ‘as available’ capacity on the following day.
- Existing shippers would retain the right to revise their nominations up to and throughout a gas day, and pipeliners would adjust ‘as available’ quantities on that basis.
- Pipeline operators would not be required to sell ‘as available’ capacity at a price less than their estimated marginal cost.
- Pipeline operators would be required to sell capacity to the highest bidder.
- Proceeds from the sale would be assigned to the pipeline operator.
- Pipeline operators and prospective shippers would settle their accounts following each gas day based on:
  - actual flows;
  - the price outcome of the bidding process; and
  - any additional charges including deviation charges.

### 13.4.2 Option 4B: UIOSI

This option would oblige shippers to trade unused firm capacity via a transparent platform if they did not fully utilise their MDQs. Importantly, the rights of existing shippers would need to be carefully considered. This option would operate on the basis of the following assumptions:

- Available ‘unused firm’ capacity being identified based on an assessment of each shipper’s maximum expected requirements over some specified period (e.g. weekly, monthly, yearly) and its contracted firm capacity.
- Any firm capacity that is deemed to be unused would be sold in increments of, say 1 TJ per day.
- Shippers would bid on the unused firm capacity and the existing shipper would be required to sell that capacity to the highest bidder.
- Proceeds from the sale would be assigned to the existing shipper.

- The acquiring shipper and the existing shipper would enter into a standardised contract to settle the transaction including any additional deviation or imbalance charges.
- The gas transport agreement between the existing shipper and the pipeline operator would not be affected by the use-it-or-sell-it scheme.

For both UIOLI and UIOSI, consideration would need to be given to:

- How to fund selected mechanisms;
- What body would be most appropriate to operate a trading platform/auction; and
- What operating and regulatory arrangements would be necessary.

## 14. IMPACT ANALYSIS

Consistent with the COAG best practice regulation guidelines, this RIS identifies the stakeholders likely to be affected by each option and assess the associated benefits and costs. In analysing each option, this RIS assesses the impact on those issues identified in Section 11, and whether the identified objectives can be achieved. A summary of the benefits, costs and risks associated with each policy option is provided at Appendix D.

### 14.1 *Cost-Benefit Analysis of Policy Options*

In response to stakeholder concerns and limitations of existing pipeline capacity information, the Commonwealth engaged NERA Economic Consulting (NERA) to undertake a detailed cost-benefit analysis (CBA) of the RIS policy options. In estimating costs and benefits, NERA considered both submissions made by stakeholders during the consultation RIS process and also the views of industry expressed during its consultations with gas producers, pipeliners, retailers, users, regulators/operators and industry associations. The full CBA can be found at Appendix E.

The principal challenge to quantifying benefits and costs for the policy options was finding objective information about the depth of the secondary market for transmission capacity, and the transaction costs for entering into secondary trades. With little or no objective information publicly available, NERA drew on anecdotal information from its discussions with stakeholders as a basis for measuring costs and benefits. NERA has estimated upper and lower bounds for costs and benefits, in present value terms over 20-year periods, as well as undertaking sensitivity analysis where appropriate. NERA also undertook a breakeven analysis.

#### 14.1.1 **Option 1**

Option 1, the status quo, was used as the base case for the cost-benefit analysis. This option assumes that the development of the Wallumbilla GSH and APA Group's trade facilitator model are instituted by March 2014.<sup>18</sup>

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<sup>18</sup> Option 1 represents the status quo and it is assumed APA Group's trade facilitator model is introduced for trial on the SWQP and RBP. However, it is recognised that at the time the CBA was undertaken, APA's plans to introduce its trade facilitator model were not known.

A summary of the key benefits, costs and risks associated with maintaining the status quo are outlined at Table 6.

**Table 6: Qualitative benefits, costs and risks of Option 1**

Benefits	Costs	Key Risks
<p><i>Existing shippers</i> Maintenance of market positions.</p>	<p>Nil</p>	<ul style="list-style-type: none"> <li>• Adequate unused capacity that would facilitate gas trade may not be offered to the market, thus limiting the ability to build market liquidity.</li> <li>• The market may operate to the detriment of the NGO resulting in higher costs to consumers.</li> </ul>

It is anticipated that market participants who are interested in accessing temporary transportation capacity are likely to be most interested in firm transportation services. Unless unused firm capacity is offered up to market, participants who currently do not have access to unused capacity will not be able to participate in gas trades. This will limit the capacity to build liquidity of the gas market and, in particular, may limit the viability of the Wallumbilla GSH.

It is recognised that APA Group’s proposed trade facilitator capacity trading model provides the potential to improve capacity trading on its two Wallumbilla pipelines, the QGP and SWQP.

On some pipelines where industrial customers dominate firm transportation capacity, these parties may offer up sufficient unused capacity to create a market.

However, given that some stakeholders have expressed concerns that they have not been able to access unused pipeline capacity in the past, it is unclear whether the current market will see adequate unused capacity offered to the market on pipelines where unused capacity is dominated by retailers.

### 14.1.2 Options 2 and 3

Options 2 and 3 are intended to reduce transaction costs and therefore facilitate increased trade. Moreover, the reduction in transaction costs is assumed to lead to an increase in gas transmission pipeline utilisation (i.e. it is assumed that there is an increase in secondary capacity trade once transactions costs are lowered).

Both Options 2 and 3 have relatively low costs when compared to the value of gas trades in the entire gas sector. As shown in Table 7, it is estimated that Option 2 will cost between \$4.7m and \$8.8m in present value terms over the next 20 years.

**Table 7: Costs of Option 2**

<b>Cost Category</b>	<b>Upper Bound (\$ million)</b>	<b>Lower Bound (\$ million)</b>
Upgrade to the National Gas Bulletin Board	\$2.0	\$1.6
Pipeline and Shipper information costs	\$5.0	\$2.2
Changes to the National Gas Rules	\$0.5	\$0.2
Additional enforcement costs	\$1.2	\$0.6
Development of a standardised contract	\$0.2	\$0.1
<b>Total present value</b>	<b>\$8.8</b>	<b>\$4.7</b>

As indicated in Table 7, Option 2 would impose costs on pipeliners and shippers. However, the significance of these costs remains unclear, with some stakeholders indicating that the required information is already gathered for operational purposes and others arguing there are significant costs associated with providing additional information and ensuring that provided information is accurate. Regardless, relatively to other business costs of pipeliners and retailers (both in terms of very large capital investment costs of building a pipeline and normal operating costs), it is considered unlikely that costs to pipeliners or retailers of Option 2 would impose a material barrier to entry. Alternatively, Option 2 through the provision of information and the development of a listing service may enhance pipeline capacity trading and reduce barriers to entry for small shippers wishing to participate in the eastern gas market.

As shown in Table 8, it is estimated that costs associated with Option 3, the development of a voluntary trading platform with standardised products, would be between \$14.7 m and \$23.9 m in present value terms over the next 20 years.

**Table 8: Costs of Option 3**

<b>Cost Category</b>	<b>Upper Bound (\$ million)</b>	<b>Lower Bound (\$ million)</b>
Platform establishment and ongoing costs	\$13.6	\$9.3
Specification of standardised products	\$1.5	\$0.7
Plus Costs of Option 2	\$8.8	\$4.7
<b>Total present value</b>	<b>\$23.9</b>	<b>\$14.7</b>

In the absence of direct information on the likely demand for currently unutilised transmission capacity, estimates were made for:

- a range of net benefits assuming an increase of either 0%, 3% or 5% capacity utilisation; and
- the breakeven increase in utilisation that would be needed to recover the expected costs of each of Option 2 and Option 3.

This approach provides illustrative bounds of the potential net benefits that might be realised should any of the policy options deliver increases in capacity utilisation.

To quantify potential capacities that could be made available for secondary capacity trade, an analysis of historic pipeline usage was undertaken. This analysis recognised

that on certain pipelines, there may be periods of peak demand where there is likely to be little or no capacity available for trade. During periods where capacities could be underutilised, potential volumes and durations of available capacity were estimated where available capacity is defined as the physical capacity of the pipeline less the sum of flows, the potential additional needs of existing holders of capacity and operational limitations of the pipeline (due to maintenance activities).

This analysis recognised that available capacity for any pipeline can be significantly less than unutilised capacity, particularly where the needs of the existing holders of capacity vary greatly from one year to the next. Further, there is currently no publicly available data on planned maintenance activities affecting all eastern market pipelines.<sup>19</sup>

NERA considers that the policy options will only likely result in very small increases in capacity traded, given Options 2 and 3 are not significant changes to the current market framework. Further, NERA consider there is a reasonable prospect that the institution of policy options will lead to no changes in capacity trading and so the benefits will approach zero. Therefore, it is assumed that, at most, an additional 5% of available capacity will be traded and used, for those durations of available capacity. Table 9 shows that, in present value terms, Option 2 could deliver up to \$11.4m in benefits and Option 3 could result in up to \$32m in benefits. A sensitivity analysis was also undertaken assuming a 3% increase use of available capacity.

**Table 9: Benefits (Present Value)**

	<b>5% increase in use (\$ million)</b>	<b>3% increase in use (\$ million)</b>	<b>0% increase in use (\$ million)</b>
Option 2: Improved information	\$11.4	\$6.8	\$0
Option 3: Voluntary capacity trading	\$32.0	\$19.2	\$0

To derive these estimates, it has been assumed that for each additional GJ of gas capacity traded and utilised, there would be \$1/GJ of benefit. This assumption reflects the benefits of both reducing current transactions costs and additional value realised from the use of traded gas. To arrive at this figure, consideration was also given to the potential implied value added per unit of gas use by downstream industry.

In the first instance, the quantified benefits of Options 2 and 3 will be distributed between the parties that trade capacity in secondary markets (i.e. shippers). Where shippers on-sell gas to end users, those end users will also benefit from implementation of the policy options. Regarding gas retail gas prices, because the likely volumes of additional gas that could be brought to market following the implementation of Option 2 measures are likely to be relatively small, it is not expected there would be an impact on retail gas prices.

The increased provision of information will allow participants throughout the gas supply chain to make more informed decisions about their operations and investments and it is expected that this will lead to additional non-quantified benefits.

<sup>19</sup> There is a currently a NGR rule change proposal in process that will require facility operators to provide AEMO with medium-term maintenance reports detailing planned capacity reductions. These reports can then be published on the BB.

Regarding the net benefits, Table 10 shows that Option 2 could potentially deliver between \$6.7m and -\$8.8m of net benefits, assuming that \$1/GJ of benefit was realised from each GJ of additional gas traded. The upper bound net benefit assumes that maximum benefits are achieved at minimum cost and the lower bound assumes that no benefits are generated at a maximum cost. The benefit cost ratio for this case is 2.4. Sensitivity analyses were also undertaken assuming benefits of \$0.50/GJ and \$1.50/GJ.

**Table 10: Net Benefits of Option 2**

	<b>Upper Bound (\$m)</b>	<b>Lower Bound (\$m)</b>
Costs	\$4.7	\$8.8
<b>Present Value (\$1 benefit for each GJ traded)</b>		
Benefits	\$11.4	0
Net Benefits	\$6.7	-\$8.8
Benefit Cost Ratio	2.4	0
<b>Present Value (\$0.50 benefit for each GJ traded)</b>		
Benefits	\$5.7	0
Net Benefits	\$1.0	-\$8.8
Benefit Cost Ratio	1.2	0
<b>Present Value (\$1.50 benefit for each GJ traded)</b>		
Benefits	\$17.1	0
Net Benefits	\$12.4	-\$8.8
Benefit Cost Ratio	3.6	0

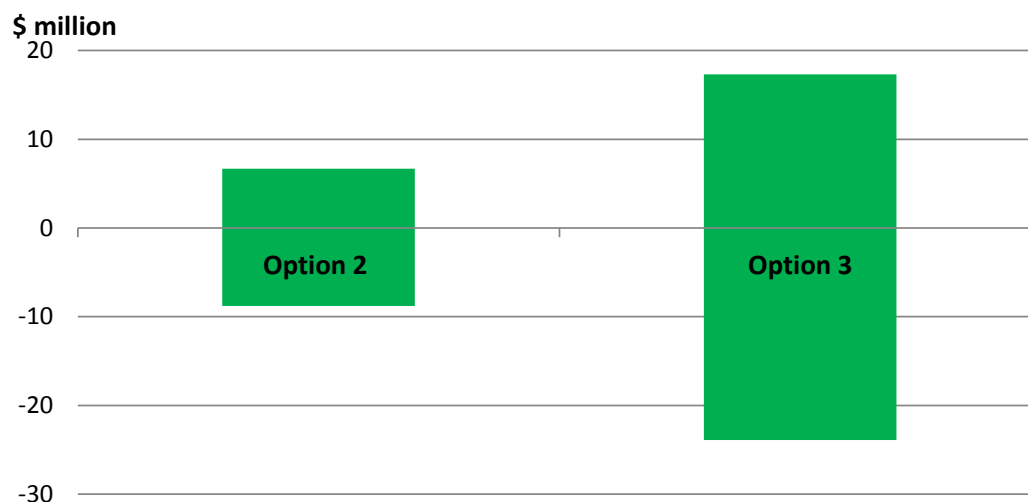
Table 11 shows that Option 3 could potentially deliver between \$17.3m and -\$23.9m of net benefits, assuming that \$1/GJ of benefit was realised from each GJ of additional gas traded. The cost-benefit ratio for this case is 2.2. Sensitivity analyses were also undertaken assuming benefits of \$0.50/GJ and \$1.50/GJ.

**Table 11: Net Benefits of Option 3**

	<b>Upper Bound (\$m)</b>	<b>Lower Bound (\$m)</b>
Costs	\$14.7	\$23.9
<b>Present Value (\$1 benefit for each GJ traded)</b>		
Benefits	\$32.0	0
Net Benefits	\$17.3	-\$23.9
Benefit Cost Ratio	2.2	0
<b>Present Value (\$0.50 benefit for each GJ traded)</b>		
Benefits	\$16.0	0
Net Benefits	\$1.3	-\$23.9
Benefit Cost Ratio	1.1	0
<b>Present Value (\$1.50 benefit for each GJ traded)</b>		
Benefits	\$48.1	0
Net Benefits	\$33.3	-\$23.9
Benefit Cost Ratio	3.3	0

Figure 9 compares the ranges of net present value of Options 2 and 3, assuming \$1/GJ of benefit.

**Figure 9: Range of Net Present Values of Options 2 and 3**



NERA notes there is a possibility that Options 2 and 3 might not lead to any increase in the trading of capacity, particularly in the short term. Further, while Option 3 has the potential to deliver greater net benefits compared with Option 2, it also carries additional risks. These risks relate to the complexities involved in developing standardised products for voluntary trading and it is conceivable that there might not be sufficient demand for standardised products to warrant the cost of their development and trading platform establishment and operation costs.

Table 12 sets out the implied increase in capacity utilisation necessary to recover the upper bound and lower bound estimates of costs. The results demonstrate that for Option 2, an average increase in utilisation of 2.1 TJ/day in total across all eastern market pipelines would need to be achieved to break even on upper bound costs.

Given that in 2012-13, Australia's eastern market produced approximately 735 PJ of gas, this break-even figure represents the transportation of approximately 0.1% of gas produced over that period. Similarly, 1.1 TJ/day increase in utilisation would be required to break even on lower bound costs. For Option 3, utilisation would need to increase 6.1 TJ/day or 3.8 TJ/day respectively.

**Table 12: Increase in Utilisation Required to Break Even**

Costs Ranges	Average Increase in Utilisation (TJ/day)
<b>Option 2: Improved information</b>	
Upper bound costs	2.1
Lower bound costs	1.1
<b>Option 3: Voluntary trading</b>	
Upper bound costs	6.1
Lower bound costs	3.8



During consultations, some stakeholders raised concerns that publishing rolling pipeline capacity data on the BB may disclose shippers' market positions and undermine their competitiveness. During the development of amendments to the NGRs care would need to be taken to ensure shippers rights and interests were appropriately protected (either by aggregation and/or use of proxies). In accordance with the NGL, stakeholders would have the opportunity to provide written submissions on the rule change proposal.

### 14.1.3 Option 4

The direct costs of Option 4 (such as platform establishment and operation, legislative amendments, compliance and enforcement costs) are likely to exceed those of either Options 2 or 3.

The benefits of Option 4 depend on the extent to which pipeliners or shippers fail to release capacity to the market under the status quo. Given that pipeliners already offer up non-firm capacity, the potential net benefits of Option 4A could reasonably be assumed to be negligible. The potential net benefits of Option 4B are less clear.

NERA notes that in a competitive gas market, if there are benefits to a holder of capacity from trading capacity and those benefits outweigh the costs of making capacity available, then capacity trading would be expected to occur (assuming there is demand for the released capacity). It is argued that any capacity that is not released most likely reflects either the holder's belief there is a lack of demand for the available capacity or the option value to the capacity holder is higher than the revenue likely to be received from trading the capacity, given uncertainties in the holder's need for gas in a downstream market (e.g. in the case of gas-fired electricity generators when demand for gas-fired generation on a daily basis is not known with any certainty).

In the context of the Australian market, NERA did not find 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.

Assuming that shippers are not engaging in anti-competitive behaviour, the implementation of Option 4B could reasonably be assumed to not result in any incremental benefits relative to Option 2, where the platform is a capacity listing service. Similarly, it could reasonable be assumed that Option 4B would not result in any incremental net benefits relative to Option 3.

## 14.2 Jurisdictional Impacts

With regards to the anticipated impacts across Australia's three distinct gas markets (north, west and east), any possible changes to the status quo are not expected to have a significant impact on either the western or northern markets. There is very limited information available concerning pipeline capacity utilisation in the west and north.

Regarding the west, given the majority of gas is used for manufacturing and mining activities, the demand profile on most western pipelines is likely to be relatively flat and capacity utilisation is likely to be relatively high. Regarding the north, given the relatively low volumes of gas being transported; few sources of supply; low demand;

and that there are several fields in decline or at the end of life, it is anticipated that contractual congestion may not be a problem.

As previously stated, the NGL and NGRs are generally nationally consistent and implemented through application Acts at the state and territory level. Any legislative or regulatory change regarding the provision of additional information for publishing on the BB would only apply to those jurisdictions currently required to provide BB data (i.e. excluding WA and NT).

## 15. CONSULTATION

Officials first undertook informal industry consultations during 2012. During this period, representatives from producers, retailers, industrial consumers, pipeline owners and AEMO were consulted to seek their views on whether there was a problem with the way in which unused pipeline capacity was traded. Officials also leveraged off AEMO's Wallumbilla GSH Industry Reference Group meetings that began in 2012.

Officials then drafted an internal discussion paper that was considered by SCER at its 14 December 2012 meeting. On 31 May 2013, a consultation RIS was publicly released on the SCER website for a period of six weeks and the formal submission process closed on Monday 15 July 2013. Interested stakeholders were invited to provide written submissions and answer specific questions listed throughout the consultation RIS (see Appendix C).

Thirteen stakeholders made submissions to the consultation RIS, of which, two were confidential submissions. Non-confidential submissions were published on SCER's website on 5 August 2013.<sup>20</sup> Stakeholders that provided non-confidential, public submissions included:

- AGL
- Alinta Energy
- APA Group
- Australian Energy Market Operator (AEMO)
- Australian Pipeline Industry Association (APIA)
- EnergyAustralia
- Energy Supply Association of Australia (ESAA)
- Epic Energy South Australia
- GDF Suez
- Jemena
- Origin Energy

In addition to reviewing the submissions, officials consulted with key industry stakeholders including representatives from the AER, AEMC, AEMO and others who did not make submissions to the consultation RIS. Further, during the development of the cost-benefit analysis, NERA Economic Consulting undertook consultations with

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<sup>20</sup> <http://www.scer.gov.au/workstreams/energy-market-reform/gas-market-development/gtpct>

gas producers, pipeliners, retailers, users, regulator/operators and industry groups. NERA used the stakeholder submissions as a basis for consultations which were targeted at discussing the likely costs and benefits associated with the policy options identified in the consultation RIS.

### *15.1 Summary of Stakeholder's Views*

During bilateral consultations and within written submissions, stakeholders presented a wide range of views on the efficiency of the existing capacity trading market. Generally, pipeliners do not support change because they do not believe there is a problem with existing capacity trading mechanisms. However, pipeliners do recognise that enhancements could be made to improve the functionality of the BB. While the views of shippers vary considerably, there is some support for the provision of information and the development of standard terms and conditions that could assist with moving toward market liquidity. These divergent views reflect the differing nature of pipeline and shipper businesses, the extent to which they are incumbents who already have contractual arrangements which are likely sufficient for their immediate needs, and the anticipated distribution of costs and benefits associated with the alternative policy options.

In their submissions, stakeholders made the following key points:

- The extent of the problem, including the demand for contracted but unused capacity remains unclear.
- Should a change from the status quo be warranted, enhanced transparency through the provision of improved information represents the most appropriate initial step. This would allow market participants to better understand what volumes of capacity are available or in demand over certain periods on particular pipelines. However, the costs associated with increased information provision should not be underestimated.
- There were divergent views on whether adequate information is already provided and if additional information would facilitate increased capacity trading.
- Some stakeholders believe that shippers may not want to use standardised terms and conditions due to a preference to maintain flexibility to tailor agreements to suit trading parties.
- There were varying views concerning the difficulty, transaction costs and timeliness of undertaking capacity negotiations/agreements. Larger entities (including incumbents) indicated that it is easy to call around and find out if market participants have spare capacity given the relatively small size of the Australian gas market.
- Capacity trading should not be reviewed in isolation to the rest of the market and a holistic review of the east coast gas market needs to be considered.
- Market-led initiatives should be permitted to develop before government intervention is warranted. Pipeliners believe that industry participants will act when it is appropriate to do so.
- Mandatory capacity trading is not supported by the over majority of stakeholders.
- Many stakeholders stated that a detailed cost-benefit analysis of the RIS policy options is required prior to possibly moving from the status quo.

No submission provided significant new data to better inform the impact analysis or to make any material changes to the options. Submissions identified a range of auxiliary issues that are beyond the scope of this RIS.

## 15.2 Issues Raised by Stakeholders in Submissions

### 15.2.1 Extent of the Problem

#### *Demand for Unused Capacity*

Numerous stakeholders – including Jemena, APA Group, APIA, Origin Energy and AGL – indicated that there is limited demand for secondary capacity. AGL stated that “opportunistic demand for gas is a very rare thing”<sup>21</sup> and it “cannot recall being approached, except for a few instances, for spare capacity that we might have on a pipeline”.<sup>22</sup> Similarly, Origin Energy stated that as a shipper it “is open to requests to trade unutilised but contracted spare capacity. It is our experience, however, that there has been limited demand for access to this type of capacity”.<sup>23</sup> APIA indicated that from the perspective of pipeliners “small quantity transactions are typically difficult to execute due to a lack of interest from the market”<sup>24</sup>. APA Group stated that there is “likely to be limited demand for pipeline capacity trading in the near to medium term”<sup>25</sup> and that given APA’s position in the market “it is unlikely that there is unmet demand of which APA is unaware”.<sup>26</sup>

APA Group, Jemena and APIA indicated that there is little justification for changes to the way secondary capacity is currently traded, as market participants already have an incentive to sell unused capacity. APIA stated that “gas transmission companies are highly incentivised to offer up any spare capacity at every opportunity”.<sup>27</sup>

#### *Is There a Market Failure?*

A range of stakeholders – such as Jemena, APA Group, Epic Energy, APIA, ESAA and Origin Energy – stated that evidence of a market failure would be needed to warrant intervention. Stakeholders cautioned against intrusive intervention until such a time that the extent of the problem is clear. Origin Energy stated that “regulatory intervention should only be pursued where a significant and clear market failure has been identified that warrants intervention”.<sup>28</sup>

Accordingly, a number of these stakeholders advocated for the maintenance of the status quo, including Jemena who “supports the conclusion that the status quo be maintained until such a time that there is clear evidence of market failure, and that it has been established that any proposed interventions will deliver market benefits which exceed their costs”.<sup>29</sup> Likewise, ESAA argues that “identifying and

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<sup>21</sup> AGL, RIS submission, pg. 1.

<sup>22</sup> AGL, RIS submission, pg. 3.

<sup>23</sup> Origin Energy, RIS submission, pg. 6.

<sup>24</sup> APIA, RIS submission, pg. 8.

<sup>25</sup> APA Group, RIS submission, pg. 1.

<sup>26</sup> APA Group, RIS submission, pg. 10.

<sup>27</sup> APIA, RIS submission, pg. 10.

<sup>28</sup> Origin Energy, RIS submission, pg. 1.

<sup>29</sup> Jemena, RIS submission, pg. 1.

understanding the nature of any perceived market failure is a prudent first step that will guide the appropriateness of regulatory intervention in the evolving east coast gas market”.<sup>30</sup>

### 15.2.2 Administrative Complexity and High Transaction Costs

Divergent views were expressed regarding the ease and expense of existing capacity trading arrangements. On one hand, a number of stakeholders indicated they had not experienced any problems accessing additional capacity. EnergyAustralia indicated that “to date we have not experienced any problems in sourcing additional firm and ‘as available’ capacity either directly through the pipeliners or in secondary markets”.<sup>31</sup> Given it is a small market with few participants involved, some stakeholders indicated that it is just a matter of making enquiries with the relevant players. AGL stated that “industry players, in terms of producers, pipeline operators, and shippers, are well-known and it would be easy enough to phone around to enquire about spare capacity and/or spare gas”.<sup>32</sup> Similarly, APA Group argued that there are no “material barriers to shippers identifying potential counterparties to such trades”.<sup>33</sup>

On the other hand, some stakeholders argue that existing capacity transactions are time-consuming, complex and costly. Alinta Energy outlined that negotiations regarding terms and conditions are often lengthy and the “costs of this process often outweighs the benefits, and as such Alinta Energy considers this arrangement to be operationally burdensome and hardly ideal”.<sup>34</sup> GDF Suez argued that capacity trading transactions, including novation and bare transfer, are problematic and can be improved to lower transaction costs and “minimise the time to put the agreement into place”.<sup>35</sup> GDF Suez provides an example of the onerous nature of undertaking a particular novation transaction:

“A novation from one party to GDFSAE completed in 2012 was a long and legalistic process that involved three direct parties, (shipper, transporter and GDFSAE) with the final agreement being in the form of a deed. This deed then required multiple business owners to be signatories that brought in a number of other corporations, not all located in Australia, so the logistics in signing this deed were challenging”.<sup>36</sup>

Furthermore, GDF Suez indicated that while bare transfers are simpler to conclude because the transfer occurs under the GTA, thus removing the transporter from the negotiation, an agreement between the two shippers is still required and “this generally is a legalistic and time consuming process”.<sup>37</sup>

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<sup>30</sup> ESAA, RIS submission, pg. 3.

<sup>31</sup> EnergyAustralia, RIS submission, pg. 3.

<sup>32</sup> AGL, RIS submission, pg. 2.

<sup>33</sup> APA Group, RIS submission, pg. 12.

<sup>34</sup> Alinta Energy, RIS submission, pg. 3.

<sup>35</sup> GDF Suez, RIS submission, pg. 6.

<sup>36</sup> GDF Suez, RIS submission, pg. 4.

<sup>37</sup> Ibid

### 15.2.3 Standardised Terms and Conditions

Stakeholder views on the value of standardising contractual terms and conditions varied considerably. APA Group and APIA indicated that each shipper has particular needs, requiring flexibility and capacity trades need to be made with regard to the underpinning GTA. APIA argued that “while a large number of conditions in transport agreements can be standardised those specific to risk allocation need to be tailored to the specific of a transaction and the shipper”.<sup>38</sup>

APA Group has developed standard terms and conditions for all its GTAs but finds that “shippers do seek modification of those terms to meet their specific needs for transportation and risk allocation”.<sup>39</sup> APA Group argues that “standardisation of terms and conditions would not be a straightforward process, and may indeed hinder the development of the market and the tailoring of products to shippers’ needs”.<sup>40</sup> Alternatively, GDF Suez argues that standardisation “would significantly reduce legal costs and speed up transaction time”.<sup>41</sup>

### 15.2.4 Adequacy of Information

#### *Is Adequate Information Currently Available?*

Pipeline operators questioned the value of providing additional pipeline utilisation information. Jemena indicated that they have not been asked by any of its shippers, or potential shippers for additional information to facilitate secondary capacity trading and therefore do not believe additional market information is required. APA Group argued that “there is already considerable information available on the Gas Market Bulletin Board regarding available pipeline capacity (that is, the difference between the pipeline capacity and daily nominations)”.<sup>42</sup> Similarly, APIA stated that “there is no obvious new information enhancements to the Bulletin Board that could be made to facilitate trading. Significant capacity data is already available through the Bulletin Board”.<sup>43</sup> During the course of consultations, several stakeholders elaborated that existing BB data could be more accessible and better presented. APIA suggested that improvements could be made to increase the utilisation of existing provisions in the NGR, particularly Rule 176, that enable parties to register their interest in trading on the BB. APIA argued that “this service should be more widely advertised and utilised before more complex platforms are considered”.<sup>44</sup> Similarly, Alinta Energy suggested “there is some merit in leveraging off the existing bulletin board as a way of facilitating greater capacity trade”.<sup>45</sup>

Pipeline operators also argued that they would incur substantial costs if required to provide additional information, although the magnitude of those costs would depend on the type and extent of data required. Jemena argued the provision of real-time data would require significant information system expenditure and operational staff, stating that the “cost to the Australian pipeline industry of providing real-time data could run into

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<sup>38</sup> APIA, RIS submission, pg. 19.

<sup>39</sup> APA Group, RIS submission, pg. 13.

<sup>40</sup> Ibid

<sup>41</sup> GDF Suez, RIS submission, pg. 4.

<sup>42</sup> APA Group, RIS submission, pg. 13.

<sup>43</sup> APIA, RIS submission, pg. 18.

<sup>44</sup> APIA, RIS submission, pg. 19.

<sup>45</sup> Alinta Energy, RIS submission, pg. 3.

millions of dollars, depending on the actual information requirements”.<sup>46</sup> APIA believes the costs of pipeliners providing additional information should be recovered from market participants “where there is a real benefit to the market from this information, it is appropriate that the market, at a minimum, cover the costs of its provision”.<sup>47</sup>

If additional information was required to be published by pipeliners, Jemena raised concerns around the risks associated with “liability for data accuracy”.<sup>48</sup>

Alternatively, there is some qualified stakeholder support for the provision of additional information that could assist with moving toward market liquidity. EnergyAustralia argued that “increased transparency and access to voluntary markets can only serve to benefit liquidity”.<sup>49</sup> Origin Energy indicated that existing BB data is simplistic and does not give an accurate picture of the market – for example hourly data would provide a better indication of capacity utilisation than the existing average daily data. GDF Suez agrees that existing information is insufficient to support effective capacity trading, and suggested that “to be effective, the information should include a forward estimate of the available capacity on a pipeline, similar to the PASA process in the national electricity market”.<sup>50</sup>

### *General Consensus*

Overall, stakeholders generally agreed that if intervention is warranted, information provision is likely to be the most appropriate initial step. ESAA indicated that “where regulatory intervention is to be considered, a light-handed and incremental approach that has appropriate regard for existing contracts is likely to be the most appropriate response”.<sup>51</sup> Similarly, AGL stated that “if regulatory intervention is to be considered, a light-handed approach that has appropriate regard for existing contracts is likely to be the most appropriate response. AGL considers there is merit exploring option 2 (improved information) in the first instance”.<sup>52</sup>

## **15.2.5 Capacity Trading Facility**

### *Voluntary Trading Platform*

Should government intervention be required and it is assessed that the establishment of a trading platform was necessary, the majority of stakeholders identify voluntary trading as being more appropriate than a mandatory regime.

GDF Suez indicated that for a voluntary model to work, the market has to provide sufficient incentives to encourage involvement. GDF Suez believes sufficient incentives could be provided in the following circumstances:

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<sup>46</sup> Jemena, RIS submission, pg. 7.

<sup>47</sup> APIA, RIS submission, pg. 18.

<sup>48</sup> Jemena, RIS submission, pg. 7.

<sup>49</sup> EnergyAustralia, RIS submission, pg. 4.

<sup>50</sup> GDF Suez, RIS submission, pg. 6.

<sup>51</sup> ESAA, RIS submission, pg. 3.

<sup>52</sup> AGL, RIS submission, pg. 3.

- There are sufficient participants participating in that market to provide a deep liquid trading environment to a level where participants have comfort that they can execute a trade irrespective of the time of day, week, month or season.
- Participants can see that the market is offering a lower transaction cost, faster execution times and/or better choice of products than are currently available.<sup>53</sup>

### *Mandatory Trading Platform*

Submissions highlighted that overwhelmingly, stakeholders do not support heavy-handed intervention through mandatory use-it-or-lose-it (Option 4a) and/or use-it-or-sell-it (Option 4b) capacity trading. APIA considers that the very suggestion of mandatory use-it-or-lose-it capacity trading ignores the existing incentives for pipeliners to increase throughput and therefore revenue when possible.

Jemena cautions against a capacity trading regime that mandates the release of unused capacity as it “would impinge on the contractual rights and flexibility of shippers and pipeliners”.<sup>54</sup> Similarly, AGL believes mandatory trading would “impinge on the property rights of shippers and on the sovereignty of pipeline operators to manage their business”.<sup>55</sup>

GDF Suez describes a mandatory pipeline capacity regime as the “least appealing” option.<sup>56</sup> Origin Energy and EnergyAustralia also do not support mandatory capacity trading. Origin Energy argues that:

“Imposing a regulatory capacity trading option on the market may have an adverse impact on investment, both in terms of investments already made and any potential future investments required. For the former, this could be in the form of sovereign risk issues where the rights of existing capacity holders could be potentially compromised. For the latter, this could affect the efficiency of future investments as intervention may dampen signals that a long-term solution is required to address a persistent constraint on a pipeline or it may hinder commercial incentives to underwrite investment”.<sup>57</sup>

EnergyAustralia believes that a mandatory trading regime “could increase the burdens and costs of secondary trading in the market and as a consequence reduce the likelihood of activity”.<sup>58</sup>

More generally, a number of stakeholders identified that government-initiated capacity trading platforms are likely to impose costs that are likely to exceed the benefits to the market. AGL argues that “trading platforms may be high risk and expose industry to transaction costs with minimal benefits when the extent of the market and the take-up of listed spare capacity have not been demonstrated”.<sup>59</sup> Similarly, APA Group believes a government-led platform “is likely to impose

<sup>53</sup> GDF Suez, RIS submission, pg. 6.

<sup>54</sup> Jemena, RIS submission, pg. 9.

<sup>55</sup> AGL, RIS submission, pg. 4.

<sup>56</sup> GDF Suez, RIS submission, pg. 7.

<sup>57</sup> Origin Energy, RIS submission, pg. 7.

<sup>58</sup> EnergyAustralia, RIS submission, pg. 3.

<sup>59</sup> AGL, RIS submission, pg. 4.



considerable costs on the gas market that, given the expectation of limited demand for capacity trading, are likely to far exceed the benefits”.<sup>60</sup>

### 15.2.6 Industry-led Solutions

A number of submissions – including those made by Origin Energy, Alinta, APA Group and APIA – indicated that industry-led solutions should be permitted prior to any government intervention. Origin Energy recommends that SCER allows industry to identify options that can strengthen the quality of price signals in the current market. Origin Energy has been working with AEMO to enhance the capability of the BB to allow for the listing of supply and capacity offers, noting that the existing facility excludes shippers from listing spare capacity as they are not the operators of the pipeline. Origin Energy argues that “improving this facility may assist those parties seeking capacity to more easily contact suitable counterparties”.<sup>61</sup>

APA Group states that it “considers that a market-led response to capacity trading is likely to deliver the most efficient market outcome, particularly as demand for capacity trading is likely to be limited”.<sup>62</sup> APA Group notes that it is currently undertaking a project to determine whether there are efficient and effective secondary capacity trading solutions that could be offered to the market. APA Group argues that market-developed products could be developed to address particular capacity trading issues “at a much lower cost than any government/regulatory model”.<sup>63</sup>

APIA considers that given the pipeline industry derives revenue from providing market services “it is reasonable to expect they will seek opportunities to deliver trading services when the market indicates a need for them”.<sup>64</sup> APIA indicates that the Western Australian gas market serves as an example that third party trading services will develop if necessary.

### 15.2.7 Harmonise Existing Market Frameworks

A number of stakeholders – including EnergyAustralia, Origin Energy, ESAA, APIA and APA Group – indicated that pipeline capacity trading should be considered in the context of a broader reform agenda for the east coast gas market. For example, ESAA argues “there is merit in taking a more holistic approach that considers the broader east coast gas market, rather than reviewing discrete aspects of the market in isolation”.<sup>65</sup>

#### *Wallumbilla*

The AEMO’s submission identified the SCER commitment to review the Wallumbilla GSH in 2015 as an appropriate time to review the effectiveness of the capacity trading measures currently being developed alongside the GSH. AEMO believes that this timeframe would have “provided the market enough time to evolve and develop the

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<sup>60</sup> APA Group, RIS submission, pg. 14.

<sup>61</sup> Origin Energy, RIS submission, pg. 7.

<sup>62</sup> APA Group, RIS submission, pg. 15.

<sup>63</sup> APA Group, RIS submission, pg. 1.

<sup>64</sup> APIA, RIS submission, pg. 16.

<sup>65</sup> ESAA, RIS submission, pg. 3.

necessary services and mechanisms to support SCER’s overall Gas Market Development Plan”.<sup>66</sup>

Alternatively, a number of stakeholders argue that the review of Wallumbilla GSH in 2015 will not provide an appropriate amount of time for the GSH to mature. APA Group and Jemena support a review of gas capacity trading activity at Wallumbilla GSH after three years of operation. Similarly, APIA indicates that “a review of capacity issues at least 2 years and preferably 3 years after the commencement of the Wallumbilla gas supply hub is appropriate”.<sup>67</sup> APIA believes that the Australian Energy Market Commission is best placed to conduct a review, assess the effectiveness of Wallumbilla initiatives and “their contribution to the National Gas Objective”.<sup>68</sup>

Origin Energy and the ESAA cautioned against using the outcomes of the Wallumbilla GSH as a signal of broader capacity trading demand and supply across the east coast market.

## 16. EVALUATION AND CONCLUSION

There is very limited publicly-available information concerning gas transmission pipeline capacity utilisation, capacity trading activity and the price and demand for secondary capacity. This type of information could reasonably be expected to underpin a transparent and efficient capacity trading market.

At the anecdotal level, some market participants believe limited transparency regarding actual utilisation of pipeline capacity and administrative complexity during contract negotiation discourages short-term capacity trading, perpetuates capacity hoarding and the market’s reliance on longer-term agreements.

Stakeholder submissions received during the consultation RIS process highlight the diverse views of market participants. In general:

- pipeliners do not support change because they do not believe there is a problem with existing capacity trading mechanisms; and
- while the views of shippers vary considerably, there is some qualified support for the improved provision of information and the development of standard terms and conditions that could assist with moving toward market liquidity.

The consultation process also indicated there is minimal stakeholder support for heavy intervention through mandatory use-it-or-lose-it (Option 4A) and no support for use-it-or-sell-it (Option 4B) capacity trading.

A CBA of the policy options identified within this RIS found that:

- The net benefits of all options are highly sensitive to the quantum of any subsequent increase in capacity utilisation and the value of benefits attributed to that increased utilisation;

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<sup>66</sup> AEMO, RIS submission, pg. 2.

<sup>67</sup> APIA, RIS submission, pg. 20.

<sup>68</sup> APIA, RIS submission, pg. 21.

- Option 2, improving the provision of market information to facilitate gas transmission pipeline trading provides a relatively low-cost mechanism that may deliver net benefits; and
- Options 3 and 4, the establishment of either a voluntary or mandatory trading platform could incur costs significantly higher than potential benefits.

The current capacity trading market situation appears to be one in which the larger incumbents have adequate information to trade capacity but new or smaller participants, who may seek new or additional capacity, would benefit from better information to enable them to effectively participate in the market.

Although there is a degree of uncertainty concerning the anticipated net benefits of instituting Option 2, recommended improvements could potentially reduce transaction costs and assist with making fundamental information available to facilitate market transactions. Improved transparency would also enable policy makers to better understand the market and hence make better-informed decisions.

Within the eastern gas market, no jurisdiction is expected to incur greater costs, receive higher benefits, or be disadvantaged as a result of implementing Option 2. It is recognised that any benefits for improving the way in which pipeline capacity is traded may be relatively small in the short term. However, as international experience suggests, the benefits of improving the way that capacity is traded may also help build competition and liquidity in the wholesale market over time.

Therefore SCER officials recommend that Option 2 be progressed. This option would require pipeliners (and shippers via pipeliners) to provide AEMO with enhanced capacity utilisation and trading data.

This option would also require AEMO to upgrade its BB to include a capacity listing service and improve the presentation of new and existing pipeline capacity and trading data.

The APA Group has recently advised it is developing an industry-led ‘trade facilitator’ model for secondary capacity it plans to trial on two pipelines associated with the Wallumbilla GSH. APA Group has stated that it will consider expanding this service to other pipelines if there is adequate demand.

It is recognised that APA Group’s plan will be an incremental step toward market liquidity but, in the first instance, will only provide enhanced capacity utilisation and trading information concerning two of eastern Australia’s pipelines. In contrast, Option 2 would provide a mechanism to improve transparency and data across all eastern market gas transmission pipelines.

## 17. IMPLEMENTATION AND REVIEW

It is proposed that Option 2 be implemented in consultation with stakeholders mindful of ongoing industry-led initiatives and the broader SCER gas market reform agenda. Option 2 would involve three distinct work streams.

1. Mandate the provision of enhanced capacity trading information for publishing on AEMO's BB. This would involve:
  - working with AEMO and stakeholders to determine what additional information can practically be provided to AEMO; and
  - working with AEMC to implement the required NGL/NGR amendments and rule changes that would be required to mandate improved information provision.
2. Improve the functionality and useability of the BB. This would involve AEMO:
  - working with stakeholders to determine how to best present new and existing information; and
  - developing and implementing an eastern market capacity listing service.
3. Develop standard contractual terms and conditions for secondary capacity trade. This would involve AEMO:
  - Leveraging off AEMO's work already undertaken for the GSH, work with stakeholders to develop standardised contractual terms and conditions that could be applicable across all eastern market pipelines.

SCER officials will develop a detailed implementation plan by mid-2014, with a view to fully implementing Option 2 as soon as possible.

SCER officials will monitor capacity trading at the Wallumbilla GSH, including the usefulness of its capacity listing service and standardised contract and industry-led initiatives and ensure that any potential duplication is avoided and costs to industry are minimised.

Option 2 does not preclude further reforms over time and will provide useful information about the costs and benefits of further reforms.

It is proposed that two years after above initiatives have been implemented, a review will be undertaken into the usefulness and effectiveness of the proposed changes. The review will also assess the level of supply and demand for unused pipeline capacity at the GSH and whether or not adequate unused capacity has been offered to the market. At this time, it will be considered whether further action is required to improve capacity trade.

## APPENDIX A – INTERNATIONAL EXPERIENCE

Examples of how unused pipeline capacity is managed in an international context include:

- United States of America’s Federal Energy Regulatory Commission (FERC) *Open Access Same-Time Information System*;
- Great Britain’s *National Balancing Point* (a virtual trading location);
- Netherlands’ *APX-ENDEX*;
- Germany’s *TRAC-X*;
- France’s and Belgium’s *Capsquare*; and
- Germany’s, Netherlands’ and Denmark’s *Link4Hubs*.

**Table A1: Pipeline Capacity Trading Initiatives**

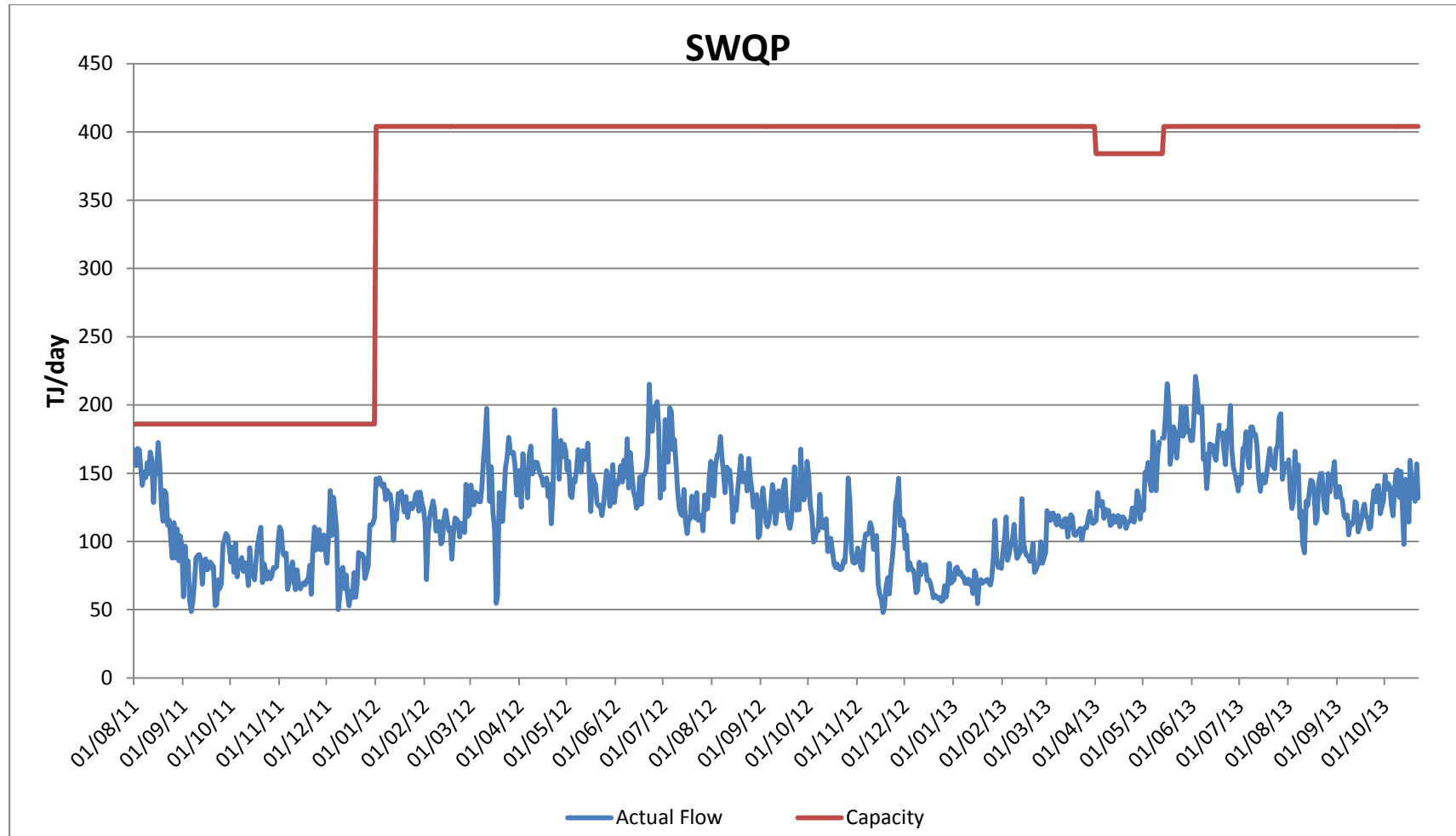
Exchange/Location	Description	Product/Features	Comments
Netherlands APX-ENDEX	<p>Part of the 2008 pilot program for the development of secondary trading of capacity.</p> <ul style="list-style-type: none"> <li>• Capacity products developed for the pipeline interconnect between Holland and Germany allowing users to transfer gas to or from the Dutch gas hub (the Title Transfer Facility).</li> </ul>	<ul style="list-style-type: none"> <li>• Secondary trading of firm capacity usage rights.</li> <li>• Day-ahead, weekend contracts</li> <li>• Centralised settlement and credit risk management.</li> </ul>	<ul style="list-style-type: none"> <li>• Transactions issued directly to transport system operator (TSO).</li> <li>• APX-ENDEX also offers physical gas trading products.</li> </ul>

Exchange/Location	Description	Product/Features	Comments
<p><b>Germany</b></p> <p>TRAC-X</p>	<p>Established in 2005 by German TSOs to facilitate secondary trading of gas transportation services.</p> <ul style="list-style-type: none"> <li>• Web-based trading platform allowing contract holders to trade or auction capacity.</li> <li>• In response to European gas market initiatives, in 2010 TRAC-X also tasked with auctions for primary capacity allocation for German pipelines.</li> </ul>	<ul style="list-style-type: none"> <li>• Short-term secondary capacity transactions are based on operational transfer and bilateral settlement</li> <li>• Medium-term secondary capacity transactions are based on contractual transfer.</li> <li>• Buyer takes on financial obligations direct to the TSO</li> <li>• Trading occurs 9am-11am Monday to Friday.</li> <li>• Seller can filter out buyers that they have not established credit support.</li> </ul>	<ul style="list-style-type: none"> <li>• Transactions executed on the exchange are sent straight to the relevant TSO to perform the transfer of capacity from the buyer to the seller.</li> <li>• Buyer makes nomination direct to the TSO.</li> </ul>
<p><b>Belgium</b></p> <p><b>France</b></p> <p>Capsquare</p>	<p>Capsquare is a web-based platform to buy or sell natural gas transmission capacity on the secondary market in:</p> <ul style="list-style-type: none"> <li>• Belgium’s Fluxys Transmission Network and Storage Installation; and</li> <li>• France’s GRTgaz network</li> </ul>	<ul style="list-style-type: none"> <li>• Short to medium-term capacity transactions.</li> <li>• Bilateral settlement.</li> </ul>	<ul style="list-style-type: none"> <li>• Capsquare sends details of capacity transactions to the relevant TSO so that the capacity usage rights can be transferred from the seller to the buyer.</li> </ul>

Exchange/Location	Description	Product/Features	Comments
<p><b>Germany</b> <b>Netherlands</b> <b>Denmark</b></p> <p>Link4Hubs</p>	<p>Web-based platform for the trading of cross-border pipeline capacity between Germany, Netherlands and Denmark.</p>	<ul style="list-style-type: none"> <li>• Day-ahead capacity product developed by TSO.</li> <li>• Capacity available for purchase based on operators' assessments of available capacity.</li> </ul>	<ul style="list-style-type: none"> <li>• Trading participants register with the relevant TSOs prior to trading.</li> </ul>
<p><b>United States</b></p> <p>Open Access Same-Time Information System</p>	<p>FERC requires pipeline operators to publish details of available services, operating capacity and scheduled capacity on the Open Access Same-Time Information System (OASIS) website.</p>	<ul style="list-style-type: none"> <li>• Information about transportation services available intraday: <ul style="list-style-type: none"> <li>– Unsubscribed: quantity of capacity that has not be sold that is available for sale as a firm service.</li> <li>– Operationally available: quantity of capacity not used by shippers that is available for sale as an interruptible service.</li> </ul> </li> </ul>	

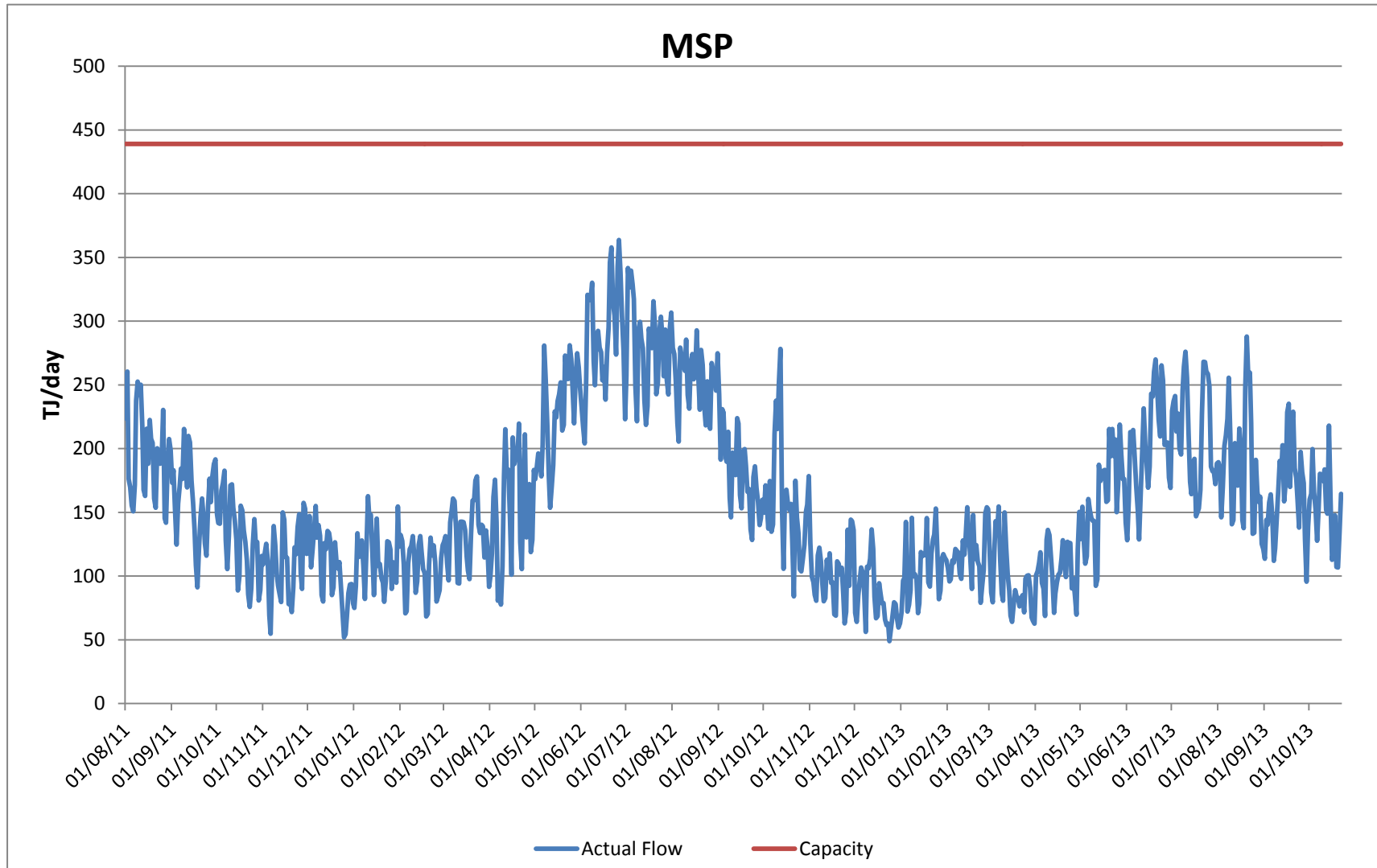
## APPENDIX B – DAILY PIPELINE CAPACITY UTILISATION

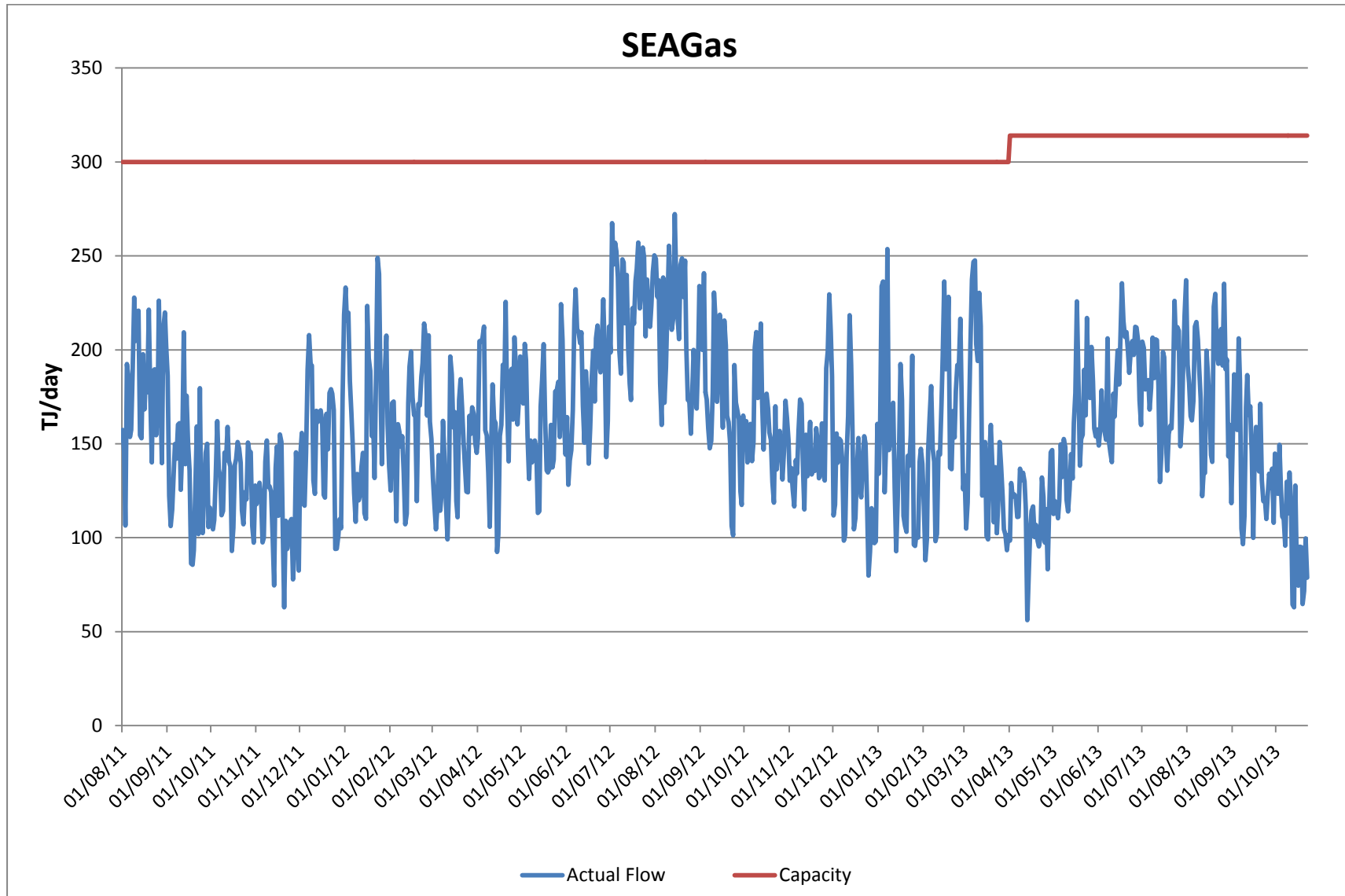
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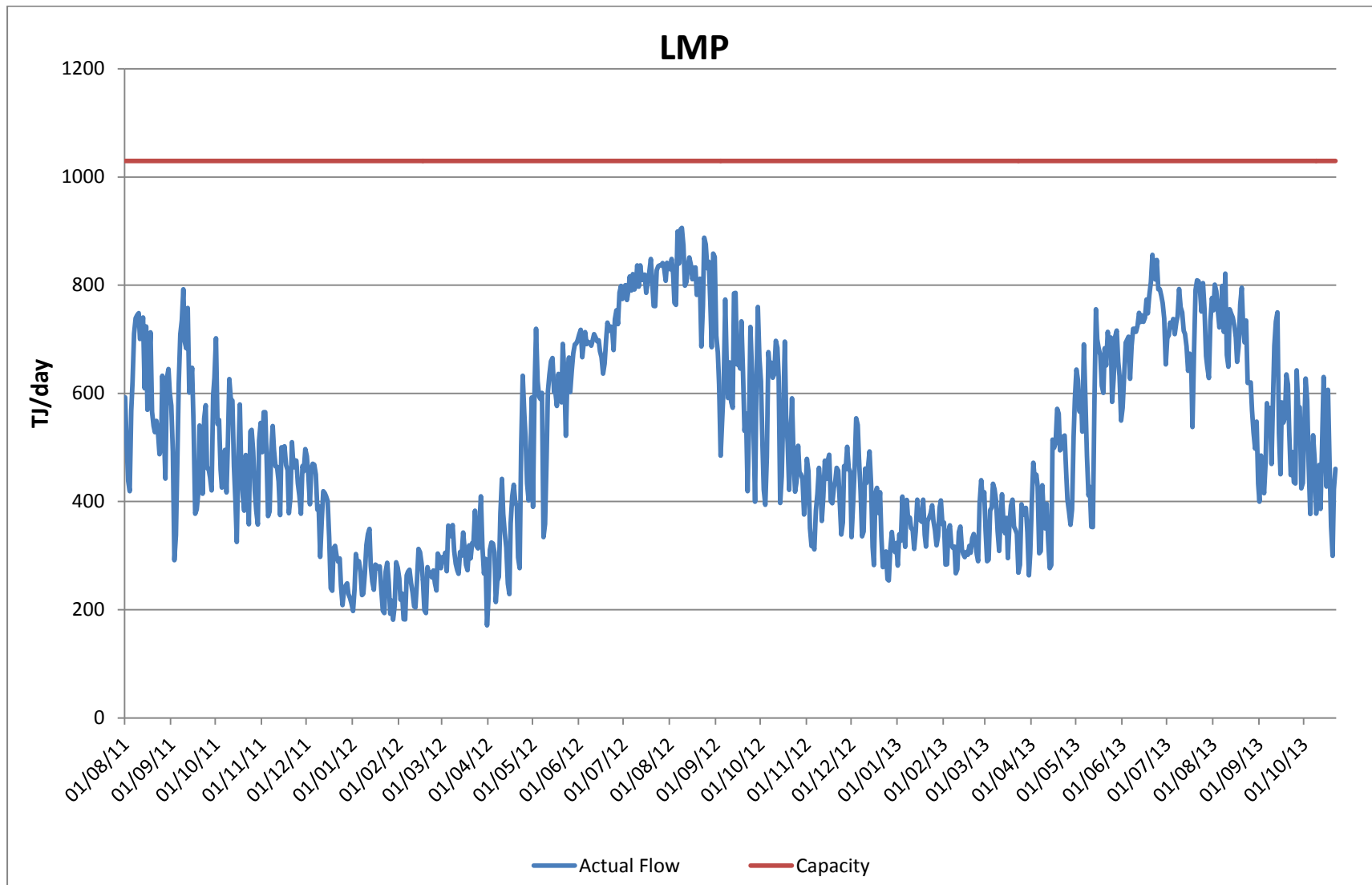


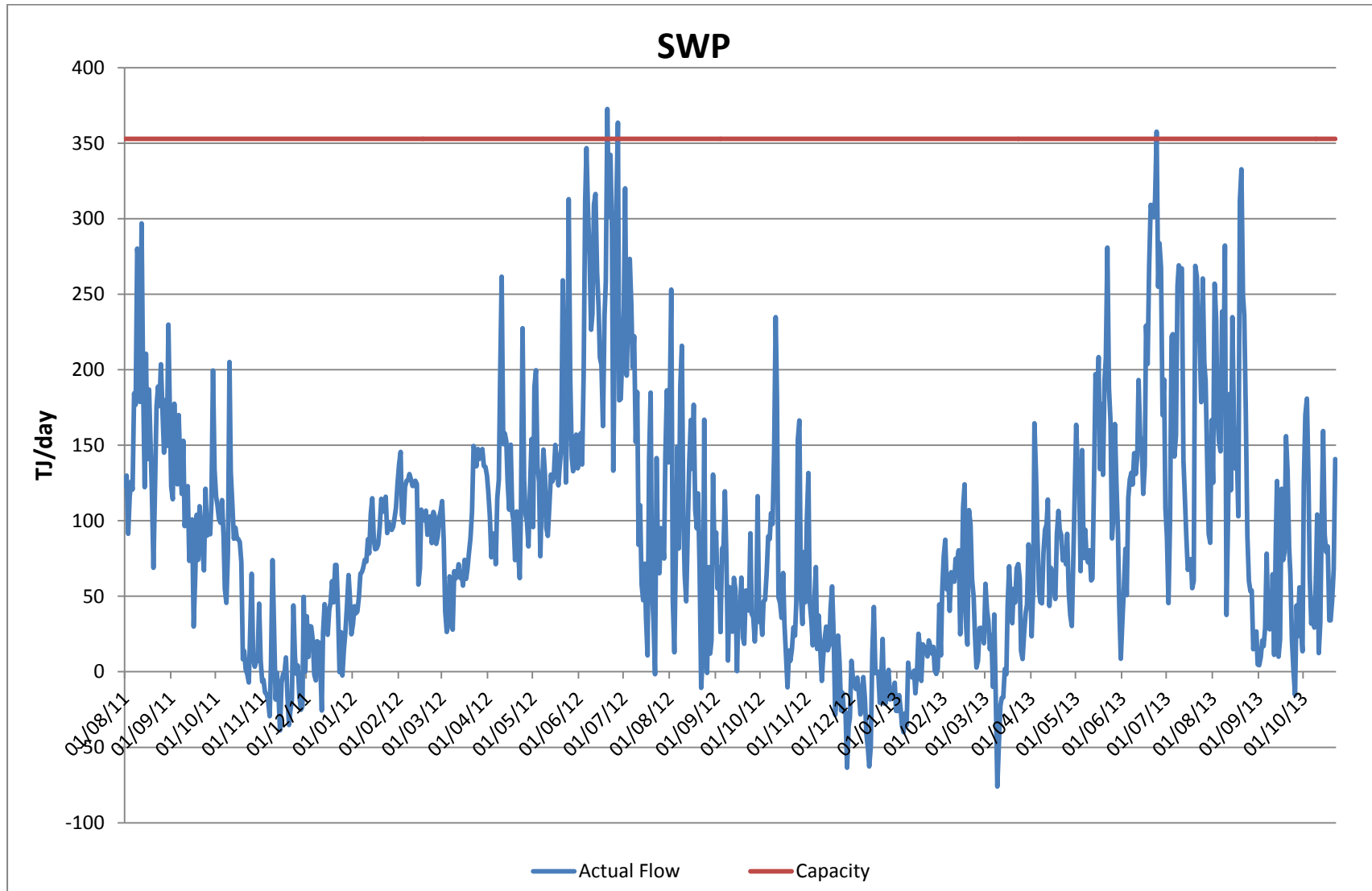
Source: AEMO, National Gas Market Bulletin Board, various actual gas flow documents, [online] [www.gasbb.com.au/viewArchive.aspx?node=archive](http://www.gasbb.com.au/viewArchive.aspx?node=archive)

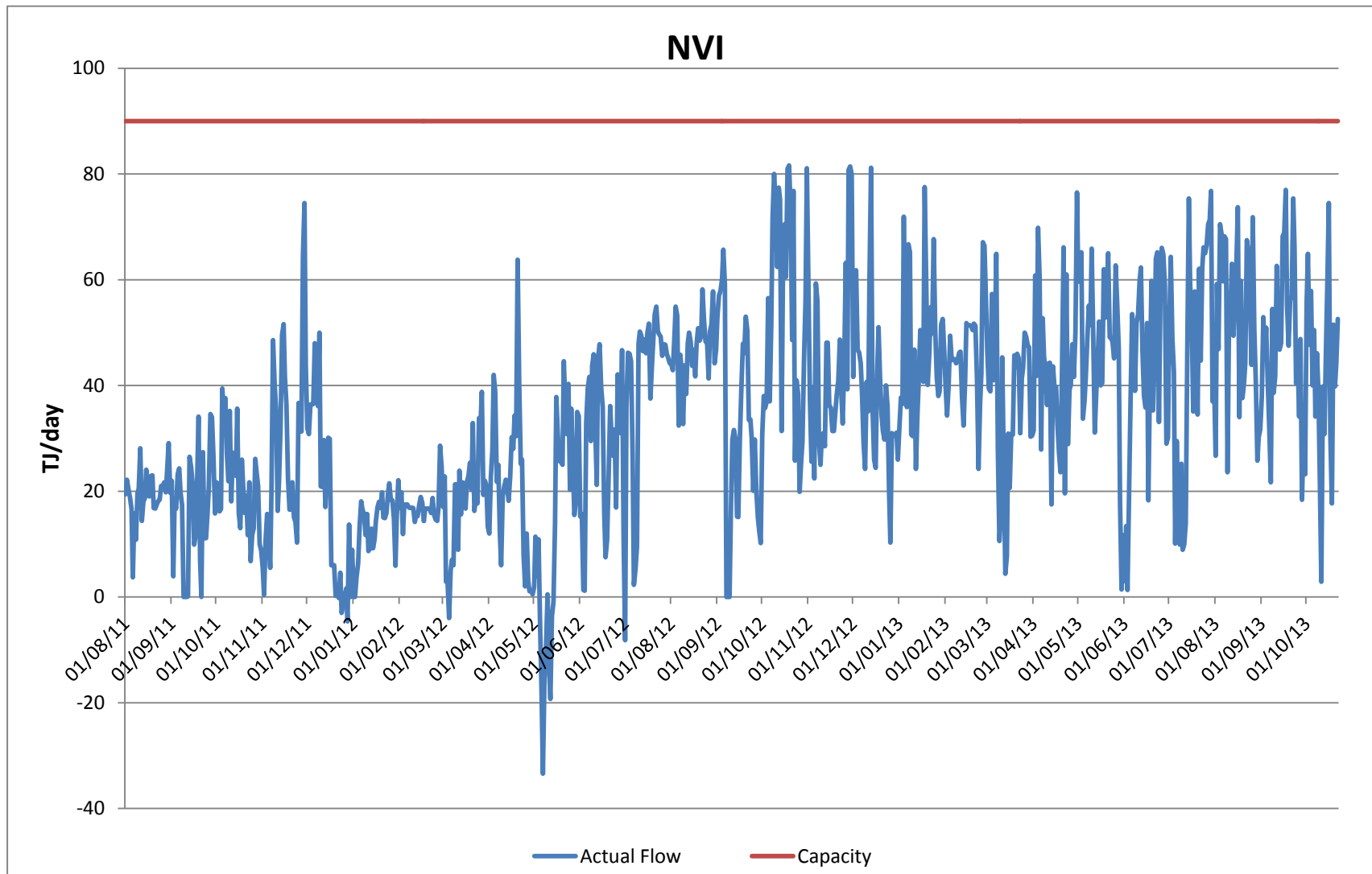


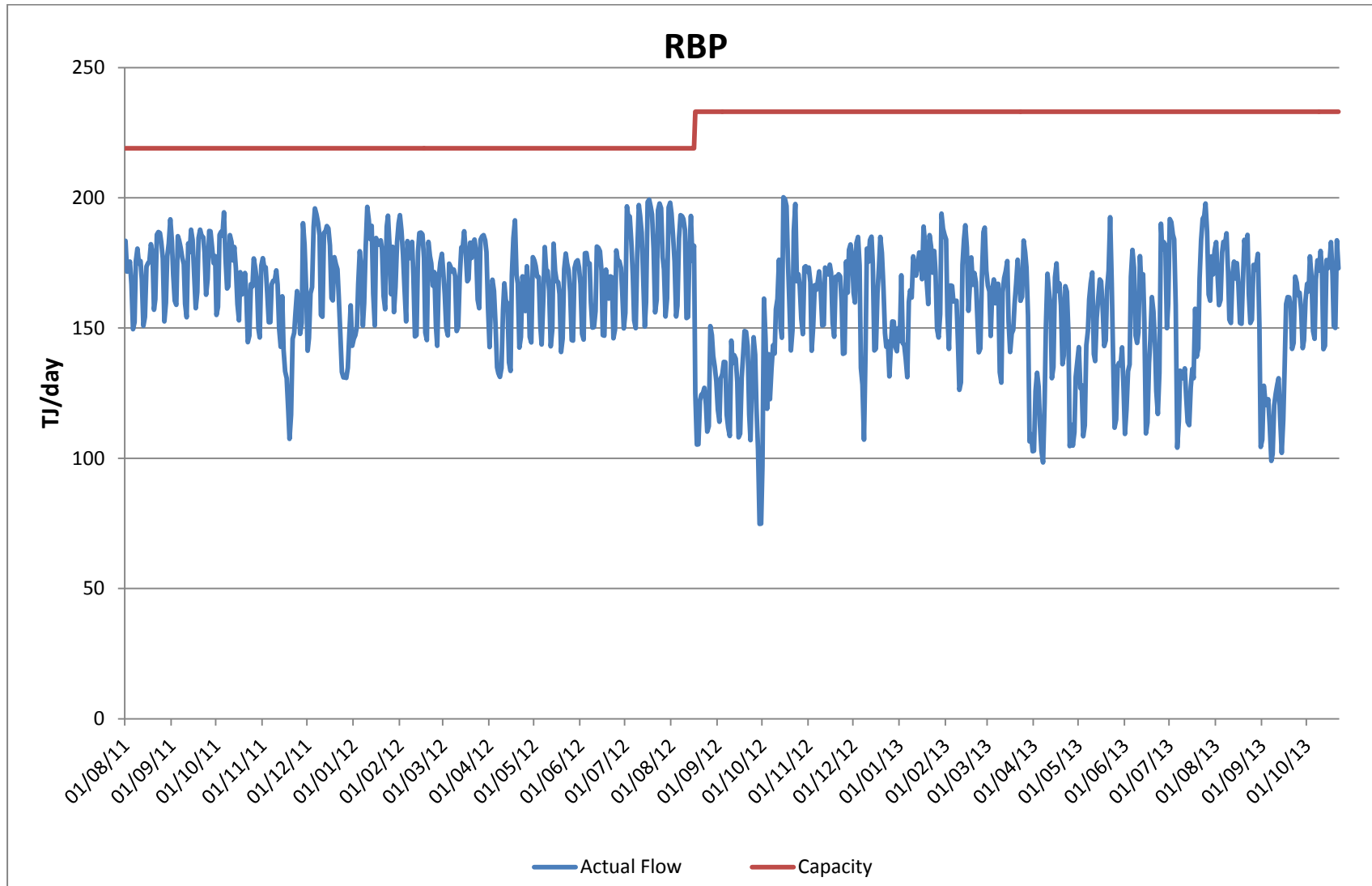


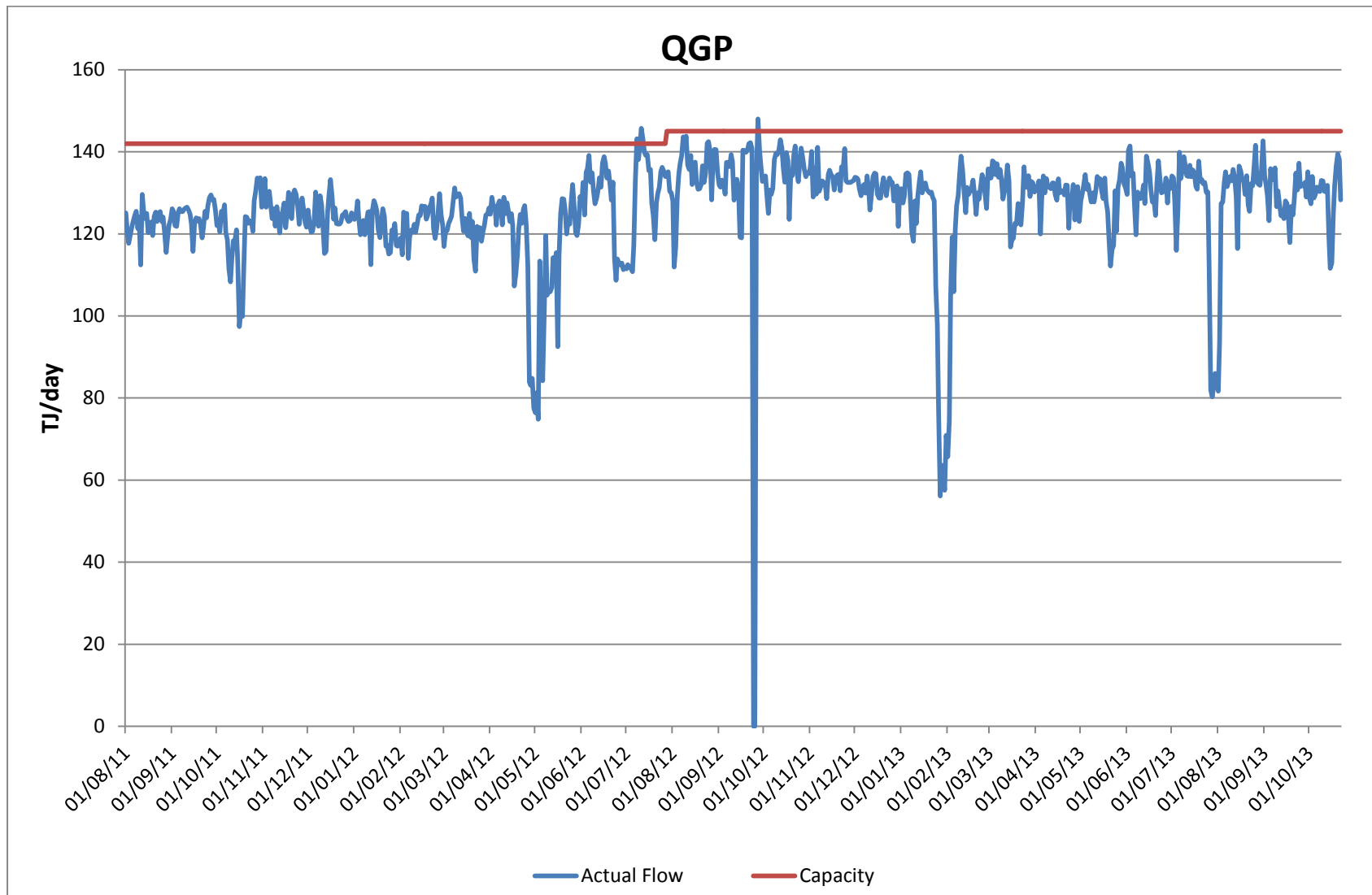


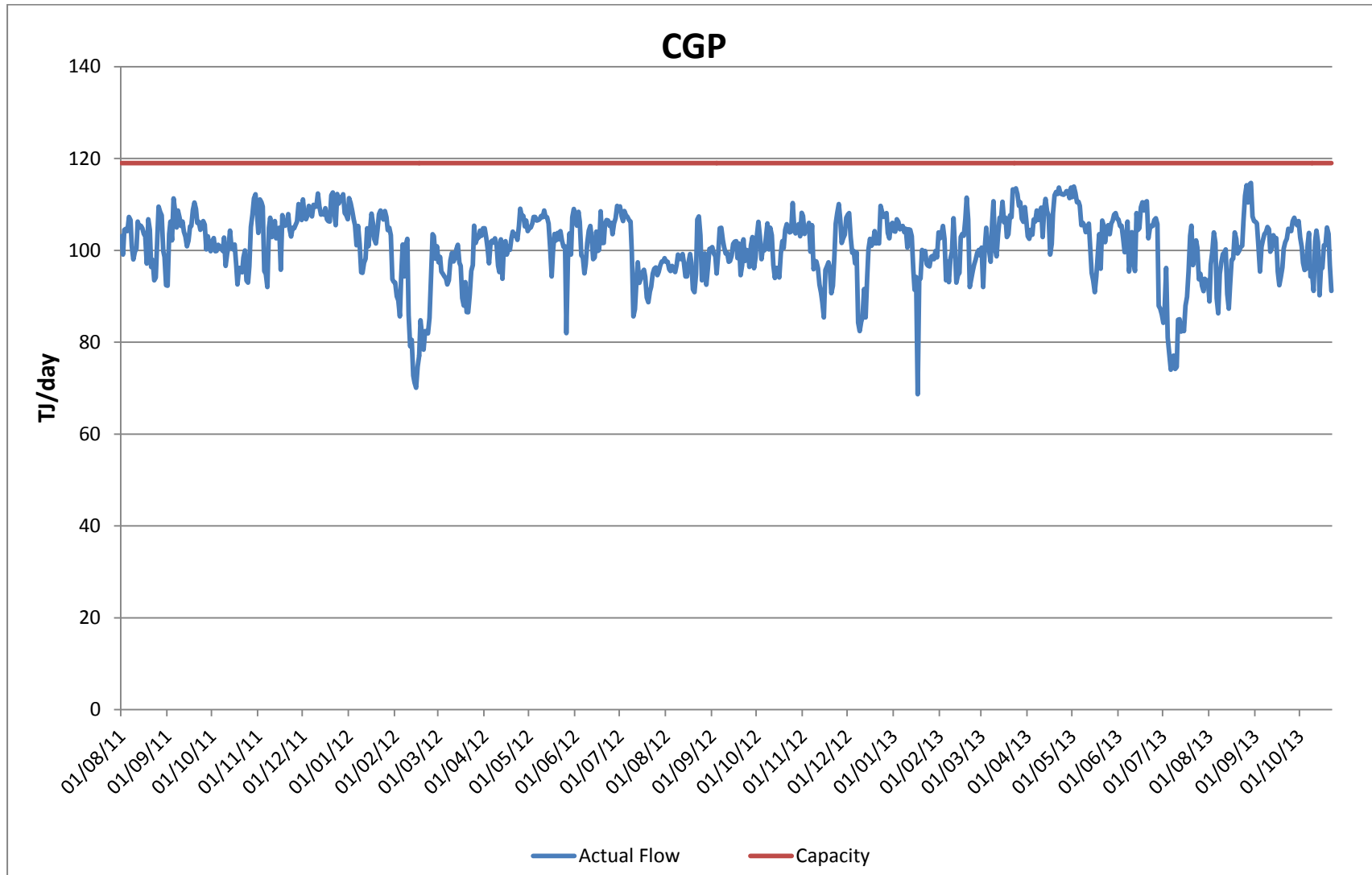




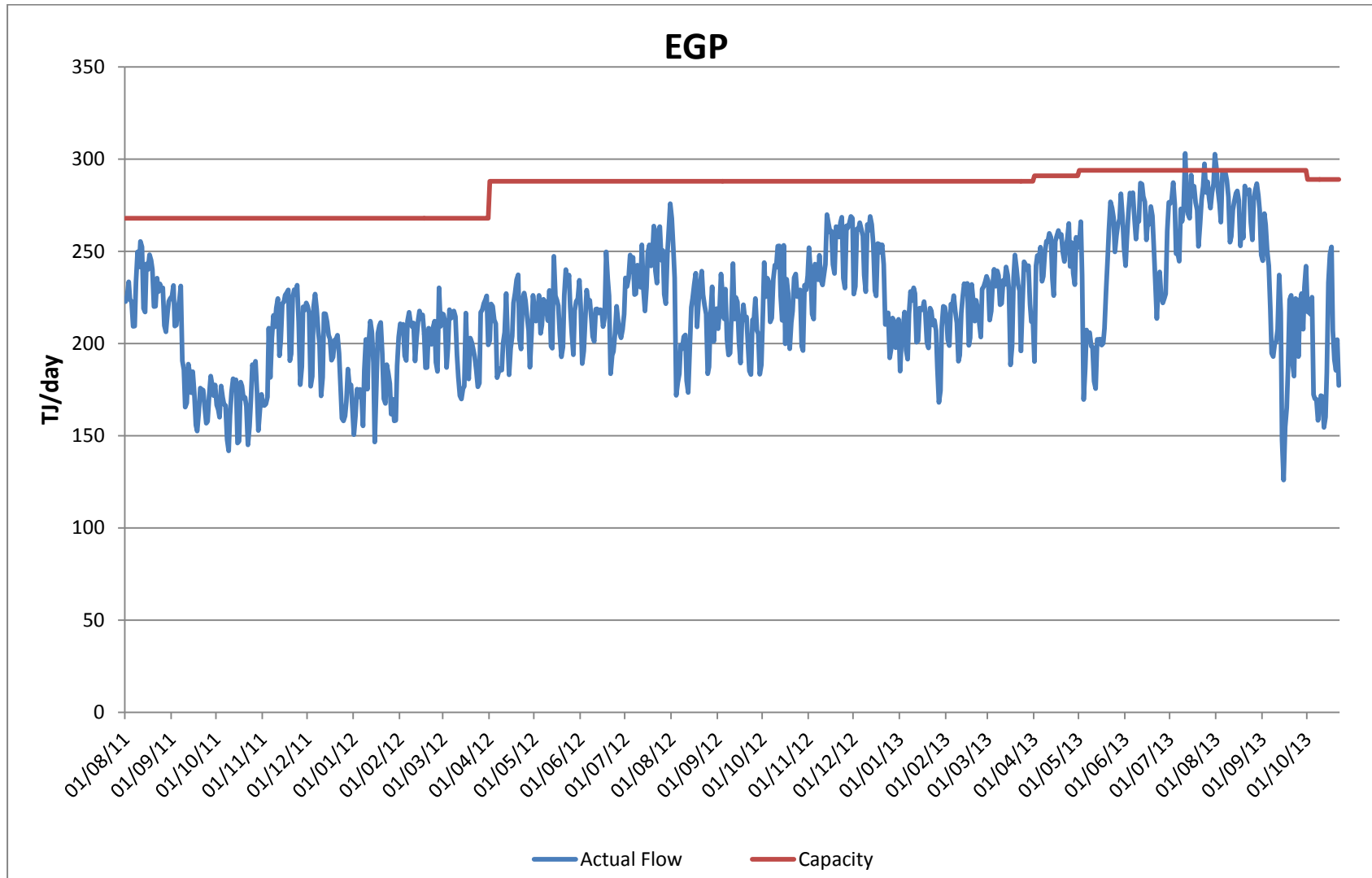


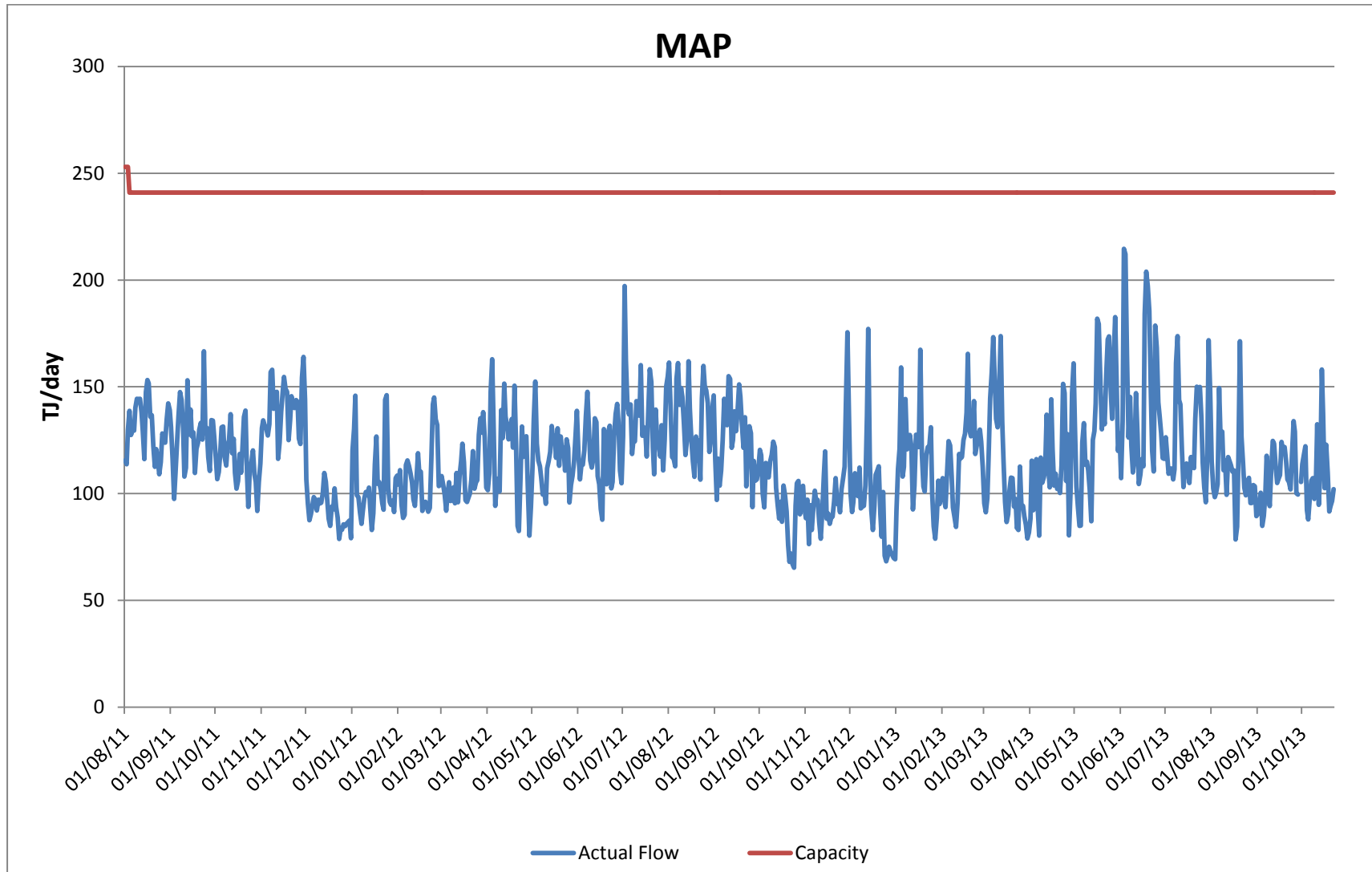












## APPENDIX C – CONSULTATION RIS STAKEHOLDER QUESTIONS

To arrive at a fully informed decision, the consultation RIS contained a number of questions for stakeholders' consideration.

1. Are there reasons why fuller pipeline capacity utilisation may be either advantageous or not desirable?
2. In Australia, how easy is it to organise and execute novation and/or bare transfer of pipeline capacity?
3. What is the likely size of the benefits, if any, associated with adopting operational transfer and/or contractual transfer for the trade of secondary pipeline capacity in Australia?
4. What operational/system changes would be necessary to allow operational transfer and/or contractual transfer to be used in Australia and what would the likely costs be to making these changes?
5. Have you engaged in capacity trading in Australia and if so: how regularly do you undertake such transactions; what volumes and types of capacity (i.e. firm or 'as available') have you typically traded; and what pipelines have you traded capacity on?
6. If you have experienced difficulties when undertaking capacity trading what specific barriers have you experienced on what particular pipelines and/or what were the particular circumstances?
7. Are there any improvements that could be made to ease the transfer of pipeline capacity?
8. What factors, including market or regulatory factors (that may include the identified factors above) may be limiting secondary capacity trading in Australia?
9. What types of transportation services would stakeholders be most interested in accessing?
10. Would stakeholders be interested in accessing short-term 'as available' interruptible gas transportation capacity?
11. What duration of capacity trades would stakeholders be most interested in seeking?
12. What pipelines and indicative annual capacity volumes would stakeholders be most interested in accessing?
13. What specific additional volumes of gas would producers be willing to supply into which specific markets?
14. Is there a problem with the way in which unused pipeline capacity is currently being traded in Australia and, if so, what are the key issues that have prevented/made difficult access to unused transportation capacity?
15. What aspects of the current capacity trading arrangements work well?
16. Is adequate market information available so that pipeline capacity can be effectively traded? If not, what specific additional information is required?
17. Would the provision of improved market information be adequate to facilitate an increase in secondary capacity trading activity and, if not, what other tools/processes could be developed/pursued?

18. What are the likely advantages, disadvantages, costs, benefits and risks associated with the provision of additional information such as close to real-time data/ex-post data, preferably supported by quantitative evidence?
19. What is the likelihood of industry participating in a voluntary pipeline capacity trading platform? If you consider the likelihood to be low, what are the key issues that could prevent incumbents from releasing unused capacity to the market?
20. What are the types of incentives that would most likely encourage industry to participate in a voluntary pipeline capacity trading platform?
21. What would be your likely costs to establish, operate and/or participate in a voluntary pipeline capacity trading platform?
22. What are the likely advantages, disadvantages, benefits and risks associated with the establishment of voluntary pipeline capacity trading platform, preferably supported by quantitative evidence?
23. Under a mandatory pipeline capacity trading regime, would it be appropriate to mandate incumbents releasing all unused capacity or just a portion of unused capacity?
24. Under a mandatory pipeline capacity trading regime, would it be appropriate to regulate the price (including floor and/or ceiling prices) of capacity?
25. What would be appropriate mechanisms to clear the market under a mandatory pipeline capacity trading regime?
26. What would be other practicalities of introducing a mandatory pipeline capacity trading regime?
27. What would your likely costs be to establish, operate or comply with a mandatory pipeline capacity trading regime?
28. What are the likely advantages, disadvantages, benefits and risks associated with the establishment of mandatory pipeline capacity trading regime, preferably supported by quantitative evidence?
29. What are the practical issues associated with mandatory UIOSI, UIOLI and auction mechanisms?
30. What entity would be the most appropriate to operate a trading platform or auction process?

## APPENDIX D – IMPACT ASSESSMENT OF THE POLICY OPTIONS

POLICY OPTION	BENEFITS	COSTS	KEY RISKS
<p><b>1. Status Quo</b></p>	<p><i>Existing shippers</i></p> <p>Maintenance of market positions.</p>	<p>Nil</p>	<ul style="list-style-type: none"> <li>• Adequate unused capacity that would facilitate gas trade may not be offered to the market, thus limiting the ability to build market liquidity.</li> <li>• The market may operate to the detriment of the NGO resulting in higher costs to consumers.</li> </ul>
<p><b>2. Information Provision</b></p>	<p><i>Industry Participants and Consumers</i></p> <ul style="list-style-type: none"> <li>• Lower barriers to market entry for new retailers.</li> <li>• Reduce capacity trading transaction costs, including search and negotiation costs.</li> <li>• Improved contestability may result in wider choice of gas retailers and potentially competitive pressure could result in lower prices.</li> <li>• Better-informed decision making.</li> </ul> <p><i>Policy Makers</i></p> <ul style="list-style-type: none"> <li>• Better-informed decision making.</li> </ul>	<p><i>AEMO</i></p> <ul style="list-style-type: none"> <li>• Upgrading data/administrative systems.</li> <li>• Staffing costs to manage additional information.</li> </ul> <p><i>Shippers and Pipeliners</i></p> <ul style="list-style-type: none"> <li>• Possible upgrading of existing data/administrative systems.</li> <li>• Staffing costs to collect and provide information to AEMO.</li> <li>• Consultation costs associated with developing a standardised contract and responding to the regulatory changes.</li> </ul> <p><i>Australian Governments/Regulatory Agencies</i></p> <ul style="list-style-type: none"> <li>• Legislative/regulatory change costs.</li> <li>• Stakeholder engagement and legal costs.</li> <li>• Enforcement costs to ensure compliance with information requirements.</li> </ul>	<ul style="list-style-type: none"> <li>• Incumbent shippers may not offer up sufficient unused capacity to facilitate the establishment of a meaningful market.</li> <li>• The market may operate to the detriment of the NGO resulting in higher costs to consumers.</li> </ul>

POLICY OPTION	BENEFITS	COSTS	KEY RISKS
<p><b>3. Voluntary Trading Platform</b></p>	<p><i>Pipeline</i></p> <ul style="list-style-type: none"> <li>• Would reveal the value of pipeline capacity rights and should assist informing efficient investment and operational decisions.</li> <li>• Reduce capacity trading transaction costs.</li> </ul> <p><i>Shippers</i></p> <ul style="list-style-type: none"> <li>• Mitigate costs by more easily trading unused capacity (i.e. lower transaction costs).</li> </ul> <p><i>Industry Participants and Consumers</i></p> <ul style="list-style-type: none"> <li>• Market participants with insufficient contracted capacity able to more easily access capacity.</li> <li>• May facilitate increased short-term capacity trades.</li> <li>• Transparent discovery of secondary pipeline capacity volume and price.</li> <li>• Lower barriers to market entry for new retailers.</li> <li>• Improved contestability may result in wider choice of gas retailers and potentially competitive pressure could result in lower prices.</li> <li>• More efficient use of existing infrastructure.</li> <li>• Better-informed decision making.</li> </ul> <p><i>Policy Makers</i></p> <ul style="list-style-type: none"> <li>• Better-informed decision making.</li> </ul>	<p><i>Market Operator</i></p> <ul style="list-style-type: none"> <li>• Trading platform establishment and operational costs.</li> <li>• Annual licencing costs for the platform technology.</li> <li>• Development of standardised products, including legal drafting and engagement costs.</li> </ul> <p><i>Shippers and Pipeliners</i></p> <ul style="list-style-type: none"> <li>• Consultation costs, associated with developing standardised products.</li> </ul>	<ul style="list-style-type: none"> <li>• Incumbent shippers may not offer up sufficient unused capacity to facilitate the establishment of a meaningful market.</li> <li>• There may be limited/inadequate demand for unused capacity and therefore trading platform establishment and operation costs may not be justified.</li> <li>• The market may operate to the detriment of the NGO resulting in higher costs to consumers.</li> </ul>

POLICY OPTION	BENEFITS	COSTS	KEY RISKS
<p><b>4A. Mandatory Trading Platform: UIOLI</b></p>	<p><i>Pipeline</i>s</p> <ul style="list-style-type: none"> <li>• Would reveal the value of pipeline capacity rights and should assist informing efficient investment and operational decisions.</li> </ul> <p><i>Industry Participants and Consumers</i></p> <ul style="list-style-type: none"> <li>• Market participants with insufficient contracted capacity able to more easily access ‘as available’ capacity to ship gas.</li> <li>• Lower barriers to market entry for new retailers.</li> <li>• Improved contestability may result in wider choice of gas retailers and potentially competitive pressure could result in lower prices.</li> <li>• Transparent discovery of secondary pipeline capacity volume and price.</li> <li>• Better-informed decision making.</li> <li>• More efficient use of existing infrastructure.</li> </ul> <p><i>Policy Makers</i></p> <ul style="list-style-type: none"> <li>• Better-informed decision making.</li> </ul>	<p><i>Pipeline</i>s</p> <ul style="list-style-type: none"> <li>• Operational costs to transparently offer up capacity.</li> </ul> <p><i>Market Operator</i></p> <ul style="list-style-type: none"> <li>• Trading platform establishment and operational costs.</li> </ul> <p><i>Australian Governments/Regulatory Agencies</i></p> <ul style="list-style-type: none"> <li>• Legislative/regulatory change costs.</li> <li>• Monitoring and enforcement costs.</li> </ul>	<ul style="list-style-type: none"> <li>• Operational costs may not be justified if there is limited/inadequate demand for released ‘as available’ capacity.</li> </ul>

POLICY OPTION	BENEFITS	COSTS	KEY RISKS
<p><b>4B. Mandatory Trading Obligations: UIOSI</b></p>	<p><i>Shippers</i></p> <ul style="list-style-type: none"> <li>Mitigate costs by more easily trading unused firm capacity.</li> </ul> <p><i>Pipeline</i></p> <ul style="list-style-type: none"> <li>Would reveal the value of pipeline capacity rights and should assist informing efficient investment and operational decisions by pipeline owners.</li> </ul> <p><i>Industry Participants and Consumers</i></p> <ul style="list-style-type: none"> <li>Market participants with insufficient contracted capacity able to more easily access firm capacity to ship gas.</li> <li>Lower barriers to market entry for new retailers.</li> <li>Improved contestability may result in wider choice of gas retailers and potentially competitive pressure could result in lower prices.</li> <li>Transparent discovery of volume and price for secondary pipeline capacity.</li> <li>More efficient use of existing infrastructure.</li> <li>Better-informed decision making.</li> </ul> <p><i>Policy Makers</i></p> <ul style="list-style-type: none"> <li>Better-informed decision making.</li> </ul>	<p><i>Incumbent Shippers</i></p> <ul style="list-style-type: none"> <li>The property rights of existing shippers would be impacted.</li> </ul> <p><i>Market Operator</i></p> <ul style="list-style-type: none"> <li>Trading platform establishment and operational costs.</li> </ul> <p><i>Australian Governments/Regulatory Agencies</i></p> <ul style="list-style-type: none"> <li>Legislative/regulatory change costs, including the development of an objective rule to define when capacity must be offered up.</li> <li>Monitoring and enforcement costs.</li> </ul>	<ul style="list-style-type: none"> <li>Concerns may be raised regarding sovereign risk due to intervening in established contractual agreements of existing GSAs and/or GTAs.</li> <li>Trading/auction platform establishment and operation costs may not be justified if there is limited/inadequate demand for released firm capacity.</li> <li>May create uncertainty for potential underwriters of new or expanded pipeline capacity.</li> <li>If shippers are forced to sell capacity which they otherwise would have derived value (i.e. managing risks associated with peak demand) it may lead to inefficient allocation of capacity and undermine the incentives that underpin investment.</li> </ul>





# **Analysis of Policy Options to Facilitate Enhanced Gas Transmission Capacity Trading**

A Report for the Standing Council on Energy and  
Resources

11 November 2013

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## Executive Summary

The Australian gas sector is currently undergoing a period of profound change. The commencement of an LNG export industry has considerable implications for Australia's eastern gas market, among which is the redirection of gas to Queensland for export. This will change the manner in which the existing transmission network is used.

In this context, the Standing Council on Energy and Resources (SCER) is undertaking a number of projects that together form the Gas Market Development Plan. One of these projects investigates policy arrangements to enhance the trading of gas transmission capacity. NERA Economic Consulting (NERA) has been engaged by SCER to undertake a benefit cost analysis of four policy options, namely:

- **Option 1** – Maintain the status quo;
- **Option 2** – Improve information provision and standardise contractual terms and conditions, to facilitate capacity trading;
- **Option 3** – Establish a voluntary trading platform with standardised products; and
- **Option 4** – Establish mandatory trading obligations requiring incumbents to release unutilised capacity to market participants on either a 'non-firm' (use-it-or-lose it) basis or a firm (use-it-or-sell it) basis.

These policy options seek to enhance the trading of gas transmission capacity by:

- lowering search and transactions costs involved with trading gas transmission capacity, by making it easier to identify the availability of capacity and to minimise the contractual negotiation costs involved in trading available capacity (Options 2 and 3); and
- eliminating any incentives that existing holders of gas transmission capacity might have to inappropriately hold capacity rather than sell unused capacity to willing buyers (Option 4).

The principal challenge to quantifying benefits and costs for these policy options has been finding objective information about the depth of the secondary market for transmission capacity, and the transaction costs for entering into secondary trades. With little or no objective information available to us, we have drawn upon anecdotal information from our discussions with stakeholders as a basis for measuring costs and benefits.

It follows that we have attempted to provide insights through our analysis of the potential range of net benefits, assuming that certain conditions hold, rather than conclusively estimating the net benefits arising from each of the options. This approach allows stakeholders to individually evaluate whether these conditions are likely to hold, thereby warranting the incurrence of the costs that we have estimated for each policy option, so as to deliver the resulting benefits.

## Evaluation of Option 2 and Option 3

Options 2 and 3 are intended to reduce transaction costs, and so facilitate increased trade. For these policies to have benefits, their implementation must lead to a reduction in transaction and search costs. Moreover, the reduction in transaction costs must also lead to an increase in gas transmission pipeline utilisation (ie, there must be additional demand for capacity once transactions costs are lowered).

Both options 2 and 3 have relatively low costs when compared to the quantity of trades in the entire gas sector. We estimate that improving information (Option 2) will cost between \$4.7 and \$8.8 million in present value terms over the next 20 years. The additional development of a voluntary trading platform with standardised products (Option 3) would cost between \$14.7 and \$23.9 million in present value terms over the next 20 years.

Whether these policy options will deliver benefits that exceed these costs hinge upon expectations of the quantum of any increase in utilisation of capacity and the value attributed to that increased utilisation. In the absence of any direct information on the likely demand for currently unutilised transmission capacity, we have calculated:

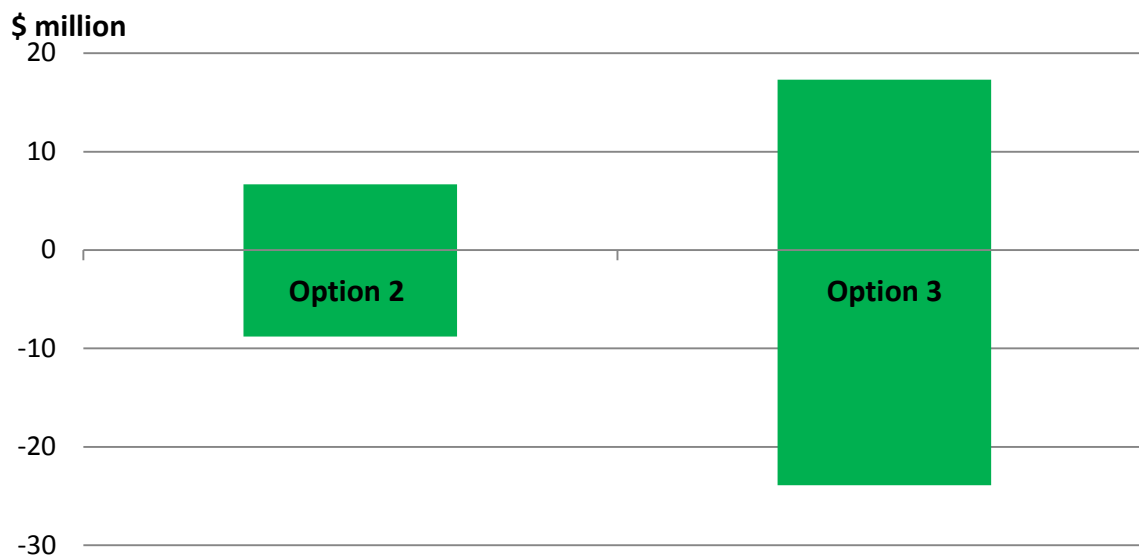
- the breakeven increase in utilisation and/or value that would be needed to recover the expected costs of each of these policy options; and
- a range of net benefits assuming both zero additional capacity utilisation, and an assumed 3 and 5 per cent increase in capacity utilisation, with an assumed value for each additional gigajoule of gas capacity traded and utilised of \$1/GJ.

This approach provides illustrative bounds of the potential net benefits that might be realised should the policy options deliver such increases in capacity utilisation given the assumed value of traded and utilised capacity.

Our assumption of \$1/GJ reflects the benefits of both reducing current transactions costs (which we estimate to be less than \$1/GJ for most current shippers) and a small additional value achieved from the use of the gas. While conservative, this approach highlights that even under conservative assumptions the policy options have the potential to deliver positive net benefits. 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.

Figure E.1 presents the results of our assessment of the benefits and costs of the policy options, in the form of the present value of the net benefits.

**Figure E.1**  
**Range of Net-Present Values for Options 2 and 3**



Despite the uncertainties involved in estimating the net benefits, they are likely to be positive if the options result in a small increase in the amount of capacity traded and utilised. Our break-even analysis suggests that options 2 and 3 would have net benefits, under the upper bound costs, if they were to result in additional trades of 2.1 TJ per day (Option 2) and 6.1 TJ per day (Option 3) in total across all pipelines. Equally, if the additional value generated from the additional trades were greater than \$1/GJ then each of the policy options would also deliver positive net benefits.

That said, in our opinion there is also a real possibility that Options 2 and 3 might not lead to *any* increase in the trading of capacity, particularly in the short term. It is for this reason that we have used a lower bound estimate of benefits of zero for both options.

Finally, while developing a voluntary trading platform with standardised products (ie, Option 3) has the potential to deliver greater net benefits compared with Option 2, we believe that there are some risks to the achievement of these additional benefits. These risks relate to the complexities involved in developing standardised products for voluntary trading and it is conceivable that there might not be sufficient demand for standardised products to warrant the cost of their development.

Given the importance of developing standardised products for the realisation of benefits under Option 3, we recommend that further stakeholder engagement be undertaken to determine whether market participants are willing to use and develop standardised products. In the absence of engagement from major participants, we expect that any external effort to encourage the development of such products is likely to prove unsuccessful.

## Evaluation of Option 4

Option 4 involves the creation of a mandatory obligation for market participants with unused pipeline capacity either to:

- offer unused capacity on an ‘non-firm’, interruptible basis – an obligation which is termed ‘use-it-or-lose-it’ (Option 4A); or
- offer unused firm capacity to the market – an obligation which is termed ‘use-it-or-sell-it’ (Option 4B).

Both of these options are similar to arrangements that are being put in place in the European Union, so as to improve shippers’ access to available capacity in circumstances where there have been concerns about shippers and pipeline operators not making capacity available, so as to gain competitive advantages in related markets.

The direct costs of Option 4—such as platform establishment and operation, legislative amendments, compliance and enforcement costs—are likely to exceed those of Option 2 and Option 3. The benefits of Option 4 depend on the extent to which pipeliners and shippers fail to release capacity to the market under the status quo. Given that pipeline operators already offer up non-firm capacity, the benefits of Option 4A could reasonably be assumed to be negligible. The potential benefits of Option 4B are less clear.

In a competitive gas market, a shipper would not be expected to fail to release pipeline capacity. If there are benefits to a holder of capacity from trading capacity and those benefits outweigh the costs of making capacity available, then capacity trading would be expected to occur. It follows that any capacity that is not traded most likely reflects either a lack of demand for the available capacity, or the option value to the capacity holder being higher than the revenue likely to be received from trading the capacity, given uncertainties in the holder’s need for gas in a downstream market (eg, for gas-fired electricity generators).

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.

Assuming that shippers are not engaging in anti-competitive behaviour, the implementation of Option 4 will not likely lead to additional trading of pipeline capacity compared against current regulatory arrangements and within the current market arrangements. It follows that Option 4 would therefore not result in any incremental benefits relative to Option 2, where the platform comprises a capacity listing service. Similarly, Option 4 would not result in any incremental benefits relative to Option 3, where shippers are obligated to trade on a cleared-exchange.

That said it was beyond the scope of this study to undertake a systematic assessment of the existence, materiality and possible inefficiencies arising from the potential exercise of market power in the gas sector or any related market.



## 1. Introduction

The Australian gas sector is undergoing a period of profound change. In 2005, the eastern gas market faced a supply crisis due to declining reserves in the Gippsland and Cooper basins. Less than a decade later, the advent of low-cost technologies to extract coal-seam gas has released vast reserves in the Bowen-Surat basin. These reserves have supported the establishment of a burgeoning liquid natural gas (LNG) export industry at the port of Gladstone in Queensland.

The commencement of an LNG export industry has enormous implications for Australia's eastern gas market, among which is the redirection of gas to Queensland for export. This will change the manner in which the existing transmission network is used. There are questions as to how the existing gas transmission pipeline market will support the profound changes occurring to the eastern gas market.

In this context, the Standing Council on Energy and Resources (SCER) is undertaking a number of projects that together form the Gas Market Development Plan. One of these projects investigates arrangements for trading gas transmission capacity. SCER has released a Regulation Impact Statement ('the RIS') that sets out some initial policy options, namely:

- **Option 1** – Maintain the status quo;
- **Option 2** – Improve information provision and standardise contractual terms and conditions to facilitate capacity trading;
- **Option 3** – Establish a voluntary trading platform and an incentive for incumbents to release capacity; and
- **Option 4** – Establish mandatory trading obligations requiring incumbents to release unutilised capacity to market participants on either a:
  - 'non-firm' (use-it-or-lose it) basis; or
  - firm (use-it-or-sell it) basis.

NERA Economic Consulting (NERA) has been engaged by SCER to undertake a cost-benefit analysis of these four policy options. This has involved:

- establishing a clear understanding of how the transmission network is currently being used, and the reasons for that pattern of usage;
- developing a methodology to assess the potential benefits that might arise from the implementation of SCER's policy options; and
- applying our methodology to estimate the benefits and costs of the alternative three policy options relative to the status quo.

In preparing this analysis, we have been informed by discussions with stakeholders across the spectrum of gas sector participants, both with respect to their role in the supply chain and their location.

This report sets out the methodology supporting our analysis and our findings for each of SCER's proposed policy options.

The remainder of this report is structured as follows:

- **Chapter 2** provides an overview of the eastern gas market and describes the economic principles that govern the way gas and transmission services are bought, sold and used;
- **Chapter 3** sets out our methodology for performing the cost-benefit analysis by means of:
  - defining key terms and stating principal assumptions; and
  - describing our approach to assessing the costs and, more critically, the benefits of each of the policy alternatives—the benefits being inherently more difficult to quantify and so value;
- **Chapter 4** sets out our results for the estimates of the incremental costs associated with each of the proposed policy options;
- **Chapter 5** sets out our assessment of the possible range of benefits for each of the proposed policy options relative to the status quo; and.
- **Chapter 6** concludes the report by bringing together the results from Chapters 4 and 5 with a view to determining the merit of each of the proposed policy options.

In addition:

- **Appendix A** provides a brief overview of gas pipeline capacity markets and policies applying in the European Union and the United States;
- **Appendix B** presents a more detailed specification of the proposed policy options that we have developed in consultation with SCER officials and used as the basis for our assessment; and
- **Appendix C** sets out the parties that we have consulted with as part of our analysis.

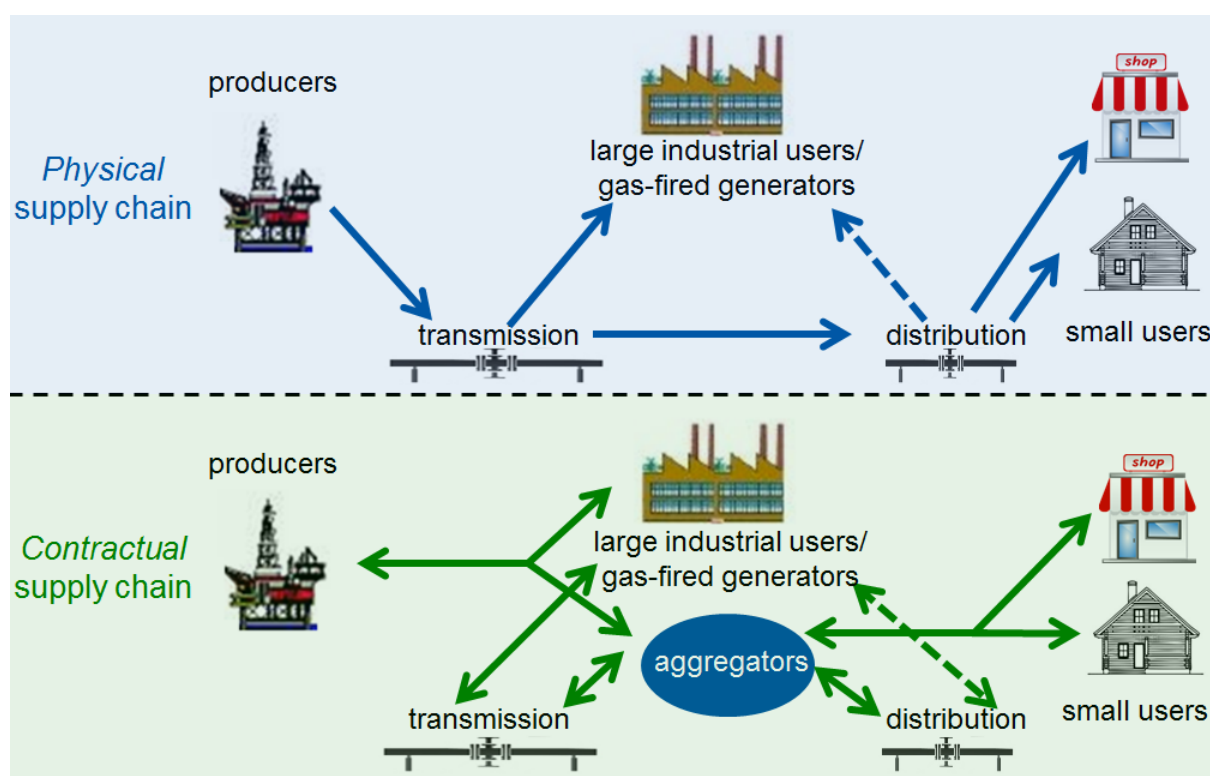
## 2. An Overview of the Eastern Gas Market and Underlying Economic Principles

In this chapter we set out the relevant context for our analysis in the form of an overview of the current state of Australia’s eastern gas market with a particular focus on the gas transmission system and the economic principles that govern the way gas and transmission services are bought, sold and used.

### 2.1. How gas is produced, transported and consumed

The gas supply chain involves the production and distribution of gas to end users. This process can be analysed on two levels: the first being the physical supply chain, and second being the contractual supply chain. Figure 2.1 illustrates these two aspects of the supply chain.

**Figure 2.1**  
**Physical and Contractual Gas Supply Chain**



The physical supply chain describes the flow of gas from the producer to the end user. Gas producers extract and process gas from gas fields. Pipeline operators transport the gas from processing facilities in high pressure transmission pipelines to withdrawal points close to large industrial users, gas-fired electricity generators or distribution networks. Pipeline operators of distribution networks deliver gas from withdrawal points in the transmission pipeline to smaller industrial and commercial customers, and residential and small business customers.

The contractual supply chain describes the network of agreements that support the physical supply of gas from producers to end users. Producers supply gas to large industrial users, gas-fired generators and aggregators under Gas Supply Agreements (GSAs). Aggregators purchase gas directly from producers in the wholesale market and then on-sell this gas to smaller end users. Concurrently, these large industrial users, gas-fired generators and aggregators must arrange for the gas supplied under their GSAs to be transported from producers processing facilities to the point of use. As a result, they are also known as ‘shippers’. Shippers contract for transport services with pipeline operators under a Gas Transportation Agreement (GTA).

We explore the characteristics of gas production, consumption and transport in Australia’s eastern gas market in more detail below.

### **2.1.1. Production**

The vast majority of gas reserves and production in Australia’s eastern gas market are concentrated in three areas, namely:

- offshore Gippsland, Otway and Bass Basins south of Victoria;
- onshore Cooper/Eromanga Basin, which spans South Australia and Queensland; and
- onshore Bowen/Surat Basin, which spans Queensland and northern New South Wales.

The Gippsland, Otway, Bass and Cooper/Eromanga Basins are sources of conventional gas. The Bowen/Surat Basin is predominantly a source of unconventional coal seam gas.

Figure 2.2 shows the geographic location of each of these gas basins and the associated transmission pipeline network that transports gas to end-users, in the eastern gas market.

**Figure 2.2**  
**Location of Basins and Transmission Pipelines**



### 2.1.2. Consumption

Gas consumption can be analysed according to three broad user groups, namely:

- large industrial users;
- gas-fired electricity generators; and
- small users represented by aggregators.

The differing gas requirements of these user groups yield differing gas consumption profiles.

Large industrial users consume gas to support the underlying industrial processes. Gas is often used as a clean burning energy source but can also be a product input. It is widely used in the manufacturing sector and it is of particular importance to the metal product industries (smelting and refining) and the chemical industry (fertiliser and plastics).<sup>69</sup> Industrial activity is relatively stable and as a result the gas consumed by large industrial users is not volatile, but rather predictable and consistent year round. As a result, the expected maximum demand for gas by most large industrial gas users will not substantially exceed their average demand for gas.

Gas-fired electricity generators consume gas to generate electricity. There are two main types of gas-fired electricity generation technologies—conventional open cycle turbines (OCGT) and combined cycle gas turbines (CCGT). CCGTs are usually base load generators and consume relatively constant quantities of gas year round. However, OCGTs are commonly used to generate electricity during peak electricity demand periods and to counteract the intermittency of renewable sources of electricity (eg, wind generators, whose output varies according to wind conditions). Electricity generated using OCGT is therefore highly correlated with the weather (and so underlying electricity demand) and tends to generate more electricity in summer months. It follows that the profile of gas consumed in OCGTs is generally volatile and unpredictable though generally higher in summer months. As a result, the expected maximum demand for gas by OCGTs will likely substantially exceed their average demand for gas.

Aggregators on-sell gas to smaller industrial, commercial and residential users. As a result, the profile of gas demand by aggregators reflects that consumed by its end users.

Consumption of gas by these end users depends on their location. In the south-eastern states—South Australia, Victoria, Tasmania and New South Wales—demand for gas is seasonal and highest in winter. While the seasonality of demand by aggregators is relatively predictable, unexpected weather variability can cause fluctuations in their gas demand profile. As a result, their expected maximum demand for gas will typically exceed their average demand for gas.

In recent years, aggregators in Australia's eastern gas market have increased their interests in gas-fired electricity generation. Where the gas demand of aggregators is the inverse of that of electricity generation there is a potential benefit in one firm integrating the two activities, which have complementary gas consumption profiles. However, due to the variable nature of gas-fired generation, the opportunities from such synergies are limited.

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<sup>69</sup> Bureau of Resources and Energy Economics, 'Gas Market Report', 2013, p. 26 <<http://www.bree.gov.au/documents/publications/gas-market/GasMarketReport-201310.pdf>> [accessed 29 October 2013].

### 2.1.3. *Transport*

The demand for gas transport services is derived from the demand for gas, given the need to transport gas from the basins where it is extracted to demand centres. Figure 2.2 illustrates the transmission pipelines that connect gas basins to demand centres.

The transmission pipelines that transport gas from the onshore and offshore gas basins to the demand centres in eastern Australia include:

- the Moomba to Sydney Pipeline (MSP)—Moomba to Sydney, Canberra and Culcairn (the entry point into the Interconnect);
- the Eastern Gas Pipeline (EGP)—Longford to Sydney and Hoskinstown (the entry point to Canberra);
- the Moomba to Adelaide Pipeline System (MAPS)—Moomba to Adelaide;
- the SEA Gas Pipeline (SEA)—Port Campbell to Adelaide;
- the South West Queensland Pipeline (SWQP)—Roma to Ballera;
- the Carpentaria Gas Pipeline (CGP)—Ballera to Mt Isa;
- the Queensland Gas Pipeline (QGP)—Roma to Gladstone;
- the Roma to Brisbane Pipeline (RBP)—Roma to Brisbane;
- the Tasmanian Gas Pipeline (TGP)—Longford to Hobart;
- the Victorian Transmission System (VTS), which includes the Longford to Melbourne Pipeline, the Western Transmission System and the South West Pipeline; and
- the NSW-VIC Interconnect (NVI), which is a bi-directional pipeline linking the MSP with the VTS.

The utilisation of any of these pipelines at a given point in time reflects the total amount of gas traded between shippers downstream of the transmission pipeline and producers upstream of the transmission pipeline.

### 2.2. *Economic concepts*

The key economic problem in the gas supply chain is to ensure that there are appropriate incentives to efficiently invest in, and use gas production, transmission and distribution infrastructure so as to satisfy consumers' gas demands. This is currently achieved in the eastern gas market principally through a series of bilateral contracting arrangements between gas suppliers, shippers and pipeline operators.

In this section, we describe some of the economic concepts that underpin gas transmission pipeline capacity trading, namely:

- large upfront capital expenditure;
- inter-temporal substitutability of demand for gas pipeline capacity;
- the value of capacity to shippers; and
- the incentives of pipeline operators.

It is the combination of these characteristics that makes it economic to construct gas transmission infrastructure to meet peak demand. We describe each characteristic below.

### **2.2.1. Large upfront capital expenditure**

Gas production, processing and transport are characterised by large upfront capital expenditures and comparatively low ongoing operating expenditures. Capital expenditure is required to explore and develop gas wells, establish processing facilities and construct transmission pipelines. For this reason, producers and pipeline operators will seek to underwrite proposed capital investments with GSAs and GTAs, to ensure a revenue stream regardless of the quantity of capital utilisation. GSAs and GTAs require that shippers to agree to take or pay for a fixed quantity of gas and transport capacity regardless of whether they use it.

Shippers are concurrently party to both GSAs and GTAs. Often shippers negotiate the terms of those GSAs and GTAs so that they are complementary and reflect their expected variability of demand, eg, a take-or-pay percentage below 100 per cent. Producers and pipeline operators provide these flexibility provisions at additional cost to reflect the opportunity cost of providing gas production or pipeline capacity to an alternative shipper.

Given the tailoring of GTAs to the needs of an individual shipper, transferring GTAs between shippers can be limited unless the underlying terms also satisfy other shippers' needs.

### **2.2.2. Inter-temporal substitutability of capacity demand**

Gas demand profiles for each type of shipper can vary considerably. Some shippers require a constant supply of gas, year round, while others have more uncertain and variable demand needs. The predictability of demand for gas (and so pipeline capacity) does vary between shippers.

Given that the demand for gas transport services is derived from gas demand, we can deduce that the profile of demand for gas transport services likely mirrors that of gas demand, ie:

- large industrial customers—maximum demand is likely to be close to average demand (ie, demand is fairly constant year round);
- gas-fired electricity generators (OCGT)—maximum demand will likely substantially exceed average demand; and
- aggregators—maximum demand will likely exceed average demand, on a seasonal basis.

The variability and unpredictability of gas demand is currently mainly managed through GTAs. That said, it can also be managed by the use of gas storage facilities near transmission withdrawal points. Gas could be injected into storage facilities in non-peak periods for consumption in peak periods to achieve inter-temporal substitutability of capacity demand. Perfect knowledge of future gas needs would enable shippers to contract only for their average gas demand instead of their maximum gas demand.

However, once gas is extracted it is relatively difficult, and so more expensive, to store than the current cost of pipeline capacity. While gas is easier to store than electricity, and some large scale gas storage facilities exist on the east coast, they are costly and are presently insufficient to substantially smooth the profile of demand for transport services.



### **2.2.3. Value of capacity to shippers**

In the absence of a tailored GTA, a shipper can only contract for a fixed quantity of capacity. In the absence of storage facilities close to demand centres, the quantity of capacity for which many shippers will contract will exceed their average demand, reflecting the uncertainties and unpredictability of gas demand.

A profit maximising shipper will therefore contract for additional pipeline capacity where the cost of an additional unit of capacity is less than the expected cost of not having that capacity to meet demand. In the case of an aggregator, the cost of failing to meet the gas requirements of its end users can be extremely high. For this reason, aggregators typically contract for capacity that is sufficient to meet their requirements for a 1-in-10 or even a 1-in-20 year peak demand event.

### **2.2.4. Incentives of pipeline operators**

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.

### 3. Methodology

This chapter sets out the methodology that we have applied to assessing the costs and benefits of each of the gas transmission capacity trading policy options developed by SCER. We start by briefly describing the policy options, before defining the key terms used throughout our analysis.

#### 3.1. Description of the policy options

The policy options that we have been asked to consider are:

- **Option 1: Status quo** – this option assumes no change to the current arrangements for transmission capacity trading,
- **Option 2: Improved information on capacity** – this option involves three components, namely:
  - improvements to the presentation and capability of the existing National Gas Bulletin Board (NGBB) data and facilities to enhance the useability of the information to market participants, including an improved voluntary capacity listing service;
  - the publishing of rolling data concerning unused pipeline capacity on the NGBB; and
  - standardisation of contractual terms and conditions applying to pipeline transport to expedite and ease the transfer of contractual rights to capacity;
- **Option 3: Voluntary capacity trading platform** – this option puts in place a voluntary pipeline capacity trading platform. This platform would be a cleared exchange operated by the Australian Energy Market Operator (AEMO), and would facilitate trading standardised pipeline capacity products; and
- **Option 4: Mandatory trading obligations** – this option requires any market participant with unused pipeline capacity either to:
  - offer unused capacity on an ‘non-firm’, interruptible basis – an obligation which is termed ‘use-it-or-lose-it’(Option 4A); or
  - offer unused firm capacity to the market – an obligation which is termed ‘use-it-or-sell-it’ (Option 4B).

Appendix B sets out the detailed descriptions and assumptions underpinning each of the policy options that we have considered.

#### 3.2. Definition of key terms

Each of the policy options being considered by SCER seeks to address the concern that current (and anticipated future) levels of pipeline capacity trading are sub-optimal. It follows that the concern requires an assessment of changes in ‘available pipeline capacity’ where capacity is traded to those shippers that value it most highly relative to the status quo. For available pipeline capacity to differ from the optimal level, there must be some impediment that prevents pipeline capacity being transferred to, or used by, those shippers that value it most highly.

The remainder of this section defines three key concepts relevant to our assessment, namely:

- gas transmission pipeline capacity (hereafter simply ‘capacity’);
- *availability* of capacity; and
- concepts of *access* or *impediments* to access.

### 3.2.1. Capacity

In simple terms gas transmission pipeline capacity is a measure of the maximum physical throughput of gas that a given pipeline is capable of transporting from one place to another. The term ‘standing capacity’ is often used to describe the physical capacity of a pipeline on a medium to long-term basis. ‘Operational capacity’ describes physical capacity on a short term basis. It is subject to discretionary maintenance.

In the context of this report, we are interested in the trading of *rights* to use, or access, the physical capacity of a transmission pipeline. This means that references to ‘capacity’ in this report refer to the rights to physical capacity, rather than the physical capacity itself.

There are two important concepts relating to capacity, namely:

- the level of ‘firmness’ corresponding to ‘firm capacity’; and
- the period of time over which the right to capacity applies, ie, the duration of the capacity.

#### 3.2.1.1. Defining the concept of firmness

There are two types of capacity rights available—firm and non-firm. A firm capacity right—ie, ‘firm capacity’—confers an unconditional right on the holder to use or access physical capacity on a given transmission pipeline irrespective of other pipeline transport demand or operating conditions. In contrast a non-firm capacity right—ie, ‘non-firm capacity’—confers a conditional right on the holder to use or access physical capacity on a given transmission pipeline. This means that the pipeline owner can provide less than the physical capacity associated with the capacity right, given other pipeline demands or operating conditions.

The distinction between firm and non-firm capacity is relevant only when physical capacity is less than total gas transport demand over the period in question. In this circumstance holders of firm capacity are given priority access to physical capacity, with holders of non-firm capacity being left to share any residual physical capacity remaining. The value of firm capacity is therefore linked to the priority given to holders of those rights to physical capacity during periods of high pipeline flow demand.

It follows that those end users of capacity for which a constant and reliable gas supply is required as part of, say a production process, will value firmness more highly than those users that have greater flexibility in gas use.

Of relevance to this report, which focuses on secondary trading of capacity, is that only firm capacity can be traded between shippers. It is for this reason that our analysis centers on firm capacity.

### 3.2.1.2. *Duration of capacity*

The right to firm capacity on a pipeline is specified for a period of time—eg, a day, a period of months, a year, or many years. For example, a shipper may hold the right to transport gas on a single day, or the right to transport gas every day of a year. The duration of firm capacity is relevant to a shipper because:

- Physical capacity can be scarce at particular times of the year, and so to ensure that a shipper has access to gas during those times they might purchase firm capacity on an annual basis.
- Shippers derive sufficient value from being able to use gas during periods of physical pipeline scarcity to justify the cost of annual firm capacity. For example, industrial users and base-load power stations that require consistent gas supply would likely derive little or no benefit from having only short-term firm capacity. Similarly, although peaking plants only use gas for brief periods, they typically require consistent capacity throughout periods given uncertainty surrounding the period when they might be required to generate.

This highlights that the value of holding annual firm capacity can arise because of the flexibility it creates to respond to demands in a downstream market (eg, electricity generation), or because of the importance of continuous supply of gas as part of a production process (eg, ammonia production). This means that the value of firm capacity that is used at particular times of the year can be retained by the holder even if they make non-firm capacity available for other periods during the year.

### 3.2.2. *Availability of capacity*

For the purposes of our analysis we draw a distinction between:

- ‘*unutilised capacity*’, defined as the total standing capacity of a pipeline less any flows on that pipeline; and
- ‘*available capacity*’, defined as a total standing capacity of a pipeline less:
  - any flows on that pipeline;
  - potential additional needs of the existing holders of firm capacity, ie, the amount of physical capacity that was available as an option in case existing holders had need of it; and
  - operational reductions in a pipeline’s standing capacity, eg, due to unavoidable maintenance.

At any time, available capacity can be significantly less than unutilised capacity, particularly given uncertainty about existing shippers’ potential needs. The profile of available capacity can therefore differ greatly from observations of unutilised capacity.

### 3.2.3. *Access to available capacity and impediments to trade*

The focus of our study is on assessing the potential benefits (and costs) of policy options that seek to remove perceived impediments to *accessing* available capacity. The draft RIS identifies two principal impediments, namely:

- **Excessive search and transaction costs**— search costs are incurred by existing and prospective shippers in the process of identifying opportunities for pipeline capacity trading. Where participants are unable to locate one another, search costs can be considered to be infinite, ie, trades are impossible. Transactions costs include any costs incurred to negotiate and alter gas transmission agreements, so as to effect a trade.
- **Failure to release**—a failure to release describes a circumstance where an existing holder of capacity chooses not to make that capacity available to the market, even though the benefits from such a trade appear to outweigh the costs (including the loss of any option values) to the existing holder.

To the extent that search and transactions costs pose a sufficient impediment to capacity trading by either current holders of capacity or potential new shippers, then lowering these costs would be expected to create benefits, from the associated trade of capacity and use of gas that would otherwise not have occurred. Importantly, the search and transactions costs need to be capable of being reduced.

In a workably competitive pipeline capacity market, a failure to release would not be expected to arise—ie, a shipper will sell capacity where they receive a net-benefit from doing so. It follows that a failure to release would only be a profitable strategy for a shipper if the pipeline capacity market was not competitive and the shipper was seeking to increase the costs of rival firms in a downstream market. In this circumstance, the shipper achieves a competitive advantage by not making pipeline capacity available. This implies that any evidence of withholding of pipeline capacity by existing shippers would imply that those shippers were potentially engaging in anti-competitive behaviour.

In conducting our analysis of the policy options we have considered information provided by stakeholders as to the existence, and potential cost, associated with these two potential impediments to access. We describe the approach that we have taken to measuring and valuing the benefits of reducing these impediments in section 3.3.3.

### **3.3. Approach to estimating benefits**

To estimate the benefits of the proposed policy options, we have adopted the following methodology:

- Step 1: Estimate how much pipeline capacity is currently available for trade, on each major gas transmission pipeline in the eastern gas market, excluding those pipelines that form part of the VTS<sup>70</sup>;
- Step 2: Qualitatively evaluate the extent that search and transactions costs, or a failure to release capacity might be impeding optimal trading of the identified capacity; and
- Step 3: Value the possible range of benefits for each policy option, based on an assessment of the value of an incremental trade of capacity, and a qualitative evaluation

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<sup>70</sup> Our analysis is only applicable for pipelines that are operated under the contract carriage model. Pipelines that form part of the VTS are operated under a market carriage model. Shippers on these pipelines are unable to trade the right to transport capacity. Instead they are able to transfer units of authorised maximum daily quantities (AMDQ). AEMO has conducted a separate cost-benefit analysis to evaluate a proposed portfolio rights trading (PRT).

of the extent that the option would likely lower search and transactions costs, or trade of unutilised capacity.

The remainder of this section describes our approach to each step in greater detail.

### 3.3.1. *Step 1: Determining available capacity*

We define available capacity as total standing capacity less historical flows, potential additional needs of existing holders of capacity and operational limitations.

Information on the standing capacity of each pipeline is readily available. Historically, the standing capacities of a number of pipelines have been expanded, underwritten by long-term contracts between pipeline operators and shippers. Historical flow data for each pipeline is published on the National Gas Bulletin Board (NGBB) and is available from July 2008 onwards.<sup>71</sup>

Information about the potential additional needs of existing capacity holders is not readily available. To understand this would require a detailed analysis of the uses of gas on each pipeline, and the relationship between gas use and pipeline flow, relative to the peak demand periods on the pipeline. Further, information on historic operational limitations is known only by pipeline operators.<sup>72</sup> In the timeframe available for our analysis, we have not sought to obtain this information from those operators.

In the absence of information on potential additional needs and operational limitations, we describe these requirements, to make a qualitative assessment of available capacity for each pipeline.

The level of unutilised capacity represents an upper bound on available capacity, ie, available capacity is always less than the observed difference between standing capacity and observed flows. To assess the level of available capacity, we have started by calculating unutilised capacity. We have considered historical flows and standing capacities as published on the National Gas Bulletin Board and, where available, by other sources. For all pipelines we have obtained a minimum of five years of data.

Having established an upper bound on available capacity, we then perform a qualitative assessment of the degree to which the profile of available capacity should be adjusted to reflect:

- shippers' gas requirements:
  - on a 1-in-20 year basis for retailers; or
  - to meet maximum generation capacity requirements for electricity generators.

Relevantly, for the purposes of our quantitative assessment, all of our estimates of benefits have been based on a measure of unutilised capacity, unadjusted by prospective potential capacity needs of shippers.

Having developed an estimate of unutilised capacity, we then determine the duration of unutilised capacity. This allows us to ascribe different values to the capacity that is assumed to become used following implementation of a policy option, reflecting the length of time for which the capacity is available and so its potential uses.

<sup>71</sup> AEMO, 'National Gas Market Bulletin Board' <<http://www.gasbb.com.au/>> [accessed 24 October 2013].

<sup>72</sup> It is important to note that by 'operational limitations' we do not mean that the capacity is capped at 'operational capacity'. This fails to capture *potential* capacity that could have been supplied.

Projecting future available capacity would in principle require us to project gas flows, potential requirements, and operational limitations—all of which is highly speculative. To simplify our analysis, we have therefore assumed that historical profiles of flows provide the best available information as to the current and future levels of available capacity on existing pipelines. We qualitatively consider the implications for our results if this assumption were not to hold over the next 20 years.

Finally, our approach assumes that the duration of capacity, and the specific timing of its availability are known with certainty by all shippers. In reality, existing holders of capacity will not be able to predict when and for how long they will not require their contracted capacity. The effect of this assumption is to overestimate actual available capacity. This approach therefore establishes an upper bound of the possible benefits arising from the policy options.

### **3.3.2. *Step 2: Qualitative evaluation of identified impediments to trading and accessing available capacity***

The next step involves a qualitative evaluation of the extent that search and transaction costs, or a failure to release, pose a potential impediment to trade on each pipeline. We have considered two factors as part of this evaluation, namely:

- information on the prevalence of capacity trading between shippers; and
- a rough assessment of the time profile of gas demand by existing downstream gas users, and the availability of capacity.

As part of our study we have sought, but have been unable to find, objective information on the depth of the market for secondary trades in capacity. Given the lack of objective information, we have relied on anecdotal information provided to us by stakeholders on the prevalence of trading of capacity between shippers.

#### **3.3.2.1. *Assessing the time profile of gas demand and available capacity***

In principle, if there are periods of unmet demand for pipeline capacity corresponding to periods of high availability, then this could be construed as evidence of an impediment to capacity trading. It follows that observing historical periods where there is likely to be high pipeline capacity demand, corresponding to high end-use gas demand, and high levels of available capacity, can provide an indicator of potential impediments to capacity trading. In contrast, periods where pipeline demand is high and capacity is unavailable, or in limited supply, would suggest that there are little or no benefits from addressing any trading impediments that may exist.

We have therefore considered the time profile of available capacity, and compared it with our own understanding of the profile of gas demand, and so pipeline capacity demand. In addition, we have also considered anecdotal information provided by stakeholders. In considering demand for, and availability of, we have had regard both to the duration of the available capacity, and the time of year that the capacity is available.

### 3.3.3. Step 3: Valuing the benefits of the policy options

Having made an assessment of available capacity and impediments to trading of available capacity trading on each pipeline, the final step of our methodology is to estimate the benefits of the proposed policy options.

Our approach to estimating the benefits comprises three steps:

- developing a rough estimate of the current value incremental trade and use of pipeline capacity ('value of capacity'), based on an estimate of transaction costs the principal end uses for gas in each key downstream gas market;
- evaluating the extent that each policy option is likely to reduce any impediments identified on each pipeline, and so potentially lead to increased use of currently available capacity and so increased downstream gas consumption; and
- valuing the benefits of any increase in pipeline capacity utilisation by multiplying the increase in capacity utilisation by the value of capacity and projecting the benefits over a period of 20 years.

#### 3.3.3.1. Rough estimate of the value of gas transmission pipeline capacity

To value the potential benefits of the three policy alternatives, we need to develop estimates of the value that might be created by greater gas pipeline utilisation and potentially gas consumption. In principle, the value of capacity with a *short duration*:

- cannot exceed the value created by greater gas use in those downstream industries that might benefit from lower search or transactions costs; and
- has a lower bound of zero, assuming there are currently no impediments to trading available capacity, or there is no additional demand for available capacity, and so making more capacity available for trading would not generate any additional value from gas use.

Similarly, the value of capacity with a *longer duration*:

- will generally tend to be limited by the per unit cost of constructing a new gas pipeline. This is because by improving the accessibility of available capacity, the cost of constructing new gas pipelines to meet growing demand can potentially be deferred, or even avoided altogether; and
- has a lower bound of zero, assuming there are no impediments to trading available capacity, or there is no additional demand for available capacity. In this case, making more capacity available for trading would not generate any additional value from gas use.

In addition, the value of capacity with a short duration will depend on the presumed nature of current search or transactions costs. If the costs are dominated by the challenge of identifying sellers or purchasers of currently available pipeline capacity (ie, the transactions costs are so high that trades are impossible), then the value will likely be closer to the value generated by society from the resultant gas use that otherwise would not have occurred. Alternatively, if the search or transactions costs are simply the negotiation and legal time involved in finalising an appropriate contract to trade capacity, then the value will likely be closer to reduction in transactions costs that result from the implementation of the policy option.



In the absence of direct information on the value of gas to downstream users, we have developed rough estimates of the value by using data on the value-add for each main gas-using industry as provided in the National Accounts, divided by an estimate of the total current gas use of that industry. This approach produces a rough estimate of the current value-add of gas use in the industry, assuming that gas is a critical input for the sector (ie, no value-add would be created in the absence of capacity being traded).

Through discussions with shippers, we have also developed estimates of the typical transactions costs involved with current gas pipeline capacity trades, so as to provide an estimate of the possible costs that might be saved.

We recognise that this approach provides only a rough estimate of the value of gas to the downstream industry, since it assumes that the industry is currently constrained in the availability of gas. Making more gas available by lowering transaction and search costs would therefore lead to increased production of the associated final product. We acknowledge that this is a circular argument—if there are no impediments to the supply of gas to downstream markets, then the associated policy options would create no benefits because each industry would not be capable of increasing the value of its production through expanded availability of gas.

### 3.3.3.2. *Evaluation of the impact of each policy option on the identified impediments*

Each of the policy options seeks to facilitate greater trading of available capacity. That said, the options seek to address different types of impediments to available capacity trading, namely:

- **Option 2 (greater information provision) and Option 3 (voluntary trading platform)**, seek to lower transaction and search costs, and so enhance available capacity trading and so use of the pipeline by those gas users for which current transaction and search costs mean that these trades are not valuable; and
- **Option 4 (mandatory trading obligation)** seeks to enhance available capacity trading by either requiring pipeline operators to offer ‘non-firm’ capacity via a transparent trading platform if shippers to not nominate use of their full contracted capacity (use-it-or-lose-it) or requiring shippers to sell firm capacity if they fail to make use of it (use-it-or-sell-it). These options target the possible anti-competitive use of capacity rights.

Given uncertainty about the likely impact of each policy option on the identified impediment, our approach to this step, for Option 2 and Option 3, has been to define a range of possible outcomes of the policy option on enhancing the value created by improving access to available pipeline capacity.

Having identified the potential for a policy option to alleviate a specific impediment, we can assess the scope for increased use of currently available capacity that may follow the implementation of each policy option. A necessary condition for there to be an increase in use of available capacity is that there is additional demand for that capacity once the impediment has been lessened or removed.

### 3.3.3.3. *Valuing benefits from the potential increased use of available capacity*

The final step involves estimating the value of the benefits resulting from increased use of currently available capacity, and projecting this value over a time horizon of 20 years.

Our approach to valuing the benefits is straightforward—we multiply estimates of the value of capacity by the assumed increase in use of available capacity. This provides an estimate of the potential benefits of the policy option that would have occurred over the last five years. This value is then projected out over the 20 year time horizon, adjusting for anticipated changes in available capacity given projected small increases in domestic gas demand in the eastern gas market, and the development of LNG export facilities in Queensland.

## 3.4. *Summary*

In summary, our methodology seeks to provide an indication of the order-of-magnitude of potential benefits that might result from the policy options. We recognise that these estimates are limited by the lack of available data on:

- the value of capacity to downstream gas using industries;
- search and transactions costs for trading gas transmission pipeline capacity;
- future developments in the gas market, which will impact on the current estimates of the availability of pipeline capacity; and
- the likely effect of the policy options on use of currently available capacity.

Our results should therefore be treated as being, at best, indicative of the possible benefits available from the policy options being considered.

## 4. Assessment of Costs

In this section we describe our assessment of the principal costs that are likely to be incurred to implement and administer each of the proposed policy options. All of these estimated costs are incremental to Option 1, ie the status quo option.

### 4.1. Common assumptions

In developing our estimates of the costs of the policy options, we have applied a number of common assumptions. These are set out in below Table 4.1.

**Table 4.1**  
**Summary of Cost Assumptions**

<b>Assumption</b>	<b>Value</b>
Annual Staff Cost (for AEMO, AEMC, Pipeline Operators and Shippers)	\$100,000/full time equivalent/year
Legal Fees	\$500/hour
Discount Rate	7.0%

### 4.2. Option 2: Data collection and reporting

Option 2 involves placing requirements on pipeline operators to make information publicly available over and above their existing requirements. For the purposes of assessing Option 2, we have assumed that pipeline operators would have to provide information including:

- a 365 day outlook of operational pipeline capacity, including the implications of any operational flow orders, maintenance and ancillary services, updated once monthly;
- day-after and a 365 day outlook of contracted firm capacity by shipper, including secondary capacity trades;
- day-after and a 365 day outlook of contracted ‘non-firm’ capacity by shipper, including secondary capacity trades; and
- day-after hourly gas deliveries categorised into three shipper types: retail, industrial, and electricity generation customers.

We assume that the information would be provided to AEMO and made available via the National Gas Bulletin Board. In addition, this option involves the creation of a standardised contract, to be used as the basis for bilateral contract negotiations to facilitate capacity trading.

We have identified a number of establishment and ongoing cost categories, including:

- costs involved with upgrading and maintaining the National Gas Bulletin Board to enable it support the provision of the information;
- costs incurred by pipeline owners and shippers to collect information and provide that information to the AEMO;

- costs incurred to change the National Gas Rules, to place the obligation on pipeline operators to provide the identified information;
- additional enforcement costs to ensure compliance with the new information requirements; and
- the costs required to develop a standardised contract.

The remainder of this section sets out our approach to estimating each of these cost categories.

#### **4.2.1. Upgrade to the National Gas Bulletin Board**

The proposed increase in the information provided as part of the National Gas Bulletin Board (NGBB) will impose costs on AEMO as well as pipeline operators and shippers. These costs will be incurred in upgrading the functionality of the current system and in collating, validating and managing the information.

We have assumed that to implement Option 2 AEMO would be required to:

- upgrade the NGBB interface to provide:
  - the capability to display and interact with the new information;
  - an improved voluntary capacity listing service with the contact details of prospective shippers and pipeline operators; and
  - documentation on standardised contract terms and conditions; and
- collate and manage new information to be presented on the NGBB.

We have estimated these costs by assuming:<sup>73</sup>

- a one-off cost of between \$750,000 and \$500,000 to upgrade the NGBB's systems and online interface; and
- AEMO will need to employ up to two additional full-time equivalent staff for the first year, and one every year thereafter, to manage the additional information provision tasks.

The total estimated upgrade costs in present value terms are set out in Table 4.2 below.

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<sup>73</sup> These costs are based on information provided by AEMO.

**Table 4.2**  
**Summary of Costs - Upgrade to the NGBB**

Entity	Upper Bound (\$ million)	Lower Bound (\$ million)
Total present value	\$2.0	\$1.6
Total annualised cost	\$0.2	\$0.2

#### **4.2.2. Costs incurred by pipeline operators and shippers**

Option 2 will require pipeline operators to provide information on pipeline usage to AEMO on a regular basis. This will require staff to collect information from shippers, collate its own information, and provide this information to AEMO.

We assume that these information requirements could be satisfied for pipeline operators by one full-time equivalent staff member for the first year and for half a full-time equivalent staff member in subsequent years.

Under current market arrangements, shippers are not required to provide information to the pipeline owner when they on-sell capacity to another shipper. Therefore, under the proposed information provision arrangement shippers will incur costs associated with the provision of this information to the pipeline owner. We estimate that this information requirement could be satisfied by 1 hour of time per week for each shipper.

In addition, we have made an allowance of \$100,000 to upgrade internal systems and processes to make the information available.

The total estimated costs to be incurred by pipeline operators and shippers in present value terms are set out in Table 4.3.

**Table 4.3**  
**Summary of Costs – Pipeline operators and shippers**

Entity	Upper Bound (\$ million)	Lower Bound (\$ million)
Pipeline operators	\$2.0	\$0.7
Shippers	\$3.0	\$1.5
Total present value	\$5.0	\$2.2
Total annualised cost	\$0.5	\$0.2

#### **4.2.3. Changes to the National Gas Rules**

The next category relates to the costs incurred to amend the National Gas Rules so as to implement the requirements for information provision.

We assume that this will involve:

- the costs to be incurred by governments and the Australian Energy Market Commission (AEMC) to frame and agree on a rule change proposal and associated amendments to the rules; and
- the costs incurred by pipeline operators and shippers to respond to a rule change proposal, as part of the associated stakeholder engagement process.

We anticipate that such a rule change process would be relatively straightforward and so we have estimated these costs by assuming that:

- the rule change would require the involvement of one full-time equivalent staff member and associated legal fees, to be incurred by the AEMC and governments;
- pipeline operators would devote approximately 15 person days to the development of submissions and general engagement on the rule change proposal; and
- shippers would likely devote approximately 5 days to the development of submissions and general engagement on the rule change proposal.

Table 4.4 summarises the estimated costs associated with changes to the National Gas Rules that would be required to implement Option 2, in present value terms.

**Table 4.4**  
**Summary of Costs – Changes to the National Gas Rules**

Entity	Upper Bound (\$ million)	Lower Bound (\$ million)
Australian Energy Market Commission and governments	\$0.3	\$0.2
Pipeline operators and shippers	\$0.2	\$0.1
Total present value	\$0.5m	\$0.3
Total annualised cost	\$0.0	\$0.0

#### **4.2.4. Additional enforcement costs**

In our discussions with the Australian Energy Regulator (AER), it was apparent that any changes to the National Gas Rules that impose new compliance obligations, typically results in a period of compliance effort until those parties with new obligations understand the requirements and put in place the necessary systems to satisfy the obligations.

We have estimated the associated additional AER enforcement costs as:

- two additional enforcement officers to provide pipelines with information about the nature of the new obligations and how they can comply with any obligations; and
- half an additional enforcement officer in every subsequent period for enforcement activities.

These assumptions are based on our discussions with the AER.

**Table 4.5**  
**Summary of Costs – Additional Enforcement Costs**

	<b>Upper Bound (\$ million)</b>	<b>Lower Bound (\$ million)</b>
Total present value	\$1.2	\$0.6
Total annualised cost	\$0.1	\$0.1

#### **4.2.5. Development of a standardised contract**

The final cost category relates to the development of a standardised contract, which can be used to facilitate trading of capacity. Importantly, the intention of this option is for the standardised contract to form a starting point for bilateral negotiations between the parties, and so is capable of being modified by the parties to a particular capacity trade.

We understand that a draft standardised contract has been drafted by AEMO for the Wallumbilla gas supply hub and developed in consultation with industry, including shippers and pipeline operators. For the purposes of our assessment, we have assumed that the final version of this Wallumbilla standardised contract forms the basis of the standardised contract developed by AEMO that is applicable to all transmission pipelines in the eastern gas market.

We have assumed that the costs of developing a standardised contract involve a combination of legal fees and stakeholder consultation. We have assumed that:

- legal costs incurred by AEMO would amount to approximately \$30,000; and
- stakeholder engagement on the standardised contract would amount to approximately four days for a staff member across 30 interested stakeholders.

**Table 4.6**  
**Summary of Costs for Option 2 – Development of Standardised Contract**

<b>Entity</b>	<b>Upper Bound (\$ million)</b>	<b>Lower Bound (\$ million)</b>
Australian Energy Market Operator	\$0.0	\$0.0
Pipeline operators and shippers	\$0.1	\$0.0
Total present value	\$0.1	\$0.1
Total annualised cost	\$0.0	\$0.0

#### **4.2.6. Summary**

Table 4.7 sets out the estimated range of costs for Option 2, in present value terms.

**Table 4.7**  
**Summary of Total Costs for Option 2**

<b>Cost Category</b>	<b>Upper Bound (\$ million)</b>	<b>Lower Bound (\$ million)</b>
Upgrade to the National Gas Bulletin Board	\$2.0	\$1.6
Pipeline and Shipper information costs	\$5.0	\$2.2
Changes to the National Gas Rules	\$0.5	\$0.2
Additional enforcement costs	\$1.2	\$0.6
Development of a standardised contract	\$0.2	\$0.1
<b>Total present value</b>	<b>\$8.8</b>	<b>\$4.7</b>
<b>Total annualised cost</b>	<b>\$0.8</b>	<b>\$0.4</b>

### **4.3. Option 3: Voluntary capacity trading platform**

Option 3 encompasses Option 2, but also involves the development of a voluntary pipeline capacity trading platform. This platform would be a cleared exchange operated by the AEMO and would facilitate trading of standardised capacity products. Importantly, the platform would be voluntary and so there would remain scope for bilateral trading of capacity outside of the platform.

The cost categories that we have identified for Option 3 include:

- the establishment and ongoing costs associated with the development of the proposed capacity trading platform; and
- the costs associated with the specification of standardised products.

The remainder of this section describes our approach to estimating the possible costs associated with Option 3.

#### **4.3.1. Platform establishment and ongoing costs**

Based on our consultations with AEMO, we understand that it would be possible to create a cleared exchange for pipeline capacity with functionality similar to the cleared exchange for gas being developed as part of the Wallumbilla gas supply hub platform.

AEMO has indicated to us that the platform costs would likely involve:

- one-off establishment costs of \$1.7 million to reconfigure the existing platform to create the capability to implement Option 3;
- ongoing costs of approximately \$170,000 each year to maintain and operate the platform; and
- an annual licensing cost of approximately \$500,000 each year for the platform technology.



Table 4.8 summarises the estimated platform establishment and ongoing costs for Option 3, in present value terms.

**Table 4.8**  
**Summary of Costs for Option 3 – Platform Establishment and Ongoing Costs**

Cost Category	Upper Bound (\$ million)	Lower Bound (\$ million)
Platform establishment costs	\$4.1 <sup>74</sup>	\$1.7
Operational costs	\$3.9	\$1.9
Annual licensing costs	\$5.7	\$5.7
Total present value	\$13.6	\$9.3
Annualised	\$1.3	\$0.9

#### 4.3.2. *Specification of standardised products*

The second cost category for Option 3 involves the costs associated with standardisation of the transmission capacity products that will be traded on the voluntary platform. A standardised product can only be traded through a cleared exchange if it has standardised terms and conditions, including a delivery location.

These standardised products would be developed in consultation with shippers and pipeline operators, in a staged manner. This means that following the development and successive amendments to the standardised contract, AEMO would develop an initial standardised product that would be transacted on the voluntary platform for a trial period of, say three years. During that trial period, AEMO would receive feedback from shippers and pipeline operators about preferred amendments to the standardised product, which would lead to the development of additional standardised products.

We have assumed that the costs for the development of standardised products principally relate to legal drafting and engagement costs. We appreciate that these costs will primarily relate to the challenge of creating a product that is acceptable to both potential sellers and buyers of those products. Indeed, we expect that a number of iterations may be required until such standardised products were well accepted by market participants and so capable of facilitating enhanced trading.

We have assumed that most of the effort involved with developing standardised products would occur in the three year trial period and will range between:

- 500 and 1000 hours of staff time for each of the three pipeline operators as part of consultation with other market participants and AEMO;
- 250 and 500 hours of staff time for each of an assumed 25 shippers as part of consultation with other market participants and AEMO; and

<sup>74</sup> Based on the costs expected to be incurred to develop the Wallumbilla platform under the brokerage model.

- 500 and 1000 hours of legal effort by AEMO, in addition to the provision of up to three staff full time to facilitate the process.

Table 4.9 summarises the resultant range of costs that we have estimated for the specification of standardised products as part of Option 3, in present value terms.

**Table 4.9**  
**Summary of Costs for Option 3 – Specification of Standardised Products**

<b>Entity</b>	<b>Upper Bound (\$ million)</b>	<b>Lower Bound (\$ million)</b>
Australian Energy Market Operator	\$0.7	\$0.3
Pipeline Operators	\$0.1	\$0.1
Shippers	\$0.6	\$0.3
Total present value	\$1.5	\$0.7
Total annualised cost	\$0.1	\$0.1

#### 4.3.3. *Summary*

Table 4.10 sets out the estimated range of costs for Option 3, in present value terms.

**Table 4.10**  
**Summary of Total Costs for Option 3**

<b>Cost category</b>	<b>Upper Bound (\$ million)</b>	<b>Lower Bound (\$ million)</b>
Platform establishment and ongoing costs	\$13.6	\$9.3
Specification of standardised products	\$1.5	\$0.7
Total incremental present value costs	\$15.1	\$10.0
Plus Costs of Option 2	\$8.8	\$4.7
Total present value	\$23.9	\$14.7
Total annualised cost	\$2.3	\$1.4

#### 4.4. *Option 4: Mandatory trading obligations*

Option 4 involves the creation of a mandatory obligation for market participants with unused pipeline capacity either to:

- offer unused capacity on an ‘non-firm’, interruptible basis – an obligation which is termed ‘use-it-or-lose-it’(Option 4A); or
- offer unused firm capacity to the market – an obligation which is termed ‘use-it-or-sell-it’ (option 4B).

In our opinion, the costs associated with Option 4 include:

- the costs of developing the necessary framework required to implement the option; and
- the costs incurred by the obligated shipper to sell capacity from which they derive some value.

Given the mandatory nature of Options 4A and 4B, a framework for monitoring and assessing compliance would need to be established. We anticipate that this framework would require:

- the establishment and operation of a transparent trading platform, such as a listing service or a cleared exchange;
- changes to the National Gas Rules to formalise the obligations;
- the mandatory provision of information by both pipeline operators and shippers; and
- monitoring and enforcement by the AER.

The costs of establishing a transparent trading platform under Option 4 are likely to be similar to Option 2 where the platform is a listing service, or alternatively, similar to Option 3 where the platform is a cleared exchange. However, we expect that the cost of implementing the other elements of the framework underpinning Option 4 would exceed those estimated for Option 2 and Option 3.

The costs of amending the National Gas Rules under Option 4 to place trading obligations on pipeline operators and shippers would be greater than that under both Option 2 and 3. The cost would mainly involve legal assessment of the implications of rule amendments on existing commercial agreements, and the legality of voiding shippers’ property rights. The cost of collating and providing information to AEMO will be more extensive under Option 4 than that under Options 2 and 3, as the AER would require detailed data against which to assess compliance. Finally, the AER would incur additional costs under Option 4, relative to Options 2 and 3, to monitor and enforce mandatory trading.

In addition, Option 4B involves costs for the shipper, resulting from the challenge of developing an objective rule to define when unused capacity is subject to the mandatory trading obligation. If Option 4B were to oblige shippers to sell capacity from which they would have otherwise derived value—such as to manage the risks associated with peak demand or supply disruptions—then the option would lead to an inefficient allocation of capacity and potentially undermine the incentives that underpin investment in the pipeline industry.

We expect that Option 4B would create considerable uncertainty for potential underwriters of new or expanded pipeline capacity about the extent to which valuable unused firm capacity might be taken away. It follows that this option might lead to less than optimal investment in pipeline capacity expansion, and either:

- increase the total cost of transmission pipeline services, compared against a counterfactual scenario where Option 4B does not proceed; or
- decrease the use of gas compared against the counterfactual scenario, and so losing the value that the associated gas use would create in the economy.

These costs can be minimised by ensuring that any mandatory trading obligations do not inappropriately force capacity holders to trade capacity that is otherwise valuable to them. The challenge would be to ensure that such a condition is met in all possible circumstances.

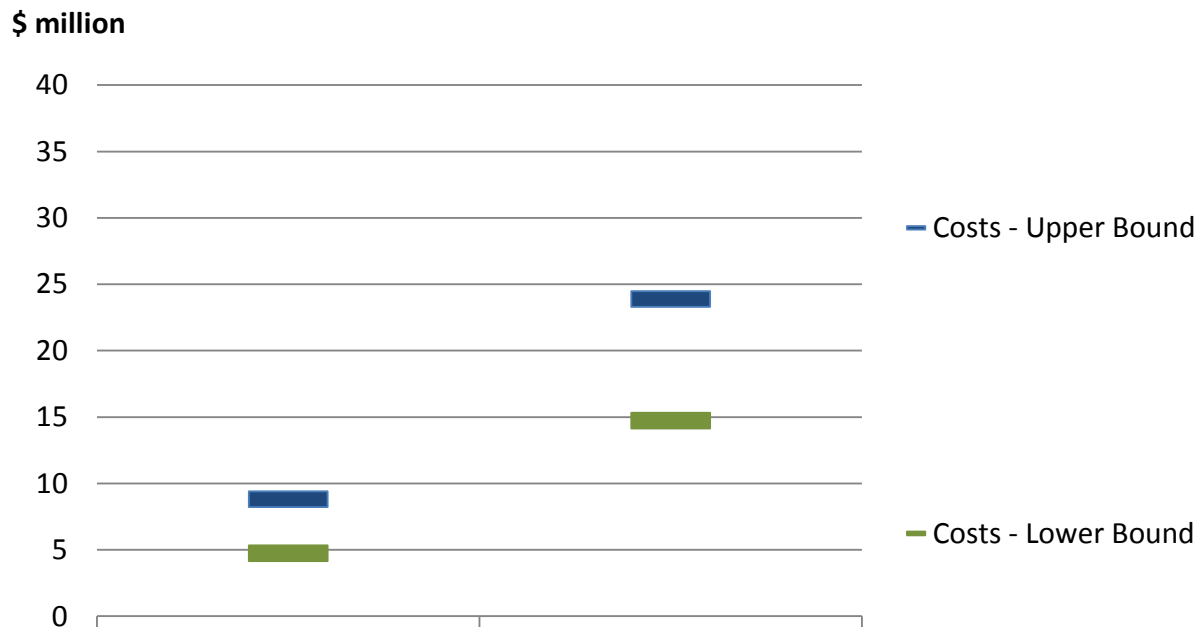
Without knowledge of the value shippers place on unutilised capacity, the incentive effect of Option 4B on pipeline capacity investment is itself highly uncertain. It might be that Option 4 would have almost no impact on pipeline capacity investment and expansion because the mandatory obligation would be sufficiently well defined that legitimate holders of capacity need not be concerned about their rights to hold the capacity. Alternatively, Option 4B might result in distortions in pipeline capacity investment with associated significant implications for the value generated by gas use.

In our opinion it is not possible to develop sensible estimates of the costs of Option 4 for the purposes of this analysis, because such an estimate would require a specification of the conditions under which shippers would be obliged to trade, and an assessment of the risk for inefficient allocation of capacity. Nevertheless, it is our opinion that the costs of Option 4 would most likely exceed those estimated for Option 2 and Option 3.

#### **4.5. *Summary of the costs of the policy options***

Figure 4.1 provides a summary of the costs of Option 2 and 3.

**Figure 4.1**  
**Present Value of the Costs of Policy Options 2 and 3**



## 5. Assessment of Benefits

This chapter sets out our assessment of the benefits of each of the proposed policy options relative to the status quo. We have described in our methodology that our approach comprises three steps:

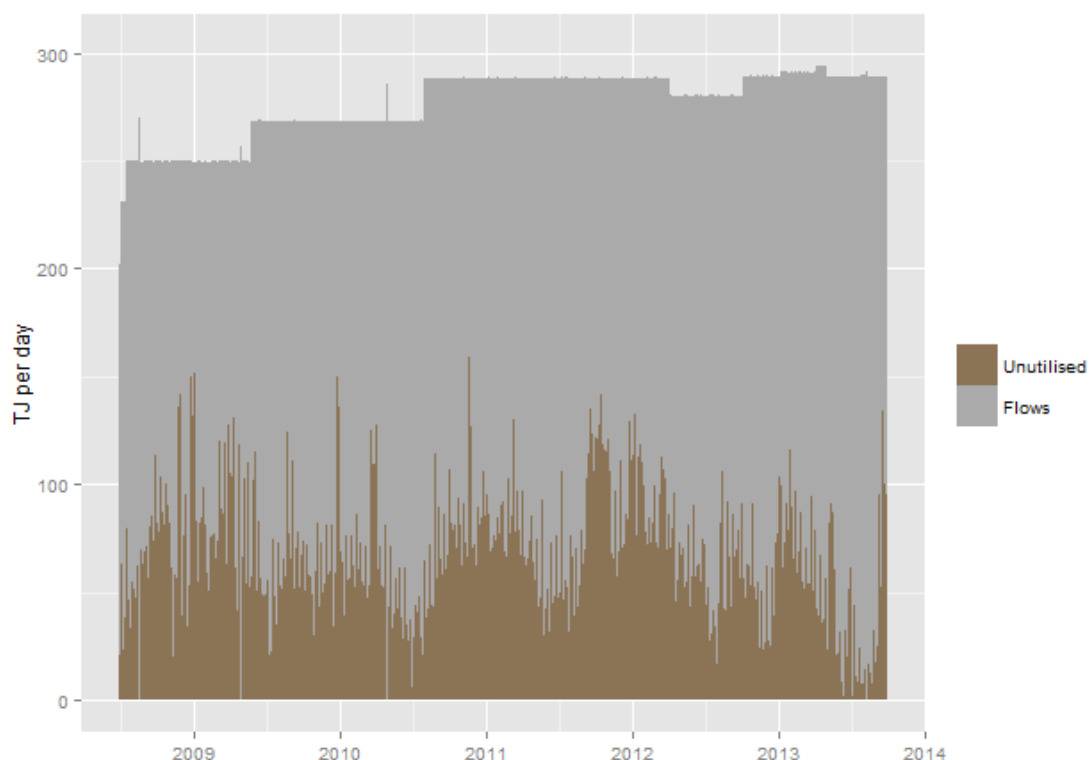
- quantifying unutilised capacity on each pipeline;
- assessing whether there are impediments to accessing available capacity; and
- valuing the possible range of benefits for each policy option.

The remainder of this chapter sets out our results for each of these steps.

### 5.1. Quantifying available capacity

We define available capacity as the standing capacity of the pipeline less flows (ie, unutilised capacity), the potential additional needs of existing holders of capacity, and operational limitations of the pipeline. To assess available capacity, the first step is to calculate the extent that each pipeline currently has unutilised capacity. Figure 5.1 illustrates the standing capacity, daily flow and so unutilised capacity for the EGP from 2008 to 2013.

**Figure 5.1**  
**Unutilised Capacity of the Eastern Gas Pipeline, 2008-2013**



The next step is to determine the duration of this unutilised capacity. We have grouped unutilised capacity into one of five bands, namely:

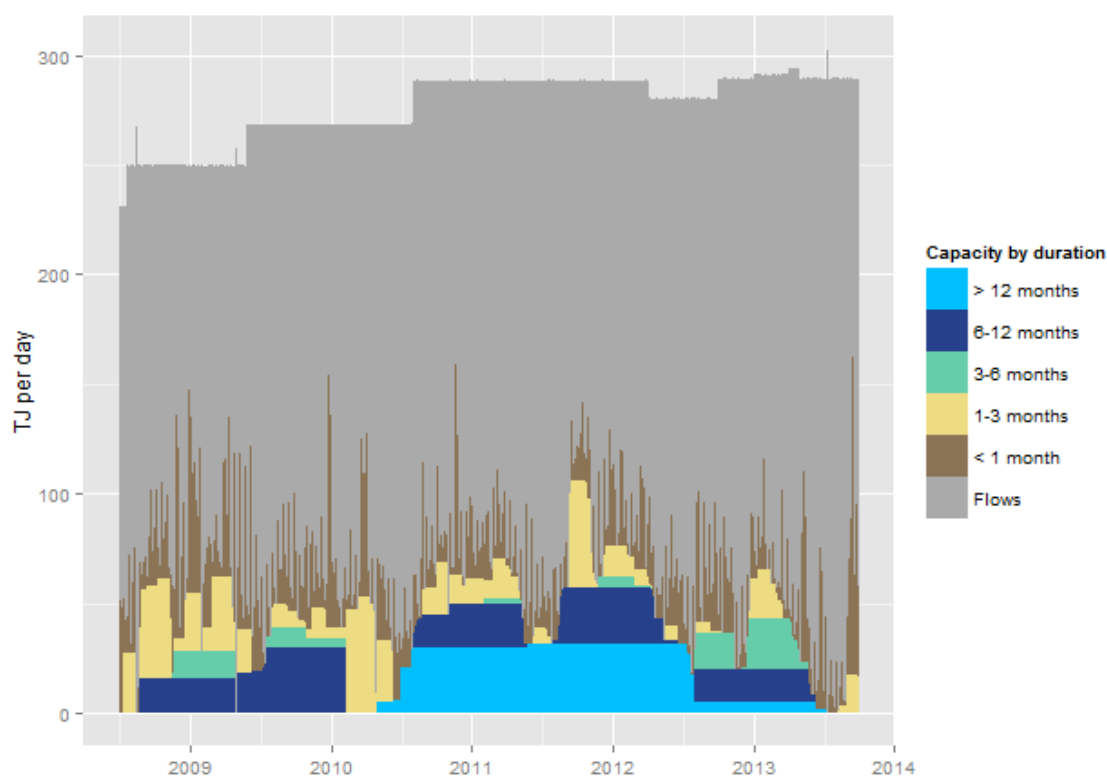
- greater than 12 months;

- between 6 months and 12 months;
- between 3 months and 6 months;
- between 1 month and 3 months; and
- less than one month.

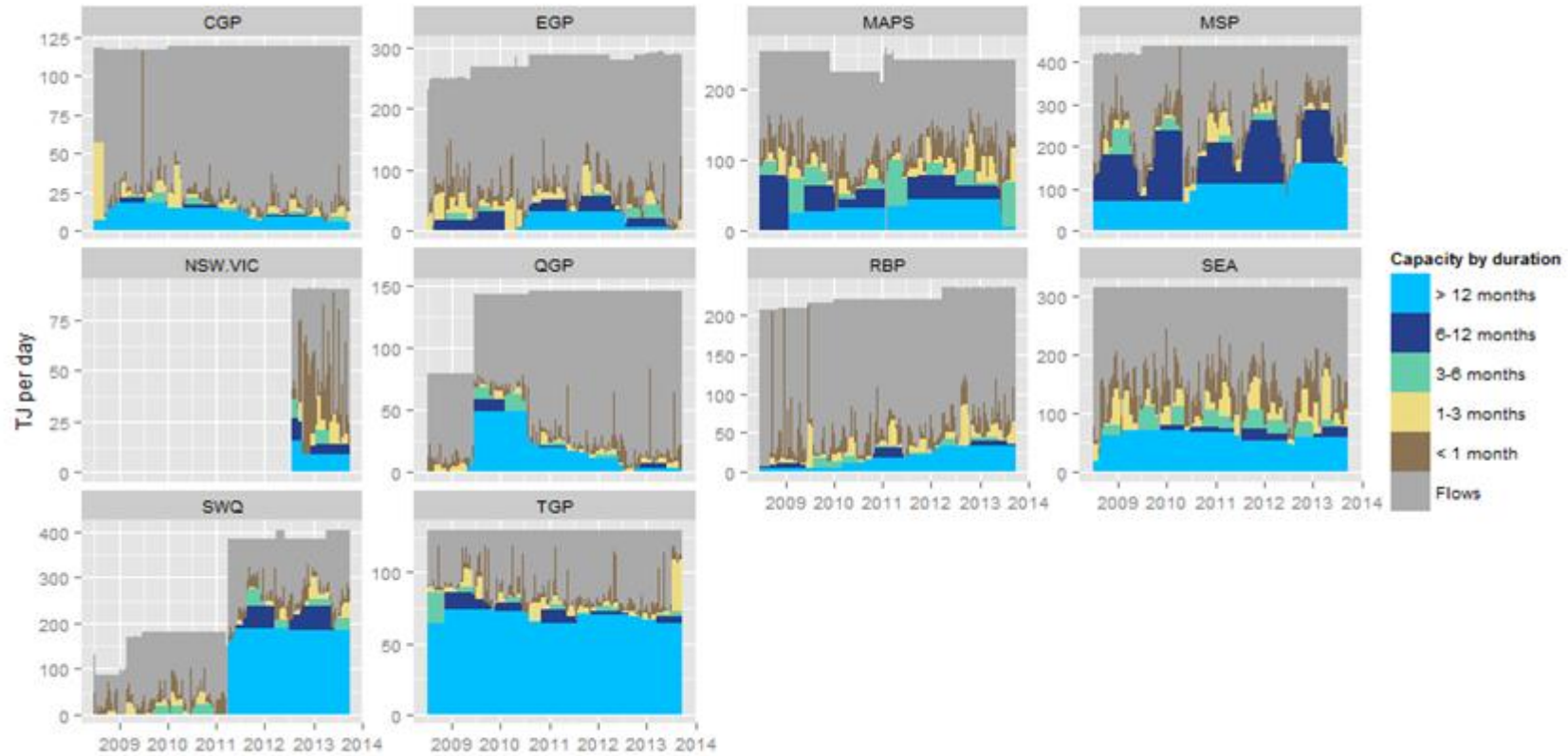
The duration of any unutilised capacity provides an indication of the potential for a shipper to trade and make use of that unutilised capacity. In addition, the policy options are focused on facilitating trades for blocks of capacity of specific duration. We have chosen these five bands to reflect the focus of the policy options. However, a different choice of bands would be unlikely to have a significant effect on our results.

Figure 5.2 shows a decomposition of capacity on the EGP from 2008 to 2013. Every unit of capacity is classified as either being a flow (ie utilised), or unutilised capacity with one of the five durations. Flows on the EGP represent a large proportion of capacity year round, meaning that the pipeline is highly utilised. Of the remaining unutilised capacity, most is only unutilised in blocks of less than 12 months. There were only small amounts of unutilised capacity with a duration of more than 12 months, and this followed an expansion to the standing capacity of the pipeline in 2010. Figure 5.3 sets out the same analysis for all pipelines in the eastern gas market, with the exception of the pipeline within the VTS.

**Figure 5.2**  
**Unutilised Capacity by Duration on the Eastern Gas Pipeline from 2008-2013**



**Figure 5.3**  
**Unutilised Capacity by Duration, by Pipeline from 2008-2013<sup>75</sup>**



<sup>75</sup> We used the last 12 months of flow data on the NVI because it is, in our opinion, likely to be more indicative of future flows. The NVI was historically bi-directional. In more recent years, flow has been predominantly into New South Wales. Recent announcements by the APA Group regarding the expansion of the NVI suggest these flows into New South Wales are likely to continue.



Available capacity for any pipeline can be significantly less than unutilised capacity, particularly where the needs of the existing holders of capacity vary greatly from one year to the next. In addition, the profile of available capacity can differ greatly from observations of unutilised capacity. We describe the potential additional capacity holding needs of capacity holders and characterise available capacity of each pipeline in Table 5.1.

**Table 5.1**  
**Characterisation of Available Capacity by Pipeline**

<b>Pipeline</b>	<b>Observed unutilised capacity</b>	<b>Potential explanations for unutilised capacity</b>	<b>Profile of available capacity</b>
CGP	12 months: available	Not fully contracted	12 months: available
EGP	3 to 12 months: available in summer	A recent expansion to meet increased demand accounts for most of the available capacity. The pipeline is now effectively fully utilised.	3 to 12 months: available in summer
MAPS	12 months: unpredictably available	Peak hourly demand from gas-fired electricity generators.	12 months: available <sup>76</sup>
MSP	12 months: available 3 to 12 months: available in summer.	Contracting for 1-in-20 year peak requirements. Seasonal profile of Sydney gas use.	3-12 months: available in summer
QGP	3 to 12 months: unpredictably available	Expansion in 2009 to meet increased demand accounts for most of the available. The pipeline is now effectively fully utilised.	None.
RBP	12 months: available 3-12 months: unpredictably available	Capacity was expanded in 2012. There has been a reduction in gas demands from gas-fired electricity generators in recent years. There is contracting for peak gas demands to support electricity generation.	12 months: available 3-12 months: unpredictably available
SEA	12 months: available 3 to 12 months: available in summer	Contracting for 1-in-20 year peak requirements. Reflects the seasonal profile of Adelaide gas use.	3 to 12 months: available in summer
SWQ	12 months: available 3 to 12 months: available in summer	Recent expansion to meet anticipated demand and flow reversal. Pipeline reversal expected from 2014-15 onwards, reflecting gas requirements of LNG facilities.	12 months: available 3 to 12 months: available in summer Only until 2014-15
TGP	12 months: available	Not fully contracted, ie, there is no unmet demand for year round capacity on this pipeline.	12 months: available

<sup>76</sup> Anecdotal evidence suggests shippers are willing to sell capacity. However, it is being used to deliver gas to meet peak gas-fired electricity demand at present.

The availability of capacity is also constrained by the operational limitations of the pipeline. Pipeline operators conduct maintenance on the pipeline during periods of low demand so as to not disrupt gas flows during periods of high demand. Maintenance reduces the capacity of the pipeline and so reduces available capacity. Information on maintenance requirements is not publicly available, and as a result we are unable to assess its effect on historic available capacity. It follows that, our assessment of historic available capacity represents an upper bound of the actual historic available capacity.

## **5.2. *Assessment of impediments***

Our assessment of the impediments to pipeline capacity trading involved:

- gauging from stakeholders their views on the existence and extent of impediments to trade capacity; and
- an analysis of the alignment of demand and available capacity.

This section sets out the results of our assessment of impediments.

### **5.2.1. *Stakeholders views on impediments***

Stakeholders expressed differing opinions as to the quantum of search and transaction costs associated with trading capacity.

Some stakeholders stated that search costs were extremely low, as it simply required a phone call to known shipper contacts to identify the availability of capacity. Other shippers suggested that it was difficult to identify counterparties or contacts within known counterparties to whom such enquiries could be made. They indicated that the resultant time and effort of searching was too costly, particularly to justify short term capacity trades.

In terms of transactions costs, which principally involved negotiating contractual terms, opinions also differed. Some stakeholders indicated that the cost of negotiating contractual terms were low, due to historic arrangements. Others stated they were high because the negotiation process would take months. Several stakeholders suggested that search and negotiation costs were significantly lower between parties with a trading history.

Based on these stakeholder discussions, we infer that search and transaction costs are potentially significant, but unlikely to dissuade participants from high value trades. It follows that these search and transaction costs might therefore be excessive for opportunistic, low value trades.

There was a general consensus among stakeholders that the value of trading capacity for periods greater than six months was sufficient to overcome current search and transaction costs. For this reason, we have assumed in our analysis that shippers are not impeded by transaction and search costs to trade capacity for periods greater than six months.

### 5.2.2. *Assessment of the coincidence of capacity demand and available capacity*

Further to our discussions with stakeholders, we have also investigated anecdotal evidence of demand for available capacity. In simple terms, where there is evidence of unmet demand for capacity during periods when that type of capacity is available, an impediment to trade might exist. In contrast, if there is little or no capacity demand during periods of available capacity, we cannot conclude whether there is an impediment.

A description of available capacity on each pipeline is set out in section 5.1. Limited information is available about the type of demand that shippers seek on each pipeline, and unfortunately our discussions with stakeholders have yielded few meaningful insights.

That said, there appears to be considerable demand for capacity on pipelines that are fully contracted. As would be expected, demand for capacity is greatest at the times it is most utilised. It is important to note that whilst a pipeline may exhibit low levels of utilisation for prolonged periods throughout the year, it is the demand for capacity on that pipeline at peak times that may be of greatest relevance to potential shippers—there is no quantity of capacity at off peak times that can be substituted for capacity at peak times of the year.

Our qualitative reconciliation of available capacity and demand on each pipeline reveals that:

- there is unlikely to be significant demand for most available capacity on most pipelines because the periods where capacity is available do not align with expected capacity demands; and
- where there is demand for capacity, it appears to be coincident with periods of limited availability of capacity.

In other words, we have not found any evidence to support a conclusion that there is significant un-met demand for available pipeline capacity. It follows that this qualitative assessment has had a significant influence on our estimation of the associated benefits of the policy options.

In relation to specific pipelines, we note that:

- the CGP and TGP have available capacity for periods greater than 12 months. However, these pipelines are not fully contracted and all potential shippers appear to be aware of this situation. This suggests that there is currently no significant demand for currently available capacity on these pipelines;
- the EGP, MSP and SEA currently have available capacity for periods in summer. However, our discussions with stakeholders have indicated that they have no additional demand for capacity at these times, despite the fact that many are currently seeking capacity during the winter peak periods. Unfortunately, there is limited availability of capacity during these times;
- capacity is available for periods of greater than 12 months on the MAPS. However, we understand from stakeholders that there is little demand for the currently available capacity on this pipeline; and
- there is no substantial and persistent available capacity on the QGP, despite there being evidence from stakeholders of demand for any capacity on this pipeline.

We recognise that the RBP appears currently to have available capacity, and there is also demand for that capacity. We understand that the RBP is currently fully contracted, and has historically seen very high levels of utilisation. The pipeline has also been expanded progressively since 2008. However, we understand that flows have gradually decreased since around mid-2010, in part due to reduced consumption of gas by gas-fired electricity generators located on the RBP, presumably in response to decreasing electricity demand in the National Electricity Market. This creates uncertainty about future pipeline capacity needs, should those gas-fired electricity generators be required to return to producing electricity at historic levels.

We have received comments from some stakeholders that they are interested in purchasing firm capacity on the RBP, but have been unable to do so. In our opinion, the inability to obtain capacity may indicate that while capacity may have been available within the last 2 to 3 years, there is considerable uncertainty by current capacity holders about possible capacity requirements in each subsequent year, given uncertainty about the recovery of electricity demand in Queensland.

In summary, our assessment of the coincidence of demand and available capacity has not provided any evidence to support a conclusion that there is significant un-met demand for available capacity.

### **5.3. *Benefits of policy options 2 and 3***

In this section we draw on our assessment of available capacity and the impediments to capacity trading to estimate the benefits of the alternative policy options. As we outline in our methodology, we estimate benefits in three steps, namely by:

- developing a rough estimate of the current value of capacity;
- evaluating the effect of policy options on impediments to trade; and
- valuing the benefits of any increase in pipeline capacity trade.

#### **5.3.1. *Value of gas transmission pipeline capacity***

To understand the possible value of gas transmission pipeline capacity to downstream end users of gas, we have combined data on gross value-added for major gas using industry, and data on gas consumption for the industry. This approach provides a rough estimate of the implied average value added per unit of gas use for the industry.

Table 5.2 sets out the estimates for each of the major industries we have considered. To obtain values relevant to the eastern gas market, we have apportioned the industry value added to the east coast using a weighting factor.

**Table 5.2**  
**Industry Value Add per Unit of Gas Consumption<sup>77</sup>**

Industry	Value (\$/GJ)
Electricity supply	\$55.1
Gas supply	\$1.6
Basic chemical and chemical polymer and rubber product manufacturing	\$97.4
Primary metal and metal product manufacturing	\$43.3
Petroleum and coal product manufacturing	\$39.9

Importantly, these values can be interpreted as an estimate of the additional value created by that industry due to the use of gas. In doing so, we assume that gas is a critical input to production in those industries and so the absence of gas would lead to the loss of the associated value add.

Relevantly, these values are meant to provide an indicative estimate of the value to end-users of gas, which differs from the price that they would be prepared to pay to purchase gas. It is appropriate to use the value-add when:

- there is simply a restriction to trading of available capacity, arising from either an unwillingness to trade or some other impediment that means it is impossible for otherwise willing buyers and sellers to interact; or
- when there is an inability to expand existing pipeline capacity.

However, much of the focus of Options 2 and 3 is on lowering the financial transactions costs of capacity trading. In this circumstance the value of capacity would be capped at the reduction in transactions costs achieved. Any value from gas use above this amount would therefore be assumed to be sufficiently high such that the financial transactions costs would not be sufficient to prevent the trade occurring within the status quo option.

To obtain a better understanding of possible transactions costs involved with current pipeline capacity trading, we have explored with shippers the time typically taken, and effort involved with, securing a contract to use available capacity from another shipper. The information that we received ranged from:

- a relatively low value, reflecting information that a trade can be completed in between one and two weeks, with almost full time involvement of a manager on both sides, and with some legal team involvement to finalise the associated contract; to
- a higher value, reflecting information that even short duration capacity trades required a team of two people practically full time for up to four months to identify available capacity, negotiate the terms of the agreement, and finalise the legal arrangements.

We have estimated a range of capacity trading transactions costs assuming the need for between one week, and four months of time of between one and two people for each party, based on an assumed salary of \$100,000 per annum. With associated legal costs of say, 40

<sup>77</sup> Source: Australian Bureau of Statistics, National Accounts; BREE, Australian Energy Statistics; EnergyQuest, EnergyQuarterly August 2012.

hours at \$500 an hour, the range of transactions cost likely lie between \$25,000 and \$115,000.

These transaction costs are likely to be the same irrespective of the amount of capacity involved in the transaction. We understand that a typical transaction for period between 1 months and 6 months would involve volumes of between 3 and 10 TJ/day. The resultant implied transactions costs would therefore be on average between say, \$0.02/GJ and \$0.37/GJ.

In principle, we believe that the likely value of the policy options will involve both the reduction in current transactions costs, and the additional freeing up of capacity and so increased gas use that will generate wider benefits to society. For the purposes of this study, and in the absence of any other reliable information, we have therefore used a reduction in transactions cost value for both Options 2 and 3 of \$1/GJ. This value is above the rough estimates of transactions as detailed above, and is less than current gas prices. A value of \$1/GJ is also broadly in line with current gas transmission prices, as charged by pipeline operators.

Importantly, our choice of \$1/GJ reflects our judgement of a reasonable value of the incremental use of gas capacity that might be realised during periods of current low gas demand, for the purposes of understanding a possible bound of benefits resulting from the policy options being considered. Others might legitimately have alternative opinions as to this value.

Finally, given the importance of this estimate we have also tested the sensitivity of our results to this assumption, with the results of this sensitivity analysis being set out in section 6.2.

### **5.3.2. Policy option effects on impediments**

In this section we assess the effect of the alternative policy options on potential impediments to capacity trading.

#### **5.3.2.1. Option 2: Improved information on capacity**

The key aim of Option 2 is to lower search and transactions costs involved with capacity trading, to lower the costs of doing business for all current market participants, and potentially increase the utilisation of existing capacity with associated increases in gas flows. Any increase in gas flows can be considered to lead to further downstream benefits.

An important question is therefore, to what extent is Option 2 expected to reduce current search and transaction costs?

In principal, providing additional information potentially lowers search and transactions costs by:

- allowing market participants to better align pipeline use with downstream production processes and uses, to make use of more cost effective available capacity; and
- identifying those shippers that might have available capacity.

In addition, improving information on gas pipeline flows would likely create other qualitative benefits by:

- revealing the extent to which there are impediments that are leading to lost opportunities from trade; and
- potentially facilitating ongoing market development.

The specific new information that we have assumed Option 2 makes available to participants is:

- forecast operational capacity;
- forecast contracted capacity by shipper; and
- historical flows by shipper.

While we have used this list of additional information for the purposes of our assessment, we acknowledge that further consideration would need to be given to any possible negative commercial consequences to businesses from making such information available. We expect that to implement Option 2, changes would be made to the National Gas Rules, via a rule change proposal considered by the AEMC. This would provide the forum for stakeholders to argue the merits and possible consequences of making particular information available.

In addition, Option 2 also involves: standardisation of contractual terms and conditions applying to pipeline transport, and the development of a voluntary capacity listing service to expedite and ease the transfer of contractual rights to capacity. The listing service is intended to assist in the matching of prospective buyers and sellers of capacity. In contrast, the standardised contract is intended to lower transaction costs via enabling parties to reference contractual terms and conditions of a standardised contract published by AEMO.

Based on this specification, we have assumed that Option 2 would incrementally lower search and transactions costs and so would:

- incrementally increase the trading of capacity with an available duration of between 3 and 6 months, where search and transactions costs might be currently creating an impediment; and
- have little or no effect on trading of capacity of less than three months duration, where the effort involved with bilateral contract negotiations are likely to be a more significant impediment.

#### 5.3.2.2. *Option 3: Voluntary capacity trading platform*

Option 3 encompasses Option 2, with the additional element of establishing a voluntary trading platform using common product specifications. Stakeholders have suggested that such an option could provide scope to facilitate increasing short-term capacity trades.

Based on our discussions with stakeholders, it is our opinion that for Option 3 to provide any additional benefits over Option 2, it would have to provide further reductions in negotiation costs, potentially by providing standardised products that were of use to all parties. Benefits might therefore arise from the further scope for cost reductions stemming from reduced negotiation costs.

We have therefore assumed that Option 3 would incrementally lower negotiation costs and so would incrementally increase trading of capacity of less than three months duration. These benefits would be in addition to those benefits created from implementing Option 2.

Importantly, the incremental benefits of Option 3 require the development of standardised products that are acceptable to both potential buyers and sellers of capacity. We appreciate that this might be a challenging task, given that shippers typically have specific desirable requirements for inclusion in products. This might impact on the size of the benefits that can be achieved from the standardisation of products.

Finally, to account for the challenges involved in developing standardised products we have assumed that they are implemented for an initial trial period of, say, three years. This period would be used to allow the products to be evaluated and refined over time. We have assumed that the benefits of Option 3, relative to Option 2, would therefore ramp up evenly over the three year period, until the maximum benefits of additional utilisation is achieved from year three onwards.

### 5.3.3. *Benefits of increased utilisation of pipelines*

Based on our assessment of the current impediments to available capacity trading, we have assumed that:

- Option 2 has the potential to incrementally increase trading of available capacity with a duration of between 3 and 6 months; and
- Option 3 has the potential to incrementally increase trading of available capacity with duration of both 3 and 6 months, and less than 3 months.<sup>78</sup>

We also assume that the benefits of product standardisation steadily increase to the maximum assumed annual amount by the end of the trial period in year three. These assumptions give rise to a range of potential increases in capacity trading and so utilisation of currently available capacity – the upper bound for increased capacity trading is theoretically full utilisation of *all* relevant available capacity blocks, and the lower bound is zero.

Hypothetically, if all available capacity were to be fully utilised following the implementation of the policy option, three conditions must be satisfied, namely:

- *perfect foresight*—all shippers must be able to predict their future gas flow requirements with 100 per cent accuracy. This assumption will invariably be violated, and potential benefits in the form of additional pipeline utilisation will be limited to the extent that the assumption fails to hold;
- *undiscerning demand*—prospective buyers are willing and able to purchase available capacity at a price acceptable to all existing shippers. Essentially, this assumption means that any capacity that is made available to the market as a result of the policy option is valuable to use and so traded;

<sup>78</sup> We assume that Option 2 and Option 3 do not incrementally increase trading of available capacity with a duration of between 3 to 6 months on the SWQ, QGP and RBP. Trading of such capacity is facilitated through the Wallumbilla hub under the base case.



- *full utilisation of traded capacity*—all capacity acquired as a result of the policy options is fully utilised by the purchasing shipper. However, in practice given uncertainties in actual future flow requirements, any traded capacity is unlikely to be fully used.

Our analysis does not rest upon any of these conditions. Rather, the upper bound reflects utilisation when these conditions are expected to hold. Alternatively, the benefits will diverge from the upper bound to the extent that actual outcomes differ from these theoretical ideals. In our opinion, the realities of the gas sector are far from each of these three conditions.

Perfect foresight is of course unrealistic, with shippers inevitably contracting for quantities of capacity on an ex-ante basis that exceed ex-post requirements. The need to contract on this basis arises because shippers cannot predict future requirements, either because of weather variation or other unforeseen events. In our opinion, shippers' ability to predict future changes in gas requirements over periods of between 1 and 6 months, and so predict their ability to identify potential capacity trades, is extremely limited.

The condition of undiscerning demand means that shippers are willing to purchase capacity at all times of year, regardless of the underlying demand for gas. Both our analysis and information provided by stakeholders suggest that there is minimal demand for capacity at certain times of year. It follows that demand for additional capacity at those times of year is likely to be lower or non-existent.

It is more difficult to comment on the validity of the condition of full utilisation of traded capacity. We do not know the extent to which a purchasing shipper, who prior to the trade may not have had access to capacity, and might change usage patterns of capacity once it has been acquired. Nevertheless, we would expect that given uncertainties about actual flow requirements, any traded capacity will not be fully used.

In summary, the extent to which available capacity is traded and then used following the implementation of the policy options is very uncertain. We would expect that an upper bound of all available capacity that is both traded and used, is therefore unrealistic in practice. For this reason, we have applied an arbitrary (but in our opinion reasonable) reduction to this theoretical upper bound for the purpose of calculating any potential benefits resulting from the policy options. We also consider the sensitivity of the benefits to the choice of this available capacity.

In our opinion, the policy options will only likely result in very small increases in capacity trading, given Options 2 and 3 are not significant changes to the current market framework. That said, there is also a reasonable prospect that the changes will lead to no changes in capacity trading and so the benefits will approach zero.

Foremost among the reasons that we have identified is the absence of any evidence that there is demand for currently available capacity for the durations that are available. In addition, given that the total number of potential parties interested in trading capacity is relatively small (at most 30 parties) the incremental changes facilitated via a capacity trading platform might be minimal, compared with current ad-hoc mechanisms. Moreover, the vast majority of contracted capacity, on all pipelines, is held by three players, ie, Origin Energy, AGL and EnergyAustralia.

We therefore expect that at most an additional 5 per cent of currently available capacity will be traded and used, for those durations of available capacity that we have previously

identified as being affected by the proposed policy option. We also consider how the benefits are influenced by making an assumption of 3 per cent of currently available capacity.

Table 5.3 sets out the assumed increase in traded pipeline capacity across the entire east-coast gas market.

**Table 5.3**  
**Average Potential Increase in Utilisation**

	<b>Option 2</b>	<b>Option 3</b>
	TJ/day	TJ/day
<b>0 per cent</b>	0.0	0.0
<b>3 per cent</b>	1.7	4.9
<b>5 per cent</b>	2.8	8.2

To estimate the value of the assumed increased trade and utilisation of the pipeline capacity resulting from the policy options, we:

- project over a 20 year time horizon, the implied increase in pipeline capacity use, based on the assumptions described above;
- apply a value of capacity of \$1/GJ; and
- discount the results using a 7 per cent discount rate.

Table 5.4 sets out the results for 2014. Table 5.5 and Figure 5.4 the results in present value terms over a 20 year time horizon.

**Table 5.4**  
**Summary of Benefits, 2014 – Increase in Pipeline Use**

	<b>5% increase in use (\$ million)</b>	<b>3% increase in use (\$ million)</b>	<b>0% increase in use (\$ million)</b>
Option 2: Improved information on capacity	\$1.0	\$0.6	\$0.0
Option 3: Voluntary capacity trading platform	\$2.3	\$1.0	\$0.0

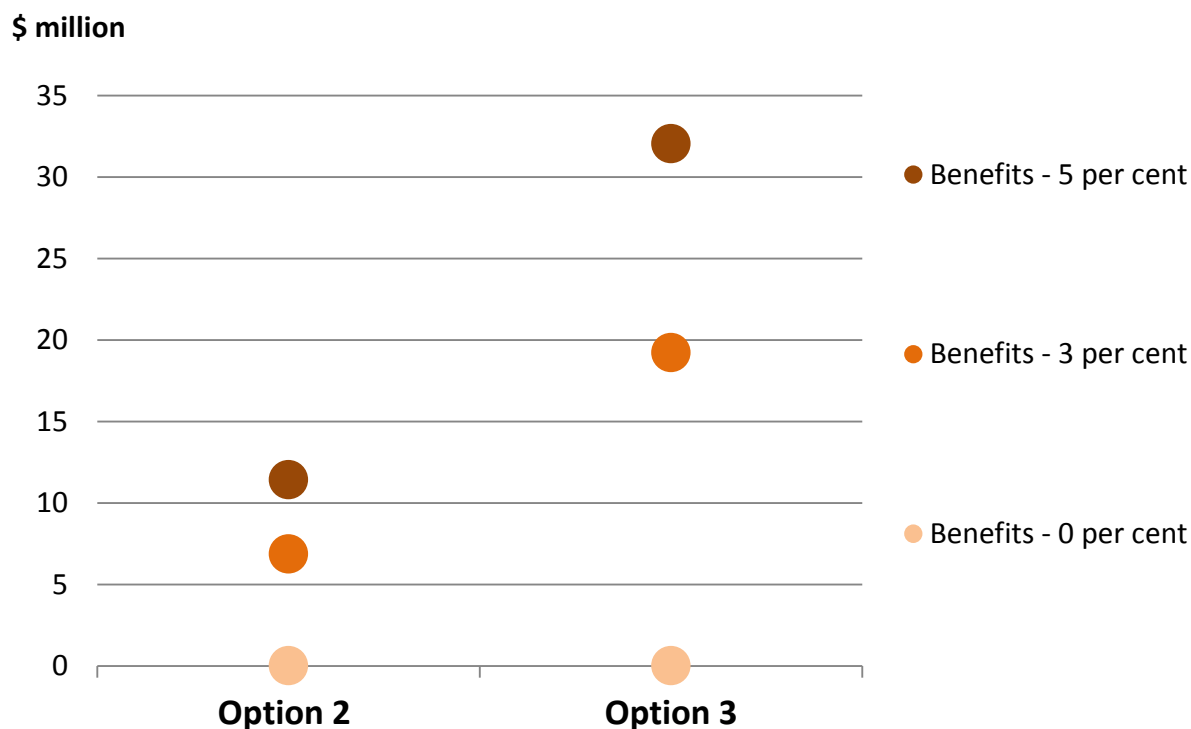
**Table 5.5**  
**Summary of Benefits, Present Value – Increase in Pipeline Use**

	<b>5% increase in use (\$ million)</b>	<b>3% increase in use (\$ million)</b>	<b>0% increase in use (\$ million)</b>
Option 2: Improved information on capacity	\$11.4	\$6.8	\$0.0
Option 3: Voluntary capacity trading platform	\$32.0	\$19.2	\$0.0

In the first instance, the quantified benefits of policy Options 2 and 3 will be distributed between the parties that trade capacity in secondary markets, ie, shippers. Where shippers on-sell gas to end users, those end users will also benefit from implementation of the policy options.

We note that there are additional benefits associated with Option 2 and Option 3. The increased provision of information will allow participants throughout the gas supply chain to make more informed decisions about their operations and investments. We expect that this will lead to additional non-quantified benefits, as the market develops into the future.

**Figure 5.4**  
**Present Value of the Benefits of Policy Options 2 and 3**



#### 5.4. *Benefits of policy option 4*

Option 4 involves the creation of a mandatory obligation for market participants with unused pipeline capacity either to:

- offer unused capacity on an ‘non-firm’, interruptible basis – an obligation which is termed ‘use-it-or-lose-it’ (Option 4A); or
- offer unused firm capacity to the market – an obligation which is termed ‘use-it-or-sell-it’ (Option 4B).

Option 4 represents the greatest change to the status quo, with the imposition of mandatory trading obligations on pipeline operators and shippers to release capacity that is deemed to be ‘unutilised’. SCER has stated in the RIS that a lack of utilisation of pipeline capacity may be an indication that:

...the current market structure may be resulting in competition failure whereby a limited number of incumbent shippers control unused capacity and are exercising market power to effectively either block the entrance of new market participants (e.g. new gas retailers) or limit the supply from producers (both existing and/or new participants) that would improve market contestability.

Option 4 does not represent an incremental change to Options 2 or Option 3, but instead is levelled at an entirely different impediment to access, ie, anti-competitive behaviour.

In light of this, we have chosen to not make a quantitative assessment of the possible benefits arising from the implementation of Option 4, for to do so would implicitly require us to

presume that there is anti-competitive behaviour, which in turn, is increasing costs in related markets. This would be highly speculative in the absence of a more detailed assessment.

We have qualitatively analysed the potential benefits of Option 4 by assessing similar policies in international markets. To do this we:

- describe the market inefficiency that the policy option is designed to mitigate;
- determine whether a similar market inefficiency exists in Australia;
- deduce the relative size of benefits that may accrue from the implementation of Option 4.

Specifically, we consider the ‘firm day-ahead use-it-or-lose-it (UIOLI)’ and ‘long-term UIOLI’ that are being implemented in the European Union (EU), which are designed to improve shippers’ access to available capacity.

#### 5.4.1. *Option 4A and the ‘firm day-ahead UIOLI’ mechanism*

The firm day-ahead UIOLI mechanism is similar to Option 4A and is scheduled to be implemented in the EU in 2016. It consists of a daily mechanism for offering non-nominated capacity back to the market on a firm basis through the restriction of re-nomination rights. Option 4A differs from the firm day-ahead UIOLI mechanism because it does not restrict shippers’ ability to re-nominate. Nevertheless, it is useful to consider the benefits that may accrue from the European mechanism so as to identify whether similar benefits might result from implementing Option 4A.

The firm day-ahead UIOLI mechanism was developed following a competition review of the energy sector found that it was ‘...difficult to secure even small volumes of short-term, interruptible capacity...’<sup>79</sup> Anecdotal evidence from participants in the EU gas market suggested that until recently pipeline operators were unwilling to facilitate shipper to shipper capacity trading. Some of these pipeline operators were vertically integrated and, it was believed, obstructed secondary trading for anticompetitive purposes.<sup>80</sup>

In the EU, the firm day-ahead UIOLI mechanism can generate two types of benefits. First, it reduces the suspected anti-competitive behaviour of pipeline operators. Second, it provides prospective shippers with a greater certainty that they will have capacity on the next day.

In Australia, pipeline operators are not vertically integrated and they do not have incentives to conduct anti-competitive behaviour. Instead, they rely on gas contracts and throughput for revenue. In our discussions with stakeholders, all of the shippers we spoke to confirmed that they had no difficulty accessing non-firm capacity from pipeline operators when the pipeline was not at full utilisation. Further, Option 4A allows shippers to re-nominate for capacity, and so pipeline operators continue to provide capacity on an ‘as available’ basis. For these reasons, we find that the benefits resulting from the implementation of Option 4A are negligible.

<sup>79</sup> European Commission, ‘DG Competition Report on Energy Sector Inquiry’, 2007, p. 8 <[http://ec.europa.eu/competition/sectors/energy/inquiry/full\\_report\\_part1.pdf](http://ec.europa.eu/competition/sectors/energy/inquiry/full_report_part1.pdf)> [accessed 31 October 2013].

<sup>80</sup> Brattle Group, ‘International Experience in Pipeline Capacity Trading’, 2013, p. 6 <[http://www.aemo.com.au/Gas/Market-Operations/Gas-Supply-Hub/~media/Files/Other/gas\\_supply\\_hub/International\\_Experience\\_In\\_Pipeline\\_Capacity\\_Trading\\_Brattle%20Group\\_August\\_2013.pdf.ashx](http://www.aemo.com.au/Gas/Market-Operations/Gas-Supply-Hub/~media/Files/Other/gas_supply_hub/International_Experience_In_Pipeline_Capacity_Trading_Brattle%20Group_August_2013.pdf.ashx)> [accessed 31 October 2013].

#### 5.4.2. *Option 4B and the ‘long-term UIOLI’ mechanism*

The long-term UIOLI mechanism is similar to Option 4B and was scheduled to be implemented in the EU in October 2013. It requires shippers who systematically underutilise their contracted capacity to surrender it back to the pipeline operator for resale to another shipper. Systematic underutilisation is specified in two ways, namely:

- where the shipper’s average deliveries are less than 80 per cent of their capacity over a 12 month period.
- where the shipper consistently nominates close to 100 per cent of their contracted capacity and then reduces their re-nomination before delivery in an attempt to evade the firm-day ahead UIOLI mechanism.

The long-term UIOLI mechanism was designed to free up contracted and unutilised capacity. However, it is difficult to identify whether this policy was implemented in response to a particular market inefficiency. To clarify, we describe instances under which shippers may be unwilling to sell capacity, and identify whether they suggest market inefficiency.

Shippers obtain value from unutilised capacity. They are unlikely to be willing to sell their capacity if the value they derive from that capacity exceeds what a prospective shipper is willing to pay for it. Possible reasons for retaining unutilised capacity include:

- to cater for unexpected increases in gas demand—where the risk of not being able to meet that demand are greater than the cost of retaining unutilised capacity;
- to broaden the gas portfolio—where the risk of a disruption of supply from an alternative supply sources is greater than the cost of retaining unutilised capacity;
- to reduce competition—where the shipper benefit from crowding out other shippers from the downstream markets is greater than the cost of retaining unutilised capacity.

There is no market inefficiency if shippers are retaining capacity to cater for unexpected increases in gas demand or to broaden their gas portfolio. In such instance, shippers are simply managing their risks to maximise expected profits. However, shippers that fail to release capacity for anti-competitive reasons are creating market inefficiency. Therefore, a policy option designed to reallocate capacity away from shippers will only generate a benefit if that capacity were retained for anti-competitive reason.

It is beyond the scope of this report to assess the existence, materiality, and potential inefficiencies arising from the exercise of market power in the gas sector, particularly on downstream gas users. Such as study would require an in-depth analysis of each shippers contracted capacity, deliveries and an understanding of their profile of gas demand.

Despite the absence of information on capacitated capacity and deliveries by shipper, we did not receive any evidence that suggested anticompetitive behaviour. 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. It follows, that in the absence of evidence of the exercise of market power by shippers, the benefits from Option 4B are likely to be minimal.

In section 4.4 we described that a mandatory trading platform could resemble the capacity listing service of Option 2 or the cleared exchange of Option 3. Under Option 2 and Option 3, shippers will trade capacity when they both obtain a net benefit from doing so. There can only be an incremental benefit generated under Option 4, relative to Option 2 or Option 3,

where it obligates shippers to sell capacity that they otherwise would have retained for anti-competitive purposes.

Assuming that shippers are not engaging in anti-competitive behaviour, the implementation of Option 4 will not result in any additional benefits. As a result, the implementation of Option 4 would not result in any incremental benefits relative to Option 2, where the platform is a capacity listing service. Similarly, Option 4 would not result in any incremental benefits relative to Option 3, where shippers are obligated to trade on a cleared-exchange.

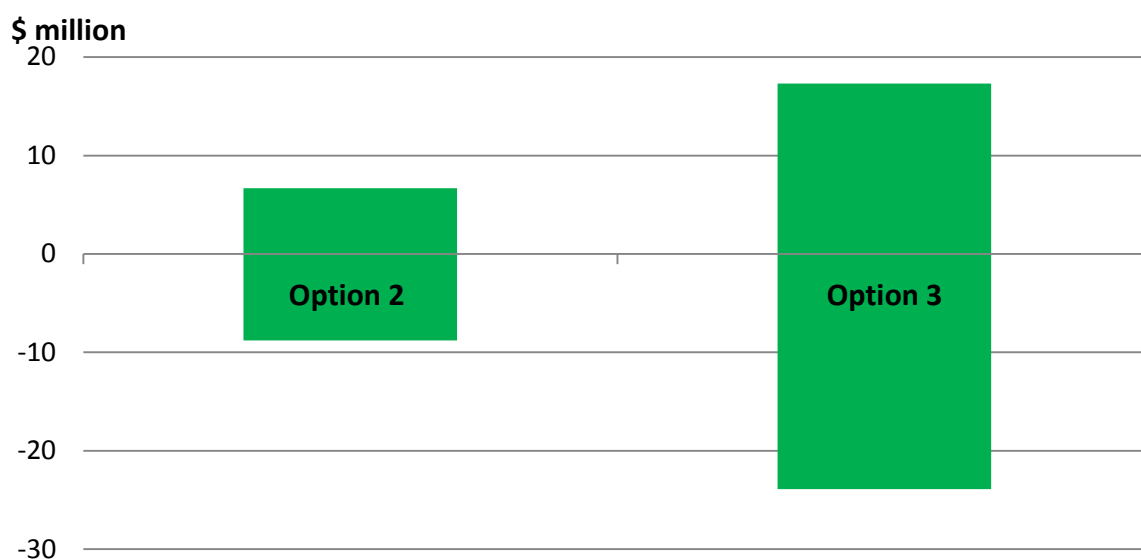
## 6. Comparison of Benefits and Costs

This chapter compares our estimates of the benefits and costs, and our associated sensitivity analysis.

### 6.1. Estimated net benefits of the policy options

Figure 6.1 and Table 6.1 summarise the results of our assessment of the benefits and costs of Option 2 and Option 3, and present the present value of the net benefits.

**Figure 6.1**  
Range of Net-Present Value of Options 2 and 3



**Table 6.1**  
Summary of Benefits and Costs – Option 2 and Option 3

	Present Value (20 years)		Annualised	
	Upper Bound	Lower Bound	Upper Bound	Lower Bound
<b>Option 2: Improved information on capacity</b>				
Benefits	\$11.4	\$0.0	\$1.1	\$0.0
Costs	\$4.7	\$8.8	\$0.4	\$0.8
Net Benefits	\$6.7	-\$8.8	\$0.6	-\$0.8
Benefit Cost Ratio	2.4	0.0	2.4	0.0
<b>Option 3: Voluntary trading platform</b>				
Benefits	\$32.0	\$0.0	\$3.0	\$0.0
Costs	\$14.7	\$23.9	\$1.4	\$2.3
Net Benefits	\$17.3	-\$23.9	\$1.6	-\$2.3
Benefit Cost Ratio	2.2	0.0	2.2	0.0

The results reflect considerable uncertainties in the:



- estimates of likely increase in pipeline capacity trade and utilisation resulting from each of the policy options; and
- estimates of the potential value associated with the reduction in transactions costs, search costs, and negotiation costs associated with trading capacity.

We therefore believe that our results should be treated as simply indicative of the potential benefits and costs of the policy options that we have been asked to consider.

That said, we believe that net-benefit estimates for Option 2 are more conservative than for Option 3. This is because:

- we would expect the provision of additional information to lead to a number of additional non-quantified benefits, as the information is used to improve operational and investment decisions across the entire gas supply chain; and
- the incremental benefits from Option 3 rely on the development of standardised capacity products that market participants are willing to trade and use. The willingness of market participants to use these products is itself uncertain at this time.

We therefore believe that there are considerable risks to the achievement of additional benefits from the development of a voluntary trading platform (ie, Option 3). These risks relate to the complexities involved in developing standardised products for voluntary trading as part of Option 3. We expect that it is conceivable that any standardised products that are acceptable to both parties, might not be sufficiently demanded so as to warrant the effort involved in developing the products.

Given the importance of developing standardised products for the realisation of benefits under Option 3, further stakeholder engagement should be undertaken to determine whether there is strong willingness by market participants to seek to identify and use standardised products. In the absence of such a willingness we would expect that any external effort to encourage the development of such products will likely be unsuccessful.

We described in section 4.4 that the costs incurred under Option 4 are likely to exceed that of Options 2 and 3. In particular, there is a considerable risk that the indirect costs resulting from the inefficient allocation of capacity and distorted investment decisions could undermine the transmission pipeline industry. We described in section 5.4 that in the absence of evidence of anti-competitive behaviour there are no incremental benefits generated as a result of Option 4, relative to Option 2 or 3—depending on the specification of the mandatory trading platform—as shippers with an incentive trade would do so under a voluntary mechanism. As a result, the net benefits of Option 4 are likely to be less than that of Option 2 or Option 3.

## **6.2. Additional pipeline utilisation and/or value required to break even**

Given the uncertainties in assumptions used to estimate the range of benefits for policy Option 2 and Option 3, we have also considered how much additional pipeline utilisation or value would need to be generated so as to justify the assumed costs associated with each option.

Table 6.2 sets out the implied increase in capacity utilisation necessary to recover the upper bound and lower bound estimates of costs. The results demonstrate that a 4 per cent increase in utilisation would need to be achieved to break even on upper bound costs. Similarly,

around a 2 per cent increase in utilisation would be required to break even on lower bound costs.

**Table 6.2**  
**Increase in utilisation required to break even**

	<b>Increase in utilisation as a per cent of potential range</b>	<b>Average increase in utilisation</b>
	Per cent	TJ/day
<b>Option 2: Improved information on capacity</b>		
Upper bound costs	3.9%	2.1
Lower bound costs	2.1%	1.1
<b>Option 3: Voluntary trading platform</b>		
Upper bound costs	3.7%	6.1
Lower bound costs	2.3%	3.8

Table 6.3 sets out the implied value of a capacity trade necessary to recover upper and lower bound costs for a given level of increased utilisation. The results illustrate that as the increase in utilisation decreases, the value of additional flow necessary to recover costs increases. An interesting inference can be drawn from these results—if the value of additional gas flow were limited to the reduction in transaction costs, a 5 per cent increase in pipeline utilisation would not be sufficient to recover to costs of the policy options.

**Table 6.3**  
**Value of a capacity trade to break even**

	<b>5% increase in use</b>	<b>3% increase in use</b>	<b>0% increase in use</b>
<b>Option 2: Improved information on capacity</b>			
Upper bound costs	\$/GJ	\$/GJ	\$/GJ
Lower bound costs	\$0.77	\$1.28	undefined
	\$0.42	\$0.69	undefined
<b>Option 3: Voluntary trading platform</b>			
Upper bound costs	\$0.75	\$1.24	undefined
Lower bound costs	\$0.46	\$0.77	undefined

### **6.3. Sensitivity analysis**

Finally, we have conducted additional analysis to determine the sensitivity of our results to:

- discount rates—3 per cent and 10 per cent; and
- the value of capacity of —\$0.50/GJ and \$1.5/GJ.

The remaining assumptions remain the same as those adopted in the body of the report.

### 6.3.1. Discount rate

The results of the discount rate sensitivities are set out in Table 6.4 and Table 6.5 below. Given that a higher proportion of the costs are incurred in early periods, relative to benefits, an increase in the discount rate decreases the present value of the net-benefits.

**Table 6.4**  
**Summary of Benefits and Costs – 3 per cent discount rate**

	Present Value (20 years)		Annualised	
	Upper Bound	Lower Bound	Upper Bound	Lower Bound
<b>Option 2: Improved information on capacity</b>				
Benefits	\$15.4	\$0.0	\$1.0	\$0.0
Costs	\$6.1	\$11.2	\$0.4	\$0.8
Net Benefits	\$9.4	-\$11.2	\$0.6	-\$0.8
Benefit Cost Ratio	2.5	0.0	2.5	0.0
<b>Option 3: Voluntary trading platform</b>				
Benefits	\$44.0	\$0.0	\$3.0	\$0.0
Costs	\$18.7	\$29.7	\$1.3	\$2.0
Net Benefits	\$25.2	-\$29.7	\$1.7	-\$2.0
Benefit Cost Ratio	2.3	0.0	2.3	0.0

**Table 6.5**  
**Summary of Benefits and Costs – 10 per cent discount rate**

	Present Value (20 years)		Annualised	
	Upper Bound	Lower Bound	Upper Bound	Lower Bound
<b>Option 2: Improved information on capacity</b>				
Benefits	\$9.4	\$0.0	\$1.1	\$0.0
Costs	\$4.1	\$7.6	\$0.5	\$0.9
Net Benefits	\$5.3	-\$7.6	\$0.6	-\$0.9
Benefit Cost Ratio	2.3	0.0	2.3	0.0
<b>Option 3: Voluntary trading platform</b>				
Benefits	\$26.2	\$0.0	\$3.1	\$0.0
Costs	\$12.7	\$21.0	\$1.5	\$2.5
Net Benefits	\$13.4	-\$21.0	\$1.6	-\$2.5
Benefit Cost Ratio	2.1	0.0	2.1	0.0

### 6.3.2. Value of capacity

To understand the sensitivity of our results to the choice of the value of capacity, we have considered alternative values of \$0.5/GJ and \$1.5/GJ.

Table 6.6 and Figure 6.2 illustrate the results of this sensitivity analysis with a value of capacity of \$0.50/GJ. Under this assumption, the net-benefits of policy options 2 and 3 are only likely to be positive if the increase in utilisation approaches 5 per cent.

**Table 6.6**  
**Summary of Benefits and Costs – \$0.50/GJ benefit of additional gas flow**

	Present Value (20 years)		Annualised	
	Upper Bound	Lower Bound	Upper Bound	Lower Bound
<b>Option 2: Improved information on capacity</b>				
Benefits	\$5.7	\$0.0	\$0.5	\$0.0
Costs	\$4.7	\$8.8	\$0.4	\$0.8
Net Benefits	\$1.0	-\$8.8	\$0.1	-\$0.8
Benefit Cost Ratio	1.2	0.0	1.2	0.0
<b>Option 3: Voluntary trading platform</b>				
Benefits	\$16.0	\$0.0	\$1.5	\$0.0
Costs	\$14.7	\$23.9	\$1.4	\$2.3
Net Benefits	\$1.3	-\$23.9	\$0.1	-\$2.3
Benefit Cost Ratio	1.1	0.0	1.1	0.0

**Figure 6.2**  
**Range of Net-Present Value of Options 2 and 3 - \$0.50/GJ value of capacity**

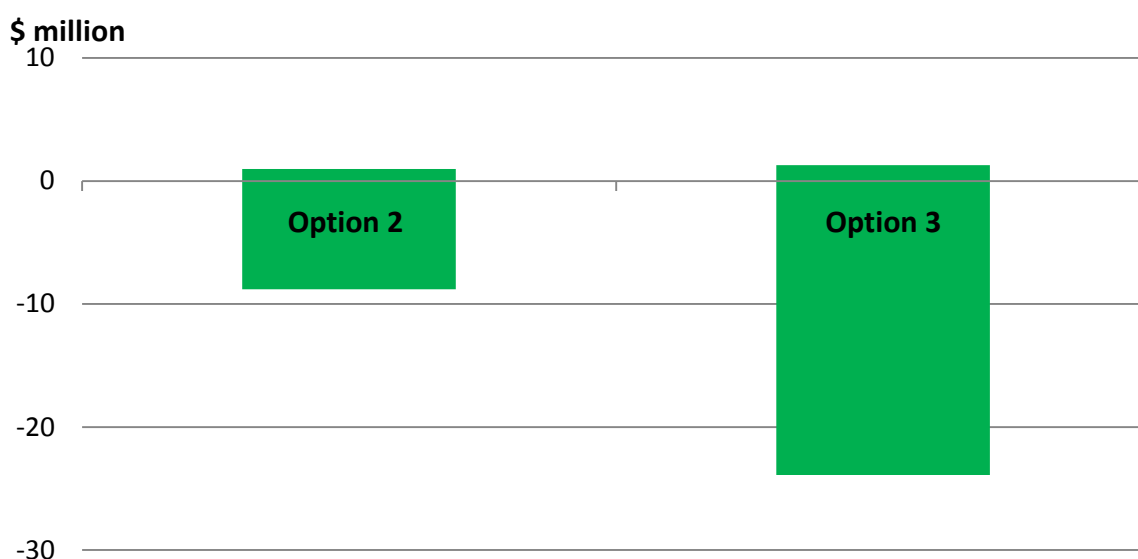
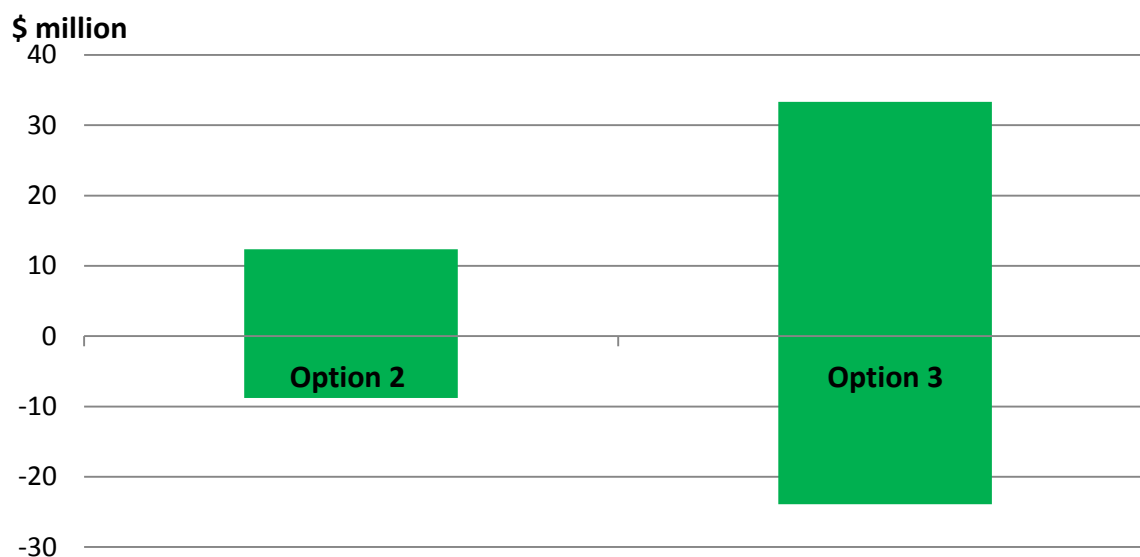


Table 6.7 and Figure 6.3 illustrate the results of this sensitivity analysis with a value of capacity of \$1.50/GJ. Under this assumption, the net-benefits of policy options 2 and 3 are likely to be positive if the increase in utilisation is greater than 2 per cent.

**Table 6.7**  
**Summary of Benefits and Costs – \$1.50/GJ value of capacity**

	Present Value (20 years)		Annualised	
	Upper Bound	Lower Bound	Upper Bound	Lower Bound
<b>Option 2: Improved information on capacity</b>				
Benefits	\$17.1	\$0.0	\$1.6	\$0.0
Costs	\$4.7	\$8.8	\$0.4	\$0.8
Net Benefits	\$12.4	-\$8.8	\$1.2	-\$0.8
Benefit Cost Ratio	3.6	0.0	3.6	0.0
<b>Option 3: Voluntary trading platform</b>				
Benefits	\$48.1	\$0.0	\$4.5	\$0.0
Costs	\$14.7	\$23.9	\$1.4	\$2.3
Net Benefits	\$33.3	-\$23.9	\$3.1	-\$2.3
Benefit Cost Ratio	3.3	0.0	3.3	0.0

**Figure 6.3**  
**Range of Net-Present Value of Options 2 and 3 - \$1.50/GJ value of capacity**



The figures in this sensitivity analysis demonstrate that the assumed value of capacity is critical to the range of resulting benefits, and so, net-benefits.

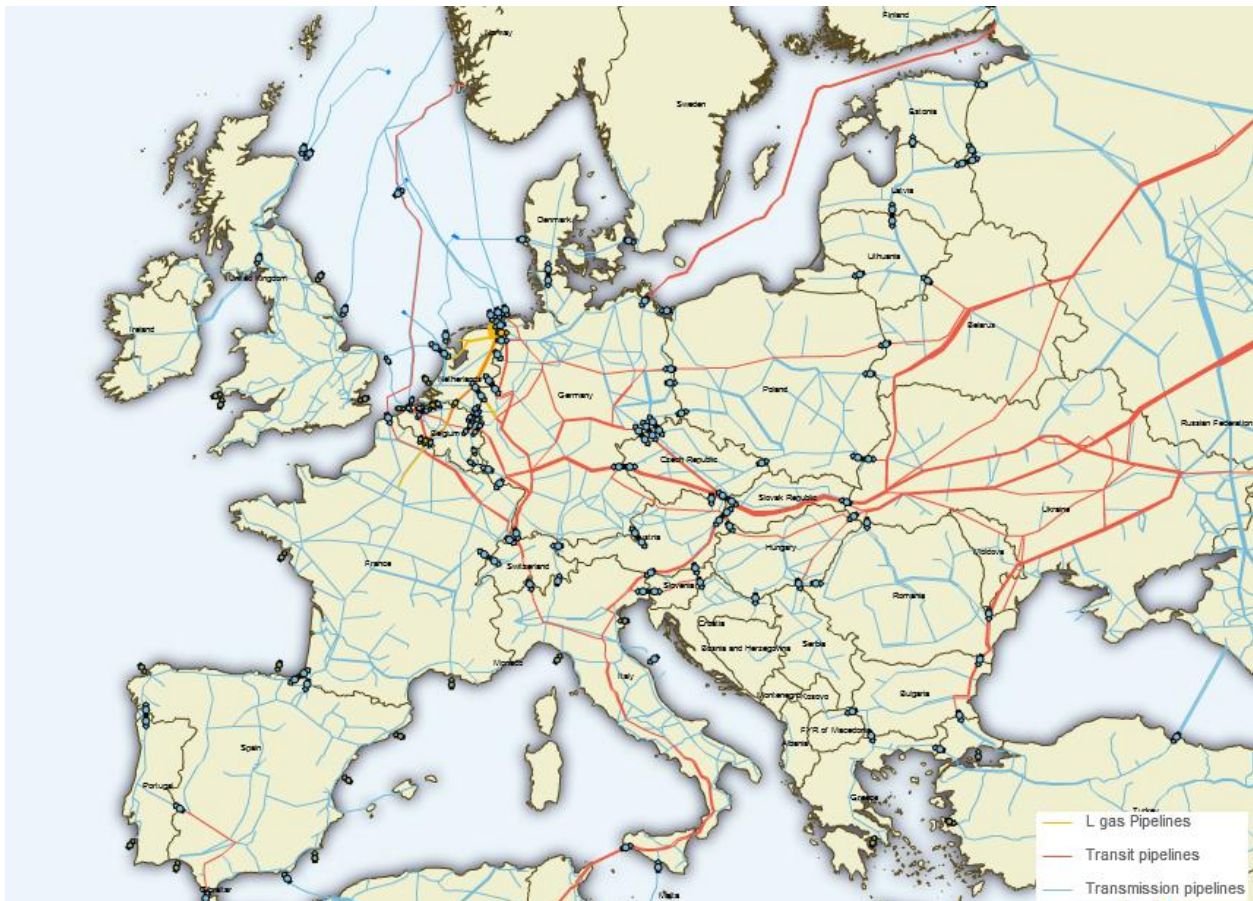
## Appendix A. International capacity markets and policies

In this section we describe the contractual and regulatory frameworks that underpin the gas transmission pipeline capacity markets operating in the European Union and the United States.

### A.1. European Union

Over 200,000 km of gas transmission pipeline extends across the European Union in a complex network. Many pipeline operators are in direct competition with each other to supply gas transport services between the same demand and supply centres. Figure A.1 illustrates the network of gas transmission pipelines operating in Europe.

**Figure A.1**  
**European Pipeline Network**



Source: International Energy Agency

Historically, pipeline operators were vertically integrated with gas supply affiliates and capacity was bundled with gas and purchased under long term capacity and supply contracts.<sup>81</sup> In 2007, a European Commission inquiry into competition in the energy sector

<sup>81</sup> Brattle Group, 'International Experience in Pipeline Capacity Trading', 2013, p. 6  
<<http://www.aemo.com.au/Gas/Market-Operations/Gas-Supply->

found that pipeline operators could suppress gas competition by withholding pipeline capacity. In response, the European Commission imposed requirements to separate pipeline operators from gas supply affiliates.<sup>82</sup> With the separation of these functions, many traditional contracts were decoupled into separate commodity and capacity contracts.<sup>83</sup>

In 2009, as part of the Third Energy Package<sup>84</sup>, the European Commission adopted an entry/exit model for capacity trading. Under this model, shippers contract for capacity at the pipeline entry and exit point independently. As a result, the gas does not follow a defined contractual path. The model also includes a virtual trading point, which facilitates trades of gas that are untied to specific locations. This model allows shippers to trade gas with a wide range of contracted entry and exit combinations.

Since the adoption of the entry-exit model by the European Commission in 2009, each EU member country is now responsible for adapting and integrating transmission contracts into the new model.

Despite having alleviated anti-competitive behaviour, by unbundling network services from gas supply services, the European Commission remained concerned that that underutilisation on fully contracted pipelines represented a market failure, which it termed ‘contractual congestion’. It revised the gas regulations to provide for the development of network codes to free up unused capacity at interconnection points between EU member states.<sup>85</sup> Two of the key network codes included the Congestion Management Procedures (CMP) and the Capacity Allocation Mechanism (CAM).

The CMPs are designed to reduce contractual congestion on Europe’s gas transmission pipelines. The impacts of the CMP were assessed<sup>86</sup> before they were adopted in 2012. The CMP consist of four mechanisms, namely:

- firm day-ahead use-it-or-lose-it (UIOLI)—implemented from July 2016;
- long-term UIOLI—implemented from October 2013;
- oversubscription and buy-back—implemented from October 2013; and
- surrender of contracted capacity—implemented from October 2013.

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Hub/~//media/Files/Other/gas\_supply\_hub/International\_Experience\_In\_Pipeline\_Capacity\_Trading\_Bratte%20Group\_August\_2013.pdf.ashx> [accessed 31 October 2013].

<sup>82</sup> European Commission, ‘DG Competition Report on Energy Sector Inquiry’, 2007 <[http://ec.europa.eu/competition/sectors/energy/inquiry/full\\_report\\_part1.pdf](http://ec.europa.eu/competition/sectors/energy/inquiry/full_report_part1.pdf)> [accessed 31 October 2013].

<sup>83</sup> DNV KEMA Energy & Sustainability, ‘Study on Entry-Exit Regimes in Gas’, 2013, p. 32 <[http://ec.europa.eu/energy/gas\\_electricity/studies/doc/gas/201307-entry-exit-regimes-in-gas-part1.pdf](http://ec.europa.eu/energy/gas_electricity/studies/doc/gas/201307-entry-exit-regimes-in-gas-part1.pdf)> [accessed 5 November 2013].

<sup>84</sup> The Third Energy Package is a set of five legislative texts comprising the following two Directives and three Regulations of 13 July 2009: Directive 2009/73/EC concerning common rules for the internal market in natural gas; Regulation (EC) No 715/2009 on conditions for access to the natural gas transmission networks; Directive 2009/72/EC concerning common rules for the internal market in electricity; Regulation (EC) No 714/2009 on conditions for access to the network for cross-border exchanges in electricity; and Regulation (EC) No 713/2009 establishing an Agency for the Cooperation of Energy Regulators. <http://eur-lex.europa.eu/JOHtml.do?uri=OJ:L:2009:211:SOM:EN:HTML>

<sup>85</sup> CER, ‘Impact of EU Network Codes on the Gas Market’, 2013 <<http://www.cer.ie/GetAttachment.aspx?id=1573ebc8-aaac-49f5-80ef-5ae684b379a3>> [accessed 7 November 2013].

<sup>86</sup> European Commission, *Commission Staff Working Paper - Impact Assessment: Commission Proposal for Guidelines on Congestion Management Procedures in the Event of Contractual Congestion Replacing Chapter 2.2 and Amending Chapter 3 of Annex I to Regulation (EC) No 715/2009 of the European Parliament and of the Council on Conditions for Access to the Natural Gas Transmission Networks* (Brussels, 2011).

The firm day-ahead UIOLI mechanism restricts shipper's rights to re-nominate, thereby allowing pipeline operators to sell firm day-ahead capacity. The long-term UIOLI mechanism obligates shippers to surrender capacity to pipeline operators where defined criteria of systematic underutilisation are met. The oversubscription and buyback mechanism incentivises pipeline operators to over sell capacity and buy it back in circumstances where demand for throughput is more than the technical capacity. The surrender of contracted capacity mechanism requires pipeline operators to accept and resell firm capacity voluntarily surrendered by their shippers. The original shipper retains its rights and obligations until the surrendered capacity is resold.

In addition, the CMP includes transparency obligations, under which pipeline operators are required to publish the information on European Network of Transmission System Operators for Gas (ENTSO-G) Transparency Platform, namely:

- instances of unsuccessful requests for firm capacity of duration one month or more;
- instances where firm capacity of duration one month or more has cleared at a price higher than the reserve price;
- instances where no firm capacity of duration one month or more was made available by a pipeline operator; and
- the amount of capacity made available to the market as a result of the application of the CMP.<sup>87</sup>

Our discussion with European stakeholders suggests that some countries are exempt from some of the mechanisms under the CMP, although the extent to which such exemptions exist is unclear.

The CAMs set out the rules and principles that govern how capacity is sold at interconnection points between EU member states. Its key features include the standardisation of capacity products, rules of capacity auctions and the bundling of entry and exit capacity. EU member countries will be bound by CAMs from 2015.<sup>88</sup> In the meantime, several platforms presently implement the mechanisms and facilitate the capacity trades. These platforms develop standardised and bundled capacity products traded under auction mechanisms, which are settled on a bilateral basis.

The European Commission plans to facilitate the creation of an integrated well-functioning capacity market by connecting entry-exit zones and eventually establishing a single integrated EU-wide platform.

## **A.2. United States**

The United States (US) gas transmission network consists of more than 100 pipelines that are highly integrated. The network is designed to deliver natural gas to demand centres from gas basins in the country's southwest, Canada and the Rock Mountains region. In many cases multiple pipeline operators provide competing services to transport gas between the same supply centres and demand centres.

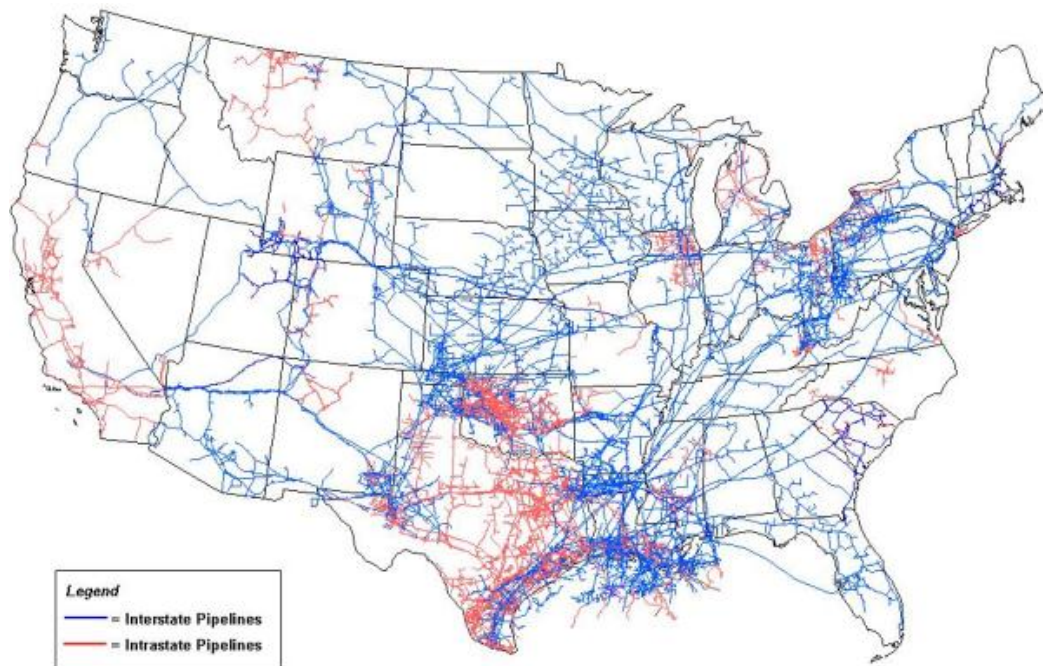
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<sup>87</sup> CER, 'Impact of EU Network Codes on the Gas Market', 2013 <<http://www.cer.ie/GetAttachment.aspx?id=1573ebc8-aaac-49f5-80ef-5ae684b379a3>> [accessed 7 November 2013].

<sup>88</sup> CER, 'Impact of EU Network Codes on the Gas Market', 2013 <<http://www.cer.ie/GetAttachment.aspx?id=1573ebc8-aaac-49f5-80ef-5ae684b379a3>> [accessed 7 November 2013].



**Figure A.2**  
**United States Pipeline Network**



Source: Energy Information Administration<sup>89</sup>

Gas transmission pipeline capacity in the US is traded under a point-to-point model that is similar to the model used in most of Australia’s eastern gas market.<sup>90</sup> As in the eastern gas market, pipeline operators in the US underwrite the construction and expansion of pipelines by long term capacity contracts. Contracts that underpin pipeline construction or expansion are often for terms greater than 15 years. Contracts for existing pipelines tend to be significantly shorter.

Capacity contracts in the US are not highly bespoke. Each pipeline operator has its own open access tariff.<sup>91</sup> The tariffs specified by pipeline operators are somewhat generic. They follow the same broad structure and include similar fundamental terms and conditions. Not only are the tariffs available on the FERC website, all capacity contracts between pipeline operators and shippers.

The Federal Energy Regulatory Commission (FERC) regulates interstate pipelines. It determines the method for calculating rates, sets rules for business practices, and authorises pipeline construction and operation.

Over the last 30 years FERC implemented regulations designed to increase the transparency, competition and efficiency of capacity markets. The most significant of these policies was Order No. 636, which FERC adopted in 1993. Overall, these policies:

- unbundled gas transport services from gas supply services;
- allowed shippers to release capacity back to the pipeline operators for resale to others; and

<sup>89</sup> EIA, ‘Natural Gas Pipeline Network - U.S.’ <[http://www.eia.gov/pub/oil\\_gas/natural\\_gas/analysis\\_publications/ngpipeline/ngpipelines\\_map.html](http://www.eia.gov/pub/oil_gas/natural_gas/analysis_publications/ngpipeline/ngpipelines_map.html)> [accessed 5 November 2013].

<sup>90</sup> Excluding the VTS.

<sup>91</sup> ‘Tariff’ describes an access arrangement, which includes the terms and conditions under which the pipeline is made available to third parties. All tariffs are available on the FERC website.

- required that pipeline operators operate an ‘electronic bulletin board’ (EBB) for their pipelines.

Capacity released by shippers must be posted by pipeline operators on their applicable EBB for bidding by other market participants. However, there are exceptions to the mandatory use of the EBB for bidding. Under certain kinds of pre-arranged trades between a releasing shipper and a replacement shipper, the trade can occur bilaterally, but the details of the transaction must be posted on the EBB. Most secondary trades that occur in the US are bilateral.

In addition, pipeline operators are required to publish all capacity release transactions and operational data, including designed capacities, available capacities, historical flow data at all receipt and delivery points, and planned and actual outage data. Combined, these policies facilitate transparent secondary trading of pipeline capacity.

FERC is not currently implementing additional regulation directly applicable to capacity trading. Overall, the US capacity market is generally thought to be transparent, competitive and efficient.

## Appendix B. Description of the Policy Options

The purpose of this section is to describe the Standing Council on Energy and Resources' (SCER's) alternative policy options to enable the identification and quantification of the costs and benefits arising from those options. We have developed the descriptions of these policy options in consultation with SCER officials.

### B.1. Base case / option 1: status quo

For the purposes of this study, we will calculate the incremental net benefits of each of the alternative policy options to a base case over the modelling period to 2032. The base case represents a possible future evolution of the gas sector, and specifically the gas transmission sector. That said, there are difficulties in making long-term projections (namely 20 years). In practice the base case should take account of known market developments, but otherwise represents a continuation of the historic evolution of the market. If necessary, sensitivity analysis can be used to understand how alternative characterisations of the base case might influence the overall results.

In the draft Regulation Impact Statement (RIS), SCER identifies the base case as the 'status quo' and described it as the 'no change' option, where market participants who hold contracted, but unused pipeline capacities are not obligated to offer capacity to the market. In the base case, market participants can choose to sell unused capacity by pursuing bilateral capacity arrangements.

For the purposes of our analysis, the base case represents market outcomes in the absence of any relevant policy intervention. In general, the market parameters of the base case are consistent with the Australian Energy Market Operator's (AEMO's) Gas Statement of Opportunities 2012 (GSOO) planning scenario with a 1-in-20 peak demand condition. The following sections set out the central assumptions underpinning the base case and, where necessary, describe where our characterisation of the market differs from that described in the GSOO.

#### B.1.1. Regulation

The National Gas Rules (NGR) govern the way gas is produced, traded and consumed. We assume that the present version (18) of the National Gas Rules does not change in a material way under the base case with a single exception – we assume amendments are made to reflect the establishment of the Wallumbilla Gas Supply Hub.<sup>92</sup>

In December 2012 SCER agreed to proceed with the development of a gas trading exchange at Wallumbilla. AEMO is currently leading the development of the hub, which is expected to come online in a trial form in early 2014. In the base case we have assumed that the hub is completed as scheduled.

#### B.1.2. Gas market arrangements

This section describes the principal assumptions surrounding wholesale market arrangements for the purchase and sale of gas and gas transmission capacity.

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<sup>92</sup> We understand that AEMO is presently proposing two changes to the National Gas Rules. First, to extend the current three day capacity outlook for gas facilities, including pipelines, from three to seven days. Second, to introduce a medium term capacity outlook for gas facilities. For the purposes of our analysis, we do not include these as part of the base case.

#### B.1.2.1. *Long term gas and transport contracts*

Gas in the eastern gas market is predominantly sold under long term bilateral contracts, generally referred to as GSAs. Similarly, gas transport services are predominantly sold through GTAs.

We assume that the existing market arrangements for the sale of gas and pipeline capacity remain in place, and that contracts are renewed on similar terms.

#### B.1.2.2. *Short term gas and capacity markets*

There are presently two gas spot markets in operation in eastern Australia, namely:

- the Victorian Declared Wholesale Gas Market (DWGM); and
- the Short Term Trading Market (STTM), which comprises three hubs:
  - the Sydney hub;
  - the Adelaide hub; and
  - the Brisbane hub.

In addition, the Wallumbilla supply hub is scheduled to come online from early 2014.

Short term gas pipeline capacity is also traded bilaterally on the secondary market. However, there is currently very limited information on the extent to which secondary trading occurs.

Given that pipeline capacity trading is the focus of this cost benefit analysis, the establishment of a framework surrounding current levels of secondary capacity trading is highly relevant. We explore this in our methodology.

Finally, we are aware that APA Group is exploring the possibility of creating a capacity trading mechanisms that would be managed by pipeline operators. While the precise form of such a mechanism is not clear at this time, we expect that it could be an alternative to the AEMO platform proposed under policy option 3. We have, therefore, assumed that any industry led mechanism is not developed as part of the status quo.

#### B.1.2.3. *Demand for gas*

The demand for gas transport services is primarily driven by the demand for gas. The type of transport service preferred by a buyer depends on the end use of the gas. For example, large industrial customers often prefer to consume gas at a roughly constant rate year round and so do not require highly flexible transport services. On the other hand, gas-fired power generators that provide peak generation typically require flexible gas transport services that allow them to increase gas flows during periods of high electricity demand.

In the base case we assume that gas demand – on both a sector-by-sector and region-by-region basis – increases in line with the GSOO projections.<sup>93</sup> Our assumptions for gas demand are therefore defined for five regions – being New South Wales<sup>94</sup>, Victoria, Queensland, Tasmania and South Australia – and for three sectors, namely:

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<sup>93</sup> GSOO adopt a carbon price assumption consistent with the Australian Treasury's core policy scenario (see *Strong Growth, Low Pollution: Modelling a Carbon Price*, 2011). In light of developments in Australian government policy and international carbon markets, prospect of a carbon price path consistent with Australian Treasury's modelling is unlikely. Nevertheless, we do not anticipate that our results will be sensitive to the carbon price.

<sup>94</sup> The Australian Capital Territory is included in the New South Wales region.

- the mass market and large industry consumers;
- gas-fired power generation; and
- gas demand from liquefied natural gas (LNG) terminals.

#### B.1.2.4. *Reserves and processing capacity*

The quantity of non-firm to the gas market depends on:

- the availability of reserves;
- the rate of development of those reserves; and
- the capacity of processing facilities.

In terms of adequacy of existing processing capacity, the GSOO states that existing gas processing facility capacity is 3,778 TJ per day. AEMO's analysis in the GSOO does not imply that there will be a supply shortfall due to processing constraints over the model's 20-year time horizon to 2032.

AEMO has acknowledged the depletion of identified 2P reserves in a number of basins including the Gippsland, Otway and Cooper-Eromanga Basins over the GSOO modelling period. However, AEMO's analysis in the GSOO has assumed that reserves will be developed in a timely manner to satisfy both projected LNG and domestic demand.

#### B.1.2.5. *Gas storage*

Gas storage facilities are used to manage load and supply security. Gas withdrawn from storage facilities close to demand centres can be used as a substitute for gas transmission capacity at peak times. There is presently around 150 PJ of gas storage available in the eastern market and AEMO has identified several expansion and construction projects that are committed or proposed.

Proposed projects are considerably less certain to proceed than committed projects. We have therefore assumed that storage is available from existing facilities and incremental increases following the scheduled completion of committed projects – Table B.1.

**Table B.1**  
**Storage Facilities**

<b>Facility</b>	<b>Status</b>	<b>Withdrawal Capacity (TJ/day)</b>
Ballera Underground Storage	Existing	na
Iona Underground Gas Storage	Existing	500
LNG Storage Dandenong	Existing	237
Moomba Underground Gas Storage	Existing	na
Newstead Underground Storage	Existing	8
Roma Underground Storage	Existing	na
Silver Springs Gas Storage	Existing	30
LNG Newcastle	Committed	120

#### B.1.2.6. *Price*

Gas prices in the eastern gas market are expected to increase over the medium term as LNG facilities link the domestic market to the higher priced international market. We adopt gas price assumptions consistent with those set out by the AEMO in the GSOO. AEMO projects a range for gas prices over this outlook period of \$4.71-12.38/GJ.

#### B.1.3. *Gas transmission*

##### B.1.3.1. *Pipeline capacity*

Figure B.1 presents the existing network of gas transmission infrastructure in the eastern gas market. For the base case we assume that the capacity of each pipeline is consistent with that published in the GSOO.

Several projects to increase the capacity of existing pipelines and to construct new pipelines are presently underway or in an advanced stage of planning. AEMO has used Core Energy's analysis of pipeline capacity as an input assumption into the GSOO. Core Energy's analysis identified existing, committed and proposed pipeline expansions and construction.

Given the uncertain nature of the development of proposed pipeline projects, we assume that only committed projects occur under the base case, as set out in Table B.2.

**Figure B.1 and Table B.2**  
**Existing Pipelines and Committed Pipeline Projects**



Project	Type	Date	New capacity (TJ/day)
APLNG Pipeline	Construction	2015	1250
GLNG Pipeline	Construction	2015	630 - 2100
QCLNG Pipeline	Construction	2014	1410
Moomba to Sydney Pipeline	Expansion	2013	90
NSW - Victoria Interconnect	Expansion	2015	42
Roma- Brisbane Pipeline	Expansion	2012	22
South West Queensland Pipeline	Expansion	na	52

We have included in Table 1.2 the NSW-Victoria Interconnect expansion that was not included in the 2012 GSOO. In September 2013, APA Group announced a new GTA with Origin Energy for the delivery of gas from Victoria to New South Wales. The GTA underpins APA’s decision to expand the NSW-Victoria Interconnect by 59 per cent by 2015. For the base case we assume that this project will also be completed as scheduled.

Under the planning scenario, the GSOO identified that projected demand exceeds the capacity of pipelines to supply gas in several demand centres in Queensland over the outlook period, including:

- Gladstone from 2013;
- Brisbane from 2018-2020; and
- Townsville from 2021.

For the base case we assume that pipeline operators undertake investment to expand the capacity of these pipelines to ensure system adequacy.

**B.1.3.2. Flow**

Both the average flow and the maximum flow on the pipeline affect the extent to which transmission capacity is traded. The profile of flows is a function of the quantity and composition of gas demand along the pipeline. Under the base case, we assume that the pipeline flow reflects historic patterns and projected changes in the composition and quality of demand as derived from the GSOO. Our methodology will describe this approach in greater detail.

### B.1.3.3. Tariffs

Tariffs charged by pipeline operators are generally split into a capacity charge and a commodity charge. The capacity charge is paid by a shipper regardless of whether the contracted capacity is used. The commodity charge is paid for each unit of gas transported. We will adopt tariff assumptions based on published tariffs for pipeline transport (where available) and assume they remain constant in real terms. For covered pipelines we assume that the tariffs published are in accordance with the relevant access regime. For uncovered pipelines, we assume pipeline tariffs are in line with those derived by Core Energy for the preparation of the GSOO –Table B.3.

**Table B.3**  
**Assumed Pipeline Tariffs – Base Case<sup>95</sup>**

Pipeline	Capacity (TJ / d)	Length (km)	Capacity Charge (AUD / GJ)	Commodity Charge (AUD / GJ)	Indicative Tariff (AUD / GJ)
Carpentaria Gas Pipeline	108	840	*	\$1.44	\$1.44
Eastern Gas Pipeline					
Firm	268	797	*	\$1.16	\$1.16
Non-Firm	268	797		\$1.51	
Longford to Melbourne Gas Pipeline	1030	174	*	*	\$0.24
Moomba to Adelaide Pipeline System	253	1185	\$0.51	\$0.14	\$0.65
Moomba to Sydney Pipeline System	439	1300	\$0.83	\$0.05	\$0.88
Queensland Gas Pipeline			*		
Firm	142	627	*	\$0.90	\$0.90
Non-Firm	142	627		\$1.61	
Roma - Brisbane Pipeline	219	438	\$0.47	\$0.03	\$0.51
South East Australia Gas Pipeline	314	680	*	*	\$0.73
South West Pipeline	353	150	*	*	\$0.27
South West Queensland Pipeline	385	937	*	*	\$0.96
Tasmania Gas Pipeline	129	734	*	*	\$2.00

Where the split between the capacity charge and the commodity charge is not stipulated, we assume that the capacity charge accounts for 80 per cent of the indicative tariff and the commodity charge accounts for the remaining 20 per cent. Based on our experience, we consider that this represents a reasonable assumption that is consistent with GTAs for major pipelines around Australia.<sup>96</sup>

The committed pipeline projects that supply LNG facilities are not included in Table B.3. We assume that the tariffs for these pipelines are derived based on a building block approach using upfront capital costs and an estimate of operating and maintenance costs.

<sup>95</sup> We note that this table includes both covered and uncovered pipelines. We will use Core Energy's tariffs only for uncovered pipelines.

<sup>96</sup> DBP, *Standard Shipper Contract - Full Haul T1, Dampier to Bunbury Natural Gas Pipeline*, January 2013 <[http://www.dbp.net.au/Libraries/Customer\\_Access\\_and\\_Information/Precedent\\_T1\\_Shipper\\_Contract\\_January\\_2013.pdf](http://www.dbp.net.au/Libraries/Customer_Access_and_Information/Precedent_T1_Shipper_Contract_January_2013.pdf)> [accessed 3 October 2013].



#### **B.1.4. Discount rate**

To assess the economic value to the current population of future net benefits we adopt a discount rate that represents a reasonable commercial rate of return. In line with the Best Practice Guidelines, we use a real discount rate of 7 per cent, and consider the sensitivity of the results to a discount rate of 5 per cent and 9 per cent.

#### **B.2. Option 2: Information provision**

The second option involves three components, namely:

- improvements to the presentation and capability of existing National Gas Bulletin Board (NGBB) data and facilities to enhance the useability of the information to market participants, including an improved voluntary capacity listing service;
- the publishing of rolling data concerning unused pipeline capacity on the NGBB; and
- standardisation of contractual terms and conditions applying to pipeline transport, and the development of business tools and processes to expedite and ease the transfer of contractual rights to capacity.

Under the existing National Gas Rules, pipeline operators, storage providers and production facility operators are required to provide information to AEMO for publication on the NGBB. Pipeline operators are already required to provide:

- nameplate capacity;
- forecast available capacity for the following three days;
- forecast linepack/capacity adequacy for the following three days;
- actual and forecast aggregated delivery nominations, if forecasts have been provided by shippers;
- actual and scheduled aggregated injections less aggregate scheduled withdrawals; and
- actual deliveries of gas on the pipeline

Further, the NGBB currently has a facility to allow pipeliners to notify that they have spare capacity available for purchase. We envisage that under this option, improvements would be made to the presentation and capability of the NGBB to enhance the usability of this notification system. It would become a voluntary capacity listing service that allows both shippers and pipeliners to notify each other of their interest in buying or selling capacity and include the contact details of the interested parties. We envisage that under this option, improvements would be made to the presentation and capability of the NGBB to enhance the usability of information presently provided to AEMO to increase the visibility of the notification facility.

In addition to improving the NGBB, we envisage that option two would be characterised by an increase in informational requirements of pipeline operators. For the purposes of this analysis, we have assumed that the National Gas Rules are amended to place additional obligations on pipeline operators and AEMO. Specifically, pipeliner operators would be required to collate and provide additional information to AEMO, who would be required to publish it. We envisage that the data and information services would also be published on the NGBB. Further, we expect that the AER will have powers of enforcement of the new rules to ensure timely, accurate and complete information is available to market participants.

We envisage that in addition to existing requirements, pipeline operators would be required to collate and publish:

- a 365 day outlook of operational pipeline capacity, including the implications of any operational flow orders, maintenance and ancillary services, updated once monthly;
- day-after and a 365 day outlook of contracted firm capacity by shipper, including secondary capacity trades;
- day-after and a 365 day outlook of contracted ‘non-firm’ capacity by shipper, including secondary capacity trades; and
- day after hourly gas deliveries by shipper type. Shipper types would include industrial, retail and electricity generation customers.

From this information it is possible to derive historical, day-after and expected levels of:

- utilised and unutilised firm capacity by shipper;
- uncontracted firm capacity; and
- uncontracted ‘non-firm’ capacity.

To ensure that pipeline operators provide accurate information to the NGBB, shippers would be required to notify the pipeline operators of secondary trading of capacity.

Under this option, AEMO would also work with pipeline operators and shippers to create a publicly available standardised capacity trade agreement for firm capacity. The contract would describe the transfer of rights and obligations from the existing shipper to the prospective shipper. Settlement between buyers and sellers could occur bilaterally under the standardised shipping contract, or a contract more tailored to the needs of the parties.

We envisage that a standardised capacity trade agreement would resemble that drafted by AEMO for the Wallumbilla gas supply hub.<sup>97</sup>

### **B.3. Option 3: Voluntary capacity trading platform**

Option 3 involves the establishment of a pipeline capacity trading platform, to allow market participants to voluntarily offer unused capacity for sale to other market participants.

This option would be incremental to option 2, with the trading platform being developed and operated by the AEMO, similar to the platforms developed by AEMO for the STTM and the DWGM.

In addition to providing a matching service, the trading platform would be a cleared exchange and facilitate the trading of standardised products between pipeline operators, existing shippers, and prospective shippers. The standardised products would reflect standardised terms and conditions and standardised units and duration, eg, increments of 1 TJ/day for a month. These standardised products would be developed in consultation with market participants to ensure that they are suitable instruments for trade and reflect the needs of potential traders. However, the platform would not be the only option available for trade. Pipeline operators and shippers would continue to be allowed to enter into tailored bilateral agreements for capacity. Similarly, in a secondary market, shippers would be able to enter into bilateral agreements outside of the platform with each other.

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<sup>97</sup> AEMO, ‘Capacity Trade Agreement (Capacity Service) Draft Version 1.0’, 2013.

#### **B.4. Option 4: Mandatory trading obligations**

The final policy option involves the creation of a mandatory obligation for market participants with unused pipeline capacity either to:

- offer unused capacity on an ‘non-firm’, interruptible basis – an obligation which is termed ‘use-it-or-lose-it’ (Option 4A); or
- offer unused firm capacity to the market – an obligation which is termed ‘use-it-or-sell-it’ (Option 4B).

##### **B.4.1. Option 4A: Use-it-or-lose-it**

Under the use-it-or-lose-it scheme, pipeline operators would be obliged to offer ‘non-firm’ capacity via a transparent trading platform if the existing shippers do not nominate use of their full contracted Maximum Daily Quantity (MDQ). For our analysis we assume this would centre around the following principles:

- On a given gas day, the quantity of ‘non-firm’ capacity a pipeliner would be required to offer would be equal to the sum of each shipper’s MDQ minus nominations.
- The initial nominations of the existing shippers for a gas day occur in advance of the commencement of a gas day, and pipeline operators would use those initial nominations to derive initial offers of ‘non-firm’ capacity for the following gas day.<sup>98</sup>
- Prospective shippers would be able to bid for a proportion of any ‘non-firm’ capacity available on the following day.
- Existing shippers would retain the right to revise their nominations up to and throughout a gas day, and so pipeline operators would adjust ‘non-firm’ quantities on that basis.
- Pipeline operators would not be required to sell ‘non-firm’ capacity at a price less than their estimated marginal cost.
- Pipeline operators would be required to sell capacity to the highest bidder.
- Proceeds from the sale would be assigned to the pipeline operator.
- Pipeline operators and prospective shippers would settle their accounts following each gas day based on:
  - actual flows;
  - the price outcome of the bidding process; and
  - any additional charges including deviation charges.

##### **B.4.2. Option 4B: Use-it-or-sell-it**

Under the use-it-or-sell-it scheme, shippers would be obliged to offer ‘firm’ capacity via a transparent platform in the event that the existing shipper has not utilised that capacity. For the purpose of our analysis, we assume that implementation of this option would centre upon the following principles:

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<sup>98</sup> Dampier to Bunbury Pipeline, ‘Standard Shipper Contract – Full Haul T1 Dampier to Bunbury Natural Gas Pipeline’, 2013, p. 53 <<http://www.dbp.net.au/files/PrecedentT1ShipperContract.pdf>> [accessed 1 October 2013].

- Available ‘unused firm’ capacity being identified based on an assessment of each shipper’s maximum expected requirements over some specified period (eg, weekly, monthly, yearly, etc) and its contracted firm capacity.
- Any firm capacity that is deemed to be ‘unused’ would be sold in increments of, say 1 TJ per day.
- Shippers would bid on the ‘unused firm’ capacity and the existing shipper would be required to sell that capacity to the highest bidder.
- Proceeds from the sale would be assigned to the existing shipper.
- The acquiring shipper and the existing shipper would enter into a standardised contract to settle the transaction including any additional deviation or imbalance charges.
- The gas transport agreement between the existing shipper and the pipeline operator would not be affected by the use-it-or-sell-it scheme.

## Appendix C. List of Organisations Consulted

Our assumptions and analysis was informed by discussions with stakeholders, including pipeline operators, shippers, producers, industry groups and government organisations. These stakeholders are listed in Table C.1.

**Table C.1**  
**Organisations Engaged in Stakeholder Consultation**

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<b>Pipeliners</b>	<ul style="list-style-type: none"> <li>APA Group</li> <li>Jemena</li> <li>EPIC Energy</li> </ul>
<b>Shippers</b>	<ul style="list-style-type: none"> <li>AGL</li> <li>Origin Energy</li> <li>EnergyAustralia</li> <li>Alinta</li> <li>GDF Suez</li> </ul>
<b>Producers</b>	<ul style="list-style-type: none"> <li>ExxonMobil</li> <li>Queensland Gas Company (BG Group)</li> </ul>
<b>Industry groups</b>	<ul style="list-style-type: none"> <li>Australian Pipeline Industry Association (APIA)</li> <li>Energy Supply Association of Australia (ESAA)</li> </ul>
<b>Government organisations</b>	<ul style="list-style-type: none"> <li>Australian Energy Market Operator (AEMO)</li> <li>Austrian Energy Regulator (AER)</li> <li>Australian Energy Market Commission (AEMC)</li> </ul>
<b>International organisations</b>	<ul style="list-style-type: none"> <li>Federal Energy Regulatory Commission (FERC)</li> <li>Office of Gas and Electricity Markets (Ofgem)</li> <li>PRISMA</li> <li>European Network of Transmission System Operators of Gas (ENTSOG)</li> </ul>

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## **Report qualifications/assumptions and limiting conditions**

Information furnished by others, upon which all or portions of this report are based, is believed to be reliable but has not been independently verified, unless otherwise expressly indicated. Public information and industry and statistical data are from sources we deem to be reliable; however, we make no representation as to the accuracy or completeness of such information. The findings contained in this report may contain predictions based on current data and historical trends. Any such predictions are subject to inherent risks and uncertainties. NERA Economic Consulting accepts no responsibility for actual results or future events. The opinions expressed in this report are valid only for the purpose stated herein and as of the date of this report. No obligation is assumed to revise this report to reflect changes, events or conditions, which occur subsequent to the date hereof.

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