
Report to
**Gas Market Leaders Group and
MCE Standing Committee of Officials**

Gas Market Options Cost Benefit Analysis

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Disclaimer

This report has been prepared solely for the Gas Market Leaders Group and MCE SCO for the purpose of assisting the Group to develop a gas market development plan for submission to the Ministerial Council on Energy. McLennan Magasanik Associates Pty Ltd shall have no liability (other than specifically provided for in the contract) for any representations or information contained in or omissions from the report or any written or oral communications transmitted in the course of the project.

EXECUTIVE SUMMARY

Introduction

The Options

In March 2006 The Gas Market Leaders Group (GMLG) commissioned McLennan Magasanik Associates (MMA) to undertake a cost benefit analysis of two options that have been developed under the auspices of the GMLG to provide increased gas market transparency:

- The Bulletin Board (BB) would be an electronic communications system providing up-to-date gas system and market information relating to pipelines, production and storage capacities and daily demand to all interested parties, promoting improved decision making and facilitating trade in gas. It would not directly provide a market price or a mechanism for trading gas or pipeline capacity.
- The Short-Term Trading Market (STTM) would be a price based balancing mechanism that would apply to gas delivered to defined “market hubs”. It would replace existing balancing mechanisms on distribution networks within hubs but would not affect the contractual obligations of pipelines and producers upstream of hubs. It would enable gas to be traded on a daily basis at market driven short-term prices. Implementation of the STTM would include implementation of the Bulletin Board.

The Cost Benefit Analysis

This cost benefit analysis is a comparative study of the costs and benefits attributable to the above options with the costs and benefits associated with the Base Case, in which neither of the options is implemented. It is noted that some of the benefits attributed to the two options could possibly be achieved by other options. Since these other options are, by definition, not part of the Base Case and have not been listed for consideration by the GMLG, they are not material to this study.

The findings in this report are based upon costs and benefits which MMA believes are:

1. Genuinely incremental i.e. not just a reallocation of Base Case costs and benefits
2. True net values i.e. not just a transfer of costs and benefits among stakeholders

MMA has carried out the study through a combination of stakeholder consultation and desk-top analysis. Stakeholders have provided estimates of costs and views on the likely sources of benefits and MMA has developed a number of approaches to quantifying the benefits. The contributions of stakeholders are gratefully acknowledged.

Both options are currently at the conceptual design stage. Consequently both costs and benefits have been estimated largely by “top-down” analogies with similar information systems and markets, rather than “bottom-up” costings and detailed market simulations. A number of costs and benefits that are not amenable to this approach remain qualitative at this stage.

Micro- and macro-economic net benefits

The micro-economic net benefit is the net present value of the quantifiable benefits less the identified costs in the gas sector.

Economy-wide benefits flowing from the Bulletin Board and STTM options have been estimated using the Monash University Centre of Policy Studies’ (COPS) model of the Australian economy, the Monash Multi-Regional Forecasting (MMRF) model.

Assumptions

The Bulletin Board is assumed to require one year for planning and implementation and then to operate for ten years. The STTM is assumed to require two to three years for planning and implementation and then to operate for ten years. While the Bulletin Board is expected to cover some 130 facilities (pipelines, producers, storage providers) and users (retailers, generators, self-contracting end-users) across Australia, the STTM is expected to be implemented initially in New South Wales and South Australia. In Victoria the existing market already provides an equivalent short-term pricing system.

To capture the uncertainty in costs we have calculated medium (best estimate) and high and low scenario costs for both Bulletin Board and the STTM. For benefits multiple scenarios have been considered only for the STTM.

All dollar values are 2006 real dollar values. Costs and benefits are summarised using a net present value (NPV) calculation over the years 2007 to 2018 at a real discount rate of 8.5%. To avoid misleading impressions of precision, many numbers presented in the report have been rounded.

Bulletin Board

Costs

The Bulletin Board costs estimated for the low, medium and high scenarios are provided in Exec Table 1. All the costs are set-up costs apart from the annual costs of operating the Bulletin Board. For Bulletin Board participants there are assumed to be some set-up costs but virtually no ongoing operating costs as the information required is already available and often already provided to other parties.

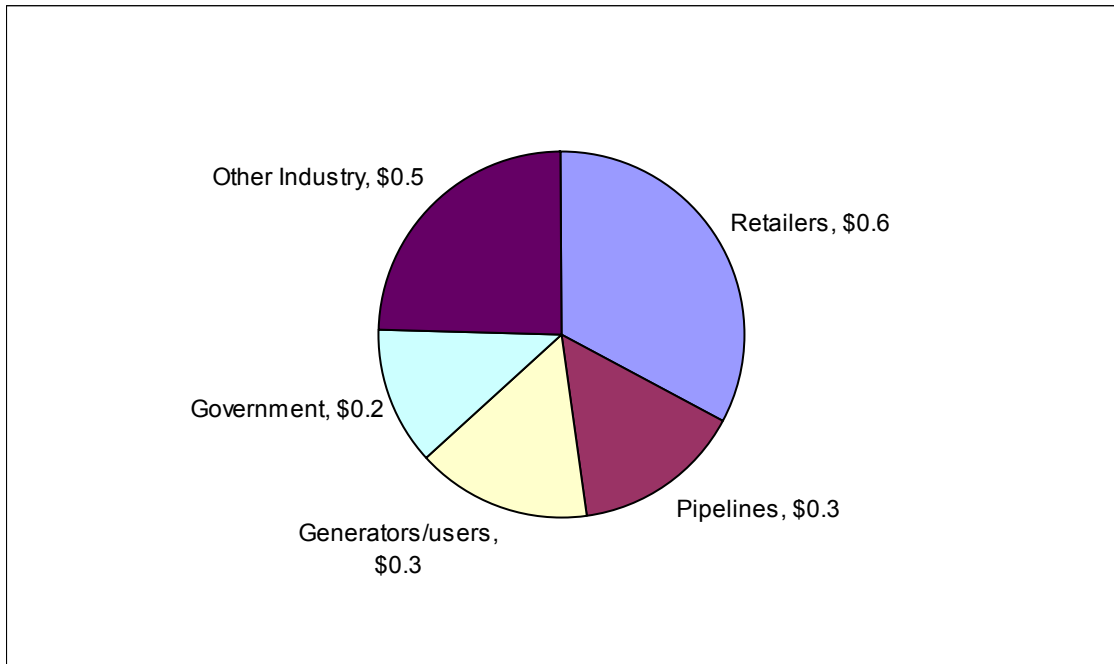
Exec Table 1 Bulletin Board cost definitions and scenario values, NPV, \$m

Cost	Definition	Low	Medium	High
Planning and project management	Cost for meetings, support and consultation related to BB design and implementation including project management.	\$0.2	\$0.5	\$0.7
System and testing	System design, implementation and testing.	\$0.2	\$0.4	\$0.7
Government	Regulatory, rules and legal costs.	\$0.0	\$0.1	\$0.2
Operation	Ongoing costs of operating the BB.	\$0.2	\$0.5	\$0.7
Costs of facility operators	Incremental costs incurred by pipelines, producers, storage operators for BB data provision.	\$0.1	\$0.1	\$0.2
Costs of other BB participants	Incremental costs incurred by retailers, generators and self-contracting end-users for BB data input.	\$0.1	\$0.3	\$0.4
TOTAL	NPV of setup and operating costs	\$0.9	\$1.8	\$3.0

The medium scenario NPV of costs for establishing the Bulletin Board is estimated to be approximately \$2m with a range between \$1m and \$3m. For the medium scenario the set-up costs are \$1.5m and annual costs are about \$0.1m.

An indicative allocation of these costs is provided in Exec Figure 1. We have assumed that industry will largely bear the costs of the system setup and operation.

Exec Figure 1 Initial allocation of Bulletin Board costs, medium scenario, NPV, \$m



Benefits

The Bulletin Board is designed to provide market participants and governments with additional gas market information to facilitate improved decision making. The information is expected to create benefits by improving pricing and gas network management during a supply shortfall.

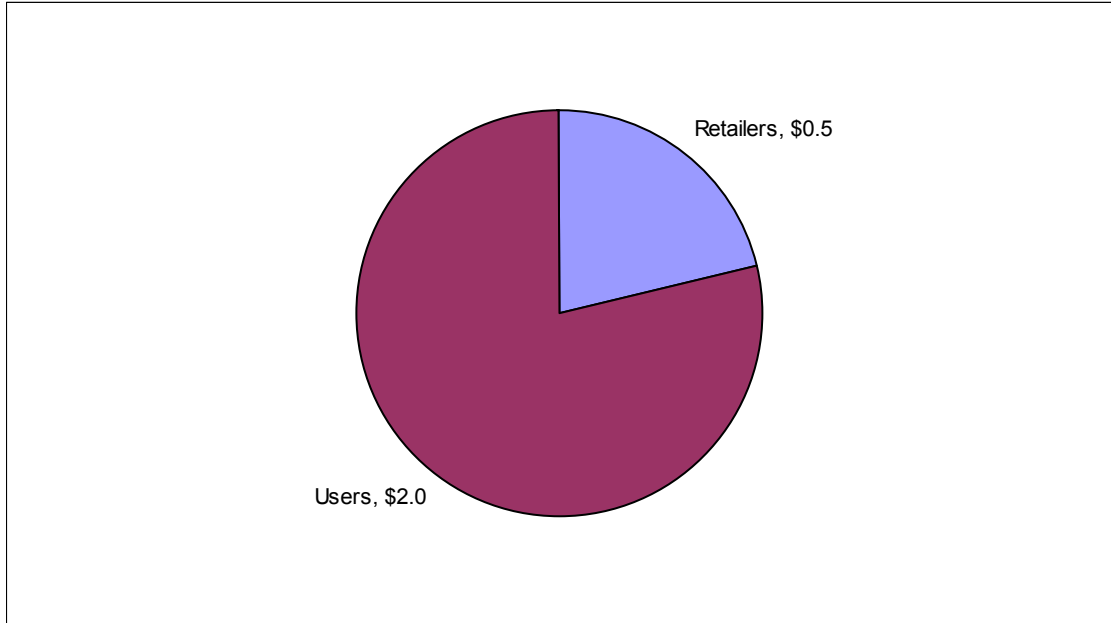
Estimating the economic value of these benefits is challenging and the following estimates are based on plausible outcomes and represent the likely magnitude of benefits rather than precise estimates. In view of this only a medium scenario benefit estimate has been prepared.

Exec Table 2 Bulletin Board benefit definitions and values, NPV, \$m

Benefit	Definition	Value
Pricing efficiency	Value of more accurate pricing, based on eliminating a pricing error of 2.5c/GJ.	\$1.1
Improved pricing and gas network management during a supply shortfall.	Value of lower level of curtailment due to improved information, based on a curtailment reduction of 16%.	\$1.5
TOTAL		\$2.6

An indicative allocation of these benefits is provided in Exec Figure 2. No material direct benefit to government, pipelines or producers is expected. Generators will share in retailer and user benefits in proportion to usage.

Exec Figure 2: Initial allocation of Bulletin Board benefits, NPV, \$m



Micro economic net benefit

The net benefit of the Bulletin Board is positive in both the low and medium cost scenarios but negative in the high cost scenario. However the benefit to cost ratio in the medium cost scenario is 1.4, which suggests that the outcome would be sensitive to small variations in the costs or benefits.

Exec Table 3 Bulletin Board net benefit NPVs and benefit-cost ratios

		NPV (\$m)	Benefit-cost ratio
	Low	\$1.6	2.8
Cost scenario	Medium	\$0.7	1.4
	High	-\$0.4	0.9

Macro economic net benefit

The Bulletin Board has no measurable economic multiplier and its effect on GDP is the same as its micro economic net benefit.

Short-Term Trading Market

Costs

The methodology for categorising and estimating each component of the costs of the STTM (including the Bulletin Board) is summarised in Exec Table 4.

Exec Table 4 STTM cost categorisation and estimation

Cost	Definition	Estimation Methodology
Planning and project management	Time spent by industry and government to establish the BB and STTM and review after five years.	Estimated from number of working groups x meetings x cost/hour inc support and consultation plus project management and travel. Five year operational review included.
Government	Additional Government cost to regulate including legal costs.	Government estimate.
Market Operation	Costs to set up and administer the new BB and STTM.	System set-up costs estimated from consultation as incremental to an existing operation. Assumed most of current market operations continue unchanged. Costs of trialling by time estimation. On-going costs estimated from consultation. Ongoing stand-alone governance from meeting assumptions. Minus avoided costs plus incremental additional costs for existing operators.
Large retailers	Setup costs (IT and communication) required to change the IT systems of large retailers plus ongoing operational costs required to trade in the new STTM markets.	Derived from industry consultation plus MMA estimates. Systems - industry range plus reality check from FRC. Some strategy costs. Assumed additional 0.75 FTE per market (i.e. 1.5 for SA and NSW). Estimated prudential costs.

Other small retailers, gas generators and end-users	Costs of system, strategy and BB for other users.	MMA estimate of strategy, IT/communication and additional operating time for each user type multiplied by est. number of such users. Set-up cost of supplying information for facilities and other from BB.
Pipelines	Additional costs incurred specifically by pipelines (typically pressure) for the impact of changing requirements and contracts.	Industry consultation plus MMA estimates. For pressure controlled pipelines initial legal/contractual costs plus ongoing operational (0.5 FTE per pressure controlled pipeline) and legal/contractual costs.
Other	Regulatory, network point to point.	Estimated after discussions with regulators and networks.

The estimated costs for the low, medium and high scenarios are provided in Exec Table 5.

Exec Table 5 STTM costs, NPV, \$m

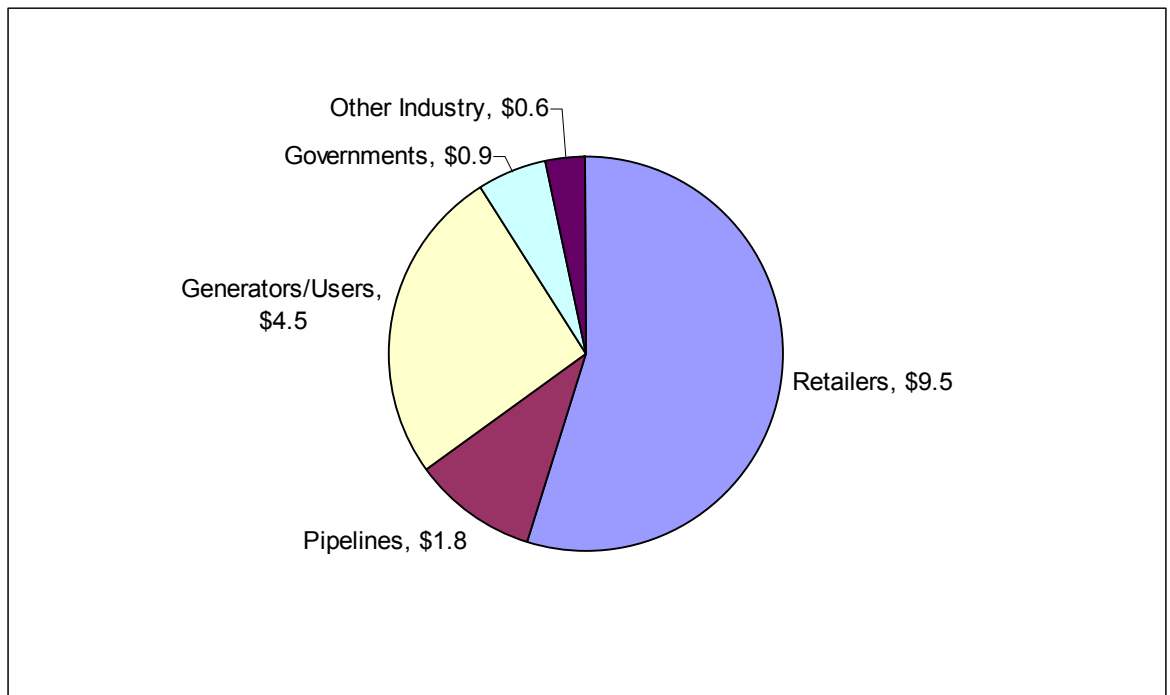
	Scenario		
	Low	Medium	High
Planning and project management	\$1	\$2	\$3
Government	\$0	\$1	\$1
System operation and governance	\$2	\$5	\$8
Large retailers	\$3	\$5	\$9
Other users	\$1	\$3	\$4
Pipelines	\$1	\$1	\$2
Reg and other	\$0	\$0	\$0
TOTAL	\$9	\$17	\$28

The medium scenario shows an estimated NPV of costs of \$17m for the STTM with a range of \$9m to \$28m. The two largest cost categories are expected to be the costs incurred by large retailers and the set-up, operation and governance of the market operating system.

For the medium scenario the (undiscounted) set-up costs are about \$9m with ongoing costs of \$1.6m pa and a one-off review cost after 5 years of operation of \$1m.

An indicative initial allocation of the medium scenario costs for the STTM is provided in Exec Figure 3. We have assumed that the costs of the STTM set-up, operation and governance will be borne by the industry, largely in proportion to demand volumes, but this remains to be confirmed.

Exec Figure 3 Initial allocation of STTM costs, NPV, \$m



Retailers are expected to bear over half the costs of the STTM with generators and other end-users making up a further quarter of the costs. Transmission pipelines are also expected to bear significant costs including those related to planning and specific legal and operating issues.

Indicative (NPV) costs of adding a hub in Queensland or Western Australia are estimated at \$4m each while adding a smaller hub would cost about \$1.5m each.

Benefits

The methodology for categorising and estimating each component of the benefits of the STTM (not including the Bulletin Board) is summarised in Exec Table 6.

Exec Table 6 STTM benefit categorisation and estimation

Benefit	Definition	Estimation Methodology
Pricing efficiency	Greater efficiency of dynamic pricing.	Estimated from Victorian gas market data using deadweight loss method. Supply and demand curves calculated from bid stack data from 2005. Difference between actual daily prices and a fixed annual price.
Value of trading	Cost savings to market participants from trading gas	Compared participant payments at Victorian market price with what they would have paid if they hadn't traded during 2005.
Curtailement management	Value of improved allocation of gas to users who value it most.	Based on net economic losses due to poor allocation of gas during supply shortfall following the Moomba fire in 2004. A proportion of the losses are assumed to be saved by the STTM
Capacity utilisation efficiency	Lower capacity requirements. The Base Case involves inefficiencies created by retailers' need to contract capacity to meet their customers' needs. Owing to a lack of diversity the sum of retailers' capacity requirements is greater than the market's. Trading eliminates some of this.	Diversity estimates based upon data supplied by GMC and REMCO. STTM ability to reduce this based on comparison with other markets. Cost savings based on pipeline and production capex.
Risk management	Value of changes in risk and risk allocation	Not estimated, qualitative benefit only
Investment signals	Pricing signals for investment in additional capacity	Not estimated, qualitative benefit only
Gas-fired generation	Benefits from more dynamic pricing	Not estimated, qualitative benefit only

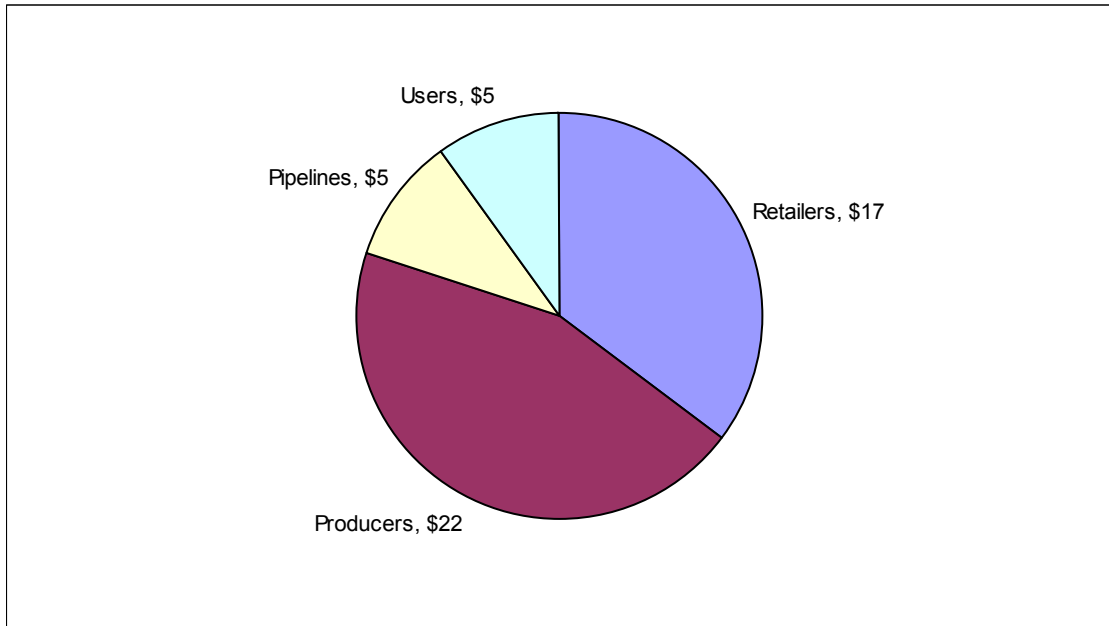
The net present values of the quantified benefits in all three scenarios, calculated at a real discount rate of 8.5%, are summarised in Exec Table 7. Total quantified NPVs are \$23m in the low scenario, \$48m in the medium scenario and \$97m in the high scenario.

Exec Table 7 STTM benefits, NPV, \$m

Benefit	Scenario		
	Low	Medium	High
Pricing efficiency	\$1	\$4	\$8
Value of trading	\$8	\$15	\$30
Curtailement management	\$2	\$3	\$6
Capacity utilisation efficiency	\$13	\$26	\$53
Risk management	+ve	+ve	+ve
Investment signals	+ve	+ve	+ve
Gas-fired generation	+ve	+ve	+ve
TOTAL	\$23	\$48	\$97

We have indicatively calculated the initial allocation of benefits (i.e. where the benefits will be accrued before pass through to other sectors, if that is possible) for the medium scenario, to retailers, producers, pipelines and end-users, with the results shown in Exec Figure 4. No material direct benefit to government is expected. Generators will share in retailer and user benefits in proportion to usage. The producer and pipeline benefits are due to reduced capital expenditure following on from lower capacity requirements, and are expected to pass directly to retailers and self contracting users.

Exec Figure 4 Initial allocation of STTM benefits, medium scenario, NPV, \$m



Other hubs

The New South Wales and South Australian hub benefits have been assessed assuming that approximately 90% of the gas in each jurisdiction is traded through the relevant hub. The benefits are likely to decline disproportionately with decreasing hub size, in a manner indicated below.

Exec Table 8 Variation of medium scenario benefits with hub size

% gas in hub	90%	80%	70%	60%	50%
Benefits (\$m, NPV)	\$48	\$40	\$32	\$26	\$19

In relation to possible hubs in Queensland (Brisbane) and Western Australia (Perth) estimated benefits are presented in the table below.

Exec Table 9 Additional hub medium scenario benefits

	Hub volume (PJ pa)	Total benefit NPV (\$m)
Queensland	50	\$10
Western Australia	231	\$47

Micro economic net benefit

The net benefit NPV of the STTM over the period 2007 to 2018 is positive in eight of the nine possible cost/benefit scenarios, ranging up to \$88m (Exec Table 10). The best estimate scenario, the combination of the medium cost and benefit scenarios, has a positive NPV of \$31 m.

Exec Table 10 STTM net benefit, NPV, \$m

		Benefits		
		Low	Medium	High
	Low	\$15	\$39	\$88
Costs	Medium	\$6	\$31	\$79
	High	-\$5	\$20	\$68

The benefit to cost ratio in the best estimate scenario is 2.8, which suggests that the outcome would not be changed by small variations in the costs or benefits (Exec Table 11). Six of the nine scenario combinations have robust ratios over 2.

Exec Table 11 STTM benefit-cost ratios

		Benefits		
		Low	Medium	High
	Low	2.7	5.6	11.2
Costs	Medium	1.3	2.8	5.6
	High	0.8	1.7	3.4

Reduction in the size of the New South Wales and South Australian hubs may reduce the net benefits. In the best-estimate scenario the net benefit NPV is positive provided more than 50% of gas consumed in the jurisdictions is traded through the hubs.

The net benefits of the additional hubs in Queensland and Western Australia are strongly positive in the medium scenario.

Exec Table 12 STTM net benefit NPVs and benefit-cost ratios, additional hubs, medium scenario

	NPV (\$m)	Benefit-cost ratio
Queensland	\$7	3.2
Western Australia	\$44	15.0

Macro economic net benefit

The impact of the STTM on the national economy is assessed to be low. Projected GDP changes mirror the NPV value in each scenario and the employment impacts are minimal. The analysis confirms the assessment of the net benefits of the STTM.

1 INTRODUCTION

1.1 Background

The Gas Market Leaders Group (GMLG) has been established by the Ministerial Council on Energy (MCE) to develop a gas market development plan which will deliver on the MCE's objectives for a competitive, reliable and secure natural gas market delivering increased transparency, promoting further efficient investment in gas infrastructure and providing efficient management of supply and demand information.

Two options for improved market transparency have been defined and scoped by the Gas Market Options Working Group (GMOWG) which was established by the GMLG:

1. A Bulletin Board Facility (Bulletin Board)
2. A Short-Term Trading Market (STTM).

McLennan Magasanik Associates (MMA) has been commissioned to undertake a cost benefit analysis (CBA) of the development of these two options.

1.2 Cost benefit analysis – methodology

A cost benefit analysis is a comparative study of the costs and benefits attributable to two or more alternative options/arrangements/paths of action. One of these options is usually a Base Case option, often referred to as the "status quo" option, because the specific actions under investigation are not taken. In this study we are making two comparisons, between the Bulletin Board and the Base Case and between the STTM and the Base Case. The Bulletin Board and the STTM are not being compared directly.

It is also noted that some of the benefits attributed to the Bulletin Board and the STTM could possibly be achieved by other options. Since these options are, by definition, not part of the Base Case and have not been listed for consideration by the GMLG, they are not material to this study.

In undertaking a CBA it is important to focus on the primary differences between the options and the Base Case. Many aspects of the industries concerned will be virtually unchanged and it is not necessary to investigate them in detail. A section of this report deals with impacts the options may have on broader aspects of the gas industry.

Undertaking a CBA presents two significant "accounting" challenges:

1. Differentiating between genuine incremental costs/benefits attributable to an option and costs/benefits that are in reality a reallocation of costs/benefits incurred in the Base Case.
2. Distinguishing between changes in the distribution of costs and benefits among the many stakeholders and the net effect across the sector as a whole and the broader economy.

The findings in this report are based upon costs/benefits which MMA believes are:

1. Genuinely incremental
2. True net values

These costs/benefits give a true account of the economic impact of implementing either the Bulletin Board or STTM options. Distributional impacts may nevertheless be important as they can affect the behaviour of stakeholders and may require compensatory structures to be established which can themselves reduce or increase the net benefits.

In view of the uncertainties surrounding both costs and benefits, low, medium and high scenarios have been developed for both options, with the exception of Bulletin Board benefits, to provide an indication of the potential ranges of values. The cost and benefit scenarios are not linked and give rise to nine net benefit estimates for the STTM.

1.3 Study process

MMA has carried out the CBA through a combination of stakeholder consultation and desk-top analysis. Stakeholder consultation was initiated by the preparation of a consultation paper that was circulated to all members of the GMLG, GMOWG, industry associations and government representatives on 3rd April 2006. The consultation paper described the Bulletin Board and STTM options, the intended study process and the information on costs and benefits that MMA sought from stakeholders.

The consultation paper was followed by three forums, in Melbourne, Sydney and Adelaide on the 11th, 12th and 21st April respectively, attended by over sixty representatives of the organisations contacted, at which presentations covering the GMLG's progress to date, the two options and the CBA study were made, followed by discussion. MMA separately contacted all those to whom the consultation paper was circulated and held discussions with more than fifty individual stakeholders representing thirty organisations, in person and in teleconference, over the period from the 5th to the 28th April. A list of all those who contributed is provided in APPENDIX A . A small number of stakeholders and stakeholder groups also communicated their views on the CBA study in writing. All information that MMA has received through this process has been treated as confidential, unless it is known also to be in the public domain, and is reported only in aggregate form in a manner that cannot be attributed to individual stakeholders.

The information on costs and benefits gathered from the discussions has been invaluable to the study. Stakeholders have provided estimates of costs and views on the likely sources of benefits. MMA has relied heavily upon cost information provided by stakeholders and estimates of the benefits of both options have been derived by desk-top analysis. The analysis is based on relatively simple concepts, rather than detailed market simulation using "black box" models, and relies upon market information provided by the New South Wales, Victorian and South Australian market operators, GMC, VENCORP and REMCO.

The contributions of stakeholders are gratefully acknowledged.

1.4 Options evaluated

Detailed descriptions of the Bulletin Board and Short-Term Trading Market are provided in section 2. The core evaluations assume implementation of the Bulletin Board nationally and initial implementation of the STTM at hubs in New South Wales and South Australia.

Later implementation of the STTM at Queensland and Western Australian hubs is assessed as an incremental option.

1.5 Changes from the draft report

The only material change since the draft report has been to the indicative allocation of costs of the BB. In the draft report we assumed, subject to confirmation, that the costs of the BB system and operation would be borne largely by Government. Comments received from the GMLG and MCE SCO suggest that the costs are more likely to be borne by industry. The allocation of BB costs has been changed to reflect this.

We had also contemplated a change to the numbers to reflect a slight timing misalignment when calculating costs and benefits for the STTM. The change would have added about \$1 M to the net benefit of the STTM. It was considered, however, that the change was relatively immaterial and did not alter the conclusions drawn. To maintain consistency with the draft report, which has been widely circulated, the numbers presented in this report are the same as in the draft report.

1.6 Abbreviations and definitions

\$m	Million Dollars
AA	Access Arrangements
ABARE	Australian Bureau of Agricultural and Resource Economics
AEMC	Australian Energy Market Commission
AER	Australian Energy Regulator
BB	Bulletin Board
CBA	Cost benefit analysis
COPS	Monash University Centre of Policy Studies
FRC	Full Retail Contestability
GJ	Gigajoules

GMC	Gas Market Company, the gas market operator for NSW and the ACT
GMLG	Gas Market Leaders Group
GMOWG	Gas Market Options Working Group
GSA	Gas Supply Agreement
MCE	Ministerial Council on Energy
MMA	McLennan Magasanik Associates
NGERAC	The MCE's National Gas Emergency Response Advisory Committee
NPC	Net Present Cost (discounted value of a stream of costs)
NPV	Net Present Value (discounted value of a stream of benefits or costs and benefits).
pa	Per Annum
Pipeline	Transmission Pipeline
PJ	Petajoules
REMCo	Retail Energy Market Company, the gas market operator for SA and WA
SCO	Standing Committee of Officials
STTM	Short-Term Trading Market
VENCorp	Victorian Energy Networks Corporation the gas market operator for Victoria (along with other functions).
WG	A working group other than GMOWG

2 BASE CASE AND OPTIONS

2.1 The Australian wholesale gas market

The Australian wholesale gas market is currently characterised by two components:

- A primary market in which gas producers sell gas to buyers (retailers, traders, generators and other large consumers), typically at the exit gate to their gas plant. The majority of these sales are under long-term (up to fifteen year) contracts.
- A secondary market in which buyers trade volumes, obtained under contract, over shorter terms for the purposes of resolving imbalances in their supply portfolios or meeting the requirements of daily balancing on pipelines¹. Secondary trading takes place at any convenient location such as a plant gate or pipeline city gate².

Both markets are currently almost entirely physical markets and rely upon delivery of the product. Financial risk management products have been offered in Victoria but have not found wide acceptance. Both markets are also in effect multiple markets owing to the existence of five unconnected networks: the Western Australian grid, the Northern Territory grid, the North Queensland grid (Townsville pipeline), the remaining Queensland grid and the connected grids of New South Wales, Victoria, South Australia and Tasmania.

Although gas production is highly concentrated, particularly in the Eastern States, competition from new entrants has ensured that prices for new contracts have remained relatively flat over the past five years and may remain so, due to the threat of large volumes of remote gas (PNG and Timor Sea) entering the market. The primary market is also workably liquid, with willing sellers for the right buyer, even though it does not see frequent trading because new long-term contracts are not frequently required. Smaller buyers may however find the cost of negotiating long-term contracts excessively high and there seems to be limited movement towards shorter term contracts. Retention of long term contracts is reinforced by new upstream entrants who require long-term sales to underwrite development because they cannot rely on spot sales. Also, owing to the commercial sensitivities of long-term agreements, primary market transparency is low.

The secondary market suffers from an equally high level of concentration among gas buyers. ABARE³ has noted that this concentration may persist and militates against development of more liquid secondary markets. ABARE and market participants report a growing number of secondary trades but none are publicly reported and transparency is low. A major exception to this is the Victorian gas market, essentially a price based approach to system balancing, which reports both market volumes and prices on a daily

¹ Gas trading in the Victorian Gas Market operated by VENCORP falls into this category

² The point of delivery of gas from a transmission pipeline to a distribution system.

³ "Australian Gas Markets, moving towards maturity". ABARE eReport 03.23, December 2003

basis. The Victorian gas market is believed to be inappropriate for other jurisdictions however⁴. The limited liquidity of secondary trading encourages large buyers to obtain supply flexibility by managing a portfolio of contracts rather than relying upon trading, which has the effect of perpetuating the illiquidity, and prevents smaller buyers from relying on the secondary market as a source of gas. This barrier to retail market entry helps to maintain the high level of buyer concentration.

Overall the market has developed since deregulation in 1997 and wholesale prices have remained steady. However, in the face of the self-perpetuating barriers noted above, there has been no clear path to greater price transparency and removal of barriers to entry of small players, or to greater short-term market liquidity, which could resolve the first two issues.

The CoAG Energy Market Review in 2002 found that there was scope for further gas market development and in 2004 the MCE released its Principles for Gas Market Development, after consultation with industry⁵:

- Information on market and system operations and capabilities at all stages of the gas supply chain (subject to recognition of existing contractual confidentiality) should be publicly available and frequently updated.
- Gas market structure to facilitate a competitive market in all sectors.
- Gas market participants should be able to freely trade between pipelines, regions and basins.
- There should be regulatory certainty and consistency across all jurisdictions.
- Market design and institutional requirements responsive to and reflective of the needs of the market and market participants.

MCE subsequently commissioned Allen Consulting Group (ACG) to report on market development options - ACG's report presented four options:

1. Organic Development
2. Bulletin Board(s)
3. City Gate Market
4. Victorian Model

MCE formed the GMLG to prepare a plan for gas market development centred on further investigation of options 2 and 3 or an alternative that meets the MCE Principles. GMLG established the GMOWG to further elaborate the options, which are now known as the Bulletin Board facility and the Short-Term Trading Market model respectively.

⁴ VENCORP submission to MCE in response to Draft Principles for Gas Market Development

⁵ Ministerial Council on Energy, Statement on Principles for Gas Market Development, December 2004

2.2 Market dimensions

Gas demand in each jurisdiction is tabled below as a point of reference for other sections in this report.

Table 2-1 Estimated gas demand 2005 (PJ)

	NSW	Victoria	SA	Qld	WA	Tas	NT	ACT	TOTAL
Mass market	32	110	11	4	13	<1	<1	6	176
Large industrial	64	88	32	62	150	3	2	1	402
Generation	8	11	57	54	153	15	18	0	316
TOTAL	105	209	99	120	316	18	20	7	894

Source: market operators and others

2.3 Base Case – business as usual

The costs and benefits of the options will be compared to the “business as usual” Base Case. This Base Case will assume that much of the status quo for the Australian gas industry will continue largely unchanged.

The structure of the Australian gas industry and of wholesale gas markets has been described in the Allen Consulting Group (ACG) report on options for the development of the Australian gas market⁶.

In summary:

- Wholesale trade in gas in NSW, Queensland, South Australia, ACT and Tasmania is characterised by large confidential bilateral contracts. There is no formalised physical spot market for gas. While some short-term trading is said to occur there is little or no transparency for third parties.
- Transmission services to these markets are also provided to shippers under confidential bilateral agreements. Many pipelines also publish firm and interruptible tariffs. There is no formalised market for trading in capacity rights.

⁶ The Allen Consulting Group, Final report to the MCE Standing committee of Officials – Gas Market Development Working Group “Options for the development of the Australian wholesale gas market”, June 2005.

Some trading is understood to occur but with little or no transparency to third parties.

- Wholesale gas and transmission market structures in Western Australia and the Northern Territory are similar to those in the above jurisdictions, but with some unique characteristics.
- Victoria, by contrast, does have a formalised daily market for gas and manages transport through a “market carriage” model. VENCORP operates the spot market and the Victorian Principal Transmission System.
- In NSW, the ACT, South Australia and Western Australia as well as Victoria independent companies (GMC, REMCO and VENCORP) manage retail markets including network balancing and gas allocation functions. Similar retail market operations are likely to be set up in Queensland, Tasmania and the NT with the implementation of full retail contestability (FRC).

The period under review is the ten years following the implementation of the Options. The Bulletin Board option is assumed to be implemented over the next six to twelve months while the STTM option is assumed to be implemented over the next two to three years.

In the Base Case, much of the above structure is expected to remain unchanged. However, the operation of the GMC and REMCO retail markets in several jurisdictions is expected to undergo significant change over the next few years, potentially providing an opportunity to introduce further gas market changes at a reduced incremental cost.

In both the Base Case and the Option Cases the Victorian spot market, as evolved, is expected to continue to operate.

The Base Case is referred to as “organic market development” in the ACG report to MCE. Key items in defining this case are:

- Potential changes in the GMC and REMCO balancing arrangements foreshadowed above.
- Gas Access Code changes resulting from the Productivity Commission review of the Code and subsequent consideration of their recommendations by MCE and the gas industry and users. The Code, and the terms of pipeline access that result from it, has a strong bearing on the ability of users to trade gas on pipelines. The Code changes may enhance trading possibilities.

2.4 The Bulletin Board

The following description is based on the initial descriptions of the Bulletin Board which have been provided to MMA to allow the cost benefit analysis to be carried out.

2.4.1 Objectives

An electronic Bulletin Board⁷ (for instance on a website) is intended to provide up-to-date system and market information relating to pipelines, production and storage to all interested parties and hence to facilitate trade in gas. It is not intended to provide a market price or a mechanism for trading gas or pipeline capacity.

2.4.2 Likely operations

The Bulletin Board would provide up-to-date information on the overall physical condition and capacity of the production, storage and pipeline system to supply projected demand, along with contact details for key industry participants. The Bulletin Board would be expected to provide up to date information to users or potential users of the pipeline as to where supply or pipeline constraints exist in real time, or may occur under certain conditions, and thus assist them in identifying potential trading, risk mitigation or investment opportunities.

The information to be published on the Bulletin Board would be in aggregated form so as not to reveal commercially confidential contractual quantities or other details. The published information would be expected to include the following:

- (a) A "baseline" set of information on supply and pipeline daily capacity. This information would be updated annually, or whenever significant changes occur.
- (b) Temporary changes to the baseline data would be required to be reported, on an exception basis, whenever maintenance or unplanned outages result in material changes in supply capacity or constraints in transportation capacity.
- (c) Details of available firm and non-firm pipeline capacity, including prices for uncontracted capacity.
- (d) Details of forecast aggregate daily demand on the pipeline, or at major demand centres (city gates), would be provided by Shippers and updated on a daily basis, for each of the next 3 days.
- (e) Key contact details for pipeline operators, producers, storage providers, shippers and retailers.
- (f) The Bulletin Board would also offer a facility for the voluntary posting of buy/sell offers for supply or transportation capacity.

Provision of the physical system information for posting on the Bulletin Board would be standardised and mandatory. Posting of buy/sell offers on a Bulletin Board would be voluntary.

It is envisaged that each Party responsible for providing information would do so directly through an electronic, automated system. It is expected that an independent administrator or service provider would be required to oversee the development, maintenance and ongoing smooth operation of the Bulletin Board.

⁷ Although we refer to a Bulletin Board, this may actually be a number of separate (or connected) Bulletin Boards with standardised content and format.

2.4.3 Parties affected

Producers, Pipeliners, Storage providers and Shippers (demand information) would be directly affected in terms of the provision and updating of information.

The Bulletin Board would be expected to have no direct impact on pipeline operations or the scheduling of gas injections and withdrawals or the Victorian gas market operations. It would be expected to have no direct impact on existing gas supply or pipeline transmission agreements. Future gas supply and pipeline transportation arrangements would generally continue to proceed on the basis of bilaterally negotiated contracts.

The Bulletin Board would provide historical (and short term future) information which existing and new industry participants could use either in negotiating new long term contracts, or for short term trading around their existing contracted positions.

The Bulletin Board may be seen as part of the response to the national coordination and management of gas emergencies being prepared by the MCE's National Gas Emergency Response Advisory Committee (NGERAC)⁸.

The Bulletin Board would not be expected to change in any material way the operations of the current market operators VENCORP, GMC and REMCO.

2.4.4 Implementation

Obligations to require provision of required information from Producers, Storage Providers, Pipeliners and Shippers would likely be through the National Gas Law. This could be through including the detailed requirements and rules in the Law, or by the Law requiring that all users comply with an appropriate scheme.

Bulletin Board governance, legislation and Code options are currently being assessed by GMOWG. For the purposes of this study it has been assumed that the model adopted will not materially impact on costs.

A Bulletin Board could be implemented within 6-12 months, with the introduction of the required legislation to impose obligations for information provision possibly being on the critical path. Development of systems and any infrastructure required to support the Bulletin Board could proceed in parallel with the drafting and passing of this legislation. Costs are projected to be incurred from 2007 onwards, with benefits accruing from 2008.

2.5 The Short-Term Trading Market

The following description is based on the current description of the STTM which has been provided by the GMOWG to MMA to allow the cost benefit analysis to be carried out.

⁸ To assist with the national coordination and management of gas emergencies, NGERAC is developing proposals in support of the National Gas Emergency Response Protocol. At its meeting on 8 March 2006, NGERAC members agreed that both the Bulletin Board and STTM proposals being developed by the Gas Market Options Working Group were complementary to the NGERAC objectives of gathering supply and demand information to prepare for and manage major gas emergencies, and enhancing the ability of the market to respond to such emergencies so as to defer the requirement for enactment of jurisdictional emergency powers.

2.5.1 Overview

Whereas the Bulletin Board described previously does not set a clearing price, provide effective price discovery or incorporate a trading mechanism, the STTM has been developed to incorporate all of these features, while seeking to provide continued, unaffected operation of the contractual arrangements between shippers/producers, shippers/pipeline operators and shippers/users. The features and requirements of the Bulletin Board discussed in Section 2.4.2 are also assumed to be included within the STTM.

The fundamental feature of the STTM is the establishment and publication of a market clearing price for delivered gas at each of a number of “hubs”. Market pricing and balancing is expected to be on a daily basis. The clearing price will be determined prior to the start of each gas day and will apply to deliveries and withdrawals at the hub cleared through the STTM for that day, and to deviations from cleared deliveries and withdrawals on the previous gas day.

The STTM has been developed on the basis that the “hubs” will be groupings of demand centres or delivery points where there are multiple parties receiving gas through one or more pipeline delivery points into the hub and selling/using it within the hub or withdrawing it from the hub. It is envisaged that hubs may therefore include sub-networks, direct connected commercial/industrial load and gas fired power generation, and that the initial hubs will be situated in South Australia and New South Wales. Further hubs may be established in other locations, such as Western Australia, Queensland, the Australian Capital Territory and the Northern Territory, if there is sufficient need.

The STTM would become the compulsory balancing mechanism, for gas delivered into the hub and gas withdrawn from the hub, and would replace the existing distribution system balancing arrangements and systems where it is implemented. The Victorian system would be left largely unaffected.

The proposed STTM arrangements should have no direct impact on existing gas supply, transportation agreements or user/shipper contracts. The STTM would provide a mechanism for short term (day to day) trading around longer-term contracted positions. The system and market information that is made available through the short-term trading market arrangements may also facilitate short-term bilateral trades, and provide a basis for negotiation of new long term contracts.

The STTM would require the establishment of a Market Operator. It is envisaged that a single operator could manage STTMs at a number of hubs.

2.5.2 Key concept and definitions

Figure 2-1 illustrates schematically a hub receiving gas from one or more pipelines and the terminology used in this paper to describe the proposed STTM concept. Terminology for a transmission hub such as Wallumbilla, where gas is withdrawn from the hub rather than used within it, would be different and, as yet, there has not been detailed consideration of how a transmission hub would operate.

The key participants in the hub that will be subject to the STTM arrangements are:

- **“Users”**, who are responsible for gas withdrawals at the hub. “Users” may be either:
 - “Retailers”, who purchase gas delivered at the hub from “Shippers”, under contract and/or via the STTM, and then on-sell the gas to end-use customers; or
 - “Direct end-use customers”, who purchase their gas at the hub directly from “Shippers”, under contract and/or via the STTM, rather than purchasing through a retailer.
- **“Shippers”**, who have a haulage agreement with the pipeline for the transportation of gas from the injection point into the pipeline to the delivery point into the hub, and sell the gas to users under contract and/or via the STTM.

“Users” may also be “Shippers” and arrange their own haulage contracts with the pipeline.

Pipeline Operators would not be required to participate either commercially or operationally in the STTM, other than being required to provide the Market Operator details of the allocated daily gas deliveries at the hub to the various shippers under their haulage contracts. The management of shipper imbalances on the pipeline, between the injection point and the delivery point, would remain a matter to be managed between the Pipeline Operator and Shippers under their contractual arrangements, outside of the STTM.

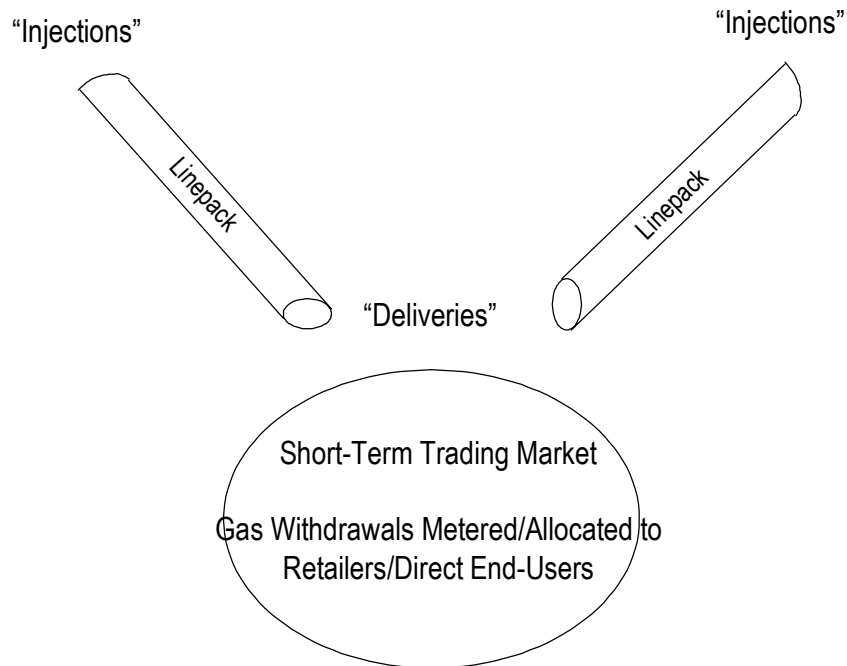
There would be no obligation on upstream gas producers or storage providers to submit bids/offers or otherwise be involved in trading arrangements under the STTM. However, such producers/storage providers would have the option of participation through offering gas deliveries at the hub, using spare capacity for which they have access to transportation rights.

Gas “Injections” are those quantities that are supplied into the transmission pipeline upstream of the hub on a day by the gas producers/storage providers, in accordance with contractual processes between themselves and the shippers.

Gas “Deliveries” are those quantities that are delivered to a gate point that is part of the hub, in accordance with contractual processes between pipeline operators and shippers.

Gas “Withdrawals” are those quantities of gas withdrawn from the hub by users at the downstream load centres, which may include distribution networks, direct connected loads and/or gas fired electricity generators.

Figure 2-1 Short-Term Trading Market - Terminology



2.5.3 Daily operations

1. Before the day:

- Users would advise the Market Operator of their projected or nominated withdrawals for the day
- Users may also submit to the Market Operator volume/price bids for gas withdrawals for the day
- Shippers would submit to the Market Operator volume/price bids for gas deliveries for the day
- The Market Operator would then construct a supply/demand curve for delivered gas from the users' nominated withdrawal quantities, including those nominations with price limits, and the shippers' gas delivery bids and, hence, establish a clearing price for the day
- Shippers' deliveries and users' withdrawals cleared in the bid stack become the basis for cash settlement in the STTM
- Cleared daily shipper deliveries and user withdrawals at the hub are cash settled at the clearing price, which is determined before the start of each gas day⁹.

⁹ Where the shipper and the user are the same entity (eg a retailer that arranges and manages its own supply contract with a producer and transmission agreement with the pipeline operator), the Market Operator may provide a single net settlement for the difference between cleared deliveries and withdrawals

2. After the day:

- Actual withdrawals by users would be determined by the Market Operator using actual meter data, estimates for those interval metered withdrawal points for which meter data is not available and an allocation process for non-daily metered withdrawal points¹⁰. A process for dealing with UAFG will be required.
- Allocations of actual deliveries to the Hub by shippers would be determined by the pipeline operators, in accordance with their transmission agreements, and advised to the Market Operator
- This method provides the greatest flexibility for pipeline operators to allocate using all contractual provisions including provisions such as firm and non-firm delivery capacity.
- The Market Operator will then determine
 - each shipper's delivery variance, which is the difference between the shipper's allocated gas deliveries, as advised by the pipeline operator, and the shipper's cleared deliveries determined before the start of the day via the bid stack
 - each user's withdrawal variance, which is the difference between the user's actual withdrawals, determined by the Market Operator, and the user's cleared withdrawals determined before the start of the day via the bid stack.
- The Market Operator would then settle each shipper's delivery variance and each user's withdrawal variance for the day, at the clearing price determined for the following day (i.e. delivery and withdrawal variances determined after the event for gas day 1, would be cash settled at the clearing price determined from the bid stack for gas day 2)¹¹.

3. Contracts for Difference

- It is anticipated that Users and Shippers who have, or wish to have, contractual arrangements for the delivery and purchase of agreed quantities of gas at the hub at an agreed fixed price, would seek to enter Contracts for Difference, to hedge themselves against the variability in the STTM clearing price. Use of Contracts for Difference is not an essential element of the STTM and is not discussed further in this report.

Differences between nominated deliveries and actual withdrawals at the hub may result in a change in linepack on the transmission pipeline (depending upon injections into the pipeline). This is because within the load centre, ignoring distribution system linepack, *actual* deliveries will, more or less, equal *actual* withdrawals¹². Therefore, the difference between actual and nominated deliveries will be made up by an increase or decrease in

¹⁰ The allocation processes related to users' withdrawals used in current retail markets would be most appropriate for re-use and this is anticipated to be process that would no longer be performed by the Retail Market Administrators of the gas markets where the STTM markets will operate.

¹¹ As described in footnote 9, where the shipper and user are the same entity, the Market Operator may facilitate a single net settlement that offsets delivery and withdrawal quantities.

¹² Actual end-usage of gas will be gas used at either a basic metered delivery point or an interval metered delivery point, or will be unaccounted for gas that is lost from the distribution system due to leakage and metering error.

transportation pipeline linepack. The management of this type of “imbalance” is through the transmission agreements between pipeline operators and shippers. Under these agreements, shippers typically have imbalance tolerances within which they are allowed to operate, with a requirement to physically restore linepack and return into balance within an agreed timeframe, which can be a day or two or, in the case of some pipelines, can extend to a number of weeks. The precise arrangements will depend upon contractual negotiations, price and the physical characteristics of the pipeline.

The objective of the STTM is to provide a short-term trading and pricing mechanism for gas delivered at the “hubs” and the variances between forecast and actual demand. The proposed STTM will not directly price the imbalances between the actual pipeline deliveries at the hub and the supply point injections¹³ (i.e. changes to linepack) arising from the variances between forecast and actual demand in the load centre. Rather, the prices bid by participants at the hub will reflect a risk weighted price for delivery of gas and settlement of prior day’s variances. Physical restoration of linepack will remain a matter to be dealt with through balancing obligations that exist in pipeline transmission agreements between shippers and pipeline operators.

The clearing price determined at the hubs, together with published system supply/demand information, would provide pricing signals and facilitate secondary trading between shippers, for gas fired power generators, for trading over interconnecting pipelines between hubs, and for demand side response, particularly at times of supply shortages or constraints.

Other features of the market will include a default or VoLL price and prudential requirements.

2.5.4 Parties and transactions affected

All participants in the STTM would be required to be subject to the market-determined clearing price for their imbalances.

As is the case under existing gas supply and transmission agreements, all shippers would also be required to provide daily nominations to their gas producers, gas storage provider and pipeline operators. The shipper nominations would be informed by the gas withdrawal forecasts made by the users.

There would be no obligation on upstream producers or storage providers to submit bids/offers or otherwise participate in the STTM. However, such producers/storage providers would have the option of participation through offering spare capacity into the market on any given day, at a price of their choosing, subject to having transportation rights to deliver the gas to the hub.

¹³ “injections” of gas into a pipeline, or “injection points” are sometimes referred to as “receipts” and “receipt points” by pipeline operators.

Pipeline operators would continue to contract their own capacity and services and be accountable for their operating practices through their transmission agreements. Transmission pipelines would continue to be operated by the pipeline owners/operators under their transmission agreements.

The STTM will not replace bilaterally negotiated long-term contracts between shippers and producers, storage providers and pipeline operators, as the primary mechanism for the wholesale sale and purchase of gas, or for underpinning investment, nor will it replace the ability for users to contract directly with shippers for delivery of gas to a load centre. It will, however, allow users to purchase gas on a short-term basis without contracting with shippers for delivery, and will allow those shippers who have supply and transmission agreements to manage short-term variations to their contracted quantities as their contracted users' usage of gas changes from day to day.

While intended to have no (or minimal) immediate or direct impact on the operation of existing shipper-pipeline operator transmission agreements, the existence of the STTM may, over time, increase the value of park/loan services, storage facilities and other transportation services and thereby provide greater incentives for parties to seek services that may increase their flexibility to manage their wholesale exposures.

A Market Operator will be required. The Market Operator will not have any pipeline scheduling or operating responsibilities. As proposed, the STTM would become the compulsory balancing mechanism between participants, which would replace the existing balancing arrangements and systems where implemented¹⁴. It is noted that participants in NSW and SA are currently considering changes to these arrangements. It is expected that the STTM Market Operator will also take on the retail market activities undertaken by the current Market Operators in NSW, ACT, SA and (potentially) WA.

While the short-term trading market may well impact on shippers' nominations to producers and pipeline operators, the pipeline operators should see no change in the nomination process itself. Participants/shippers will continue to nominate based on their contractual rights. These contractual rights will, in effect, have been offered to the market and only those bids accepted by the market would be required to flow. These would then form the basis for shippers' nominations to the pipeline operator(s). However, shippers will not be obliged to use their accepted bids as their nomination for the day as this would restrict their ability to exercise commercial judgment in the management of their contractual position on the pipeline on a daily basis.

The STTM will not operate in Victoria but will provide price signals that can be used in conjunction with the price signals from the Victorian gas market which participants will react to when deciding how to best use their gas supply and transportation rights across

¹⁴ The proposed arrangements could apply to all loads connected to the pipeline systems in the NSW, ACT, SA, WA, QLD and NT gas markets. However, as part of any decision on whether to proceed with this STTM, there is the need to consider whether there would be adequate benefits on non-interconnected pipeline systems such as (currently) WA, NT and QLD.

the interconnected gas markets of New South Wales, the Australian Capital Territory, Victoria, South Australia and Tasmania.

2.5.5 Information systems and information requirements

The information systems and requirements of the STTM are:

- A Bulletin Board containing the same information as provided in Section 2.4.2 plus a range of additional market information such as published prices etc.
- Market Systems, including systems for:
 - Submission of withdrawal forecasts and delivery offers;
 - Clearing of bids/offers and determination of clearing price;
 - Collection, processing and storage of metering data (including profiling where required);
 - Settlement systems.

Market information, including the clearing prices at each hub would be published as soon as practical each day, along with projected clearing prices for the following two days.

Market participants will require facilities to submit their daily nominations/bids/offers to the market operator and are likely to require confidential access to data on their own market positions – cleared quantities, imbalances (in GJ), market exposures (in dollars).

It is anticipated that it will be possible to leverage off existing metering, balancing, settlement and information systems that are currently in use in various jurisdictions for management of retail competition.

2.5.6 Implementation

STTM governance, legislation and Code options are currently being assessed by GMOWG. For the purposes of this study it has been assumed that the model adopted will not materially impact on costs.

Implementation of a STTM is expected to take about 2 - 3 years. Costs are projected to be incurred from 2007 onwards, benefits from 2010.

2.5.7 Hub definition

Estimates of the quantities of gas that would fall within each hub have been prepared for New South Wales, South Australia and ACT hubs using information provided by GMC and REMCO, together with information on gas usage for generation compiled from NEM data by MMA. Estimates for gas quantities in potential hubs in Queensland, Western Australia and the ACT have been derived by MMA on the assumption that the hubs are located in the Brisbane, Perth and Canberra regions respectively. No estimates have been prepared for hubs elsewhere in Queensland and Western Australia, or in Tasmania or for transmission hubs.

The New South Wales and South Australian hubs forming the basis of this cost-benefit analysis account for 185 PJ¹⁵ of gas demand, over 90% of their respective jurisdictions' totals. If STTM implementation was limited to these two hubs, the total quantity of gas traded through short-term markets, including the Victorian market, would be 394 PJ, 44% of the national total. The other hubs considered would add a further 288 PJ of demand, taking the total quantity of gas traded through short-term markets to 682 PJ, 76% of the national total.

Table 2-2 Estimated hub gas demand 2005 (PJ)

	NSW	SA	Qld	WA	ACT	TOTAL
Mass market	28	11	4	13	6	62
Large industrial	58	27	34	112	1	232
Generation	8	53	12	106	0	179
Hub Total	95	90	50	231	7	473
% of State Total	90%	91%	42%	73%	100%	

Source: market operators and others

¹⁵ In 2005 terms. Market growth would increase these values prior to STTM implementation.

3 COMPARABLE STUDIES

3.1 Competitive wholesale gas markets

This section provides background information on gas market development in the US, UK and Victoria, to provide a context for the discussion of various features or analyses of these markets in other sections of the report.

3.1.1 US

Development of the US wholesale gas market¹⁶ was stimulated by a series of legislative and regulatory measures in the 1980s and 1990s driven by the Federal Energy Regulatory Commission's (FERC) broad mandate to increase competition at the wholesale level¹⁷:

- Before 1985 pipeline companies concluded long-term take-or-pay supply contracts with gas producers to secure gas supply for distribution utilities and end users.
- FERC Order No. 436 allowed these customers to exit from long-term supply contracts, and encouraged open access
- The Wellhead Decontrol Act of 1989 deregulated the wholesale price of natural gas in all interstate transactions. This promoted competition in the wholesale gas market
- FERC Order No. 500 allowed pipeline companies to pass a share of the transition costs to their customers
- FERC Order No. 636 required pipeline companies to unbundle gas sale operations from transportation. This supported the development of competitive gas marketing

Order No. 636 also promoted fair tariffs and permitted shippers to trade contracts which led to the development of a secondary transportation market. Order No. 636 was followed by further measures promoting competition in the gas market and increased flexibility in pipeline transportation. FERC issued orders to increase transparency and flexibility in short-term capacity resale, allow shippers choice in delivery locations on interstate pipeline systems, and promote the standardization of contracts and pipeline system operation. The Gas Industry Standards Board (now part of the North American Energy Standards Board) was established by the industry to pursue standardization of matters such as the gas-day, nomination and gas allocation procedures and trading contract standardization.

¹⁶ Development of Natural Gas and Pipeline Capacity Markets in the United States. Andrej Juris, 1998

¹⁷ It is noted that while the US wholesale market is highly competitive, the US gas retail market is less competitive than the UK or Australian retail markets.

In the US wholesale gas market trading takes place through bilateral transactions between producers, marketers (shippers), retailers and self-contracting users. The large number of participants has generated liquid markets in both physical and financial contracts. Physical contracts include: long-term – over 18 months; medium-term – 1 to 18 months; and short-term – 1 day to 1 month. Gas scheduling takes place through shipper nominations to producers and pipelines, with incentives for pipeline receipts and deliveries to remain in balance, and short-term contracts are mostly used for balancing purposes.

Financial contracts include futures, forwards, swaps, and options. Futures are traded on the New York Mercantile Exchange (NYMEX) and most other contracts are traded over-the-counter. Price indices were created by the trade press based on polling market participants.

Physical trading has become concentrated on market centres or hubs, usually at the confluence of two or more pipelines and frequently with an associated underground storage facility. Hubs offer a variety of services including: park and loan; peaking or balancing sales; storage; electronic trading; and administration. The first, Henry Hub, was established in 1988 and is still a leading market centre though there are now 37 hubs in total in the US and Canada¹⁸. Henry Hub is the delivery point for NYMEX Futures.

The North American gas market suffered a severe set back in 2001 with the collapse and withdrawal of Enron, which had been the largest market maker and provider of trading services, and the subsequent withdrawal of other large traders such as AEP, Aquila, CMS, Dynegy, El Paso, Mirant, PG&E and TXU. Significant concerns arose in regard to declining credit ratings and alleged manipulation of market price indices. Market liquidity fell significantly, with both NYMEX futures and Henry Hub trading falling during 2002¹⁹. However the market has ultimately proved resilient with new institutions such as the Intercontinental Exchange (ICE) and market hubs taking the place of Enron - US concerns have since moved on to the high price of gas.

3.1.2 UK

The gas market in the UK emerged during the 1990s as a consequence of the British Government's desire to promote gas retail competition. Third party access to National Grid's (then British Gas) network in 1990 initiated short-term bi-lateral trading and in 1996 revised network balancing arrangements under the Network Code created a short-term "on-system" market for shippers to manage their imbalances and a "flexibility" market for use by National Grid to manage physical imbalances. The flexibility market was a pool market with bids by shippers scheduled by National Grid to minimise the cost of gas.

The separation of the two markets proved a costly way of managing imbalances and in 1999 the New Gas Trading Arrangement (NGTA) was introduced. Under the NGTA a single "On-the-day" Commodity (OCM) Market was created as a platform for balancing

¹⁸ Natural Gas Market Centres and Hubs: a 2003 Update. Energy Information Administration October 2003.

¹⁹ 2003 Natural Gas market Assessment. Staff Report by office of market oversight and investigations, FERC.

between shippers and National Grid²⁰. Balancing rules provide incentives for shippers to manage their own imbalances – daily imbalance cash-out charges are based on prices paid²¹ by National Grid in the OCM, so shippers can reduce their costs by out-trading National Grid in the same market. As National Grid is not the only buyer in the OCM, it cannot simply select least cost bids and has to trade bi-laterally with shippers.

Trading in the OCM takes place at the National Balancing Point, a virtual hub, and is anonymous. Capacity to inject into and withdraw from the NBP is subject to auction and trading. OCM volumes account for 9% of gas used in the UK and National Grid's share of this is just 8%, or less than 1% of gas shipped.

The OCM is operated by an independent market operator, EnMO, which also operates a physical futures market at the NBP. ICE also operates a physical futures market at the NBP and there are also bi-lateral forwards markets for contracts of various terms from day-ahead to annual and longer terms. In general while the OCM and futures markets are liquid, the forwards markets are regarded as having only functional liquidity and transparency and even after ten years are not fully mature²². This is most certainly due to the more limited number of participants in the UK, approximately 40, compared to the US.

3.1.3 Victoria

The Victorian gas market was established in 1999 as a pool arrangement in which participants bid to inject gas volume/price combinations. The independent system operator, VENCORP, determines a least cost schedule from the bids, to meet forecast withdrawals. The arrangement caters for non-priced "nominations" (effectively zero priced bids) and controlled withdrawals i.e. withdrawals that will only take place if the price is below a nominated level.

A market price is set ex-post, allowing for variation to the withdrawals but not allowing for the impact of constraints or surprise events, and participant imbalances between injections and withdrawals are cashed out at the market price. The costs of constraints are recovered through separate uplift charges.

Participant dissatisfaction, with ex-post pricing in particular, led to a review of alternative models during 2003 and 2004. Following detailed evaluation, including cost benefit studies, an ex-ante model involving four hourly rebidding was selected and developed for implementation during the last quarter of 2006.

3.1.4 The ideal wholesale gas market

For the purpose of estimating the benefits of the STTM by comparing it with more competitive, transparent markets in general, the market elements that would promote the

²⁰ Gas Balancing System in UK under NGTA. On-the-day commodity market (OCM). EnMO,

²¹ Low or highest paid by National Grid according to whether the shipper's balance is negative or positive.

²² Ensuring Effective and Efficient Forward Gas Markets. Report to DTI by Global Insight. March 2005.

greatest efficiency are set out below. Based on the examples of the US and the UK, these would be:

1. Physical markets of varying duration:
 - Day ahead and day after
 - On the day
 - Weekly, monthly, seasonal
 - Annual and longer
2. Financial markets
 - Futures
 - Options
 - Forwards
 - Swaps
3. Provision of information
 - Sufficient to enable participants to manage their risks; and
 - The risks to security of supply

The current market in Australia lacks most of the above features. Even in Victoria only the short-term market is liquid and other sectors lack depth, where they exist. Similarly, even with the STTM, these additional features would be absent from markets in NSW, SA and elsewhere. As it does not seem feasible to carry over the pool model to create liquidity in markets other than spot markets (see box below) this situation would not change until the national market matured to a higher level of significant, well informed participants. Based on the UK experience at least 20 and possibly more participants would be required for functional liquidity.

Our estimates of what the STTM can achieve are therefore based on this view that while there would be short-term liquidity, other important market components would not be expected to develop over the ten year timeframe of the CBA.

Pool and Bi-lateral Markets

The proposed STTM and the Victorian Gas Market are both pool markets whereas the US and UK gas markets are both based on bi-lateral trading. As observed by Juris²³, in theory if properly applied both pool and bi-lateral market models lead to the same efficient pricing outcome. However, in practice the two models are not equally suited to the characteristics of actual markets. Bi-lateral trading works best in large markets with sufficient participants to ensure liquidity and in long trunk networks with few pipeline interdependencies, whereas pool markets work best in smaller markets with too few initial participants to provide liquidity and dense pipeline networks with alternative flow routing.

The strength of pool markets is that they “create” liquidity by compelling all network users to offer gas to the pool. However this compulsion can only be exercised on gas injections that would have to be made through this or another necessary process such as the standard nomination process. Thus it is difficult to create pool markets for month ahead contracts or futures etc that are not directly concerned with network scheduling.

3.2 Cost benefit analyses of other energy market developments

The rapid development of gas markets in the US, UK and Victoria during the 1990s, described in the previous section, and the parallel development of electricity markets, took place without significant efforts to confirm in advance that their benefits exceeded their costs. According to market participants, neither the Australian National Electricity Market nor the initial version of the Victorian gas market was subjected to cost-benefit analyses.

Ofgem, the UK energy regulator, has gone so far as to argue that, “A cost benefit analysis was difficult because both the costs and benefits of reform were very difficult to quantify. Any cost benefit analysis would be very subjective and unlikely to inform a decision as to whether or not to reform the gas balancing regime”²⁴. This was stated in the context of Ofgem’s desire to change the gas balancing regime in response to a perceived problem, which later turned out to be unimportant.

A number of retrospective analyses of US electricity market reform have been undertaken but the conclusions appear to be divergent. Larry Ruff, a leading proponent of competitive energy markets who played an active role in Australian wholesale market development, has concluded that for the US electricity markets as a whole, “net real benefits so far are probably negative²⁵”. A detailed study of the PJM region on the eastern seaboard however shows net cost savings from all aspects of electricity reform of 15% per annum²⁶. Possibly Ruff would agree that PJM has done it well while the national average is influenced by the market failure in California.

²³ The Emergence of Markets in the Natural Gas Industry, Andrej Juris , 1998.

²⁴ Ofgem’s revised proposals to reform the gas balancing regime. Notes of the workshops held by Ofgem. May 2002

²⁵ UnReDeregulating Electricity: Hard Times for a True Believer, Larry E. Ruff, 1 May 2003.

²⁶ Estimating the benefits of restructuring electricity markets: an application to the PJM region. Centre for the advancement of energy markets, October 2003

A retrospective assessment of UK electricity reform by Littlechild²⁷ concludes that there has been a significant net benefit, distributed to both investors and consumers. The contribution of NETA, the new electricity trading arrangements, is not identified but receives favourable comments.

The following sections describe a limited number of forward looking CBAs with some relevance to the present study.

3.2.1 Victorian gas market pricing and balancing review

The Victorian gas market pricing and balancing review, conducted during 2003 and 2004, investigated the possibility of replacing the current daily, single zone market model with shorter period multiple zone markets. Following detailed evaluation, the review identified a preferred alternative daily model involving four hourly rebidding. An initial study by Frontier Economics²⁸ found no net benefits for a range of broadly defined directions but a study of more defined options by ICF Consulting²⁹ identified two preferred packages.

The Frontier Economics benefit methodology relied principally upon price efficiency gains measured by the reduction in deadweight loss, as also used in the present study.

3.2.2 Provision of gas market information - UK

The provision to the market of further information regarding gas flows into the National Grid network from producers has been the subject of (at least) two cost-benefit analyses. The further information is additional to the already significant level of information provided to the market in the UK, which considerably exceeds the information content of the Bulletin Board – an overview is provided in APPENDIX C.

Ofgem, the UK energy regulator, based on a report by Barclays Capital, estimated a gross benefit of £265m per annum³⁰, composed of: increased competition £45m; coordination of outages £20m; and efficient risk management £200m. MMA understands that this value, which is approximately 2% of the UK wholesale market value, is a benefit to consumers only and is not a net economic value.

Oxera, an energy consultancy, estimated the benefits of a more restricted set of information and determined a gross benefit in the region of £39m–£176m net present value over 15 years³¹ and corresponding costs of less than £2m. The net benefit is in the range 0.04% to 0.15% of the wholesale market value. Oxera derived the benefit from the gains from smaller market price spreads at times of uncertainty, a benefit purely to consumers, but could not place a value on pricing efficiency. Thus Oxera's estimate is also not a net economic value, though it believes that the net economic value would be positive.

²⁷ Competition and regulation in the UK electricity market, Professor Stephen Littlechild, Aix-en-Provence, 23 January 2004

²⁸ Analysis of high-level design directions for the Victoria gas market, Frontier Economics, December 2003

²⁹ Stage 2 evaluation of market design packages detailed report, ICF Consulting, April 2004

³⁰ Ofgem (2005), 'Offshore Gas Production Information Disclosure: Initial Consultation and Draft Impact Assessment',

³¹ What are the costs and benefits of near real-time gas information? Report prepared for UK Offshore Operators Association by Oxera, May 2005

From the Australian perspective we believe it is important that in the UK value is attributed to further information even in a relatively well informed market.

3.2.3 US electricity market redesign

Ongoing debate about the US electricity market structure in response to initial design flaws is characterised by emphasis on proper assessment of the costs and benefits of the key proposals, such as LMP (locational marginal pricing) and RTOs (regional transmission organisations). The CBA debates however are characterised by disagreements and misunderstandings about what the real issues are: the impact on existing rights; what the options are; what the status quo is; and how to do the CBA³². The methodology issue centres on the pros and cons of historical analysis vs simulation, the value of which is highly sensitive to assumptions about the future, such as bidding behaviour. Supporters of CBAs fear that stakeholders will not be swayed from their views by study outcomes.

3.2.4 Conclusions

The net benefits of new market structures have proved difficult to estimate, both ex ante and ex post. Typically the benefits are a small percentage of the total market value.

³² The costs and benefits of cost-benefit studies - a clients perspective. Steve Greenleaf, May 22, 2003.

4 OPTION IMPACTS

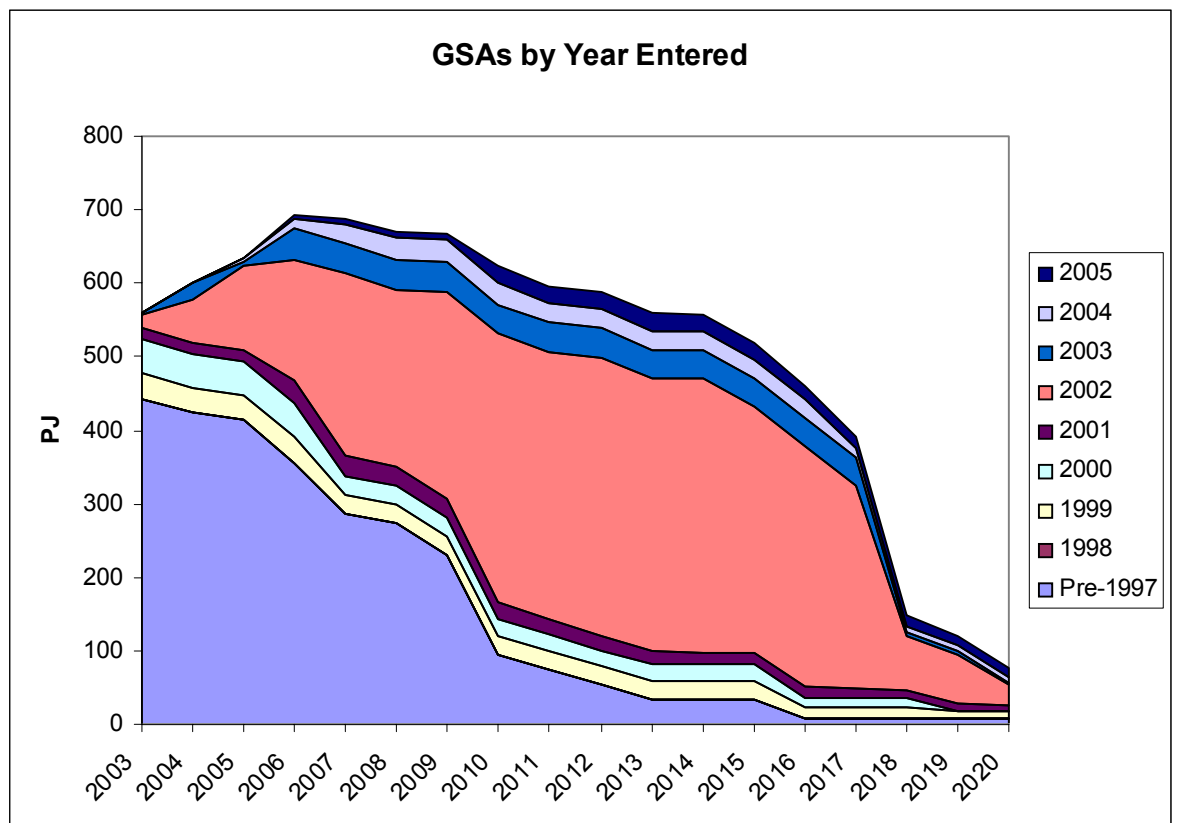
4.1 Introduction

This section considers the potential for the STTM to have impacts that are not strictly costs or benefits. The impacts are primarily within the gas industry and include: gas supply; gas wholesale and retail prices; gas demand; the number of gas market participants; and market power. The Bulletin Board is considered unlikely to have material impacts on any of these factors.

4.2 Gas supply

Gas supply is dominated by long term gas supply agreements (GSAs) between producers and retailers, generators and other self-contracting users. While some recent agreements have been of a shorter duration, the volume of gas contracted is such that changes to this pattern will be limited over the study period, particularly if large volume GSAs for PNG gas are confirmed (Figure 4-1).

Figure 4-1 Gas supply agreements, Eastern States



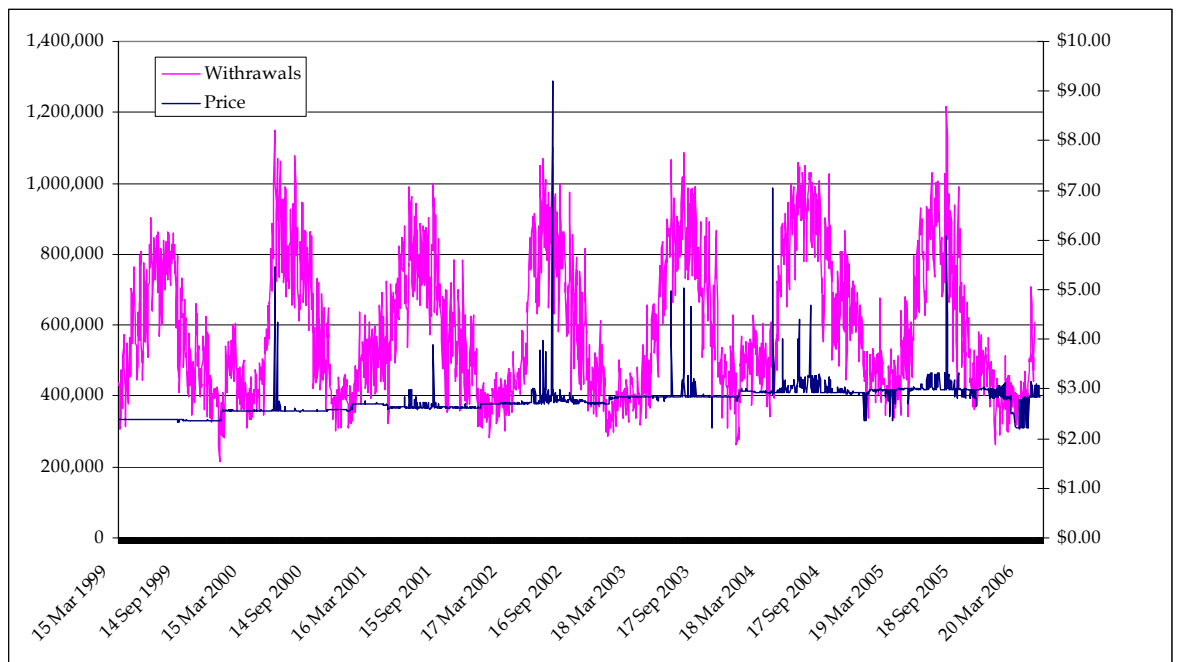
Source: MMA database compiled from public sources

The majority of gas entering the STTM will therefore be supplied under long-term GSAs and there will be limited opportunities for producers to supply spot gas. It is possible that with the opportunity for spot trades under the STTM, future production capacity will be developed without 100% being covered by GSAs but the funding requirements for capacity will ensure that high levels of cover are retained. The STTM is therefore not expected to have a material impact on gas supply.

4.3 Gas wholesale and retail prices

The evolution of spot prices under the STMM is expected to follow that of the Victorian market over its initial period. In Victoria early prices deviated little from GSA prices except on occasional high demand or supply shortfall days, when there was an upward spike (Figure 4-2). Even annual GSA indexation is visible in the chart. Progressively more days deviated from the base level as underground storage was used more and recently the price has deviated downwards on low demand days, possibly as a result of oversupply, creating a defined seasonal pattern.

Figure 4-2 Victorian gas price and withdrawals



The impact of this on retail prices has been very limited to date as retail price caps in Victoria are set by reference to both the spot price and a capacity element not reflected in the spot price³³. It may be expected that more seasonal pricing would be offered to end-users to whom it had some value.

³³ Final Report. Special Investigation. Proposed Retail Tariff Amendments. Essential Services Commission December 2003.

The STTMs would be expected to have similar price trends, driven by both internal mechanisms and by interaction with each other and the Victorian market through arbitrage.

The potential net impact of the STTMs on end-user prices in the medium cost/benefit scenario has been estimated assuming that the net benefit of \$31m in NVP terms is wholly applied to reducing retail prices, i.e. all cost and benefits are ultimately passed through to end users in New South Wales and South Australia. The discounted weighted average price reduction to 2018 would be 2.1c/GJ, less than 0.5% of end user prices.

Table 4-1 Potential impact of STTMs on end-user prices in NSW and SA

	Generation	Large Industrial	Mass market
End-user price	\$4/GJ	\$6/GJ	\$18/GJ
Price reduction	0.5%	0.3%	0.1%

4.4 Gas demand

It is anticipated that the majority of end users will continue to purchase gas through retailers and will not directly face the spot price. The major impact the STTM will have on these users will be through the impact on average prices as detailed in Table 4-1. The demand impact depends upon the demand elasticities, for which the following long-run estimates made by Frontier Economics³⁴ have been used: mass market, -0.8; industrial, -1.5; gas-fired generation, -1.0. These suggest that the STTM induced price reductions would lead to small increases in demand, of the order of 0.5% for industrial and generation sectors and 0.1% for the mass market.

The demand impact on end users that choose to be exposed to the spot price may be more significant, in line with expected variations in the spot prices in each hub, described in the previous section. Such users may include gas-fired generators and large industrial users. For users to adjust demand in response to spot prices, the spot price has to vary across a range of values that incorporates the users' marginal value of gas. For gas fired generators the marginal value is set by the electricity pool price and their heat rate – a typical generator with a heat rate of 10 GJ/MWh will generate if the gas spot price in \$/GJ is less than the electricity pool price in \$/MWh divided by 10. Assuming that the pool price ranges from \$0/MWh to \$10,000/MWh, the marginal value of gas will range from \$0/GJ to \$1,000/GJ, possibly capped by the cost of using an alternative fuel such as fuel oil or distillate. Taking the gas spot price in Victoria as an example, STTM prices may range from \$2/GJ to \$10/GJ under normal operating conditions, which may sometimes be above and sometimes below the generators marginal value, leading to a significant demand response. This is discussed further in section 7.7.

³⁴ Analysis of high-level design directions for the Victoria gas market, Frontier Economics, December 2003

In the case of industrial users however it is not clear that their marginal value of gas will fall into the \$2/GJ to \$10/GJ range. MMA research³⁵ suggests that the value of lost production to the average industrial user is \$86/GJ and the value to the most energy intensive manufacturer is likely to be at least \$30/GJ. Although some users may offer to partially reduce their demand at lower prices, this makes any price based demand response from industrial users unlikely under normal market conditions. Under more extreme price conditions caused by a gas supply shortfall a demand response is more likely - a description of the impact of the STTM in these circumstances is provided in section 7.3.

4.5 Number of market participants

The STTM may facilitate the entry of new market participants, by reducing the costs and risks of entering the wholesale and/or retail market. A self contracting user observed to MMA that in Victoria it could contract for a fixed volume less than its peak and rely upon the Victorian spot market to absorb/provide unders/overs with limited risk. A new retail entrant in the Victorian market also observed that prior to market entry it was difficult to forecast its gas requirements and it was more cost effective to buy from the spot market during the initial phase, rather than enter multiple contracts with take-or-pay risks.

The number of actual new entrants in each major gas retail market tells a mixed story (Table 4-2) as each is linked to the others and to competition in electricity retail markets. While there are three new entrants in each market, their backgrounds are different. In NSW Energy Australia entered the market to defend its electricity retail customers against dual fuel offers by the larger incumbent, AGL. TRUenergy and Origin, incumbents elsewhere, appear to have limited their entry to larger customer markets. In Victoria, Energex, a Queensland gas and electricity retailer, initially entered the market by purchasing "release gas" from the Victorian Government, Energy Australia entered after entering the NSW market and Victoria Electricity entered as a start-up gas/electricity retailer. In South Australia, which opened its mass market two years after NSW and Victoria, all market entrants were well established elsewhere prior to entry. As footnoted below, the number of self-contracting users and large user retailers is very similar in New South Wales and Victoria.

Table 4-2 Gas market retail³⁶ participants

	Incumbents	New Entrants
NSW	AGL, Country Energy	Energy Australia, TRUenergy, Origin
Victoria	AGL, Origin, TRUenergy	Energex, Energy Australia, Victoria Electricity
South Australia	Origin	AGL, TRUenergy, Energy Australia

³⁵ The Value of Customer Reliability for Gas. MMA September 2005. Available on www.vencorp.com.au

³⁶ Mass market retailers only. In Victoria and NSW there are also five self-contracting users/large user retailers.

Given the number of incumbents in Victoria, there were fewer “ready made” new entrants and Victoria has seen the first start-up gas retailer, Victoria Electricity. This suggests that Victoria is more attractive to new entrants than New South Wales and South Australia but the attraction could be due to a number of factors including the presence of the gas spot market in Victoria and the considerably larger gas mass market in Victoria.

It is also noted that the number of entrants in retail electricity markets, in which there is a spot market, is greater than the number of entrants in retail gas markets, though in this case too some of the attraction may be the larger scale of the electricity mass markets.

On balance we believe that the STTM would support the entry of further participants but that it may not of itself directly lead to further entry.

4.6 Market power

Market power is defined as the ability of individual participants to increase prices without losing market share. Markets with few participants, where few generally means less than about ten³⁷, are regarded as concentrated and are susceptible to the exercise of market power – nevertheless, market power as evidenced by large price rises has not been observed in gas upstream or retail markets in Australia in spite of there being fewer than ten participants in most sub-sectors. In the Victorian gas market VENCORP reports³⁸ on the factors behind significant pricing events and has not found any events to be due to market power.

The positive impact of the STTM on market entry discussed in the previous section suggests that it would act to reduce market power. There are nevertheless two factors that could cause the STTM to increase market power:

1. Complexity. The designs of markets such as the STTM are complex and this can confer advantage on participants that can afford to master the complexity
2. Conferring pricing significance on market elements that are accessible to a limited number of participants, for example possibly linepack.

At the present stage of market development it is not possible to provide definitive views on either factor. Further development of the STTM concept will undoubtedly be cognisant of the risks posed by the factors and will seek to mitigate any adverse effects.

³⁷ Corresponding generally to a Herfindahl-Hirschmann Index of 1000 or more.

³⁸ Significant pricing event reports are available on www.vencorp.com.au.

5 BULLETIN BOARD

5.1 Costs

5.1.1 Assumptions

In our calculation of costs for the Bulletin Board (BB) we have made the key assumptions described below.

5.1.1.1 Coverage

BB costs have been calculated assuming Australia-wide coverage of facilities (production, transmission and storage) and loads (retailers, generators and self-contracting end-users) of a material size. There are an estimated 130 such facilities and loads.

5.1.1.2 Implementation period

We have assumed that the MCE will make its decision about the BB and STTM by the end of 2006. No costs incurred before this time are included in our analysis as they would be incurred in any case.

We have assumed that the BB by itself would be planned and implemented in 2007 with operations starting in 2008. The costs are estimated assuming a one year implementation phase followed by ten years of operation.

5.1.1.3 Full costing of time

We have included the costs of all government and industry personnel involved in planning, testing and other activities at their estimated average annual or hourly costs. This is on the assumption that this best reflects their opportunity cost.

5.1.1.4 BB concept

It has been assumed that the BB will be implemented largely as described in Section 2.4. While a few questions and issues were raised during consultation, the key concepts are reasonably understood.

We have assumed the costs are fully met as being a gas market option rather than being met in full or in part by the MCE's National Gas Emergency Response Advisory Committee (NGERAC).

While it is understood that the BB as specified will meet a part of the NGERAC needs (see Section 5.2.3) it will not meet the full NGERAC requirements, for example as specified it will not include any of the modelling and scenario analysis required by NGERAC.

5.1.1.5 *Indicative nature of costs and cost ranges*

It must be stressed that the costs estimated, assumed and calculated for the BB are indicative only. Although they have been derived largely through consultation, the range of cost estimates provided has varied greatly, often by an order of magnitude.

MMA has in its medium scenario analysis used the cost estimates it considers best meet the nature, scope and complexity of the specific task within the BB. However, because the estimates we have received have ranged widely, we have also calculated high and low scenario costs. Generally these are calculated as $\pm 50\%$ of the medium scenario cost, however, sometimes the upper limit has been set higher.

5.1.2 **Cost components**

We have costed the following cost components of a BB:

- Planning phase;
- Government and legal;
- System implementation;
- Ongoing operation by BB operator;
- Implementation and ongoing operation by facilities participants;
- Implementation and ongoing operation by load or user participants.

5.1.3 **Planning Phase**

The planning phase of the BB is expected to cover the following key areas of uncertainty:

- Coverage and Regulation. This component will consider what facilities and loads will need to be covered by the BB requirement, how this will change over time³⁹, how coverage can be best defined and also the type of regulation or rules which will be required to implement the BB.
- Information. Exactly what information will be required, how and in what form it is to be provided and how often it is to be updated. The information expected to be provided to the BB has been discussed in section 2.4.2.

While most parties consulted during the course of the assignment have accepted the defined level of information as reasonable for the BB, several have raised questions about the actual definitions and how and when the information will need to be provided.

- System definition and ongoing operation.

³⁹ For example with the addition of new facilities or division of responsibility for loads.

There has been some debate about what the BB system will actually look like. While there has largely been consensus that it should be web-based and integrated, it is unclear whether the system adopted should be “low end” or “high end”. For example, will most of the operations be automatic or manual, will the display be tabular or graphical and will it be possible to easily generate reports and history.

5.1.3.1 Costs of the Planning Phase

We have been provided with a range of expected costs for planning and implementing a BB. The expected costs have differed widely, depending largely upon the assumptions made about the scope of the BB and level of consultation expected. We have generally made assumptions which lie within the extremes of inputs provided.

We have assumed that during the planning phase there will be three working groups (WG) established:

- A Governance WG to decide the form and content of rules and/or regulations.
- An Information WG to determine exactly what information will be required and how it is to be provided.
- A System WG to determine the system specifications.

We have made the following assumptions about the Working Groups:

- Each WG will have between 9 and 13 members (including a Chair).
- There will be a total of 14 meetings, each of 2-4 hours duration.
- Support and consultation will be required, each at a level of 2 times the amount of WG member contribution.
- Costs of senior personnel are estimated at \$125/hour and of support personnel half this amount.
- 50% of members will travel.

We have assumed that a Project Manager, at a cost of \$200,000, will be required for a period of a year to manage the planning and implementation of the Bulletin Board.

Based on the above assumptions the cost of the Planning Phase is expected to be of the order of \$500,000, with an estimated range of uncertainty of some $\pm 50\%$.

5.1.4 Government Costs

Government personnel have estimated the costs to Government for legal advice, policy advice and developing necessary legislation has been estimated by Government personnel as between \$0.5m and \$1m for the BB and STTM combined.

We have assumed a relatively low cost of \$100,000 for the Bulletin Board alone. Some Government representation on working groups is assumed in the planning phase. The range of certainty around this estimate is assumed to be - 50% and+ 100%, but could be greater depending on the level of involvement of jurisdictions.

5.1.5 System implementation

The system specification is expected to be one of the outputs of the WGs. The costs estimated for the actual system and implementation have ranged widely from about \$100,000 for a “low end” system with largely manual inputs and manipulation and limited reporting to about \$500,000 for a “high end” system.

System testing for the 130 or so expected participants Australia-wide is expected to add a cost of a further \$50,000.

We have assumed a cost of \$400,000 for system implementation and testing, with a range of + 100% and -50%. The uncertainty is higher on the upper side because of the expectation that a higher end outcome will be sought.

5.1.6 Ongoing BB operation

The ongoing costs of a BB operator will depend on the level of automation of the system. At its simplest a BB could be managed largely manually, with daily demand inputs being aggregated manually. Alternatively, this could be automated at a higher initial system cost.

We have again assumed a middle path with an annual requirement of about \$60,000 (approximately 50% FTE support staff) for operating the BB plus a further \$20,000 pa for IT and infrastructure costs.

5.1.7 Facility participants

We estimate that there will be around 65 facility participants, producers, storage providers, transmission pipelines and network operators, who will need to provide initial inputs to the BB and then occasional updates as required.

We understand that the information required is already available to the facilities and that the information required for the BB during facility maintenance and “incidents” is also currently available. The cost of collecting this information is estimated to be low.

The cost of providing this information in the form required by the BB is also assumed to be low, some \$2,000 set-up cost per facility participant. There are assumed to be no material incremental ongoing costs for facility participants.

This results in an estimated set-up cost for facility participants of around \$130,000.

5.1.8 Retailer and user participants

Retailers and users will be required to provide daily demand data forecasts to the BB operator. Such data is already required for current operations so it is assumed that no incremental costs will be incurred to collect this data.

However, again, there will generally be costs to set up system interfaces for the provision of such information. We have estimated that such costs will range from \$2,000 for small users with largely invariant load to \$50,000 for large retailers.

We have estimated a total set-up cost of \$300,000 for retailers, generators and self contracting users implementing the BB. We have not factored in any incremental operating costs for such users.

5.1.9 Liability issues

We have assumed that information posted on the BB will generally not be subject to liability issues, and have not factored in any costs related to change in risks for parties providing such information.

5.1.10 Avoided costs

While some costs in the current system may be avoided, such as the time taken by Government officials and end-users to look up information, these are considered relatively immaterial and have not been calculated.

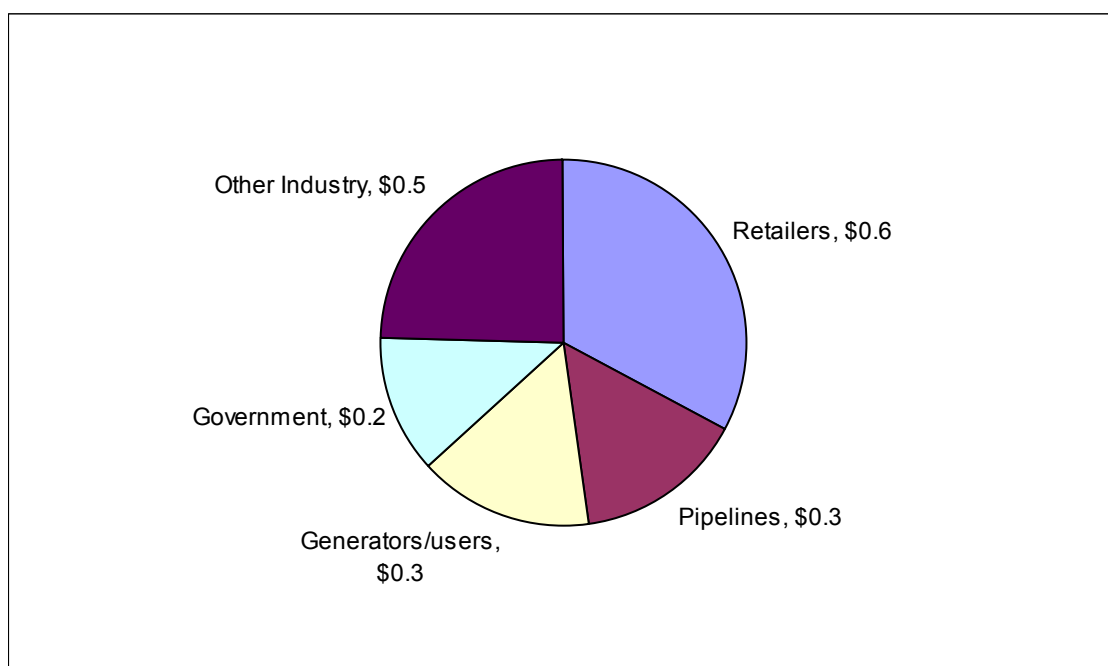
5.1.11 Net Present Cost

The net present cost of the BB, at a real discount rate of 8.5% is estimated to be \$2m with a range of \$1m to \$3m. The medium case scenario cost includes a set-up cost of \$1.5m and an annual operating cost of about \$0.1m pa.

5.1.12 Initial allocation of costs

We have indicatively calculated the initial allocation of the medium scenario BB costs to retailers, pipelines, generators and other self-contracting end-users, other gas industry participants (eg producers, storage operators, and networks) and government. We have assumed that the costs of the BB (system set-up and operations) will be borne largely by the industry.

The cost of the BB is expected to be shared across the industry, with retailers making up some one-third of costs. We have not calculated how, and to what extent, costs can be passed through to end-users.

Figure 5-1 Initial cost allocation of medium scenario BB, \$m NPV

5.2 Benefits

5.2.1 The value of information

The Bulletin Board is designed to provide market participants and governments with additional gas market information to facilitate improved decision making. The information is expected to impact on two aspects of the market:

- Pricing
- Gas network management during a supply shortfall

In evaluating the Bulletin Board benefits it has been assumed that a voluntary buy-sell trading facility would not attract interest. This is the near unanimous view of stakeholders that commented on the issue to MMA and is based on their experiences with similar structures set up by Duke Energy Australia to trade gas and pipeline capacity on the Queensland Gas Pipeline and the Eastern Gas Pipeline. The QGP facility was used initially but participants found it easier to arrange deals over the phone.

Estimating the economic value of information is challenging, as noted in section 3.2.2. The following estimates are based on plausible outcomes and represent the likely magnitude of benefits rather than precise estimates.

5.2.2 More efficient pricing

The information provided by the Bulletin Board would permit participants to make more efficient pricing decisions, which would result in net economic benefits. While the exact

impact of additional information is difficult to judge, the benefits that would flow from particular price changes can be estimated using the concept of deadweight loss, which measures the combined losses of producers and consumers. Deadweight loss is described in more detail in APPENDIX B .

To do so we assume that without the Bulletin Board annual gas prices are inefficient and that the Bulletin Board information enables participants to more closely estimate true supply and demand curves and that this changes prices by a small amount, 1c/GJ for example. The economic benefit of the information is then the reduction in deadweight loss due to the price change – it does not matter whether the change is up or down. Deadweight loss depends on supply and demand elasticities, for which the following long-run estimates made by Frontier Economics⁴⁰ have been used: supply elasticity, 0.5; residential demand elasticity, -0.8; industrial demand elasticity, -1.5; gas-fired generation demand elasticity, -1.0.

The annual deadweight losses for all states except Victoria, which may not benefit in this way from the Bulletin Board, associated with various price changes, are shown in Table 5-1. The considerable range of the estimates reflects the fact that deadweight loss increases as the square of the price change.

Table 5-1 Annual deadweight losses due to pricing inefficiency

Price change	\$0.01/GJ	\$0.025/GJ	\$0.05/GJ	\$0.10/GJ
Deadweight Loss	\$30,000	\$170,000	\$690,000	\$2,750,000

Given the nature of the information on the Bulletin Board it seems unlikely that a change of more than 2.5c/GJ would result from it, which caps the value of more efficient pricing at \$170,000 per annum. The net present value of this amount over the period from 2007 to 2018, assuming that the Bulletin Board is operational by 2008, is \$1.1m.

5.2.3 Gas network management during a supply shortfall

The information provided by the Bulletin Board will assist in the management of the gas supply network during a supply shortfall. The NGERAC has determined independently that it will establish a Bulletin Board for this purpose, with the data also to be used to develop a simple broad model of the inter-connected network to provide an understanding of gas supply and demand of the south east Australian gas system and support emergency management.

The improved information on gas supply capability available through the Bulletin Board will enhance decision making by system operators and governments on matters such as

⁴⁰ Analysis of high-level design directions for the Victoria gas market, Frontier Economics, December 2003

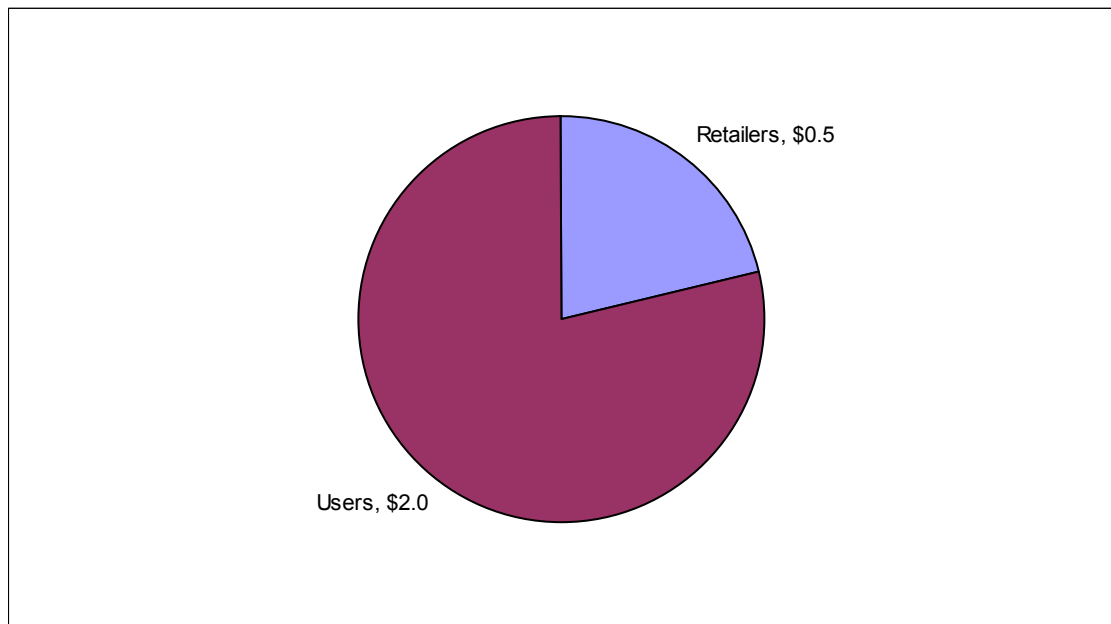
end-user curtailment, reducing the high costs that it imposes. An indicative value of this contribution can be estimated using the experiences following the Moomba plant fire and the consequent gas supply shortfall in January 2004. In section 7.3 it is shown that the supply shortfall led to total curtailment of approximately 60 TJ/d for 4 days, which cost users approximately \$86/GJ, a total of approximately \$21m. If we hypothesize that the Bulletin Board information would enable the curtailment to be reduced by just 10TJ, it would save \$3.4m in a similar future event. This can be translated into a net present value by estimating the likelihood of future gas supply shortfalls of similar magnitude and impact as the 2004 Moomba incident.

Severe gas incidents such as the Moomba plant fire and the even more severe explosion at Longford in 1998 occur relatively rarely. In both cases these were the most severe incidents at each plant over 30 years of operation. In terms of the New South Wales and South Australian gas markets, it would be reasonable to expect a rate of one incident every fifteen years in future, equivalent to a probability of 6.67% each year. This makes the \$3.4m equivalent to \$230,000 per annum and its net present value from 2007 to 2018 is \$1.5m.

5.2.4 Initial allocation of benefits

An indicative allocation of these benefits is provided in Figure 5-2. No material direct benefits to government, pipelines or producers are expected. Generators will share in retailer and user benefits in proportion to usage.

Figure 5-2 Initial allocation of Bulletin Board benefits, \$m NPV



6 SHORT TERM TRADING MARKET - COSTS

6.1 Assumptions

In our estimation of costs we have made the key assumptions described below.

6.1.1 Coverage

BB costs have been calculated assuming Australia-wide coverage. Our STTM costs have been initially calculated for hubs in NSW and SA, as required by the brief. However, the costs of an additional hub in either Queensland or Western Australia and for simpler hubs have also been calculated.

6.1.2 Implementation period

We have assumed that the MCE will make its decision about the BB and STTM by the end of 2006. No costs incurred before this time are included in our analysis as they would be incurred in any case.

We have assumed that the BB by itself would be planned and implemented in 2007 with operations starting in 2008.

We have assumed that the STTM including the BB would be planned and implemented in 2007 and 2008 with operations starting in 2009. For the STTM it is assumed that the start-up costs are incurred half in 2007 and half in 2008.

6.1.3 Full costing of time and BB

We have included the costs of all government and industry personnel involved in planning, testing and other activities at their estimated average annual or hourly costs. This is on the assumption that this best reflects their opportunity cost.

We have also costed fully the incorporation of the BB into the STTM and have assumed the costs are fully met as a gas market option rather than being met in full or in part by NGERAC (see section 5.1.1.4).

6.1.4 STTM concept and interaction with the existing FRC markets

It has been assumed that the STTM will be implemented largely as described in section 2.5. Although there has been much debate about the operation and likely impact of the STTM during the consultation phase, we have assumed that the underlying concepts remain largely unchanged from those described. However, given the large number of issues raised, we have taken into account that significant consultation and a trial period will be required before the STTM actually gets accepted and underway.

A key assumption behind the costing of the STTM has been that existing FRC systems for:

- Customer registration and transfer;

- Load profiling;
- Metering and
- B2B systems

will not require any changes, in other words, that the market operators REMCo and GMC continue to provide these services, with appropriate data transfer to the STTM as required. It is assumed that only the balancing, trading and settlement systems will require any change. This is the basis of the costing in the following steps. Further, the VENCorp system is also assumed to require no change at all.

We have assumed that the BB as discussed in Chapter 5 above will be incorporated in the STTM. The costs discussed below include costs associated with the BB.

6.1.5 Indicative nature of costs and cost ranges

It must be stressed that the costs estimated, assumed and calculated for the BB and especially the STTM are indicative only. Although they have been derived largely through consultation, the range of costs provided has varied greatly. Cost estimates provided by gas industry personnel have often varied by an order of magnitude – sometimes more.

One reason for this variation is almost certainly due to the absence of hard specifications of the STTM, its expected interactions with the industry and the changes, and hence costs, required. Thus the understanding of the STTM and its impacts has varied significantly. A further reason is that different parties have aggregated costs differently.

MMA has in its medium scenario cost analysis used the cost estimates it considers best meet the nature, scope and complexity of the specific task within the STTM. However, because the estimates we have received have ranged widely, we have also calculated high and low scenario costs. Generally these are calculated as $\pm 50\%$ of the medium scenario cost, however, sometimes the upper limit has been set higher. While this provides a significant uncertainty about costs we consider this reflects reasonably the current underlying uncertainty about how the STTM will evolve and its impact on the industry.

6.1.6 Base Case

Cost-benefit analyses are generally carried out to provide comparison against a “business as usual” Base Case. This describes how the gas industry would be expected to evolve if the MCE decided against the implementation of either the BB or the STTM.

The Base Case for balancing assumes the following:

- The South Australian, Western Australian, New South Wales and Australian Capital Territory markets currently operated by REMCo (SA, WA) and GMC (NSW, ACT) will continue with some modifications.
- REMCo and GMC will merge in mid 2007 with an estimated cost saving of more than \$1m pa.

- Costs associated with these markets will further reduce significantly at the end of 2006 (GMC) and in September 2009 (REMCo) as the major capital investments for these markets are fully depreciated.
- In the absence of the STTM both NSW and SA will undergo changes to their balancing systems with estimated costs of about \$0.2m each. Most of the consultation for these changes has already taken place. If the STTM is implemented it would probably result in the additional NSW (but not SA) changes and associated costs being avoided.
- Queensland FRC proceeds, with a balancing system similar to that used elsewhere and at a relatively low cost.
- The Victorian system proceeds with organic changes as currently envisaged.

Key players, large retailers, small retailers, electricity generators and self-contracting users, producers, storage providers, traders, pipelines and networks are assumed to continue operating largely as currently, although some costs will be incurred by several of these parties due to the changes to the balancing arrangements envisaged in SA and NSW.

Our cost analysis has been based on costs incremental to this Base Case.

6.2 Cost components

We have considered and costed the following components of a STTM:

- Planning phase;
- Government and legal;
- System implementation and trialling;
- Ongoing operation by the STTM market operator including governance;
- Implementation and ongoing operation by large retail participants;
- Implementation and ongoing operation by smaller retail participants, generators and other self-contracting end-users;
- Costs of the BB to facilities and other participants not included in the STTM;
- Implementation and ongoing operation by pipeline companies;
- Network costs;
- Existing market operator costs including consideration of avoided and sunk costs;
- Regulation;
- Prudential requirements;
- Market review after five years of operation.

6.3 Planning phase

The planning phase of the STTM is expected to cover the following key components:

- Regulation, governance and coverage. This component will consider the regulatory framework for the establishment and ongoing governance of the STTM including the BB and make decisions about coverage in terms of hubs and facilities.
- Business rules. The development and codification of the business rules essential to the market, related to bidding, clearing, settlement, prudentials and BB.
- Information requirements. Definitions, interactions, timing, flows, transfer protocols and reporting and system tendering.

There has been a significant level of debate about how the STTM will actually develop. While the required outcome, a set of daily price signals by hub, is relatively straightforward, how to best achieve this is not yet agreed and a number of practical issues still remain to be resolved. MMA considers that the planning phase will require a significant devotion of resources.

6.3.1 Costs of the planning phase

Through the consultation process MMA has been provided with a range of expected costs for planning and implementing a STTM. The costs anticipated have differed widely, depending largely upon the assumptions made about the scope of the STTM, the starting point and the level of consultation expected to achieve the final model. We have generally made assumptions which lie within the extremes of consultation inputs provided.

We have assumed that during the planning phase there will be four working groups (WG) established:

- A Governance WG to decide the form of legislation, regulations and governance.
- A Rules WG to explore, model, clarify, review, redefine and finally decide and codify exactly how the STTM will work.
- A System WG to determine exactly what information will be required and how it is to be provided and to produce detailed system specifications including those for interactions with other parties. This WG will also supervise the tender for IT systems.
- A BB WG to determine the coverage, information requirements and system specifications for the BB.

We have made the following assumptions about the Working Groups:

- Each WG will have between 9 and 15 members (including a Chair).

- There will be a total of 44 meetings, each of 2-4 hours duration, covering the 2 years planning and implementation period.
- Support and consultation will be required, at an estimated average level of three and two times respectively the time spent by the WG member.
- Costs of senior personnel are estimated at \$125/hour and of support personnel half this amount.
- 40% of members will travel (the expected geographical coverage of the STTM is expected to be less than that of the BB).

We have assumed that a Project Manager, at a cost of \$0.2m pa, and an Assistant Project Manager at a cost of \$0.1m pa will each be required for a period of two years to manage the planning and implementation of the STTM.

Based on the above assumptions, the cost of the Planning Phase is expected to be of the order of \$2m with a range of $\pm 50\%$. We expect that the incremental planning cost for planning an additional hub or extending the STTM to an additional jurisdiction will be small⁴¹.

6.4 Government and legal costs

Government personnel have estimated the costs to Government for legal advice, policy advice and the development of necessary legislation as lying between \$0.5m and \$1m for the BB and STTM combined.

We have assumed a cost of \$0.8m for the Bulletin Board and STTM combined. Some Government representation on working groups is also assumed in the planning phase. The range of certainty around this estimate is assumed to be - 50% and + 100%, but could be even greater depending on the level of involvement of jurisdictions. We have assumed an additional cost of \$50,000 for each additional jurisdiction covered.

6.5 System implementation and trials

The final system specification for the STTM is expected to be one of the outcomes provided by the working groups. In the absence of a firm specification for the actual system and implementation the costs estimated by those consulted have ranged very widely from less than \$1m to over \$4m. Clearly, significant differences exist with regard to the understanding of the scope of the task and the extent to which average or incremental approaches and costing are used. We have assumed that STTM operations (but not governance) will be an incremental activity undertaken by one of the existing market operators.

⁴¹ Assuming that this is decided at the planning stage.

We have on this basis estimated a cost of \$2.5m for the system as a whole including the STTM for the SA and NSW hubs and the Bulletin Board across Australia⁴².

During the consultation phase of this assignment it has become clear that stakeholders consider extensive trialing by the industry to be an essential part of the development of the STTM.

We have assumed for the trialing phase:

- A 3 day paper trial of the market with 24 participants (assuming half a day for testing, half for analysis).
- A two week trial of the actual market with 35 participants (assuming a quarter of the day for testing, three quarters for analysis).
- System testing for the remaining 100 or so participants in the BB.

The cost of trialing and testing under these assumptions is estimated to be \$0.4m. If changes are then made to the STTM then further trialing may also be required, at perhaps half the cost of the original trial. We have included this additional amount as a contingency within combined cost of \$3m for the system implementation and testing/trialing for NSW and SA. We have estimated an error range of - 50% and +75%, with the latter covering the cost of changes and further trials and testing if required.

Adding extra hubs is estimated to cost \$0.1m each.

6.6 Ongoing STTM operation

Expected daily STTM-related operations are described in Section 2.5.3.

The STTM is expected to be largely automated, with inputs from participants (both STTM and BB components) being received and manipulated automatically. Daily outputs, including prices and settlement quantities and dollar values would also be generated automatically.

Based on information from two sources we have estimated that the annual operating cost of the STTM Operator will be of the order of \$0.3m pa, allowing for the equivalent of an additional 2 full time equivalent (FTE) staff⁴³ and some annual expenditure on IT and infrastructure. This is on the basis that the STTM would require active involvement for a few hours per day every day of the year and that support will be required to answer questions and respond to problems related to the STTM and BB.

6.6.1 Market operator governance

Additional governance costs also need to be considered. We have calculated this on the expectation that a “stand-alone” governance structure⁴⁴ will be required even if the actual

⁴² Also including the cost of additional hardware and communication infrastructure.

⁴³ This assumes that the STTM Operation will be an incremental, not stand-alone, operation .

⁴⁴ But not a stand-alone executive structure.

market operations are incremental to activities elsewhere. The annual cost of governance is estimated to be some \$0.2m, assuming one independent Chair and 11 other senior members, 4 meetings per year and taking into account support, consultation and travel.

There will be some limited reduction in operating and Board Costs for existing REMCo and GMC activities, discussed in Section 6.12.

We estimate that the incremental operating and governance cost for each additional hub or jurisdiction added would be of the order of \$0.1m pa.

6.7 Costs for largest gas retailers in NSW and SA

The three largest gas retailers in the markets of initial concern, SA and NSW are AGL, Origin Energy and TRUenergy. These retailers will face additional costs associated with:

- Required changes to IT systems to cater for changes to the new STTM wholesale, operating and settlement provisions;
- Incremental operating costs;
- Strategic decision making and bidding strategy.

The range of costs estimated for these changes by the above retailers has again been very wide. In terms of IT system, additional cost estimates have ranged from less than \$0.5m to \$5m per retailer.

This wide range may be a result of different understandings of what changes to systems will actually be required and whether planning and trialing costs are included. The assumption used by MMA has been that the implementation of the STTM will result in no changes to the large volume interactions associated with customer billing or transfers. Changes will be limited to wholesale market systems and operations only – resulting in only a limited amount of transactions per day. As well, the costs of planning and trialing have been included elsewhere by MMA.

We have assumed that additional system costs are \$0.75m per retailer with a range of +100% and -50%. The costs for extending the STTM to Queensland or WA would in part depend on the timing. We have assumed that a further increase in IT system costs of \$0.75m per state would be incurred.

A “reality check” is available through consideration of the costs of implementing FRC changes required by a large retailer. The Western Australian Gas Retail Deregulation Project Steering Committee provided in 2001 an indicative estimate of the system IT cost to retailers of implementing FRC in Western Australia of \$3 to \$5m⁴⁵. However, these costs relate mainly to changes to the mass market functions. Changes only to the wholesale systems required due to a change in the STTM are expected to only result in a fraction of

⁴⁵ Reported in Alintagas Networks Pty Ltd., “Submission on full retail contestability costs”, available at <http://www.era.wa.gov.au/library/FRC%20Submission%20to%20OffGAR%2020%20June%202003.pdf> page 7

this cost. A cost of \$0.75m for the STTM would represent some 10% to 20% of the above estimated costs.

In terms of additional operating requirements, we have again received a wide range of estimates of incremental personnel requirements ranging from an additional 8 FTE staff to no extra staff required. The latter estimate was based on the assumption that the expected synergies resulting from a STTM operating across a number of jurisdictions would offset any additional personnel requirements. We understand that current market operations in NSW and SA generally already require some (largely dedicated) personnel and that some of these costs would be avoided. Similarly, there are already balancing settlements or tracking costs incurred in the SA and NSW markets which would be avoided.

We have estimated the incremental costs for operating according to the STTM to be an additional 0.75 FTE persons for each of the large retailers for each major market in which operations occur. For the SA and NSW markets this would mean an additional 1.5 FTE person per retailer. Each additional hub would be expected to add a further 0.5 persons.

We have estimated incremental strategic considerations to be handled largely during the planning and trial phases, but have estimated an additional initial cost of \$20,000 per major retailer.

6.8 Costs of smaller retailers, generators and self-contracting end-users

Smaller retailers and generation end-users will also face increased costs, however, not of the same magnitude as those faced by the large retailers. Firstly, the systems used by the smaller retailers and others for handling wholesale gas transactions are unlikely to be as automated, secondly most already experience costs associated with the markets, for example providing nominations and experiencing significant balancing interactions and, thirdly, they generally have a lower level of portfolio complexity and strategic considerations.

We have estimated the incremental start-up costs for small retailers and generators to be of the order of \$0.03m each for system and strategic costs and operating costs of one quarter of a FTE person pa for 9 such retailer/generators.

For (an estimated) ten non-generation end-use participants we have assumed a capital cost of \$0.01m each and an increased operating cost of \$0.025m pa, equal to 1 person-hour per day.

We have assumed four small retailers/generator and 4 end-users for each additional hub.

6.9 Costs of the Bulletin Board to facilities and end-users not covered by STTM

The above costs for participants have included the costs for the Bulletin Board. However, the costs of the BB for the other facilities and those retailers and end-users not covered by the STTM are estimated to be about the same as that of the BB, \$0.2m in total.

6.10 Costs to pipeline companies

A key underlying assumption behind the STTM has been that it will leave transmission pipeline companies largely unaffected. However, the pipeline industry has argued that additional costs could be incurred including the costs of IT systems, legal services for review of contracts and additional operating costs. There has also been an argument put forward that the cost of capital for pipelines would increase by 0.1% in order to reflect the overall increase in risk for the pipeline.

MMA accepts that the changes to the STTM may have an impact over the longer term on the operations and revenues attributable to pipeline operations. For example, the ability of end-users to better handle “unders and overs” may result in a reduction of contracting over the longer term (refer to section 7.4). However, much of the capacity of pipelines is already contracted for the medium to longer term, and in regulated pipelines any reductions in contracted quantities for the STTM may be compensated for at the next review of Access Arrangements. Additionally, although there may be a reduction in the ability of the pipeline to offer peaking services as the current users “work their contracts harder”, this will be a transfer between gas industry participants, rather than an additional cost. The STTM should also provide an opportunity for pipelines to provide additional valued services.

MMA understands that pipelines may attempt to change the way they contract for capacity in the future in order to both ensure that current imbalance and overrun provisions are not under-priced and to attempt to share in some of the potential benefits achievable through a STTM.

Overall MMA expects that the operations of “flow controlled pipelines” will be largely unaffected by the move to a STTM and has assumed that operations and allocation procedures and costs will be unchanged. However, MMA does accept that while the operations of the “pressure-controlled pipelines” will be largely unchanged, there may be a need for somewhat closer monitoring and to review charging, allocation procedures and contracts.

MMA has already factored a significant amount of pipeline company involvement into the planning and trialing process. However, MMA considers it reasonable to assume that there may be some additional initial expenditure required by the pipeline companies, including review of some contracts. A cost of \$0.1m for the two pressure-controlled pipelines affected over the initial two years of the planning process has been factored into the analysis and it has further been assumed that additional operating costs of one half of a FTE person per pressure-controlled pipeline per year are required in order to better manage the pipelines and to devise and implement services valued by the STTM.

MMA has also factored in annual pipeline related costs of a further \$0.1m pa to cover the handling of additional contractual review and other issues arising from the STTM on the pipelines over the period. Pipeline costs for additional hubs are expected to be of the same order or less.

MMA is of the opinion that the STTM is unlikely to result in any material reduction in pipeline or system security or on overall risk over the medium to longer term. MMA has not factored in any change to the cost of capital.

6.11 Network costs

The networks are expected to continue to operate largely unaffected by the STTM. Information which is currently provided by the networks will continue to be provided, although it may be routed differently. We have not included any requirement for additional capital or operating expenditures for the networks.

An issue has been raised by AGL Gas Networks (AGLGN) about the impact of hubs on point to point pricing arrangements which are in place under its current Access Arrangement (AA). The impact of the hubs will be to raise uncertainty about the entry point of the gas into the network and hence the amount charged for transport through the network. We consider it likely that this will require resolution to eliminate the difference caused by different entry point charges – either through an AA reopening⁴⁶ or by agreement between AGLGN and users. Given that the AA is scheduled for review in 2010 only one or two years after the expected commencement of the STTM, we suspect it will be the latter. We have included a cost of \$50,000 for a review of point to point charges.

The issue of network security has also been raised by a network operator in the context of potential liability in the event supply to the network fails as a result of the STTM. We understand that security of supply issues will be resolved through the planning process discussed in Section 6.3 above, and have not factored in any additional costs related to this.

6.12 Existing market operator costs

We expect VENCORP operations to remain largely unchanged and have not factored in any cost changes related to VENCORP.

The existing market operators, GMC and REMCO will be affected by the STTM proposals. However, a key underlying assumption in our analysis has been that the bulk of the operations carried out by these operators will remain unchanged – as discussed in Section 6.1.4. We expect that the commencement of the STTM will result in some initial costs to the current market operators (turning off systems and establishing communications with the new market operator) and some avoided costs. The additional initial costs are estimated to be some \$0.2m. The avoided costs (included as negatives in the analysis) are those related to the expected system implementation costs to change the NSW balancing system (estimated at \$0.2m) and net avoided costs for administering the current balancing markets (estimated as \$0.1m pa combined).

⁴⁶ AGL Gas Networks did initially propose uniform pricing for injection at both delivery points but after some debate this was rejected by the regulator.

There has been some debate about the impact of the STTM on-going market operator costs for the NSW and SA systems. A key assumption of the cost analysis, derived after discussion with market operators, has been that the majority of the functions undertaken by these operators are expected to continue largely unchanged. This being the case, the cost recovery for these functions will also continue, with the only major changes being the expected merger of GMC and REMCo and full depreciation of systems (included in the business as usual case) and the inclusion or avoidance of costs discussed above. Handling of sunk costs for these operators and operations is not, therefore, a material issue for this analysis.

6.13 Regulation

We have assumed that the STTM will require authorization by the AEMC/AER. After indicative discussions with the AER we have estimated the time taken for such a review to be four person months, with a similar expenditure on costs by both the Market Operator in its own right and additionally for legal costs, making a cost of about \$0.1m in total.

We also expect there to be a requirement for annual budgetary review for the operator. Given that the REMCo and GMC annual budgetary reviews are likely to continue, we have included this as a separate additional cost at \$0.01m pa.

6.14 Prudential requirements

We have assumed that market participants will face prudential requirements. However, given that most of the shippers will also be the retailers/end-users, we expect that the net value actually traded will be significantly less than the value of the gross market.

We have calculated the prudential requirement by estimating that 15% of the annual "market" volume is traded at a value of \$4/GJ with billing every 30 days (allowing a 50-day payment cycle) and a net financial cost of a guarantee of 0.25%. The prudential requirement for the NSW and SA markets is thus calculated to be about \$0.05m annually.

6.15 Review after five years

Given the history of the VENC Corp, REMCo and GMC markets and balancing arrangements, it would be surprising if a review of the STTM was not required. We have factored in a review after five years of operation at a cost of \$1m, nominally half for planning and half for system change implementation.

6.16 Division of costs between set-up and operating and the NPV of costs

Based on the assumptions and estimates discussed above the initial set-up, on-going annual and one-off review costs are provided in Table 6-1.

Table 6-1 Set up, ongoing and review costs, \$m

	Set-up	Annual	Year 6 review
Medium scenario	\$9.0	\$1.6	\$1.0
High scenario	\$16.7	\$2.4	\$1.5
Low scenario	\$4.5	\$0.8	\$0.5

Using the above costs, the net present cost of the STTM at a real discount rate of 8.5% is calculated to be \$17m for the medium scenario with a range of \$9m to \$28m.

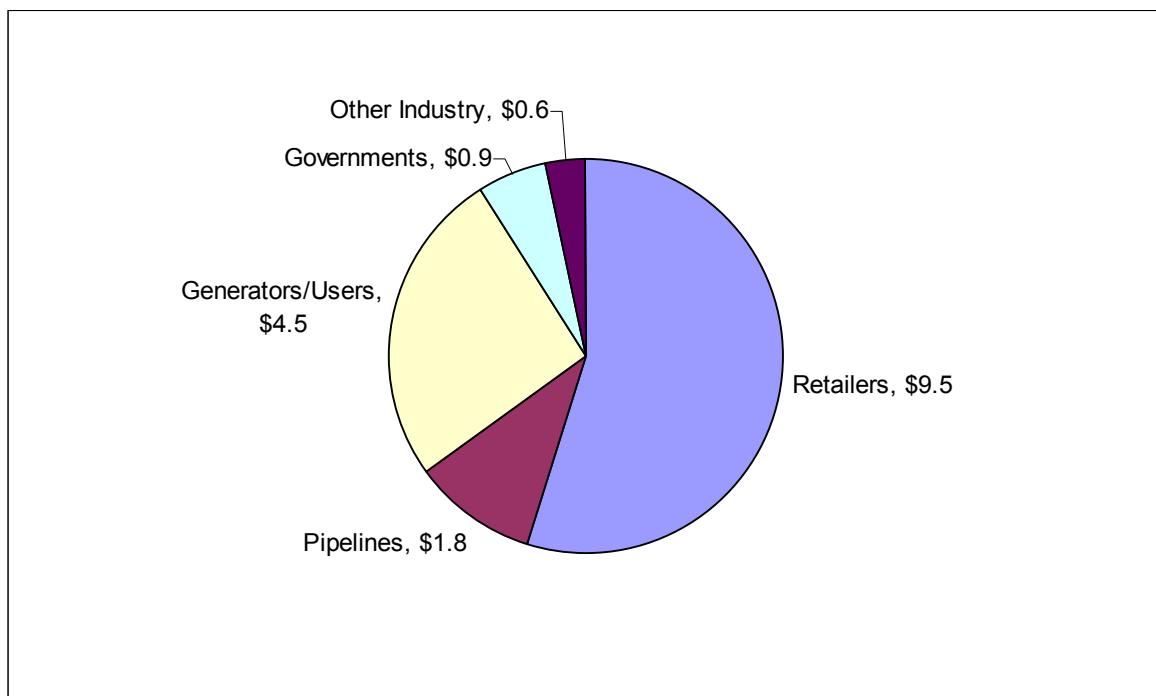
A breakdown of the net present value (NPV) of the costs to the nearest million dollars is provided in Table 6-2.

Table 6-2 Cost categories, NPV, \$m and %

	Medium \$m	%	High \$m	Low \$m
Planning and project management	\$2	13%	\$3	\$1
Government	\$1	4%	\$1	\$0
System operation and governance	\$5	28%	\$8	\$2
Large retailers	\$5	30%	\$9	\$3
Other users	\$3	16%	\$4	\$1
Pipelines	\$1	7%	\$2	\$1
Regulatory and other	\$0	1%	\$0	\$0
Total	\$17	100%	\$28	\$9

6.17 Initial allocation of costs

We have indicatively calculated the initial allocation of costs (i.e. where the costs will be accrued before pass through to other sectors, if that is possible) for the medium scenario costs to retailers, pipelines, generators and other self-contracting end-users, other gas industry (eg producers, storage operators, networks) and government. We have assumed that the costs of the STTM market operator (system set-up, operations and governance) will be borne by retailers, generators and self-contracting end-users approximately in line with consumption quantities.

Figure 6-1 Initial cost allocation, medium scenario, \$m NPV

Retailers are expected to bear over half the \$17m costs with generators and other end-users bearing a further quarter. The remaining costs are divided between pipelines, other industry and government. We have not calculated how and to what extent costs can be passed through to end-users.

6.18 Additional hubs

We have indicatively calculated the net present cost of an additional hub in WA and Queensland to be about \$4m each. The cost to implement hubs in smaller jurisdictions is estimated at about \$1.5m each. In both cases the retailer and other end-user costs are the largest cost components.

6.19 Sunk costs

The costs of systems that will be replaced by new systems implementing the STTM are sunk costs that are not taken into account in net economic cost calculations. However their owners will still want to recover their remaining value from users, which will continue to generate transfer payments. It is understood that the majority of systems that will be replaced would in any case be almost fully depreciated by the time the STTM is implemented, hence the value of the payments would be small.

6.20 Cost of decision to discontinue implementation of the STTM

Some of the stakeholders consulted have raised the risk of “failure” of the STTM concept as a potential cost. MMA considers that most of the issues raised during the consultation

phase are likely to be solvable – either during the planning phase or trial phase. However, the possibility of a potential failure of the STTM concept due, for example, to unresolved concerns about system security or the perceived detrimental impacts of gaming, cannot be completely discounted.

If such a failure was to occur then the most likely outcome is that part of the way through the process a decision would be made that the STTM concept is flawed and not to proceed. In that case costs would have been incurred without any benefit deriving from the market. Using costs from our medium scenario assessment, the most likely extent of such costs would be:

- Up to \$2m if the decision not to proceed is made at the planning phase.
- Up to \$7m if the decision not to proceed takes place during system trialling.
- Up to \$9m if the decision not to proceed takes place just before the STTM is due to commence.

As stated previously, we consider such an outcome (that is a decision to discontinue implementation) unlikely.

7 SHORT TERM TRADING MARKET – BENEFITS

The benefits of STTM implementation at hubs in New South Wales and South Australia are described in detail in the following sections. The benefits cover most of those discussed with stakeholders, with the exception of those whose analysis requires market simulations that cannot as yet be undertaken. The sensitivity of the estimates to assumptions regarding the size of the hubs and potential benefits associated with additional hubs are discussed in section 7.10.

7.1 More efficient pricing

The introduction of the STTM would enable the short-term value of gas in each hub to be discovered each day. This value would vary from the effectively static value in the Base Case, which is established by long-term contracts, and would send a more appropriate signal for a short-term demand side response. The absence of dynamic pricing in the Base Case is a pricing inefficiency that carries an economic cost which can be estimated using the concept of deadweight loss described in APPENDIX B .

Deadweight loss is the net loss of economic value to both producers and consumers of gas when gas prices are not set at a level that balances supply and demand. The deadweight loss that could be eliminated by the STTM has been estimated by calculating the loss that would have resulted in the Victorian gas market if the Victorian market price had been set at a fixed value through the year 2005, rather than being set daily at a level that balances supply and demand. For each day of the year the following were calculated:

- The slopes of the gas supply and demand curves at the actual price/quantity point, based on daily participant injection and withdrawal bid data provided by VENCORP⁴⁷. Typical supply and demand curves are depicted in Figure B- 1. For those days where, owing to the juxtaposition of supply and demand bids, the demand curve was vertical, a demand curve equivalent to a price elasticity of -0.1 was substituted.
- The difference between the actual price that day and the notional fixed price for the year.
- The deadweight loss, based on the slopes of the gas supply and demand curves and the actual – notional price difference, using the formula in Appendix B.3.

The total annual deadweight losses for a range of plausible fixed price values similar to the long-term contract prices paid for gas in Victoria are presented in Table 7-1. The deadweight loss is clearly lowest when the fixed price is set close to the actual market

⁴⁷ This data is publicly available from www.vencorp.com.au. VENCORP has provided MMA with a conveniently sorted database.

median price of \$2.99/GJ, however without the actual market in place it would not be possible to estimate this value precisely.

Table 7-1 Hypothetical deadweight losses due to fixed prices, Victoria, 2005

Fixed price	\$2.90/GJ	\$2.95/GJ	\$3.00/GJ	\$3.05/GJ	\$3.10/GJ
Deadweight Loss	\$328,000	\$239,000	\$226,000	\$286,000	\$421,000

In using this hypothetical Victorian deadweight loss to estimate the gains from more efficient pricing due to the STTM, the following is noted:

- In the Victorian data most of the demand curve structure is due to bids to withdraw gas into underground storage or for export to NSW or South Australia, rather than to controlled withdrawal bids by gas users in Victoria. If Victorian generators submitted controlled withdrawal bids, which for technical reasons they do not at present, the demand price elasticities and deadweight losses would have been considerably higher.
- The Victorian supply curve structure is determined by bids from a variety of gas sources including Gippsland and Otway Basin gas production, gas storage and LNG, though LNG prices did not impact on Victorian market prices during 2005. The NSW and SA supply bids under the STTM would be influenced by similar sources, possibly excluding Victorian LNG, plus Cooper Basin production.
- The total combined market in NSW and SA is comparable in size to the Victorian market but has significantly more generation load (Table 2-2). This suggests that the gains from more efficient pricing in NSW and SA would be greater than those estimated for Victoria.
- During the first four months of 2006 the Victorian gas market has seen unusually low prices ranging from \$2.21/GJ to \$3.15/GJ and averaging only \$2.72/GJ, 10% below the 2005 average. There is no evidence to suggest that long-term gas contract prices have fallen and MMA believes this pricing phenomenon to be due to a supply surplus driving a more seasonal pricing pattern. The economic value of these trades, measured by the deadweight loss that would have occurred if there had been a fixed market price, amounts to between \$250,000 and \$350,000 for the four months of 2006 to date.
- The Victorian price volatility, measured by the price standard deviation, was \$0.21/GJ in 2005 and \$0.29 for the first four months of 2006. Using the 2005 Victoria price elasticities, MMA modelling shows that if the price volatility rose to \$0.45/GJ, the deadweight loss would rise to \$2m per annum.

The pricing efficiency gains from introducing STTMs in New South Wales and South Australia are likely to be similar to those estimated for Victoria. As a medium scenario it is

assumed that the gain starts at \$250,000 per annum and rises to \$1m per annum over four years as more seasonal trends are established. Owing to arbitrage between the Victorian market and the STTMs this is likely to occur faster than in Victoria. The net present value of this benefit from 2007 to 2018 is \$4m.

Low and high scenarios are set at fourth year levels of \$250,000 (no seasonal pattern emerges) and \$2m (stronger price rises or volatility) respectively. The net present values of these benefits from 2007 to 2018 are \$1m and \$8m respectively.

7.2 The net value of short-term trading

The STTM would enable market participants to trade gas to their mutual benefit. Shippers with more expensive gas can purchase some gas from the pool to meet their obligations to users, subject to any contractual constraints on their deliveries to the hub. Shippers with less expensive gas could profitably sell into the pool in excess of their obligations to users. VENCORP reports Victorian gas market trading volumes in the range 10% to 20% of withdrawals and reports the associated gross revenue but not a net value to participants.

The net value of Victorian gas trades would be the sum (for all participants) of the costs that participants would incur to precisely match their gas injections and withdrawals, less the market value of gas i.e. price x withdrawals. The precise net value of Victorian gas trades cannot be estimated, because the costs that participants would incur to match their gas injections and withdrawals are confidential. However a proxy for these costs can be estimated from individual participant bid stacks, by determining the prices that would result if each participant's withdrawals were met by its own bids, that is, by assuming that participant bid stacks are broadly reflective of their costs of supply.

MMA has calculated these proxy costs for most participants for each day of 2005, using the above mentioned bid stack data and information regarding participant withdrawals provided by VENCORP⁴⁸. For some participants, particularly those whose injection bids are less than their withdrawals and those who are pure injectors or withdrawers, injections and withdrawals cannot be balanced. Reliable estimates were obtained for the three largest participants, which accounted for over 90% of market withdrawals in 2005.

The net value of trades for the three largest participants has been calculated by subtracting from their proxy costs of meeting their own withdrawals the market costs of their withdrawals, calculated using three different versions of the daily market price: prices as reported by VENCORP; prices calculated by MMA from total withdrawals and supply bid stack; and prices calculated by MMA from the three largest participants withdrawals and associated supply bid stack. The last two alternatives were used to test for bias, as the individual participant withdrawal data provided by VENCORP was preliminary and did not add to the total reported with VENCORP's market prices.

⁴⁸ This information, which is not publicly available, was provided anonymously.

The estimated net values of trade in Victoria are reported in Table 7-2. The three versions are broadly consistent, with an average value of approximately \$11m. The value of trades to the smaller participants is probably proportionally greater but cannot be estimated using this approach.

Table 7-2 Estimated net values of trade, Victoria 2005

	Market price based on		
	VENCorp	MMA, whole market	MMA, top three participants
Total value	\$12,292,000	\$10,287,000	\$11,307,000
August 10 value	\$6,806,000	\$7,392,000	\$7,392,000
Net of August 10	\$5,485,000	\$2,895,000	\$3,915,000

It is noted that more than 50% of this value was generated on one day, August 10, when Victoria experienced extremely cold weather that sent daily demand to its highest ever level of 1,214 TJ. On this day the market price of \$6.07/GJ was set by a bid from VicHub but one of the top three participants would have had to rely upon LNG which it valued at \$24.95/GJ and most of the \$7m trading value on that day was due to the \$18.88/GJ saving this participant made.

As LNG is unlikely to play any role in the STTMs in NSW or SA, the August 10 value is regarded as unrepresentative of the trading values likely to be achieved in the STMM. A value of \$4m per annum is therefore viewed as a realistic medium scenario estimate for the STTM in New South Wales and South Australia, noting that the volume of gas in the combined markets is similar to that in Victoria. It is assumed that the value starts at \$1m and grows to \$4m over four years. The NPV of this value is \$ 15m from 2007 to 2018.

Low and high scenario estimates are \$2m and \$8m respectively, the latter based on the greater trading opportunities presented by the generation load in South Australia.

7.3 Improved gas allocation during a supply shortfall

The majority of gas supply shortfalls, caused by short-term production/transmission difficulties, are met by supply side responses in the form of drawdown of linepack and gas in storage or increasing supply from other sources. In South Eastern Australia, since completion of the Eastern Gas Pipeline and the SEAGas pipeline, the security of supply from other sources has been considerably enhanced.

Nevertheless large scale supply shortfalls can result in the need for an orderly curtailment of end-users to preserve pipeline and network pressures. Without orderly curtailment, pressures would fall to the extent that users would lose supply in an uncontrolled and

potentially hazardous fashion. Curtailment can be voluntary, subject to market forces, or mandated by government or network operators under emergency procedures.

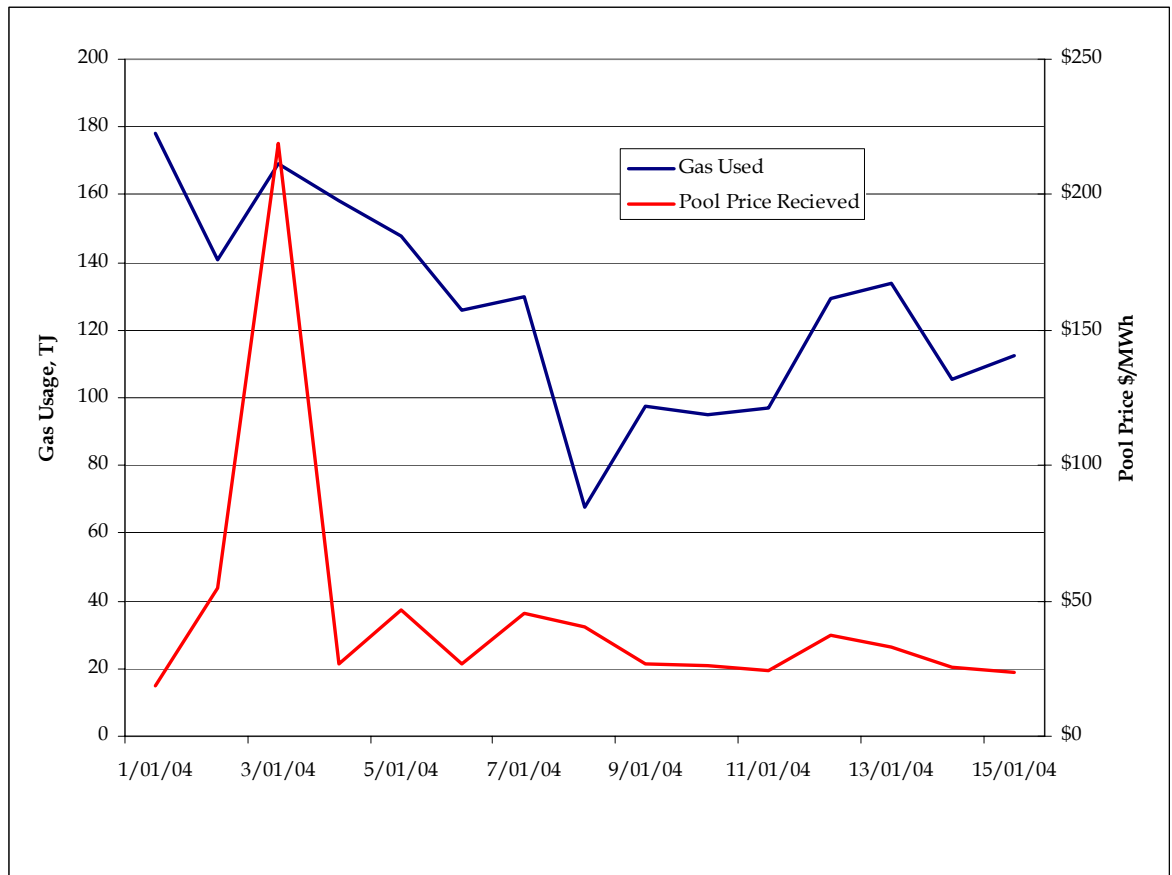
Many users believe that mandatory curtailment is inefficient and that the STTM would provide significant economic benefits by ensuring that scarce gas was allocated to those users willing to pay for it. Users cite the curtailment of industrial users following the Moomba plant fire and the consequent gas supply shortfall in January 2004 as evidence of this.

Immediately the Moomba plant was shut down, industrial users in South Australia were required by the SA Government to reduce their gas offtakes, some including OneSteel and Adelaide Brighton Cement almost completely and another 30-50 only partially⁴⁹. OneSteel estimated it had suffered a \$5m loss over 3 days of curtailment, equivalent to a cost of \$128 per GJ of gas not received⁵⁰. At the same time, gas fired generators in South Australia continued to generate, even though the electricity pool price was for the most part in the range \$25-50/MWh, equivalent to a netback value of approximately \$2.50-5.00/GJ (Figure 7-1), and electricity import capacity was not fully utilised.

Curtailment in New South Wales was milder, with Orica cutting production by 20% and switching to supply from Longford in Victoria and Caltex substituting electricity for gas in its refinery. A number of other users also switched to Victorian supply, for which they are believed to have paid a premium to cover the additional transportation cost.

⁴⁹ Awaiting the Moomba backdraft. Michael Harrison. www.lawyersweekly.com.au 23 January 2004.

⁵⁰ Based on OneSteel communication to MMA.

Figure 7-1 Gas-fired generation fuel use and revenue, SA, January 2004

The net economic cost of the misallocation of gas in South Australia has been estimated as follows:

- The total curtailment was approximately 60 TJ/d for 4 days
- The average cost of curtailment to users was \$86/GJ. This figure is based on research undertaken by MMA for VENCORP⁵¹ – it is the average of values applying to 1 day and 7 day curtailments.
- The value of gas to generators was \$6.65/GJ, based on the pool prices they received between 1 and 4 January 2004.

The costs in New South Wales would have been considerably lower as users were paying a relatively small premium for alternative gas.

Using these figures the net economic cost of the misallocation of gas in South Australia was approximately \$19m. In relation to benefits of the STTM, two questions must be addressed:

⁵¹ The Value of Customer Reliability for Gas. MMA September 2005. Available on www.vencorp.com.au.

1. What is the likelihood of future gas supply shortfalls of similar magnitude and impact as the 2004 Moomba incident?
2. How much the cost of misallocation would be reduced by the presence of the STTM?

1. Likelihood of future supply shortfalls

Severe gas incidents such as the Moomba plant fire and the even more severe explosion at Longford in 1998 occur relatively rarely. In both cases these were the most severe incidents at each plant over 30 years of operation. In terms of the New South Wales and South Australian gas markets, it would be reasonable to expect a rate of one incident every fifteen years in future, equivalent to a probability of 6.67% each year.

2. Cost reduction attributable to the STTM

The ability of the STTM to allocate gas efficiently during a gas supply shortfall would rely upon demand side bids establishing prices at which users are prepared to voluntarily reduce their usage. Such bids need not be all-on or all-off but could comprise a number of steps at different prices to enable users to use small amounts of gas to avoid plant damage. In discussion, a number of stakeholders have questioned how this will happen fast enough, given that the STTM is a daily market and gas supply problems are unlikely to occur just before the next market bids are due. We believe this question is based on the premise that demand side bids would only be made after the supply shortfall emerges – what is required are effectively standing demand side bids at prices considerably higher than normal prices, in the \$10/GJ to \$100/GJ range, which would normally have no effect but which would provide the market (and governments and pipeline operators) with a clear indication of the curtailment available at various price levels.

It is clearly possible for mandatory curtailment to achieve a better outcome than in South Australia in 2004 and indeed we would expect this to result from the activities of NGERAC and the information available through the Bulletin Board. Consequently we have attributed a medium curtailment cost reduction of 50% or \$9.5m to the STTM. In annualised terms this is equivalent to \$600,000 and its net present value from 2007 to 2018 is \$3m.

Low and high scenario curtailment cost reductions have been set at \$5m and \$20m respectively, the latter taking into account the possibility of a greater total cost of curtailment as well as a larger STTM contribution.

7.3.1 Compensation and security of supply

A matter related to gas supply shortfalls is compensation for gas taken from one participant that is curtailed and used by another participant whose gas supply failure has caused the shortfall. Under current balancing arrangements the participant that is curtailed gets virtually no compensation for its loss of revenue, which as noted above could be \$86/GJ or more, as its gas balance is “paid back” only when the value of gas

returns to a normal \$4/GJ. Under the STTM the participant would get paid the market value, which would have to at least equal its marginal cost of curtailment if the curtailment is to be a voluntary, market driven curtailment. Even if the market failed during the supply shortfall, settlement would occur at a default administrative value which would be higher than the normal market value.

The economic impact of this is the same as described above and the lack of compensation represents a transfer of value. The importance of compensation however is in the incentives it provides for security of supply. Without compensation there is no incentive for users to place a premium on more secure sources of gas or to provide back-up fuel capacity. The Base Case in fact provides disincentives to users to provide back-up fuel since during a supply shortfall those with back-up, such as generators with diesel stored on-site, are generally curtailed before those without, and incur the cost of running on the back-up fuel, typically at a cost of \$30/GJ or more while others are running on gas at approximately \$4/GJ.

The economic value of compensation is difficult to determine because it depends upon both the operation of the incentive to increase security and the value of the security, which is lower under the STTM because of the improved allocation of gas during shortfalls. Consequently no value has been placed on this factor.

7.4 Improved capacity utilisation

A fundamental characteristic of the Base Case market model is that each user is required to arrange for its own supply. For example, in New South Wales each retailer's pipeline nomination must equal its forecast withdrawals, adjusted for linepack and to reduce imbalances. In principle each user must contract to meet its own peak demand and because user peaks are generally non-coincident, the total supply contracted exceeds the total market requirement. In practice some users may under-contract and rely upon imbalance tolerances to meet their peak loads, however this is frowned upon by other users who are making up the imbalance and in other jurisdictions, such as Canada, the US and UK, imbalance tolerances were progressively tightened to discourage the practice.

The need to contract to meet peak demand has a further consequence of penalising smaller users who have fewer end use customers and less load diversity, which tends to result in higher peak supply costs than for larger users. A self contracting user observed to MMA that in Victoria it could contract for a fixed volume less than its peak and rely upon the market to absorb/provide unders/overs with limited risk. A new retail entrant in the Victorian market also observed that prior to market entry it was difficult to forecast its gas requirements and it was more cost effective to buy from the market during the initial phase, rather than enter multiple contracts with take-or-pay risks.

The Base Case model therefore leads to demand for supply capacity in excess of market requirements and the more competitive the market becomes, with a greater number of

users, the greater the excess becomes. Where there is a surplus of supply capacity this may have no immediate net economic consequences but in the longer term it will result in the construction of unnecessary capacity with attendant economic inefficiency. A related example of this is the requirement for new entrants (users) to contract for additional capacity even if they are only competing for existing end-use customers. If all existing capacity is booked then a producer or pipeline will have to construct additional capacity even though the market has not grown.

The STTM would overcome some if not all of this inefficiency. It is generally acknowledged that the US gas market has achieved very high levels of asset utilisation, particularly in gas production, due to the extent of trading and the development of trading hubs.

7.4.1 Base Case market inefficiency

Base Case market inefficiency has been quantified using New South Wales and South Australian market data provided by GMC and REMCO. The data comprised daily gas usage for each day in 2005 by each daily metered end use customer and for the net system load (NSL) as a whole in the network zones likely to be included in market hubs. To this data we added daily gas usage by gas-fired generators estimated from NEM generation information. The overall picture of load coincidence is presented in Table 7-3. This picture is derived from actual peak days and a similar picture would apply to the peak usage criterion used by retailers to book capacity, such as the 1 in 20 peak day.

Table 7-3 Peak daily hub loads 2005 (TJ/day)

New South Wales	Generation	Tariff D	Tariff V	Total
Non-coincident	27	266	156	449
Sector coincident	27	197	148	372
Coincident	27	197	136	360
South Australia	Generation	Tariff D	Tariff V	Total
Non-coincident	282	137	68	488
Sector coincident	233	95	66	394
Coincident	223	84	60	367

The sum of individual user peaks is 25% higher than the overall market in NSW and 33% higher in SA. Most of the non-coincidence is in the generation and large industrial user (tariff D) categories – small users (Tariff V) are more coincident because their peaks are driven by a common factor, the weather.

If each end-user were self contracting and had to contract for its individual peak demand, supply capacity would be 25% higher than market requirements in NSW and 33% higher in SA. This inefficiency is significantly reduced by the load aggregation undertaken by retailers. If there were just one monopoly retailer then all the diversity would be captured and the inefficiency would be eliminated. In competitive markets with two or more retailers, some inefficiency remains - the estimated inefficiencies in Table 7-4 illustrate the increasing inefficiency as the number of retailers increases. The figures represent the average percentages resulting from 200 random end-use customer allocations to each retailer. Analysis of the data has showed that the number of retailers is more important than their market shares in determining the level of inefficiency. The New South Wales figures are lower than the South Australian ones because of the larger number of Tariff D customers in New South Wales and the larger Tariff V load, both of which give each retailer more diversity.

Table 7-4 Supply capacity inefficiency (%)

Number of retailers	2	3	4	5	6	7	8	9
New South Wales	1%	2%	3%	4%	4%	5%	6%	6%
South Australia	5%	9%	12%	14%	16%	18%	20%	21%
South Australia excl Generation	5%	9%	10%	12%	14%	15%	16%	17%

For the purpose of estimating the impact of the STTM, we have used the current inefficiencies in the New South Wales and South Australian markets, which would be approximately 6% and 10% respectively based on 9 (including self contracting users, refer to section 4.5) and 4 retailers respectively. The potential inefficiencies in more competitive markets would be higher.

7.4.2 STTM Impact

The impact of the STTM on supply capacity inefficiency is extremely difficult to judge. As noted in section 3.1.4 the STTM by itself lacks many of the features of more developed markets in the US and UK. In these markets the volumes of gas traded are approximately 10 times the physical flows and we would judge this to be sufficient to eliminate the inefficiency, as market participants would view the market as highly liquid and a reliable source of short-term supply.

The minimum level of trading necessary to eliminate the inefficiency has been estimated using the random allocation of users to retailers described above, creating an allocation of the efficient capacity pro-rated to retailers maximum demand and calculating the level of trading required to match supply and demand. The minimum level was found to be approximately 20% of physical flows. If the STTM sees similar levels of trades to the Victorian market, where the volumes of gas traded are 10% of the physical flows during

peak demand periods, clearly the STTM could not eliminate the inefficiency and would be unlikely to eliminate more than 50%.

Based on the views expressed to us by stakeholders, it seems reasonable to assume that the STTM would eliminate at least 10% of the inefficiency, which is therefore our medium scenario assumption. Corresponding low and high scenario assumptions are 5% to 20% respectively. These gains would not be immediate but would be realised over four years after the STTM was introduced.

7.4.3 Cost Impact

The cost impact of the above has been estimated by calculating the supply capacity investment requirements under the Base Case and STTM scenarios using the following assumptions:

- The supply capacity required is the underlying market demand plus the inefficiency factor. Peak demand growth is a modest 1.5% p.a. Capacity requirements in the Base Case and STTM option eliminating 10% of the inefficiency are shown in Figure 7-2
- Current pipeline and production capacity is as per Table 7-5
- Pipeline capacity does not decline but production capacity needs to be replaced at 5% pa, corresponding to a field life of 20 years. This rate may err on the low side.
- The capital costs of incremental capacity are: NSW and SA transmission, \$1.9m/TJ/d; and gas production \$4.1m/TJ/d. These values are consistent with current pipeline tariffs and gas wholesale prices, assuming that 95% of pipeline and 80% of production costs are capacity related.
- Additional capacity is constructed incrementally each year as required. In reality it will be lumpy, with periods of excess capacity, and this will increase the value of capacity savings.

Table 7-5 Current pipeline and production capacity (TJ/day)

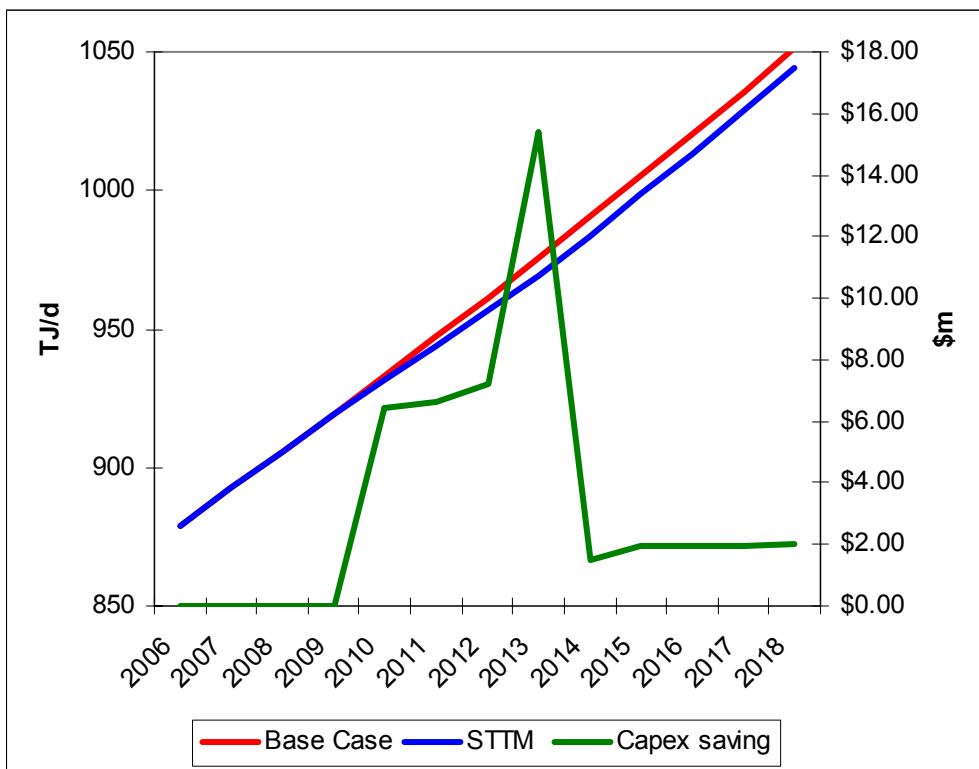
	New South Wales	South Australia	TOTAL
Moomba-Sydney PL	483		
Eastern Gas PL	210		
Moomba Adelaide PL		210	
SEAGas PL		338	
Gas Production			1060

The capital savings due to the STTM option in the medium scenario are shown in Figure 7-2. The initial savings of \$6-7m pa are the one-off efficiency gains (over four years) of introducing the STTM, after which the regular gains are just \$2m pa, with the exception of a spike in 2013 due to deferral of pipeline expenditure. The NPV of these gains is \$26m from 2007 to 2018.

In the low efficiency gain scenario (5% of Base Case inefficiencies eliminated), the NPV is \$13m and in the high efficiency gain scenario (20% of Base Case inefficiencies eliminated), the NPV is \$53m.

It is noted that the gains are made by capital savings rather than improved utilisation of existing assets, which may simply transfer value from pipelines/producers to retailers. Existing assets are a sunk cost.

Figure 7-2 Base Case and medium scenario STTM option capacity requirements and capital savings



7.5 Improved market risk allocation

One of the purposes of introducing the STTM is to enable the short-term value of gas and gas delivery capacity to be (more accurately) priced than under the Base Case. This pricing

refinement would clearly introduce price volatility where there was none apparent before and could therefore appear to increase the level of market risk to participants.

A large retailer has, for example, raised the concern that the advent of the STTM as currently understood could increase the risks of very high prices and hence the costs faced by large retailers. There appears to have been no experience of very high prices in the day to day operations of the Victorian market⁵², however, which probably serves as the best available example of the type of outcomes likely under the STTM elsewhere. In the Victorian market the larger retailers have tended to contract “long” with their spot market exposures on normal days covered by physical contracts. Discussions with some of the major retailers has led MMA to the conclusion that this approach has also been adopted elsewhere and is likely to remain largely unchanged for the major retailers under the STTM.

This view also ignores the supply uncertainty inherent in the Base Case - participants face uncertainty as to what, if any, gas is available beyond their own portfolio to meet their balancing requirements. The STTM converts this uncertainty, or unquantifiable risk, into a more readily quantified risk, based on a supply curve that prices the gas available for balancing. While it is extremely difficult if not impossible to verify, since no numbers are available for the Base Case or the STTM, we believe that the impact of the STTM would be to leave the total level of risk relatively unchanged.

An example of the change in risk is during a period of supply shortage caused by an “incident” at a source of supply or transmission. In the Base Case the impact of such an incident was likely to have been a curtailment of large users with little concern for the economic ramifications of this curtailment and no compensation received by the curtailed users. This may change under a STTM, with those large users with property rights to gas being able to continue to use the gas or to sell it at the (presumably high) spot market price. In that case the retailer serving the mass market load which is generally considered uninterruptible may be forced to pay a higher price for continuing to serve this uninterruptible market. This would be a change from the current system. However, it would largely involve an economic transfer - from retailers (or possibly generators) to large customers, not an additional economic cost in itself⁵³. Additionally, some retailers have stated that they would plan for such an eventuality by contracting for interruptible supply with some large customers. Again this would involve a transfer of money and risk, rather than new economic costs.

It is recognised that this position relies upon the detailed design of the STTM being undertaken thoroughly, in particular ensuring that participants are not faced with unmanageable risks. Poor market design, as in the electricity market in California, can lead to significant economic costs. Stakeholders consulted by MMA have raised a number of

⁵² The number of incidents causing price spikes in the Victorian market has been limited - with prices greater than \$6/GJ only occurring three times since the market started in 1999 and the price never reaching \$10/GJ.

⁵³ Indeed under the market system there would be an economic benefit due to those attributing the highest value of the gas having access to it.

risk related concerns, such as the potentially inequitable treatment of users transporting gas on pressure-controlled and flow-controlled pipelines. These concerns can only be addressed at the detailed design stage by simulating market outcomes.

The allocation of risk under the STTM would undoubtedly change however, because risks would be more accurately quantified and risks will be taken by the parties most willing and able to manage them. Analogous to the deadweight loss concept in regard to pricing, this should create a small net benefit for the market as a whole.

7.6 Additional investment signals

In the Base Case, investment is driven largely by capacity signals. For example, investment in gas production capacity is made when retailers or other buyers are willing to contract for it, because of projected shortfalls in the supply portfolios. Investment in capacity is preceded by negotiation of a long-term GSA that will provide financial support. A similar process applies to pipeline capacity under the contract carriage model.

Under the STTM option a transparent short-term price signal will be created. Price rises will in general be associated with a decline in capacity relative to demand and may therefore provide additional signals for investment. The value of these signals however is questionable:

- Investment decisions are typically made three to five years before the capacity is available, whereas by the time prices are rising the need for capacity is likely to be more immediate. This is evident even in markets with highly developed short-term trading, such as the UK⁵⁴.
- Decisions are made on the basis of projections of capacity availability, which will still be required. Projections of STTM prices would be added to the decision making process, though they may be less influential than negotiated GSA prices in determining whether investments proceed.
- At least initially STTM prices are likely to be set by GSA prices (plus delivery charges) as in the Victorian gas market (refer to section 4.3).

MMA has discussed the influence of the Victorian gas market price on production contracting and investment decisions with stakeholders. Discussions confirmed the limited influence of the market price on the timing of the decision but stakeholders noted that the option to trade in the market was nevertheless seen as an advantage.

STTM price signals are likely to be of more relevance to investment in seasonal capacity facilities such as underground storage or LNG facilities designed to serve hub markets. The commercial viability of such facilities is more dependent upon short-term price

⁵⁴ “Investments are also driven by analysis of market fundamentals, as is witnessed by the large number of investment projects in the UK initiated ahead of the price increase” In: Market failures and government policies in gas markets. CPB Memorandum CPB Netherlands Bureau for Economic Policy Analysis Number 143, 23 February 2006

variations than pipeline or production capacity and may be signalled by a steady increase in the number of days that the STTM price is above a base level set by GSA prices plus delivery charges. Similarly, STTM prices may stimulate creation of additional capacity services by pipelines, possibly requiring additional compressor capacity or upgrading.

The value of the pricing signal is therefore viewed as small and has not been quantified.

7.7 Value to gas-fired generators

The value of the STTM to gas-fired generators arises principally from two factors:

- Reduced costs of capacity/ability to purchase spot gas, which is particularly valuable to low load factor intermediate or peaking generators. The economic benefit of this is covered by the trading value and capacity efficiency benefit in sections 7.2 and 7.4.
- Opportunities presented by gas spot price volatility. An estimate of this effect has been derived using a simple model based on South Australian electricity pool prices for 2005. For a given daily gas spot price profile, the model calculates a generator's dispatch based on when the pool price is greater than its heat rate times the gas spot price. The calculations show that a generator will generate more and make a higher net profit (revenue less gas costs) when the gas spot price is volatile (under the STTM) than when it is fixed at the same average price (in the Base Case). The effect appears to be caused by the shape of the electricity pool price duration curve and is quite small, less than 1%, when the gas price volatility is at the levels that may be expected initially in the STTM i.e. \$0.20/GJ.

This analysis ignores a great deal of the complexity in both markets but the results are believed to be in the right direction. It may also lead to a net benefit since the additional gas-fired generation would displace more expensive generation, however this is likely to be considerably less than the revenue gain by gas fired generators and has not been quantified.

7.8 Benefit summary

The cash flows of each benefit in the medium scenario are set out in Table 7-6.

Table 7-6 Medium scenario benefit cash flow (\$m)

	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018
Pricing efficiency	\$0.0	\$0.0	\$0.0	\$0.3	\$0.5	\$0.8	\$1.0	\$1.0	\$1.0	\$1.0	\$1.0	\$1.0
Trading	\$0.0	\$0.0	\$0.0	\$1.0	\$2.0	\$3.0	\$4.0	\$4.0	\$4.0	\$4.0	\$4.0	\$4.0

Curtailment	\$0.0	\$0.0	\$0.0	\$0.6	\$0.6	\$0.6	\$0.6	\$0.6	\$0.6	\$0.6	\$0.6	\$0.6
Capacity efficiency	\$0.0	\$0.0	\$0.0	\$6.5	\$6.7	\$7.2	\$15.4	\$1.5	\$1.9	\$1.9	\$2.0	\$2.0
TOTAL	\$0.0	\$0.0	\$0.0	\$8.3	\$9.8	\$11.5	\$21.0	\$7.1	\$7.5	\$7.5	\$7.6	\$7.6

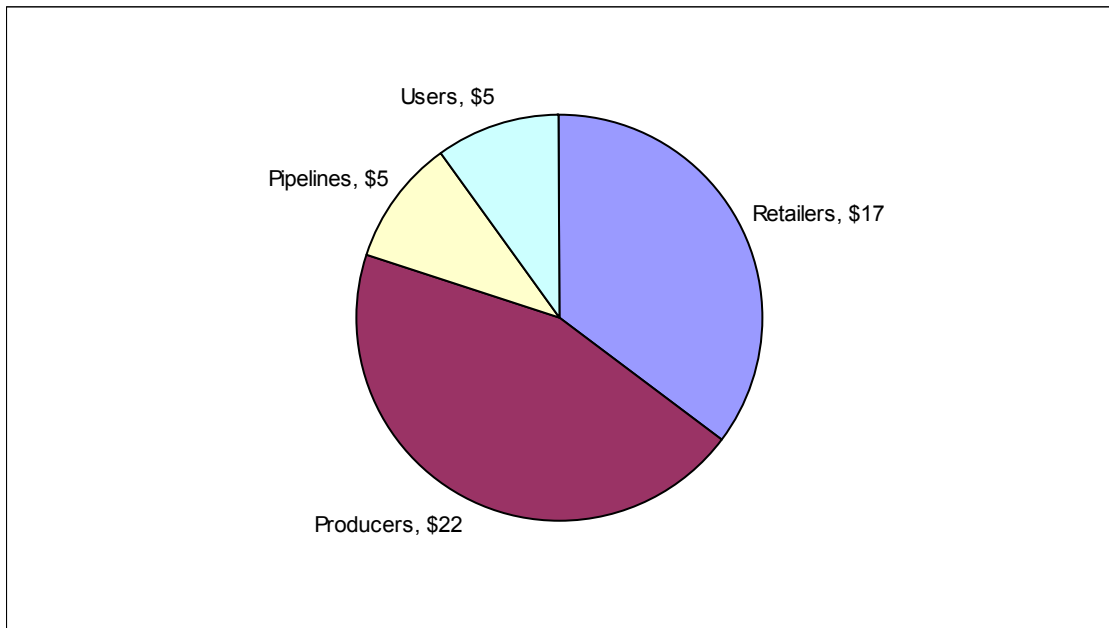
The net present values of the quantified benefits in all three scenarios, calculated at a real discount rate of 8.5%, are summarised in Table 7-7. Total NPVs are \$23m in the low scenario, \$48m in the medium scenario and \$97m in the high scenario. These benefits exclude the benefits attributable to the Bulletin Board.

Table 7-7 Benefit NPVs (\$m)

Benefit	Benefit scenario		
	Low	Medium	High
Pricing efficiency	\$1	\$4	\$8
Value of trading	\$8	\$15	\$30
Curtailment management	\$2	\$3	\$6
Capacity utilisation efficiency	\$13	\$26	\$53
Risk management	+ve	+ve	+ve
Investment signals	+ve	+ve	+ve
Gas-fired generation	+ve	+ve	+ve
TOTAL	\$23	\$48	\$97

7.9 Initial allocation of benefits

We have indicatively calculated the initial allocation of benefits (i.e. where the benefits will be accrued before pass through to other sectors, if that is possible) for the medium scenario, to retailers, producers, pipelines and end-users. No direct benefit to government is expected. Generators will share in retailer and user benefits in proportion to usage. The producer and pipeline benefits are due to reduced capital expenditure due to lower capacity requirements, and are expected to pass directly to retailers and self contracting users.

Figure 7-3 Initial benefit allocation, medium scenario, \$m NPV

7.10 Other hubs

7.10.1 Alternative hub structures

The hubs assessed in the preceding sections include 90% of the gas consumed within both New South Wales and South Australia. If for any reasons the sizes of the hubs were reduced, the benefits would fall.

The drivers of the benefits calculated for the hubs are:

- Pricing efficiency – volume traded
- Value of trading – volume traded
- Curtailment management – level and likelihood of curtailment
- Capacity utilisation efficiency – current market inefficiencies and market growth

A reduction in hub size is likely to involve exclusion of a small number of large users, which may disproportionately reduce the level of likely curtailment within the hub and increase the Base Case capacity utilisation efficiency. The hub benefits from curtailment management and capacity utilisation are therefore likely to reduce disproportionately to hub volumes.

Indicative variation of medium scenario benefits with hub size has been estimated by assuming volume elasticities of 2 for curtailment management and capacity utilisation, reflecting the above observations, and elasticities of 1 for pricing efficiency and value of trading (Table 7-8).

Table 7-8 Variation of medium scenario benefits with hub size

% gas in hub	90%	80%	70%	60%	50%
Benefits (\$m, NPV)	\$48	\$40	\$32	\$26	\$19

7.10.2 Additional hubs

In relation to the possible hubs in Queensland (Brisbane) and Western Australia (Perth) defined in section 2.5.7, and the benefit drivers outlined above, the volume traded information is defined in Table 2-2 but MMA has not sought details of other factors. Current market inefficiencies may be quite high in both markets as they are characterised by small numbers of very large industrial users. It is therefore believed that calculating benefits for Queensland and Western Australia by prorating the New South Wales and South Australian benefits by volumes traded would yield conservative estimates. This approach has been used in Table 7-9, which also takes into account three additional years of discounting, to align the results with the STTMs in these hubs starting three years after the New South Wales and South Australian hubs. The NPV period extends to 2021.

Table 7-9 Additional hub medium scenario benefits

	Hub volume (PJ pa)	Total benefit NPV (\$m)
Queensland	50	\$10
Western Australia	231	\$47

8 OPTION NET BENEFITS

8.1 Micro economic net benefit

The micro-economic net benefit is the net present value of the quantifiable benefits less the identified costs in the gas sector.

8.1.1 Bulletin Board

In considering the net benefit of the Bulletin Board it is emphasized that while the costs are based upon reasonable evidence, the benefits represent an order of magnitude “plausible” estimate – only one benefit scenario was estimated.

The net benefit is positive in both the low and medium cost scenarios but negative in the high cost scenario. However the benefit to cost ratio in the medium cost scenario is 1.4, which suggests that the outcome would be sensitive to small variations in the costs or benefits.

Table 8-1 Bulletin Board net benefit NPVs and benefit-cost ratios

		NPV (\$m)	Benefit-cost ratio
	Low	\$1.6	2.8
Cost scenario	Medium	\$0.7	1.4
	High	-\$0.4	0.9

8.1.2 Short-term trading market, NSW & SA

The cost and benefit scenarios are independent, i.e. any combination could occur. In eight of the nine possible scenarios the net benefit NPV over the period 2007 to 2018 is positive, ranging up to \$88m (Table 8-2). The best estimate scenario, the combination of the two medium scenarios, has a positive NPV of \$31m.

Table 8-2 STTM net benefit NPVs (\$m)

		Benefits		
		Low	Medium	High
	Low	\$15	\$39	\$88
Costs	Medium	\$6	\$31	\$79
	High	-\$5	\$20	\$68

The benefit to cost ratio in the best estimate scenario is 2.8, which suggests that the outcome would not be changed by small variations in the costs or benefits (Table 8-3). Six of the nine scenario combinations have robust ratios over 2.

Table 8-3 STTM benefit-cost ratios

		Benefits		
		Low	Medium	High
	Low	2.7	5.6	11.2
Costs	Medium	1.3	2.8	5.6
	High	0.8	1.7	3.4

8.1.3 Short-term trading market, other hubs

Reduction in the size of the New South Wales and South Australian hubs reduces the net benefits. In the best-estimate scenario the net benefit NPV is positive down to a hub size equivalent to 50% of gas consumed in the jurisdictions.

For the additional hubs only the medium scenario has been evaluated (Table 8-4). Owing to the relatively low costs of incremental hub implementation, both the Queensland and Western Australian hubs have very favourable NPVs and benefit-cost ratios.

Table 8-4 STTM net benefit NPVs and benefit-cost ratios, additional hubs

	NPV (\$m)	Benefit-cost ratio
Queensland	\$7	3.2
Western Australia	\$44	15.0

The viability of further hubs has been assessed by calculating the breakeven volumes at which the NPV is positive. Assessed against the “large” hub incremental cost the breakeven volume is 15 PJ p.a. and assessed against the “small” hub incremental cost the breakeven volume is 6 PJ p.a. These suggest that an ACT hub may be marginal but that other hubs in Tasmania, the Northern Territory and other parts of Queensland could be economic.

8.2 Macro economic net benefit

Economy-wide benefits flowing from the Bulletin Board and STTM options have been estimated using the Monash University Centre of Policy Studies' (COPS) model of the Australian economy, the Monash Multi-Regional Forecasting (MMRF) model. An outline description of the model is provided in APPENDIX D .

In view of the very limited overall costs and benefits and similar cost/benefit structures associated with each scenario, for the purposes of this draft report MMRF has been run only for the STTM best estimate (medium costs and benefits) scenario (Table 8-5) and these have been prorated to other scenarios. COPS advises that the errors in this procedure will be very limited. The GDP multiplier (ratio of GDP change to net benefits) in this scenario is approximately 1, indicating almost no broader economic impact.

Table 8-5 STTM best estimate scenario economic impacts

	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018
GDP change (\$m)	-\$4	-\$5	-\$3	\$9	\$8	\$9	\$17	\$0	\$7	\$8	\$5	\$6
Employment change (persons)	-1	-2	-1	9	2	2	2	-12	5	6	-2	0

The GDP and employment changes in other scenarios are summarised in Table 8-6 and Table 8-7. The GDP impacts are virtually the same as the net benefits and the employment impacts are minimal.

Table 8-6 STTM GDP impacts (\$m, NPV)

		Benefits		
		Low	Medium	High
	Low	\$13	\$37	\$82
Costs	Medium	\$4	\$27	\$73
	High	-\$7	\$16	\$61

Table 8-7 STTM employment impacts (persons, NPV)

		Benefits		
		Low	Medium	High
	Low	2	7	16
Costs	Medium	-0	5	13
	High	-4	1	10

The GDP impacts of the Bulletin Board are as per Table 8-1. The Bulletin Board has no employment impacts.

APPENDIX A STAKEHOLDERS CONSULTED

The following people and organisations have been consulted or provided input during the course of this assignment. Their input has been greatly appreciated.

People	Organisations
Mr M Harris	Adelaide Brighton Cement
Mr G Foley, Mr H Sherer, Mr R Phillips	AGL Retail
Mr A Rapisarda, Mr S Martin, Mr C Harvey and Mr M Kilgariff	AGLGN and Energy Networks Assoc.
Mr D Dwyer	Australian Petroleum Production and Exploration Association (APPEA)
Mr S Ronan	Australian Pipeline Trust (APT)
Mr W Anderson	Australian Energy Regulator (AER)
Mr B Bloking	BHP Billiton
Ms C Buchanan	BP
Mr R Domanski	Energy Users Association of Australia (EUAA)
Ms C Tang	EnergyAustralia
Mr L Berry, Mr M Kimber	Enertrade
Mr S Livens, Mr S Banning and Mr S Mudge	Epic Energy
Mr M Arnold, Mr J Hunsaker	Exxon Mobil
Mr A Smart of ACIL Tasman	For Australian Pipeline Industry Association (APIA)
Ms P McKenzie and Mr S Slack of M-Co	Gas Market Company (GMC)
Mr T Woodley	Gas Market Leaders Group (GMLG)
Mr D Barnes	GMLG (Origin Energy)
Mr M Zema	GMLG (VENCORP)
Mr J McDonald	GMLG (APIA)
Mr R Wilkinson	GMLG (Santos)
Mr P Fennessy	GMLG (Alinta)

Mr M Gell	GMLG (OneSteel)
Dr S Bell, Mr R Harrison, Mr R Coughlin	GMLG, Qenos
Mr B Lim	Major Energy Users Inc
Mr D Headberry	Major Energy Users Inc
Ms M Taylor, Mr W Antioch	MCE Secretariat
Mr S Appleby I Tannebring, M Williamson	NRG
Mr J Turecek	Origin Energy
Mr S Thomson	REMCo
Mr P Bresloff-Barry	Synergy (Western Power Retail)
Mr M Frewin and Mr D Vigilante	TRUEnergy
Mr T Grimwade, Mr R Shaw, Mr A Screen	VENCorp
Mr R Hardwick, Mr R de Souza	Visy

APPENDIX B ASSESSING THE BENEFITS FROM MORE EFFICIENT PRICING

B.1 Supply and demand

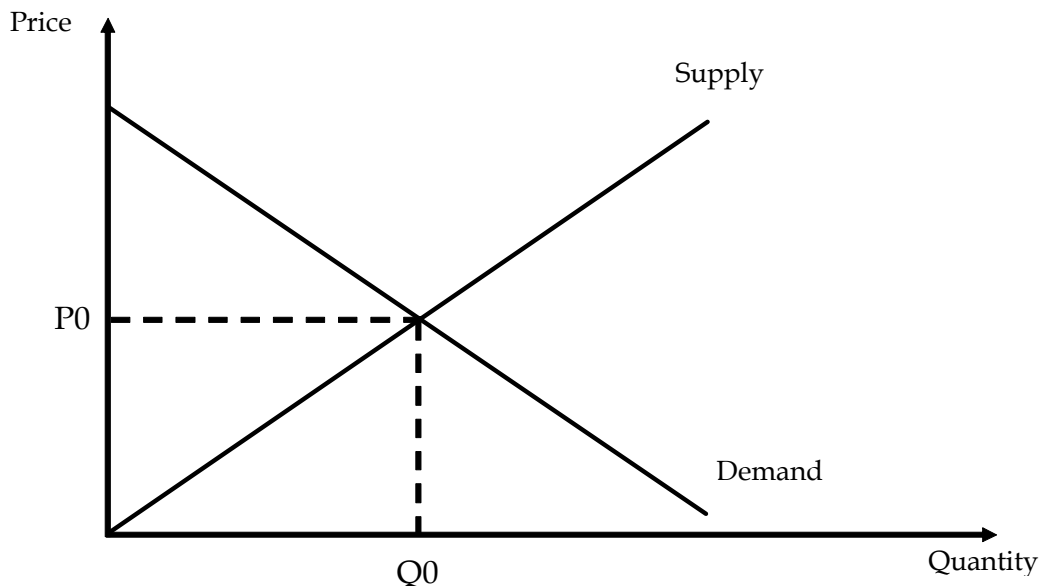
The economic value of gas supply to producers and consumers is measured using the concepts of producer and consumer surplus. Changes in the combined surplus provide a means of estimating the economic cost or benefit arising from a change in pricing – the change in surplus when moving to less efficient prices is known as the deadweight loss.

Supply and demand are typically characterised by:

- Upward sloping supply, reflecting producers willingness to offer more gas at higher prices
- Downward sloping demand, reflecting consumers willingness to purchase less gas at higher prices

These are illustrated in Figure B- 1. In this market the intersection of the supply and demand curves sets the equilibrium price and quantity at P_0 and Q_0 respectively. P_0 is also an efficient price if the supply curve is representative of the cost of supply.

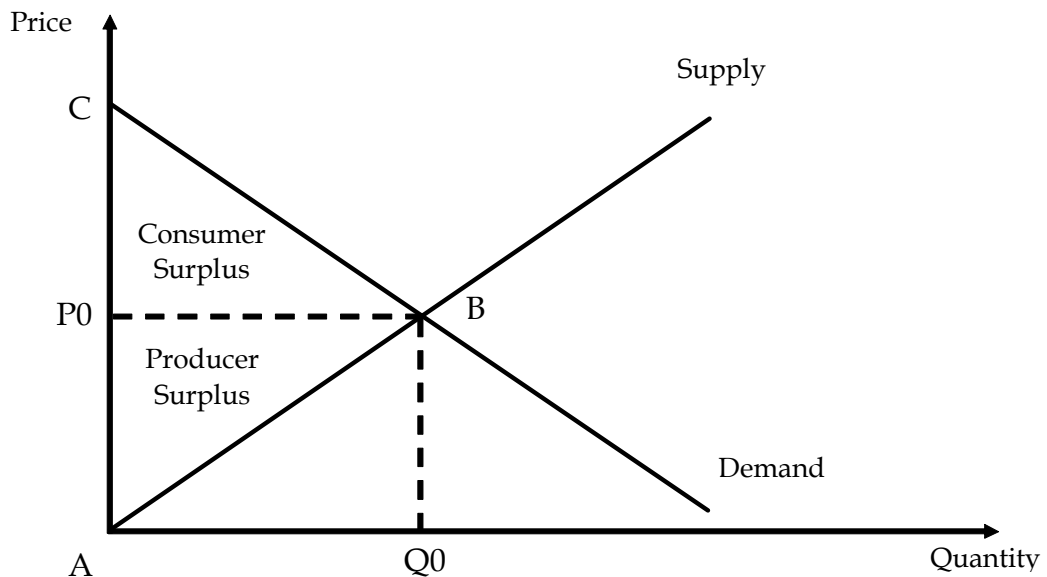
Figure B- 1 Supply and demand



B.2 Producer and consumer surplus

At P_0 the producers are not prepared to sell more than Q_0 and much production is sold at a higher price than they would have been willing to sell at. The excess of P_0 over the price at which they would have sold, i.e. the supply curve, is known as the producer surplus and is measured by the triangle $A P_0 B$ in Figure B- 2. Similarly at P_0 the consumers are not prepared to buy more than Q_0 but many purchases are made at a lower price than they would have been willing to purchase at. The deficit of P_0 relative to the price at which they would have purchased, i.e. the demand curve, is known as the consumer surplus and is measured by the triangle $C P_0 B$ in Figure B- 2. The combined producer and consumer surplus is represented by the triangle ABC .

Figure B- 2 Producer and consumer surpluses

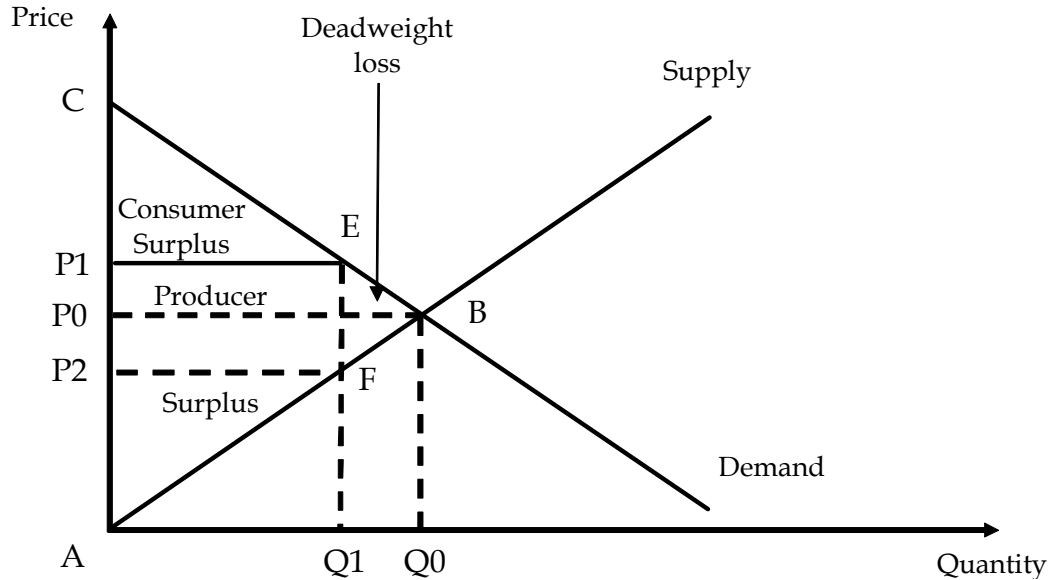


B.3 Deadweight loss

If for some reason the price is not set at the efficient equilibrium price P_0 then a situation as in Figure B- 3 applies. Here, with the price at P_1 , consumers are only prepared to purchase a quantity Q_1 and the consumer surplus reduces to the triangle $C P_1 E$. The producer surplus now has two components, the triangle $A P_2 F$ (based on the lowest price P_2 at which they would sell Q_1) plus the pure profit due to the fact that the price they are receiving, P_1 , is greater than P_2 - the profit is represented by the rectangle $P_1 E F P_2$.

The combined producer and consumer surplus is clearly AFEC and is less than the equilibrium surplus ABC by an amount equal to the small triangle FBE, which is the deadweight economic loss associated with the less efficient price P_1 . If P_1 is less than P_0 then the deadweight loss is equal to a similar triangle to the right of B.

Figure B-3 Deadweight loss



The value of the deadweight loss can be expressed in terms of the slopes of the demand and supply curves, denoted by “d” and “s” respectively, or in terms of the demand and supply elasticities, “ed” and “es”:

$$\text{Deadweight loss} = (P_1 - P_0)^2 \times d^2 \times (-1/d+1/s)/2$$

or

$$\text{Deadweight loss} = (Q_0/P_0) \times (P_1 - P_0)^2 \times (ed)^2 \times (-1/ed+1/es)/2$$

It is noted that the deadweight loss is proportional to the square of the “price inefficiency” $P_1 - P_0$ so that a doubling of the pricing inefficiency quadruples the deadweight loss.

APPENDIX C MARKET INFORMATION PROVIDED BY NATIONAL GRID, UK

The following summarises information provided to the UK gas market by National Grid⁵⁵.

Daily Summary Report - Overview

1. The purpose of this report is to:
 - _ Inform participants daily of the “status” of the gas transmission system
 - _ Provide a useful signal to participants to stimulate additional demand side response
 - _ Response over and above existing interruption capability
 - _ May be turndown
 - _ Be the platform for gas system warnings called Gas
2. Balancing Alerts - Based on defined criteria and data
3. System alerts
 - _ Combination of new Gas Balancing Alert, relevant ANS warnings and freeform notes field
4. Daily snapshot supply/demand summary
 - _ Intended to give an indication of how things are currently - is today looking OK?
5. Winter to date supply/demand summary
 - _ Intended to give an indication - are we looking OK based on historical trend
6. _ Storage position
 - _ This is key to understanding to what extent demand side response is needed
7. Report available from the National Grid corporate website (Gas/Operational Data) <http://www.nationalgrid.com/uk/Gas/Data/dsr/>
 - _ Gives a snapshot of the latest available information
 - _ Summarises information which can then be investigated in more detail in other parts of the NG website, mainly ‘Operational Data’ area, and other websites (with suitable links provided)
8. _ Elements of the report are updated throughout the day as new information becomes available, e.g.
 - _ Day ahead demand available after 1400
 - _ Storage data available from 1600
 - _ Entry flows updated hourly

⁵⁵ Information provision to the Gas Market. Paul Gallagher, National Grid, 2005

Managing Information issues

1. _ We understand the importance that the industry places on the information we provide
2. _ We are committed to delivering accurate and timely information to the industry
3. _ Within NG we have approval to deploy appropriate resources to effectively manage the issue
4. _ We have a number of initiatives under way to deliver improved performance - given feedback we have received

APPENDIX D DESCRIPTION OF THE MMRF MODEL

The MMRF model divides Australia into the six states and two territories. There are five types of agents in the model: industries, capital creators, households, governments, and foreigners. The number of industries is limited by computational constraints. Currently, MMRF identifies 54 products produced by 49 industrial sectors. For each sector in each region there is an associated capital creator. The sectors each produce a single commodity and the capital creators each produce units of capital that are specific to the associated sector. Each region has a single household and a regional government. There is also a federal government. Finally, there are foreigners, whose behaviour is summarised by export demand curves for the products of each region and by supply curves for international imports to each region.

MMRF determines regional supplies and demands of commodities through optimising behaviour of agents in markets. Optimising behaviour also determines industry demands for labour and capital. Labour supply at the national level is determined by demographic factors, while national capital supply responds to rates of return. Labour and capital can cross regional borders so that each region's stock of productive resources reflects regional employment opportunities and relative rates of return.

The specifications of supply and demand behaviour co-ordinated through market clearing equations comprise the general equilibrium (GE) core of the model.

MMRF-Green contains a number of factors that enhance its capability for energy analysis. These include:

- An energy and gas emission accounting module, which accounts explicitly for each of the 49 industries/54 products and eight regions recognised in the model.
- Equations that allow for inter-fuel substitution in energy use by region.
- A multi-product specification for oil refineries.
- An enriched treatment of renewable generation.

MMRF tracks (primary and final) energy usage and emissions of greenhouse gases at a detailed level. It breaks down energy-usage/emissions according to:

- Using/emitting agent (49 industries and residential).
- Using/emitting state or territory (8).
- Using/emitting activity (10).

Most of the using/emitting activities are the burning of fuels (black coal, natural gas, brown coal or petroleum products). A residual category, named Activity, covers emissions such as fugitives and agricultural emissions not arising from fuel burning.

Energy usage is measured in units of PJ. Emissions are measured in terms of carbon dioxide equivalents, CO₂-e.

Inter-fuel substitution in electricity generation and other stationary energy activities is handled using the "technology bundle" approach. In the electricity generation sector, nine power-generating industries are distinguished based on the type of fuel or renewable resource used (black coal, brown coal, gas, oil products, hydro, biomass, biogas, solar and wind). There is also an end-use supplier (Electricity Supply). The electricity generated in each state/territory flows directly to the local end-use supplier, which then distributes electricity to local and inter-state users. The end-use supplier can substitute between the five technologies in response to changes in their production costs. For example, the Electricity supply industry in NSW might reduce the amount of power sourced from coal-using generators and increase the amount sourced from gas-fired plants.

For other energy-intensive commodities used in industry, MMRF allows for substitution possibilities by including a weak form of input-substitution specification.

MMRF makes allowance for multi-product industries and multi-industry products.

Regional economic impacts can also be estimated using the MMRF model. Few multi-regional models of the Australian economy have the level of sectoral detail supported by MMRF. This detail is usually more than adequate for contributions to public discussions on the effects of changes in policies concerning taxes, trade and the environment. However, people wanting to use MMRF in business and public sector planning are often frustrated by the lack of relevant regional detail. This applies especially to people interested in regional adjustment issues.

It is with these people in mind that CoPS have incorporated into MMRF a tops-down method that enables disaggregation of state-level results for output, employment and greenhouse-gas emissions down to projections for 56 sub-state regions.

These regions are based on the Statistical divisions defined in the Australian Standard Geographical Classification (ABS catalogue number 1216.0). Our division structure differs slightly from that of the ABS. We combine the ABS's Darwin and Northern Territory - balance divisions into one division, Northern Territory. Similarly, Canberra and ACT - balance are combined into one division, Australian Capital Territory. Note that both territories are distinguished as separate regions in MMRF. Hence, the tops-down disaggregation facility provides no additional detail for them. We also adopt a slightly different regional classification for WA than that defined by the ABS. Our WA regions are based on the classification used by the WA department of Commerce. Finally, we identify the energy intensive Latrobe Valley in Victoria as a separate region (region 24), with 23 Gippsland defined to include all areas in the ABS statistical division Gippsland other than the Latrobe Valley.